2018 Annual Markets Report

Internal Market Monitor

MAY 23, 2019

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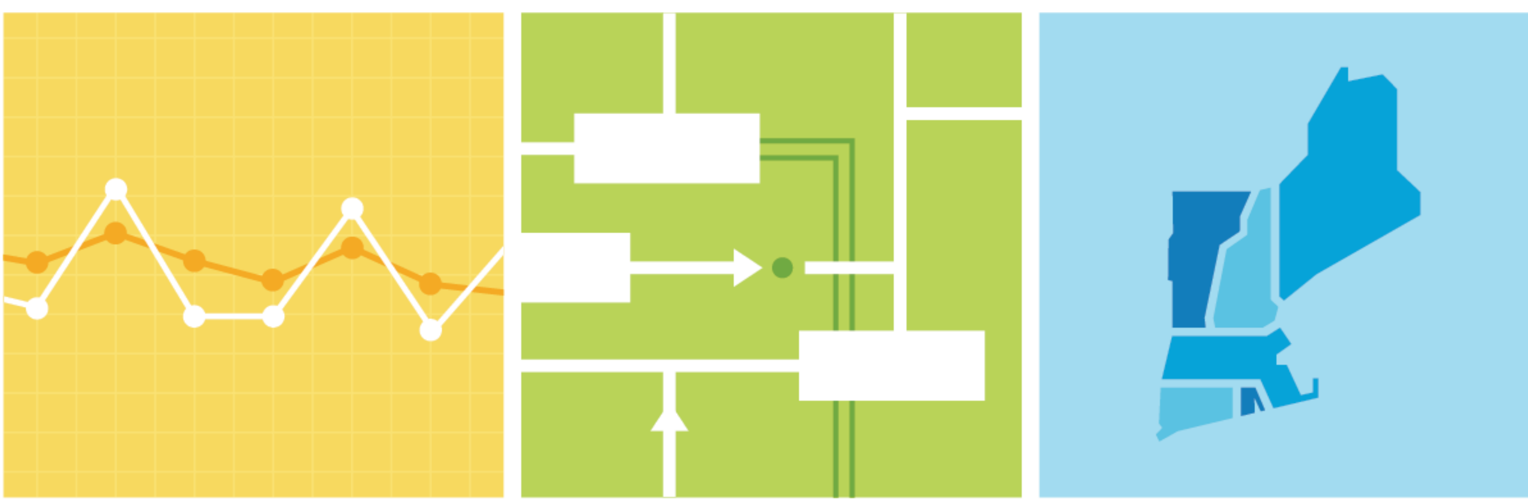

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Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2018 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2018. 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 2018. 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. Section 1 through Section 8 includes 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. Key terms are italicized and defined within the text and footnotes.

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

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

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

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Section 1
Executive Summary

The *2018 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 (i.e. ancillary services), Financial Transmission Rights (FTRs), 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.

Overall, the ISO New England capacity, energy, and ancillary service markets performed well and exhibited competitive outcomes in 2018. The day-ahead and real-time energy markets performed well, with electricity prices reflecting changes in underlying primary fuel prices and electricity demand. There were few periods in the real-time energy market when a relative shortage of energy and reserves resulted in scarcity pricing, and overall price-cost markups in the day-ahead energy market were within a reasonable range for a competitive market. There was an overall improvement in the structural competitiveness of the real-time energy market. There were fewer hours with pivotal suppliers in real-time, as new entrant generators and the participation of active demand response in the energy and reserve markets reduced the market share of existing suppliers. The number of energy market supply offers mitigated for market power remained very low, totaling 1,273 unit-hours, or just 0.02% of all supply offers.

For the fifth consecutive year, the forward capacity auction procured surplus capacity, and clearing prices were the result of a competitive auction.

The total wholesale cost of electricity in 2018, at $12.1 billion, was considerably higher than 2017, increasing by 32%, or by $2.9 billion. Together, energy and capacity costs accounted for 98% of the overall increase.

Energy costs totaled $6 billion, up 34%, or $1.5 billion, on 2017. The increase was driven by higher natural gas prices, particularly during the winter, and higher electricity demand during a hot and humid summer. Natural gas prices averaged $4.95/MMBtu in 2018, up by $1.23/MMBtu (33%) on 2017 prices. Electricity demand in the third quarter of the year increased by 8%, or by 1,186 MW per hour, and drove a 2% year-over-year increase in demand. On a weather-normalized basis, demand was down slightly, continuing a longer-term downward trend due to the increase in utility-backed energy efficiency programs and behind-the-meter photovoltaic generation.

Capacity costs totaled $3.6 billion, up 61%, or $1.4 billion, due to higher clearing prices in the eighth and ninth Forward Capacity Auctions (FCA 8 and 9).[4] Up until FCA 8, capacity prices were relatively low and set administratively at the market floor prices due to surplus capacity conditions. The clearing price in FCA 7 was $3.15/kW-month. Generator retirements in FCA 8 triggered a capacity deficiency and administrative pricing, which set the clearing price for existing resources at

[4] FCA 8 corresponds to the delivery period June 1, 2017 to May 31, 2018, FCA 9 to June 1, 2018 to May 31, 2019

$7.03/kW-month and new resources at $15/kW-month. In FCA 9, the clearing price of $9.55/kW-month incented new entry and brought the region back to surplus capacity.

Capacity costs will begin to decline after June 2019, as new resources enter the market and a higher capacity surplus applies downward pressure to capacity prices. In the past two auctions (FCA 12 and 13), the market has responded to lower clearing prices by removing a significant amount of existing capacity, either permanently or temporarily. In the most recent auction, FCA 13, almost 600 MW of existing capacity retired, while over 1,500 MW of existing capacity exited the market for a one-year period.

Capacity prices have fluctuated in response to changes in the region's capacity margin as one would expect, with prices increasing in response to low or negative margins, and vice versa. However, achieving sound economic price formation in the Forward Capacity Market (FCM) continues to be a challenge. Two factors negatively impacting price formation have been the participation of state-sponsored resources with out-of-market revenues in the auction, and the reliability retention of resources for their energy security attributes. Both of these factors have reduced the auction clearing price (for at least a portion of supply) as a result of out-of-market payments.

The first challenge has been to accommodate new resources that secure revenue through state-sponsored programs designed primarily to meet state environmental goals. These out-of-market revenues economically advantage a subset of resources and can lead to market distortions and price suppression in the capacity market. For FCA 13, the ISO introduced Competitive Auctions with Sponsored Policy Resources (CASPR) to help address this issue. CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. However, while the price-suppressing impact is mitigated in the first year, the sponsored resources will likely be price-takers in subsequent auctions, thereby applying downward pressure to FCA clearing prices in the long-term. This underlying compromise behind the CASPR design is unavoidable as long as (a) the resource is counted toward meeting capacity requirements and (b) the resources continue to receive out-of-market revenues. Also, while CASPR and the associated market power mitigation rules help mitigate price suppression concerns for new resources, they do not address the impact of out-of-market revenues paid to retain existing resources, when they might otherwise retire.

The first CASPR substitution auction was conducted in February 2019 with a limited amount of participation. A 54-MW wind resource cleared in the auction against an existing dual-fuel oil/gas-fired resource, which will now retire. The clearing price in the substitution auction was $0/kW-month, meaning the retiring resource sells its capacity supply obligation to the new resource for $0/kW-month and receives a net amount of $3.80/kW-month – the difference between the primary and substitution auction prices - similar to a severance payment.

The second challenge is the reliability retention of resources in the FCM based on their underlying energy-security attributes; attributes that are not explicitly valued in the current FCM or energy market designs. The ISO retained the Mystic 8 and 9 resources (approx. 1,400 MW in total) in FCA 13 to satisfy a reliability need for energy security. This was done prior to the auction, and the retained capacity from the two resources was represented as price-taking capacity ($0 bid price) in the auction. While this administrative pricing action likely impacted price formation in FCA 13, the price formation issue more directly derives from a missing product (energy security) that is not being appropriately valued in the energy markets or reflected in the capacity market. Whatever impact the retention of the Mystic resources had on price was a byproduct of that market flaw.

Out-of-market actions often have the potential to interfere with price formation. It is not clear to what extent FCA prices would have been different had energy security been explicitly valued and those that could provide it appropriately compensated. A completely different market model (including FCM, energy, and reserves) would need to be developed in order to accurately simulate the resulting valuation, which is the appropriate counter-factual to estimate the impact. While the Mystic resources will receive revenue (through the out-of-market settlement process) for the energy security they provide, other resources that can provide fuel security will not be compensated for that service in the FCA 13 delivery period, nor did they have the opportunity to compete for such compensation.

However, the issue of not valuing energy security is a transient. Going forward, the ISO has proposed an interim measure to compensate for energy security for CCP 14 and 15, and is in the process of developing a long-term market-oriented approach. These measures will seek to explicitly value the energy security service and put all resources that can provide the service on equal footing to compete for the resulting market opportunity.

Overall, the FCM and the energy market exhibited competitive outcomes despite the continued presence of structural market power. Measures are in place in both of these markets to identify and mitigate market power. The identification of seller-side market power in the energy and capacity markets relies on a pivotal supplier test that measures the ability of a supplier to increase price by withholding supply. Buyer-side market power mitigation in the capacity market prevents the use of buyer-side subsidies to allow a participant to enter via the primary auction at prices below competitive levels and to artificially lower the market-clearing price. Both mitigation processes for the energy and capacity markets have functioned reasonably well and have resulted in competitive outcomes. 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 would trigger and mitigate a supply offer. The potential impact of structural market power in the real-time market and the effectiveness of existing mitigation thresholds will be further evaluated.

An important function of the IMM is to assess and make recommendations on potential enhancements to current market design and rules. Table 1-2 at the end of this section contains a list of our recommended changes and areas to be further evaluated by the ISO that could improve market performance. In 2018, we have added an additional recommendation to address the concern that participants are taking on additional FCM obligations during winter months, with little to no expectation that the capacity can be offered in the energy market.

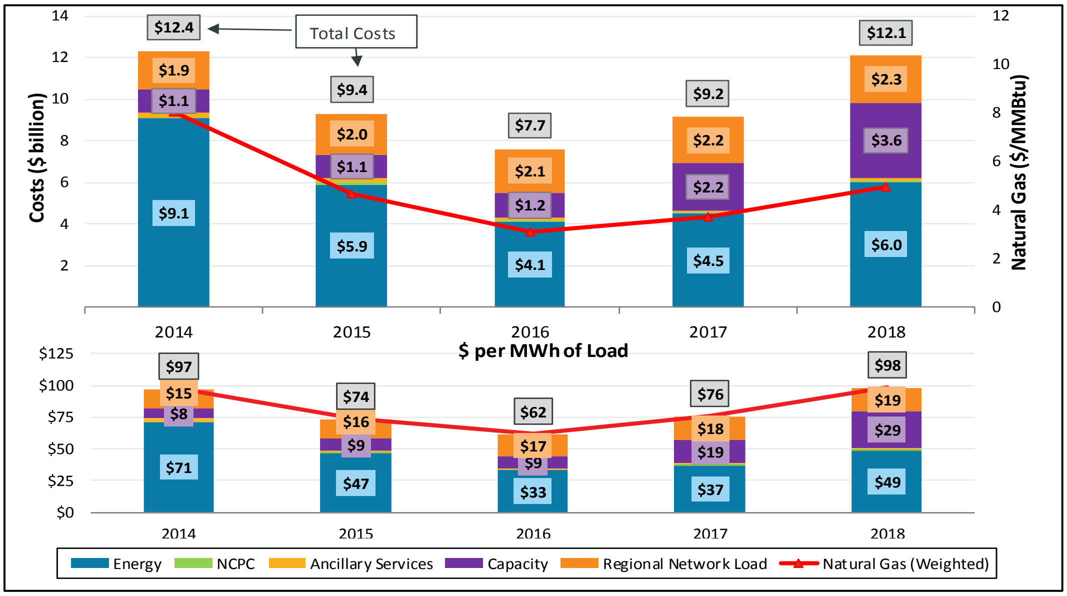
1.1 Wholesale Cost of Electricity

In 2018, the total estimated wholesale market cost of electricity was $12.1 billion, an increase of $2.9 billion (32%) compared to 2017 costs.[5] Together, energy and capacity costs accounted for 98% of the overall increase. The total cost equates to $98/MWh of wholesale electricity demand, the

[5] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead Locational Marginal Price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP.

highest over the past five years. 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 1-1 below.[6]

Figure 1-1: 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, along with the percentage contribution of each category to the overall wholesale cost in 2018 is shown in parenthesis.

Energy ($6.0 billion, $49/MWh, 50%): Energy costs are a function of energy prices (the LMP) and wholesale electricity demand:

- Day-ahead and real-time LMPs averaged $44.13 and $43.54/MWh, respectively (simple average). Compared with 2017, prices were up by between 28-32%, or by $9.60 to $10.78/MWh, in the real-time and day-ahead market, respectively.
- Supply and demand-side participants continued to exhibit a strong preference towards the day-ahead market, with approximately 97% of the cost of energy settled on day-ahead prices.
- Total energy costs track closely with average natural gas prices. Natural gas prices continued to be the primary driver of LMPs. Prices averaged $4.95/MMBtu, representing an increase of 33%, or $1.23/MMBtu, compared with 2017. Energy costs were at their lowest point in 2016 over the five-year period. This was due to a warmer-than-usual winter, with lower gas demand and exceptionally low gas prices.
- Demand (or real-time load) saw its first year-over-year increase since 2013, up by 1.7% (or 239 MW per hour) on 2017. Wholesale load has declined in recent years due, in part, to energy efficiency gains and increased behind-the-meter solar generation, but a particularly hot and humid summer resulted in an 8% increase (1,186 MW per hour) in Q3 demand and drove the

[6] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland 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.

annual increase. On a weather-normalized basis, however, load growth remained relatively flat (declined by only 0.1%).

Regional Network Load Costs ($2.3 billion, $19/MWh, 19%): Regional Network Load (RNL) costs cover the use of transmission facilities, reliability, and certain administrative services. Transmission costs in 2018 were slightly higher (2%) than 2017 costs, primarily driven by a relatively modest increase of $52 million in infrastructure costs, due to continued investment in regional transmission infrastructure.

Capacity ($3.6 billion, $29/MWh, 30%): Capacity costs increased by 61%, or by $1.4 billion, because of higher clearing prices in both the eighth and ninth Forward Capacity Auctions (FCAs 8 and 9) as the system experienced negative or low capacity margins compared to the installed requirements. Compared to the clearing price of $3.15/kW-month in FCA 7 (for delivery in 2016/2017), the payment rate for resources increased to $7.03 and $9.55/kW-month in most capacity zones in FCAs 8 and 9, respectively. Capacity costs are estimated to remain at their current peak in 2019, before declining in future years in line with lower clearing prices and the return of the system to a higher surplus of capacity.

NCPC ($0.1 billion, $0.6/MWh, 1%): Uplift, the portion of production costs in the energy market not recovered through the LMP, totaled $70 million, an increase of $18 million (up by 35%) on 2017. NCPC remained relatively low when expressed as a percentage of total energy payments, at just 1.2%, continuing a downward trend in the share of NCPC from prior years as a result of market design improvements and fewer reliability commitments.

The dollar increase was driven by two factors: an increase in fuel costs, and the manual posturing of oil-fired generators for fuel security during the "cold snap" in early January. January NCPC payments accounted for about 30%, or $20.3 million, of total annual payments, with 80% of those payments made during a four-day period of very cold weather and high natural gas prices (January 4 through 7, 2018).

Ancillary Services ($0.1 billion, $1.0/MWh, 1%): These are costs of additional services procured to ensure system reliability, including operating reserve (real-time and forward markets), regulation, and the winter reliability program. In 2018, the costs of most ancillary service products were similar to 2017 costs. Winter reliability program payments were lower in 2018 because the ISO ended the program in March 2018, and therefore there were no payments in December unlike prior years.

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 fuel mix.

Table 1-1: High-level Market Statistics

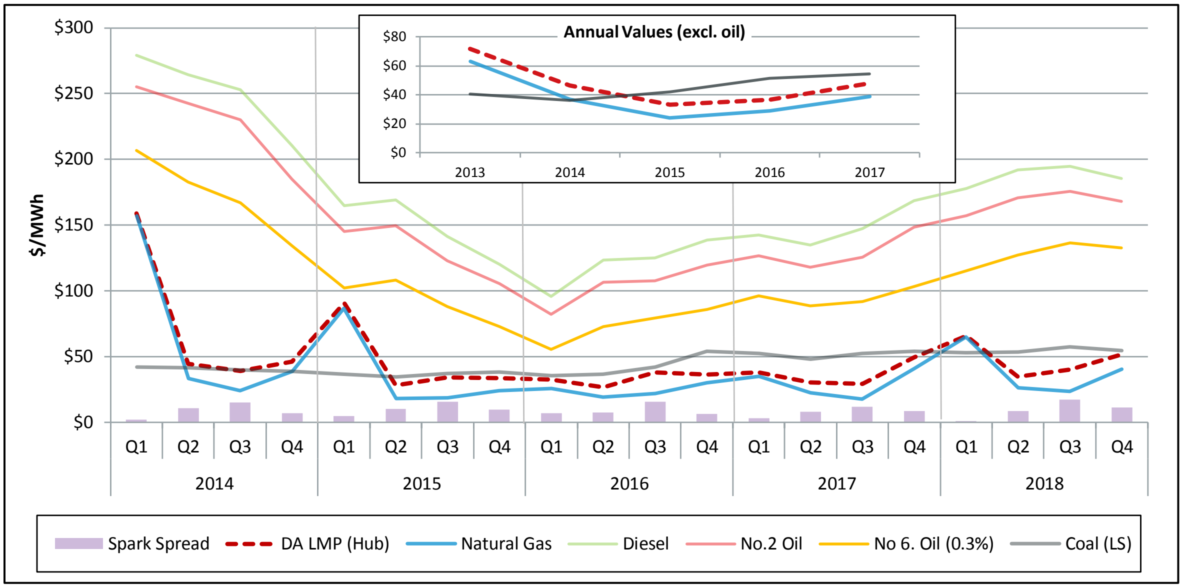
Statistic	2014	2015	2016	2017	2018	% Change 2018 to 2017
Demand (MW)						
Real-time Load (average hourly)	14,518	14,493	14,165	13,837	14,076	2%
Weather-normalized real-time load (average hourly)[a]	14,511	14,358	14,111	13,737	13,725	0%
Peak real-time load (MW)	24,443	24,437	25,596	23,968	26,024	9%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	62.87	36.62	24.29	29.02	38.61	33%
Coal	40.45	36.34	41.97	51.57	54.54	6%
No.6 Oil	172.38	92.63	73.34	94.76	127.80	35%
Diesel	251.49	148.68	120.78	148.36	187.60	26%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	64.56	41.90	29.78	33.35	44.13	32%
Real-time (simple average)	63.32	41.00	28.94	33.94	43.54	28%
Day-ahead (load-weighted average)	69.26	45.03	31.74	35.23	46.88	33%
Real-time (load-weighted average)	68.58	44.64	31.56	36.15	46.85	30%
Estimated Wholesale Costs ($ billions)						
Energy	9.1	5.9	4.1	4.5	6.0	34%
Capacity	1.1	1.1	1.2	2.2	3.6	61%
Net Commitment Period Compensation	0.0	0.1	0.1	0.1	0.1	36%
Ancillary Services	0.2	0.1	0.1	0.1	0.1	4%
Regional Network Load Costs	1.9	2.0	2.1	2.2	2.3	2%
Total Wholesale Costs	**12.3**	**9.3**	**7.6**	**9.1**	**12.1**	**33%**
Fuel Mix (% of native New England Generation)						
Natural Gas	44%	49%	49%	48%	49%	1%
Nuclear	34%	30%	31%	31%	30%	0%
Hydro	8%	7%	7%	8%	8%	0%
Other[c]	7%	7%	7%	7%	7%	0%
Wind	2%	2%	2%	3%	3%	0%
Coal	5%	4%	2%	2%	1%	-1%
Oil	1%	2%	0%	1%	1%	0%

[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] The "Other" fuel category includes landfill gas, methane, refuse, solar, 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 2018, with gas prices being the key driver of the increase in electricity prices. Native supply continues to be highly dependent on natural gas, accounting for almost half of the fuel mix. The fuel mix did not change substantially year-over-year. A significant amount of new entrant gas generation (totaling 1,400 MW) went commercial in June 2018 and largely displaced the output of existing, and more expensive, gas generation.

Energy Market Supply Costs: The trend in quarterly estimated generation costs for each major fuel, along with the day-ahead on-peak[7] LMP over the past five years, is shown in Figure 1-2 below.[8] The inset graph shows annual values and excludes oil prices to better illustrate the long-term trend.

Figure 1-2: Quarterly and Annual (Inset) Generation Costs and Day-Ahead LMP (On-Peak Periods)



The cost of all major fuels increased in 2018, continuing the upward trend from Q1 2016. The strong positive correlation between natural gas prices (blue line) and the LMP (dashed red line) is evident.

The average cost of a natural gas-fired generator was about $39/MWh in 2018, compared to $29/MWh in 2017. On-peak LMPs also increased by 33%. The average natural gas cost ranged from $23/MWh in Q3 to $65/MWh in Q1 2018, the highest Q1 price since 2015. The price increase in 2018 was driven by cold weather and high prices in January 2018, and to a lesser extent, higher prices due to a warmer summer. January 2018 alone accounted for most of the 33% year-over-year increase.[9]

Spark spreads (the difference between the LMP and the estimated energy production cost of a gas-fired generator) were highest again during Q3 2018, when more expensive, or less efficient, generators were dispatched to meet higher system demand. In contrast, Q1 spreads were less than $1/MWh, as high gas prices pushed gas-fired generators out-of-merit in the first week of the year. Spreads were up overall in 2018, at $10.70/MWh for the average gas-fired generator, driven by higher electricity demand in Q3.

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

[8] 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.

[9] When January is excluded, the average 2018 and 2017 natural gas prices are $3.94 and $3.58/MMBtu, respectively, a 10% year-over-year increase. The remaining 23% increase was driven by January prices.

The difference between average generation costs for natural gas-fired generators and competing fuels (coal and oil) remained large in 2018. Coal prices in 2018 increased by 6% over the previous year, despite decreased demand for coal across the country. The price increase was driven by higher global demand for coal generation.[10] Oil prices rose in 2018 for New England generators, with No. 6 oil prices rising 35% and diesel prices rising 26%. The price increase was largely driven by crude oil production cuts from OPEC and its allied producers that carried throughout most of the year.[11] On average, coal and No.6 oil were higher than natural gas by $16 and $89/MWh, respectively.

Emissions costs are not included in the generation cost estimates in Figure 1-2 above, but are having an increasing impact. The key driver of emission costs for New England generators is the Regional Greenhouse Gas Initiative (RGGI), the marketplace for carbon dioxide (CO_2) credits. In addition, a new CO_2 cap-and-trade program that places an annual cap on aggregate CO_2 production from fossil fuel generators began in Massachusetts in 2018.[12] 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.

In 2018, RGGI prices increased 25% year-over-year, (from $3.59/short ton to $4.50/short ton), with the final auction of the year closing at $5.35/short ton.[13] The increase appears to be a market response to a 30% reduction on the CO_2 cap by 2030, relative to 2020 levels (from 78.2 million short tons to 54.7 million short tons).[14,15] The average 2018 RGGI CO_2 cost for a natural-gas fired generator was $2.05/MWh. Massachusetts CO_2 prices were estimated to range from $6.71 to $19.52/short ton in 2018, adding between $3.06 and $8.19/MWh to the average variable generation cost of a natural-gas fired generation located in that state.[16]

Generator 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, or CONE.

A simulation analysis was conducted to assess whether historical energy and capacity prices were sufficient to cover CONE. The results are presented in Figure 1-3 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 CONE for combined cycle (CC) and combustion turbine (CT) resources. If the height of a stacked bar chart rises above the relevant CONE estimate, overall market revenues are sufficient to recover total costs.

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[10] https://www.eia.gov/todayinenergy/detail.php?id=38132&src=email

[11] https://www.eia.gov/todayinenergy/detail.php?id=37852

[12] 310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

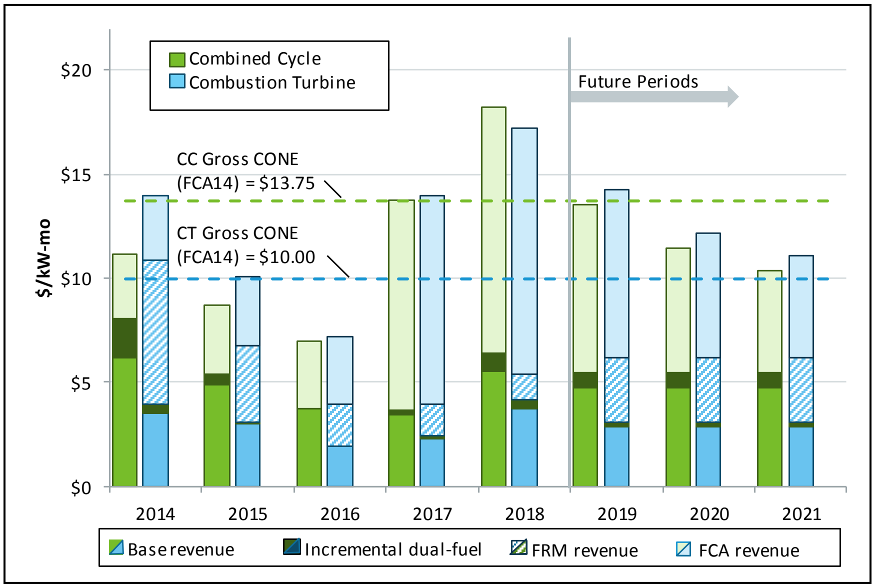
[13] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/42/PR120718_Auction42.pdf

[14] 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/PressReleases/2017_08_23_Announcement_Proposed_Program_Changes.pdf

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

[16] The conversion of CO_2 costs in $/ton to $/MWh assumes an average heat rate of 7.8 MMBtu/MWh and a natural gas emissions rate of 117 lbs/MWh.

Figure 1-3: Estimated Revenue and Profitability for New Gas-fired Generators



Notes: Base revenue is the net revenue from E&AS markets. Additional revenue to CTs in the forward reserve market and to CC and CT with dual-fuel capability is also modelled.

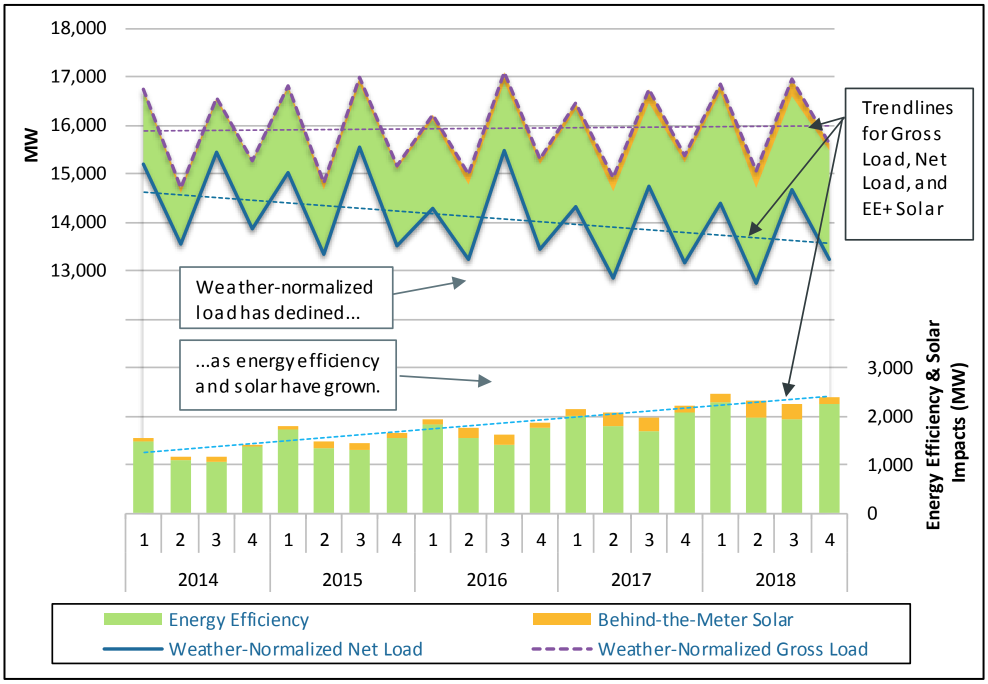
Energy net revenues refers the margins earned from the energy and ancillary services markets, after deducting variable costs. . The simulation results show energy net revenues increasing by approximately 70% from 2017 to 2018. This rise is driven by increased loads resulting in greater spreads between fuel and energy prices throughout 2018, especially during nuclear plant outages in the fall. In addition, generators with dual-fuel capability are able to take advantage of the extremely cold weather at the start of the year by burning oil when natural gas was priced higher.

The results indicate that prior to 2017 capacity prices were generally too low to incent investment in new gas-fired generators because the system was long on capacity. For 2017 onward, the situation changed with generator retirements moving the system into a state where it is not long on installed capacity and total estimated revenue is sufficient to support the new entry of gas-fired generators. In practice, FCM auction results show entry from one or both types of gas-fired generators for two of the three capacity commitment periods that encompass these future years.[17]

Energy Market Demand: The demand for electricity is weather-sensitive and this contributes to the seasonal variation in energy prices. New England's native electricity demand, referred to as net energy for load (NEL) averaged 14,076 MW per hour in 2018, up 2% on 2017. Energy efficiency, and to a lesser but growing extent, behind–the-meter photovoltaic (PV) generation have a significant downward impact on NEL as shown in Figure 1-4 below.

[17] It should be noted 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, or higher, than the current CONE benchmarks for a number of reasons. In particular, when new generators 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. Conversely, the cost of permitting and litigation in New England can add significantly to project costs, including time delays, of new projects.

Figure 1-4: Weather-Normalized Quarterly Load with Energy Efficiency and Solar Impacts



From the figure above, we can see that energy efficiency has the largest impact on NEL; the average hourly reduction has grown from 1,250 MW in 2014 to 2,115 MW in 2018. Behind-the-meter PV had a smaller impact, decreasing average load by about 240 MW in 2018, but has increased nearly four-fold from about 65 MW in 2014.

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 a total ten-minute reserve requirement of 1,708 MW and total thirty-minute reserve requirement of about 2,496 MW in 2018.

In 2018, the average thirty-minute operating reserve margin was about 600 MW higher than the average reserve margin in 2017. This was due to increased availability of offline reserves, driven by increased pumped-storage generator availability and the implementation of price-responsive demand. The 10-minute spinning reserve margin decreased slightly.

Imports and Exports: New England has transmission connections with 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. Net imports have been consistent over the past four years, meeting between 16% to 17% of native demand. In 2018, net imports averaged 2,460 MW per hour, an increase of about 130 MW on 2017.

Almost 85% of net imports were from the Canadian provinces, with the remaining imports coming from the New York North interface. Real-time net interchange with Canada averaged 2,056 MW per hour in 2018, a decrease of 4% (89 MW) on 2017. The average hourly real-time net interchange with New York increased by 123% in 2018 relative to 2017 (from 181 MW to 403 MW per hour), driven by higher imports at the New York North interface.

Most external transactions continue to be insensitive to price. That is, participants submitting import and export bids tend to submit fixed-priced bids or bid at extreme prices such that the bid will always flow. Over 80% of day-ahead transactions across the Canadian interfaces were fixed-priced in 2018.

Real-time external transactions across the New York North interface are subject to the Coordinated Transaction Scheduling (CTS) rules. Overall, the bids submitted at New York North in 2018 allowed power to flow in the correct economic direction (from low- to high-priced region) 59% of the time – declining from 68% in 2017. The increase in negative import spread bids into New England contributed to this reduction. Negative import bids will be scheduled even when the power is being imported from the higher-cost region to a lower-cost region. This change in import behavior, on average, provided the CTS process with an aggregate transaction curve that allowed the direction of flows to be less consistent with price differences than in the prior year.[18]

Economic scheduling is based on forecast price differences between the New England and New York markets, and therefore poor forecasting by the ISOs can reduce the efficiency of CTS. In 2018, the average difference between the forecast NE-NY spread and the actual NE-NY spread was $0.74/MWh, down from $2.42/MWh in 2017. However, the absolute average forecast error improved by only $0.39/MWh. The ISOs' (ISO-NE and the New York ISO) forecast errors continue to be higher in some hours of the day than in other hours, and the hours with the higher errors are not always the same for each ISO. There continues to be a consistent bias[19] in the ISOs' internal price forecasts, which may reduce the effectiveness of CTS. We have recommended that the ISO assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved.

Capacity Market Supply and Demand: As with energy prices, there is also a strong link between capacity prices and natural gas-fired generators, with gas generators comprising 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 contributed to more investment in new natural gas-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. Generation resources make up 88% of total capacity (about 30,400 MW), with the remainder comprising import (4% or about 1,400 MW) and demand response (8% or about 2,800 MW).[20] 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 generation resources by fuel type is shown in Figure 1-5 below.

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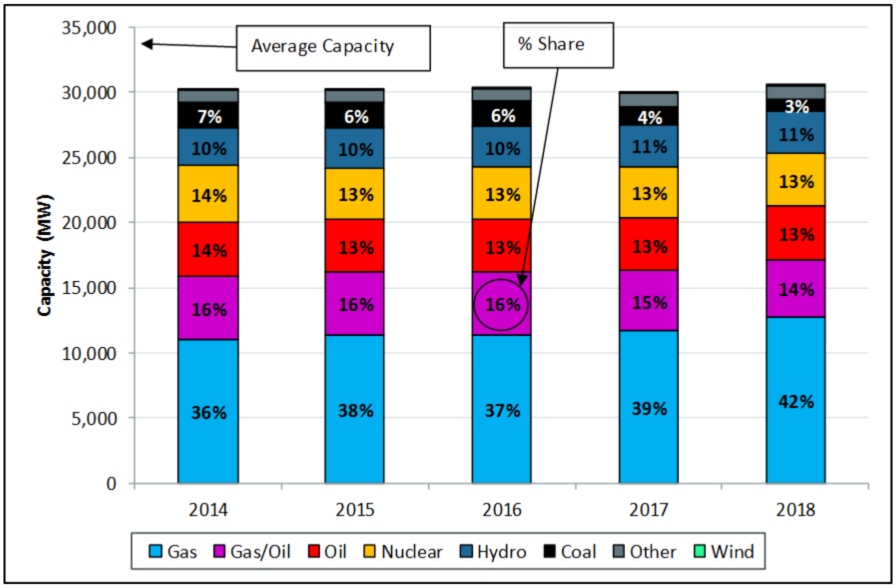
[18] In 2018, participants were willing to import power to New England when New York prices were higher by $8/MWh, compared to $2/MWh in 2017; in other words, they were willing to begin moving power at a loss of $8/MWh. This behavior may be explained by contractual arrangements some participants have in place underlying these flows, including participants wishing to adhere to their day-ahead cleared imports.

[19] The term "bias" here relates to attributes of the modelling and mechanics of CTS that result in measureable differences between forecast and actual outcomes. It is not intended to refer to human-driven bias.

[20] Values relate to the eighth capacity commitment period (CCP 8).

Figure 1-5: 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 landfill gas, methane, refuse, solar, steam, and wood.

Natural gas continues to be the dominant fuel source of capacity in New England. The percentage of capacity from gas-fired and gas/oil-fired dual-fuel generators has increased slowly over the past few years with the retirement of generators of other fuel types. Combined, gas-fired and gas/oil-fired dual-fuel generators accounted for 56% of total average generation capacity, up from 54% in 2017. The increase is due to the commissioning of CPV Towantic in Connecticut (725 MW dual-fuel) and Footprint in NEMA (674 MW single fuel) in June 2018.[21]

Capacity from coal-fired generators decreased in 2018 due to the retirement of Brayton Point in June 2017. Coal-fired capacity accounted for 920 MW in 2018, down from 1,350 in 2017, and 2,000 MW from 2014 to 2016. Nuclear generation remained unchanged from 2017, accounting for 4,000 MW (13%) of the capacity fuel mix. The retirement of the Pilgrim nuclear facility (about 680 MW) in June 2019 will reduce the capacity and energy share of nuclear generation. By 2020, the capacity of nuclear generation is expected to be 3,350 MW, which is less than 10% of the installed capacity requirement that year.

Demand: The system Net Installed Capacity Requirement (NICR) has been relatively flat over the past three FCAs, ranging from 34,075 MW in FCA 11 (for the delivery period 2020/21) to 33,750 MW in the most recent auction, FCA 13.[22] The flat demand for capacity is driven by slow demand growth coupled with increased energy efficiency and behind-the-meter PV.

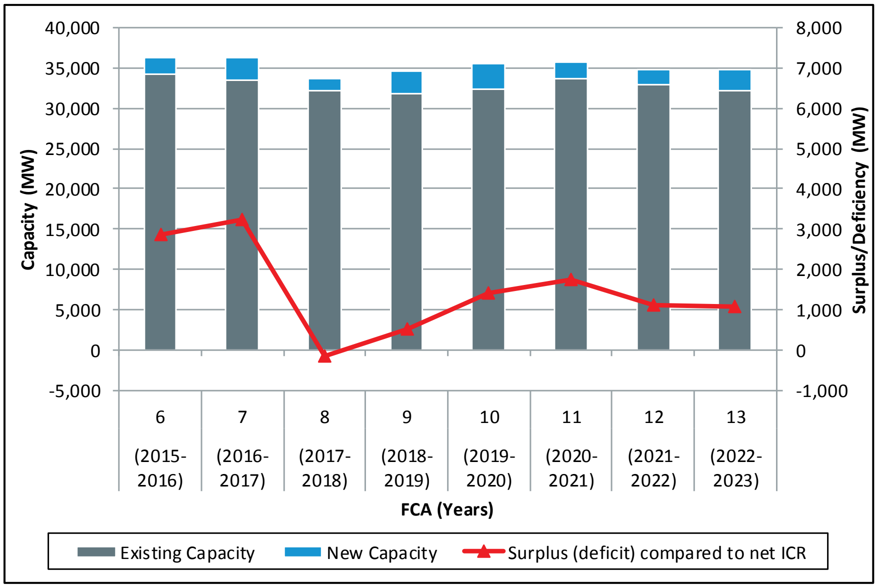
Supply/Demand Balance: The supply and demand balance in the FCM has gone through a number of shifts in recent years. The volume of capacity procured in each auction relative to the NICR is shown

[21] Given the mid-year commissioning of these new generators, their full capacity does not count towards the 2019 statistics.

[22] 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.

in Figure 1-6 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 1-6: Cleared and Surplus Capacity in FCAs 6 through FCA 13



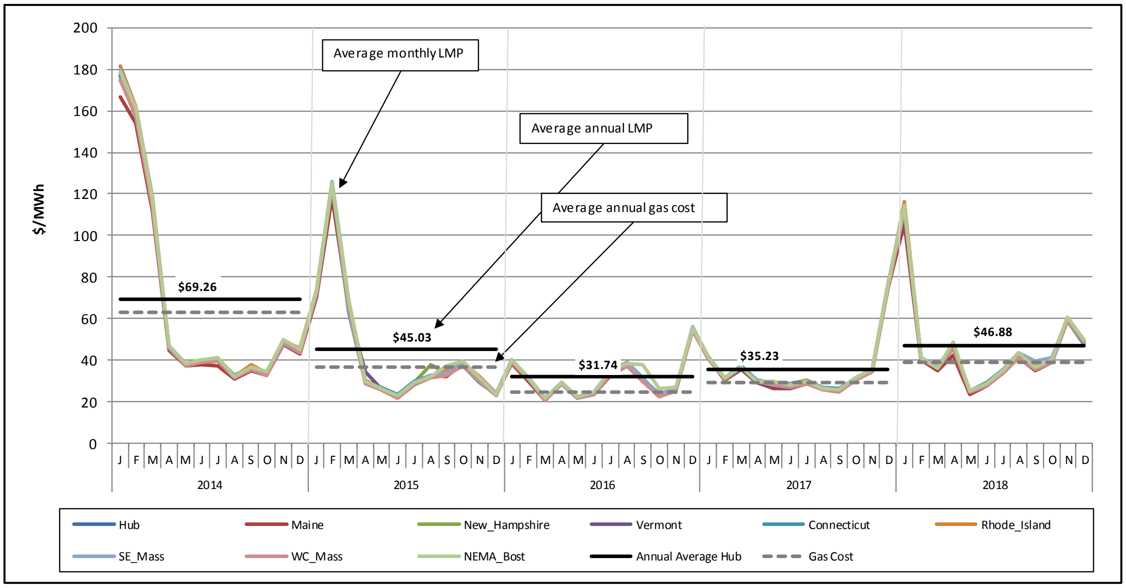
Following resource retirements of 2,700 MW in FCA 8 (and an increase in NICR), the surplus capacity in FCA 7 of over 3,000 MW was quickly eroded. However, higher clearing prices brought new capacity to the market in the three subsequent auctions; in the subsequent three auctions (FCA 9, 10, 11) new generation 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 into a 1,800 MW surplus in the span of three auctions. With lower capacity clearing prices, the surplus declined in FCA 12 and 13, primarily due to one-year de-lists of existing resources.

1.3 Day-Ahead and Real-Time Energy Markets

Prices: Price differences among the load zones were relatively small in 2018, reflecting modest levels of both marginal losses and congestion. The average absolute difference between the Hub annual average price and average load zone prices was $0.43/MWh in the day-ahead energy market and $0.59/MWh in the real-time energy market – a difference of approximately 1.0-1.3%.

The monthly load-weighted prices across load zones over the past five years are shown in Figure 1-7 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 1-7: 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. For winter months in 2014, 2015 and 2017-18 constraints on the natural gas system resulted in large price spikes in natural gas and electricity prices in the months of January and February (2014 and 2015) and December and January (2017-18). Extreme pricing did not occur in Q1 during 2016 and 2017. The highest prices in 2018 were in January, with (load-weighted) prices of $114/MWh in both the day-ahead and real-time energy markets. This was driven by extremely cold weather and high natural gas prices of up to $69/MMBtu early in month.[23]

Price-setting transactions: A significant proportion of the aggregate supply and demand curves in the energy markets are not price-sensitive. On the supply side, this is due to importers offering fixed bids, generators self-scheduling, or generators operating at their economic minimum levels. 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, participants with load submit a large amount of fixed bids. Overall, only 26% to 35% of aggregate supply and demand can set price in the day-ahead energy market. However, this amount effectively falls to about 5% on the demand side when very high-priced bids (whereby the bids always clear) are taken into account.

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. The cleared volume of virtual transactions has increased steadily over the last five years, rising from 433 MW per hour in 2014 to close to 1,000 MW per hour in 2018. However, this is still about a half of the cleared volume in 2008 and 2009. Virtual transactions (virtual demand bids and virtual supply offers) set price for about 23% of day-ahead load in 2018. This is about 10% below 2017, when virtual transactions set price for about a third of load, but very similar to 2014–2016. The decrease relative to 2017 was driven by fewer virtual supply offers at several nodes in areas of Vermont and Maine with sizable wind generation.

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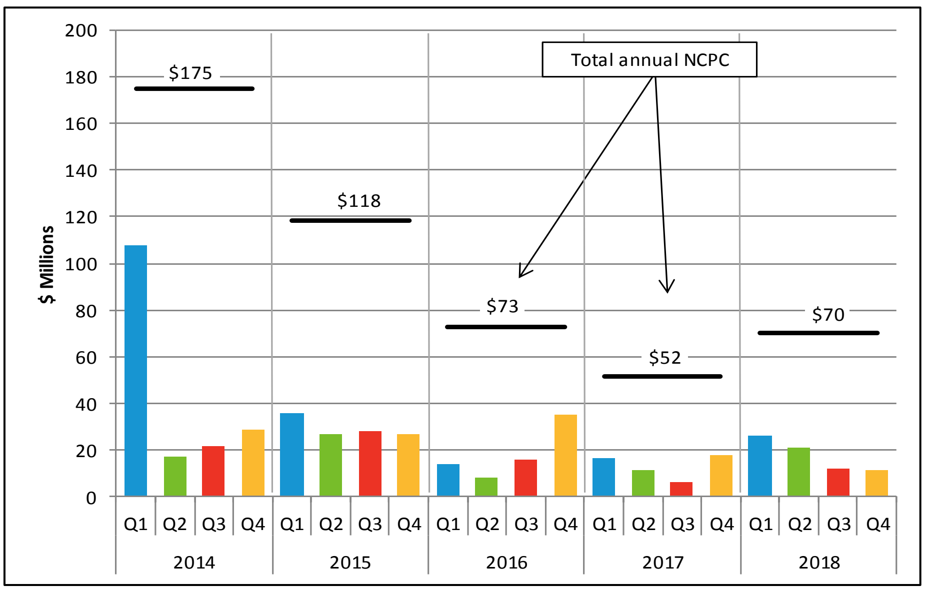
[23] Gas price is a volume-weighted average for the trading day across four gas indexes.

As virtual supply's share decreased, the share of load for which natural gas was the marginal fuel rose. Natural gas was marginal for about half of day-ahead load in 2018, an increase from 42% in 2017.

In the real-time energy market, there are no virtual transactions and the majority of price-sensitive offers are from natural gas-fired (or dual-fuel) generators. Consequently, the price-setting intervals for natural gas-fired generators are significantly higher in real-time at 70%. Pumped-storage units (both generator and pumps) are the second largest marginal transactions types, being marginal for about 20% of load in 2018. Because they are online relatively often and priced close to the margin, they can set price frequently. Although wind generators are frequently marginal, they are usually marginal for only a small share of total system load (~1% in 2018). 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 2018, NCPC payments totaled $70 million, an increase of $18 million (up by 35%) compared to 2017. Like last year, NCPC remained relatively low when expressed as a percentage of total energy payments, at just 1.2%, continuing a downward trend in the share of NCPC from prior years, driven by a number of market rule changes.[24] Quarterly (colored bars) and annual total NCPC payments (black lines) are shown in Figure 1-8 below.

Figure 1-8: Total NCPC Payments by Quarter and Year



The dollar increase in 2018 NCPC payments was driven by two factors: an increase in fuel costs, and the manual posturing of oil-fired generators for fuel security during the "cold snap" in early January.

Price-Responsive Demand: The ISO integrated Price-Responsive Demand (PRD) into the day-ahead and real-time energy market on June 1, 2018. PRD resources now participate in the clearing of the energy markets, based on supply offers to reduce consumption. With this change, demand

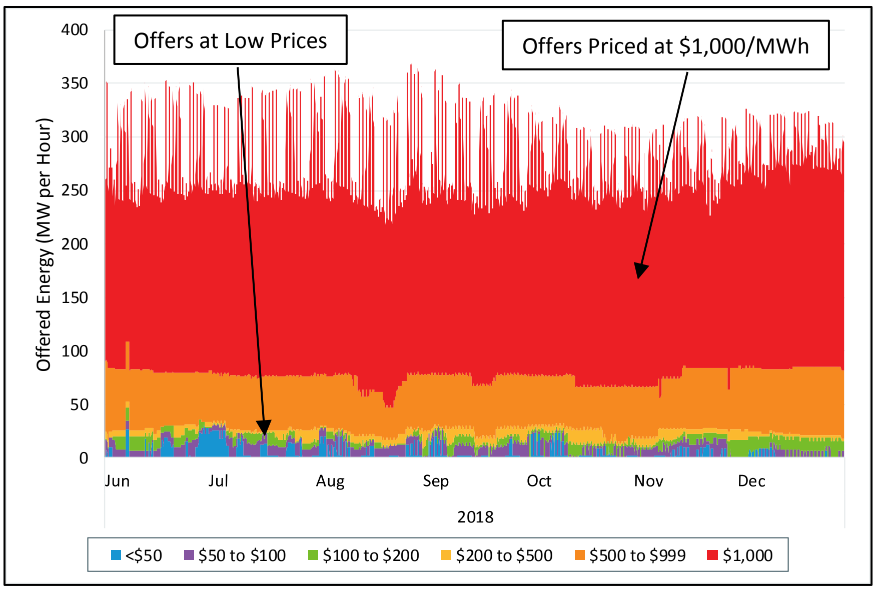
[24] The elimination of eligibility of day-ahead commitments for real-time NCPC (in February 2016) and the introduction of fast-start pricing (in March 2017) both applied downward pressure on NCPC costs. _

resources are committed and dispatched in the energy market based on economics and are eligible to set price. In the capacity market, PRD resources with Capacity Supply Obligations (CSOs) now have a "must-offer" obligation that requires these resources to offer all physically available capacity (up to the CSO) into the energy markets. Prior to this change, the majority of active demand response resources participated in the ISO's energy markets as emergency response resources, only being dispatched during capacity deficiency (Operating Procedure 4) periods.

Consistent with pre-PRD behavior, most demand resources continue to predominately function as capacity deficiency resources, providing a source of high-priced energy and 30-minute operating reserves in the real-time energy market. Seventy-two percent of offered capacity, on average, is priced at the energy market offer cap of $1,000/MWh. Lower-priced tiers of offered capacity ($200/MWh or less) did not exceed 20% of offered demand reduction capacity in any hour of 2018, and averaged just 7%. As a consequence of this offer behavior, PRD resources are not dispatched in the energy markets except at low levels, outside of system scarcity events.

Offers from PRD resources are shown in Figure 1-9 below. The figure illustrates the pattern of hourly supply offers from these resources by offer price category for June through December 2018.

Figure 1-9: Demand Response Resource Offers in the Day-Ahead Energy Market



Virtual Transactions: The volume of cleared virtual transactions has increased in each of the last four years, rising from 433 MW per hour in 2014 to close to 1,000 MW per hour in 2018. The growth in cleared virtual transactions has been particularly pronounced for virtual supply, which has increased by 163% (from 236 MW to 621 MW) in this five-year period. The higher percentages of virtual transactions clearing may be the result of three notable market rule changes: (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 volume increase is expected as the market rule changes resulted in lower NCPC transaction costs, or created differences in day-ahead and real-time operating conditions which, in turn, created opportunities for virtual transactions to converge day-ahead and real-time prices.

While less pronounced than in previous years, NCPC charges continue to limit the extent to which virtual transactions can help with day-ahead and real-time price convergence. The average per-MW real-time NCPC charge was approximately $0.95 in 2018 versus $2.80 in 2015. This means that it is still unprofitable for virtual supply and demand to converge price in certain hours.

We have previously recommended that 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 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.

Congestion Costs and Financial Transmission Rights: Congestion revenue totaled $65 million in 2018. This represents a 56% increase from $41 million dollars in 2017 and is the highest amount in the last five years. The congestion revenue in 2018 still represents only 1% total energy costs, similar to the prior two years. The majority (58%) of the congestion revenue in 2018 occurred in three months: January, April, and November and was partly driven by constraints at the New York – New England interface limiting relatively lower-cost imports.

Participants purchased fewer FTRs in 2018 than in 2017, continuing a trend of steady decreases in FTR auction volumes that has occurred for the last four years. FTRs were fully funded in 2018 meaning there was sufficient congestion revenue collected in the energy market and from negative target allocations to pay positive target allocations, the full amount of revenue they were owed.

In fact, FTR profitability was at its highest amount over the past five years. The increase in FTR profitability indicates that increased congestion materialized in the day-ahead market relative to the expectations of congestion reflected in the FTR auctions. The total profit from FTRs was $27 million, which is an increase of $13 million from 2017, when total FTR profit was $14 million. Many of the most profitable FTR paths in 2018 sourced from locations that tend to be export-constrained, making them more prone to negative congestion pricing. The most profitable FTR path in 2018 – by a significant margin – was a path that sourced from the New York North interface, and sank at the Hub, a location designed to have little congestion. Participants were able to acquire FTRs along this path for $4 million and they yielded positive target allocations of $12 million, earning a profit of $8 million. As mentioned above, congestion and the profitability of this path was particularly concentrated over three months of the year when the interface was constrained with imports into New England, due to a combination of relatively low-priced offers and reduced transfer capability in some months.

Market Competitiveness: A number of metrics were applied to the energy market to assess general structure and competitiveness. A broad range of industry-standard economic metrics are presented in this report, such as market concentration and the C4, the Residual Supply Index and Pivotal Supplier Test, and the Lerner Index. Each metric assesses market concentration or competitiveness with varying degrees of usefulness, but combined, can complement each other. Market power mitigation rules are also in place in the energy market (as well as the capacity market) that allow the IMM to closely review underlying costs of offers and to protect the market from the potential exercise of market power.

The following metrics were calculated for the real-time energy market:[25]

[25] In each metric we account for our best estimate of affiliate relationships among market participants.

- *Residual Supply Index (RSI) and Pivotal Supplier Test (PST)*[26]
  Results from the RSI and pivotal supplier analysis for 2018 indicate that there have been supply portfolios with market power in about 31% of hours. This represents an improvement in structural competitiveness compared to prior years, down from 58% of hours in 2017.

  The reduction in the number of intervals with pivotal suppliers appears to be driven by two factors: 1) the increase in the 2018 reserve margin, and 2) changes in the available supply of individual companies due to new entrant generators and changes to the economic merit order. The reduction in available supply from a large supplier was offset by an increase in the supply share of a participant with two new-entrant generators, as well as increases across other suppliers. This essentially had the impact of splitting the portfolio of a large participant into multiple parts, thereby reducing overall market concentration.

- *C4 for supply-side participants*
  The C4 value expresses the percentage of real-time supply controlled by the four largest companies. In 2018, the C4 value was 44%, a slight decrease compared to 48% in 2017. The suppliers that make up the top four have changed over the past year due to mergers and the output levels of existing generators. The metric indicates low levels of system-wide market concentration, particularly given that the market shares are not highly concentrated in any one company.

- *C4 for demand-side participants*
  The demand share of the four largest firms in 2018 was 53%, similar to 2017. 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 exercise buyer-side market power.

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, whereby 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. Further analysis is required to assess the appropriateness of the mitigation thresholds.

The competiveness of pricing outcomes in the day-ahead energy market was assessed using the Lerner Index:

- *Lerner Index*
  The Lerner Index is a measure of market power that estimates the component of the price that is a consequence of offers above marginal cost.[27] In a perfectly competitive market, all

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[26] 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.

[27] The Lerner Index 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.

participants' offers would equal their marginal costs. Since this is unlikely to always be the case, the Lerner Index is used to estimate the divergence of the observed market outcomes from this ideal scenario.

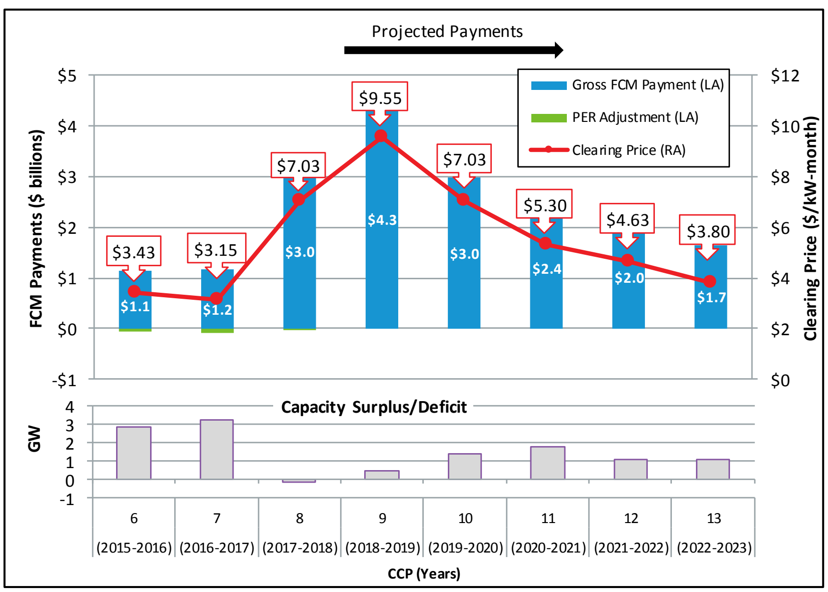
The Lerner Index remained small in 2018, indicating that competition among suppliers limited their ability to increase price by submitting offers above estimates of their marginal cost. For 2018, the Lerner Index for the day-ahead energy market was 5%, meaning that offers above marginal cost increased the simulated day-ahead energy market price by 5%. These results are consistent with previous years and within an acceptable range given modeling and estimation error.

1.4 Forward Capacity Market (FCM)

Overall, the FCM has achieved its design objectives of attracting new efficient resources, maintaining existing resources and encouraging the retirement of less efficient resources. 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 surplus capacity have changed.

FCM Prices and Payments: Rest-of-Pool clearing prices, payments and the capacity surplus from the sixth capacity commitment period (CCP 6) through CCP 13 are shown in Figure 1-10 below.[28] The 2018 capacity market costs presented earlier in this section includes half of CCP 8 and half of CCP 9.

Figure 1-10: FCM Payments and Capacity Surplus by Commitment Period



The first eight FCAs used a vertical demand curve that had a fixed capacity requirement. A vertical demand curve, by definition, lacks price-sensitivity and can result in large changes in capacity prices from year to year. Starting with *FCA 9* a sloped demand curve replaced the vertical demand curve. The system sloped demand curve improved price formation; specifically, it reduced price

[28] Payments for future periods, CCP 9 through CCP 13, have been estimated as: $FCA\ Clearing\ Price\ \times Cleared\ MW\ \times 12$ for each resource.

volatility and delivered efficient price signals to maintain the region's long-run reliability criteria. Figure 1-10 shows the inverse relationship between the surplus of capacity above the Net Installed Capacity Requirement (NICR) and capacity clearing prices.

The system was relatively long on capacity until *FCA 7*, with prices clearing at an administrative floor price averaging $3.26/kW-month over the first seven auctions. Capacity payments more than doubled from *CCP 7* to *CCP 8* due to higher primary auction clearing prices (from $1.2 billion to $3 billion). *FCA 8* cleared with a capacity deficiency, primarily due to a large amount of retirements. The capacity deficiency triggered administrative pricing rules, which set the clearing price for existing resources at $7.03/kW-month and new resources at $15/kW-month. This resulted in a 160% increase in capacity payments, from the *CCP 7* payment of $1.2 billion to $3.0 billion in *CCP 8*. 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).[29] The combination of higher Rest-of-Pool and SEMA/RI prices results in increased projected payments in *CCP 9* of $4.3 billion.

On September 3, 2018, the system experienced its first capacity shortage conditions under the Pay-for-Performance (PFP) market rules that went into effect on June 1, 2018. There were 32 intervals of capacity scarcity conditions (2.4 hours). This led to $44.2 million in PFP credits to over-performers and $36.3 million in PFP charges to under-performers.[30] In general, long-lead time generators under-performed, while fast-start generators, base-load nuclear generators, and imports performed well.

High clearing prices in *FCA 8* and *FCA 9* provided price signals to the market that new generation is needed. As more capacity cleared in those auctions, clearing prices have continued to decline through to the most recent auction, FCA 13.

In FCA 13, the auction fell below the dynamic de-list bid threshold for the third consecutive auction, clearing 34,839 MW (a surplus of 1,089 MW) at a price of $3.80/kW-month for rest-of-system. Significant retirements in FCA 13 included Mystic 7, a 575-MW oil-fired resource in Southeast New England (SENE) that was held for reliability in FCA 12. Existing resources totaling of 1,356 MW shed their obligations for one year, through static and dynamic de-list bids. Mystic 8 and 9, two combined cycle generators in SENE that submitted retirement bids, were retained for reliability due to fuel security concerns. New resources entering the market totaled 1,490 MW, comprised mostly of combined cycle gas turbine, energy efficiency, active demand response and solar capacity.

FCA 13 was the first year with a substitution auction. The substitution auctioned cleared 54 MW at a price of $0/kW-month. This means the state-sponsored resource will receive $0/kW-month in FCA 13, and clear subsequent auctions as an existing capacity resource. The shedding resource was a dual-fuel oil/gas-fired generator and will receive their full FCA 13 payment for that capacity. The resource will also retire from all New England markets starting June 1, 2022.

Market Competitiveness: Two metrics were calculated to evaluate the competitiveness of the capacity market: 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

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

[30] The $7.9 million difference between credits and charges was due to energy efficiency exemption rules and were charged pro-rata to resources holding a capacity supply obligation.

competitiveness has fluctuated widely across capacity zones over the last five auctions as the margin (the difference between the capacity requirement and the capacity of existing resources) has changed. In all five auctions there has been at least one pivotal supplier in each zone.

For this reason, the market has both buyer- and supplier-side mitigation rules to prevent the potential exercise of 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 13), a number of pivotal suppliers submitted a de-list bid, which is the mechanism a supplier may use when it wants to attempt to withdraw capacity in an auction. In all, there were 11 pivotal suppliers, four submitted de-list bids and/or new supply offers that entered the FCA. These bids and/or offers were associated with five resources, all located outside of the SENE capacity zone. Of these five resources, the IMM agreed with the prices submitted by four (totaling 930 MWs),[31] and disagreed with one (totaling 530 MWs), which was later reduced by the participant to a price below the IMM-determination.

1.5 Ancillary Services Markets

The ancillary services markets includes a number of programs designed to ensure the reliability of the bulk power system, including operating reserves (forward and real-time), blackstart, voltage, regulation and the winter reliability program. In 2018, the costs of most ancillary service products were similar to 2017 costs. Winter reliability program payments were lower in 2018 because the ISO ended the program in March 2018, and therefore there were no payments in December unlike prior years.

Real-time Reserves: Total gross real-time reserve payments for 2018 were $33.4 million, a decrease of $2.4 million (or 7%) from 2017. This decline reflects a fall in TMSR and TMOR payments of $1 million (4%) and $1.7 million (33%), respectively. Net real-time reserve payments were $29.8 million, slightly under the 2017 value of $29.9 million. Shortage conditions and scarcity pricing on September 3, accounted for $9.1 million, or 27%, of total annual gross payments. The 2018 gross reserve payment total of $33.4 million was less than 1% of total wholesale market costs in New England.

The implementation of the Fast-Start Pricing rules continued to have the expected impact of increasing the magnitude and frequency of operating reserve prices and increasing payments. Because the price of real-time energy has increased, so too has the opportunity cost of holding back generators to provide reserves rather than energy, which has resulted in higher and more frequent reserve pricing. Without fast-start pricing, real-time reserve payments would have been approximately $17 million in 2018, compared to $33 million.

Forward Reserves: Costs associated with the Forward Reserve Market (FRM) totaled $41 million in 2018, up by 4% on 2017 costs, consistent with auction clearing prices. Auction clearing prices increased in 2018 relative to 2017 for the summer period, reflecting increased offer prices for the TMOR product. Clearing prices for the 2018 winter delivery period were down, compared to earlier periods. However, for zonal pricing, there have been six instances of significant price separation during the five-year period. In the summer periods for 2015, 2016, 2017 and 2018 and

[31] Despite originating from pivotal supplier, the IMM deemed one de-list bid or new supply offer as non-pivotal due to conditions outlined in III.A.23.2

the winter periods for 2017-18 and 2018-19, there was price separation between NEMA/Boston and all other zones.[32] In these instances, supply was inadequate to satisfy the local Thirty Minute Operating Reserve (TMOR) requirement, and pricing reached the auction offer cap in each period. In the Winter 2018-19 auction, the cap was $9,000/MW-month.

The FRM was structurally uncompetitive (i.e. had at least one pivotal supplier or a RSI < 100) in eight out of the ten auctions since Summer 2014 for at least one reserve product. There is currently no market power mitigation in the FRM beyond auction price caps. Further analysis indicates that there is eligible capacity that is not offered into the FRM.

Regulation: The regulation market has an abundance of regulation resources and relatively unconcentrated control of supply, which implies that market participants have little opportunity to engage in economic or physical withholding. Payments to resources providing regulation service 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 also 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.

Winter reliability program: The winter reliability program was established to ensure adequate fuel supply during winter months when residential, commercial, and industrial demand for natural gas can create a shortage of availability of natural gas for electricity producers. The winter reliability program covering the most recent winter (2017/18), cost $24 million, the lowest of the five winters during which the program has been in place. This was primarily the result of lower remaining volumes of oil at the end of the program, and no contracted LNG.[33]

1.6 IMM Market Enhancement Recommendations

The following table summarizes the IMM's recommended market enhancements from this report and from previous reports, along with the status and 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.

[32] The 2015 NEMA/Boston summer period price exceeded the 2016 and 2017 prices because the offer cap was reduced in 2016 (from $14,000/MW-month to $9,000/MW-month) when FCA price-netting was eliminated. See ISO New England and New England Power Pool, Docket No. ER16-921-000; *Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting*. https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf

[33] The program ended with the implementation of the FCM pay-for-performance rules in June 2018.

Table 1-2: Market Enhancement Recommendations

Recommendations	Status as of the AMR '18 Publication Date	Priority Ranking
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.	The External Market Monitor is actively assessing the price forecast and the ISO is periodically reporting on the forecast accuracy. Future improvements are not in the scope of the ISO's current work plan.	High
Corporate relationships among market participants: The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	IMM and ISO are currently implementing a new IMM market analysis system that will address this recommendation.	Medium
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.	IMM and ISO to assess the implementation requirements for this project.	Medium
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 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.	Not in the scope of the ISO's current work plan.	Medium
Demand response baseline methodology: The ISO make available to the market the metrics that describe the accuracy of the new baseline methodology for demand resources. The implementation date for a new methodology for determining demand-resource baselines was June 1, 2018, at which time new market rules became effective that will fully integrate dispatchable demand resources into the day-ahead and real-time markets. The new methodology's predictive ability in estimating a resource's actual load should be made transparent to the market.	The ISO plans to periodically measure and report on the accuracy of the new baseline methodology post implementation.	Medium
***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.	Related to the item above (Improving price forecasting for CTS). Not in the scope of the ISO's current work plan.	Medium

Recommendations	Status as of the AMR '18 Publication Date	Priority Ranking
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.[34]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 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	Not in the scope of the ISO's current work plan.	Medium
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.	New recommendation from analysis presented in the recent Fall 2018 Quarterly Markets Report. Not in the scope of the ISO's current work plan.	Medium
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.	The IMM will evaluate revising or eliminating mitigation exemptions for FRM resources to resolve the market power issues.	Low

[34] 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.

Recommendations	Status as of the AMR '18 Publication Date	Priority Ranking
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.	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

Section 2
Overall Market Conditions

This section provides an overview of the key trends in wholesale market outcomes over the past five years (2014 through 2018). 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 2018, the total estimated wholesale market cost of electricity was $12.1 billion, an increase of $2.9 billion compared to 2017 costs.[35] Together, the increase in energy and capacity costs accounted for 98% of the overall increase in 2018 wholesale costs.

First, energy costs were up by 34%, or by $1.5 billion, driven by a 33% increase in New England natural gas prices. Second, capacity costs increased by 61%, or by $1.4 billion, as a result of higher clearing prices in the ninth Forward Capacity Auction as the system required new capacity to meet ISO requirements. Compared to the eighth auction, the payment rate for resources increased from $7.03 to $9.55/kW-month in most capacity zones.

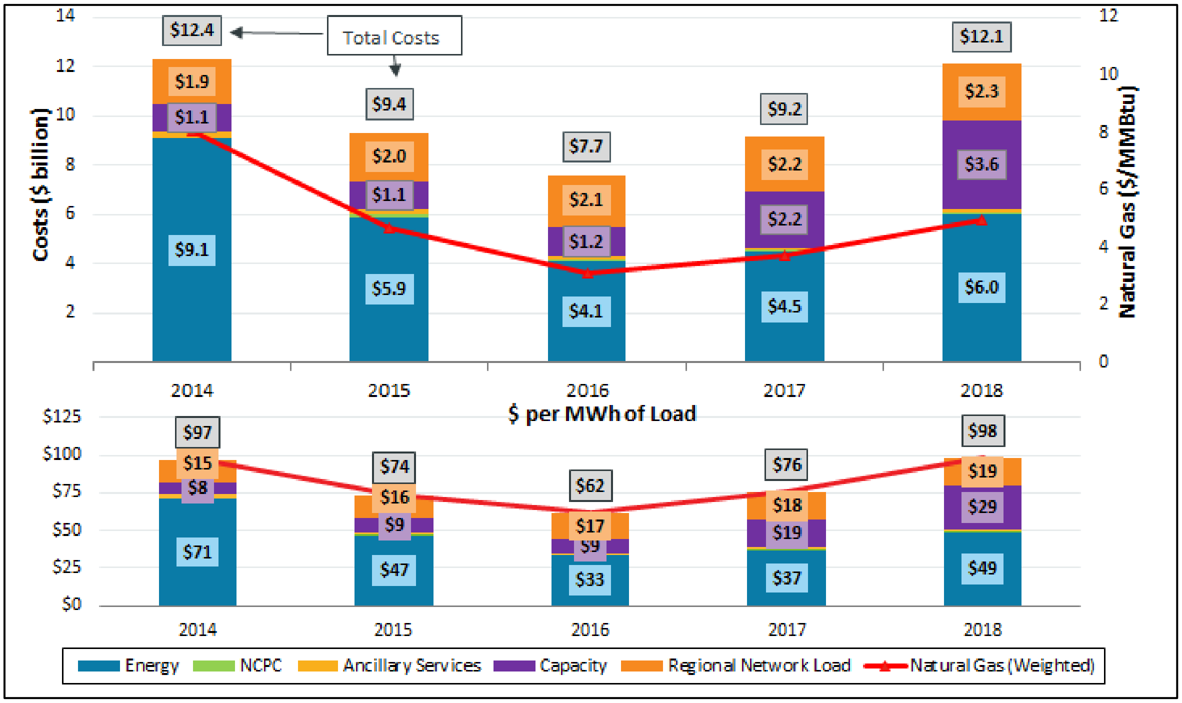
The estimated wholesale electricity cost for each year by category, along with average natural gas prices, is shown in Figure 2-1 below. The wholesale cost estimate is made up of several categories:

- Energy includes costs to load from the energy market (associated with Locational Marginal Prices or "LMPs").
- Net Commitment Period Compensation ("NCPC") category shows total uplift payments.
- Ancillary Services includes the costs of operating reserves, regulation service, and the Winter Reliability Program.
- Capacity reflects the cost to attract and retain sufficient capacity to meet energy and ancillary service requirements.
- Regional Network Load (RNL), or transmission costs, category includes transmission owners' recovery of infrastructure investments, maintenance, operating, and reliability costs.[36]

[35] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead Locational Marginal Price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP.

[36] Transmission network costs, known as Regional Network Load (RNL) costs, are also included in the estimate of annual wholesale costs. The annual figure is the sum of the monthly Total RNL Costs as reported in the ISO's Monthly Regional Network Load Cost Reports, available at: https://www.iso-ne.com/markets-operations/market-performance/load-costs/

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



Natural gas prices are the primary input to electricity production and thus a key 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. Natural gas prices were 33% higher in 2018 compared to the previous year, while energy costs increased by 34%.

In addition to energy and capacity payments, Regional Network Load (RNL) costs also account for a large share of total costs each year. Transmission costs in 2018 were slightly higher (2%) than 2017 costs, primarily driven by a relatively modest increase (of $52 million) in infrastructure costs. The increase was the result of continued investment in new regional transmission infrastructure to ensure compliance in meeting reliability criteria, as well as investment to address deficiencies in the condition of existing regional transmission assets.

NCPC costs, at $70 million in 2018, increased by 36% relative to 2017 due to higher economic and second contingency protection payments in the first two quarters of the year. Ancillary service costs[37] totaled $117 million in 2018, $9 million under 2017 costs. This decrease was driven by lower Winter Reliability Program (WRP) costs in 2018, the final year of the program.

2.2 Supply Conditions

This section of the report provides a macro-level view of supply conditions across the wholesale electricity markets in 2018, and describes how conditions changed over the past five years. Topics covered include the generation mix within New England (Section 2.2.1), fuel and emission market prices (Section 2.2.2), and estimates of generator profitability (Section 2.2.4).

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

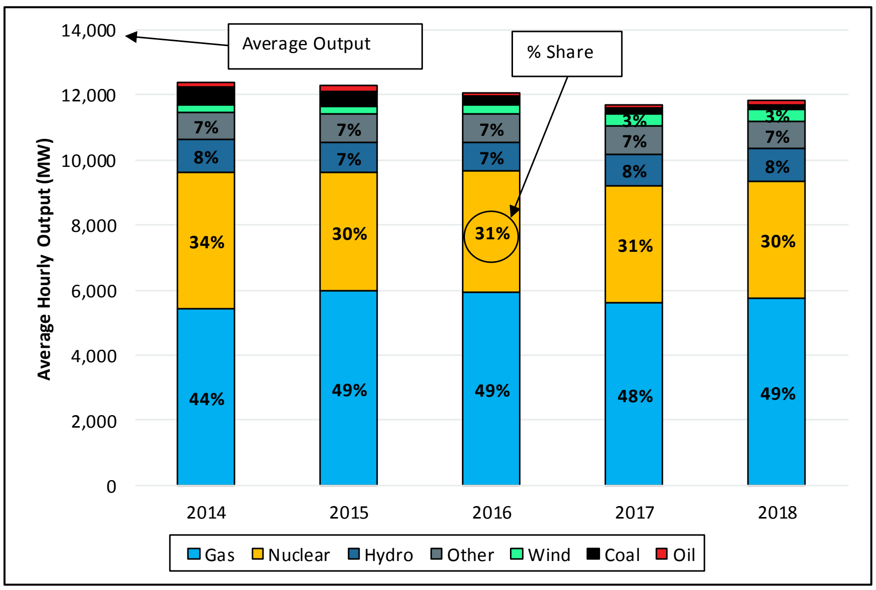
2.2.1 Generation and Capacity Mix

This subsection provides a summary of the generation mix in New England over the past five years. The composition of New England's native generation provides important context to overall supply conditions and market outcomes. Information about generation is provided across a series of different dimensions, including fuel type, location, and age. The focus here is on generators located within New England and excludes power imported from generators located outside New England (which are covered separately in Section 2.4).

Average Generator Output by Fuel Type: Analyzing actual energy production (generation output in megawatt hours) provides additional insight into the technologies and fuels used to meet New England's electricity demand. Knowing what fuel is burned and where generators are located in the context of actual energy production helps us to understand and frame market outcomes.

Actual energy production by generator fuel type is illustrated in Figure 2-2 below. Each bar represents a fuel type's percent share of generation.

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



Notes: "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

Annual energy production share by fuel type remained consistent between 2017 and 2018. In 2018, nuclear generation accounted for 30% (approx. 3,600 MW per hour) of annual energy production while natural gas-fired generation accounted for 49% (approx. 5,800 MW). Even though two new combined cycle gas power plants came online in 2018, the share of gas generation did not increase significantly. Instead, these generators displaced less efficient gas generation in the ISO-NE fleet.

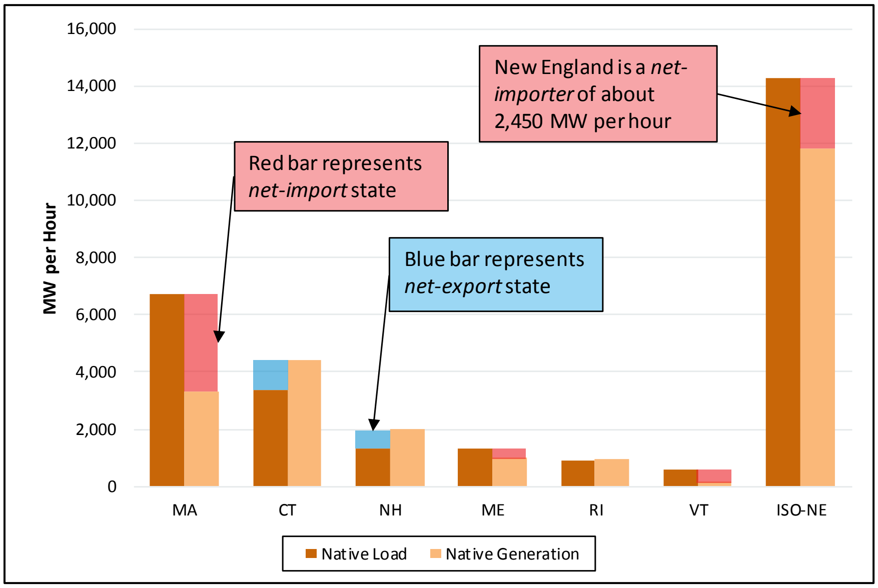
Capacity Factors: In general, capacity factors remained constant year-over-year.[38] Natural-gas fired generators had an average capacity factor of 34%. Coal- and oil-fired generation had lower capacity factors, of about 14% and 3%, respectively. Their low capacity factors are driven by high operating costs compared to more efficient natural gas-fired generators with lower average fuel prices. A

[38] A capacity factor indicates how much of the full capability of a generator is being utilized in the energy market. For example, a capacity factor of 60% for a 100MW generator means that the generator is producing 60MW on average each hour.

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.

A breakdown of energy production and consumption by state and aggregated across ISO-NE is shown in Figure 2-3 below. The state breakdown provides an idea of where energy is being produced and consumed. Darker shaded bars represent native load while lighter shaded bars represent native generation. The red bars show net imports into each state and the blue bars show net exports out of the state.

Figure 2-3: Native Electricity Generation and Load by State, 2018



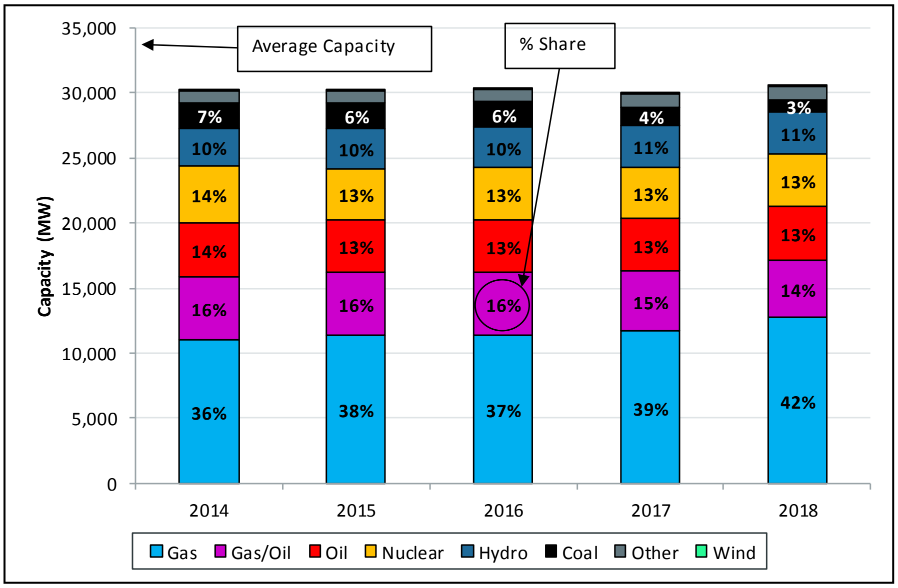
Massachusetts was a major importer of power, while New Hampshire and Connecticut produced more than they consumed. Massachusetts generated roughly 50% of what it consumed due to declining generation within the state, down from 58% in 2017. First, the 1,490-MW Brayton Point coal-fired facility retired in June 2017. Second, Massachusetts natural gas-fired generation decreased 18% compared to the prior year. The decrease in gas-fired generation in Massachusetts was driven by a sharp reduction in the output of two existing combined cycle generators due relatively expensive fuel input costs (liquefied natural gas), which was only partially offset by output from a new gas-fired generator in the state.

As discussed above, natural gas generation in other states offset the decline in Massachusetts. In contrast to Massachusetts, New Hampshire produced 50% more energy than it consumed. The state contains baseload nuclear generation, and several natural gas-fired plants that consistently provide energy throughout the year. Connecticut provided the most native generation (37%) in New England, and 31% more energy than it produced. The addition of CPV Towantic, a 730-MW natural gas-fired combined cycle generator, increased Connecticut's average native generation in 2018 compared to prior years.

The final bars show that New England is a net importer of power. In 2018, New England imported 17% of its load consumption, or 2,450 MW per hour. The imports come from Canada into Vermont, Massachusetts and Maine, and from New York into Vermont, Massachusetts and Connecticut. This is discussed further in Section 2.4.

Capacity by Fuel Type: Capacity by fuel type provides context about the capabilities of ISO-NE's fleet, rather than actual generation. Average generator capacity by fuel type for the past five years is shown in Figure 2-4 below.[39]

Figure 2-4: 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 landfill gas, methane, refuse, solar, steam, and wood.

Natural gas continues to be the dominant fuel source in New England. The percentage of capacity from gas- and gas/oil-fired dual-fuel generators has increased slowly over the past few years with the retirement of generators of other fuel types and the building of new combined cycle generators. Natural gas-fired generators accounted for 42% of capacity in 2018. The addition of CPV Towantic in Connecticut accounts for a majority of the increase compared to 2017. Combined, gas- and gas/oil-fired dual-fuel generators accounted for 56% of total average generation capacity in 2019.

Capacity from coal-fired generators decreased in 2018 due to the retirement of Brayton Point in June 2017. Coal-fired capacity accounted for 920 MW in 2018, down from 1,350 in 2017, and 2,000 MW from 2014 to 2016. Nuclear generation remained unchanged from 2017, accounting for 4,000 MW (13%) of the capacity fuel mix. The retirement of the Pilgrim nuclear facility (about 680 MW) in June 2019 will reduce the capacity and energy share of nuclear generation. By 2020 the capacity of nuclear generation is expected to be 3,350 MW, less than 10% of the installed capacity requirement for that year.

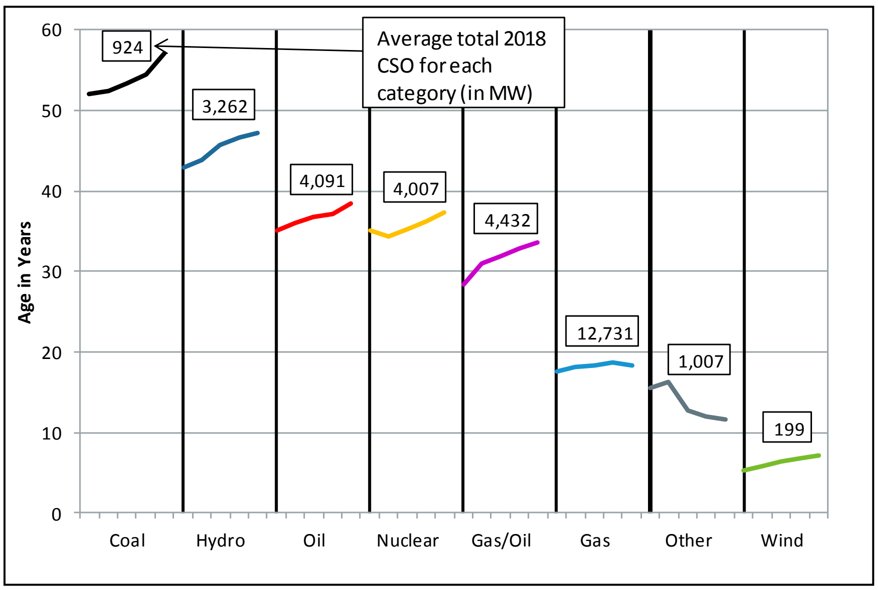
Average Age of Generators by Fuel: As generators age, they require increased maintenance and upgrades to remain operational. This is true for all generators, but older coal- and oil-fired

[39] 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).

generators in New England face other market dynamics, including higher emissions costs and costs associated with other public policy initiatives 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 new investments have been in new natural gas, wind, and solar generators. 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 2-5 below. Age is determined based on the generator's first day of commercial operation. Each line represents average generator age by fuel type, from 2014 to 2018. If there were no retirements or new generation, we'd expect the line to increase by one year as resources age. An influx of new generators can cause a decline in average age, as was the case with solar resources in the "Other" category. Data labels above the bars show total capacity in 2018 by fuel type.

Figure 2-5: Average Age of New England Generator Capacity by Fuel Type (2014-2018)



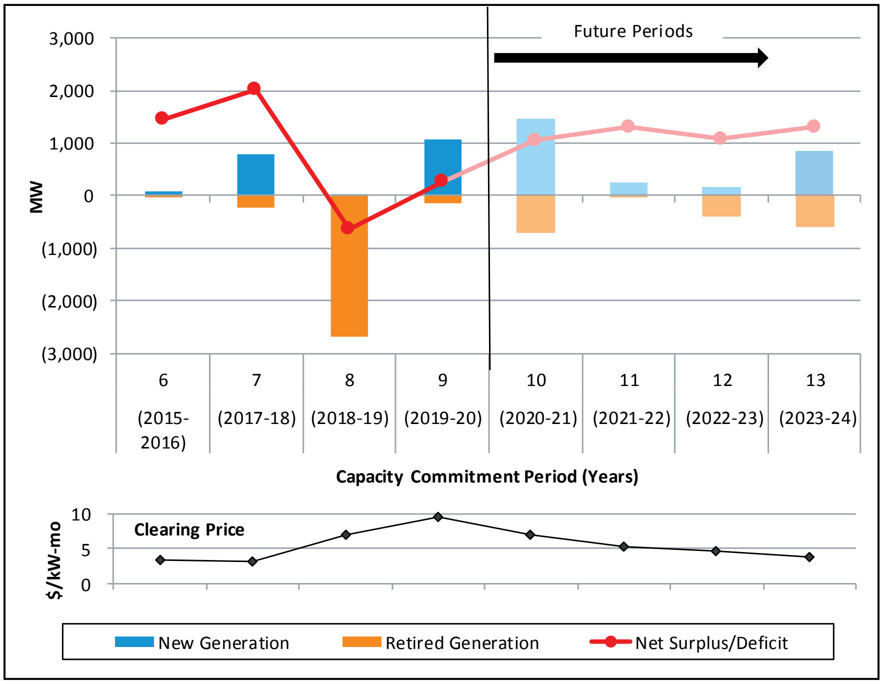
Note: "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

The average age of New England's generators in 2018 ranged from 7 years to 57 years, with weighted-average total system age of 30 years. Coal-fired generators, which comprise 3% of total generation capacity, have the highest average age of 57 years. This was a 3-year increase from 2017, due to the retirement of the relatively younger Brayton Point facility. The addition of CPV Towantic caused a one-year decline in the average age of natural gas-fired generators, from 19 years in 2017 to 18 years in 2018.

Generator additions and retirements beginning with Capacity Commitment Period 6 (CCP 6) are shown in Figure 2-6 below.[40] 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) has taken place, but the capacity is yet to be delivered. The FCA clearing prices (for existing rest-of-system resources) are also shown for further context.

[40] Capacity Commitment Periods start on June 1st and end on May 31st of the following year. For example CCP 7 started June 1st 2016 and ended May 31st 2017. The CCP numbers correspond to the FCA numbers (e.g. FCA 7 procures capacity for delivery during CCP 7).

Figure 2-6: Generator Additions, Retirements and FCM Outcomes



There have been large swings in generation additions and retirements over the past eight commitment periods. Many of the large retiring resources cite long-run economic issues as the reason for exit, including emissions, capital and maintenance costs for coal and oil-fired generators. It also includes persistently low wholesale energy prices, mostly cited by base-load nuclear generators.

After FCA 8, higher clearing prices in response to a capacity deficit signaled a need for more capacity. Subsequently, a large number of resources, including five combined cycle natural gas-fired resources totaling 2,659 MW, entered the market as new capacity in the past five auctions. In addition, smaller renewable resources have cleared based on low costs of new entry.

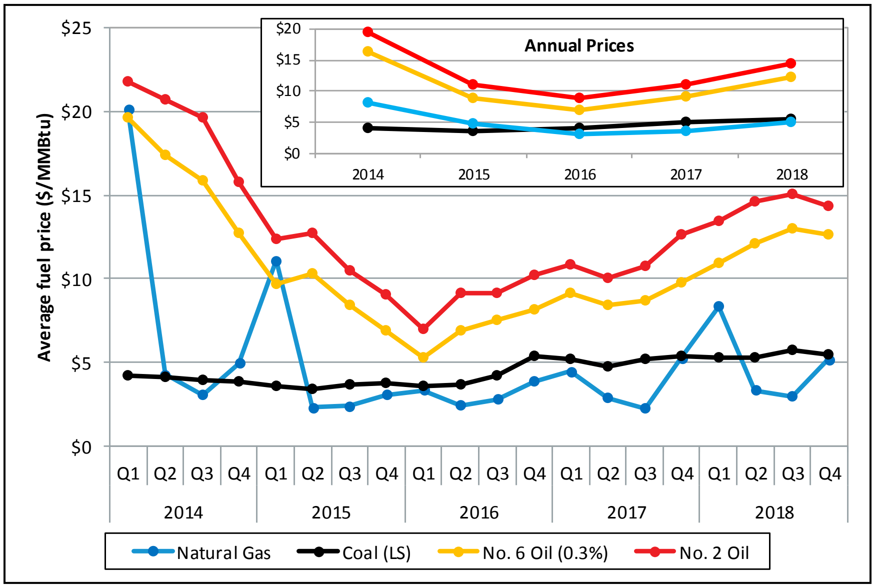
2.2.2 Generation Fuel Costs

Fuel Prices: For the most part, fuel costs and the operating efficiency of combustion generators drive New England's electricity prices. Average prices for all fuels increased year-over-year; natural gas (33%), No.2 oil (29%), No.6 oil (35%) and coal (6%).

Natural gas-fired generators produce 49% of New England's electricity, while oil and coal account for about 1% each. Quarterly average cost of natural gas[41], low-sulfur (LS) coal, No. 6 (0.3% sulfur) oil, and No. 2 fuel oil for the past five years are shown in Figure 2-7 below. Average annual prices are shown in the inset graph.

[41] A weighted natural gas price for the region is calculated using trade volume data and index prices for relevant pipelines supplying New England generators.

Figure 2-7: Average Fuel Prices by Quarter and Year



Natural Gas: In 2018, natural gas prices averaged $4.95/MMBtu, a 33% (or $1.23/MMBtu) increase compared to the 2017 average price. The price increase in 2018 was primarily driven by high prices during January 2018, and to a lesser extent, higher prices in Q3 due to a warmer summer. January 2018 alone explained 23% of the year-over-year increase.[42]

In Q1 2018, natural gas prices increased by 86% (or $3.87/MMBtu) over Q1 2017, largely because of the "cold snap" during January 2018. In January 2018, the average natural gas price was $15.97/MMBtu, a 210% increase over January 2017. The average temperature in January 2018 was 7°F colder than the previous January, which caused New England natural gas pipelines to become constrained. The first week of January was particularly harsh, with temperatures averaging 10°F compared to 30°F during the rest of the month. During this week, gas pipeline demand increased to a weekly average 4.25 million Bcf/d compared to 3.62 million Bcf/d during the first week of 2017, and daily gas prices reached as high as $61.54/MMBtu.

While the January "cold snap" was the primary driver of increased natural gas prices for the year, Q3 2018 also experienced higher gas prices. Q3 2018 gas prices were 33% (or $0.73/MMBtu) higher than in Q3 2017. This increase was driven by a combination of higher New England power demand and higher Marcellus shale prices.

Oil: Oil prices rose in 2018, with No. 6 oil prices rising 35% and No. 2 oil prices rising 29%. The price increase was largely driven by crude oil production cuts from OPEC and its allied producers that carried throughout most of the year, pushing Brent crude prices to a peak of $86/barrel in October.[43] However, crude oil prices fell towards the end of the year, due to increased domestic production causing crude oil to end the year lower (at $54/barrel) than it started.

[42] When January is excluded the average 2018 and 2017 natural gas prices are $3.94 and $3.58/MMBtu, respectively, a 10% year-over-year increase.

[43] https://www.eia.gov/todayinenergy/detail.php?id=37852

Coal: Coal prices in 2018 increased by 6% over the previous year, despite decreased demand for coal across the country. The price increase was driven by higher global demand.[44]

2.2.3 Generation Emissions Costs

While fuel prices and generator operating efficiencies are the main drivers of electricity prices, emission allowances, as required by federal and state regulations, are a secondary driver of electricity production costs for fossil fuel generators. New England has two cap-and-trade programs (aimed at reducing carbon levels) that influence electricity prices: the Regional Greenhouse Gas Initiative (RGGI), covering all New England states, and 310 CMR 7.74, which covers only Massachusetts.

Regional Greenhouse Gas Initiative Prices:

The key driver of emission costs for New England generators is RGGI, which is a marketplace for CO_2 credits in the Northeast and Mid-Atlantic, and covers all six New England states. RGGI operates as a cap-and-trade system, where fossil fueled generators, among other CO_2 emitters, must hold allowances equal to their emissions over a certain period.[45] Market prices for CO_2 credits affect total energy costs of fossil fuel generators that must purchase allowances to meet RGGI requirements. This creates a market incentive for lower emitting generators to operate, and pushes new generation facilities to use less carbon-intensive resources.

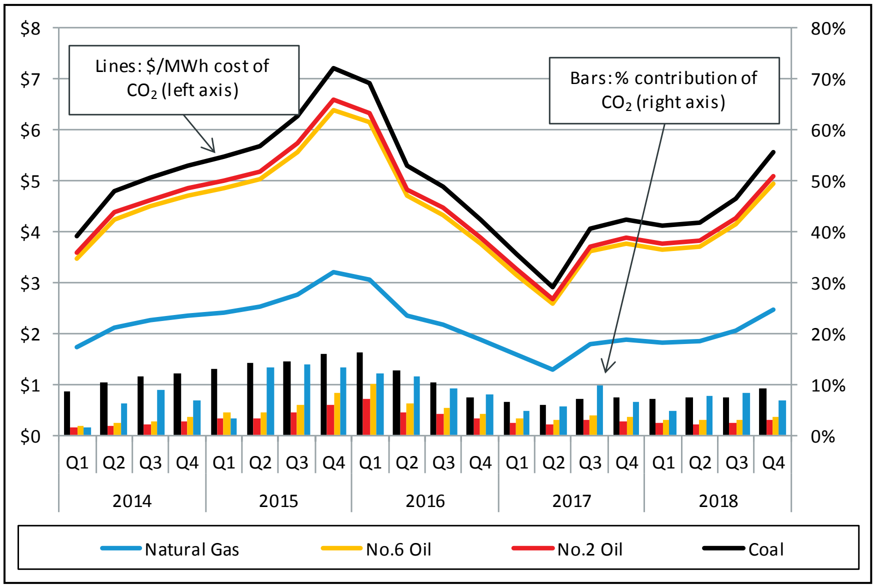
The estimated dollar per MWh costs of CO_2 emissions and their contribution as a percentage of total variable costs is shown in Figure 2-8 below.[46] The line series illustrate the average estimated cost of emission allowances for fossil fuel for the past five years. The bar series on the figure shows the proportion of the average energy production costs attributable to emissions costs for each year.

[44] https://www.eia.gov/todayinenergy/detail.php?id=38132&src=email

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

[46] CO_2 prices in $ per ton are converted to estimated $/MWh units using average generator heat rates for each fuel type and an emissions rate for each fuel.

Figure 2-8: Average Cost of CO_2 Allowances and Contribution to Energy Production Costs



Since the second half of 2017, emissions prices trended higher due to changes in the RGGI. In Q2 2017, natural gas-fired generators' emissions costs were $1.29/MWh, the lowest cost since Q1 2013. However, emissions prices increased 40% from $3.30/short ton to $4.60/short ton on August 23, 2017 after a RGGI review placed a 30% reduction on the cap by 2030, relative to 2020 levels (from 78.2 million short tons to 54.7 million short tons).[47,48] In 2018, emissions prices increased 25% year-over-year, (from $3.59/short ton to $4.50/short ton) , with the final auction of the year closing at $5.35/short ton.[49] The average 2018 CO_2 cost for a natural-gas fired generator was $2.05/MWh.

The bar charts in Figure 2-8 show the relative contribution of CO_2 emissions allowance costs to generation costs, which increased this year for coal and gas, but decreased for No.2 and No. 6 Oil. For natural gas-fired generators, the CO_2 share of variable generation costs ranged from 4.7% in Q1 when gas prices were highest, to 8.2% in Q3, due to lower gas prices and higher emissions costs.

A wider view of the impact of CO_2 allowances on generation input costs is presented in Figure 2-9 below. The line series in the figure illustrates the quarterly estimated production cost 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 additional energy production costs attributable to CO_2 emissions costs in each quarter.

[47] 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/PressReleases/2017_08_23_Announcement_Proposed_Program_Changes.pdf

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

[49] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/42/PR120718_Auction42.pdf

Figure 2-9: Contributions of CO_2 Allowance Cost to Energy Production Costs

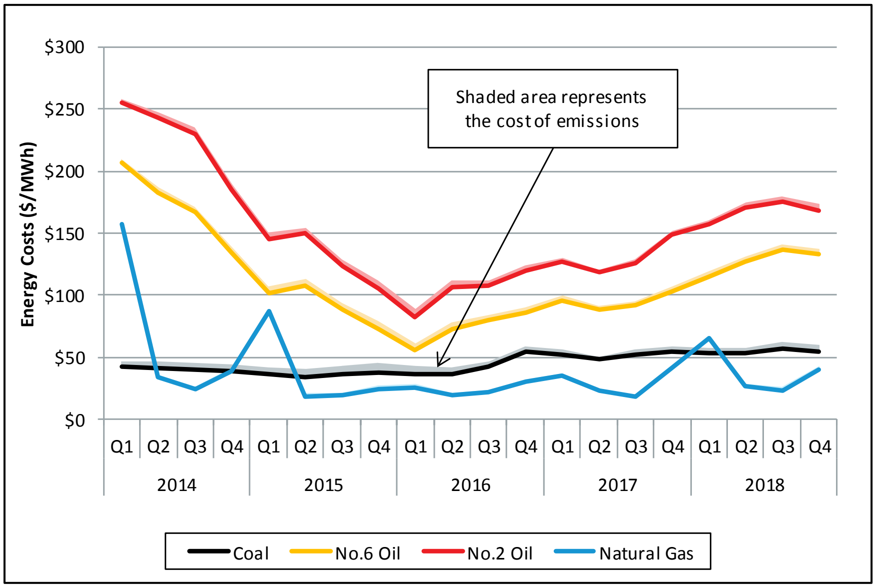


Figure 2-9 highlights that CO_2 allowance costs have a relatively small impact on generation production costs and consequently do not have a noticeable impact on the economic merit order of generation. For instance, the additional CO_2 costs for coal do not push coal-fired generators out of merit relative of gas-fired generators on average; rather the underlying difference in fuel cost is the dominant factor in determining the economic merit order.

Massachusetts GHG (310 CMR 7.74)

In January 2018, a new CO_2 cap-and-trade program began in Massachusetts.[50] The program is in addition to the RGGI discussed above. 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 generators within the state. The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050. To ensure compliance, the regulation requires electricity generators to hold a permit, called an allowance, for each metric ton of CO_2 they produce during a year. For the first year, these allowances were allocated based on historical emissions levels but future years' allowances will be auctioned.[51] The program allows generators to trade emissions allowances to meet their quotas.

The cap-and-trade program attempts to make the environmental cost of CO_2 explicit in dollar terms so that energy producers consider it in their production decisions. Consequently, carbon emission costs must be incorporated when developing the reference levels used to assess energy offer competitiveness. By neglecting to consider the cost of carbon, market power mitigation could result in energy offers that are below actual variable and opportunity cost leaving generators unable to recover their cost of production.

To begin the program, the MassDEP allocated allowances based on historical emissions levels. Consequently, the market value of an allowance was unknown - though independent forecasts

[50] 310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

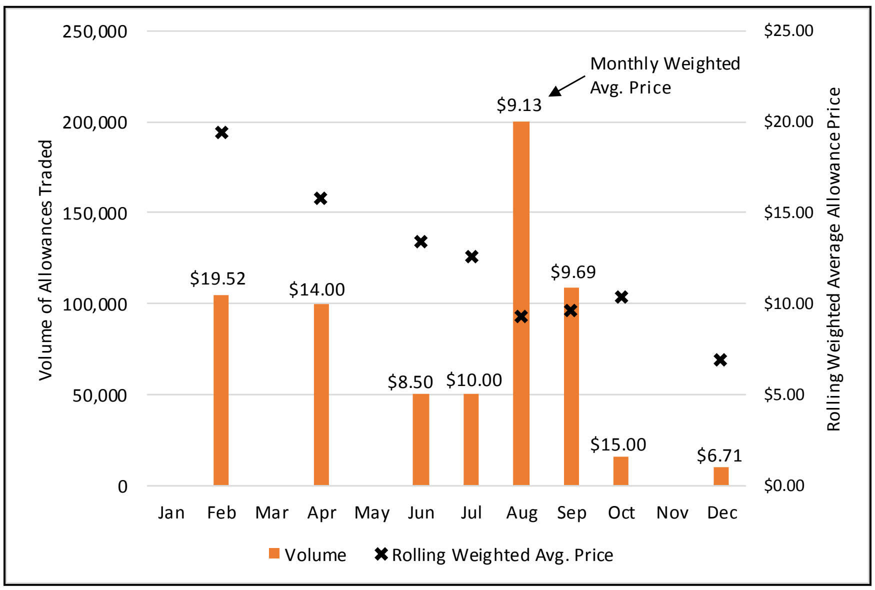
[51] A portion of the 2019 and 2020 allowances will also be allocated to facilities

ranged from $0 to $40 per allowance. Without a market price, the IMM assessed the value of the allowances for each affected facility based on an assumption that the allowance market was highly illiquid and trading would be limited. Under this assumption, the IMM calculated an opportunity cost-based adder for each facility using historical data to estimate the potential net revenue associated with each metric ton of CO_2 output, i.e., the profit associated with each allowance held by a facility of generating assets. In general, generators incorporated the allowance adder into their offers.[52]

In the absence of market price information, the opportunity cost approach provided an empirical mechanism with which to value an allowance. A 2018 survey of facilities for emissions and allowance trading data indicated that, as the year progressed, allowance trading increased, providing data points on its market value. In early fall, the results from the opportunity cost model appeared to be diverging from the observed trading prices. At this point, there was sufficient trading activity to begin calculating the reference level adder by valuing the allowances based on a weighted average of recent trades.

Allowance trading activity was not observed until late winter after which trades were spread evenly across the remainder of the year. Eight of the 15 participants traded a total of 630,000 allowances over the course of the year. This represents approximately 7% of the total allowance allocation for the year. Figure 2-10 shows reported allowance trading volumes and weighted average prices for each month of 2018. The graph also shows a rolling average weighted allowance price that illustrates the general price movement over the year.

Figure 2-10: 2018 Allowance Trading Activity



Massachusetts CO_2 prices were estimated to range from $6.71 to $19.52/short ton in 2018, adding between $3.06 and $8.19/MWh to the average variable generation cost of a natural-gas fired

[52] For the set of assets impacted by the cap-and-trade program, the average energy offer markup above reference level remained consistent with the average value for the prior four years.

generation located in that state.[53] Higher allowance prices at the beginning of the year were the result of the uncertainty surrounding allowance usage and valuation through the balance of the year. Participants understood that the price of the allowance would be driven primarily by the amount of fossil fuel generation in Massachusetts. With a relatively mild winter, participants were aware that the chance of the aggregate constraint on CO_2 emissions binding was decreasing which implied that a surplus of allowances would be available for those that might need them. Consequently, allowance prices tended to trend downwards towards the end of the year. For 2019, the Massachusetts CO_2 related reference level adder will continue to be derived from an estimated allowance price. However, with auctions for allowances starting in 2019, the allowance price will be estimated from both bilateral trading and auction clearing prices.

2.2.4 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 developing a new project. Given the cost of a new project (CONE, or cost of new entry), developer expectations for minimum capacity revenues will be based on this cost 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 services markets in each of the previous five years. In addition to providing a basis for the amount of revenue required from the capacity market to build a new generator, this section also highlights the incremental revenue that could be earned from dual-fuel capability and evaluates participation in the Forward Reserve Market (FRM) for a combustion turbine generator.

The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down times, and economic limits.[54] The results of the simulations are shown in Figure 2-11 below.[55] 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 years 2014-2018. Estimates of future year's base and dual-fuel revenue are simple averages of these numbers. For all years, the FCA and FRM revenue numbers shown are calculated using the actual payment rates applied to calendar years.

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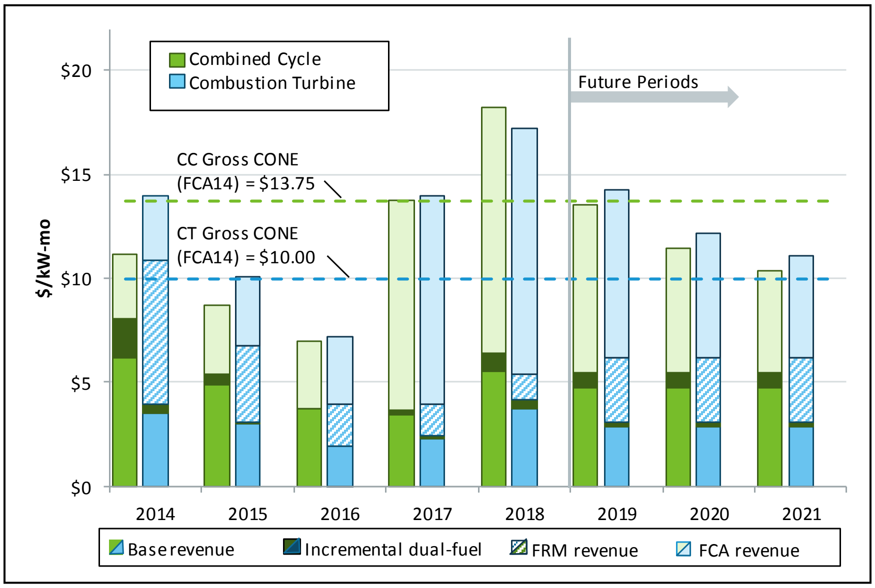
[53] The conversion of CO_2 costs in $/ton to $/MWh assumes an average heat rate of 7.8 MMBtu/MWh and a natural gas emissions rate of 117 lbs/MWh.

[54] 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).

[55] The Gross CONE figures for the CC and CT gas-fired resources reflect Net CONE values of $8.21/kW-month and $6.72/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

Figure 2-11: Estimated Revenue and Profitability for New Gas-fired Generators



The simulation results show energy net revenues increasing by approximately 70% from 2017 to 2018. This rise is driven by increased loads resulting in greater spreads between fuel and energy prices throughout 2018, especially during nuclear plant outages in the fall. In addition, generators with dual-fuel capability were able to take advantage of the extremely cold weather at the start of the year by burning oil when natural gas was priced higher.

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 $4.76/kW-month which increases to $5.45/kW-month for generators with dual-fuel capability. Under the same conditions, new combustion turbines could expect net revenue earnings from $3.36/kW-month for single fuel generators to $3.63/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 generators, but both technologies can expect significant revenue gains when gas prices rise above oil prices as occurred in the winter of 2014 and 2018.

A combustion turbine generator can also participate in the Forward Reserve Market (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 abnormally 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 appear to be trending lower, this analysis shows that a new combustion turbine which is designated as an FRM resource could earn $2.61/kW-month more net revenue than the same resource could have accumulated in the real-time energy market alone. In addition, participation in the FRM market results in greater net revenue than non-participation in all five years where these revenues have been observed (not future periods). Note, however, that the profitability of FRM participation is particularly sensitive to the frequency of scarcity pricing events via the Reserve-Constraint Penalty Factor (RCPF) in the real-time energy market.

The simulations show that average revenues for new gas-fired generators appear to be in-line with benchmark estimates used to establish CONE numbers for the FCM auctions. The most recent CONE revisions filed with FERC establish net revenue components of $5.53/kW-month and $3.28/kW-month for combined cycle and combustion turbine generators respectively.[56] However, revenue numbers in this range are clearly insufficient to support new entry without the addition of capacity payments to cover the fixed costs of a new gas-fired generator.

Figure 2-11 shows that, prior to 2017, capacity prices were generally too low to incent investment in new gas-fired generators because the system was long on capacity. For 2017 onward, the situation appears to change with generator retirements moving the system into a state where it is not long on installed capacity and total revenue is sufficient to support the new entry of gas-fired resources. In practice, FCM auction results show entry from one or both types of gas-fired generator for two of the three capacity commitment periods that encompass these future years. 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 generators 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.. Conversely, the cost of permitting and litigation in New England can add significantly to project costs, including time delays, of new projects.

2.3 Demand (Load) Conditions

Consumer demand for electricity is a key determinant of wholesale electricity prices in New England.[57] The section focuses on wholesale demand, otherwise known as Net Energy Load (NEL). 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. 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

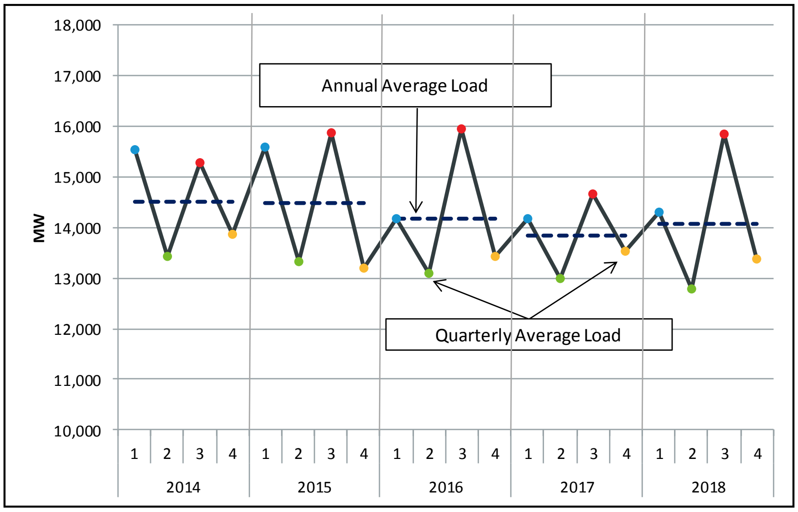
In 2018, New England saw the first year-on-year increase in average wholesale electricity load since 2013. Wholesale load has declined in recent years due, in part, to energy efficiency gains and increased behind-the-meter solar generation, but a particularly hot and humid summer drove the uptick in average load, which grew by 1.7% from the 2017 average. On a weather-normalized basis, however, load was relatively flat (declined by only 0.1%).

The average load by quarter from 2014 through 2018 is shown in Figure 2-12 below. The solid black line shows average quarterly load and the dashed black lines represent the annual average. Calendar quarters are identified by different colored dots (Q1- blue, Q2- green, Q3- red, Q4- yellow).

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

[57] 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.

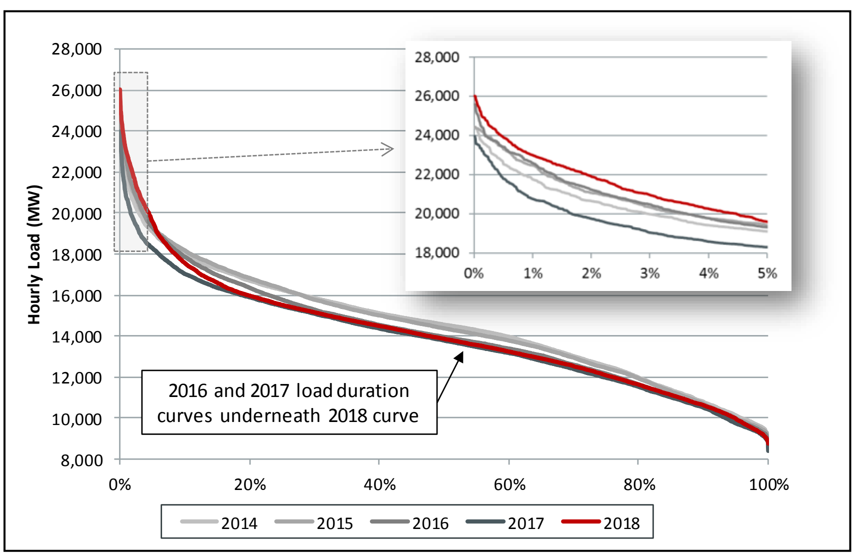
Figure 2-12: Average Hourly Load by Quarter and Year



The first and third quarters of 2018 saw increases in load relative to 2017. Q1 load rose by 0.9% (or by 130 MW per hour) compared to Q1 2017 due to a colder January, where temperatures averaged 26°F, a 7°F drop from the 33°F average in January 2017. Average load in Q3 jumped 8% (or 1,186 MW per hour) from Q3 2017, reflecting a 3°F rise in the average temperature. There were over 30 days in Q3 where the average temperature exceeded 75°F compared to just 9 days in Q3 2017. Average loads declined year-over-year in the second and fourth quarters of 2018. Cooler temperatures in June were the primary driver of the 1% drop in Q2 average load relative to Q2 2017. Average load fell by 1% in Q4 compared to Q4 2017 due to a warmer December, where temperatures averaged 6°F higher than temperatures in December 2017.

The system load for New England over the last five years is shown as load duration curves in Figure 2-13 below. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. The red line shows 2018 and the gray lines show years 2014–2017.

Figure 2-13: Load Duration Curves



The 2018 load duration curve is often well below the 2014 and 2015 duration curves, reflecting the trend of declining load levels over time (average 2018 load was about 3% lower than 2014 and 2015). The 2018 load duration generally tracks the 2017 duration curve until the 20% of hours with highest load, when the 2018 curve (red) begins to diverge upwards from the 2017 curve (darkest grey). This divergence, which represents the relatively high load levels in 2018 Q1 and Q3 (these quarters make up a majority of the hours in the top 20%), led to the growth in average load from 2017.

The inset graph of Figure 2-13 zooms in on the 5% of hours with the highest load levels and illustrates the impact that the hot and humid Q3 weather had on peak load. Nearly all hours in the top 5% occurred during the third quarter, where loads are typically the highest due air conditioning demand for cooling. Q3 2018 saw eight days with an average high of 90°F or above; the high never reached 90°F in 2017or 2014, which have the lowest peaks loads in Figure 2-13. July and August of 2018 were especially hot and humid. The daily high temperature humidity index (THI) averaged 75°F in July and nearly 76°F in August, the highest levels seen over the period, 2014–2018.[58]

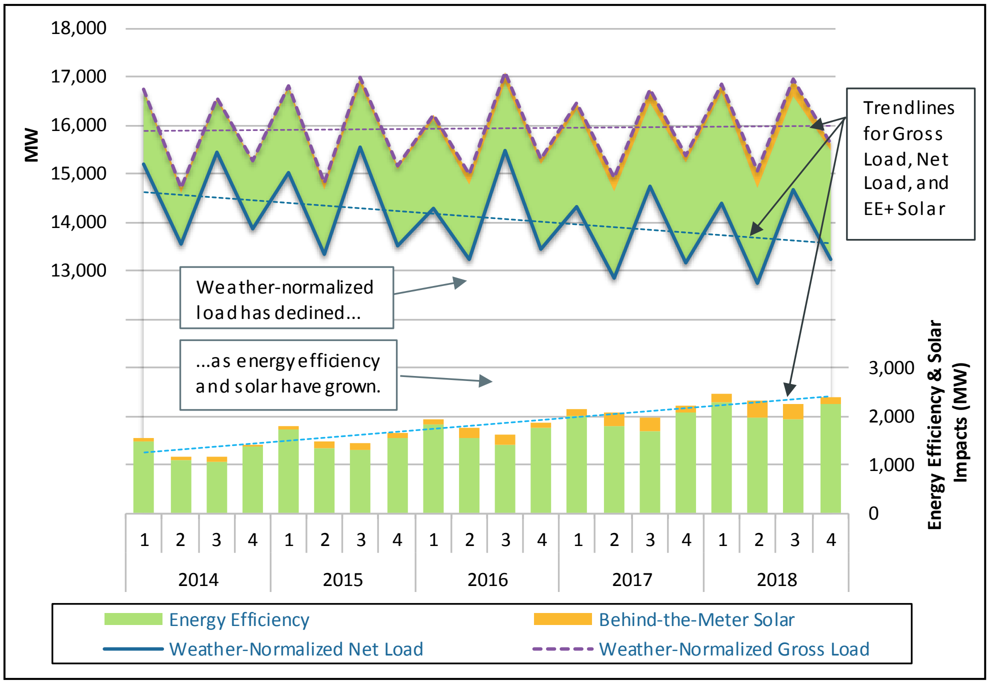
While average load rose in 2018, on a weather-normalized basis load declined relative to 2017.[59] Average annual weather-normalized load has fallen every year since 2011 due to growth in energy efficiency and, to a lesser extent, behind-the-meter solar generation. Figure 2-14 displays the estimated impact of energy efficiency and behind-the-meter solar have had on quarterly load levels over the past five years.[60]

[58] The THI combines temperature and dew point (humidity) into a single 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.

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

[60] 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 measures are aggregated to On-Peak and Seasonal-Peak resources. Performance of DG accounts for only 5% of energy efficiency performance.

Figure 2-14: Weather-Normalized Quarterly Load with Energy Efficiency and Solar Impacts



Weather-normalized load (solid blue line in Figure 2-14) fluctuates from quarter to quarter but has trended downward over the past five years. Weather normalized *gross* load (dashed purple line), which shows what load would have been without the effects of energy efficiency and behind-the-meter solar, has grown slightly since 2014. The gap between weather-normalized gross load and actual load is the combined impact of energy efficiency (green area) and behind-the-meter solar (gold area). Greater energy efficiency and behind-the-meter solar have helped offset the increase in gross load and caused weather-normalized load to fall.

In 2018, energy efficiency helped reduce average load by about 2,115 MW, compared to about 1,250 MW in 2014, an increase of 70% in five years. Behind-the-meter solar had a smaller impact, decreasing average load by about 240 MW in 2018, but has increased nearly four-fold from about 65 MW in 2014. Figure 2-14 also highlights that the load-reducing effects of energy efficiency and solar are not constant throughout the year. Energy efficiency impacts are highest in the first and fourth quarters, and behind-the-meter solar peaks in the second and third quarters.

2.3.2 Reserve Requirements

All bulk power systems need reserve capacity to respond to contingencies. ISO New England's reserve requirements are designed to allow the bulk power system to serve load uninterrupted if there is a loss of a major generator or transmission line.[61] The ISO maintains a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency (N-1) within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. At least 25% of the total 10-minute reserve requirement must be synchronized to the power system. The exact amount is determined by the system operators, and this amount is referred to as the 10-minute

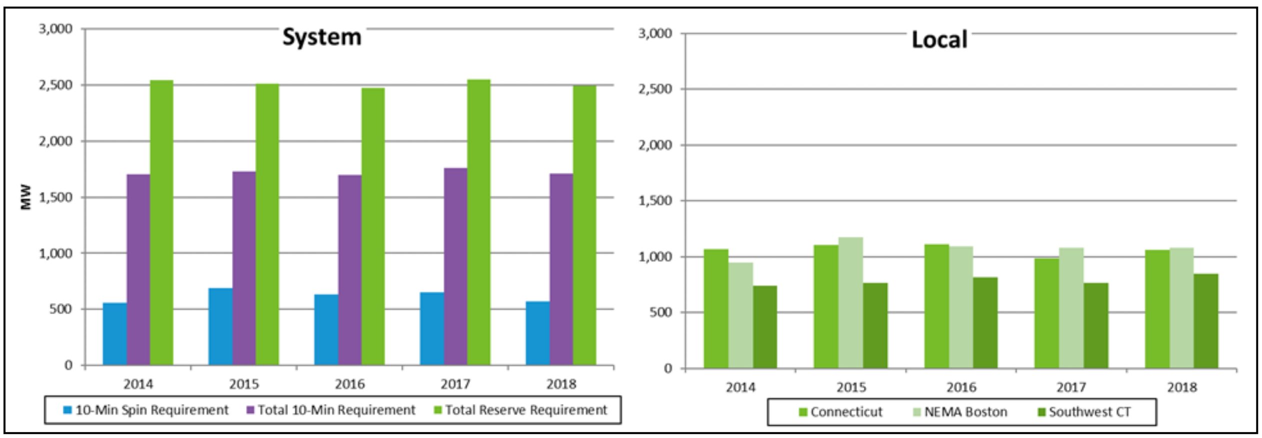
[61] Operating Procedure No. 8, *Operating Reserves and Regulation* (December 10, 2018), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

spinning reserve (TMSR) requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute non-spinning reserve (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 thirty-minute operating reserves (TMOR). Starting in October 2013, the ISO added a thirty-minute replacement reserve requirement of 160 MW for the summer and 180 MW for the winter months. [62] Adding these additional requirements to the total 10-minute reserve requirement comprises the system total reserve requirement.

In addition to the 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 (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABSTN). 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 2-15 below.

Figure 2-15: Average System Reserve and Local 30-Minute Reserve Requirements



The average 10-minute spinning requirement was just under 600 MW in 2018, a 12% decline from 2017. This decrease was due to a fall in the average MW of the largest contingency on the system compared to 2017. Over the past five years, the 10-minute spinning and total 10-minute reserve requirements have averaged around 600 MW and 1,700 MW, respectively. The total reserve requirement (including replacement reserves) has average about 2,500MW. The requirements are

[62] OP 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 Ten-Minute Reserve. 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 Ten-Minute Reserve within NERC requirements.

largely determined by the size of the first and second largest contingencies on the system, so the average annual requirements don't tend to fluctuate substantially from year to year.

Rule changes also impact the reserve requirements. In July 2012, the ISO increased the total 10-minute reserve requirement by 25% to account for generator non-performance that had been observed in prior years. In October 2015, this amount was reduced to 20% due to improved generator performance. One of the reasons generator performance improved was due to improved auditing practices implemented by the ISO in 2013. These auditing changes altered the way the ISO calculates Claim 10 and Claim 30 values for fast-start generators.[63] The auditing practice now takes historical generator performance into account, resulting in a more accurate estimation of capacity available to the system within 10 or 30 minutes of a contingency.

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 once every ten years.[64]

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 2015 and 2023 are shown in Figure 2-16 below. The system ICR and Net ICR are represented as line series. LSRs (positive bars) and MCLs (negative bars) are also shown.

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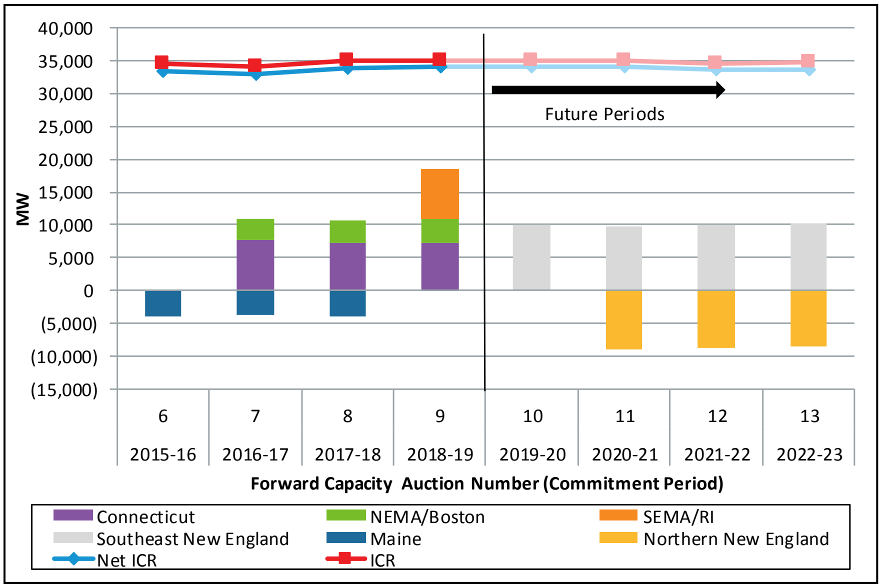
[63] Claim 10 is the generation output level, expressed in megawatts, a resource can reach within 10 minutes from an off-line state after receiving a dispatch instruction. Or, the amount of reduced consumption, expressed in megawatts, a dispatchable asset-related demand resource can reach within 10 minutes after receiving a dispatch instruction. Similarly, Claim 30 is the generation output level, expressed in megawatts, a resource can reach within 30 minutes from an off-line state after receiving a dispatch instruction. Or, the amount of reduced consumption, expressed in megawatts, a dispatchable asset-related demand resource can reach within 30 minutes after receiving a dispatch instruction.

[64] 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.

Figure 2-16: ICR, NICR, Local Sourcing Requirements, and Maximum Capacity Limits



Relatively stable Net ICR (blue line) over the past several commitment periods is the result of slow demand growth coupled with increased energy efficiency and behind-the-meter solar PV. Net ICR increased 1.2% from Capacity Commitment Period (CCP) 10 (34,151 MW) to CCP 13 (33,750 MW).

Another noticeable difference in future periods are the Southeast New England and Northern New England capacity zones. Infrastructure upgrades across the system meant the ISO did not have to model separate capacity zones for SEMA/RI and NEMA/Boston. However, modelled constraints meant that power could flow freely within SENE, but was still limited outside of SENE. Therefore, the ISO combined SEMA/RI and NEMA/Boston to create the SENE capacity zone in CCP 10. The local sourcing requirement has ranged from 9,810 MW in CCP 11 to 10,141 MW in CCP 13.

The ISO introduced the NNE boundary (Vermont, New Hampshire, and Maine) in CCP 11 after analyzing shifts along the North-South interface.[65] Northern New England is export constrained, which means that beyond a certain amount of capacity, each incremental MW is valued at a lower price compared to the system price. The maximum capacity limit in CCP 11 was 8,980 MW, and fell to 8,545 MW in CCP 13.

2.4 Imports and Exports (External Transactions)

New England engages in external transactions, the buying and selling of power, with its neighboring control areas of New York, Hydro Québec, and New Brunswick over the transmission lines that interconnect the regions. Power can be purchased in one region, and sold in another, in the day-ahead and real-time markets, with the goal of profiting from the spot price difference (or spread). Market participants can also use external transactions to fulfill other contractual obligations to buy or sell power (e.g., a power purchase agreement) or to import and collect a premium for renewable power.

[65] Shifts driven by retired generation in southern New England, and new qualified capacity in Norther New England. For more information see https://www.iso-ne.com/static-assets/documents/2015/04/er15-___-000_identification_of_potential_new_capacity_zone_boundaries.pdf

External transactions allow competitive wholesale markets to deliver load at a lower cost by displacing more-expensive native generation when imported power is available at lower cost. In other words, importing ISOs are able to serve demand at an overall lower production costs than could be achieved using only native supply. Generators in exporting ISOs also benefit when there is no willing buyer of their power in their region, but there are customers willing to purchase their energy in another region.

Participants submit external transactions to specific locations known as external nodes, which are affiliated with specific external interfaces. The nodes represent trading and pricing points for a specific neighboring area. A pricing node may correspond to one or more transmission lines that connect the control areas. The ISO schedules the transactions and coordinates the interface power flow with the neighboring area based on the transactions that have been cleared and confirmed. The energy price produced by ISO-NE for an external node represents the value of energy at the location in the New England market, *not in the neighboring area.* 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 the other side of the interface.

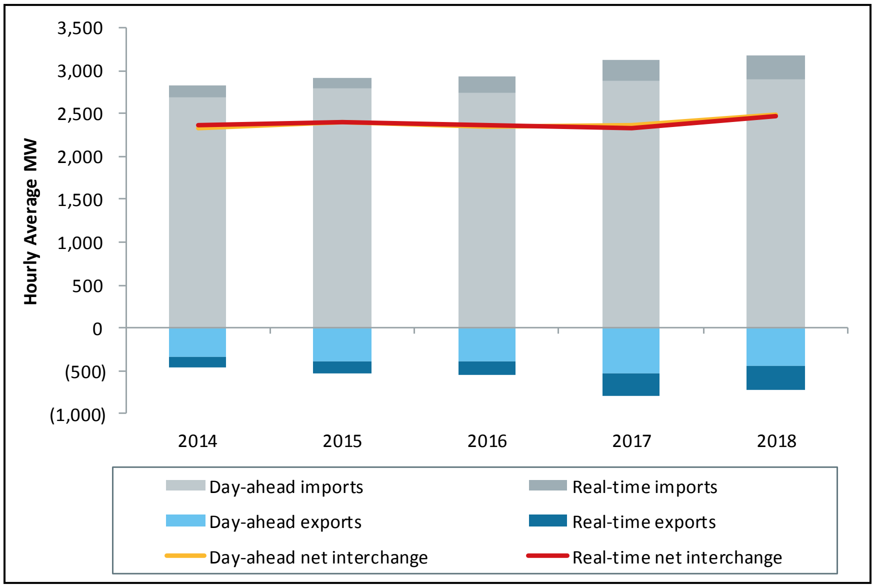
New England's six external nodes are listed in Table 2-1 below along with the commonly used external interface name. These are the names of the interfaces that will be used throughout this report. There are three interfaces with New York, two with Hydro Québec and one with New Brunswick. The table also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

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.HQHIGATE 120 2	225	0-75
New Brunswick (Canada)	New Brunswick	.I.SALBRYNB345 1	1,000	550
Total			**5,171 – 5,371**	**3,480-3,555**

In 2018, New England remained a net importer of power. Over the year, net imports during real-time averaged 2,459 MW each hour, meeting 17% of New England's wholesale electricity demand. Total net interchange was 6% higher than in 2017 and has been relatively steady since 2014. This overall increase is the result of a 65 MW increase in average import transactions and a 69 MW decrease (totaling 134 MW difference) in average export transactions relative to 2017. The hourly average net interchange amounts in the day-ahead and real-time markets for 2014 through 2018 are shown in the line series of Figure 2-17 below. The figure also charts the hourly average imported volume (positive values) and exported volume (negative values) in the bar series. The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

Figure 2-17: Day-Ahead and Real-Time Pool Net Interchange



The average real-time net interchange has been relatively constant for the past five years and mostly unchanged for 2018 as shown by the red line series. One notable change over the last five years is that real-time energy exports have increased by 57%, or by approximately 260 MW per hour on average, compared to 2014. The increase in export transactions occurred primarily at the New York North interface, where Coordinated Transaction Scheduling (CTS) went into effect on December 15, 2015. CTS was designed to improve the efficiency of energy transactions between New England and New York and is discussed in more detail in Section 5.5.

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, closely predict the real-time scheduled flows.[66] 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 nearly offset each other. In aggregate, real-time net interchange was greater than day-ahead by only 0.1% during 2018 (*i.e.*, slightly more power was imported in real-time than planned for day-ahead). For the remainder of this section, only the real-time values will be presented since they align so closely with day-ahead values.

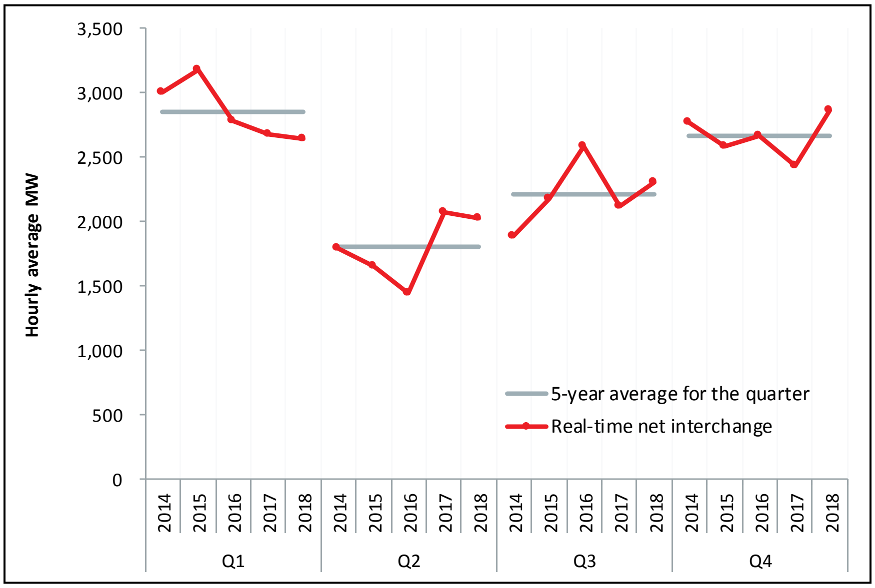
The level of net interchange varies by season. Typically, New England imports the most power in the winter and mid-summer. In recent years, the region's power prices have been highest during the winter months, when the natural gas network becomes constrained, and in the mid-summer, when New England experiences peak loads. High energy prices in New England during these periods can create opportunities for market participants to profit by importing lower-cost power into the region.

The hourly average real-time pool-wide net interchange value is plotted by quarter for 2014 through 2018 in Figure 2-18 below. Note that the observations are grouped by calendar quarter in

[66] 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 equivalent to physical imports or exports.

the chart. Each quarter's net interchange value is plotted with the red line series and, for comparison purposes, the five-year averages for each quarter are shown with the gray line series.

Figure 2-18: Real-Time Pool Net Interchange by Quarter



As the quarterly-segmented plots in Figure 2-18 show, there is seasonal fluctuation in the system net interchange. The fluctuation is demonstrated by the movement in the five-year average lines (gray) from a high during late winter (*i.e.*, Q1) when heating demand and natural gas-fired power plants compete for constrained gas supplies, down to a low during the spring (*i.e.*, Q2) when temperatures are moderate, and loads and natural gas prices are typically at their lowest. The average net interchange climbs during the summer (*i.e.*, Q3) when New England loads are typically highest, and moves to a second peak at the start of winter (*i.e.,* 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.

Relative to 2017, the 2018 quarterly average net interchange was similar in both Q1 and Q2. New England imported more power in Q3 and Q4 of 2018 than in those quarters in 2017. Notably, in Q4 2018, the average net interchange into New England was over 400 MW more per hour than in Q4 2017. The majority of this increase occurred at the New York North interface, where the average net interchange increased by almost 300 MW between Q4 2017 and Q4 2018. The average net interchange at the New York North interface in Q4 2017 was impacted by planned transmission work, which reduced the import capability of this interface to 600 MW for much of October. Additionally, in Q4 2018, ISO-NE modified the import limits for the New York North interface such that the interface now has a different winter and a summer limit. The winter import limit is 1,600 MW but the summer import limit continues to be 1,400 MW. This higher winter import limit went into effect in December 2018.

New England imports significantly more power from the Canadian provinces than it does from New York. Across all three Canadian interfaces (*i.e.*, Phase II, New Brunswick, and Highgate) the real-time net interchange averaged 2,056 MW per hour in 2018, which was 89 MW less than the average interchange volume during 2017. The real-time net interchange across the three interfaces with New York (New York North, Cross Sound Cable and Northport-Norwalk) averaged 403 MW per hour in 2018, 222 MW more than the average 2017 net interchange. Section 5 of this report provides further detail on the breakdown of total external transactions among the various interfaces with the New York and Canadian markets.

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 producing electricity are the 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 the cost of production), suppliers lose the incentive to deliver power when it is needed. Further, investment in new, economically viable resources 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 2018, total day-ahead and real-time energy payments reflected changes in underlying primary fuel prices, most notably natural gas. The average Hub price was $44.13/MWh in the day-ahead market, up by 32% on 2017, and consistent with the 33% increase in natural gas prices.

Under certain system conditions, suppliers can have local or system-wide market power. If suppliers take advantage of market power opportunities, by inflating energy offers, it can result in uncompetitive market prices. To diminish the impacts of market power, energy market mitigation measures are applied to replace uncompetitive offers with reference levels consistent with the cost of generation when market power is detected.

Overall, price-cost markups in the day-ahead energy market were within reason and market concentration levels, on average, remained reasonably low. Energy supply portfolios with structural market power in the real-time market declined markedly in 2018, from over half of all hours in 2017, down to about one third of all hours in 2018. The reduction in the number of intervals with pivotal suppliers (and a higher residual supply index) is consistent with a number of market trends, including a higher reserve surplus, the commissioning of new entrant generators, and changes in the economic merit order reducing the market share of an existing participant who was frequently a pivotal supplier in the past.

The energy market has a fairly 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. We are currently evaluating the potential impact of structural market power in the real-time market and the effectiveness of existing mitigation thresholds. The analysis will be presented in a future report.

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

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

The *day-ahead energy market* allows participants to buy and sell electricity the day before the operating day. Electricity buyers, also known as Load-Serving Entities (LSEs), acting on behalf of end-users may submit demand "bids" and schedules, which express their willingness to buy a quantity of electricity at prescribed prices. Electricity sellers (suppliers) have the option to submit day-ahead supply offers, which express their willingness to sell a quantity of electricity at prescribed prices. Suppliers, or generators, with a Capacity Supply Obligation (CSO) are required to sell into the day-ahead market at a quantity at least equal to the CSO MW value. In addition, as described in Section 4, any market participant may submit *virtual* demand bids (decrement bids) or *virtual* supply offers (incremental offers) into the day-ahead market. As the name implies, virtual demand bids and supply offers do not require a market participant to have physical load or supply.

Supply offers from generators are submitted at a nodal level, while demand bids from LSEs are submitted at a zonal level. Virtual bids and offers can be submitted at a nodal level, zonal level or at the Hub.[67] The bids and offers indicate the willingness to buy or sell a quantity of electric energy in the day-ahead market at that location. The ISO uses a clearing algorithm that selects bids and offers to maximize total benefit to supply and demand, subject to transmission constraints. The day-ahead market purchases enough physical and virtual supply to meet the physical and virtual demand. Operating reserves, described in Section 7.1, are not explicitly purchased through the day-ahead market. Operating reserves are procured in the Forward Reserve Market (see Section 7.2), and additional procurement occurs in the real-time energy market where reserve procurement is co-optimized with energy procurement.

The day-ahead market results are usually posted no later than 1:30 p.m. the day before the operating day. Resources that clear in the day-ahead energy market, but do not recover their as-offered costs through the hourly Locational Marginal Price (LMP), receive additional payment in the form of day-ahead Net Commitment-Period Compensation (NCPC).

The *real-time energy market* is the physical market in which generators sell, and LSEs purchase, electricity during the operating day. The ISO coordinates the production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. The ISO calculates LMPs every five minutes for each location on the transmission system at which power is either withdrawn or injected. The prices for each location reflect the cost of the resource needed to meet the next increment of load at that location.

Energy and reserves are co-optimized in the real-time energy market and the resulting LMPs reflect the relationship between energy price and reserve procurement. Reserve prices reflect the opportunity cost of dispatching generators down from their otherwise optimal energy output to ensure adequate 10- or 30-minute reserves and are capped at values known as Reserve Constraint Penalty Factors (RCPFs). The real-time energy market can also be thought of as a "balancing market," settling the difference between positions (production or consumption) cleared in the day-ahead energy market and actual production or consumption in the real-time energy market. Participants that consume more, or provide less, than their day-ahead schedule pay the real-time

[67] The Hub, load zones, and internal network nodes 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. *Load zones* are aggregations of internal nodes within specific geographic areas. The *Hub* is a collection of internal nodes intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace. 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 a load zone. An *external interface* 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.

LMP for the difference, and participants that consume less, or provide more, than their day-ahead schedule are paid the real-time LMP for the difference.

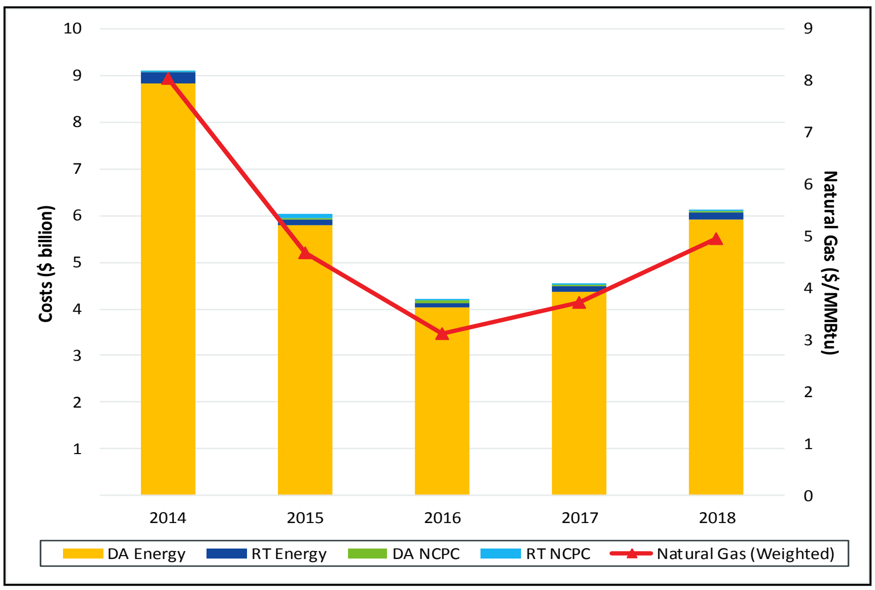
Similar to the day-ahead energy market, generators are entitled to NCPC payments in the real-time energy market if they do not recover their as-offered costs through the LMP.

3.2 Energy and NCPC (Uplift) Payments

In 2018, total estimated energy and NCPC payments increased by 35% compared to 2017 ($6.1 billion in 2018 compared with $4.5 billion in 2017) largely due to a 33% uptick in natural gas prices.

Energy payments in the day-ahead market accounted for approximately 97% of total energy market payments, driven by load clearing 99% of its real-time requirements day-ahead. NCPC accounted for just 1.2% of total energy payments, similar in relative terms to 2017. Energy and NCPC payments for each year (billions of dollars), by market, along with the average natural gas price ($/MMBtu[68]), are shown in Figure 3-1 below.

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



The relationship between natural gas prices and energy market payments is clear from the graph, specifically how natural gas prices were the primary driver behind the year-to-year changes in energy payments. Natural gas prices averaged $4.95/MMBtu in 2018, up by $1.23/MMBtu (33%) on 2017 prices.

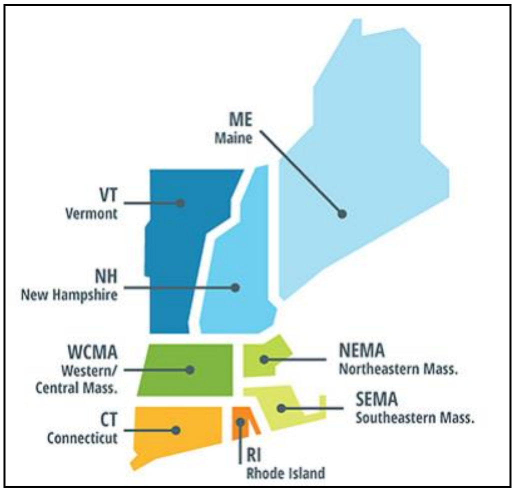
3.3 Energy Prices

Day-ahead and real-time LMPs are presented in this section. Both simple-average and load-weighted prices are summarized by time period and location. All pricing data are summarized as either annual average or monthly average values. On-peak periods are weekday hours ending 8 to

[68] MMBtu stands for one million British Thermal Units (BTU).

23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation [NERC] holidays); the off-peak period encompasses all other hours. Pricing data are differentiated geographically by "load zone" (as shown in Figure 3-2 below) and the "Hub".

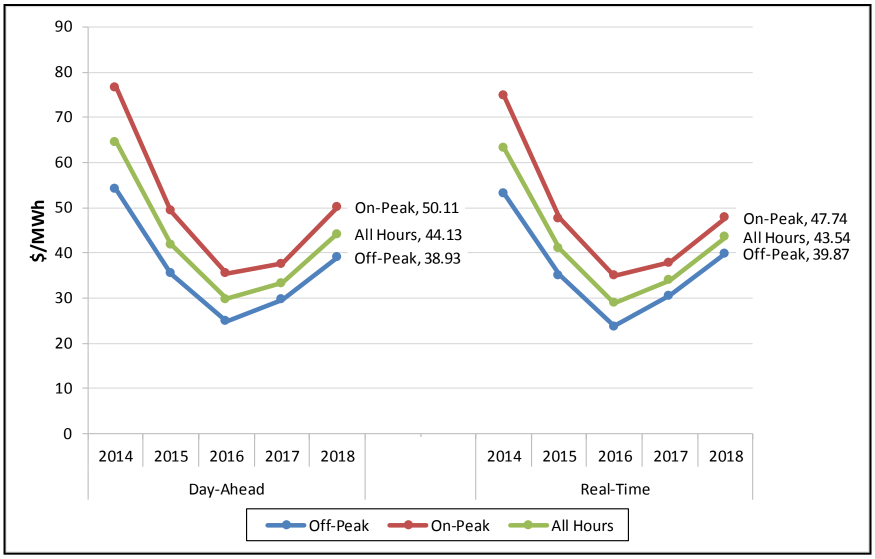
Figure 3-2: ISO New England Pricing Zones



3.3.1 Hub Prices

An illustration of energy market price trends in the day-ahead and real-time markets, from 2014 to 2018, is provided in Figure 3-3 below.

Figure 3-3: Annual Simple Average Hub Price



In 2018, the average Hub price (in all hours) was $44.13/MWh in the day-ahead market and $43.54/MWh in the real-time market. Hub prices were up by 32% in the day-ahead market and by 28% in the real-time market compared to 2017 prices.[69]

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

Pricing by time-of-day (i.e., on-peak and off-peak) in 2018 exhibited the same trend when compared with 2017: on-peak prices increased by 33% in the day-ahead market and 26% in the real-time market, while off-peak prices increased by 31% in both the day-ahead and real-time markets.

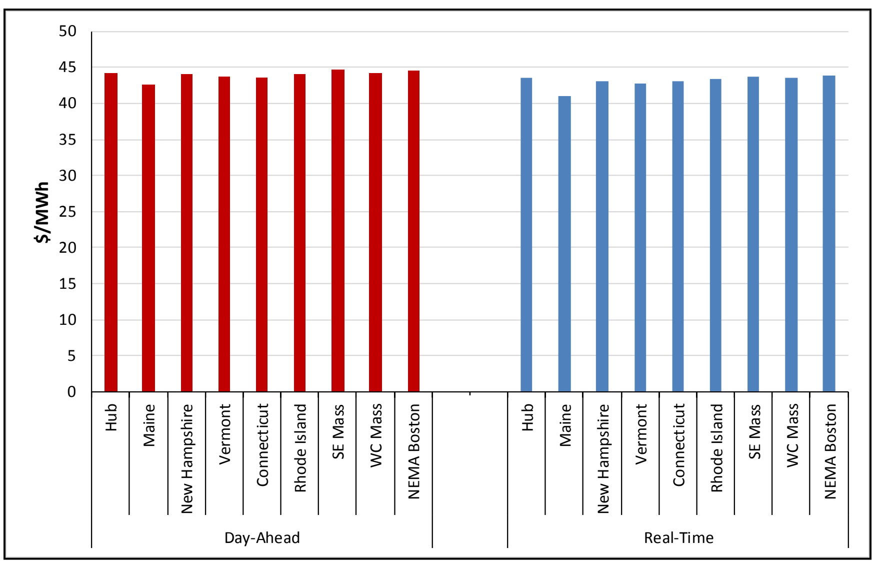
These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Compared to 2017, fuel prices increased significantly in 2018; in particular, natural gas and fuel oil increased by approximately 33% and 32%, respectively. The increase in fuel prices and related colder winter weather in 2018, including a significant "cold snap" in January 2018, explain the increase in LMPs. A small increase in 2018 loads (2%), driven by higher summer demand, also contributed to the increase in LMPs.

Average real-time prices were slightly lower than day-ahead prices in 2018 overall (-1.3% in "All Hours") and during on-peak periods (-4.7%). Off-peak prices were slightly higher in the real-time market (2.4%). The lower average overall real-time prices continue a longer-run trend of average day-ahead prices slightly exceeding real-time prices, except in 2017 when real-time prices were higher than day-ahead prices resulting primarily from relatively high real-time prices in the latter part of December 2017.

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 will result from energy "losses" and transmission congestion that vary by location.[70] In 2018, price differences among the load zones were relatively small, as shown in Figure 3-4.

Figure 3-4: Simple Average Hub and Load Zone Prices, 2018



[70] The loss component of the LMP is the marginal cost of additional losses resulting from supplying an increment of load at the 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).

The relatively small prices differences between the load zones were the result of modest levels of both marginal losses and congestion. The average absolute difference between the Hub annual average price and average load zone prices was $0.43/MWh in the day-ahead energy market and $0.59/MWh in the real-time energy market – a difference of approximately 1.0-1.3%.

The Maine load zone had the lowest average prices in the region in 2018. Maine's prices averaged $1.50/MWh (3%) and $2.51/MWh (6%) lower than the Hub's prices for the day-ahead and real-time markets, respectively. Maine tends to be export-constrained, and therefore cannot export all of its relatively inexpensive power to the rest of New England because of transmission constraints.

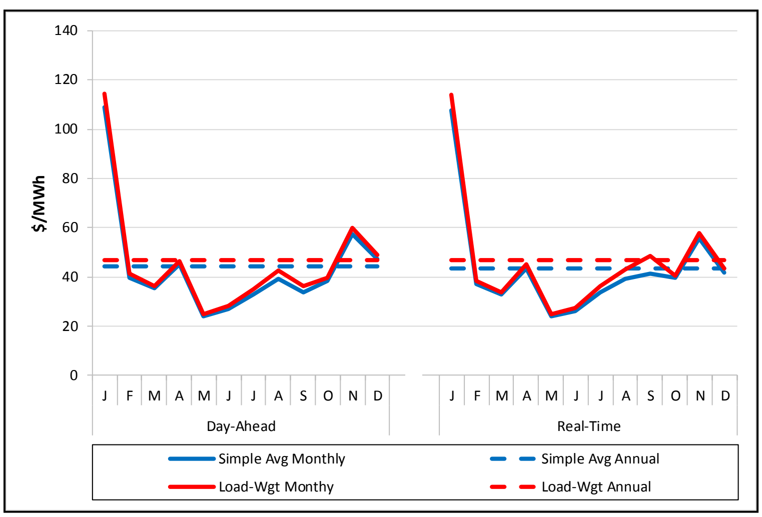
Conversely, NEMA and SEMA had the highest average prices in the day-ahead and real-time markets. SEMA's average day-ahead price was slightly higher than the Hub's (by $0.48/MWh), while the NEMA average real-time price was higher than the Hub's price (by $0.33/MWh). SEMA and NEMA are import-constrained at times, with the transmission network limiting the ability to import relatively inexpensive power into the load zone.

3.3.3 Load-Weighted Prices

While simple average prices are an indicator of the actual observed energy pricing within the ISO's markets, load-weighted prices are a better indicator of the average price that Load Serving Entities (LSEs) pay for energy.[71] The amount of energy consumed in the markets can vary significantly by hour and energy prices. Load-weighted prices reflect the increasing cost of satisfying demand during peak consumption periods when load is greater; during high load periods more expensive supply resources must be committed and dispatched to meet the higher loads. Load-weighted prices tend to be higher than simple average prices.

The average load-weighted prices were $46.88 and $46.85/MWh in the day-ahead and real-time markets, respectively. Monthly load-weighted and simple average prices for 2018 are provided in Figure 3-5.

Figure 3-5: Load-Weighted and Simple Average Hub Prices, 2018

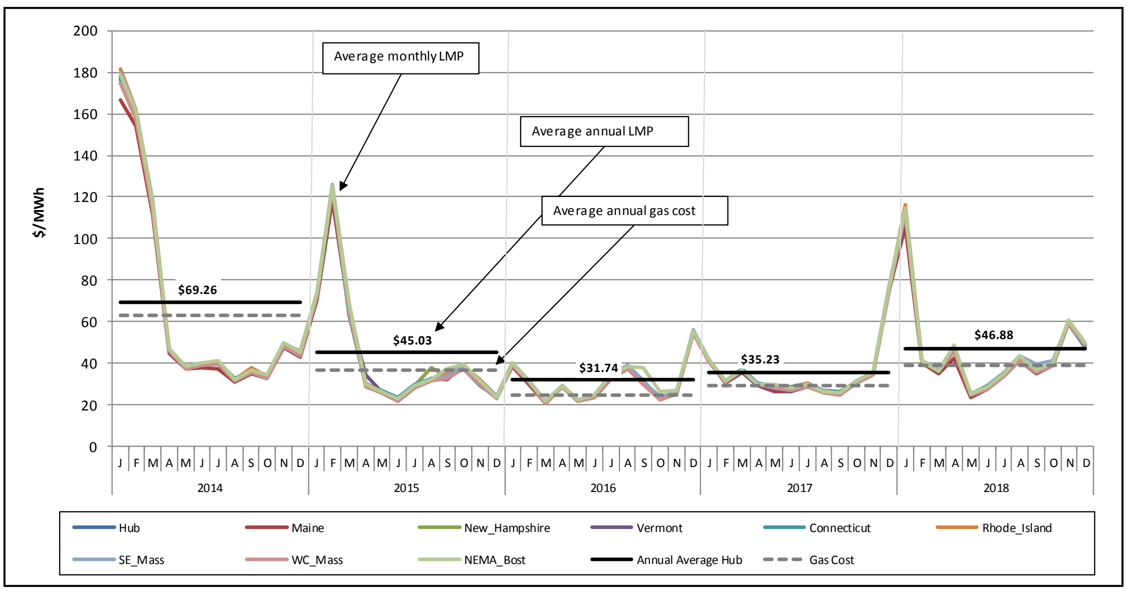


[71] While a simple average price weights each energy market price equally across the day, load weighting reflects the proportion of energy consumed in each hour: load-weighted prices give higher weighting to high-load consumption hours than to low load consumption hours, with each hour being weighted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

As expected, load-weighted average prices were higher than simple average prices in 2018. The difference ranges from approximately 2% to 15%, depending on the month and energy market (day-ahead and real-time). These price differences reflect the variability of 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 2018, load variability during the day had the least impact on the average prices paid by wholesale consumers in March, when simple and load-weighted average prices differed by just 2% in the day-ahead and real-time markets. Warm weather months exhibited the greatest impact of load variability on the average prices paid by wholesale consumers, with load-weighted prices exceeding simple average prices by 8% (day-ahead market) and 15% (real-time market) in August and September, respectively. The larger price differences in Summer 2018, compared to 2017, resulted from the shortage event and associated real-time scarcity pricing on September 3, 2018.

Day-ahead load-weighted prices across load zones over the past five years are shown in Figure 3-6 below. The black lines show the average annual load-weighted Hub prices and highlight the degree of variability in prices throughout the year. The dashed grey lines show the annual average cost of natural gas.

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



Load-weighted energy prices by load zone from 2014 to 2018 indicate a pattern that varies considerably by year and month, but typically not by load zone. As described above, a primary driver of material price differences between load zones is congestion; with a few exceptions (such as January 2014 and May 2017), monthly average prices did not exhibit significant price differences across load zones over the review period.[72] Extreme pricing in the months of January 2014, February 2015, and January 2018 occurred due to high natural gas prices. This is consistent with varying weather patterns and natural gas prices over the period, and reasonably uniform load

[72] In May 2017, transmission line outages and warm temperatures, with elevated load levels, resulted in noticeable differences in average monthly prices across load zones.

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 pricing trend applies to the real-time market.

3.3.4 Energy Price Convergence

This section focuses on three aspects of price convergence. First, this Section describes the importance of price convergence as a signal of market efficiency. Second, we review the degree of day-ahead and real-time energy price convergence in recent years. In 2018, the average day-ahead Hub price was $0.59/MWh (or 1.3%) higher than the average real-time Hub price, and the level of price convergence was similar to previous years. Lastly, this section examines the drivers that influence energy price convergence, including the factors that cause real-time and day-ahead prices to differ.

Importance of Price Convergence

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.

Scheduling generators in the day-ahead market is advantageous because it allows for more flexibility in unit selection. After the day-ahead market closes and 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, are no longer available to dispatch in the real-time market. Thus, in real-time, there is a greater reliance on more-expensive, fast-start generators.[73]

Price convergence comes into play because it reflects how well the day-ahead market is anticipating real-time conditions. For example, consider a day where real-time load is much higher than the amount of demand that had cleared in the day-ahead market (e.g., September 3, 2018). To meet this additional load, the ISO would need to commit additional (and often more expensive) fast-start generators in real-time. The result would be a real-time price that is greater than (sometimes much greater than) the day-ahead price.

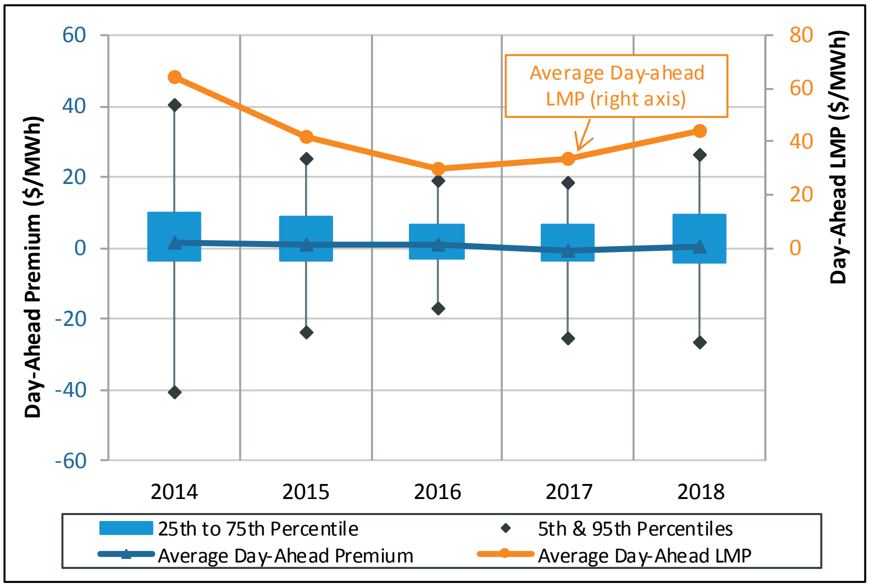
If the day-ahead market had better anticipated real-time conditions, the day-ahead and real-time prices would have been better aligned. Participants forecasting high real-time load would have cleared more demand in the day-ahead market, which would have led to less-expensive, longer-lead time generators being committed in the day-ahead market. The result would be a lower overall dispatch cost as these less-expensive generators would remove the need to commit a more-expensive, fast-start generator in real-time. Day-ahead and real-time prices would move closer; more demand in the day-ahead market would increase the day-ahead price, while no longer needing to dispatch an expensive fast-start generator would decrease the real-time price. Thus, strong price convergence serves as a signal that the day-ahead market is accurately anticipating real-time conditions and helping ensure reliable, least-cost dispatch.

[73] Scheduling in the day-ahead is also beneficial for generators that have operational and fuel procurement constraints, which can be better managed when they are committed in the day-ahead market.

Price Convergence 2014-2018

The overall convergence between day-ahead and real-time prices has remained relatively stable over the past five years. Figure 3-7 below shows the distribution of the day-ahead price premium at the Hub (day-ahead Hub price minus real-time Hub price) along with average day-ahead Hub LMP (orange line) for 2014–2018.

Figure 3-7: Day-Ahead Hub LMP Premium and Mean Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged $0.59/MWh in 2018 (i.e., the day-ahead Hub price averaged $0.59/MWh more than the real-time Hub price). However, there was considerable variation around this average over the year. The blue boxes in Figure 3-7, which denote the range of 25th and 75th percentiles of the day-ahead premium for each year, show that for half of all hours in 2018, the day-ahead Hub premium was between -$3.93/MWh and $9.22/MWh.

The whiskers in Figure 3-7 show the 5th and 95th percentiles for the day-ahead Hub premium, which were -$26.83/MWh and $26.13/MWh, respectively, in 2018. Over time, the 5th/95th percentiles generally track the average day-ahead LMP (orange series, right axis). Since average LMPs are primarily driven by natural gas prices, differences between day-ahead and real-time prices tend to be larger when gas prices are higher. This is because the difference in cost between two gas-fired generators with different heat rates is greater when gas prices are higher.[74]

Drivers of Price Divergence

Real-time conditions will usually differ from day-ahead expectations. Market efficiency does not require that real-time and day-ahead prices be equal all the time. Rather, it means that prices reflect

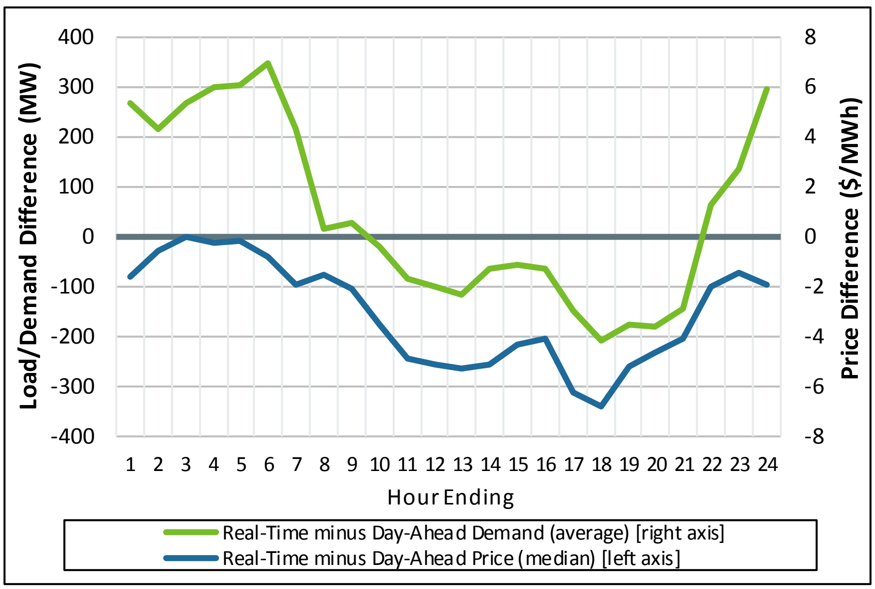
[74] For example, consider two gas-fired generators: Gen A has a heat rate of 7 MMBtu/MWh and Gen B has a heat rate of 10 MMBtu/MWh. If the gas price is $5/MMBtu, the generation cost for Gen A is $35/MWh (7 MMBtu/MWh x $5/MMBtu) and the cost for Gen B is $50/MWh (10 MMBtu/MWh x $5/MMBtu). The difference in generation cost between Gen A and Gen B is $15/MWh. If the gas price increases to $10/MMBtu, the generation costs for Gen A and Gen B are now $70/MWh and $100/MWh, respectively, for a difference of $30/MWh.

all available information, and in turn, day-ahead prices represent an unbiased expectation of real-time prices.

Ultimately, supply and demand forces, as well as actions taken by the ISO to ensure reliability, determine day-ahead and real-time prices. Thus, when day-ahead and real-time prices do vary, it is often driven by shifts in supply and demand conditions. On the supply-side, for example, if a generator clears in the day-ahead market and then has a forced (unplanned) outage, the available system capacity falls and real-time prices will likely rise. On the demand-side, for example, warmer-than expected temperatures on a summer day can translate to greater real-time loads and higher real-time prices.

The close connection between deviations in real-time load and day-ahead demand and the differences in real-time and day-ahead Hub prices are shown in Figure 3-8 below. The green line depicts the average difference between real-time load and day-ahead demand (i.e., the real-time load minus the day-ahead demand) during 2018 by hour of the day (hours ending 1–24). The blue line shows the median difference between real-time and day-ahead Hub prices (i.e., the real-time Hub price minus the day-ahead Hub price) during 2018 by hour of the day.

Figure 3-8: Deviations in Real-Time and Day-Ahead Demand and Hub Price by Hour Ending in 2018



The difference in real-time and day-ahead Hub prices correlates well with the deviations in real-time and day-ahead demand. For example, the hours with less real-time load compared to day-ahead demand (e.g., HE 17-20) tend to have lower real-time prices. When real-time load falls below day-ahead demand (e.g., if temperatures on a summer day end up cooler than expected), the ISO will often back down the most-expensive generators; this results in moving down the supply stack to less-costly generators, which translates to a lower real-time price relative to the day-ahead price.

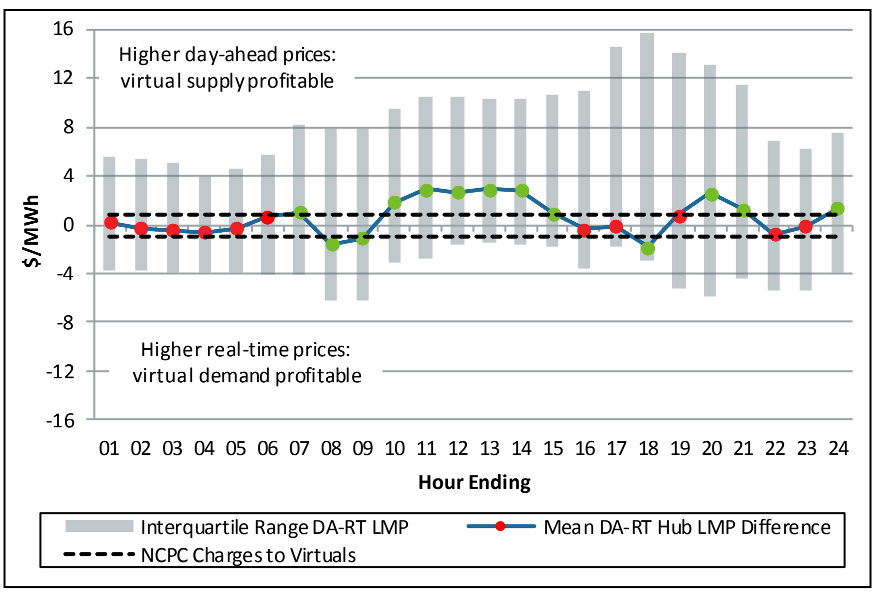
In addition to unforeseen changes between day-ahead and real-time conditions, market participants may have a preference for one market over another. For example, a supplier with a gas-fired generator may prefer to sell power in the day-ahead market. Receiving an operating schedule the day before expected physical delivery allows the supplier to better manage buying and scheduling natural gas for the following day. Similarly, an LSE may want to limit their exposure to more volatile real-time prices and prefer to purchase load in the day-ahead market.

Role of Virtual Transactions in Price Convergence

As discussed in more detail in Section 4.1, virtual transactions play a critical role in improving market efficiency and price convergence. Virtual traders profit from differences between the real-time and day-ahead price. Generally, profit earned by a virtual trader is a reflection of the value that the trader brings in helping price convergence. For example, consider a virtual trader who anticipates that higher-than forecasted temperatures will cause real-time load and price to be much higher than others expect. The trader submits a virtual demand bid and it clears 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 helped improve price convergence: by clearing the demand bid, the trader increased the day-ahead price, thereby bringing day-ahead prices closer to real-time prices. Importantly, by increasing day-ahead demand, it may have worked to commit additional physical generators that could serve the higher load and preclude the need to call upon higher-cost, fast-start generators in real-time.

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. This is demonstrated in Figure 3-9 below which shows average hourly trends in the day-ahead and real-time price differences at the Hub in 2018, together with average NCPC charges. The blue line shows the mean price difference. When price differences are above zero it is profitable for virtual supply to clear, and below zero for virtual demand to clear, before considering NCPC. The dashed black lines show the average NCPC charge to virtual supply and virtual demand. Where the blue line falls between the two dashed black lines (red circles), on average, neither virtual supply nor virtual demand is profitable 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 (green circles).

Figure 3-9: Hourly Day-Ahead to Real-Time Price Differences and NCPC Charges, 2018



In some hours, it was not profitable (on average) for a virtual participant to help converge prices. For example, in hours ending one through six, the average gross profit to be made from a virtual transaction at the Hub is less than the NCPC costs it would be charged. Although a participant will not know in advance what the NCPC charge will be, this expectation of a loss (or a higher possibility of a loss) diminishes the incentive for a virtual participant to capture these price differences.

In other hours, it was profitable on average for virtual traders to help converge prices, yet this did not occur. This is most apparent for hours ending 10 through 15, when day-ahead prices were on average above real-time prices and this difference exceeded the average NCPC charge. It would have been profitable (on average) for a participant to clear a virtual supply offer in the day-ahead in these hours — effectively selling at the higher day-ahead price and buying back at the lower real-time price. The lack of price convergence may have been hindered by uncertainty over NCPC charges or uncertain load conditions in these hours, with the latter being impacted more and more by the growth in behind-the-meter solar generation.

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 areas 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)
- Load and weather conditions (Section 3.4.3)
- Demand bidding (Section 3.4.4)
- Load forecast error (Section 3.4.5)
- Supply margin (Section 3.4.6)
- System events (Section 3.4.7)
- Reliability commitments (Section 3.4.8)
- Congestion (Section 3.4.9)
- Marginal resources (Section 3.4.10)

3.4.1 Generation Costs

In 2018, day-ahead and real-time electricity prices continued to be closely correlated with the estimated cost of operating a natural gas-fired generator. As discussed later in section 3.4.10, the price of electricity is set by the offer price of one or more marginal resources in any given time interval. In a competitive uniform clearing price auction, a resource's offer price should reflect its variable production costs, which for fossil fuel generators, is largely determined by its fuel cost and efficiency (heat rate). Since gas-fired generators set price more frequently than generators of any other fuel type in New England, it is expected that New England electricity prices are positively correlated with the estimated marginal costs of a typical gas-fired generator.

One way to understand the relationship between electricity prices and fuel costs is to compare the variable costs of generating electricity with different fuels to the wholesale price (LMP). Quarterly average day-ahead LMPs, alongside the estimated generation costs of various fuel types assuming standard heat rates are illustrated in Figure 3-10 below.[75]

Figure 3-10: Estimated Generation Costs and LMPs during Peak Hours

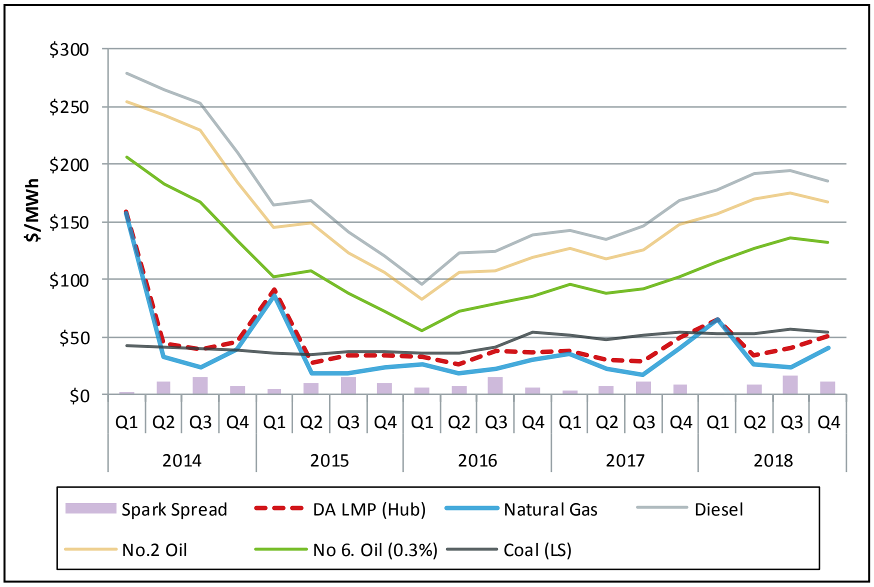


Figure 3-10 shows that changes in the average day-ahead electricity prices are closely correlated with the estimated costs of operating a natural gas-fired generator. The correlation can break down during the summer months when high electricity demand often requires the operation of less efficient natural gas-fired generators and/or generators that burn more expensive fuels. During the summer, efficient natural gas-fired generators earn higher margins (commonly referred to as spark spreads) compared with the winter months.[76]

As natural gas-fired generators are the dominant price-setters and comprise roughly 50% of native generation, it is worth reviewing average annual on-peak spark spreads and implied gas heat rates across a range of efficiencies in the New England fleet. Table 3-1 below shows key inputs into the calculations; LMP and gas prices, the implied (or breakeven) gas generator heat rate. Spark spreads are shown across a range of efficiencies, with 7,800 Btu/kWh representing the average New England fleet and 7,000 Btu/kWh reflecting a new entrant combined cycle.

[75] The variable generation costs are calculated by multiplying the daily fuel price ($MMBtu) by the average standard efficiency of generators of a given technology and fuel type (MMBtu/MWh). Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas – 7.8, Coal – 10, No. 6 Oil – 10.5, No. 2 Oil – 11.7

[76] During the winter months, coal and oil-fired generators can displace natural gas-fired generators in economic merit order more frequently than 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 3-1: 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)				
				7,000	7,800	8,000	9,000	10,000
2014	76.60	8.28	9,247	18.62	11.99	10.33	2.05	(6.23)
2015	49.32	4.81	10,262	15.68	11.83	10.87	6.06	1.26
2016	35.39	3.17	11,149	13.17	10.63	9.99	6.82	3.65
2017	37.64	3.69	10,188	11.78	8.82	8.08	4.39	0.69
2018	50.11	5.05	9,918	14.74	10.70	9.69	4.64	(0.41)

Table 3-1 shows that the spark spreads for a New England gas-fired generator, assuming a standard efficiency, increased by 21% year-over year ($8.82/MWh to $10.70/MWh). The implied heat for New England gas-fired generators decreased 2.7% year-over-year (10,188 Btu/kWh to 9,918 Btu/kWh). This indicates that less efficient gas-fired generators are making lower gross margins compared to 2017.

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 following:

- An influx of natural gas-fired generating capacity over the past 25 years.[77]
- The natural gas system becoming increasingly constrained due to high heating demand during winter months and greater demand from natural gas-fired generators.
- Limited additional gas pipeline capacity to alleviate those constraints due to regulatory, political and market challenges.
- An aging and declining fleet of nuclear, oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s.
- Lower natural gas prices resulting from increased production of domestic shale gas from the Marcellus Shale region of the country.

The confluence of these factors has resulted in a much higher proportion of electricity being generated by gas-fired generators in New England, while pushing gas pipeline capacity to its limits during winter periods of peak gas demand. Consequently, the reliability of New England's wholesale electricity grid is partially dependent on the owners and operators of natural gas-fired generators to effectively manage natural gas deliveries during contemporaneous periods of high gas and electric power demand. Reliability is also increasingly dependent on the region's oil fleet having sufficient oil on hand to operate when the gas network is highly constrained and gas prices

[77] During the 1990s, the region's electricity was produced primarily by oil-fired, coal-fired, and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal-fired plants produced about 18% of New England's electricity. In contrast, by 2018, oil-fired plants produced approximately 1% of electricity consumed in New England. Approximately 49% of electricity was produced by gas-fired generation and 1% by coal-fired generation.

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.

rise to levels that exceed the oil prices. When this occurs, oil-fired generators are 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.[78] The ISO has undertaken a number of projects aimed at improving reliability through better generator performance and fuel assurance. The following initiatives address these issues:

- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design, which began June 1st, 2018 [79]
- Introducing the Winter Reliability Programs, which was needed until PFP became fully effective in 2018
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generations 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 ten-minute non-spinning reserve to be procured in the Forward Reserve Market to account for generator non-performance
- Recent proposal to compensate generators for providing energy security through the Interim Compensation Treatment and longer term efforts to develop a market-based approach to valuing and pricing energy security

Relationship between natural gas and electricity prices

Average day-ahead LMPs and natural gas prices from 2014 to 2018 are shown by quarter in Figure 3-11 below. Given that the highest natural gas and electricity prices occurred in the first quarter (Q1) of the year, Q1 is shown separately from the remainder of the year.

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

[79] See Section 6.2.2 for information on Pay-For-Performance

Figure 3-11: Average Electricity and Gas Prices for Q1 Compared with Rest of the Year

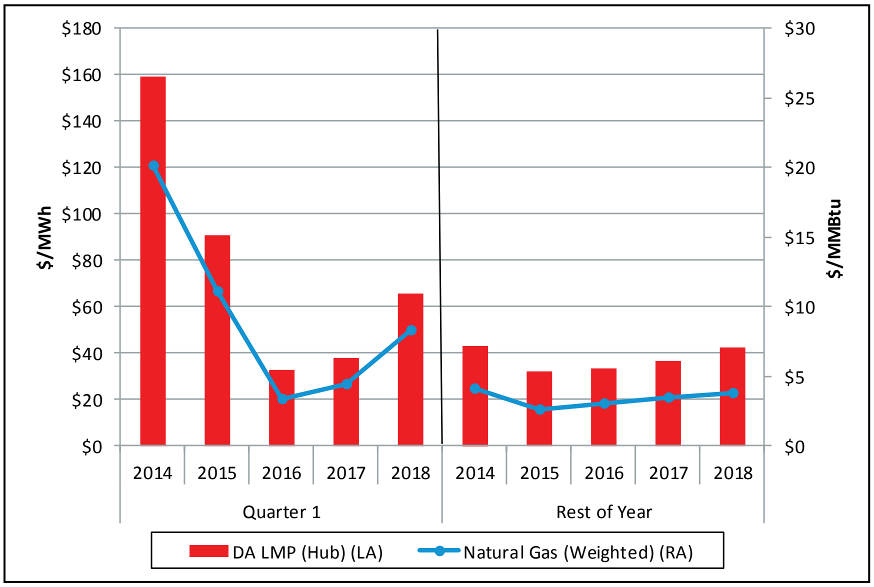


Figure 3-11 shows that in Q1, 2018 had higher prices than 2016 and 2017, but remained below 2014 and 2015 levels primarily because of temperature fluctuations. Q1 2018 was slightly colder than Q1 2016 and Q1 2017, but warmer than Q1 2014 and Q1 2015. The "cold snap" was the major driver of colder weather and higher gas prices in Q1 2018. From January 1 to January 9, temperatures averaged 14^{0}F compared to 27^{0}F over the same period in 2017[80]. The colder weather drove higher natural gas demand, leading to a 349% year-over-year increase in natural gas prices during the 9-day period ($6.95/MMBtu to $31.22/MMBtu).[81]

Seasonal temperature fluctuations typically drive quarterly natural gas price variation. When temperatures are low during the winter, gas-fired generators must compete for natural gas with heating demand for limited natural gas because of scarce gas network capacity. The resulting constraints on the natural gas system cause higher prices. The relationship between lower temperatures and higher gas prices at a daily level for Q1 of 2016, 2017 and 2018 is illustrated in Figure 3-12.

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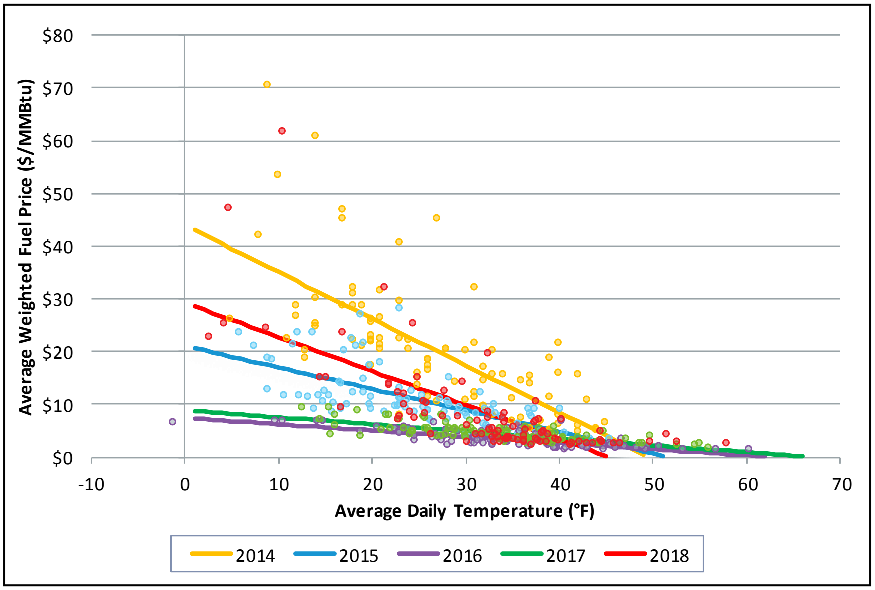
[80] Temperatures in Q1 2018 were warmer (1^{0}F) than Q1 2017 when the "cold snap" is removed. For more information on the "cold snap" see the IMM's 2018 Winter Quarterly Markets Report

[81] Gas prices were 86% ($8.34 vs $4.48) higher in Q1 2018 than Q1 2017, but only 38% ($5.80 vs $4.20) higher when the "cold snap" is removed.

Figure 3-12: Daily Temperatures and Natural Gas Prices in Q1



The trend lines in Figure 3-12 illustrate the negative correlation between gas prices and temperature; gas prices increase as temperatures decrease. The graph illustrates two trends. First, Q1 2018 prices were significantly higher than both Q1 2017 and Q1 2016. This was driven by more extreme temperatures. While the average quarterly temperature in 2018 (32°F) was not much colder than 2017 (33°F) or 2016 (35°F), Q1 2018 had more days 10°For below than 2016 and 2017. In 2018 the extremely low temperatures were sustained over a 9-day period of the "cold snap", and corresponded to the highest gas prices.

Second, gas prices were more volatile in 2018. The volatility increase can mostly be attributed to stress on pipelines from the "cold snap". On days with similar temperatures, natural gas prices in 2018 were higher than in 2017 and 2016. For example, when the daily average temperature was less than 20°F in Q1 2018, gas prices averaged about $ 27/MMBtu. For the same temperature range in 2017 and 2016, prices averaged about $6-7/MMBtu. During periods with consecutive cold days, gas prices tend to be more susceptible to price spikes.

3.4.2 Supply-Side Participation

In 2018, unpriced supply made up nearly 75% of total supply, a level similar to previous years. Unpriced supply consists of offers from suppliers that are willing to sell (i.e., clear) at any price, or 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. Unpriced supply is not eligible to set price, so only a small share of total supply—the remaining 25% that is considered priced supply— is eligible to set energy prices.

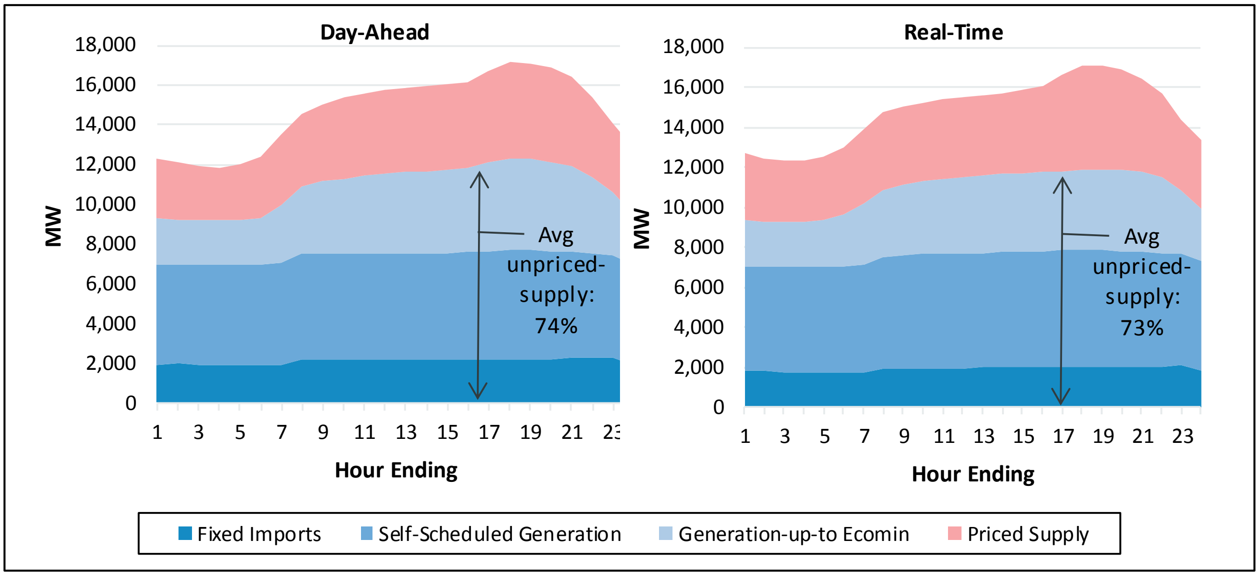
There are three categories of unpriced supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

- **Fixed imports** are power that is scheduled to flow 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).[82]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is equal to or below EcoMin. For example, if a unit generating 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is 100 MW. Generation-up-to economic minimum is ineligible to set price, as the market software is unable to dispatch it down without turning off the generator.

An hourly average breakdown of unpriced supply by category as well as priced supply for the day-ahead and real-time markets in 2018 are provided in Figure 3-13 below.

Figure 3-13: Day-Ahead and Real-Time Supply Breakdown by Hour Ending in 2018

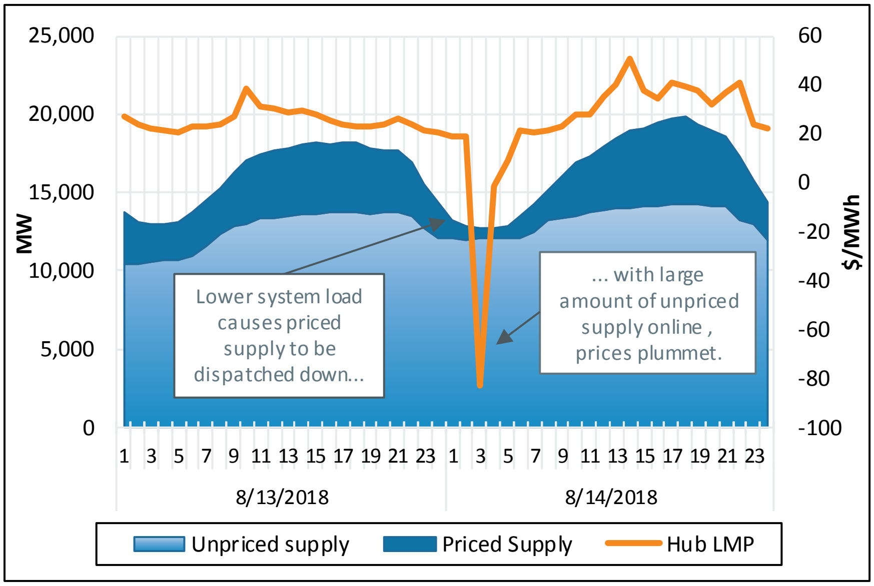


Over the course of a day, the share of supply from self-scheduled generation (the largest component of unpriced supply) and fixed imports tends to be fairly stable. The daily ramp-ups in load are typically met by additional supply from generation-up-to EcoMin and priced supply. Priced supply averaged 27% of total supply in the real-time market over all hours in 2018, with its share peaking in Hour Ending (HE) 19 at 31%. On average, unpriced supply made up 74% and 73% of total supply in the day-ahead and real-time, respectively.

The large amount of unpriced supply has 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 3-14 below, which shows unpriced and priced supply along with the Hub LMP for August 13-14, 2018.

[82] The Economic Minimum (EcoMin) is the minimum MW output that a generating resource must be allowed to produce while under economic dispatch.

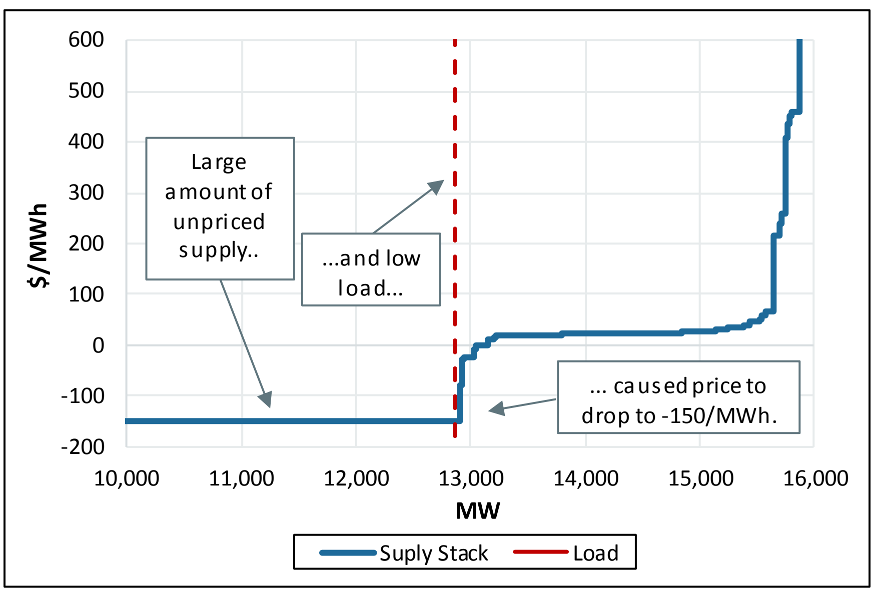
Figure 3-14: Price and Unpriced Supply vs. Real-Time LMP, August 13-14, 2018



The early morning hours of August 14 saw lower than expected real-time loads. To keep total supply and demand in balance, the ISO dispatched down priced supply. As priced supply shrunk, system load fell very close to the level of unpriced supply. The result was a sharp decline in price, with the 5-minute Hub LMP falling to about -$150/MWh and averaging -$83/MWh during HE 3.

The swiftness of the price drop was a consequence of the supply stack being very steep as it approaches the level of total unpriced supply. That is, a small change in load would translate to a relatively large change in the market-clearing price. Figure 3-15 highlights this for the interval beginning at 2:30AM, during the period of negative prices on August 14.

Figure 3-15: Real-Time Supply Stack and Load, August 14, 2018 2:30AM



The flat portion of the supply stack (blue line) at -$150/MWh represents the large amount of unpriced supply. As load (dashed red line) fell, it approached this unpriced portion of the supply stack and the price quickly fell from $11.69/MWh at 2:00AM to -$148.36/MWh at 2:05AM. In situations like this, there is very little generation with price-setting capability that can be dispatched economically. The small amount of generation dispatched economically had offered into the market with negative offers, resulting in negative prices. The combination of relatively low load and a large amount of unpriced generation can thus bring about a sudden drop in prices to low or even negative levels.

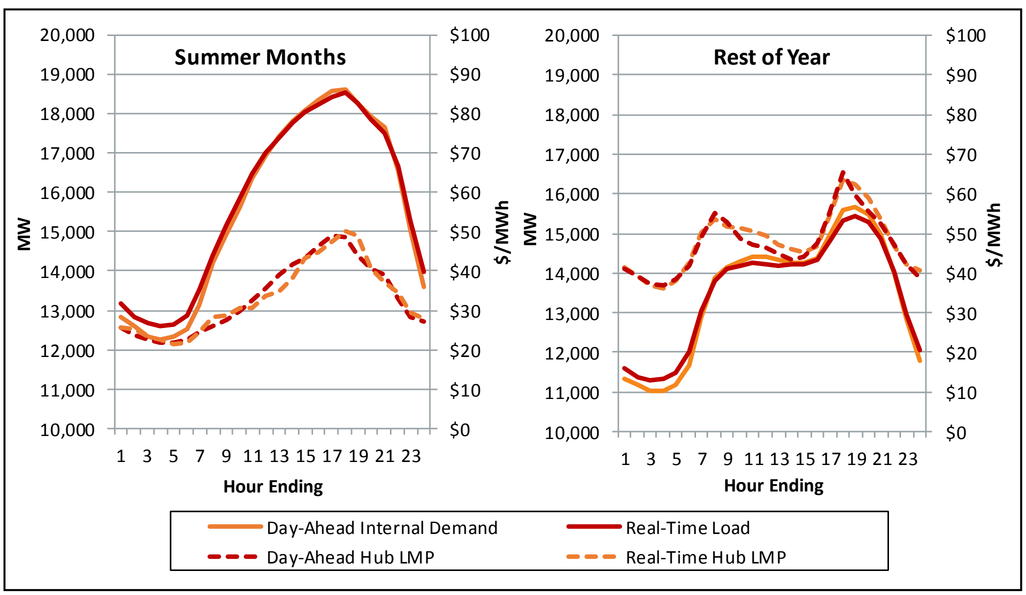
3.4.3 Load and Weather Conditions

Load is a key determinant of day-ahead and real-time energy prices. Higher load generally leads to higher prices when other factors, such as fuel prices and outages, are similar. Trends in wholesale electricity load trends are primarily driven by weather, economic changes, and energy efficiency measures. Behind-the-meter photovoltaic generation, albeit relatively small in New England, is also working to reduce wholesale load.[83]

Demand/Load Statistics

The strong connection between energy prices and load levels is particularly evident within an operating day. The hours with lowest loads typically have the lowest prices, and the hours of highest loads usually coincide with highest prices. Figure 3-16 below depicts the average time-of-day profile for day-ahead demand and real-time load compared to LMPs for 2018. The left panel of Figure 3-16 shows the summer months only (June–August), where loads climb throughout the day as air conditioning demand rises; the right panel shows the other months of the year, when there is usually a morning peak and evening peak with a dip in the middle part of the day.

Figure 3-16: Average Demand and LMP by Time of Day in 2018



The figure shows a clear positive correlation between demand levels and prices in both the day-ahead and real-time markets. The early-morning hours typically see the lowest prices, when load levels are at their lowest, and highest prices correspond to the hours of peak load. It also shows that

[83] For more information on ISO New England's investment in forecasting with behind-the-meter PV, see https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/

most demand clears in the day-ahead market, with relatively small demand deviations settled in the real-time market on average. The average difference between day-ahead cleared demand and real-time load was less than 1% in 2018.

Net Energy for Load (NEL) averaged 14,076 MW per hour in 2018, a 1.7% increase (239 MW per hour) from 2017. This is the first year-over-year increase in average load in New England since 2013. New England's native electricity load is shown in Table 3-2 below.[84]

Table 3-2: Load Statistics

	NEL (GWh)	Hourly NEL (MW)	Peak Load (MW)	Weather Normalized NEL (GWh)	Hourly Weather Normalized Load (MW)
2014	127,175	14,518	24,443	127,114	14,511
2015	126,956	14,493	24,437	125,779	14,358
2016	124,425	14,165	25,596	123,953	14,111
2017	121,215	13,837	23,968	120,668	13,737
2018	123,306	14,076	26,024	120,560	13,725

Note: *Weather-normalized* results are an estimate of load that would have been observed if the weather were the same as the long-term average.

The uptick in load during 2018 was driven by a relatively hot and humid summer, which resulted in an 8% jump in Q3 2018 load relative to Q3 2017. Annual average load was still 10% below the all-time New England high of 15,566 MW in 2005. Peak load in 2018 occurred in hour ending 17 on August 29 at 26,024 MW as the New England average temperature reached 93°F. This was the highest hourly average load observed since July 2013 and nearly 6% above the average peak load for years 2014–2017. On a weather-normalized basis, load was 13,725 MW in 2018, which was a 0.1% decline from 2017. Annual weather normalized load has dropped continuously since 2010 due in part to energy efficiency and, to a lesser extent behind-the-meter solar (see Section 2.3.1).

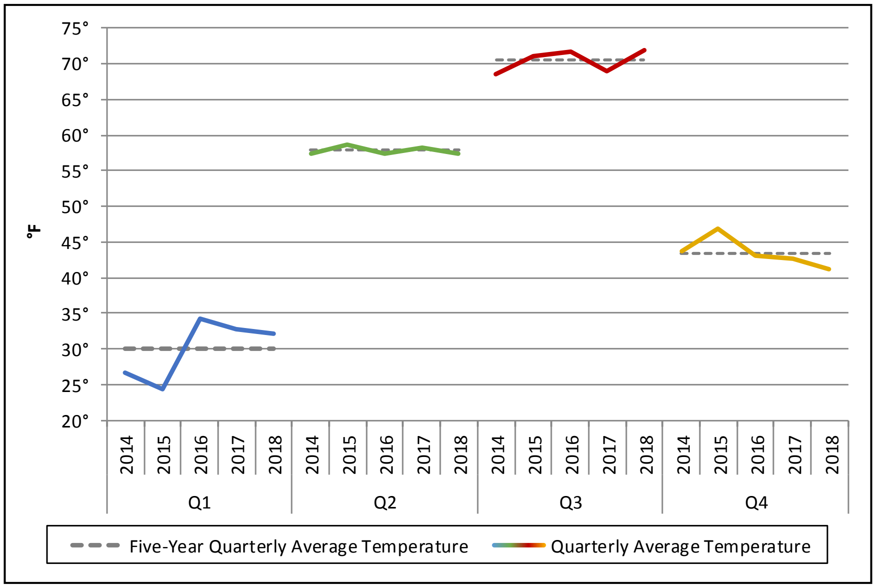
Impact of Weather

Weather is the primary driver of load in New England. Temperature varied throughout 2018, leading to strong fluctuations in load. Quarterly average and five-year average temperatures for 2014 through 2018, are provided in Figure 3-17 below.[85] The first quarter (Q1), which includes a majority of the winter (January–March), is shown in blue, Q2 (April–June) is green, Q3 (July–September) is red, and Q4 (October-December) is yellow.

[84] Load in this analysis 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 minus exports). It excludes pumped-storage demand.

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

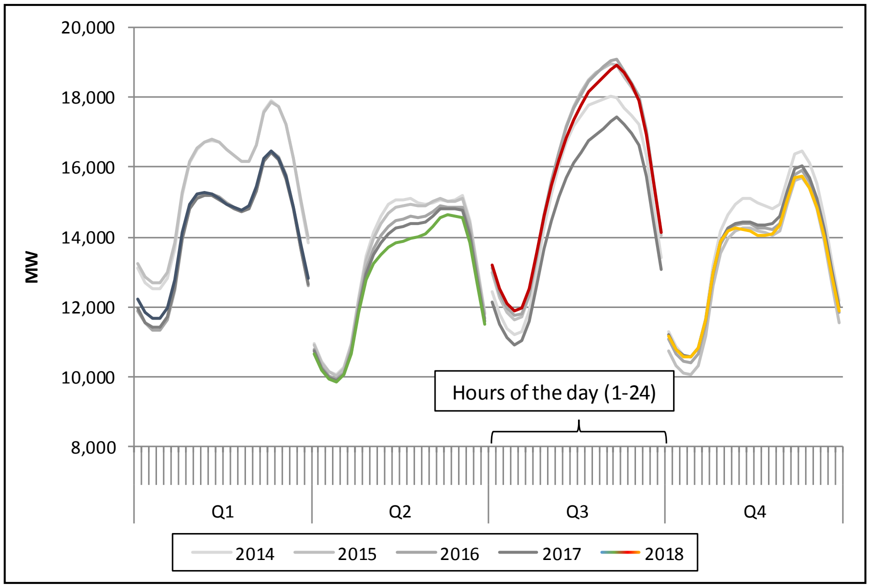
Figure 3-17: Actual and Normal Temperatures



The bitter cold seen in early January 2018 gave way to an unseasonably warm March, which led to a warmer Q1 relative to the 5-year average. After mild weather in Q2, with temperatures averaging very close to the 5-year norm, the summer brought about hot and humid weather. The average temperature in Q3 was 72°F, a 3°F increase from 2017 and about 1.4°F above the 5-year average. The fourth quarter of 2018 saw colder than usual temperatures for October and November, resulting in a lower-than average temperature for Q4.

Quarterly average load tracked the swings seen in temperatures during 2018. Average quarterly load by time of day (hour endings 1–24) is shown in Figure 3-18. The shape of the load curve differs by quarter. In the summer, load typically rises steadily until the peak hours, and then declines as temperatures cool. When the weather gets colder, load peaks twice, once after the morning ramp, then again in the evening.

Figure 3-18: Average Hourly Load by Quarter



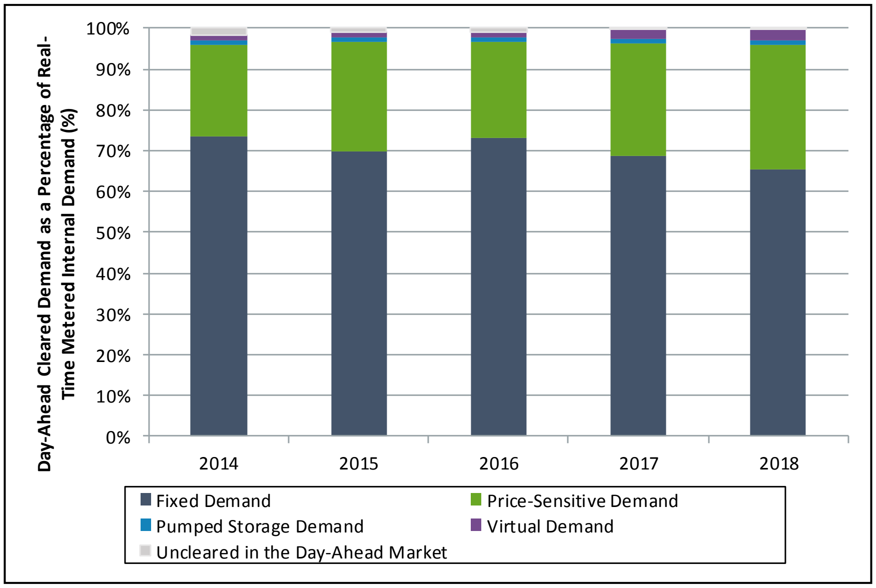
Average load was lower than the 5-year average (2014–2018) for all quarters of 2018, with the exception of Q3. In the third quarter of 2018, average load was 2% above the five-year average because of hot and humid weather (Figure 3-17). The decline in average loads for the remaining quarters was due to a combination of milder temperatures (in the case of Q1 and Q2) and greater energy efficiency (see Section 2.3.1).

3.4.4 Demand Bidding

The amount of demand that clears in the day-ahead market is important, because along with the ISO's Reserve Adequacy Assessment, it influences the generator commitment decision for the operating day.[86] Day-ahead demand is comprised of fixed, price-sensitive, virtual, asset-related (pumped-storage) demand and exports. This section focuses on internal demand to highlight demand participation within New England. Exports are discussed in Section 2.4 and Section 5. The components of demand clearing in the day-ahead market are shown in Figure 3-19 below.

[86] The Reserve Adequacy Assessment (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. The objective is to minimize the cost of bringing the capacity to the market.

Figure 3-19: Components of Cleared Demand in the Day-Ahead Market

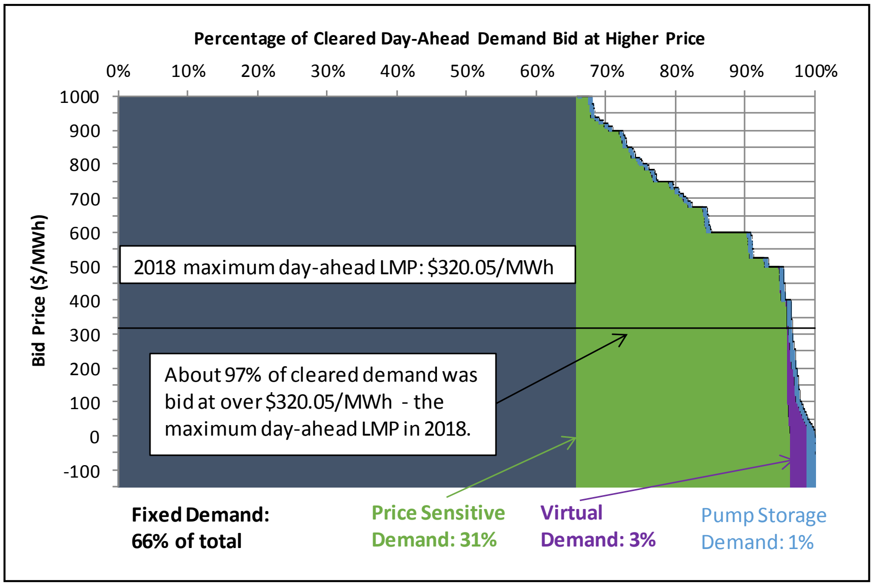


Fixed demand bids indicate that participants are willing to pay the market-clearing price, regardless of cost. Fixed demand averaged 65.5% of real-time load in 2018, compared to 69% in 2017. This slight decline from 2017 was made up by an increase in the share of price sensitive-demand, which rose from 27% of real-time load to 30.5%. Participants that submit price-sensitive bids are only willing to have their bid clear if the market-clearing price is below their bid price. At 2.6%, virtual demand made up a similar share relative to 2017. Trends in virtual demand transactions are discussed in detail in Section 4.

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

Cleared internal demand bids by price are shown in Figure 3-20 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, about 97% of cleared day-ahead demand was willing to pay more than $320.05/MWh, the maximum day-ahead hub LMP that was observed in 2018.

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



Note: *Percentages will not add to 100% due to rounding*.

Generally, demand cleared in New England is price insensitive. About two-thirds of total day-ahead demand was fixed and would have cleared at any price. Additionally, nearly all price-sensitive demand cleared with a bid above the maximum day-ahead LMP in 2018 of $320.05/MWh. About half of pump-storage demand, which accounts for about 1% of total demand, was bid as fixed energy. Overall, over 97% of cleared day-ahead demand was willing to pay a higher price than was realized at the Hub at any time in the day-ahead market in 2018.

3.4.5 Load Forecast Error

The ISO produces several different load forecasts, ranging from long-term projections that look out 10 years to short-term forecasts made within the operating day. This section focuses on the *day-ahead load forecast*: the forecast made around 9:30AM each day that projects hourly load for the next operating day.[87] This forecast is the ISO's last load projection that is made prior to the close of the day-ahead market. It is published on the ISO's website and available to the 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.

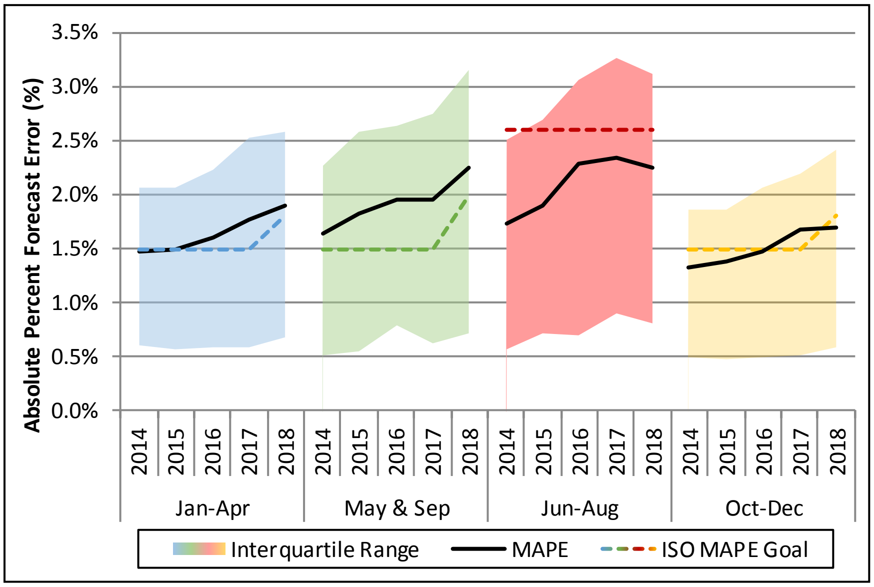
Additionally, the ISO's load forecasts are used in reserve adequacy analysis (RAA) process to make supplemental generator commitment decisions. During the RAA process, the ISO may determine that, based in part on their load forecast, the day-ahead market has scheduled insufficient capacity. In these situations, the ISO will commit additional capacity to satisfy load and reserve requirements. These commitments do not happen often, but when they occur, real-time market outcomes and prices are affected.

The absolute percent error of the ISO's day-ahead load forecast over the past five years by the time of year is shown in Figure 3-21 below. Months of the year are partitioned into four groups based on the ISO's monthly load forecast goal (shown as dashed lines). Prior to 2017, the ISO had a goal of

[87] 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 after 6AM and the second and final forecast is the published near 10AM.

2.6% mean absolute percent error (MAPE) in the summer months (June-August) and 1.5% MAPE for the other months.[88] The ISO revised its goals for 2018, which were 1.5% MAPE in months January–April and October–December; 1.8% in May and September; 2.6% remained the goal for months June–August.

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



Two key takeaways emerge from Figure 3-21. First, the summer months usually have the greatest forecasting error, since load is driven by cooling demand and very sensitive to swings in temperatures. Second, over the past five years, the average load forecast error has generally increased across all seasons. The largest increase in load forecast error has been for the months of May and September, which had a MAPE of 2.2% in 2018 (average for both months) compared to 1.6% in 2014. Overall, the ISO's load forecast error averaged 2.0% in 2018, an increase from 1.9% in 2017.

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 thus challenging to forecast. Other factors, such as behind-the-meter solar and industrial demand processes, compound the difficulty in accurately estimating load even in short time horizons. The growth of behind-the-meter solar in recent years makes accurate forecasting particularly more challenging. For one, it is hard 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.[89]

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 prices. ISO load forecast error tends to be consistent with the market's forecast error. That is, when the ISO over-

[88] 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] |.

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

forecasts, the day-ahead demand tends to over-clear in the day-ahead market compared to real-time load. Therefore, when the ISO's load forecast is greater than actual load, excess resources tend to be committed in the day-ahead market. This can result in depressed real-time prices as more expensive generators are backed down from their day-ahead positions. Alternatively, when actual loads are greater than the ISO's forecast, fewer resources are committed in the day-ahead market than what is needed in real-time. This can result in real-time prices that are higher than day-ahead prices because more expensive resources (than what cleared in the day-ahead) are required, and there is a smaller selection of resources to choose from due to start-up time constraints. In some cases, expensive fast-start resources are required to serve actual load.

The interaction between forecast error and pricing outcomes in 2018

The statistical relationship between the load forecast error and price divergence during 2018 is shown in Figure 3-22 below.

Figure 3-22: Price Separation and Forecast Error Relationship

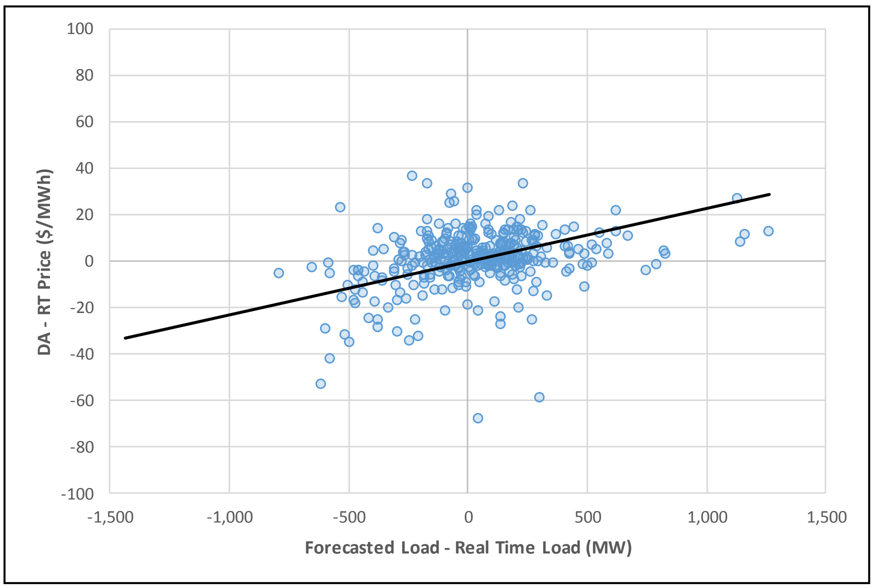
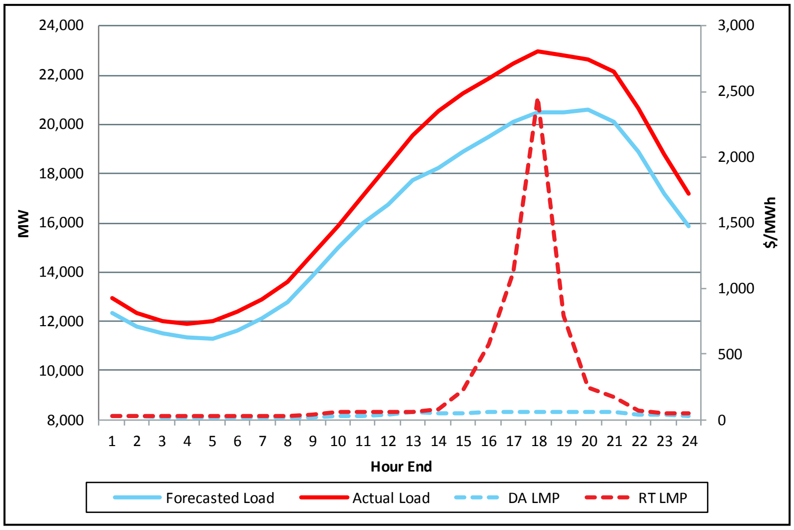


Figure 3-22 shows that there is a positive correlation between forecast error and price separation between real-time and day-ahead prices. In other words, higher real-time loads than the forecast tend to lead to higher real-time prices, and vice versa.

September 3, 2018 illustrates how higher than anticipated actual loads can contribute to prices spikes, and also to scarcity events.[90] Real-time loads were far higher than anticipated, driven by significantly hotter and more humid weather. The solid lines in Figure 3-23 show forecasted load and actual load, while the dashed lines show day-ahead and real-time hourly prices.

[90] The September 3 capacity shortage event is covered further in Section 3.4.7. Load forecast error was one of two contributing factors to the shortage conditions; forced generation outages was also another major factor.

Figure 3-23: September 3 Load Forecast Error



On September 3, actual loads were higher than forecasted loads in every hour of the day due to temperatures being consistently warmer than the forecast. Average daily load was 17,450 MW, while the forecast predicted an average daily load of 16,013 MW. Hourly actual load peaked at 22,956 MW in HE 18, 2,466 MW higher than the forecasted load at the same time.[91] The combination of higher real-time loads and forced (unplanned) generator outages drove real-time prices higher than day-ahead prices for every hour of the day, and contributed to a capacity scarcity event.[92] Hourly real time prices reached a peak of nearly $2,455/MWh, over 40 times higher than the day-ahead price.

3.4.6 Supply/Reserve Margin

The supply margin measures the additional available capacity over load and reserve requirements. If the supply margin is low, the ISO may have to commit more expensive supply to meet load and reserves, resulting in elevated prices. Additionally, the energy market is more susceptible to market power when system conditions are tight. In Section 3.7.3, statistics on the number of pivotal suppliers are presented; a participant is pivotal if its available capacity is greater than the reserve margin.

We use the reserve margin as a proxy for the supply margin because 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:

$$Supply + Gen_{Reserves} - [Reserve\ Requirement] = Demand$$

$$Supply + Reserve\ Margin = Demand$$

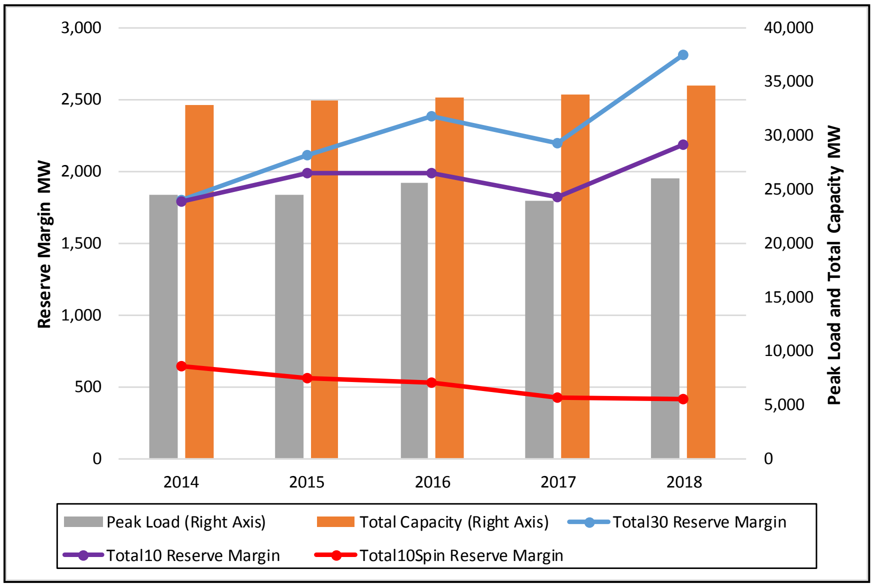
[91] The ISO's forecast had a peak hourly load of 20,590 MW in HE 20.

[92] Generator outages also contributed to higher real-time prices. See Section 3.4.7 for more information on the September 3 system event.

The reserve margin is the only difference between supply and demand, and represents the additional supply on the system in excess of demand.

The annual average margins for each type of reserve requirement and product (10-minute spinning reserve, total 10-minute reserve, and total 30-minute reserve) are shown in Figure 3-24 below. The margins are equal to the actual amount of reserves provided in excess of the corresponding reserve requirement. The total 30 surplus is the overall reserve surplus. The total 30-reserve requirement is equal to the total 10-minute reserve requirement, plus 50% of the second largest system contingency.

Figure 3-24: Reserve Margin, Peak Load, and Total Capacity



In 2018, the average thirty-minute operating reserve (TMOR) margin was over 2,800 MW, about 600 and 400 MW higher than the average reserve margins in 2017 and 2016, respectively. This was driven by the increased availability of offline 10- and 30-minute reserves. The 10-minute spinning reserve (TMSR) margin actually decreased slightly between 2017 and 2018. The increase in offline reserves was driven by several factors, including generator availability and market rules changes. There were no notable changes to self-scheduled commitments or uneconomic ISO commitments that appear to have increased the amount of online capacity and the reserve margin.

First, there was more pumped-storage generation available in 2018 than any other year in the study period. Historically, pumped-storage hydro generators have provided a significant portion of non-spinning reserves, as these generators have large capacities and can synchronize to the grid quickly. In 2016 and 2017, certain pumped-storage generators took extended outages for planned maintenance work. Outages for this type of generator were less prominent in 2018. In 2018, pumped-storage generator capacity out-of-service averaged 130 MW, compared to over 300 MW in 2017 and 2016.

Second, a market rule change introducing price-responsive demand was implemented in June 2018. This allowed demand response resources to begin providing reserves. Together, these resources typically provide around 140 MW of offline reserve capacity. On average for all of 2018 (including January through May), demand response resources provided 83 MW of reserves.

Third, a generator that changed to a more flexible open-cycle mode in August 2018 provided almost 50 MW more offline reserves in 2018 than it did in 2017. The rest of the increase in reserves was spread among many different generators. About 46% of generators provided more reserves on average in 2018 than in 2017, while 27% provided the same amount and 27% provided less.

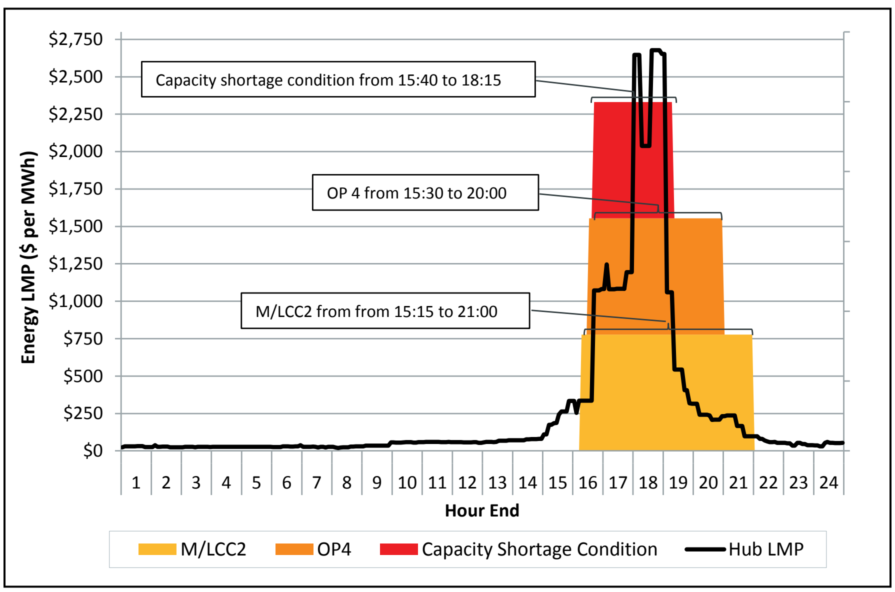
3.4.7 System Events during 2018

System events, such as the unexpected loss of major generation or transmission equipment, can have a significant impact on energy market outcomes. Two such events in 2018 bear specific mention.

Market Performance during September 3 System Event

On Monday, September 3, 2018, the system experienced the first capacity scarcity conditions (CSC) under the ISO's new pay for performance rules. On this hot Labor Day, a combination of unplanned generator outages and higher than anticipated loads resulted in emergency procedure actions, operating reserve deficits, and high energy and reserve prices. The ISO implemented both M/LCC 2 (Abnormal Conditions Alert) and OP4 (Action during a Capacity Deficiency) protocol actions in the afternoon, shortly after the unexpected loss of generation capacity. The capacity scarcity conditions were triggered at 3:40pm, and persisted for 2 hours and 40 minutes. Real-time prices and a timeline of the system events are shown in Figure 3-25 below.

Figure 3-25: System Event Categories and Real-Time Pricing Outcomes



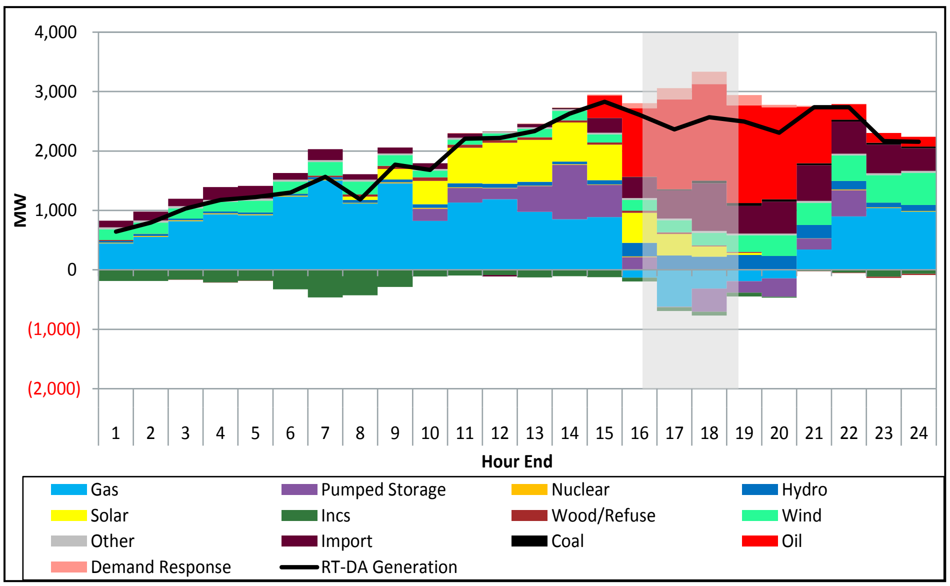
The following paragraphs detail the factors that contributed to the event and how event outcomes were reflected in market settlements.

Forecast error: Real-time loads were much higher than forecasted, with a maximum error of 2,466 MW. The forecast error was driven by the weather, which was much hotter and more humid than expected. The amount of demand (and supply) that cleared in the day-ahead market was consistent with the load forecast, indicating that the market had also expected lower loads on September 3. See section 3.4.3 for more detail on the load forecast error on September 3.

Unplanned generator outages: The system lost a large volume of generation capacity throughout the day due to unplanned generator outages. Total unplanned outage capacity ranged from 2,330 to 2,450 MW for much of HE 16 through 18, an increase of nearly 1,700 MW from earlier in the day. Much of the generation on unplanned outage during the day was expected to be online and contributing to the energy and reserve requirements during the evening peak. The most significant outages occurred in the afternoon (around HE 15 through 16), when two large natural gas-fired generators and one dual-fuel generator tripped, with losses totaling around 1,160 MW. The shortage event began at 15:40, just after these outages occurred.

Real-time commitments: Both the unplanned outages and higher load obligations led operators to commit large volumes of additional generation in real-time. During the shortage event, there was increased generation from fast-start oil-fired generators, imports, and demand response. The breakdown in differences between day ahead and real-time generation obligations is shown in Figure 3-26 below.

Figure 3-26: Differences between Real-Time and Day-Ahead Generation Obligations



Real-time obligations were roughly 1,900 MW higher than day-ahead generation obligations, on average, throughout the day. Prior to the shortage event, natural gas-fired generators provided additional energy in real-time. During the shortage event (highlighted on graph), natural gas-fired generators collectively provided less than their aggregate day-ahead supply obligation, mostly due to unplanned outages. Deviations from natural gas-fired generators led to increased generation from fast-start oil-fired generators, imports, and demand response.

LMPs and real-time reserve pricing: Five-minute real-time energy prices reached a peak of \$2,677/MWh at the Hub over a twenty-minute period beginning at 5:35pm. High energy prices were a result of high reserve prices, which were incorporated into the LMP. During the scarcity event, there were deficits in both the thirty-minute operating reserve (TMOR) requirement and the ten-minute non-spinning reserve (TMNSR) requirement. These deficits triggered reserve constraint penalty factors. The TMOR penalty factor (\$1,000/MWh) was in effect from 15:40 to 18:20. The TMNSR (\$1,500/MWh) penalty factor was also activated for 45 minutes during this interval, resulting in a combined reserve price of \$2,500/MWh for that duration.

Market settlements-energy market: Real-time costs were significant. Because of larger real-time load obligations, deviations from generator day-ahead schedules, and very high real-time prices, real-time costs made up about 47% of total energy payments. Uplift payments totaled $1.87 million on September 3, with a large portion paid to generators that were postured (constrained down from their economic level) for reliability. Dispatch lost opportunity cost uplift and rapid-response pricing-opportunity cost uplift also accounted for a significant amount of the real-time uplift payments.

Market settlements-pay for performance rules: Under pay for performance rules, participants with a Capacity Supply Obligation (CSO) were expected to provide an average of 72% of their contracted capacity in form of energy or reserves during this event. Deviations from obligated performance were settled at the performance payment rate of $2,000/MWh during each 5-minute interval of the capacity scarcity condition. Credits totaled $44 million, while charges amounted to $36 million. Performance varied widely by fuel type. Self-scheduled generators and generators with shorter lead-times saw the largest payments, while longer lead-time generators incurred charges.

Software Outage on May 15, 2018

On May 15, severe weather and a software outage resulted in notable system conditions and market outcomes. Average hourly prices were amongst the highest of Spring 2018, with a high of $280.95/MWh, including thirty-minute operating reserve pricing.

During the afternoon on May 15, a series of violent thunderstorms swept through New England, producing 100 mph winds and spawning four tornadoes in Connecticut. The Storm Prediction Center issued a “moderate” tornado risk by midday, and by the afternoon, areas of New England experienced one of the worst thunderstorm outbreaks in decades. As thunderstorms moved across the region, cloud cover reduced the output of wholesale and behind-the-meter solar generation. Shortly before the storm, behind-the-meter and settlement-only solar generation were producing about 1,600 MW at 2 p.m. Solar generation declined as the storm progressed, decreasing to just 330 MW by 4 p.m. Additionally, the ISO expected humidity to decrease as the storm passed, but humidity remained high, resulting in significant load forecast error. The loss of solar generation and the relatively high humidity contributed to actual loads running higher than the forecast, by 844 to 1,405 MW from 3 to 5 p.m. (as shown in the inset graph in Figure 3-27).

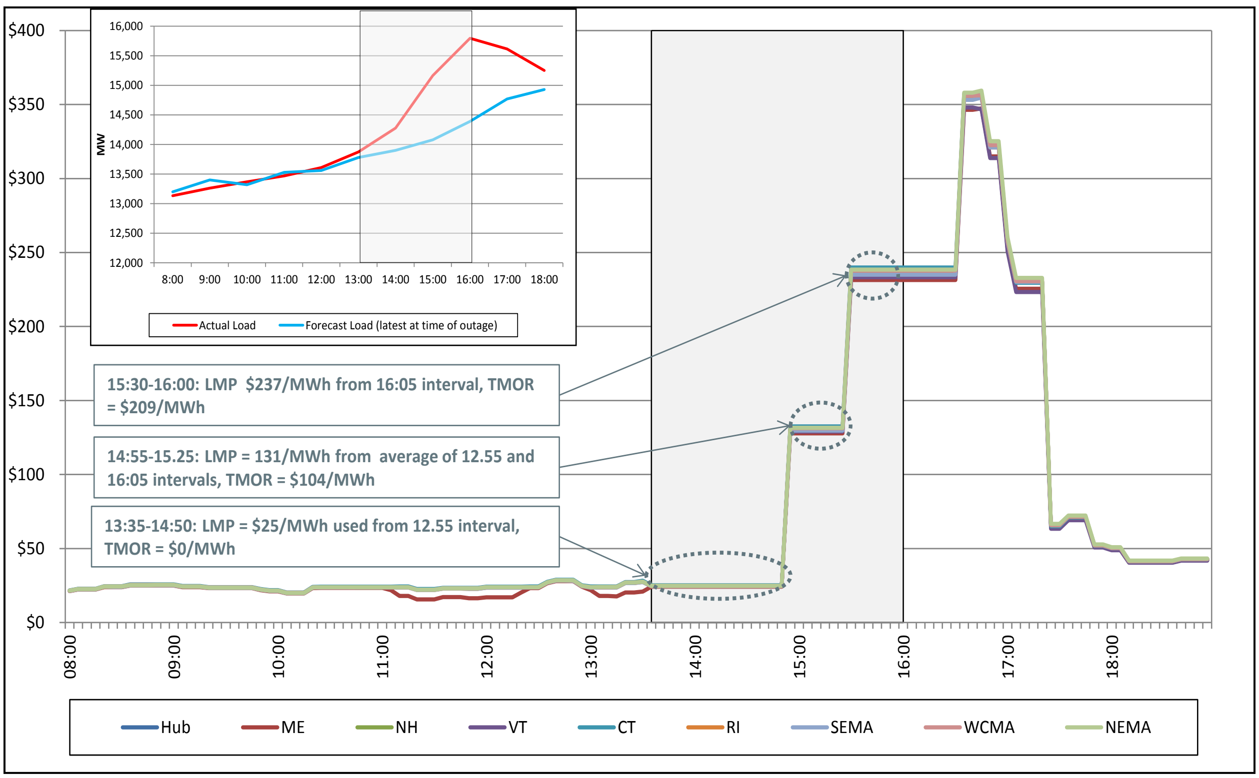
The severe weather resulted in tight system conditions. Multiple transmission elements tripped due to high winds, and the large load forecast error caused available reserves to decline at around 2:55 p.m. The operating reserve margin (the amount of reserves available in excess of the reserve requirement) dropped to nearly 0 MW at around 4 p.m. The ISO committed additional generation to maintain adequate operating reserves. Between 3 and 6 p.m., 1,300 to 2,000 MW of fast-start generation was required to meet load and operating reserve requirements.

Prior to the thunderstorms, the ISO took a planned software outage of the Energy Management System/Market power system beginning at 1:35 p.m. to update the network model.[93] During the outage, all of the reliability tools required to operate the system remained in service and were

[93] Network model updates generally occur three times per year. The ISO typically schedules the updates and software outages during the day. This network model upgrade was critical to the implementation of Pay for Performance and Price Responsive Demand and was scheduled to be completed prior to the storms entering the area.

used.[94] However, the outage removed the market software that determines economic commitment and pricing. While the software was unavailable, no LMPs were automatically calculated. Rather, ISO Operators managed commitments manually in economic order. Afterwards, the ISO used established protocols to recreate prices, as it typically does during market software outages. Given the large load forecast error towards the end of the software outage, LMPs were relatively low going into the outage ($27.62/MWh at 1:30 p.m.), and very high once the software came back online ($237/MWh at 4:05 p.m.). There was no notable reserve pricing in the intervals immediately preceding the outage, but by the time the software returned the reserve price was $213.49/MWh. To estimate prices, the ISO considered the LMPs before and after the software outage, as well as the load levels, reserve margins, and manual fast-start generator commitments during the outage. Below, Figure 3-27 shows LMPs for several hours on May 15, with the time of the outage highlighted in gray.

Figure 3-27: Forecast Error and Reconstituted 5-Minute LMPs on May 15, 2018



From 1:35 to 2:50 p.m., information from the 12:55 p.m. market case was used to set the LMP at $24.66/MWh and reserve pricing at $0/MWh.[95] From 2:55 to 3:25 p.m., the 12:55 and 4:05 p.m. case prices were averaged to create an LMP of $130.92/MWh, with a TMSR price of $2.45/MWh and a TMOR price of $104.30/MWh. From 3:30 to 4 p.m., the 4:05 p.m. price was used to set the LMP at $237.19/MWh, with a TMSR price of $4.89/MWh and a TMOR price of $208.60/MWh. The times at which the LMP increased during the outage correspond to changing reserve margins and commitments: At 2:55 p.m., the operating reserve surplus dropped, prompting the first round of

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[94] The outage to the ISO's energy management software was much shorter (minutes) than the market software, which allowed the Operators to continue to monitor and operate the system reliably during the storm.

[95] Market cases refer to the execution of the optimization software that produces commitment, dispatch or pricing results.

manual fast-start commitments. At 3:30 p.m., the operating reserve margin declined again, and additional fast-start generators were manually committed.

3.4.8 Reliability Commitments and Posturing

The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[96] 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 constraint (posture) resources from operating at a higher level as determined by the economic dispatch software, in order to improve reliability. This typically occurs in order to maintain adequate reserves from fast-start pumped-storage resources and to reserve limited fuel oil inventory.

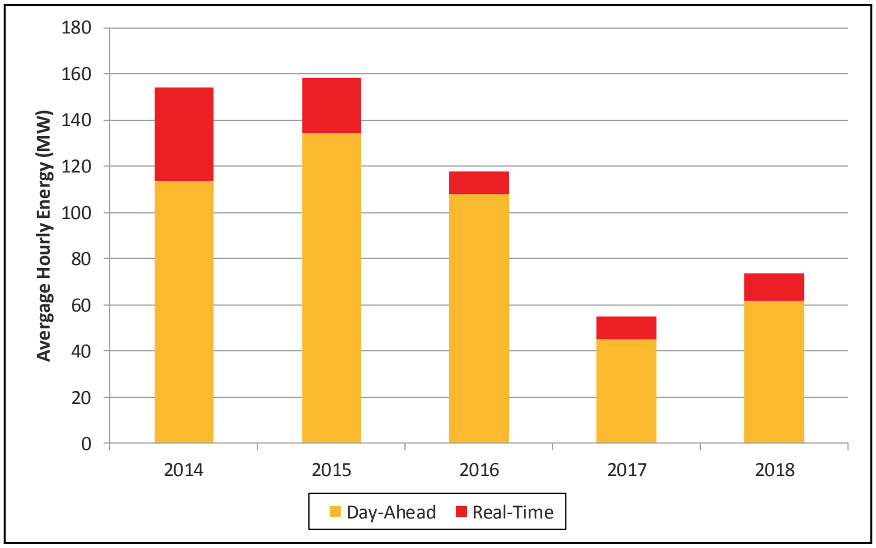
Reliability commitments

Reliability commitment decisions are often "out-of-merit", meaning that they are not based on the economics of the 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, this increases overall production costs in the market. If LMP payments 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 generator needed for reliability will operate at its economic minimum and price will be set by a less expensive generator. In some cases, generators needed for reliability can make themselves appear less flexible and potentially increase their uplift compensation.

In 2018, the amount of ISO reliability commitments increased but remained relatively low. The real-time average hourly energy output (MW) from reliability commitments during the peak load hours (hours ending 8-23) for 2014 through 2018 is shown in Figure 3-28. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

[96] 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/Standards/default.aspx. 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 0.5%, on average. The average hourly energy from reliability commitments during the peak load hours has decreased significantly starting in 2016. Commitments in the day-ahead market have become more common as a percentage of total reliability commitments.

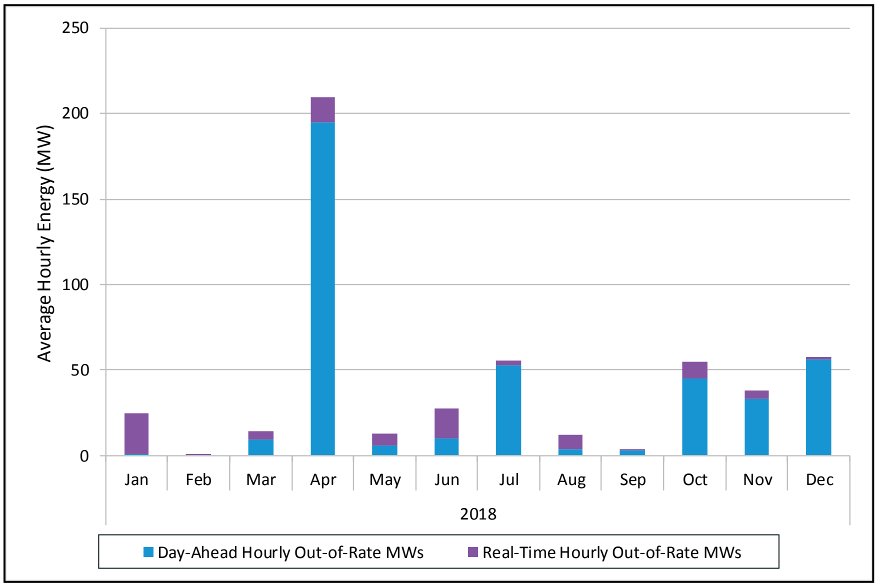
The increase in overall reliability commitments in 2018 resulted from local reliability commitments in NEMA/Boston, Rhode Island and SEMA during April 2018, to support planned transmission work. In 2018 overall, 90% (66.5 MW/hr) of the output from reliability commitments was for Local Second Contingency Reliability Protection (LSCPR), with 36% (24 MW/hr) of LSCPR commitments in the NEMA/Boston area, 19% in RI (13 MW/hr), and 20% in SEMA (13 MW/hr). Voltage support commitments tend to represent a relatively small percentage of overall reliability commitments and, in 2018, accounted for just 5% of reliability commitments (3.6 MW/hr).

Prior to 2018, reliability commitments decreased significantly in 2016 and 2017, compared to earlier years. The completion of planned transmission work that required must-run generation in the Boston area led to these overall reductions.

Beginning in 2013 (prior to the current review period), there was a shift from reliability commitments being made in the real-time market to the day-ahead market. Reductions in real-time reliability commitments in Figure 3-28 can be seen by the decrease in the height of the red bar during the review period. The shifting of reliability commitments to the day-ahead market was primarily due to the introduction of minimum capacity constraints in the day-ahead market model. Minimum capacity constraints set a minimum target for the amount of online capacity in a particular system area to meet reliability criteria.

A monthly breakdown of reliability commitments made during 2018 is shown in Figure 3-29 below. The figure shows the out-of-merit energy for reliability commitments during the peak load hours in 2018, by market and month. Out-of-rate energy includes reliability commitment output that is offered at a higher price than the LMP, and, therefore, would not likely have been committed or dispatched in economics.

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



Of the roughly 74 MW of average hourly output from generators committed for reliability, about 42 MW was out-of-rate. This is a relatively small amount of out-of-rate energy (in the context of average hourly load of 14,076 MW in 2018) that is being 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 April. As noted earlier, LSCPR commitments explain the out-of-rate April commitments. Approximately 96% of the output from reliability commitments in April was for LSCPR in NEMA/Boston, Rhode Island, and SEMA.[97] In terms of the uplift payments required to support out-of-rate commitments, total LSCPR NCPC payments in 2018 were approximately $15 million; while this represented 21% of total uplift payments for the year, it represented just 0.2% of total energy payments.

As shown in the two figures above, a large majority of the 2018 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. 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 Resource Adequacy Assessment (RAA) process or in real-time as day-ahead commitments tend to reduce the risk of suppressed real-time prices and NCPC. If reliability commitments are known in the day-ahead market, the commitment schedules of other generators can be adjusted to accommodate the reliability commitment. This provides more flexibility than if the commitment is made later, reducing the risk of having excess inflexible supply online. Excessive generator commitments can distort prices by removing other generators from the supply stack and adding

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

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, to allow 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 also provide either 10- or 30-minute operating reserves, if fast-start capable.

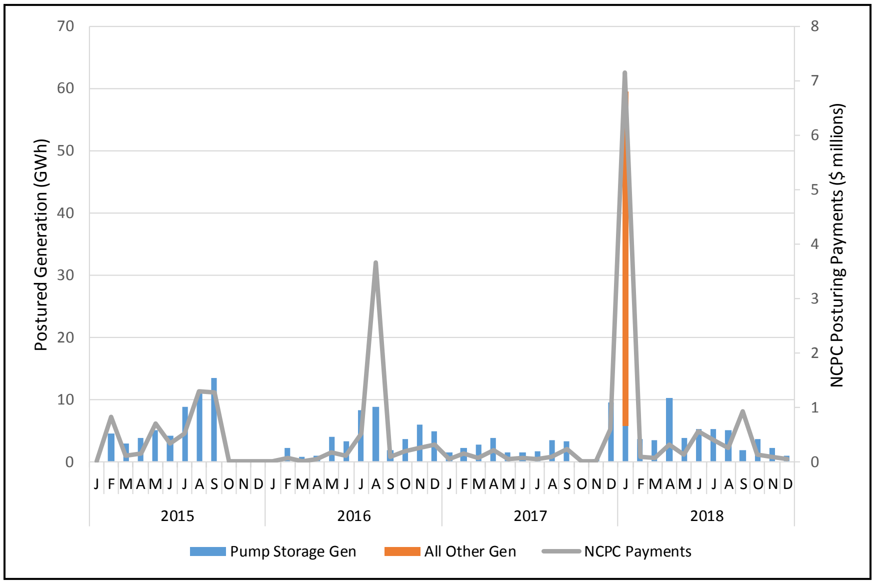
Because posturing removes potentially in-merit generation from economic dispatch, postured generators may be worse-off as a result of the ISO's actions, unless the ISO provides uplift payments to compensate for foregone profitable dispatch. Postured generators may receive NCPC for any foregone profits that occurred during the posturing period. Generally, the remaining energy at the postured generator 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.[98]

Postured energy (GWh) and NCPC payments by month are shown in Figure 3-30 below. The bars indicate the postured energy obtained (the amount of energy constrained down) from pumped-storage generators and all other types of generators.[99]

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

[99] 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. Only during January 2018 have other types of 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 resources were effectively providing back-up electricity supply, in the event of natural gas shortages during the "cold snap".

As indicated in the figure, 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 is noticeable in August 2016, when pumped-storage generators were postured on August 11, during a capacity deficiency period (Operating Procedure 4) with operating reserve deficiencies and very high energy prices.

3.4.9 Congestion

This section provides an overview of how congestion occurs in an electrical transmission system and how this congestion affects the locational marginal prices (LMPs) that are used to settle generation and load. The section then discusses the amount of congestion that the New England power system experienced in 2018 and compares it against historical levels of congestion over the last five years.

Overview of Congestion

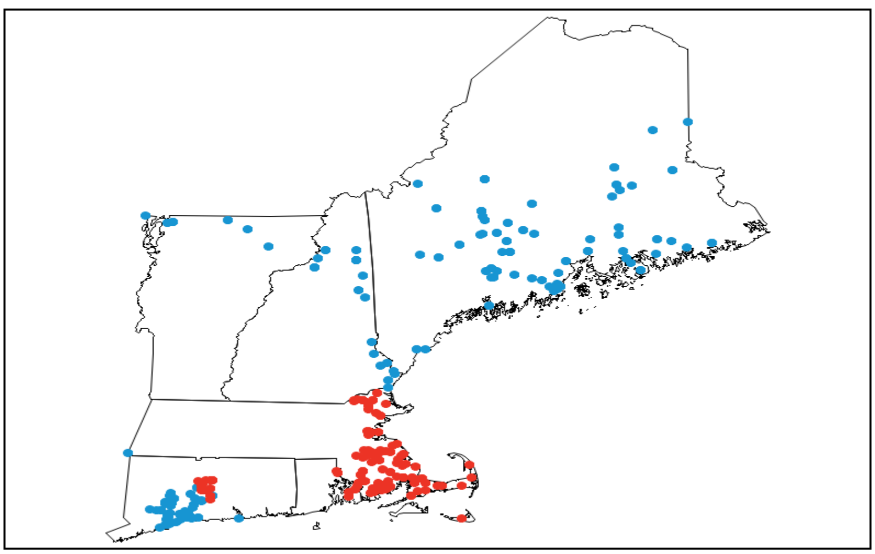
At every node in the New England power system, LMPs reflect the cost of delivering the next megawatt (MW) of energy at the lowest cost to the system. The LMP is comprised of three components: the energy component, the congestion component, and the loss component. The energy component is the same for all locations in the power system. The congestion component reflects the additional system costs when transmission constraints prevent the use of the lowest-cost generation to meet the next increment of load. The loss component reflects the dispatch of additional generation because some electric energy is lost during transmission. Breaking down the LMP into these components enables the ISO to determine how much of the difference in LMPs at two locations is due to transmission congestion versus losses. Locational differences in the congestion component serve as the basis for determining the value of financial transmission rights (FTRs), a financial instrument that market participants can use to hedge transmission congestion cost risk. FTRs are covered in more detail in Section 4.2.

When transmission lines connecting a part of the power system to the rest of the system reach the maximum amount of power allowed, the transmission line is said to "bind." When this happens, each of these areas has at least one marginal resource that is setting the price in that area (marginal resources are discussed in more detail in Section 3.4.10) For example, when a transmission line connecting an area with low-cost generation to the rest of the system binds, the two areas will have different prices. A low-cost resource will set the price in the lower-cost area and a different resource will set the price for the rest of the system. Locational difference in prices caused by a binding transmission constraint like the one just discussed are reflected in the LMP through the congestion component. The congestion component can be positive or negative. A negative congestion component indicates an export-constrained area, and a positive congestion component indicates an import-constrained area.

Congestion patterns in New England

The nodes in New England most affected by transmission congestion in 2018 are shown in Figure 3-31.[100] The nodes in blue represent export-constrained areas (i.e., areas where there is an imbalance of generation relative to load and there is insufficient transmission capability to *export* the excess generation). The nodes shown in red represent import-constrained areas (i.e., areas where there is an imbalance of load relative to generation and there is insufficient transmission capability to *import* the additional needed generation). Day-ahead data was used to produce the map because the majority of congestion revenue accrues in the day-ahead market.

Figure 3-31: New England Pricing Nodes Most Affected by Congestion



[100] Only nodes that had an average day-ahead congestion component of greater than or equal to \$0.15/MWh or less than or equal to -\$0.15/MWh in 2018 appear in this figure.

Three main patterns of congestion emerge in Figure 3-31:

1) Areas on the system with a high concentration of wind generation have lower prices, on average, than the rest of the system. In 2018, areas in northern New Hampshire and Vermont, as well as the entire state of Maine were frequently export-constrained. Often the magnitude of the congestion component of the LMP in these locations was high. Renewable generators (predominantly wind) are frequently the marginal resources in these areas and they commonly offer their energy at very low, even negative, prices.

2) NEMA/Boston and Southeast Massachusetts had higher prices in 2018 relative to the rest of the region. In 2018, the transmission lines connecting NEMA/Boston and Southeast Massachusetts to the rest of the system were frequently at their maximum import limit. With the highest concentration of load in New England, the Boston area has traditionally been import-constrained.

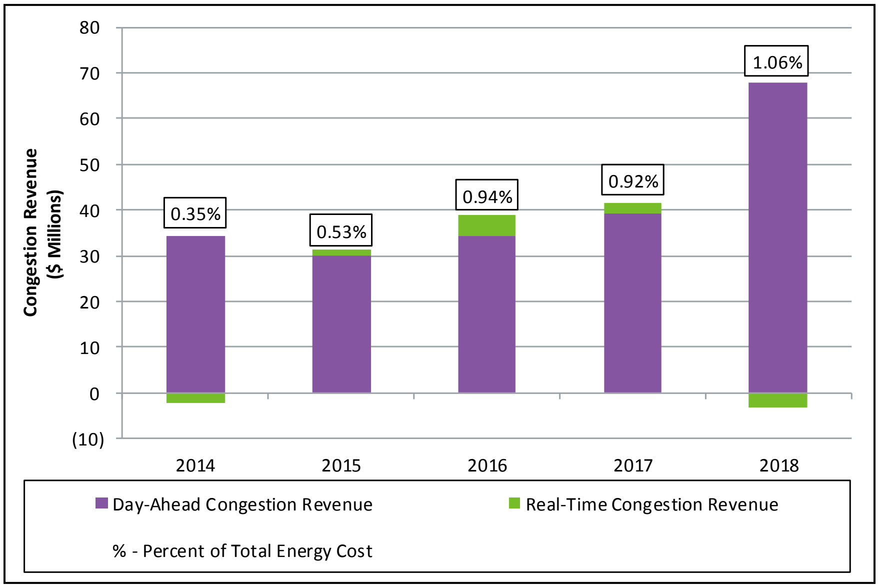
3) Southwestern Connecticut experienced both positive and negative congestion, depending on the node location relative to the binding constraint. There were a few short-lived periods of extreme congestion in Fall 2018 when elements on the 115-kV transmission system were binding. When these elements bound, less expensive energy from the southern part of Connecticut couldn't reach the load pocket to the northwest of it (greater Hartford) and more expensive generation needed to be dispatched resulting in positive congestion pricing in the load pocket and negative congestion pricing outside it.

Cost of congestion

One measure of the financial impact of transmission congestion is 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 in the system. Energy market settlement is performed on each part of the three components of the LMP separately. The credits and charges based on the congestion component of the LMP form the basis of the congestion revenue fund. By design, these charges and credits do not balance; the charges are expected to exceed the credits. The surplus revenue is called congestion revenue and it is used to pay the holders of FTRs. Congestion revenue is collected in both the day-ahead and real-time markets.

The congestion revenue in New England by market and year is shown in Figure 3-32 below. The purple bars represent the day-ahead congestion revenue, and the green bars represent the real-time congestion revenue. The percentages in the figure are the total congestion revenue each year expressed as a percent of total energy costs.

Figure 3-32: Congestion Revenue Totals and as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $64.5 million in 2018. This represents a 56% increase from $41.4 million dollars in 2017. The congestion revenue in 2018 represents slightly more than 1% of total energy costs (labels) and is the highest amount in the last five years. Day-ahead congestion revenue is much higher than real-time congestion revenue because the real-time market is a balancing market. In 2018, approximately 99% of real-time load in New England cleared in the day-ahead market.

The majority (58%) of the congestion revenue in 2018 occurred in three months: January, April, and November. The amount of congestion revenue in a month depends on the transmission constraints that bind in that month. Identifying the contribution of each binding constraint to the amount of congestion revenue in a month is complex.[101] However, two factors that can be examined to explore this relationship are the frequency with which a constraint bound in a given month and the marginal value of the constraint when it bound.[102] For example, a constraint that bound very frequently in a month but did not have a large marginal value could have the same impact on congestion revenue as a constraint that bound infrequently but had an extreme marginal value when it did.

One constraint that bound frequently in 2018, and tended to be impactful when it did, was the New York – New England (NYNE) interface. This interface is a collection of seven lines that controls the flow of power between the New York and New England control areas. As discussed in Section 5.2, New England typically imports power over this interface. This constraint frequently binds during periods when there are large spreads between the price of power in New England and New York (e.g., some winter months, when New England's gas infrastructure can become constrained) or

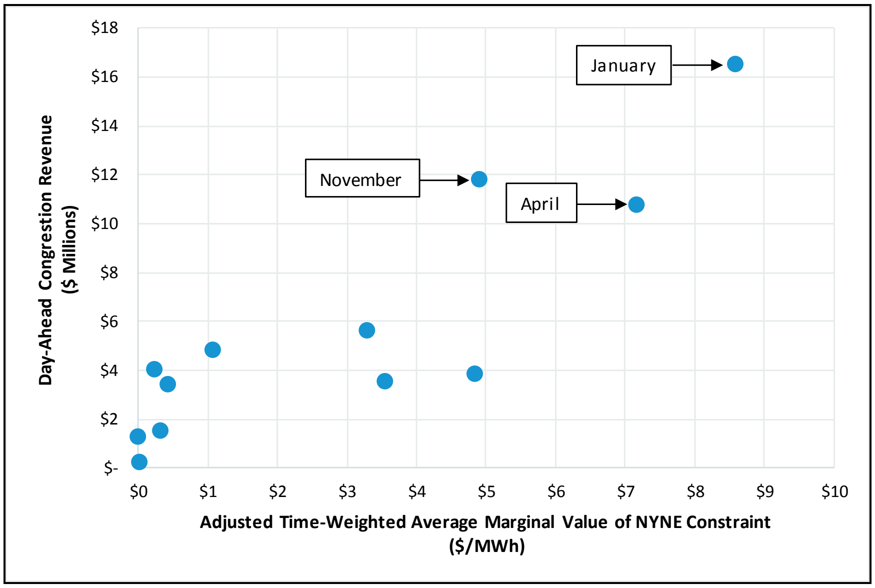
[101] Determining the amount of congestion revenue associated with a particular constraint is dependent upon many factors including: 1) the sensitivity of each node within the constrained and unconstrained areas to the binding constraint, 2) the amount of load and generation at each node that has a nonzero sensitivity to the constraint, and 3) the marginal value of the binding constraint.

[102] The marginal value of the constraint indicates how much the production cost of the system would change if the limit of the interface increased by one megawatt. All the marginal values are negative because allowing an additional megawatt to flow over the binding constraint would *reduce* total system production costs.

when there are reductions in the interface limit (e.g., in April 2018, when a major 345 kV line that is part of the NYNE interface was out of service).

The 2018 monthly day-ahead congestion revenue values are plotted against a measure that captures both the frequency and the magnitude of the NYNE constraint when it bound in the day-ahead market in Figure 3-33 below.[103]

Figure 3-33: Monthly Day-Ahead Congestion Revenue Values in 2018 by Average Marginal Value of the NYNE Constraint in the Day-Ahead Market



There is a clear and positive relationship between this metric and the amount of day-ahead congestion revenue in 2018. The relationship between this constraint and congestion revenue is further explored in Section 4.2.

The 10 interface constraints that bound the most frequently in 2018 are listed in Table 3-3 below. Interfaces are sets of transmission elements whose power flows are jointly monitored for voltage, stability, or thermal reasons. Interface constraints can often have a larger impact on congestion revenue when they bind than individual transmission elements because more load and generation are likely to be affected. Also included in the table is the average marginal value ($/MWh) of each constraint when it bound in 2018.

103 The x-axis in Figure 3-33, which is labeled Adjusted Time-Weighted Average Marginal Value of the NYNE Constraint, is equal to the average marginal value of the NYNE constraint when it bound in the day-ahead market multiplied by the percent of hourly intervals in the day-ahead market that the constraint bound. It is considered *adjusted* because it is further multiplied by -1 in order to make the values positive.

Table 3-3: Most Frequently Binding Interface Constraints in the Day-Ahead Market in 2018

Constraint Name	Constraint Short Name	% of Hours Binding	Average Marginal Value of Constraint ($/MWh)
New York - New England	NYNE	23.1%	-$12.38
Keene Road Export	KR-EXP	22.0%	-$22.69
Orrington - South	ORR-SO	13.4%	-$16.78
Bull Hill Wind Generation	BLHW	9.4%	-$32.42
Burgess Generation	BURG	7.7%	-$26.86
Sheffield + Highgate Export	SHFHGE	6.7%	-$7.30
Whitefield South + GRPW	WTS+GR	2.3%	-$13.31
Bingham Wind Generation	BNGW	2.0%	-$54.94
Coopers Mill - South	COMI-S	2.0%	-$28.29
Orrington - Import	OR-IMP	1.9%	-$15.87

The most frequently binding interface constraint in the day-ahead market in 2018 was the New York – New England interface. The average day-ahead congestion revenue (system-wide) in the 2,022 hours that the New York – New England interface was binding was $18,597 per hour compared to the average revenue of $4,480 per hour in the hours in which it was not binding. The interface bound in only 659 hours in 2017. Although the interface was only binding in 23.1% of hours, the congestion revenue within these hours comprised 55.5% of the total day-ahead congestion revenue.

The Keene Road Export interface consists of a line and a transformer that control flows through the Keene Road substation. The Keene Road substation is where one of the two 345-kV lines that electrically connects the New England and New Brunswick control areas terminates. There are numerous wind generators located at nearby substations whose power flows through the Keene Road substation, and the Keene Road Export interface helps manage these flows. The average day-ahead congestion revenue in the 1,927 hours the Keene Road Export interface was binding was $16,593 per hour compared to the average revenue of $5,242 per hour in the hours in which it was not binding. Although it was only binding in 22.0% of hours, the congestion revenue within these hours comprised 47.2% of the total day-ahead congestion revenue.

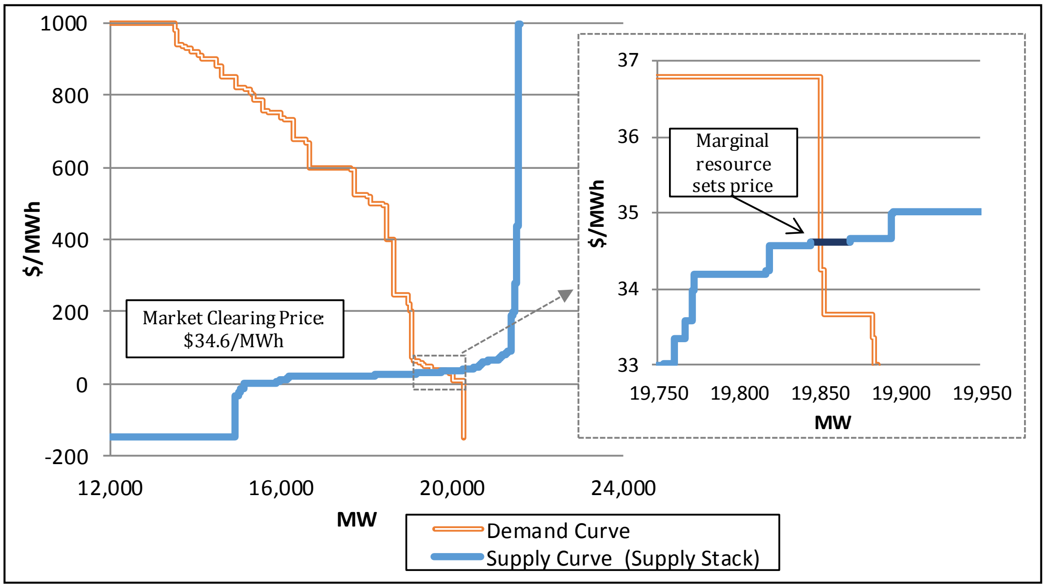
3.4.10 Marginal Resources

The LMP at each pricing location is set by the cost of the next MW 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 cost creates a supply curve or "supply stack" with the 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 Load Serving Entities (LSEs) by 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.[104] The individual offer or bid located at the intersection of the supply and demand curves sets the market price and that offer/bid said to be marginal.

An example of a marginal supply offer setting the price for a particular hour in the day-ahead market (hour ending 13 on July 25, 2018) is shown in Figure 3-34 below. The blue curve shows the supply stack, where supply offers are ranked from lowest to highest. The large section of supply at -$150/MWh 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 consists of day-ahead demand bids, with a large section of fixed demand bids shown at the offer cap of $1000/MWh.

Figure 3-34: Day-Ahead Supply and Demand Curves – July 25, 2018, HE 13



At the intersection of the supply and demand curves, which is highlighted in the inset graph of Figure 3-34, a supply offer of $34.6/MWh intersects with the demand curve at about 19,850 MW. The resource that submitted this supply offer is therefore marginal, as an incremental MW of demand would be served by an increase in supply from this resource. As a result, this marginal resource sets the market-clearing price at $34.6/MWh.

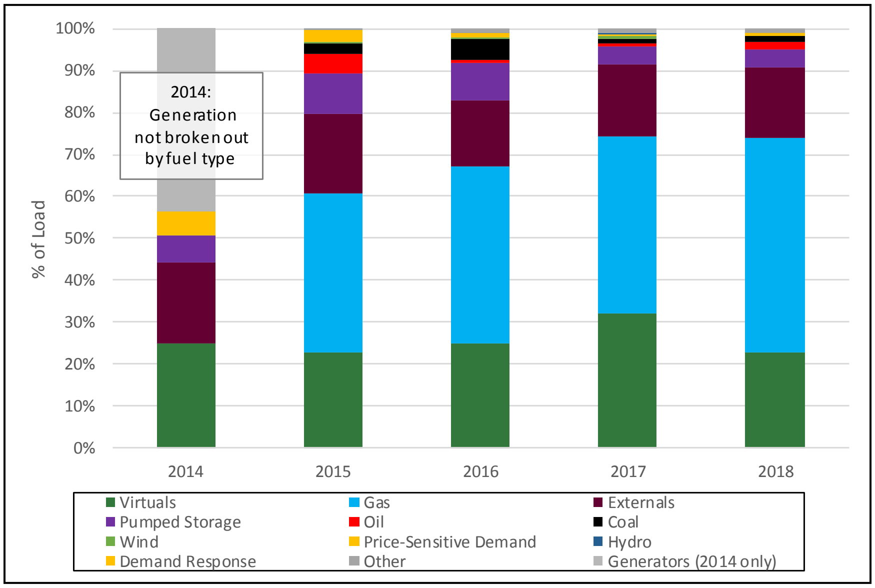
In cases where transmission constraints are binding and energy cannot flow freely, there will be more than one marginal resource. For example, if transmission lines are limiting the amount of generation exported from a given area, that area is *export-constrained*; transmission limitations do not allow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

[104] 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.

Marginal resources in the day-ahead market

In the day-ahead market, many different types of transactions can be marginal: virtual transactions, price-sensitive demand bids, price-responsive demand, asset-related demand, generator supply offers, and external transactions. The percentage of load that each transaction type was marginal for over the past five years is illustrated in Figure 3-35 below. Beginning in 2015, the graph illustrates a breakdown of the generation by generator fuel type.[105]

Figure 3-35: Day-Ahead Marginal Units by Transaction and Fuel Type



Virtual transactions (virtual demand bids and virtual supply offers) set price for about 23% of day-ahead load in 2018. This is about 10% below 2017, when virtual transactions set price for about a third of load, but very similar to 2014–2016. The decrease relative to 2017 was driven by fewer virtual supply offers at several nodes in areas of Vermont and Maine with sizable wind generation. Virtual supply activity is often associated with expected real-time wind output at or nearby nodes within export-constrained areas. This is because wind generators typically clear much less energy in the day-ahead market compared to their real-time generation, which puts downward pressure on real-time prices relative to day-ahead prices. The result is an arbitrage opportunity for virtual supply traders to sell at the higher day-ahead price and buy back at the lower real-time price.

As virtual supply's share decreased, the share of load for which natural gas was the marginal fuel rose. Natural gas was the marginal fuel for about half of day-ahead load in 2018, an increase from 42% in 2017. External transactions (imports and exports) were marginal for about 20% of load, which is consistent with its share of over the past five years.[106] Price-Responsive Demand (PRD)

[105] With the introduction of Energy Market Offer Flexibility (EMOF) in December 2014 generators submit information regarding fuel represented in their supply offer. This provides better information on the fuel underlying the marginal unit than existed prior to EMOF.

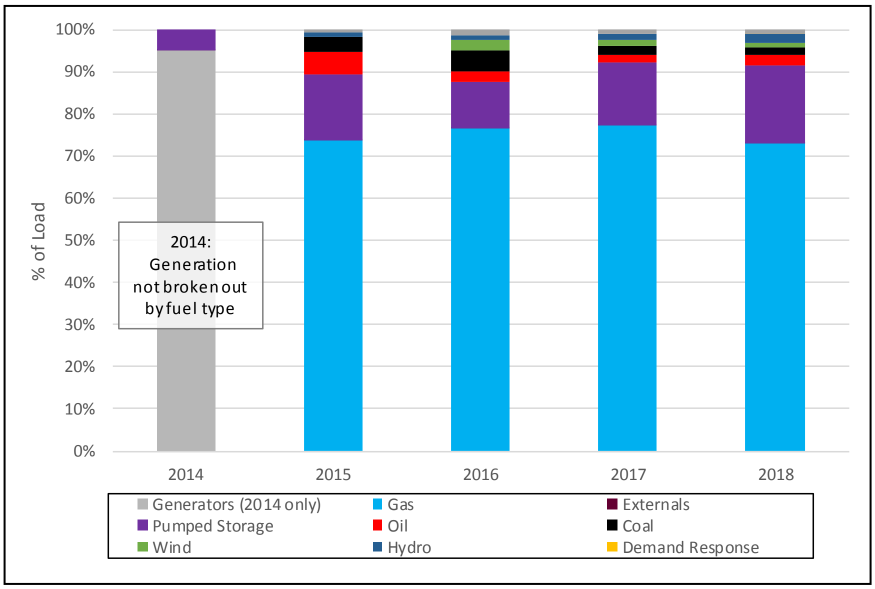
[106] In the day-ahead market, external transactions at CTS and non-CTS interfaces can also be marginal, but the marginal external transactions at non-CTS interfaces only determine the flow over the interface but not the LMP. The LMP is administratively set to the price of an adjacent node in the day-ahead market at non-CTS interfaces to maintain consistency between the day-ahead and real-time prices.

was implemented on June 1, 2018, which allows demand response resources to set price in the energy markets. They were infrequently marginal, setting price for 0.1% of load in the day-ahead market, and 0.2% in the real-time. For more information on PRD see Section 3.6.

Marginal resources in the real-time market

In the real-time market, only physical supply, pumped-storage demand, price-responsive demand, and some external transactions can set price. In practice, marginal resources in the real-time market are typically generators (predominantly natural gas-fired generators) and pumped-storage demand. The marginal fuel mix in the real-time market over the past five years is shown in Figure 3-36 below.[107]

Figure 3-36: Real-Time Marginal Unit by Fuel Type



Natural gas was the marginal fuel for over 70% of load in the real-time market during 2018. Gas-fired generators are typically the lowest-cost fossil fuel type generation and thus typically operate much more often than coal- or oil-fired generators. Since the more expensive coal- and oil-fired generators are usually not required to meet system demand, gas-fired generators tend to be the most expensive generators operating, and in turn, they frequently set price.

Pumped-storage units (both generators and demand) are the second largest marginal transactions types, being marginal for about 20% of load in 2018. 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 generators.

The remaining transaction types were marginal for less than 10% of load in 2018. Although wind generators are frequently marginal, they are usually marginal for only a small share of total system

[107] Pumped-storage generation and demand are broken into different categories as they 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 has lower offers and typically consumed energy and sets price in off-peak hours when it is generally cheaper to pump water.

load (~1% in 2018). 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. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

3.5 Net Commitment Period Compensation

This section provides an overview of the types and reasons for Net Commitment Period Compensation (NCPC) and covers the trends in NCPC payments over the prior five years.

Generators are eligible for NCPC or *make-whole* payments when they are unable to recover their cost of operation in the day-ahead and real-time energy markets. The NCPC rules are designed to make generators that follow the ISO's operating instructions no worse off financially than the generator's next best alternative.[108] Generally, generators following ISO instruction can expect to receive energy market payments that cover their as-offered costs. However, marginal cost markets, by design, do not ensure cost recovery of fixed or sunk commitment production costs. NCPC payments are necessary to make generators "whole" to their as-offered costs, when those costs are not recovered through the LMP.

NCPC is also paid to generators for "lost opportunities", or situations in which generators forego 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 its economically optimal level based on posted prices. The majority of these payments are made because a generator was held back (or postured) by the ISO (i.e., has its output reduced from its economic dispatch level) in order to maintain system reliability. A generator may have the opportunity to earn additional revenue by ignoring the ISO dispatch instruction and producing additional energy. In order to incent the generator to follow the ISO posturing instruction, NCPC is paid to the generator to ensure that it is not financially better off by pursuing its best alternative (i.e., operating at a higher MW output).

In 2018, NCPC payments totaled $70 million, an increase of $18 million (up by 35%) compared to 2017. Like last year, NCPC remained relatively low when expressed as a percentage of total energy payments, at just 1.2%, continuing a downward trend in the share of NCPC from prior years.

The dollar increase in 2018 NCPC payments was driven by two factors: an increase in fuel costs and the manual "posturing" of oil-fired generators for fuel security during the "cold snap" in early January. January NCPC payments accounted for about 30%, or $20.3 million, of total annual payments, with 80% of those payments made during a 4-day period of very cold weather and high natural gas prices (January 4 through 7, 2018).

[108] 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.

3.5.1 NCPC Payment Categories

The ISO pays NCPC to generators under a number of circumstances. Generators that operate at the ISO's instruction may be eligible for one of the following types of NCPC depending on the reason the ISO committed the generator:[109]

- **Economic/first-contingency NCPC**: Generation is committed in economic merit order to satisfy system-wide load and reserves but fails to recover costs.
- **Local second-contingency protection NCPC:** Generation is committed to provide local operating reserve support in transmission-constrained areas to ensure local reliability needs.
- **Voltage reliability NCPC**: Generation is dispatched by the ISO to provide reactive power for voltage control or support.
- **Distribution reliability NCPC**: Generation is operating to support local distribution networks.
- **Generator performance auditing NCPC**: Generation is operating to satisfy the ISO's performance auditing requirements.[110]

3.5.2 NCPC Payments for 2014 to 2018

NCPC payments have increased by $15 million in 2018, from $52 million in 2017 to $70 million in 2018. This is the first time in the last four years that total NCPC payments have increased year to year. Economic NCPC payments make up most of the increase, up by $15.3 million, while payments for local reliability rose by $2.5 million.

NCPC Payments by Category

Most NCPC payments are for economic (or first contingency) needs, as shown in Figure 3-37, which depicts total NCPC payments by year and payment category. The inset table also shows the percentage share of total NCPC payments for each category by year.

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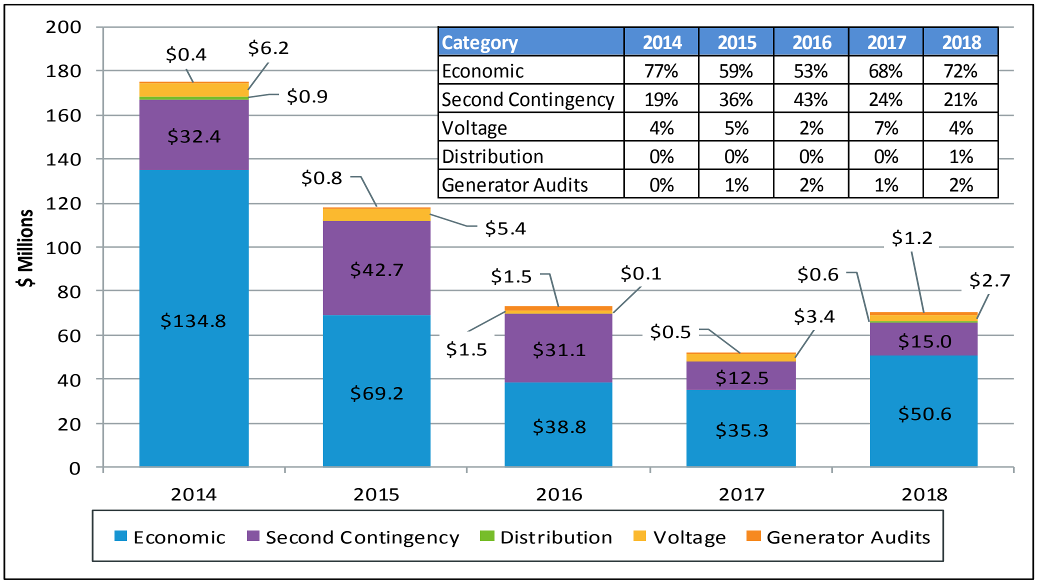
[109] A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

[110] NCPC payments for generator performance audits became effective on June 1, 2013. NCPC payments to participants for this category are incurred for the following: 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 services as part of the ISO's Winter Reliability Program.

Figure 3-37: Total NCPC Payments by Year and Category



Category	2014	2015	2016	2017	2018
Economic	77%	59%	53%	68%	72%
Second Contingency	19%	36%	43%	24%	21%
Voltage	4%	5%	2%	7%	4%
Distribution	0%	0%	0%	0%	1%
Generator Audits	0%	1%	2%	1%	2%

Every category of NCPC payments increased in 2018, with the exception of voltage reliability which decreased by $0.7 million, to $2.7 million. Economic NCPC comprises most of the payments, $51 million, representing 72% of the total in 2018. This is a $15.3 million (43.5%) increase from 2017, but a decrease of $84 million (or 62.4%) from the high in 2014.

Over the reporting period, the top ten recipients of economic NCPC were combined cycle or pumped-storage generators. Combined cycle generators received 36% of economic NCPC, pumped-storage received 57% and steam turbines received 7%. On average, these recipients received 39% of total economic NCPC.

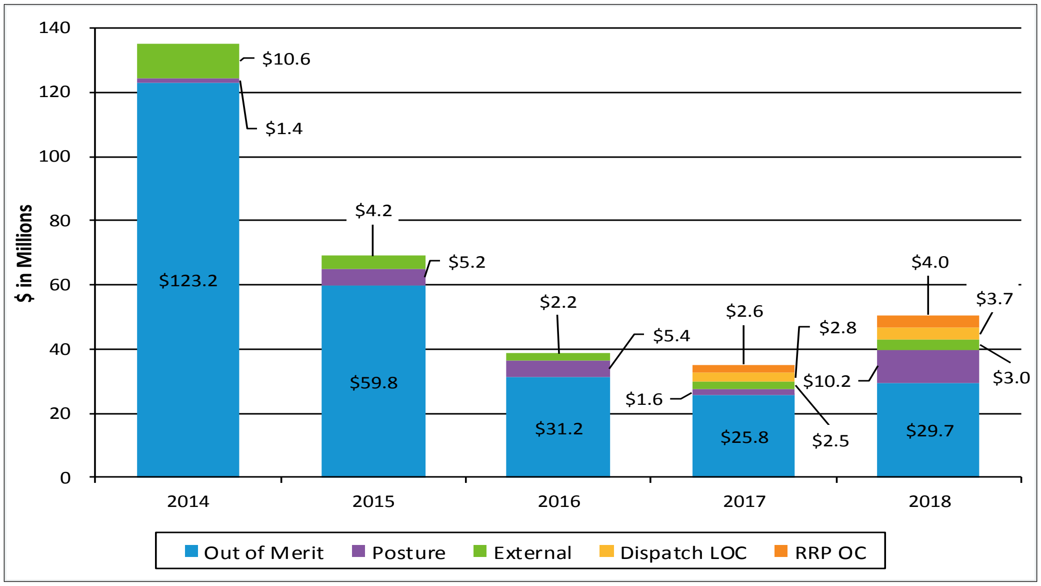
Economic NCPC Drivers

One factor behind the increase in economic NCPC was an increase in opportunity cost payments. These payment are made to generators that follow the ISO's dispatch instructions even when a more profitable dispatch level might exist. These generators receive one of the following sub-types of opportunity cost payments to ensure they are financially no worse off:

- *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:* Payments provided to a resource that follows an ISO manual action that alters the resource's output from its economically-optimal dispatch level in order to create additional reserves.
- *Rapid-response pricing opportunity costs (RRP OC):* Payments provided to a resource that is instructed by the ISO not to operate at its economic dispatch point when fast-start generators are setting the LMP.

A breakdown of economic NCPC by year and by sub-category is shown in Figure 3-36 below. In addition to the three opportunity cost-based payments discussed above (DLOC, Posture and RRP OC), the more traditional uplift categories are also included. Out-of-merit NCPC ensures recovery of as-offered commitment and dispatch production costs that are not recovered through the LMP, while external NCPC also covers payments made to external transactions and virtuals for relieving congestion at the external interfaces.[111]

Figure 3-36 Economic NCPC by Sub-Category



Opportunity cost payments totaled $17.9 million, almost $11 million higher than 2017 payments. This was driven by generator posturing in January 2018 to conserve fuel during a sustained "cold snap". January 2018 posturing payments of $7.2 million accounted for 71% of total 2018 posturing payments. Oil-fired generators were paid $6.6 million in NCPC to recover their lost opportunity to not generate at higher levels when it was economic for them to do so. Total posturing uplift payments were $10.2 million, a 547%, or $8.6 million increase from 2017 and an 87%, or $4.8 million increase from 2016. The level of capacity postured over the past five years was discussed in Section 3.4.8.

A second factor behind the increase in economic NCPC was fuel prices. Natural gas costs increased by an average of 33% through the year. During the January "cold snap" natural gas prices were 210% higher than in the previous January. This increase in natural gas costs was muted by the first full year of the new fast-start pricing rules. By design the decoupling of dispatch and pricing optimization lead to higher real-time LMPs, reducing economic out-of-merit NCPC. Fast start pricing also introduced a new category of opportunity cost called rapid-response pricing. RRP OC uplift payments totaled $4.0 million, representing a 55% increase from 2017 payments.

Reliability NCPC Payments

Local Second Contingency Protection (LSCPR) payments increased by $2.5 million, or 20%, from 2017. Approximately 77%, or $11.5 million, of all 2018 LSCPR were made across three months: January (due to the "cold snap"), April and July (due to planned transmission work and local reliability protections in NEMA Boston). Of the $11.5 million, 79%, or $9 million, was paid to gas-fired generators. In 2018, the MW amount of ISO reliability commitments increased slightly due to

[111] See Section 5.4 for further detail on external transaction NCPC payments.

transmission work in NEMA/Boston, Rhode Island and SEMA during April 2018, but remained relatively low (see Section 3.4.8).

The largest percentage increase in 2018 was seen in the Distribution (Security Constrained Resource or SCR) NCPC category. In 2018 SCR NCPC payments totaled $0.6 million, compared to just $0.01 million in 2017. Over half of the 2018 total payments were made in the real-time to a single oil-fired generator located in SEMA during the summer. For the first time in the reporting period a generator received day-ahead SCR NCPC payments. The entirety of the day-ahead SCR NCPC payments were made to a single generator in Connecticut over a continuous sixteen hour period.

NCPC Payments Relative to Energy Market Costs

To add perspective of magnitude, NCPC payments as a percentage of total energy costs are detailed in Table 3-4 below.[112]

Table 3-4: NCPC Payments as a Percent of Energy Costs

	2014	2015	2016	2017	2018
Day-Ahead NCPC	0.9%	0.6%	1.1%	0.6%	0.4%
Real-Time NCPC	1.0%	1.4%	0.7%	0.5%	0.7%
Total NCPC as % Energy Costs	**1.9%**	**2.0%**	**1.8%**	**1.2%**	**1.2%**

Total NCPC payments represent a relatively small portion of total energy costs and remain consistent from 2017. Day-ahead NCPC payments have ranged from 0.4% to 1.1% of total energy costs over the five year review period, while real-time NCPC payments have ranged from 0.5% to 1.4%.

NCPC Payments by Quarter

NCPC payments can vary significantly by season as a result of fluctuating fuel prices, diverse load conditions, the timing of major transmission outages, and other factors. The quarterly total NCPC payment amounts for each year between 2014 and 2018 are shown in Figure 3-38 below. The colored bars indicate the quarterly NCPC 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 NCPC payments for that year.

[112] The energy costs presented are the amounts cleared at the day-ahead and real-time LMPs, excluding ancillary services costs.

Figure 3-38: Total NCPC Payments by Quarter

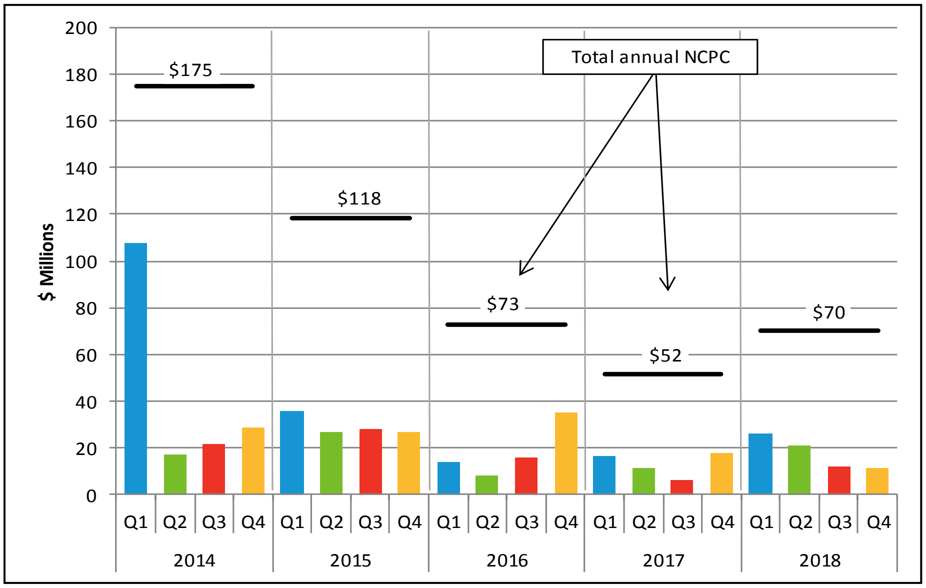


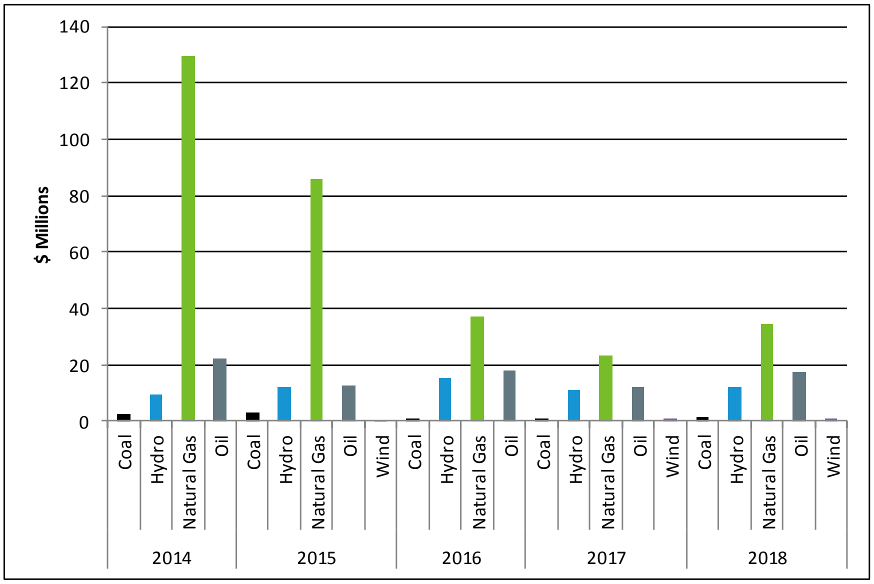
Figure 3-38 illustrates that the highest NCPC payments tend to occur in winter months (Q1 and Q4 of each year). This largely reflects increased economic and LSCPR NCPC payments during the winter months. Generators that are committed for LSCPR are often more expensive units that would not otherwise operate based on economics.

Looking more narrowly at 2018, the highest payments occurred in Q1 and Q2. Approximately two thirds of the economic payments made in 2018 occurred in these two quarters. The "cold snap" from December 2017 through January 2018 lead to an increase in posturing payments.

NCPC by Fuel Type

Total NCPC payments by generator fuel type are shown in Figure 3-39 below; note that the chart omits fuel types that received less than $100,000 in total NCPC payments within a year.

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



Natural gas-fired, oil-fired, and hydro generators receive the majority of NCPC payments. This is 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 pricing does not allow the generators to fully recover production costs.

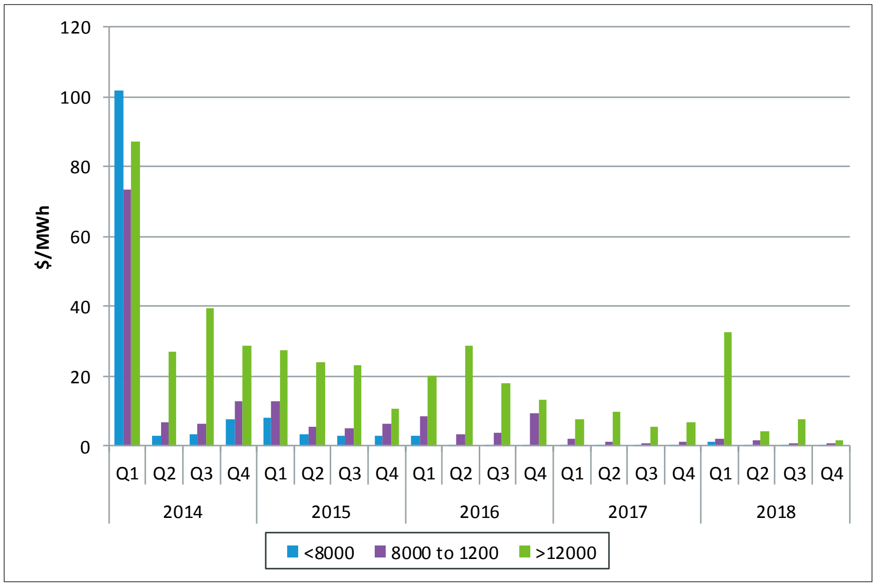
NCPC by Heat Rate

To examine NCPC payments further, we classified average payments for real-time economic NCPC by generator heat rate.[113] It is expected that generators with higher heat rates (i.e., generators that require more fuel to create a unit, MWh, of electricity) will also require higher average make-whole payments when revenues are insufficient to cover costs.[114] Figure 3-40 below indicates the average real-time NCPC payments ($/MWh) to generators according to generator heat rate categories.

[113] Heat rates indicate the rate at which fuel (e.g., natural gas) is converted into electricity. These rates are typically stated in Btu/kWh. "Real-time" refers to the real-time energy market.

[114] Heat rates are one component of production costs; fuel prices are another important element and have a significant impact on production costs and make-whole payment magnitude. We have not tried to control for fuel price variation in our review.

Figure 3-40: Average Real-Time Economic NCPC Payments by Generator Heat Rate



As expected, higher average real-time NCPC payments are made to generators with higher heat rates. However, this relationship may not always hold. For example, in Q1 2014, New England experienced very high natural gas prices; as a consequence, even fuel-efficient natural gas-fired generators (with heat rates below 8,000 Btu/kWh) had higher operating costs than, for instance, oil-fired generators with heat rates greater than 8,000 Btu/kWh.

Although generators with high heat rates (>12,000 Btu/kWh) receive relatively high average NCPC payments, these generators received only approximately 12% of total real-time economic NCPC payments from 2014 to 2018. These generators were committed less frequently throughout the year with the exception of Q1 2018 where they were utilized during the “cold snap”. Average payments to these generators have generally declined over time, and represented just 26% of total real-time economic NCPC payments in 2018. This is a slight increase from 2017 due to the January 2018 “cold snap”.

3.6 Demand Resources in the Energy Market

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). This program allows demand response resources to submit demand reduction offers into the day-ahead and real-time energy markets. With the program change, demand resources now are committed and dispatched in the energy market based on economics and are eligible to set price. Demand resources also provide operating reserves, in a manner similar to traditional generators. Along with energy market integration, active demand resources are now treated similarly to other resources in the capacity market, having a must-offer obligation in the energy market for capacity with a CSO.

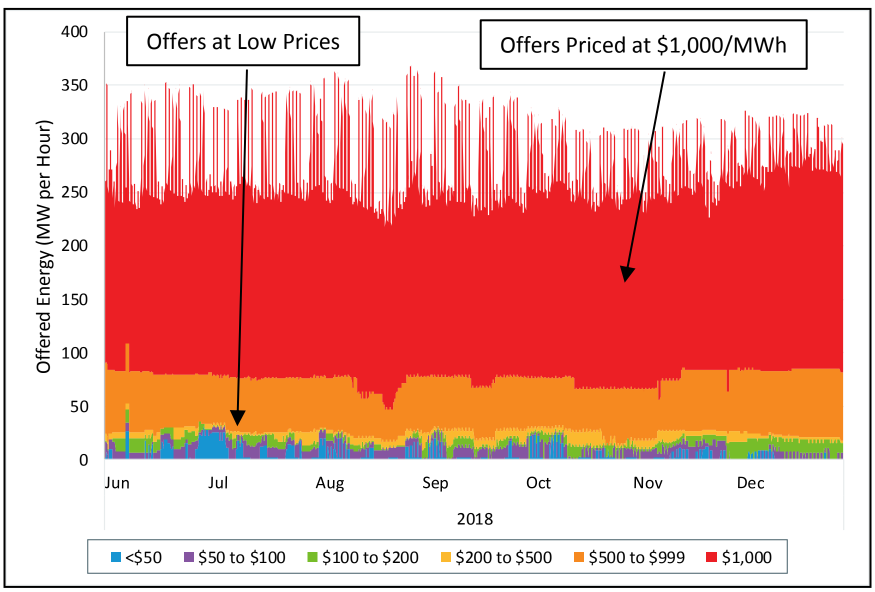
Prior to June 1, 2018, demand response resources participated in the ISO’s energy markets (1) as emergency resources activated during OP4 system conditions (i.e., a capacity deficiency) in the real-time market and (2) through the Transitional Price-Responsive Demand (TPRD) Program in the day-ahead market. Participation in the real-time energy market as an emergency resource was required for all active demand resources with a CSO, and these resources were subject to financial penalties and gains based on their performance during an event. These resources were not required to participate in the energy market, except during capacity deficiency conditions. In May 2018, these resources had approximately 290 MW of CSO.

The TPRD program allowed market participants with demand response resources to elect to participate in the day-ahead energy market. These resources were able to receive payments for load reductions offered in response to day-ahead LMPs, although the resources were not integrated into the actual clearing of the day-ahead market. Market participants were paid the day-ahead LMP for their cleared load reductions, were obligated to reduce load by the amount cleared day-ahead, and were charged or credited for real-time deviations from day-ahead clearing. Reviewing TPRD participation from January 2017 through May 2018, TPRD resources were not very active in the energy market; just 14 assets obtained at least 1 hour of demand reduction obligation in the day-ahead energy market, and day-ahead cleared reductions averaged just 6 MW and never exceeded 19 MW in any hour over this time period.[115]

3.6.1 Energy Market Offers and Dispatch under PRD

Under the Price-Responsive Demand (PRD) program implemented in June 2018, over 300 MWs of demand response resources participate in the day-ahead and real-time energy markets, slightly higher than pre-PRD active demand response participation levels. However, consistent with pre-PRD participation, demand resources continue to predominately function as capacity deficiency resources, providing a source of high-priced energy and 30-minute operating reserves in the real-time energy market. Figure 3-41 indicates hourly demand reduction offers in the day-ahead energy market, by offer price category for segment energy offers.

Figure 3-41: Demand Response Resource Offers in the Day-Ahead Energy Market

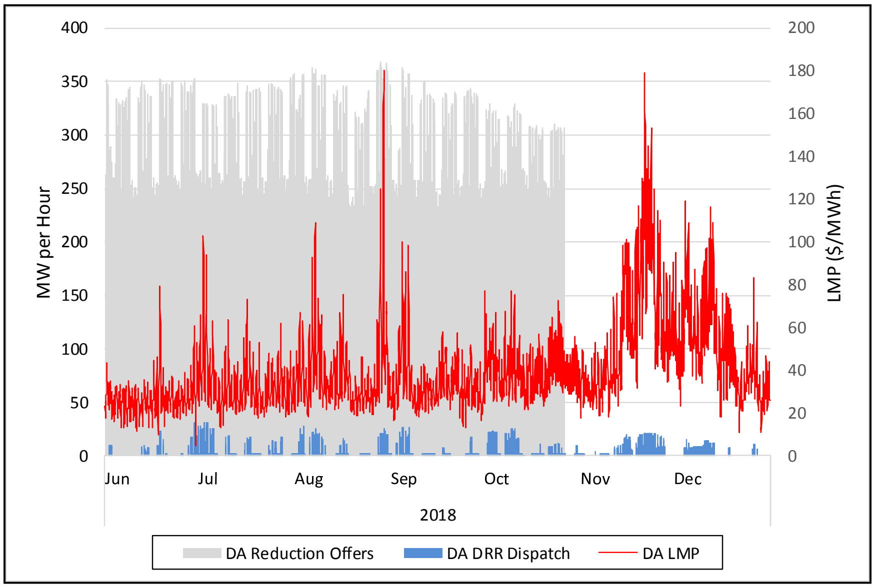


[115] Enrollment in TPRD program in May 2018 was approximately 220 MW. Since these resources could have CSOs, the TPRD resources were not mutually exclusive from the active resources participating during capacity deficiency conditions.

As indicated in the figure, most offers (72% of offered capacity on average) are priced at the energy market offer cap of $1,000/MWh. Only the lower tiers of offered capacity ($200/MWh or less) have a reasonable likelihood of being dispatched in the day-ahead energy market; these offers did not exceed 20% of offered demand reduction capacity in any hour of 2018, and averaged just 7% of offered capacity.[116]

Given the pattern of offer prices for PRD, relatively small quantities are dispatched in the ISO's energy markets. Figure 3-42 indicates the hourly dispatch of Demand Response Resources (DRRs) in the day-ahead energy market, relative to resources' offered reductions and hourly energy prices.

Figure 3-42: Demand Response Resource Dispatch in the Day-Ahead Energy Market



The maximum hourly quantity of demand response capacity dispatched in the day-ahead energy market was 31.2 MW, representing about 10% of offered demand reduction for that time period. While demand resources were dispatched frequently - in 46% of hours in the day-ahead market– the level of dispatch was very small, averaging just 7.7 MW.[117]

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.[118] While DRRs can provide 10 minute reserves, that requires interval metering with granularity of 1 minute or less, to be able to provide either non-synchronized (TMNSR) or synchronized reserves (TMSR). From June to December 2018, DRRs provided only 1.3 MW on average of ten-minute operating reserves, but provided substantially more in thirty-minute operating reserves (TMOR), averaging 146.6 MW per

[116] Energy prices in the day-ahead market did not exceed $200/MWh in any hour during the period of June to December 2018, and in the vast majority hours were below $100/MWh.

[117] Because real-time energy market dispatch is similar to day-ahead dispatch (with the exception of the capacity scarcity period on September 3), real-time dispatch is not displayed.

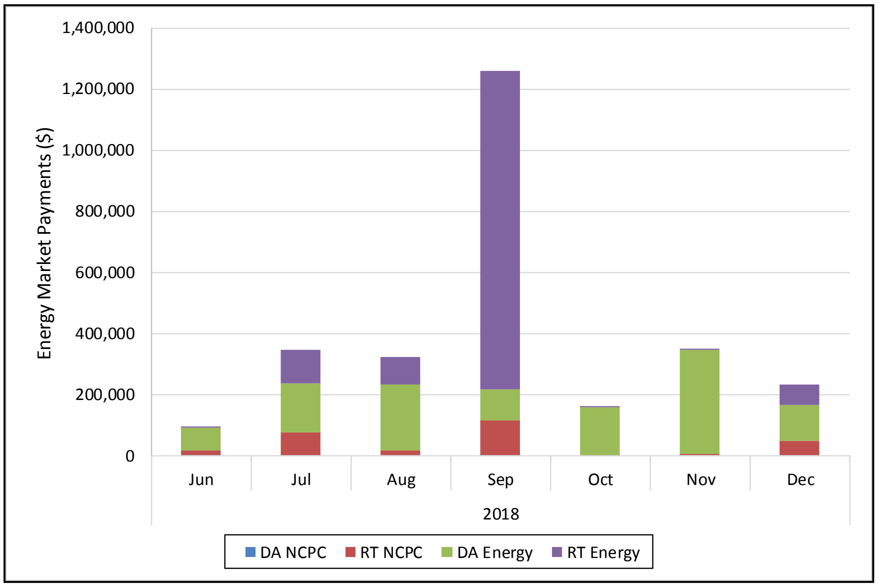
[118] These operating constraints are: total start-up time (including notification time) of less than or equal to 30 minutes, minimum time between reductions and a minimum reduction time of less than or equal to 1 hour, and a "claim 30" (30-minute reserve capability) greater than 0.

hour. This has had an upward impact on the total operating reserve margin, as discussed in Section 3.4.6.

3.6.2 NCPC and Energy Market Compensation under PRD

Demand Response Resources (DRRs) have received relatively modest energy market compensation. This results from low dispatch rates in the energy market and infrequent thirty-minute operating reserve pricing in the real-time energy market. When dispatched, DRRs are eligible to receive uplift payments (Net Commitment Period Compensation, NCPC). 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 3-43 indicates energy and NCPC payments by month.

Figure 3-43: Energy Market Payments to Demand Response Resources

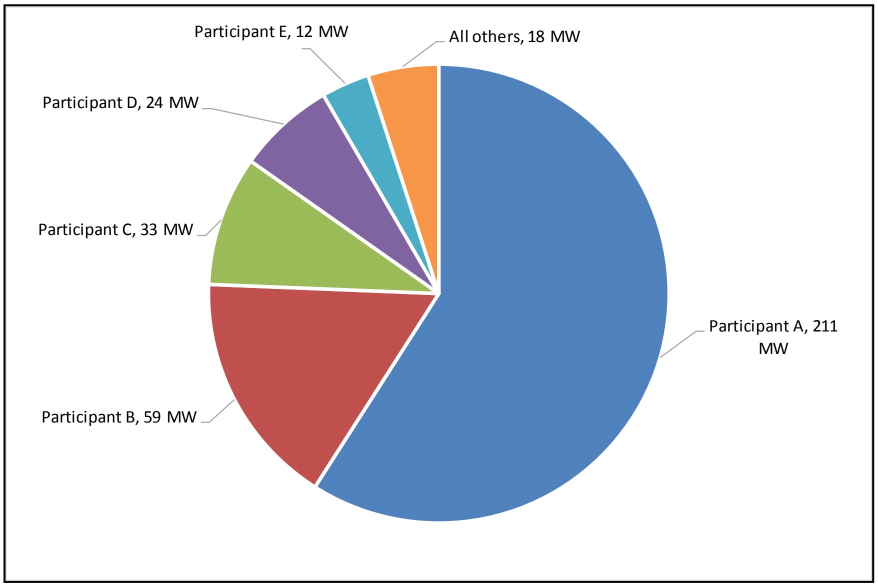


As indicated in the figure, both NCPC payments and energy market payments have been relatively small, since the implementation of PRD. Payments for NCPC represent just 10% of total energy market compensation for DRRs, and total energy payments for the period were approximately $2.8 million. (This compares to energy market payments of $6 billion for all resources during the full year.) Except for the capacity scarcity event in September (when many DRRs were providing either demand reductions or operating reserves), day-ahead energy market payments were the largest source of revenue.

3.6.3 Capacity Market Participation under PRD

For the Capacity Market, DRRs have Capacity Supply Obligations (CSOs) totaling approximately 350 MW. 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.[119] Figure 3-44 indicates the CSO by participant for ADCRs.

Figure 3-44: CSO by Lead Participant for Active Demand Capacity Resources



Just eight participants have CSOs; the two largest participants account for approximately 75% of ADCR capacity supply obligations. Capacity market compensation for the delivered obligations has totaled about $24 million, or about nine times the amount of energy market compensation received by these resources.[120]

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. Opportunities to exercise market power are discussed first. The market impact of uncompetitive (i.e. above cost) offers is presented next. At the end of the section, IMM measures to prevent the exercise of market power are then discussed.

Opportunities for market participants to exercise market power are examined using two metrics: the C4 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. The RSI is an effective tool to identify opportunities for the largest supplier to exercise market power at any given time. The RSI represents the amount of demand that can be met without the largest supplier. If the value is less

[119] 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.

[120] The FCM compensation estimate focuses just on the payments for the actual obligation that these resources need to deliver in each month from June to December 2018. It does not take into account any payment gains or losses that might have occurred from altering obligations through FCM bilateral and reconfiguration activities.

than 100%, the largest supplier is necessary to meet demand and could exercise market power if permitted.

The Lerner Index is presented to estimate the impact of uncompetitive offer behavior in the day-ahead energy market. To produce the Lerner index, 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 to highlight the role the IMM plays in ensuring wholesale energy prices reflect the marginal cost of generation.

The competiveness of the capacity and ancillary services markets is covered Section 6.7 and Section 7, respectively.

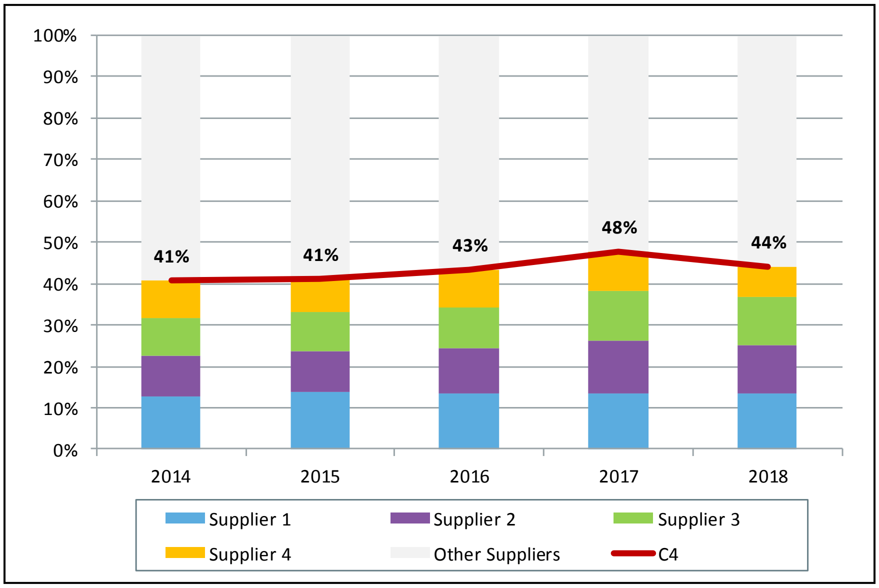
3.7.1 C4 Concentration Ratio for Generation

This section 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 to understand the general trend in supply concentration over time as companies enter, exit, or consolidate control of supply assets serving the New England region.

The C4 is the simple sum of the percentage of system-wide market supply provided by the four largest firms in all on-peak hours in the year and reflects the affiliate relationships among suppliers.[121] The C4 value expresses the percentage of real-time supply controlled by the four largest companies. C4 values in the range of 40-50% indicate low levels of system-wide market concentration in New England, particularly when the market shares are not highly concentrated in any one company. As shown in Figure 3-45 below, the C4 value was 46% in 2018, a small decline from 48% in 2017 and just above the average for 2014–2017.

[121] On-peak hours are the 16 hours of each weekday between hour ending 8 and hour ending 23, except for North American Electric Reliability Corporation (NERC) off-peak days (typically, holidays). Affiliate relationships are based on IMM's research of controlling entities of power generators in New England using a combination of non-public ISO and public information.

Figure 3-45: System-wide Supply Shares of the Four Largest Firms



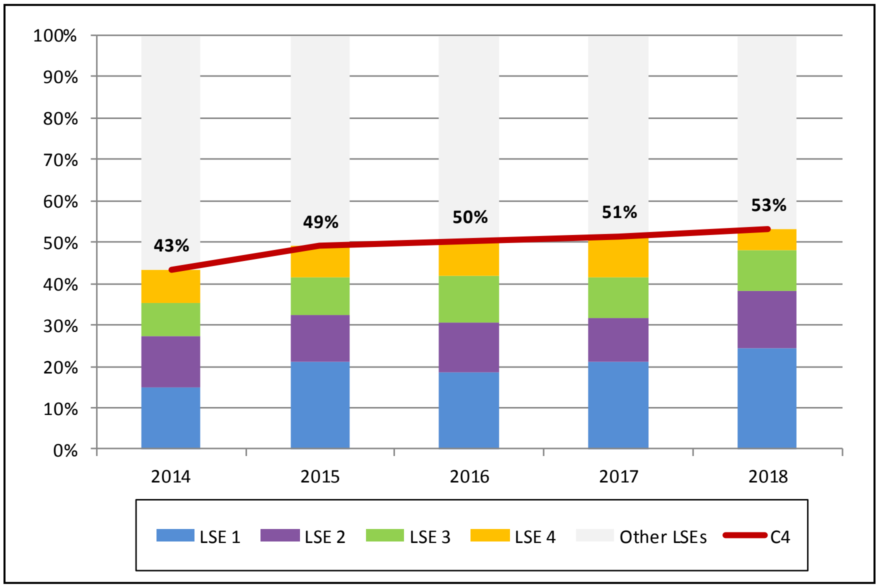
Note: The firms labeled "Supplier 1," "Supplier 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

In 2018, the total supply of generation and imports during on-peak hours was about 67,600 GWh, of which about 29,800 (44%) came from the four largest suppliers. The suppliers that make up the top four have changed over the past year due to mergers and generator output levels. The red C4 trend line red in Figure 3-45 shows no clear trend in the concentration ratio over the past five years. Despite the slight increase relative to earlier years, the observed C4 values indicate low levels of system-wide market concentration in a relatively small market. Moreover, no one company maintains a dominant share of supply, and the split among the top four suppliers has remained stable.

3.7.2 C4 Concentration Ratio for Load

This section applies the same C4 metric discussed in the previous section to real-time load. The C4 for load measures the market concentration among the four largest firms controlling load in the real-time energy market. As with the generation C4 metric, we also account for affiliations among load-serving participants. The results are presented in Figure 3-46 below, which shows the market shares of the top four firms and the combined market share of all remaining firms.

Figure 3-46: System-wide Demand Shares of the Four Largest Firms



Note: The firms labeled "Consumer 1," "Consumer 2" and so on are not necessarily the same companies across all years.

In the on-peak load hours in 2018, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 66,661 GWh.[122] Overall, the four largest load-serving market participants served 53% of the total system load for the 2018 on-peak hours. As shown by the red C4 trend line in Figure 3-46, the load share of the four largest firms is 10% higher than 2014 due to a merger between two participants. Since 2015, the C4 value has been relatively stable at around 50%.

The C4 analysis presented here does not account for market participants with both load and generation positions, which generally have less incentive to exercise market power. Actions that would tend to raise prices for their generation would come at a cost to their load, and any actions that would suppress prices would come at a cost to their generation.

The observed C4 values presented above indicate relatively low levels of system-wide market concentration in a relatively small market, and individual shares are not highly concentrated in any one company. Additionally, there is no evidence to suggest that load serving entities exhibit bidding behavior in the energy market that would have the effect of suppressing prices. The vast majority of demand clears in the day-ahead market, averaging about 99% in 2018, and aggregate demand curve is relatively price-insensitive (see Section 3.4.4).

3.7.3 Residual Supply Index and the Pivotal Supplier Test

The Residual Supply Index (RSI) identifies instances when the largest supplier has market power.[123] Specifically, the RSI measures the percentage of real-time demand (load and operating reserve requirements) that can be met without energy from the largest supplier's portfolio of generators. When the RSI is below 100, at least a portion of the largest supplier's generation is required to meet real-time energy demand. In such instances, the largest supplier is considered a "pivotal supplier" and has market power to unilaterally raise the real-time energy price or LMP. The pivotal supplier

[122] This number differs from the generation number by losses and by exports.

[123] There may be presence of other forms of market power such as local market power in the real-time energy market.

can set an uncompetitive market price by offering a portion of its supply above marginal cost and force the market to clear at a higher than competitive price level. When the RSI exceeds 100, there is enough supply available in the market to meet demand without any generation from the largest supplier. In such cases no individual supplier is pivotal and sufficient competition exists in the market.

This RSI analysis uses the same data that is used in the real-time pivotal supplier tests conducted by the ISO's real-time market software (the Unit Dispatch System, or UDS). A pivotal supplier test is performed before issuing generator dispatch instructions.[124] The test results are used in conjunction with the energy market mitigation system and processes. The data used in the calculation of the RSI comes from the real-time pivotal supplier test inputs. Based on these data the RSI for an interval t is calculated as follows:

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

In this analysis the average RSI value of all the dispatch intervals in an hour are reported. There are typically six to seven UDS runs each hour. Table 3-5 shows the hourly average of the RSI values and the resulting percentage of hours with at least one pivotal supplier for years 2014 to 2018.

Table 3-5: Residual Supply Index and Intervals with Pivotal Suppliers

Year	% of Hours with a Pivotal Supplier	RSI
2014	61.6%	95.5
2015	53.9%	96.8
2016	46.8%	100.6
2017	57.9%	99.1
2018	30.8%	103.4

There were significantly fewer hours with a pivotal supplier in 2018 than in the last four years. This indicates that during 2018 suppliers faced relatively higher competition compared to the past four years. The increase in the structural competitiveness is consistent with the higher level of 10-minute and 30-minute operating reserves surpluses on the system during 2018 compared to 2017. The UDS case solutions show that the average total 10-minute reserve surplus was about 365 MW or 20% higher in 2018 compared to 2017 and average 30-minute reserve surplus was about 606 MW or 27% higher for the same period.

The reduction in the number of intervals with pivotal suppliers appears to be driven by two factors: 1) the increase in the 2018 reserve margin, and 2) changes in the available supply of individual companies due to new entry and other market dynamics.

The supply/reserve margin section (Section 3.4.6) discussed the increase in the reserve surplus in 2018, citing two likely drivers that increased off-line reserves: the increase in pumped-storage

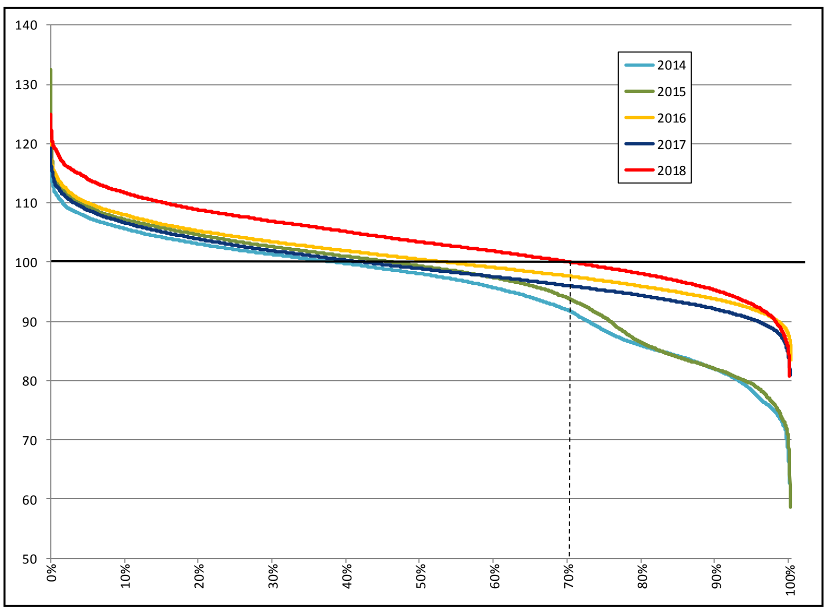
[124] There are typically six to seven pivotal supplier tests conducted each hour coinciding with each run of the Unit Dispatch System.

availability and the incorporation of demand resources into the energy and reserve market co-optimization process. When reserve margins are higher, it is less likely that the available capacity of a supplier is needed to satisfy load and reserve requirements. In 2018, almost 90% of suppliers were pivotal in fewer hours compared to 2017.

Additionally, 2018 saw decreased available supply from a supplier that was frequently pivotal in 2017 due to the economics of that supplier's generators. The reduction in available supply from this large supplier was offset by an increase in the supply share of a participant with two new entrant generators, as well as increases across other suppliers. This essentially had the impact of splitting the portfolio of a large participant into multiple parts, thereby reducing overall market concentration.

A duration curve shows the hourly RSI level over the year arranged in a descending order. Figure 3-47 shows the percent of hours, on an annual basis, when the hourly RSI was above or below 100 for the period between years 2014 and 2018. There is at least one pivotal supplier when the RSI is below 100.

Figure 3-47: System wide Residual Supply Index Duration Curves



Like the pivotal supplier statistics, Figure 3-47 shows that there was greater availability of competitive supply in year 2018 than in any other year in the reporting period, with the RSI above 100 in about 70% of the time.

3.7.4 Lerner Index

Participants can raise their supply offers above marginal costs by a certain threshold before mitigation is applied. The Lerner Index estimates the extent to which marked-up supply offers influence LMPs. In a perfectly competitive market, all market participants' offers would equal their marginal costs. The price is then set by the marginal supply offer (or demand bid). The Lerner Index estimates the divergence of the observed market outcomes from this ideal scenario. Since market competition incentivizes participants to offer at marginal cost, the Lerner Index provides insight into market power and competitiveness. Uncompetitive offers priced above marginal cost can distort prices and impact resource allocation decisions, leading to inefficient market outcomes.

To calculate the Lerner Index, the day-ahead market clearing was simulated using two scenarios:[125]

- Scenario 1 was an *offer case* that used the actual offers market participants submitted for the day-ahead energy market.
- Scenario 2 was a *marginal cost case* that assumed all market participants offered at an estimate of their short-run marginal cost.[126]

The Lerner Index (L) was then calculated as the percentage difference between the annual generation-weighted LMPs for the offer case and the marginal cost case simulations:

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

where:

LMP_O is the annual generation-weighted LMP for the offer case

LMP_{MC} is the annual generation-weighted LMP for the marginal cost case

A larger L means that a larger component of the price is the result of marginal offers above estimates of their marginal cost.

The 2018 Lerner Index for the day-ahead energy market was 4.9%. This indicates that offers above marginal cost increased the day-ahead energy market price by approximately 4.9%. This result is the same as the 2017 value, and is consistent with normal year-to-year variation given modeling and estimation error.[127] Table 3-6 shows the annual Lerner Index values.

Table 3-6: Lerner Index for Day-Ahead Energy

Year	Lerner Index
2014	9.0
2015	8.3
2016	8.2
2017	4.9
2018	4.9

[125] 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.

[126] The marginal costs estimates are based on underlying variable cost data and generator heat rate parameters used in the calculation of 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 (for virtual transactions for example) the marginal cost is set equal to the supply offer. Some differences between estimated and actual marginal costs are to be expected.

[127] Note that the IMM's estimates of marginal cost are an approximation of actual marginal costs, and the simulations used to calculate the Learner Index are subject to modeling differences when compared to the market model the ISO runs for the day-ahead market. Additionally, the methodology used to calculate the 2015-2017 Lerner Indices differs slightly from methods used in previous years.

The 2018 Lerner Index is relatively low. This indicates that competition among suppliers in the day-ahead market limited their ability to inflate the LMP by submitting offers above marginal cost.

This analysis also calculated Lerner Index values at an hourly level, and compared the peak load hour Lerner Index with the forecasted supply margin at peak. Comparing these attributes provides insight into whether participants are taking advantage of tight system condition by exercising increased market power during those times. There was no meaningful correlation between the Lerner Index and the supply margin in 2018, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low.

3.8 Energy Market Mitigation

Mitigation rules, systems, and procedures are applied in the day-ahead and real-time energy markets to attenuate the impact of uncompetitive generator offers. The mitigation rules are intended to prevent market prices from being set above competitive levels and avoid the potentially harmful effects of market power. When a participant's supply offer fails specific mitigation tests the offer is replaced with a competitive benchmark price known as the reference level. Generator reference levels are determined in consultation with the participant and are intended to reflect a competitive supply offer.[128]

This section provides an overview of the energy market mitigation tests and presents statistics on the occurrences of offer mitigation.

3.8.1 Types of mitigation

There are eight types of mitigation, each corresponding to a scenario where market power could be exercised. The two primary categories of mitigation are *commitment* scenarios and *energy* dispatch scenarios. Commitment mitigation scenarios pertain to when generators are started or kept on at the ISO's request. The energy mitigation scenarios evaluate the online resources that are being dispatched by the market software or manual instructions.

Determining whether a participant's supply offer must be mitigated involves up-to three tests depending on the applicable scenario: the structure, conduct, and impact tests.

Structure test. The market structure test evaluates the amount of competition faced by a participant to determine whether they possess market power. A participant is deemed to have market power in any of three conditions. The first is when they are a *pivotal supplier* controlling resources needed to meet system-wide load and reserve requirements. The second condition is when their resource is in a *constrained area* of the system and has the ability to affect local area prices. And the third is when their resource is required to meet a specific *reliability need* such as voltage support; in this scenario the resource may be the only generator, or one of very few, capable of serving the need.

Conduct test. The conduct test checks whether the participant's offer is above its competitive reference level by more than the allowed thresholds. The allowed threshold, expressed as a percentage or dollar amount, depends on the type of market structure test that applies in the

[128] There are three methodologies prescribed in Appendix A to Market Rule 1 for setting the reference level: (i) calculating the marginal cost of production, (ii) considering historical accepted supply offers, and (iii) using historical prices at the generator node. The IMM consults with the participant to determine the appropriate inputs to the marginal cost estimate. The highest value determined by these three methodologies is used to set the reference level except in certain circumstances.

scenario. The threshold values are tightest for scenarios where opportunities to exercise of market power are most prevalent.

Impact test. The market impact test gauges the degree to which the participant's offer affects the energy LMP relative to an offer at its competitive reference level. The impact test applies to energy dispatch scenarios that require testing the incremental energy offers of online generators.

The participant's offer must fail all the applicable tests in order for mitigation to occur. When a generator has been mitigated, all three components of the offer (*i.e.*, start-up, no-load, and incremental energy) are replaced by the reference level values and mitigation remains in effect until the market power condition is no longer present.

An overview of energy market mitigation types and each of the tests applied for the scenario is provided in Table 3-7 below.[129] Where a certain test is not applicable it is noted in the table with the text "n/a." Note that the dollar and percentage thresholds specified for the conduct and impact tests are the values at which the participant's offer is determined to fail the test.

Table 3-7: 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)		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)		25%	n/a
Reliability Commitment	Reliability	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy		10%	n/a

Most mitigation types are applied in both the day-ahead and real-time markets, but the few that are only applied in real-time are indicated by the "(real-time only)" note below the mitigation type name in Table 3-7. Except for manual dispatch energy, the energy mitigation types involve all three tests. For commitment mitigation only the structure and conduct tests apply since the impact on LMPs is not relevant to commitment events. Energy and commitment mitigation types also differ in terms of the supply offer components evaluated. For energy mitigation, only the incremental energy segments of the supply offer are relevant. In commitment tests, the aggregate cost of start-up, no-load, and incremental energy at minimum output (*i.e.*, the commitment or "low load" cost) are evaluated over the commitment duration.

There is one additional mitigation type specific to dual fuel resources not listed in Table 3-7. 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

[129] Dual fuel mitigation is excluded from the summary.

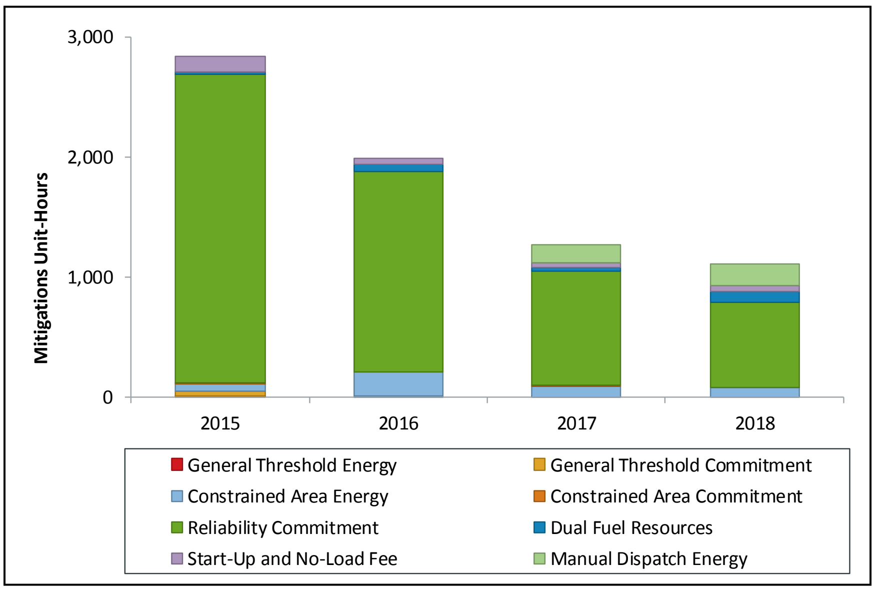
using natural gas). This mitigation will affect the amount of NCPC payments the generator is eligible to receive in the market settlements.

3.8.2 Mitigation event hours

In this section, energy market mitigation occurrences are summarized for 2015 - 2018. For these summaries, each hour that the submitted offer for an individual generator was mitigated in either the day-ahead or real-time energy market is counted as one observation (i.e., the tallies represent unit-hours of mitigation). For example, if a single generator offer was mitigated for five hours when committed in the day-ahead market, the mitigation count for this day will be five unit-hours. If a second generator offer was mitigated on the same day for three hours during real-time, the total for this hypothetical day would then be eight unit-hours.

In 2018, the total amount of mitigations declined relative to earlier periods. There were 1,104 unit-hours when some form of mitigation was applied. This is 13% lower than the 1,273 total unit-hours that occurred in 2017. For context, if every available generator were mitigated in every hour in the day-ahead and real-time markets, there would be 5.1 million unit-hours of mitigation. The amount of 2018 mitigations is 0.02% of this total. Figure 3-48 below presents the annual tallies of mitigations by type for each year between 2015 and 2018.

Figure 3-48: Mitigation Events by Annual Period



The number of energy (i.e., non-commitment) mitigations increased slightly (3%) year-over-year during 2018 and also increased relative to 2016. These increases were the result of an increase in "manual dispatch energy" mitigation; overall, other energy mitigation types decreased in 2018.[130, 131]

Reliability commitment mitigations in 2018 remained the predominant mitigation type, accounting for 68% (751) of mitigation occurrences. The frequency of reliability commitment mitigations is consistent with the Energy Market Offer Flexibility rule changes that expanded the application of this mitigation test to scenarios where a generator remains online beyond the end its scheduled commitment.[132] During 2018, reliability commitment mitigations occurred mostly during the winter, spring and fall months, reflecting increased reliability commitments during the "cold snap" in January 2018, and reliability commitments to support transmission outages for upgrades and maintenance during the shoulder months.

[130] Is excluded from the summary. Manual dispatch energy (MDE) mitigation was implemented on March 1, 2017, with the implementation of the ISO's "fast start" pricing rules. The increase in manual dispatch energy (MDE) mitigations from 2017 to 2018 is consistent with the larger number of manual dispatches for the full-year of 2018 compared to the partial year for 2017 (March to December).

[131] Manual Dispatch Energy (MDE) Mitigation is applied to generators dispatched manually, out-of-merit by the ISO. When the system operator manually dispatches a unit out of merit for any reason, and the energy offer segment prices exceed the 110% mitigation threshold (relative to LMP), a unit will be mitigated for a period of time equal to (1) the duration of the dispatch period, (2) its return to its economic minimum, or (3) the unit's offer price is equal to or less than the LMP.

[132] In 2018, the logic for mitigating generators that were held on-line beyond a scheduled commitment was slightly refined. Commitment mitigation no longer applies to the period when a generator is held on-line; only energy mitigation applies during this period.

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 type of financial 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. While the volume of *submitted* virtual transactions has declined each year since 2015, the volume of *cleared* virtual transactions has increased in each of the last four years, rising from 3.8 million MWhs in 2014 to 8.7 million MWhs in 2018 (to roughly 1,000 MW per hour on average). One possible reason for this increase in cleared volumes in the last few years is that recent changes to market rules have created more opportunities for virtual players to arbitrage day-ahead and real-time prices. Section 4.1 below provides more details about these changes.

The second type of financial instrument is a financial transmission right or "FTR". Financial transmission rights allow participants to take financial positions on day-ahead congestion between two pricing points. FTRs provide participants with a way to manage the costs associated with transmission congestion. They can also be used as a speculative instrument. In general, the amount of congestion in New England has declined in recent years as significant improvements have been made to the transmission system. However, there was more congestion revenue collected in 2018 than in any of the previous five years. In 2018 the total profitability for holders nearly doubled from 2017, from $13.5 million to $26.7 million. Section 4.2 below discusses trends in FTRs.

4.1 Virtual Transactions

This section provides an overview of how virtual transactions can benefit the wholesale energy market by helping converge the commitments made in the day-ahead market toward the commitments needed in real-time. It also explores the extent to which the ability of participants to improve commitment convergence can be hindered by transaction costs in the form of Net Commitment Period Compensation (NCPC) charges. Additionally, it looks at how recent market rule changes may have impacted virtual transaction activity.

4.1.1 Virtual Transaction Impact and Mechanics

In the New England day-ahead energy market, participants submit virtual demand bids and virtual supply offers to capture differences between day-ahead and real-time LMPs. The primary function of virtual transactions is to improve the day-ahead dispatch model to better reflect real-time conditions. Virtual demand bids and supply offers that clear in the day-ahead market (based on participants' expectations of *future* real-time system conditions) can improve the generator commitments made in the day-ahead market. The resulting day-ahead commitments will better reflect market participants' *combined* expectations of real-time market conditions.

Virtual transactions that are profitable based on the price difference between the day-ahead and real-time markets generally improve price convergence. Price convergence demonstrates improved day-ahead scheduling that better reflects real-time conditions. If day-ahead prices are systematically higher due to over-commitment in the day-ahead market, virtual suppliers will take advantage of the price difference, displacing some of the excess generation and improving the day-ahead schedule. If real-time prices are systematically higher due to under-commitment in the day-ahead market, virtual demand will take advantage of the price difference, resulting in more generation being committed in the day-ahead market and prices converging.

Virtual bids and offers can be submitted into the day-ahead market 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 Section 3.1 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 profit if the day-ahead price is less than the real-time price (buy low, sell back high).

The ISO allocates NCPC to cleared virtual transactions.[133] The total profit after these charges are levied will be referred to as "net" profit in this section.[134] These NCPC charges effectively serve as "transaction costs" for virtual transactions, reducing a virtual transaction's profit. As such, 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. For example, if expected spread (or gross profit) is $1/MW and the magnitude of NCPC charges (transaction cost) is uncertain, but may be greater than $1/MW resulting in a net loss, NCPC charges can discourage virtual participation, thus inhibiting price convergence. 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.

4.1.2 Analysis of Virtual Transactions and Price Convergence

In this section, we present an analysis of the relationship between the real-time economic NCPC charge rate, virtual transactions, and price convergence.

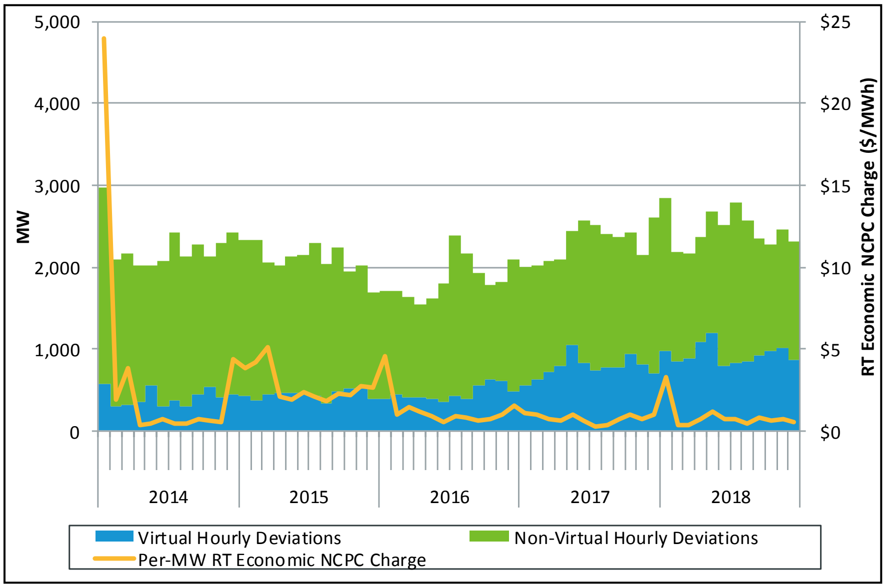
The average hourly real-time system deviation (MW) broken down by the deviation type (virtual or non-virtual), along with the average real-time economic NCPC charge rate ($/MWh) over the past five years are shown in Figure 4-1 below.[135]

[133] All cleared virtual transactions (supply and demand) are obligated to pay a per-MW charge to contribute towards the payment of real-time economic NCPC. Virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation, but this charge is typically much smaller because the total day-ahead economic NCPC is divided among a much larger quantity of energy.

[134] Virtual transactions can also receive NCPC for relieving congestion at the external interfaces. These payments are transfers between the participants causing the congestion and those relieving the congestion and are only applied to transactions that clear at the external interfaces. Because they do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in this analysis.

[135] Virtual supply is always treated as its own real-time deviation, but virtual demand is included as a part of load obligation deviation and can therefore increase or decrease deviations. The methodology for attributing real-time deviations to virtuals and non-virtuals that was used to develop Figure 4-1 accounts for this relationship that virtual demand has on system deviations.

Figure 4-1: Monthly Average of Hourly Real-Time Deviation MWs and Real-Time Economic NCPC Charge Rate



There are several key observations to be made from Figure 4-1:

- Virtual deviations (blue bars) have generally increased over the last five years to account for a larger share of average hourly deviations, which have stayed relatively constant over the same period.
- The average real-time economic NCPC charge rate has been relatively stable over the last three years, averaging around $1/MWh.
- With that said, real-time economic NCPC and associated deviation charges can be extremely volatile (e.g. January 2014).

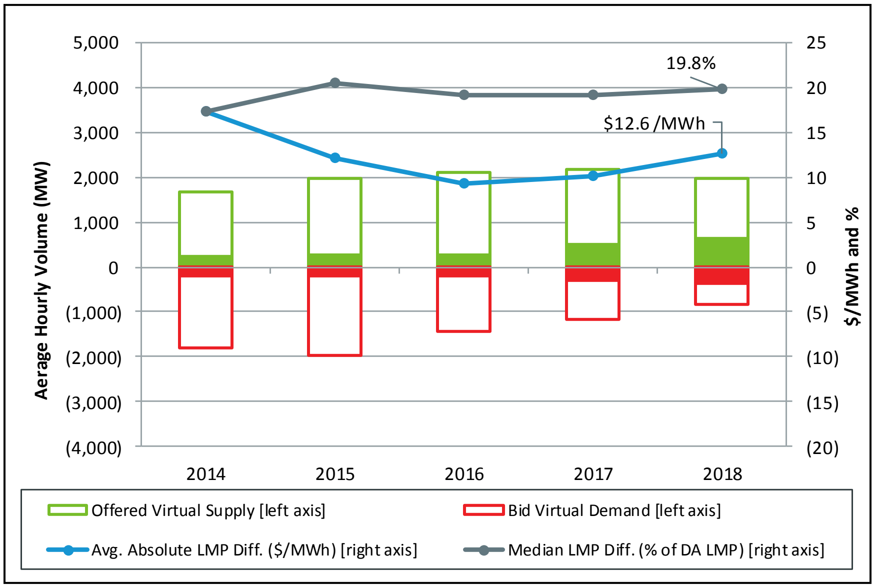
Participants have increased their virtual activity over the last five years in part because of lower real-time economic NCPC charges. The real-time economic NCPC charge rate is a function of the total amount of real-time economic NCPC charges and the total volume of deviations over which to allocate the charges. As more participants clear virtual transactions, the real-time economic NCPC charges are spread across more deviations and the transactions that clear the market incur lower NCPC charges. This increases participants' ability to arbitrage smaller price differences, thereby increasing the frequency of potentially profitable price spreads and finally the volume of virtual transactions looking to arbitrage those price differences. For example, if there is a $1 per-MWh NCPC charge, a virtual transaction will be profitable if the price difference between the day-ahead and real-time markets is greater than $1.

The increase in cleared virtual transaction volumes between 2014 and 2018 is evident in Figure 4-2 below. The figure also provides two measures of price convergence:

1) the mean absolute difference in $/MWh between the real-time and day-ahead Hub prices (blue line series) and
2) the median absolute difference between real-time and day-ahead Hub prices as a percentage of the day-ahead Hub LMP (gray line series).

For this second metric, the price difference is divided by the day-ahead LMP to help normalize for systematic differences between prices in different years and the median is used to reduce the influence of outliers.

Figure 4-2: Virtual Transaction Volumes and Price Convergence



Despite the increase in cleared virtual transactions over the last five years, the two measures of price convergence do not provide a strong indication that the gap between day-ahead and real-time prices is narrowing. During the last five years, the average absolute price difference between the day-ahead and real-time Hub prices fluctuated between $9.27/MWh in 2016 and $17.30/MWh in 2014 (blue line).[136] In 2018, it was $12.58/MWh. Overall, price convergence has remained relatively constant since 2014 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 day-ahead Hub price) rose to 19.8% in 2018, up slightly from the 19.1% observed in 2017. Section 3.3.4 discusses price convergence in more depth.

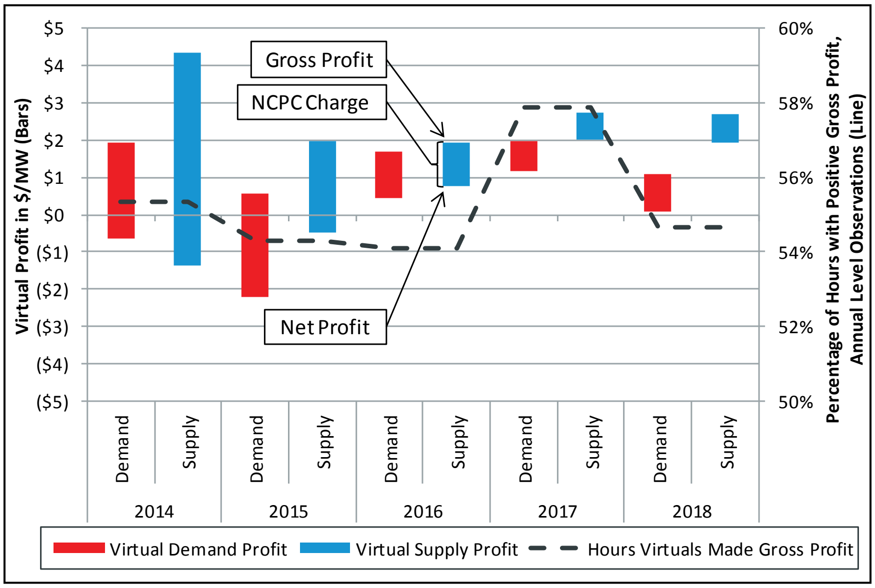
As mentioned above, highly variable transaction costs in the form of NCPC charges can serve as an impediment for virtual participants to close the spread between day-ahead and real-time prices.[137] Figure 4-3 below provides additional detail on the impact of NCPC charges on the profitability of virtual transactions. The figure displays the average annual net and gross profit of virtual transactions since 2014. 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 height of the bar represents the per-MW NCPC charge. The net profits consider real-time economic NCPC charges for both virtual demand and virtual supply as well as

[136] The price difference that is shown 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.

[137] The NCPC charges to cleared virtual transactions are calculated after the market has cleared. Participants must have a sense of what their expected exposure to NCPC charges is before those charges are calculated and, of course, before submitting their virtual bids. 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 lack of information available to the participant in advance.

day-ahead economic NCPC charges for virtual demand. In addition, the dashed black line shows the percentage of hours during the year that virtual transactions were profitable on a gross basis, computed annually. The line is flat for observations in the same year because the value is computed as the number of hours that all virtual transactions together were profitable on a gross basis, as a percentage of total hours in the year.

Figure 4-3: Gross and Net Profits for Virtual Transactions

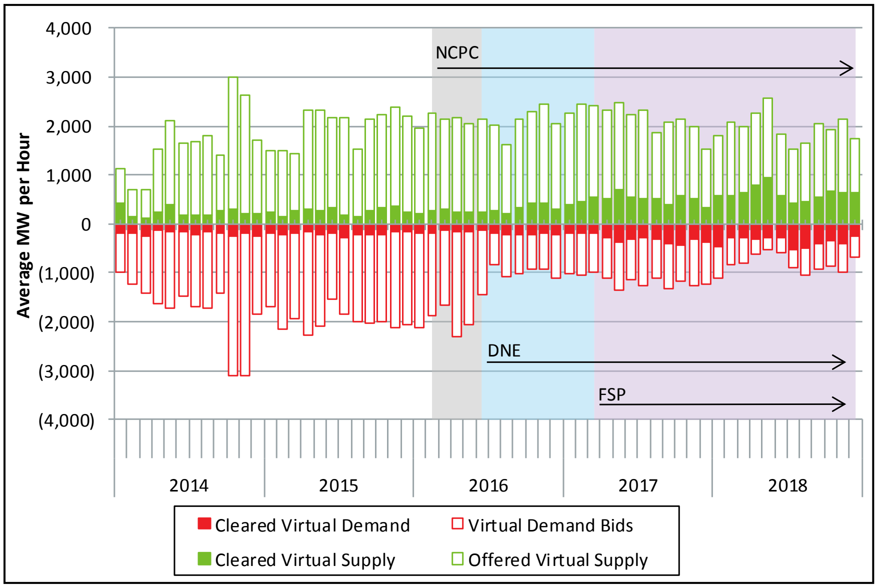


Virtual transactions have had positive annual gross profits, on average, since 2014. However, during years when virtual transactions have been profitable on a gross basis, they have often incurred net losses after accounting for NCPC charges. For example, virtual transactions have only had positive annual net profits, on average, since 2016, as high NCPC charges in 2014 and 2015 resulted in negative net profits in those years. Beginning in 2016, the average annual NCPC charge has decreased resulting in positive net profits for virtual transactions in these years. The reduction in NCPC charges can be seen as the bars decrease in length over the study period. In 2018, virtual transactions remained profitable after NCPC charges were levied; virtual supply made a net profit of $1.93/MWh, on average, while virtual demand made a net profit of $0.09/MWh. Virtual transactions were profitable on gross basis in 55% of hours in 2018.

4.1.3 Volumes of Virtual Transactions

Average monthly virtual transaction volumes from 2014 through 2018 are shown in Figure 4-4 below. The figure shows virtual supply in green and virtual demand in red. In the timeline, a number of market rules changes that have likely had an impact of virtual trading are highlighted.

Figure 4-4: Total Monthly Offered and Cleared Virtual Transactions (Average Hourly MW)



In 2018, participants submitted an average of 2,790 MWs of virtual transactions per hour. This represents a 16% decrease from the roughly 3,340 MWs of virtual transactions that were submitted, on average, in 2017. However, cleared virtual transactions have increased steadily over the last five years, rising from 433 MW per hour in 2014 to close to 1,000 MW per hour in 2018. The growth in cleared virtual transactions has been particularly pronounced for virtual supply, which has increased by 163% (from 236 MW to 621 MW) in this five-year period. The higher percentages of virtual transactions clearing may be the result of three notable market rule changes: (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). Each of these market rule changes is discussed in more detail below.

Changes to NCPC

In February 2016 (gray shaded area), real-time economic NCPC payments made to generators with a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid. The average per-MW real-time NCPC charge was approximately $0.95 in 2018 versus $2.80 in 2015. While lower real-time economic NCPC reduced transaction costs for virtual transactions, it is still unprofitable for virtual supply and demand to converge price in certain hours.

Do-Not Exceed Dispatch rules

Beginning in May 2016 (blue shaded area), certain wind and hydro resources became dispatchable under the Do Not Exceed (DNE) Dispatch rules. Under this change, DNE resources can set price in the real-time energy market. DNE resources 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 agreement. Consequently, the resources clear less day-ahead energy compared to their real-time production. When there is more certainty in real-time, DNE resources 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 is frequently marginal in the day-ahead energy market in geographic areas with DNE resources. In the real-time energy market, DNE resources are frequently marginal in these same areas. Additionally, there has been lower offered virtual demand since the implementation of DNE, which may also reflect the expectation of lower real-time prices.

Fast-Start Pricing

In March 2017 (purple shaded area), the Fast-Start Pricing (FSP) rules went into effect. These changes more accurately reflect the cost of operating higher cost fast-start generation in the real-time market; the changes increased real-time energy market prices. The day-ahead market does not apply the FSP mechanics. Higher real-time LMPs may increase the opportunity for virtual demand to converge price under certain conditions.

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 reflecting expectations for real-time operating conditions in the day-ahead market. Virtual supply prevents higher-cost generators from being committed in the day-ahead market that would not actually be needed in real-time because of lower-cost wind generation. Virtual demand prevents under-commitment in the day-ahead market thereby preventing the need to commit fast-start generators in real-time.

4.1.4 Top Locations of Virtual Transactions by Net Profit

The top 10 most profitable locations for virtual demand in 2018 after accounting for transaction costs and NCPC charges (ranked by Net Profit ($k)) are shown in Table 4-1 below.

Table 4-1: Top 10 Most Profitable Locations for Virtual Demand

Location	Location Type	Submitted MW	Cleared MW	Gross Profit ($k)	Net Profit ($k)	Gross Profit Per MW	Net Profit Per MW	# of Participants
.H.INTERNAL_HUB	Hub	1,619,000	1,167,000	1,773	$434	$1.52	$0.37	29
.Z.WCMASS	Load Zone	277,000	231,000	432	$210	$1.87	$0.91	10
LD.W_AMESBY13.2	Load Node	29,000	15,000	183	$170	$12.12	$11.25	6
UN.BERLN_NH13.8BURG	Generator Node	59,000	8,000	158	$151	$18.81	$17.98	7
UN.OCEAN_ST13.8OSP1	Generator Node	11,000	10,000	98	$92	$10.28	$9.70	2
.Z.VERMONT	Load Zone	145,000	61,000	98	$52	$1.61	$0.85	9
.Z.NEWHAMPSHIRE	Load Zone	177,000	75,000	104	$45	$1.38	$0.59	10
UN.TOWANTIC18.0TO1A	Generator Node	6,000	5,000	35	$34	$7.21	$7.07	1
LD.KING_ST 23	Load Node	2,000	2,000	23	$22	$13.15	$12.64	3
LD.W_AMESBY23	Load Node	6,000	3,000	23	$21	$6.91	$6.29	4

The Hub was the most profitable location for virtual demand in 2018 after taking into account transaction costs and NCPC charges. In total, market participants made a gross profit of $1.8 million and a net profit of $0.4 million in 2018 by placing virtual demand bids at the Hub. Virtual demand bids made a gross profit of $5.2 million on three days in 2018 – January 4, January 5, and September 3. In the other 362 days, they lost $3.4 million (gross) and $4.6 million (net). Table 4-1 also shows the magnitude of the transaction costs and NCPC charges. For example, based on the difference in day-ahead and real-time prices alone, virtual demand at the Hub made a gross profit of $1.8 million in 2018. These additional costs reduced the profitability of virtual demand at the Hub by more than

$1.3 million, or by about $1.15/MW. The hub was the most active location for virtual traders in 2018. Twenty-nine different participants submitted more than 1.6 million MW of virtual demand bids at the Hub in 2018, both of which are the highest totals for any location at which virtual demand bids were placed.

The top 10 most profitable locations for virtual supply in 2018 after accounting for transaction costs and NCPC charges are shown in Table 4-2 below.

Table 4-2: Top 10 Most Profitable Locations for Virtual Supply

Location	Location Type	Submitted MW	Cleared MW	Gross Profit ($k)	Net Profit ($k)	Gross Profit Per MW	Net Profit Per MW	# of Participants
UN.OAKFIELD34.5OAKW	Generator Node	652,000	433,000	2,300	$1,866	$5.31	$4.31	15
UN.BINGHAM 34.5BNGW	Generator Node	266,000	174,000	1,293	$1,132	$7.41	$6.49	17
.I.SALBRYNB345 1	Interface Node	309,000	209,000	1,147	$996	$5.49	$4.77	13
.Z.MAINE	Load Zone	1,904,000	703,000	1,252	$764	$1.78	$1.09	20
UN.STETSON 34.5STE2	Generator Node	140,000	65,000	696	$615	$10.79	$9.53	12
UN.SEABROOK24.5SBRK	Generator Node	85,000	35,000	596	$573	$17.08	$16.43	11
UN.ROLLINS 34.5ROLL	Generator Node	129,000	87,000	551	$467	$6.35	$5.38	14
UN.BULL_HL 34.5BLHW	Generator Node	162,000	84,000	483	$394	$5.79	$4.72	17
LD.KEENE_RD46	Load Node	95,000	38,000	379	$322	$9.92	$8.44	12
UN.PASADMKG34.5PASW	Generator Node	39,000	24,000	278	$262	$11.40	$10.76	8

Many of the most profitable locations for virtual supply in 2018 were locations where wind power resources are interconnected. These locations include UN.OAKFIELD34.5OAKW, UN.BINGHAM 34.5BNGW, UN.STETSON 34.5STE2, UN.ROLLINS 34.5ROLL, UN.BULL_HL 34.5BLHW, and UN.PASADMKG34.5PASW. All wind generators are part of the set of resources known as DNE Dispatchable Generators (DDGs), who operate under the DNE rules discussed above. These locations tend to be the most profitable given the opportunity virtual participants have to take advantage of the difference between day-ahead and real-time supply offers by DNE resources. These locations tended to be competitive in 2018 with between 8 to 17 different participants offering virtual supply over the course of the year.

4.2 Financial Transmission Rights

FTRs are a financial instrument that provide participants with physical generation or load in New England's energy markets a way to manage the risks associated with transmission congestion. They also provide market participants a way to speculate on locational congestion differences in the day-ahead market. These rights entitle holders to a share of the "excess congestion revenue" collected by the ISO. This section provides an overview of the Financial Transmission Rights (FTR) market in ISO-NE and assesses its performance in 2018.

Overview of the FTR Market

As mentioned above, FTRs provide participants with a way to hedge or speculate on transmission congestion in New England's day-ahead energy market. 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 existed in the absence of that limiting element. Re-dispatching resources incurs additional production costs on the power system because the most economic generation isn't able to provide all the needed energy. The energy market reflects these additional costs through the congestion component of the LMP. FTRs provide participants with a mechanism to reduce their exposure to these additional costs.

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. The amount of FTRs awarded by the ISO in each auction depends on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the relevant period.[138] The rights awarded in one of the two annual auctions have a term of one year, while FTRs awarded in one of the monthly auctions have a term of one month. Participants can purchase and sell FTRs in annual and monthly auctions. FTRs can be purchased in all auctions, but can only be sold in the second annual auction or the monthly auctions. Only FTRs that are owned (i.e., have been purchased) can be sold by participants. The five important elements in a bid to purchase an FTR are shown in Table 4-3 below.

Table 4-3: Elements of an FTR Bid

Element	Description
Path	2 points on the electrical system: 1) the point of withdrawal or the "sink" (where power is withdrawn from the New England grid) and 2) the point of injection or the "source"
Price	$/MW value the participant pays to acquire the FTR
MW-amount	FTR size
Term	A monthly or annual period
Class	On-peak or off-peak

Once awarded, target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount 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 amount to a credit to FTR holders. Negative target allocations occur in the opposite situation and equate to a financial liability to FTR holders.

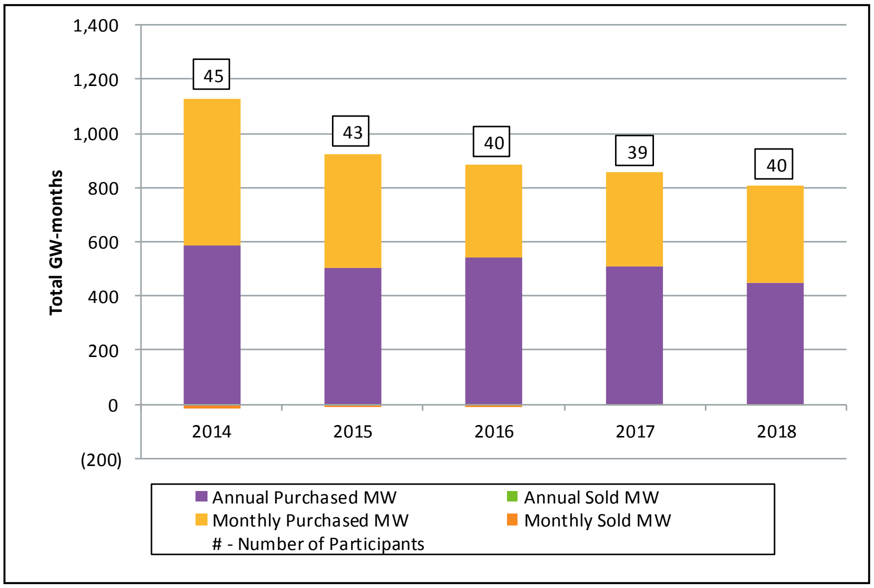
FTR settlement occurs on a monthly basis, and payments to FTR holders with positive target allocations come from day-ahead and real-time congestion revenue and from FTR holders with negative target allocations. The transaction is profitable if the FTR cost is less than the revenue realized from the target allocations.

[138] The market feasibility test helps ensure the revenue adequacy of the awarded FTRs. Revenue adequacy means that there is sufficient congestion revenue collected in the energy market to pay the holders of FTRs.

FTR Market Performance

Participants purchased fewer FTRs in 2018 than in 2017, continuing a trend of steady decreases in FTR auction volumes that has occurred for the last four years. Figure 4-5 shows the volume of FTRs purchased during each year between 2014 and 2018.

Figure 4-5: Financial Transmission Rights Purchased and Sold



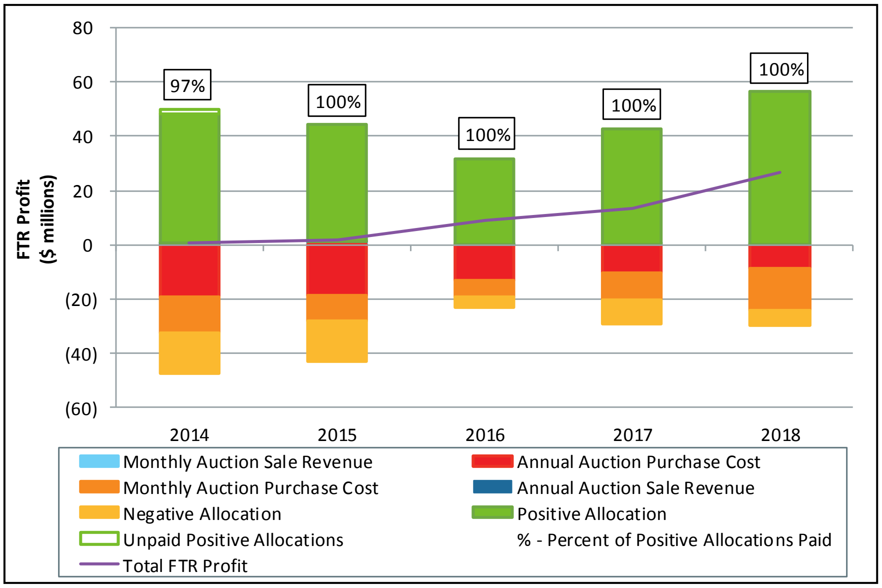
In 2018, 40 market participants purchased approximately 809 GW-months of FTRs. This represents a 6% decrease from the amount of FTRs that were purchased in 2017 (857 GW-months) and a 28% decrease from the amount purchased in 2014 (1,130 GW-months). The volume of FTRs purchased in 2018 means that an average of roughly 33,704 MWs of FTRs were in effect each hour in 2018.[139] In 2014, there was an average of roughly 47,075 MWs in effect each month. There are many factors that could explain this decrease in purchase volumes since 2014, including the adjustment of assumptions that are used in the FTR auction-clearing software.

FTR holders sell very few FTRs each year, as can be seen below the horizontal axis in Figure 4-5. The volume of bids in the auction typically far exceeds the actual amount of FTRs that clear in the auction. In the 2018 annual auction, 20% of the MW volumes bid into the auction cleared, while 32% of bids by MW cleared in the monthly auctions. These clearing percentages are in-line with prior years.

As a whole, FTRs were profitable in 2018. Total profit in the FTR market is the sum of the positive target allocations and the revenue from FTR sales, minus negative target allocations and the cost of purchases. Each of these components, as well as total profit (purple line), can be seen in Figure 4-6 below.

[139] In 2018, there were approximately 809,000 MW-months of FTRs purchased, which includes both on-peak and off-peak FTRs. To get a rough estimate of the average MW amount of FTRs that were in effect in a given hour in 2018, this yearly total is divided by 12 (because there are twelve months in a year) and divided again by two (because the total includes the FTRs from both on-peak and off-peak periods). A more accurate value would account for the number of on-peak and off-peak hours in each month.

Figure 4-6: Financial Transmission Profits and Costs



In 2018, the total profit from FTRs was $26.7 million (purple line), which is an increase of $13.2 million from 2017, when total FTR profit was $13.5 million. Three primary factors led to the increase in FTR profitability in 2018:

1. The revenue to positive target allocations *increased*. Payments to FTR holders with positive target allocations increased by $13.8 million in 2018 relative to 2017. In fact, positive allocations in 2018 were at their highest level of the last five years.
2. The payments from negative allocations *decreased*. Payments from FTR holders with negative allocations decreased by $3.4 million in 2018 relative to 2017.
3. The cost to acquire FTRs in the annual auction *decreased*.[140] Participants spent $1.9 million less to procure FTRs in the two annual auctions in 2018 than they did in 2017. In fact, the cost to acquire FTRs in the annual auctions has fallen in each of the last four years.

The increase in FTR profitability indicates that increased congestion materialized in the day-ahead market relative to the expectations of congestion reflected in the FTR auctions. Participants in the FTR market paid, on average, $30 per MW-month in the auctions, compared to about $23 in 2017, and $22 in 2016. The total allocations to the FTR holders increased to $63 per MW-month (profit of $33) from $39 (profit of $15) in 2017 and $32 in 2016 (profit of $10). The profit in 2018 of $26.7 million was the largest it has been in the last five years.

Significant investment in transmission infrastructure over the past ten years, targeted primarily at import-constrained areas, has reduced the amount of positive congestion in the New England footprint. However, the growth in wind power, the implementation of Coordinated Transaction Scheduling (CTS) at the New York North interface (see Section 5.5), and other factors have led to more export-constrained areas, which, in turn, has led to more negative congestion. This is reflected in Table 4-4 below, which provides information about the most profitable FTR paths in 2018.

[140] While the cost to acquire FTRs in the annual auction decreased relative to 2017, the total cost to acquire FTRs actually increased because of increase in the cost of acquiring FTRs in the monthly auctions.

Table 4-4: Top 10 Most Profitable FTR Paths in 2018

Source Location	Sink Location	Purchase Amount ($k)	Sale Amount ($k)	Positive Target Allocations ($k)	Negative Target Allocations ($k)	Profit ($k)
.I.ROSETON 345 1	.H.INTERNAL_HUB	$4,157	$(21)	$12,025	$(12)	$7,877
.I.SALBRYNB345 1	.H.INTERNAL_HUB	$251	$(9)	$1,764	$(14)	$1,508
UN.SEABROOK24.5SBRK	.H.INTERNAL_HUB	$651	$10	$2,164	$(46)	$1,457
UN.STETSON 34.5STE2	LD.MASON 34.5	$201	$(20)	$1,559	$(0)	$1,378
.I.ROSETON 345 1	UN.COSCOB 13.8CC12	$260	$(8)	$1,406	$(18)	$1,135
UN.POWERSVL115 GNRT	.H.INTERNAL_HUB	$1,744	$-	$2,815	$(6)	$1,065
.Z.MAINE	.H.INTERNAL_HUB	$147	$-	$929	$(68)	$713
UN.SEABROOK24.5SBRK	LD.LAWRENCE34.5	$196	$-	$830	$(0)	$634
UN.POWERSVL115 GNRT	LD.BELFAST 34.5	$88	$-	$657	$(0)	$569
LD.BUCKSPRT13.8	LD.BELFAST 34.5	$196	$(7)	$754	$(0)	$565

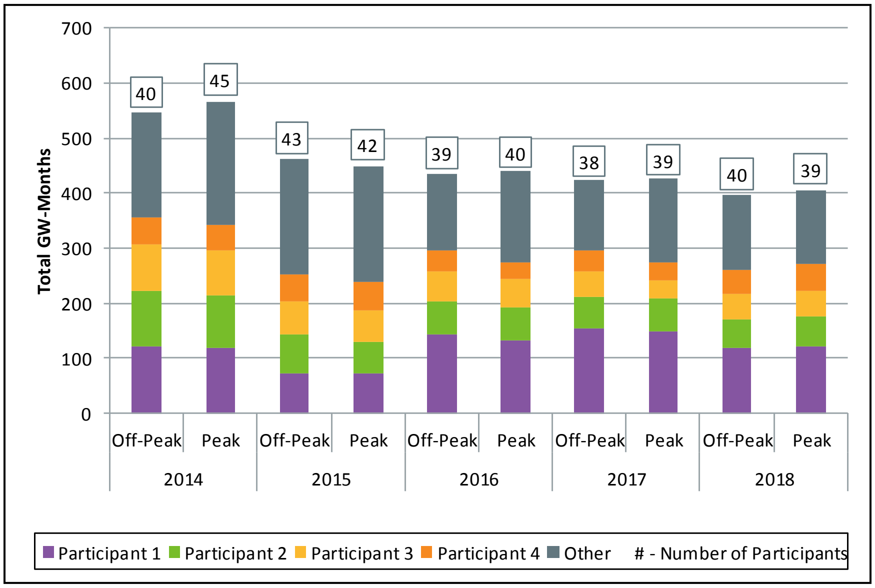
Many of the most profitable FTR paths in 2018 sourced from locations that tend to be export-constrained, making them more prone to negative congestion pricing. The most profitable FTR path in 2018 – by a significant margin – was a path that sourced from .I.ROSETON 345 1, ISO-NE's external node for trading across the New York – New England interface, and sank at the .H.INTERNAL_HUB, a location designed to have little congestion. Participants were able to acquire FTRs along this path for $4.2 million and they yielded positive target allocations of $12.0 million, earning holders of these FTRs $7.9 million in profit. Positive target allocations for this path were concentrated around the winter months, with 98% of positive allocations arising from January to April or October to December. As discussed in Section 3.4.9, the New York – New England interface was the most frequently binding interface constraint in the day-ahead market in 2018.

FTRs were fully funded in 2018 as indicated by the labels above the bars in Figure 4-6. FTRs are said to be fully funded when there is sufficient congestion revenue collected in the energy market and from negative target allocations to pay positive target allocations the full amount of revenue to which they were entitled. FTRs are paid from the congestion revenue fund, which was discussed in Section 3 FTRs with positive target allocations were not fully funded in 2014, and holders of FTRs with positive target allocations only received 97% of the revenue that was due to their FTRs.

The concentration of ownership of FTRs among market participants was similar to prior years. The amount of FTRs held by the top four participants with the most MW each year in on-peak and off-peak hours is shown in Figure 4-7 below.[141]

[141] On-peak hours are defined by the ISO as weekday, non-holiday hours ending 8-23. The remaining hours are off-peak hours.

Figure 4-7: Top Four Holders of Financial Transmission Rights



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.

In 2018, the percentage of on-peak FTR MWs held by the top four participants was 67%. This ratio is often referred to as the C4. The off-peak concentration ratio of the top four FTR holders in 2018 was similar to the on-peak; the top four participants held 66% of the off-peak FTR MWs. The concentration ratio of the top four FTR holders has held relatively steady over the five-year report horizon, staying between a 53% - 70% bandwidth depending on the class (i.e., on-peak or off-peak) and year.

Section 5
External Transactions

This section examines trends in participant's use of external transactions in the day-ahead and real-time energy markets. In addition, this section assesses the market outcomes at the New York North interface where Coordinated Transaction Scheduling (CTS) was implemented in mid-December of 2015.

5.1 Bidding and Scheduling

The bidding and scheduling of external transactions begins with a market participant's decision to take a financial position in the energy markets associated with the movement of power between control areas. Except for import resource obligations acquired through the Forward Capacity Market, there are no requirements to submit external transactions. Participants may opt to trade power in anticipation of profiting on price differences or to fulfill other contractual obligations assumed outside the markets administered by ISO-NE.

There are several external transaction types. The primary category is an import or export at a single external node. These transactions may be submitted as either a priced or fixed transaction and are allowed in both the day-ahead and real-time markets. 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 offer; there is no price evaluation and the transaction will be accepted unless there is a transfer constraint. In the day-ahead market there is also an up-to congestion transaction type, which allows a participant to create sell and buy obligations at an external and internal node based on differences in LMPs between the nodes. In real-time, participants may use wheel-type transactions to ship power across New England between two external nodes. Wheel transactions are evaluated as fixed transactions. CTS introduced an additional real-time transaction type called an interface bid. 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 to clear.

In the day-ahead market, external transactions establish financial-only obligations to buy or sell energy at external nodes. There is no coordination with other control areas when clearing day-ahead transactions. In contrast, in the real-time market the scheduled transactions define the physical flow of energy that will occur between control areas. 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.

The clearing of external transactions in the day-ahead and real-time markets occurs independently, although a single transaction can have day-ahead and real-time offers. 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 or 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 MW-amount cleared in day-ahead 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.[142]

In the day-ahead market, external transactions are cleared for whole-hour periods based on economics while respecting interface transfer limits. In real-time, at locations other than New York North, where CTS is enabled, transactions are scheduled at 45 minutes ahead for a one-hour schedule duration and must be confirmed by the neighboring area. At the CTS location, interface bids are cleared 20 minutes ahead for 15-minute schedules.[143]

5.2 External Transactions with New York and Canada

As discussed in Section 2.4, there are six external interfaces that interconnect the New England system with its neighboring control areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound Cable, and the Northport-Norwalk Cable. These last two run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces (which both connect with the Hydro-Québec control area) and the New Brunswick interface.

In 2018, New England remained a net importer of power with net imports during real-time averaging 2,459 MW each hour. This section provides a detailed breakdown of the total flows across each of the six interfaces with New York and Canada.

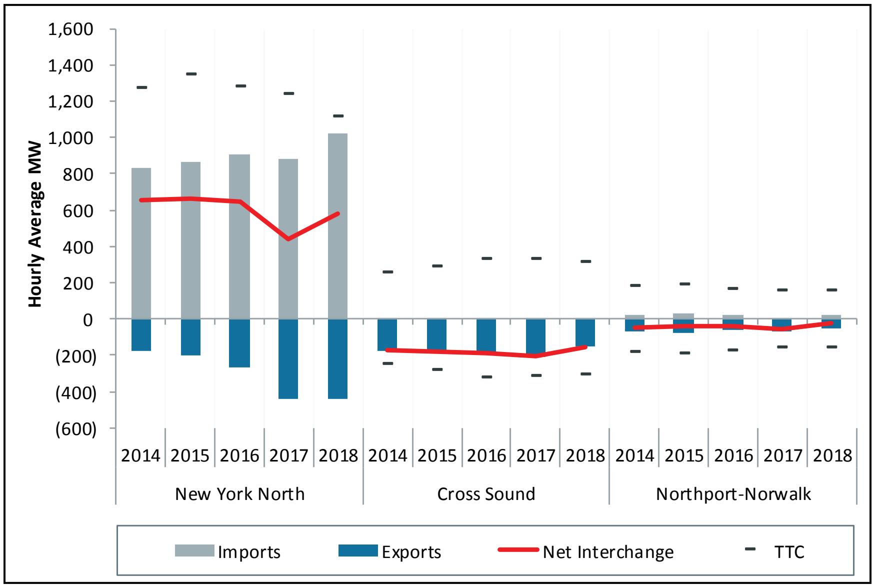
New York Interfaces

While New England is a net importer of power from both New York and the Canadian provinces, there are also substantial volumes of power exported from New England, particularly at the New York interfaces. The annual average real-time net interchange volumes and the gross import and export volumes at each interconnection with New York are shown for each year between 2014 and 2018 in Figure 5-1 below. The average hourly values of the real-time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted in Figure 5-1 using the black dash lines. The TTC ratings are included to indicate typical transmission capacity utilization at each interface. The New York North export TTC values were omitted from the chart since the average export volumes are far below the rated 1,200 MW export capability. Note that the annual observations are grouped by interface.

[142] This scheduling priority is not applicable to real-time interface bids at CTS locations.

[143] The clearing process *begins* 45 minutes before the 15-minute interval and ends 20 minutes before.

Figure 5-1: Real-Time Net Interchange at New York Interfaces



New England predominately imports power over the New York North interface and exports power at both the Cross Sound and Northport-Norwalk interfaces. Combining flows at all three interfaces, the real-time net interchange with New York averaged 403 MW per hour in 2018, making New England a net importer of power from New York. The New York North interface is comprised of seven AC lines between New York and New England. It has the largest import and export transfer capacities among the New York interfaces and facilitates the majority of power transactions between the two markets.[144] The Cross Sound Cable and Northport-Norwalk Cable ties run between Connecticut and Long Island and are typically utilized to deliver power to New York as shown in Figure 5-1. On average over the last five years, the New York interfaces have not been near their full capability ratings.

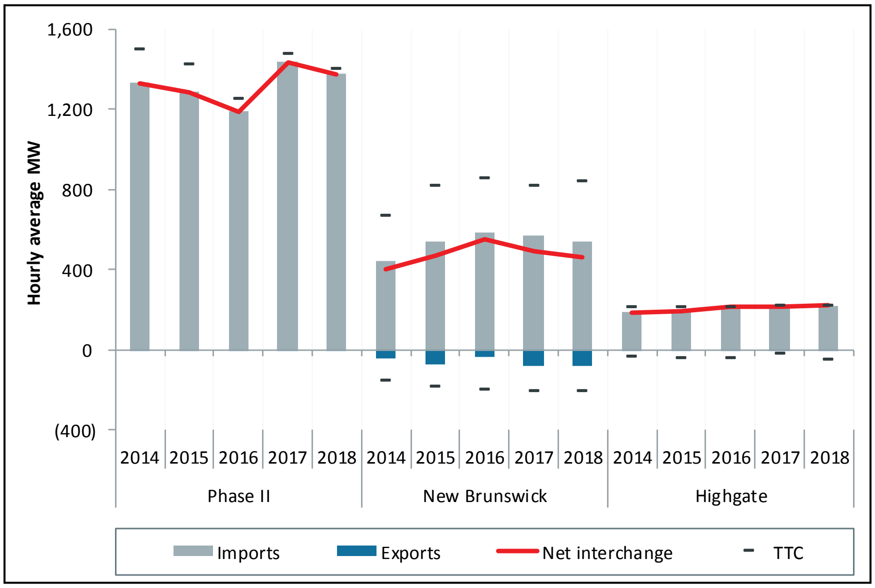
The average hourly real-time imports at the New York North interface increased by 16% in 2018 relative to 2017 (from 882 MW to 1,023 MW per hour). Meanwhile, average hourly real-time exports at the New York North interface stayed about the same between 2017 and 2018. The combined effect of these two outcomes was that average hourly real-time net interchange at the New York North interface increased by 31% in 2018 relative to 2017 (from 443 MW to 581 MW per hour). A primary driver of this increase in imports was an increase in the amount of offered supply at low, and even negative, price spreads (see Section 5.5 for more detail). One other notable trend is that the amount of average hourly real-time exports at the New York North interface has increased by 154% over this five-year period (from 174 MW per hour in 2014 to 442 MW per hour in 2018). This increase in exports is related to CTS, which was implemented at the New York North interface in mid-December 2015 to improve the efficiency of real-time power flows between the two control areas. Section 5.5 of this report discusses the observed impacts of this market change in further detail.

[144] New York North has a 1,400 MW import capacity in the summer, 1,600 MW import capacity in the winter, and 1,200 MW export capacity year round.

Canadian Interfaces

The annual average real-time net interchange volumes and the gross import and export volumes at each interconnection with Canada are graphed for each year between 2014 and 2018 in Figure 5-2 below. The average hourly values of the real-time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted in Figure 5-2 using the black dash lines. The Phase II export TTC values were omitted from the chart since the average export volumes are far below the rated 1,200 MW export capability. Note that the annual observations are grouped by interface.

Figure 5-2: Real-Time Net Interchange at Canadian Interfaces



New England imports significantly more power from Canada than it does from New York. Across all three interfaces (i.e., Phase II, New Brunswick, and Highgate) the real-time net interchange with Canada averaged 2,056 MW per hour in 2018, which was a decrease of 4% (89 MW) relative to the average real-time net interchange in 2017. New England predominately imports power from Canada with the exception of some limited quantities of exports to the New Brunswick system, but these averaged only 77 MW per hour in 2018. One of the major factors that contributed to the decrease in average real-time net interchange in 2018 was a forced outage at Phase II in August. An explosion at the Sandy Pond substation removed one of the two poles bringing power into New England from service until near the end of September. For much of the period of this outage, the Phase II import capability was capped at 1,000 MW. The average real-time import TTC in 2018 was 5% lower than the 2017 value (1,402 MW in 2018 versus 1,479 MW in 2017).

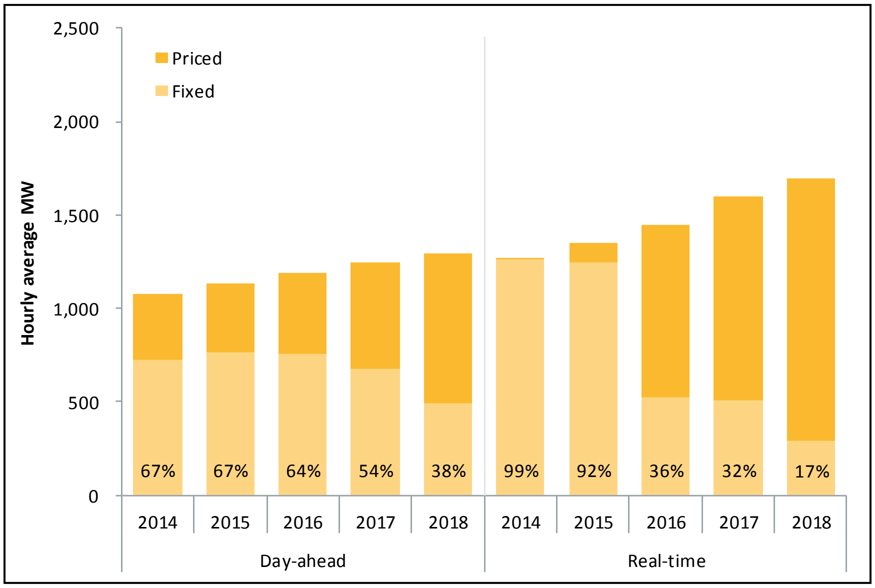
5.3 External Transaction Types

In this section, we examine the external transactions that underlie the transacted energy volumes discussed in the preceding section. We consider the make-up of the transactions that participants utilized to transact power. Specifically, where and when participants elect to use priced versus fixed transactions.

New York Interfaces

The composition of day-ahead and real-time cleared transactions at the New York interfaces is charted in Figure 5-3 below for each year between 2014 and 2018.[145] The lighter yellow series is the total volume of fixed transactions and the percentage value is the share of overall cleared transactions that were fixed. The darker yellow series is the volume of priced transactions. The volumes presented are the average MW per hour values each year.

Figure 5-3: Cleared Transactions by Type at New York Interfaces



Beginning in 2016, a large percentage of New York real-time transactions shifted from fixed to priced as seen in Figure 5-3. This trend continued in 2018 as the percentage of New York real-time transactions that are fixed transactions fell to only 17%, the lowest percentage in the last five years. The shift is largely due to the implementation of CTS in December 2015. All real-time transactions at New York North are now evaluated based on price, although participants may offer prices as low as -$1,000/ MWh to effectively schedule the transaction as fixed. The percentage of transactions that are priced continued to grow in the day-ahead market at the New York interfaces in 2018 as well, with fixed transactions making up only 38% of cleared day-ahead volumes.

For Figure 5-3 above, as well as Figure 5-4 (Canadian interfaces) below, the amount of imports and exports are added together. The breakout of fixed and priced-type transactions is separated by import and export transactions at the New York interfaces in Table 5-1 below. The values presented in this table are for cleared transactions and the volumes are the average MW per hour.

[145] Refer to Section 2.4 for details of the external nodes associated with the New York, Québec, and New Brunswick areas.

Table 5-1: Transaction Types by Direction at New York Interfaces (Cleared MW per hour)

Market	Direction	Type	2014	2015	2016	2017	2018
Day-ahead	Import	Priced	63	89	133	195	447
		Fixed	687	700	709	577	441
		Percent Priced	8%	11%	16%	25%	50%
	Export	Priced	291	281	298	375	354
		Fixed	33	61	48	101	54
		Percent Priced	90%	82%	86%	79%	87%
Real-time	Import	Priced	13	70	651	657	967
		Fixed	845	827	281	234	82
		Percent Priced	2%	8%	70%	74%	92%
	Export	Priced	0	32	272	436	442
		Fixed	413	418	242	272	205
		Percent Priced	0%	7%	53%	62%	68%

Comparing the percentages of priced transactions in the day-ahead market among imports and exports using Table **5-1** highlights that, while the majority of export transactions at the New York interfaces have been priced for the last five years, the percentage of priced imports is growing. The volume of imports has also grown substantially, with the additional volume adding to the amount of priced transactions, across a broad range of offer prices.

In 2018, 50% of import transactions that cleared in the day-ahead market at the New York interfaces were priced-type transactions. On average, 447 MWs of priced import transactions were cleared per hour in the day-ahead market at the New York interfaces. This represents a 129% increase from the average amount of priced import transactions that were cleared per hour in the day-ahead market at the New York interfaces in 2017. The vast majority of imports that clear at the New York interfaces in the day-ahead market occur at the New York North interface (99% in 2017, 98% in 2018). Therefore, changes to the mix of day-ahead imports reflect what is occurring at the New York North interface. Between 2017 and 2018, the amount of fixed imports that cleared in the day-ahead market at the New York North interface fell by 142 MWs (25%) on average, while the amount of cleared priced imports at the New York North interface increased by 243 MWs (128%), on average.

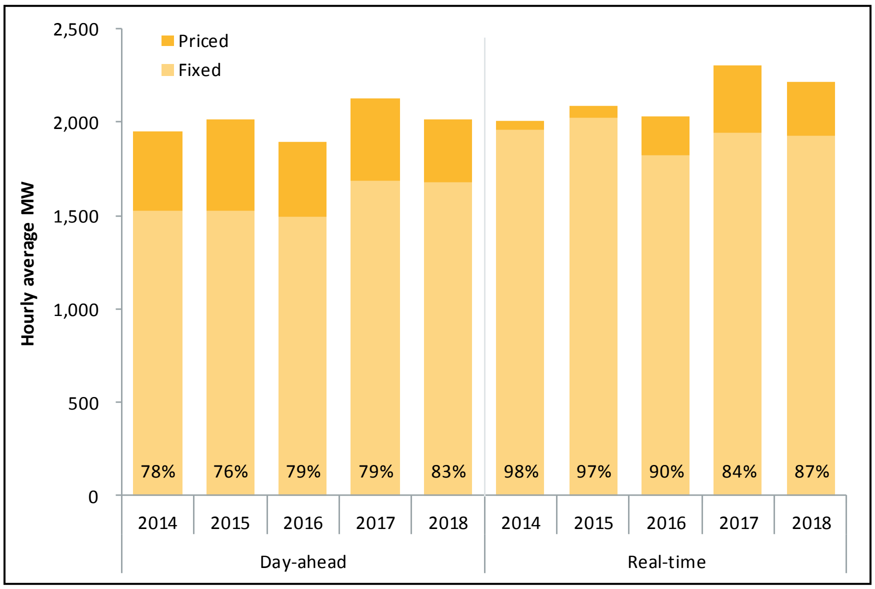
The transformation of external transactions at the New York interfaces in the real-time market from predominantly fixed to predominately priced is also evident in Table 5-1. In 2014, only 2% of real-time cleared import transactions were priced transactions and 0% of export transactions were priced. This is in stark contrast to 2018, when 92% of real-time cleared import transactions were priced transactions and 68% of export transactions were priced. Similar to the day-ahead market, the vast majority of imports that clear at the New York interfaces in the real-time market occur at the New York North interface (99% in 2017, 98% in 2018). Between 2017 and 2018, the amount of fixed imports that cleared in the real-time market at the New York North interface fell by 167 MW (74%), on average, while the amount of cleared priced imports at the New York North interface increased by 310 MWs (47%), on average. The reasons for this significant change are discussed in

Section 5.5, which covers the implementation of Coordinated Transaction Scheduling at the New York North interface in more detail.

Canadian Interfaces

The composition of transactions cleared in the day-ahead and real-time markets at interfaces with the Canadian provinces is charted for each year between 2014 and 2018 in Figure 5-4 below. The lighter yellow series is the total volume of fixed transactions and the percentage value is the share of overall cleared transactions that were fixed. The darker yellow series is the volume of cleared priced transactions. The volumes presented are the average MW per hour values each year.

Figure 5-4: Transaction Types Cleared at Canadian Interfaces



The higher volumes of power transacted over the Canadian interfaces compared with the New York interfaces are highlighted by comparing Figure 5-4 to Figure 5-3. Roughly 2,200 MW each hour are scheduled over the Canadian interfaces compared with around 1,700 MW at the New York interfaces. The very high volumes of fixed transactions are also evident; in 2018, 83% of day-ahead and 87% of real-time scheduled volumes were fixed-price transactions. As discussed above, a real-time transaction will be scheduled as if it were fixed if it has cleared in the day-ahead market and was not later modified. Based on this real-time scheduling practice, it is actually the case that upwards of 96% of the real-time priced-type transactions in 2018 were scheduled as fixed (but offered as priced in the day-ahead market) transactions. The ratio of priced transaction power scheduled as fixed in real-time has been above 78% each year since 2014.

The breakout of fixed and priced transactions by import and export transactions at the interfaces with the Canadian provinces is shown in Table 5-2 below. Here again, the values presented are for cleared transactions and the volumes are the average MW per hour.

Table 5-2: Transaction Types by Direction at Canadian Interfaces (MW per hour)

Market	Direction	Type	2014	2015	2016	2017	2018
Day-ahead	Import	Priced	420	486	399	418	327
		Fixed	1,517	1,509	1,491	1,677	1,667
		Percent Priced	22%	24%	21%	20%	16%
	Export	Priced	6	3	2	18	12
		Fixed	9	20	6	11	12
		Percent Priced	42%	12%	22%	61%	50%
Real-time	Import	Priced	42	64	203	354	275
		Fixed	1,919	1,955	1,788	1,871	1,859
		Percent Priced	2%	3%	10%	16%	13%
	Export	Priced	3	2	4	13	10
		Fixed	44	70	35	69	69
		Percent Priced	7%	3%	10%	16%	12%

Both imports and exports at the Canadian interfaces are typically submitted as price-insensitive fixed transactions as shown in Table 5-2. Fixed price imports to New England make up the majority of transactions occurring at the Canadian interfaces. Also, as discussed in Section 5.2, there are very small volumes of power exported at the New Brunswick interface.

5.4 External Transaction Net Commitment Period Compensation Credits

The high volumes of day-ahead fixed transactions at the external interfaces, particularly at non-CTS interfaces, bear mention of the market clearing outcomes and special Net Commitment Period Compensation (NCPC) credits for external nodes in the day-ahead market.

Where the ISO lacks sufficient information to calculate real-time congestion prices at the external nodes (*i.e.*, the marginal cost of power at the other side of the interface), it also does not produce a congestion price at the external nodes in the day-ahead market.[146] Instead, the cost of relieving the congestion is reflected in a transfer of NCPC between those causing the congestion and those relieving the congestion.

To expand further on this point, absent congestion pricing, the day-ahead market applies a nodal constraint that limits the net injections to the transfer capability of the external interface. Under these mechanics, offsetting injections (import transactions and virtual supply) and withdrawals (export transactions and 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

[146] Prior to the CTS design, 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.

offers that exceeds the import transfer capability can be cleared if offsetting export transactions or virtual demand bids are available. The clearing of these offsetting transactions does not affect the nodal LMP. The typical way that NCPC payments accrue in the day-ahead market is when fixed import or export transactions exceed the transfer capability of the interface and offsetting withdrawals or injections 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 NCPC and the participant with the fixed transaction that was allowed to clear is charged the NCPC.

The annual NCPC credit totals (millions of $) at all external nodes in both the day-ahead and real-time markets for each year from 2014 through 2018 are presented in Table 5-3 below.

Table 5-3: NCPC Credits at External Nodes

Year	Day-ahead credits ($million)	Real-time credits ($million)
2014	$10.03	$0.59
2015	$3.05	$1.15
2016	$0.90	$1.28
2017	$0.56	$1.92
2018	$0.30	$2.73

The total amount of NCPC credits paid at external nodes is very small compared with other types of NCPC. NCPC is discussed in detail in Section 3.5. In the day-ahead market, we typically see these payments occur when there is an unexpected or large decrease in the Total Transfer Capability (TTC) until participants adjust their fixed bidding behavior. The relatively high total credits that accrued during 2014 occurred primarily in February and March when total volumes of fixed import transactions increased as New England prices were particularly high (See Section 3.3 on energy prices). The credits coincided with TTC reductions at the New Brunswick and New York North interfaces, as well as at the Phase II interface during December while planned line outages were ongoing.

Day-ahead NCPC credits at external nodes decreased 47% in 2018 compared to 2017. The vast majority (96%) was paid at the Phase II interface. Total day-ahead credits at this interface in 2018 ($285k) increased by 313% from their total in 2017 ($69k). There is no longer any NCPC paid at the New York North interface since congestion pricing was implemented at this interface on December 15, 2015, under the CTS design. In 2015, day-ahead credits at New York North totaled $1.2 million. Only 3% of day-ahead NCPC paid out at the external nodes in 2018 went to virtual transactions; in 2017, virtual transactions accounted for nearly 90% of the day-ahead NCPC paid out at external nodes.

Real-time NCPC credits at external nodes are paid to priced transactions scheduled during real-time that prove to be out-of-merit for the hour, similar to generator out-of-merit credits.[147] In the real-time energy market, external transactions are scheduled based on a comparison of the transaction

[147] Real-time transactions at the New York North interface also are not eligible for NCPC credits, with limited exception, under the CTS design.

price to the ISO-NE forecasted price for the external node.[148] For example, if a participant has submitted an import offer in the real-time and the price of the offered energy is less than the forecasted price for the relevant external interface, the import offer will clear (assuming there is sufficient transfer capability on the relevant external interface). If the actual real-time LMP for that external node turns out to be less than the offer price in the cleared import transaction, the participant would receive NCPC to be made whole to its offered price. Real-time NCPC payments to external transactions can only be paid to priced transactions – fixed transactions are willing to clear at any price, and therefore cannot clear out-of-merit.

As Table 5-3 shows, total real-time external transaction NCPC credits during 2018 were 42% higher than in 2017. The increase was primarily due to an increase in NCPC credits at the New Brunswick interface, where payments rose by 78% from $1.24 million in 2017 to $2.20 million in 2018. Real-time external NCPC payments at the New Brunswick interface were particularly high in April and May, when payments totaled $0.4 million and $1.06 million, respectively. During parts of these months, planned transmission work in Maine reduced the limits on several internal interfaces – notably, the Coopers Mill – South (COMI-S) and the Orrington – South (ORR-SO) interfaces. The external node associated with the New Brunswick interface, .I.SALBRYNB345 1, has a very high sensitivity to these constraints. This means that when either of these constraints bind, a significant percentage of the constraint's marginal value is reflected in the congestion component of .I.SALBRYNB345 1. Because .I.SALBRYNB345 1 is export-constrained relative to these constraints, the congestion component of .I.SALBRYNB345 1 is negative when these constraints bind (resulting in a lower LMP all else equal). Importantly, it appears that the price forecast used by ISO-NE to schedule import transactions at New Brunswick in the real-time did not fully reflect the impact that these binding constraints would have on the real-time price at .I.SALBRYNB345 1.

In December 2014, the NCPC design changes for hourly market offers modified the real-time credit for external transactions to consider all MWs scheduled in real-time based on a price evaluation rather than just the MWs above the day-ahead cleared amount for the transaction. This settlement change produced an increase in the real-time credits paid beginning in 2015 relative to the preceding years.

5.5 Coordinated Transaction Scheduling

The Coordinated Transaction Scheduling (CTS) design is intended to improve the efficiency of real-time energy trades between New England and New York. In this section, we present measures of real-time price convergence, the risk of ISO internal price forecast errors borne by competitive arbitrage bidders, price forecast accuracy and bidding behavior. A CTS analysis where many of these metrics were first shown was presented in the 2016 Spring Quarterly Markets Report.[149]

CTS was implemented by ISO-NE and the New York Independent System Operator (NYISO) in December 2015, for the New York North interface. The design modified the bidding and scheduling mechanics for real-time transactions between the two markets. At a high level, the design changes unified the bid submission and clearing process, decreased the schedule duration from one hour to 15-minute intervals, moved bid submittal and clearing timelines closer to the interval when power

[148] This is for non-CTS interfaces. For CTS interfaces (i.e., the New York North interface), real-time interface bids are cleared based on forecasted price *differences* between NYISO and ISO-NE.

[149] The 2016 Spring Quarterly Markets Report is available here: https://www.iso-ne.com/static-assets/documents/2016/08/q2_spring_2016_qmr_final.pdf

flows, and eliminated transaction fees.[150] The CTS design was intended to improve the frequency that power moves from the lower- to higher-cost region and increase the utilization of interface transfer capability to better converge prices between the regions.

CTS scheduled flow in the correct direction 63% of time in 2018

As discussed in Section 5.2 above, New England was a net importer of power across the New York North interface, importing an average of 581 MW each hour in 2018. Average annual data on CTS schedules are presented in Table 5-4 below. The table shows the percentage of intervals when the net CTS schedule was in either the New England or New York direction, and the percentage of intervals when the flow was in the economically correct direction (i.e. from lower-cost to higher-cost market). The latter statistic is shown based on the forecast of price difference (relevant to the actual clearing of CTS bids), as well as on actual settled prices.

Table 5-4: Summary of CTS Outcomes

	Net Flow (% of intervals), to		Correct Flow (% of intervals), based on:	
Year	**ISO-NE**	**NYISO**	**Forecast Spread**	**Actual Spread**
2016	94%	6%	63%	56%
2017	79%	20%	68%	61%
2018	88%	12%	59%	63%

In 2018, New England was a net importer during 88% of real-time intervals. Overall, CTS bids in 2018 allowed power to flow consistent with *forecast* price differences only 59% of the time, which was down on 68% observed in 2017. This trend is generally consistent with the increase in negative import spread bids into New England. Negative import spread bids will be scheduled even when the power is being imported from the higher-cost region to a lower-cost region. This is discussed further towards the end of this section.

Based on *actual* price differences, power flowed in the correct direction 63% of the time, which was an improvement over the 61% observed in 2017. The percentage of correct flows based on forecast and on actual price spreads was closer than prior years (a 4% difference in 2018 compared to 7% in 2017).

Price convergence improved slightly in 2018

To examine the degree of real-time price convergence achieved under the CTS design relative to prior years, we've calculated the percentage difference between the average hourly prices at each ISO's respective pricing location for the New York North interface and present the results in Figure 5-5 below.[151] Percentage differences are to adjust for absolute price levels.[152] The line series in Figure 5-5 plot the cumulative distribution function for observations of the absolute percentage

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[150] 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/

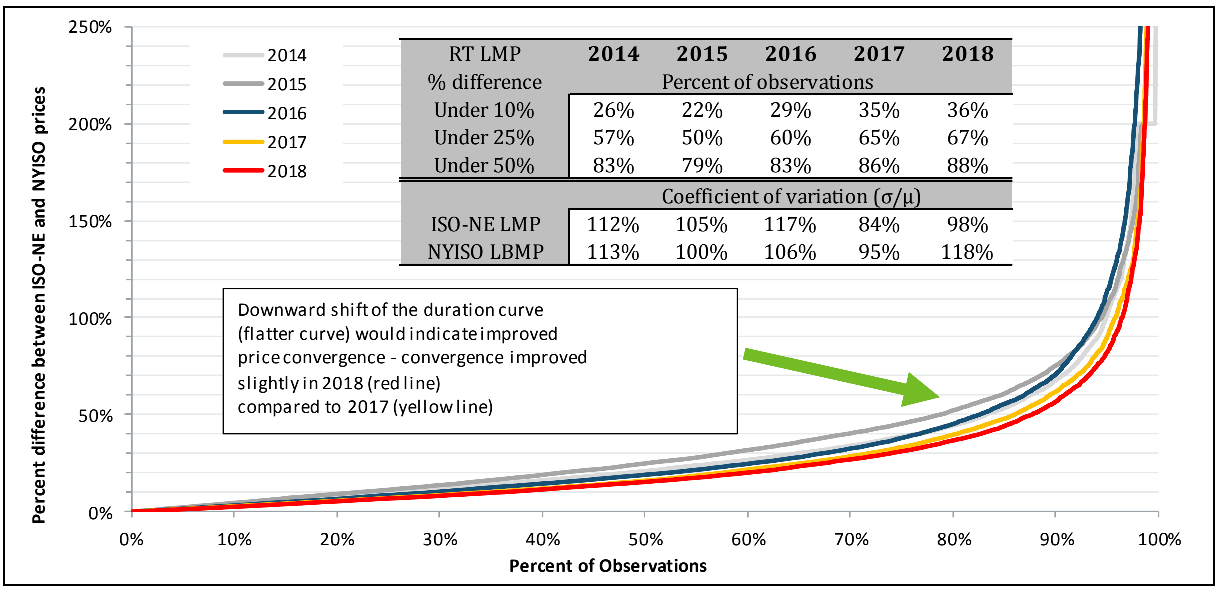
[151] The NYISO pricing node is called "N.E._GEN_SANDY PD" and the ISO-NE node is "I.ROSETON 345 1."

[152] Higher absolute prices often result in larger price differences. Percentage differences are shown so that larger magnitude price divergences due to higher absolute prices are not attributed to CTS.

difference between the ISO-NE and NYISO real-time hourly energy prices at the New York North interface.

To read the values presented in the chart, choose a value (say, 10%) on the vertical axis, which plots the absolute percentage difference in prices at each side of the interface, then scan horizontally until you've intersected with a line series. At the point of intersection, read the value from the horizontal axis, which is the probability of a price difference of 10% or less. To help compare across years, the table embedded in the chart provides the probabilities of a few price difference values (i.e., 10%, 25%, 50%) for each year. To describe the relative market price volatility in each of these years, the table in Figure 5-5 also includes the coefficient of variation for real-time energy prices. The coefficient of variation measures how much each ISO's real-time price varied relative to its average price for the year.[153] If price volatility was low for both markets, it would not be surprising to observe New England and New York prices remaining close in value. However, when price volatility is higher, a greater degree of price divergence between the regions is expected, unless a scheduling system like CTS is frequently adjusting the interface flow.

Figure 5-5: New York North Real-Time Price Difference between ISO-NE and NYISO



RT LMP % difference	2014	2015	2016	2017	2018
	Percent of observations				
Under 10%	26%	22%	29%	35%	36%
Under 25%	57%	50%	60%	65%	67%
Under 50%	83%	79%	83%	86%	88%
	Coefficient of variation (σ/μ)				
ISO-NE LMP	112%	105%	117%	84%	98%
NYISO LBMP	113%	100%	106%	95%	118%

Figure 5-5 indicates that there was an improvement in price convergence in 2018. Real-time price differences were generally lower than any of the prior four years. At all three values of price difference shown in the embedded table in Figure 5-5, 2018 contains the highest percentage of observations. Meanwhile, prices were more volatile in 2018 than in the prior year. In 2018, the coefficient of variation in real-time price was 98% for ISO-NE, the second lowest value in the study period, but 118% at the NYISO side, the highest value in the last five years. While price volatility in 2018 was comparable to levels observed prior to the implementation of CTS, price differences between New York and New England have decreased, indicating that CTS may be improving price convergence between the two control areas.

[153] The coefficient of variation is the ratio of the standard deviation to the mean.

Price forecast error improved on average but may continue to inhibit CTS effectiveness

The efficiency of CTS schedules can be greatly impacted by the accuracy of the ISOs' internal price forecasts at the external node. Price forecasts are calculated for each 15-minute interval and used to determine the direction of price differences between the regions, which participant bids clear, and the interface flow. Interface bids clear if the offer price is below the forecasted price difference. ISO-NE creates its CTS price forecast using current offers and system conditions at about 45 minutes ahead of the scheduling interval. The NYISO forecasts its internal price at about 30 minutes ahead of the scheduling interval. A summary of forecast versus actual prices is provided in Table 5-5 below.

Table 5-5: Forecast Error in CTS Solution

	Forecast LMP			Actual LMP			Average Forecast Error		
	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread
2016	$28.82	$27.64	**$1.18**	$28.02	$29.23	**$(1.22)**	$0.80	$(1.60)	**$2.40**
2017	$33.37	$31.29	**$2.08**	$32.02	$32.37	**$(0.34)**	$1.34	$(1.08)	**$2.42**
2018	$38.21	$38.99	**$(0.77)**	$39.29	$40.80	**$(1.51)**	$(1.07)	$(1.81)	**$0.74**

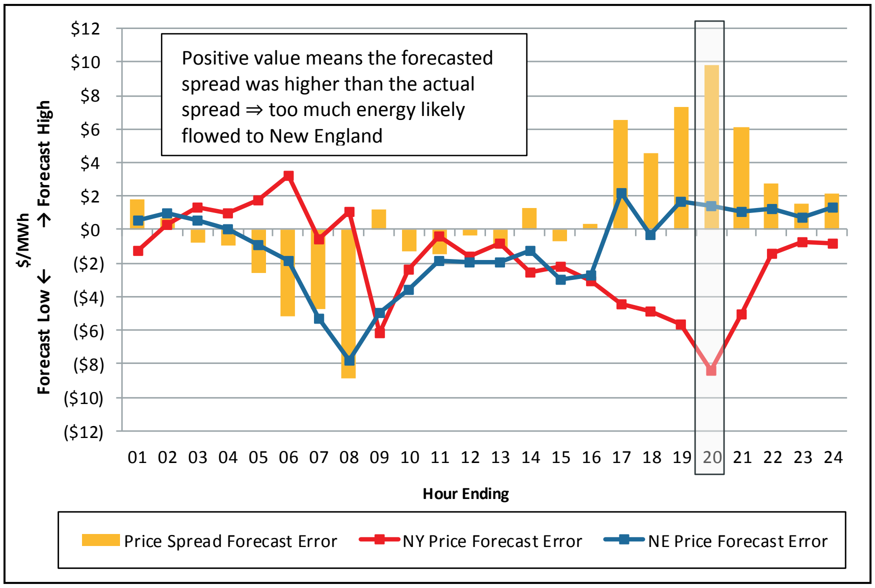
CTS price forecast accuracy improved in 2018 relative to 2017. In 2018, the average difference between the forecast NE-NY spread and the actual NE-NY spread was $0.74/MWh, down from $2.42/MWh in 2017, a $1.68/MWh improvement.[154]

On average in 2018, the forecasted price for power in New England was $1.07/MWh less than the actual price. The forecast for the price of power in New York in 2018 was slightly worse; on average, the forecasted price of power was $1.81/MWh less than the actual price. In general, the forecast errors were offsetting, rather than compounding as they had been in 2016 and 2017, resulting in the smallest average difference between the forecast NE-NY spread and the actual NE-NY spread in the last three years.

However, the improvement in the average forecast error of $1.68/MWh presented above does not provide a complete picture. The absolute average forecast error improved by only $0.39/MWh. This is because the forecast performance remains inconsistent for both ISO-NE and NYISO across many hours of the day. The ISOs' forecast errors tend to be higher in some hours of the day than in other hours, and the hours with the higher errors are not always the same for each ISO. Figure 5-6 below shows the simple average of forecast errors calculated by hour of the day with data from 2018.

[154] Price difference forecast error is: (Forecast $_{\text{New England}}$ – Forecast $_{\text{New York}}$) – (Actual $_{\text{New England}}$ – Actual $_{\text{New York}}$).

Figure 5-6: Average Real-Time ISO Price Forecast Errors, by hour



A positive observation in Figure 5-6 indicates the forecast is higher than the actual price and a negative observation indicates the forecast is lower than actual price. The red line series represents the average error in the NYISO price forecast for each hour and the blue line series represents the average error in the ISO-NE price forecast each hour. The tendencies for New England and for New York to forecast too low are evident in most hours. On average, errors in the New England price forecast are largest during the morning hours (i.e., HE 7-10), while New York forecast errors are most apparent in the evening hours (i.e., HE 17-21).

When there is a positive price spread error, indicated by a positive value of the yellow bar series in Figure 5-6, this means that the forecast NE-NY spread was *greater* than the actual NE-NY spread. For example, in HE 20 (the hour with the highest error) the New England forecast price was higher than the actual price by $1.46/MWh, on average, and the New York forecast price was less than the actual price by $8.38/MWh, on average. Thus, the forecast NE-NY spread was greater than the actual NE-NY spread by $9.83/MWh, on average. In hours like this, it is likely that too much energy was scheduled to flow into New England. This trend is particularly prominent for hours ending 17-21. Conversely, when the yellow bars are negative, this means that the forecast NE-NY spread was *less* than the actual NE-NY spread. In these hours, it is likely that too little energy was scheduled to flow into New England. This trend is particularly prominent in hours ending 5-8. These trends are similar to those reported in the prior two Annual Markets Reports. The cause of this shift in error tendencies during the morning and evening hours is not yet known.

The ISOs' forecast biases may consistently produce inefficient tie schedules. When the forecasted price difference is over-estimated, more higher-priced interface bids can clear than will actually be in rate and the tie schedule can exceed the economically efficient level. Conversely, when forecasted price differences are under-estimated, too few interface bids may clear and the interface may be underutilized.

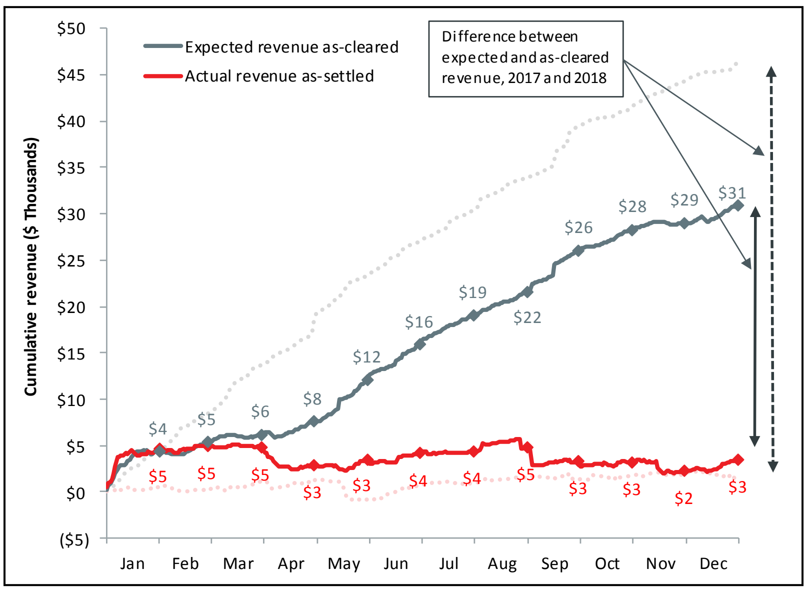
The impact of the ISO price forecast errors

The risk of ISO price forecast error is not insubstantial and is borne by the participants because there is no make-whole compensation for cleared interface bids. Next, we examine the cost to participants of the ISOs' price forecast error tendencies using a hypothetical participant's earnings on a competitive arbitrage bid strategy.

To evaluate the impact of the ISOs' price forecast errors on the profitability of trading power across the CTS interface, we've compiled an ex-post calculation of the earnings of a competitive arbitrage bidding strategy. Recall that the interface bid price expresses the minimum price difference between regions the participant is willing to accept to be scheduled and interface bids are cleared if their bid price is less than the forecasted price difference. For this analysis, we assume a participant submits both an import and export interface bid transaction in every 15-minute interval during 2018. Both transactions are for 1 MW and have a bid price of 1 penny. In any interval when the difference in the ISOs' forecasted prices is greater than a penny, either the import or the export transaction will clear depending on the direction of the forecasted price difference.

The cumulative value of end-of-day earnings on the hypothetical 1 penny interface bid strategy over the duration of 2018 (and 2017 for comparison) is plotted in Figure 5-7 below. Solid lines depict 2018 observations, and dashed lines show 2017 observations. The gray line series is the expected revenue based on the forecasted price differences at the time the bid is cleared. The red line series is the actual revenue based on the final LMPs for market settlements. The month-end cumulative revenue totals for 2018 are displayed above the diamond line markers. As the chart shows, both the expected and actual revenues for 2018 are positive, but actual revenue falls 89% short of expected over the period.

Figure 5-7: Cumulative Return on a 1 Penny CTS Interface Bid Strategy



The actual cumulative revenue of $3,481 under this hypothetical strategy produces a positive return for 2018, but that actual return is 89% below the forecasted value of $30,945. Overall, this is a slight improvement on 2017. The large difference in the as-cleared and as-settled revenue amounts is due to the ISOs' price forecast errors.

The return on the hypothetical bid strategy is shown separately for the import and export bid direction in Table 5-6 below. Notably, the import bid produces a loss at settlement.

Table 5-6: Gain or Loss on a 1 Penny CTS Interface Bid Strategy by Bid Direction

Bid direction	Bid price	Frequency cleared	Expected revenue as-cleared	Actual revenue as-settled	Gain or Loss at settlement
Export	$0.01/MWh	47.5%	$18,743	$8,296	(56%)
Import	$0.01/MWh	51.2%	$12,203	($4,816)	(139%)

The results by bid direction in Table 5-6 highlight the problem caused by the ISOs' price forecast biases. As discussed previously, while both ISO-NE and NYISO tend to forecast their prices too low, the NYISO's price forecast tends to be off by a greater magnitude (see Table 5-5). This creates a forecasted price difference that tends to indicate additional power should flow to New England (when New England is forecasted to be the higher price region). Accordingly, the 1 penny import transaction tends to clear more frequently; the import transaction clears in 51.2% of scheduling intervals compared to 47.5% for the export transaction. However, for the intervals in which the import offer cleared, exporting was a more profitable strategy, on average. Participants who submit competitive bids to profit from price differences across the interface will face non-trivial risk of settlement losses in the face of the ISOs' forecast errors.

Participants increased price-sensitive CTS transactions

The ability to schedule real-time power efficiently under the CTS design is also dependent on the bids submitted by market participants. The CTS process can only schedule import and export volumes up to the amount of the bid volumes submitted and at prices up to the forecasted price spread. Bid prices can be positive, negative, or zero. A positive bid price indicates the participant is willing to move power when, as forecasted, 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 counterintuitively buy high and sell low).

Average CTS transaction curves, by year, are shown in Figure 5-8 below. Import offers and export bids are shown separately, followed by an aggregated curve. The import and export curves show the average volume of energy willing to clear at each New England - New York price spread. The aggregated curve shows the net flow that would be produced if all of the economic import and export transactions were to clear. The darker-colored lines show the 2018 curves and lighter colored lines show the 2017 curves. The x-axis shows the spread of New England and New York prices – positive numbers indicate that New England prices are higher. When New England prices are higher (i.e. the price spread is positive), the expectation is that more imports and less exports would be willing to clear. The y-axis shows the volume of energy that would clear, on average, at each price spread. For example, in 2018, at a price spread of $0/MWh, 825 MW of imports would have cleared, 340 MW of exports would have cleared, and the net flow of CTS transactions would have been 485 MW.

Figure 5-8: Price Sensitivity of Offered CTS Transactions

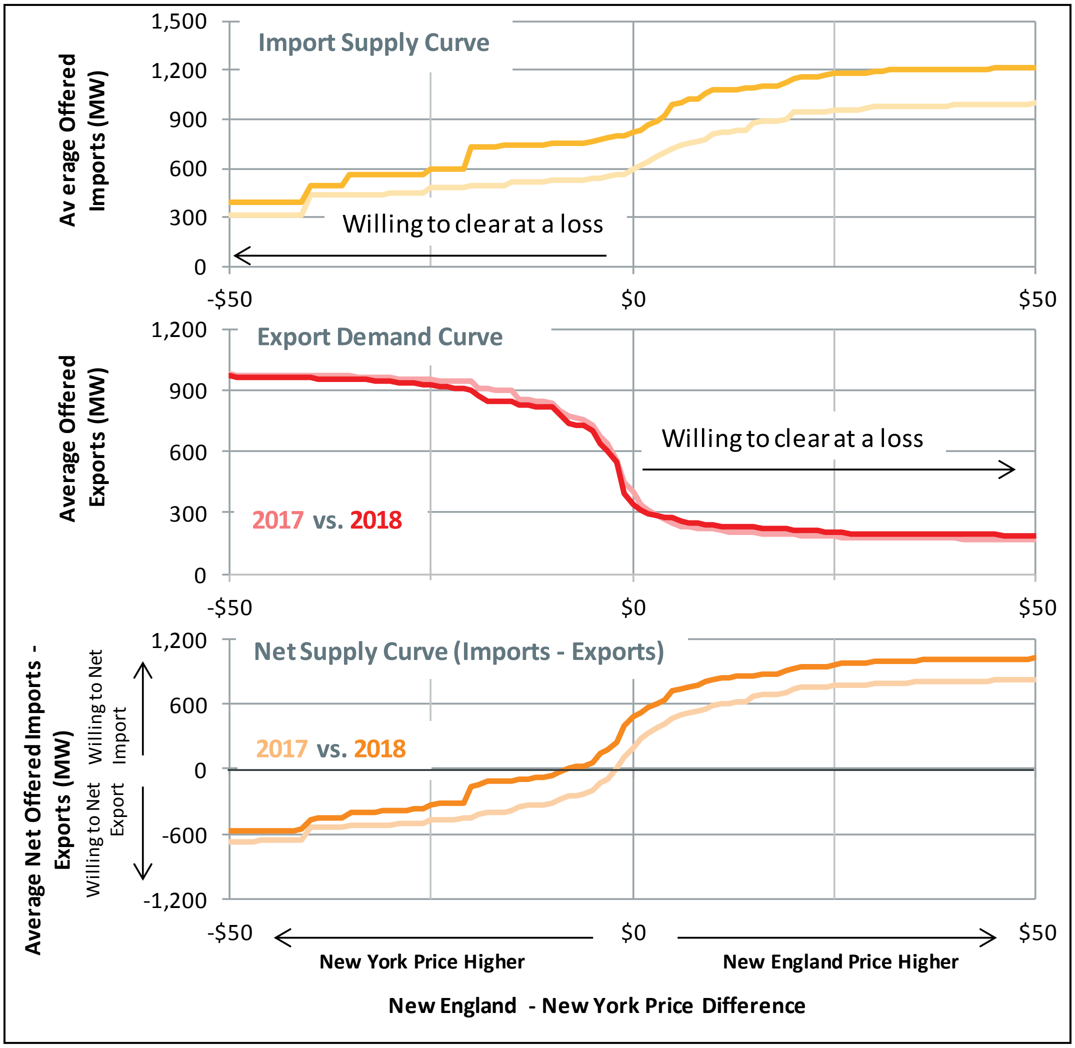


Figure 5-8 shows a large increase in import offers in 2018 compared with 2017. This increase in import offers was driven by an increase in offers below $0/MWh (the price spread at which imports are willing to clear at a loss). The aggregate export demand curve was similar to last year.

This change in import behavior provided the CTS process with an aggregate transaction curve that allowed the direction of flows to be less consistent with price differences than the prior year, on average. In 2017, on average, market participants were willing to *export* energy to New York when New York prices were at least $3 higher (see the intersection of the 2017 net supply curve at 0 MW). In 2018, participants, as a whole, required New York prices to be around $9/MWh higher than New England prices in order to export to New York. Conversely, in 2018 participants were willing to *import* power to New England when New York prices were higher by $8/MWh, compared to $2/MWh in 2017; in other words they were willing to begin moving power in the economically incorrect direction at a loss of $8/MWh.

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 competiveness.

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

However, achieving sound price formation in the FCM continues to be a challenge. Two factors negatively impacting price formation have been the participation of state-sponsored resources with out-of-market revenues in the auction, and the reliability retention of resources for their energy security attributes. Both of these factors have reduced the auction clearing price (for at least a portion of supply) as a result of out-of-market payments.

The first challenge has been to accommodate new resources that secure revenue through state-sponsored programs designed primarily to meet state environmental goals. These out-of-market revenues economically advantage a subset of resources and can lead to market distortions and price suppression in the capacity market. For FCA 13, the ISO introduced Competitive Auctions with Sponsored Policy Resources (CASPR) to help address this issue. CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. However, while the price-suppressing impact is mitigated in the first year, the sponsored resources will likely be price-takers in subsequent auctions, thereby applying downward pressure to FCA clearing prices in the long-term. This underlying compromise behind the CASPR design is unavoidable as long as (a) the resource is counted toward meeting capacity requirements and (b) the resources continue to receive out-of-market revenues. Also, while CASPR and the associated market power mitigation rules help mitigate price suppression concerns for new resources, they do not address the impact of out-of-market revenues paid to retain existing resources, when they might otherwise retire.

The first CASPR substitution auction was conducted in February 2019 with a limited amount of participation. A 54-MW wind resource cleared in the auction against an existing dual-fuel oil/gas-fired resource, which will now retire. The clearing price in the substitution auction was $0/kW-month, meaning the retiring resource sells its capacity supply obligation to the new resource for $0/kW-month and receives a net amount of $3.80/kW-month – the difference between the primary and substitution auction prices - similar to a severance payment.

The second challenge is the reliability retention of resources in the FCM based on their underlying energy-security attributes; attributes that are not explicitly valued in the current FCM or energy market designs. The ISO retained the Mystic 8 and 9 resources (approx. 1,400 MW in total) in FCA 13 to satisfy a reliability need for energy security. This was done prior to the auction, and the retained capacity from the two resources was represented as price-taking capacity ($0 bid price) in the auction. While this administrative pricing action likely impacted price formation in FCA 13, the price formation issue more directly derives from a missing product (energy security) that is not being appropriately valued in the energy markets or reflected in the capacity market. Whatever impact the retention of the Mystic resources had on price was a byproduct of that market flaw.

Out-of-market actions often have the potential to interfere with price formation. It is not clear to what extent FCA prices would have been different had energy security been explicitly valued and those that could provide it appropriately compensated. A completely different market model (including FCM, energy, and reserves) would need to be developed in order to accurately simulate the resulting valuation, which is the appropriate counter-factual to estimate the impact. While the Mystic resources will receive revenue (through the out-of-market settlement process) for the energy security they provide, other resources that can provide fuel security will not be compensated for that service in the FCA 13 delivery period, nor did they have the opportunity to compete for such compensation.

However, the issue of not valuing energy security is a transient. Going forward, the ISO has proposed an interim measure to compensate for energy security for CCP 14 and 15, and is in the process of developing a long-term market-oriented approach. These measures will seek to explicitly value the energy security service and put all resources that can provide the service on equal footing to compete for the resulting market opportunity.

Summary of FCA Trends Covered in this Section

The first seven FCAs, for the commitment periods between June of 2010 through 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 prior commitment period ($1.2 billion).

The trend of low surpluses and increased capacity payments will continue into 2018-19. As capacity prices increased, new suppliers entered the market in FCAs 9 and 10. However, as new suppliers entered the market, the amount of system surplus increased, resulting in declining prices. This pattern of prices in response to fluctuating capacity margins is what one would expect. Further, planned transmission improvements, coupled with an increase in the number of resources competing in the auctions, increased the capacity market's overall competitiveness.

After low amounts of new generation in FCA 11 and 12, the most recent auction (FCA 13) cleared 1,490 MW of new generation and demand response resources. This included a 632 MW natural gas-fired generator and 141 MW of solar resources.[155] Additionally, 867 MW of capacity de-listed below the dynamic de-list bid threshold (DDBT); a value meant to ensure suppliers do not withdraw capacity at uncompetitive prices to raise the FCA clearing price.

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 covers the inputs and outcomes of the most recent forward capacity auction, FCA 13.
- Section 6.4 reviews key trends in primary (FCA) and secondary trading of capacity.

[155] Except for a small amount of grandfathered import resources, imports are treated as new capacity in each auction. This tends to overstate auction-to-auction changes in total new capacity. Therefore, we treat all imports as existing.

- 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 6.6 and 6.7 present metrics on the structural competiveness of the FCAs. It also describes market power mitigation measures in place to address the potential exercise of market power, and provides statistics on the extent to which uncompetitive offers were mitigated.

6.1 Forward Capacity Market Overview

The 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, the FCM can provide new resource owners with reasonable certainty about future capacity revenues, particularly when they choose to lock in the payment rate for up to seven years. A developer or owner will know their capacity payment rate ($/kW-month) 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 (new and existing resources) 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 the energy market prices and their resource's variable costs) to cover fixed costs, reasonable profits, and return on capital investments in the long run. Marginal cost bidding and energy market offer caps intrinsically limit energy market prices, creating "missing money" or a gap between the revenues developers and owners need to justify capital investments and the revenue available to fund those investments. This "missing money" is synonymous with several specific terms used throughout this report, including Net CONE, Offer Review Trigger Prices (ORTPs), offer floor prices, net going-forward costs, and de-list bids.

The FCM's capacity prices and revenues 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 were retained for fuel security within the Southeastern New England capacity zone, and entered into a cost-of-service agreement with the ISO.[156] Their agreement suggests that the Forward Capacity Auction (FCA) could not facilitate an efficient *and* reliable solution. The ISO is working on an interim compensation method and multi-day-ahead market to address fuel security through other means.[157]

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[156] For more information on the fuel security order see: https://www.iso-ne.com/static-assets/documents/2018/12/fuel_security_order.pdf

[157] For more information on the interim compensation treatment see: https://www.iso-ne.com/static-assets/documents/2019/01/a2_iso_presentation_interim_compensation_treatment.pptx

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. The delivery period is known as the Capacity Commitment Period (CCP). The primary auction is referred to as the Forward Capacity Auction (FCA). 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. 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 trading of CSOs 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.[158] Second, changes were made to the FCM rules starting with FCA 9 to improve resource performance. The changes are known as the "Pay-For-Performance" (PFP) rules.[159] 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 the incentive to make investments that ensure the performance of their resources when needed most. Also, absent these incentives, participants that have not made investments to ensure their resources' reliability would be more likely to clear in future FCAs because they can 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 investments and perform routine maintenance to ensure that their resources will be ready and able to provide energy or operating reserves during these periods.

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 expectations, 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 former rules included numerous exemptions, which dilute performance incentives.

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[158] See Section III.13.6.1. of the tariff for more information.

[159] The PFP rules have been in effect since FCA9, which means that the settlement rules will be effective from the CCP beginning on June 1, 2018.

Another adjustment to FCM payments is Peak Energy Rent (PER). The PER adjustment is primarily a protection for load against energy prices in real-time that are above a threshold or "strike" price.[160] Under the PER concept, load has paid in advance for sufficient capacity to maintain reliability through the FCM. The PER adjustments limit payments to generator and import capacity resources in hours with high real-time prices.[161] This helps ensure that load does not pay through the FCM to maintain a fleet of resources that meets reliability conditions and then later pays when those reliability conditions are not met and results in high real-time prices.

The PER adjustment is also intended to discourage physical and more extreme economic withholding. The PER adjustment is based on the entire quantity sold in the capacity market, not just the portion of that capacity subject to the high real-time price. As a result, a withholding strategy that increases real-time price above the PER strike price can cause a significant revenue adjustment for the portfolio that outweighs the potential benefits of withholding.[162]

On March 6, 2015, the ISO filed market rule changes to eliminate PER on a prospective basis starting with the CCP that begins on June 1, 2019. The stronger performance incentives of the PFP rules largely make the PER mechanism redundant, and retaining the mechanism could result in higher capacity market costs without producing substantial benefits.

The FCM produces market-based capacity prices

The ISO conducts a primary Forward Capacity Auction (FCA) once per year. 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 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).[163] Load Serving Entities (LSEs) do not actively participate in the FCA. Instead, the willingness of demand to pay for the capacity at certain levels of reliability (relative to ICR) is determined by an administrative demand curve. Over the 13 FCAs to date, the market has transitioned from vertical to sloped demand curves. A vertical demand curve, by definition, lacks price sensitivity and therefore can result in large changes in capacity prices at different quantity levels. Accounting for price elasticity through sloped curves reduces market

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[160] The PER threshold is based on revenues that would be earned in the energy market by a hypothetical peaking generator with heat rate of 22,000 British thermal units/kilowatt-hour (Btu/kWh) that uses the more expensive of either natural gas and No. 2 fuel oil.

[161] Demand resources were excluded from the PER adjustment through FCA 8. The PER Adjustment was applied to Demand Response Resources on June 1, 2018 (FCA 9) once these resources were able to participate in the energy markets.

[162] The lower volatility of total payments might not affect the entire amount that load market participants pay in the long run because the resources' capacity bids reflect the lower PER-adjustment amounts.

[163] 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").

price volatility; it allows the market to procure more or less than ICR, and reduces the likelihood of activating any market protection mechanisms, such as price floors and caps.

The supply curve used in the auction is based on offers from market participants seeking to enter the FCM with new resources, and market participants seeking to remove their existing resources from the FCM. All other existing resources are price takers.

Market participants seeking to enter the capacity market with a new resource 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, new resources are subject to buyer-side market power mitigation rules, which are administered by the IMM. This is done through a cost-review process, which mitigates the potential for new resources that receive 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 competitive offer price (known as Offer Review Trigger Prices) is required to provide cost justification for review and approval by the IMM.

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 process, at high level, 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 overview of FCM payments, including trends in overall payments and Pay-For-Performance (PFP) outcomes in 2018. Total payments more than doubled in *CCP 8* (2017/18) due to higher system-wide clearing prices in the corresponding Forward Capacity Auction (FCA). Projected payments in *CCP* 9 (2018/19) are expected to reach a record $4.3 billion. After the peak of *CCP 9*, projected payments declined by an average of $667 million each year through *CCP 13*. This is primarily due to an increasing capacity surplus and lower clearing prices.

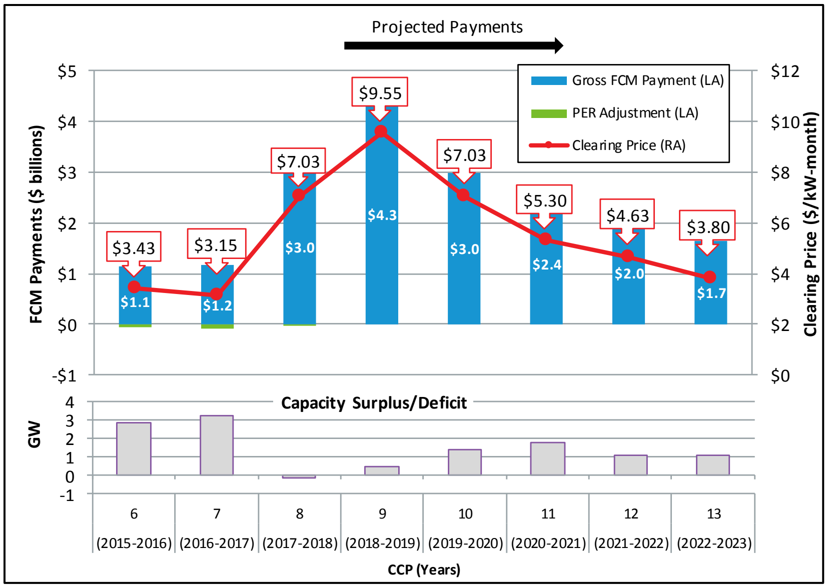
PFP rules, as discussed in Section 6.1, were introduced on June 1, 2018; the beginning of *CCP* 9. On September 3, 2018, there were 32 intervals of capacity scarcity conditions. This led to $44.2 million in PFP credits, and $36.3 million in PFP charges. In general, long-lead time generators under-performed, while fast-start generators, base-load nuclear generators, and imports performed well. The $7.9 million difference between credits and charges we're charged pro-rata to resources holding a Capacity Supply Obligation (CSO).

6.2.1 Payments by Commitment Period

Trends in FCM payments are driven by underlying FCA clearing prices and volumes. Payments for CCPs 6 -13 are shown in Figure 6-1 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs

9-13 are projected payments based on FCA outcomes, as those periods have not yet been settled.[164] The green bar represents PER adjustments made in past commitment periods. The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[165] Payments correspond to the left axis while prices correspond to the right axis.

Figure 6-1: FCM Payments by Commitment Period



In *CCP 6* through *CCP 7*, payments remained relatively low due to system-wide surplus capacity and clearing prices set at the administrative floor price.[166] Capacity payments than doubled from *CCP 7* to *CCP 8* due to higher primary auction clearing prices. FCA 8 cleared with a capacity deficiency, primarily due to a large amount of retirements. The capacity deficiency triggered administrative pricing rules, which set the clearing price for existing resources at $7.03/kW-month and new resources at $15/kW-month. This resulted in a 162% increase in capacity payments, from the *CCP 7* payment of $1.2 billion to $3.0 billion in *CCP 8*. Peak energy rents declined year-over-year from $87 million in *CCP 7* to $33 million in *CCP 8* due to a system event in August 2016. The event led to PER adjustment settlements in nine months of *CCP 7*, but did not impact *CCP 8* PER adjustments.[167]

The following commitment periods are either ongoing (*CCP 9*), or have yet to start (*CCPs 10 to 13*). 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).[168] The

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[164] Payments for incomplete periods, CCP 9 through CCP 13, have been estimated as: $FCA\ Clearing\ Price\ \times Cleared\ MW\ \times 12$ for each resource.

[165] The Rest-of-Pool capacity zone is made up of all unconstrained import/export capacity zones.

[166] In FCA 7, Northeastern Massachusetts/Boston capacity zone (NEMA/Boston) supply fell short of the Local Sourcing Requirement (LSR). The price in this import-constrained zone was administratively set at $14.99/kW-month for new resources, and $6.66/kW-month for existing resources. This caused the payments for CCP 7 to be slightly higher than CCP 6, despite the decline in the Rest-of-Pool clearing price.

[167] For more information on the August 2016 event, see our Summer 2016 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2016/11/qmr_2016_q3_summer_11_15_2016.pdf

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

combination of higher Rest-of-Pool and SEMA/RI prices led to increased projected payments in *CCP 9* ($4.3 billion) compared to *CCP 8* ($3 billion).

High clearing prices in *FCA 8* and *FCA 9* provided price signals to the market that new capacity is needed. 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 $4.63/kW-month in *FCA 12***.** In the most recent auction, 1,490 MWs of new generation and demand response capacity cleared, even as the clearing price fell to $3.80/kW-month. Lower clearing prices are expected to cause a 60% decrease in projected payments, from $4.3 billion in *CCP 9* down to $1.7 billion in *CCP 13*.

6.2.2 Pay-for-Performance Outcomes

On September 3, 2018, a combination of unexpectedly high loads and unplanned generator outages caused reserve shortage conditions. Consequently, reserve constraint penalty factors bound and triggered scarcity pricing. This also triggered Capacity Scarcity Conditions (CSC) for the first time under the capacity market's Pay-For-Performance (PFP) rules.[169] After the event was settled, credits totaled $44.2 million, while charges amounted to $36.3 million. This means charges were under-collected by $7.9 million during the event. Energy efficiency exemptions during off-peak hours resulted in a majority of the under-recovery of charges.[170] This under-recovery was charged pro-rata to resources with a Capacity Supply Obligation (CSO).[171]

There were 32 five-minute intervals of system-wide scarcity conditions. During this period, each participant's load and reserves were measured against the balancing ratio. The balancing ratio represents a resource's obligation to provide energy or reserves during a scarcity condition.[172] The September 3 event resulted in a balancing ratio of 72%, meaning resources with a CSO were expected to provide an average of 72% of their contracted capacity in the form of energy or reserves.

Performance during the event varied widely by fuel type. Import and natural gas-fired resources with the ability to respond quickly over-performed. Nuclear resources also over-performed, but not because they quickly responded to changing conditions. Instead, they provide base load energy typically close to their full CSO, meaning they typically have a performance score close to 100%. Longer-lead time generators, such as those burning coal and heavy fuel oil, were unable to respond to changes in system conditions.[173]

6.3 Review of the Thirteenth Forward Capacity Auction (FCA 13)

This section a summary of the most recent auction, FCA 13, which was conducted in February 2019. The auction was held in February 2019. Further detail on the auction is contained in the IMM's Winter 2019 Quarterly Markets Report.[174] This section is organized into three subsections. First, the

[169] A CSC occurs when the system or local area is short on ten- and thirty-minute non-spinning reserves. In this instance, the CSC was a system-wide event.

[170] See Section III.13.7.2.4 of the tariff for energy efficiency exemptions.

[171] See Section III.13.7.4 of the tariff for pro-rata charge of under-collected PFP charges.

[172] For more information on the balancing ratio, see Section III.13.7.2.3 of the tariff.

[173] Heavy fuel oil refers to generators that typically operate off residual fuel oils.

[174] See Winter 2019 Quarterly Markets Report at https://www.iso-ne.com/static-assets/documents/2019/05/2019-winter-quarterly-markets-report.pdf

issue of the retention of the Mystic 8 and 9 generators for fuel security is discussed. Second, an overview of qualified and cleared capacity across a number of different dimensions is provided. Then the focus shifts to auction results, with particular emphasis on the mechanics around the demand curve in FCA 13.

6.3.1 The Retention of Mystic 8 & 9 for Energy Security

The ISO retained Mystic 8 & 9 (approx. 1,400 MW in total) in FCA 13 to satisfy a reliability need for energy security. This was done prior to the auction, and the retained capacity from the two resources was represented as price-taking capacity ($0 bid price) in the auction. While this administrative pricing action likely impacted price formation in FCA 13, the price formation issue more directly derives from a missing product (energy security) that is not being appropriately valued in the energy markets or reflected in the capacity market. Whatever impact the retention of the Mystic resources had on price was a byproduct of that market flaw.[175]

The underlying price formation principle in this instance is that there is a missing product in the ISO market that procures energy security. The Mystic retention indicated that there is value to energy security that Mystic 8 & 9 presumably received through their Reliability Must Run (RMR) agreement that was not received by other resources that also could provide energy security.

Out-of-market actions often have the potential to interfere with price formation. But simply comparing the FCA 13 clearing price to a simulated clearing price with the Mystic resources included at their retirement bids would not provide an accurate comparison for measuring the impact of not explicitly valuing energy security. Here, it is not clear to what extent FCA prices would have been different had energy security been explicitly valued and those that could provide it appropriately compensated. While the Mystic resources receive revenue (through the out-of-market RMR process) for the energy security they provide, other resources that can provide fuel security will not be compensated for that service in the FCA 13 Capacity Commitment Period (CCP), nor did they have the opportunity to compete for such compensation.

A completely different market model (including FCM, energy, and reserves) would need to be developed in order to accurately simulate the resulting valuation. However, the issue of not valuing energy security is a transient, one-period issue. Going forward, the ISO has proposed an interim measure to compensate for energy security for CCP 14 and 15, and is in the process of developing a long-term market-oriented approach. These measures will seek to explicitly value the energy security service and put all resources that can provide the service on equal footing to compete for the resulting market opportunity.

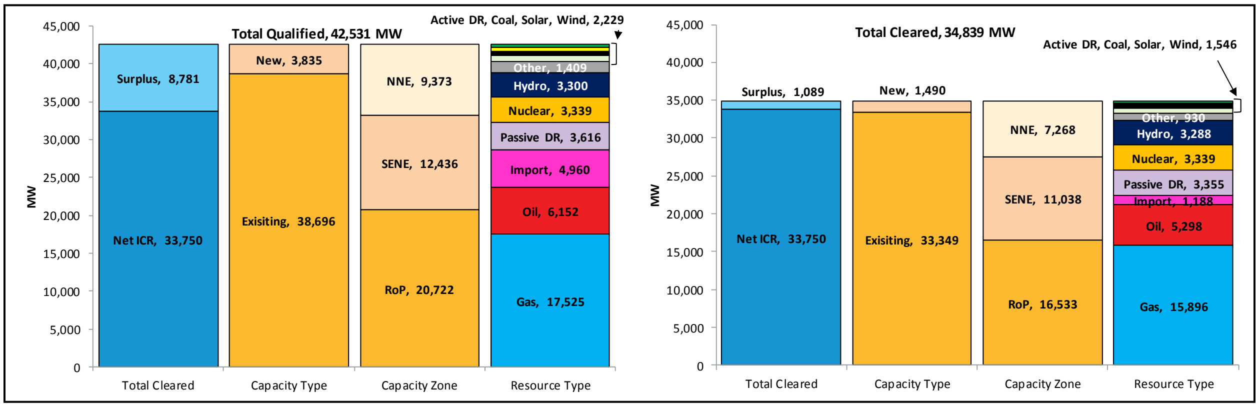
6.3.2 Qualified and Cleared Capacity

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 13 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. The height of the stacked bars equals total capacity. The three orange bars in each graph

[175] We distinguish impacted price formation in this context from price impacts resulting from manipulation or the exercise of market power. Price formation can be impacted by many factors that include, but by no means are limited to, manipulation or the exercise of market power. As such, having price formation impacted does not mean the resulting price was uncompetitive.

show the breakdown of total capacity across three dimensions: capacity type, capacity zone and resource type.

Figure 6-2: Total Qualified and Cleared Capacity in FCA 13



There was a surplus of qualified capacity of about 8,781 MW, or 26%, above Net ICR. Net ICR increased by only 25 MW compared to FCA 12, reflecting low demand growth in the region, while qualified capacity increased 2,565 MW. The increase in qualified capacity was driven by new natural gas-fired (1,678 MW), demand response (1,081 MW), and energy storage (458 MW) resources.

The large surplus in qualified capacity fell to 1,089 MW of cleared capacity. Low clearing prices meant a majority of new capacity exited the auction for two reasons. First, the price in the auction may go below their offer floor price. Secondly, new resources bid during each round, and may choose to remove their capacity at a price higher than their offer floor price. Only 5 MW (of the 458 MW) of energy storage cleared, while the repowering resource did not clear as new capacity and remained in the FCM as existing capacity. Solar, wind, and passive demand response resources cleared 762 MW, or 53% of total new qualified capacity. Additionally, existing resources were able to submit dynamic de-list bids after the auction price went below $4.30/kW-month.

Two capacity zones were modelled in addition to Rest-of-Pool; the import-constrained zone of Southeastern New England (SENE) and the export-constrained zone of Northern New England (NNE). If the import-constraints and export-constraints were binding in the auction, one would expect higher prices in SENE and lower prices in NNE. However, neither constraint bound. In SENE there was 12,436 MW of qualified capacity, 2,295 MW in excess of the Local Sourcing Requirement (LSR) of 10,141. At the end of the auction, 11,038 MW of supply cleared within the zone, 897 MW in excess of LSR.

In NNE there was 9,373 MW of qualified capacity, 828 MW in excess of the Maximum Capacity Limit (MCL) of 8,545 MW. However, 2,105 MW of capacity dropped out of the auction, resulting in the cleared amount of 7,268 MW; 1,277 MW below MCL. Therefore, there was no negative price separation in NNE.

6.3.3 Auction Results

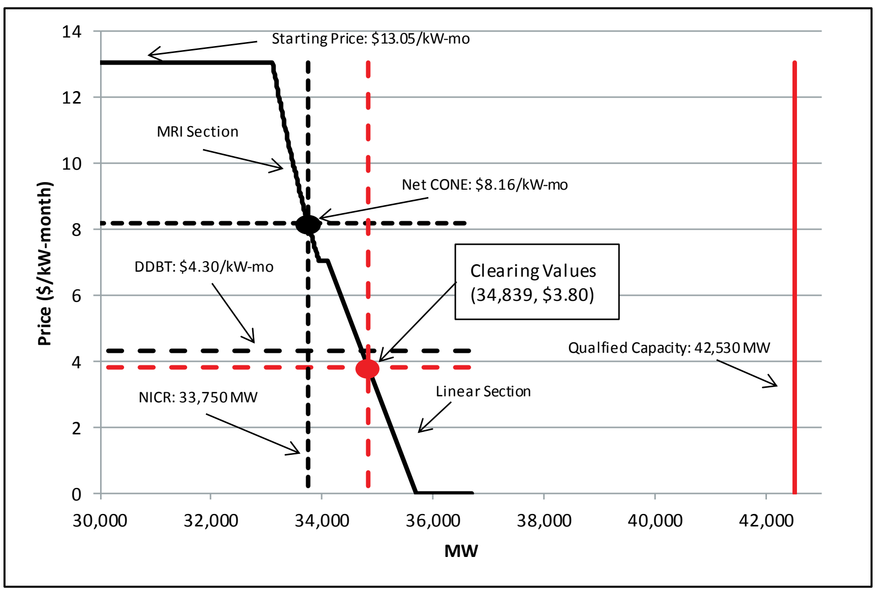
In addition to the amount of qualified capacity eligible to participate in the auction, there are several other factors that contribute to auction outcomes. These factors, including the auction parameters provided by the ISO and participant behavior, are summarized below for FCA 13.

FCA 13 incorporated 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.[176] However, the full MRI curve was not implemented for FCA 13. Instead, 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.[177]

The system-wide transitional demand curve (black solid line), which is the combination of the convex MRI curve and a linear demand curve (labeled as the MRI Section and the Linear Section) is illustrated in Figure 6-3 below. The first sloped section of the demand curve, which begins at the starting price and ends at the horizontal section, is based on the MRI methodology. The horizontal section begins at the FCA 10 clearing price of $7.03/kW-month and is 150 MW long. The demand curve then becomes linearly sloped down to $0/kW-month. The curve shows the price that load is willing to pay at various levels of capacity, which in turn provides various levels of system reliability. For example, at the Net ICR value of 33,750 MW, which meets the 1-in-10 year reliability criterion, load is willing to pay the Net Cost of New Entry (Net CONE) price of $8.16/kW-month (the intersection of the dotted black lines).

On the supply side, the qualified and cleared capacities are shown (solid and dashed red lines, respectively). The clearing price of $3.80/kW-month is shown at the intersection of the cleared MW (dotted red line) and the demand curve. This is well below the dynamic de-list bid threshold (DDBT) price of $4.30/kW-month (black dashed line).

Figure 6-3: System-wide FCA 13 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for the Rest-of-Pool, SENE and NNE zones. As qualified capacity exited in previous rounds, the solid red line moved towards the dotted red line. The fourth round opening price was the DDBT price, meaning existing resources could submit bids to exit (de-

[176] For more information on why the ISO implemented a sloped demand curve, see Section 6.1

[177] 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.

list) the market during the fourth round. The DDBT also serves as an important threshold for market power mitigation, whereby an existing resource that submits bids above this level is subject to a mitigation review by the IMM.

A dynamic de-list bid set the clearing price when supply fell short of demand. The marginal resource de-list bid was then rationed to allow for demand to exactly equal supply. The auction cleared 34,839 MW at a price of $3.80/kW-month. As shown in Figure 6-3, supply met demand and price was set along the linear sloped portion of the transitional demand curve. The New Brunswick interface had excess supply at the end of round four and needed an additional round to clear. The auction continued into the fifth round and cleared 184 MW at a price of $2.68/kW-month.[178]

Bids from existing resources below the DDBT are not subject to IMM review for consistency with net going forward costs under the Tariff. This is because resources in the DDBT range are unlikely to be able to profit from the exercise of market power. The supply curve in Round 4 was relatively flat, which would make it difficult for a market participant to profit from economic withholding given the small impact on clearing prices of doing so.

6.3.4 Results of the Substitution Auction (CASPR)

As mentioned in Section 6.1, this was the first year with a substitution auction immediately after the Forward Capacity Auction (FCA) (see Section 8.1 for further detail and references). Prior to the FCA, resources must submit demand bids and supply offers as inputs into a double auction. Submitting a demand bid or supply offer in the substitution auction does not guarantee inclusion in the double auction. For example, resources that submitted supply offers in the substitution auction, but cleared capacity in the FCA have that capacity removed from the substitution auction. Like all other auctions in the FCM, prices can separate at external interfaces and capacity zones if certain constraints bind.[179] Supply offers that clear obtain capacity from the FCA, and demand bids that clear shed their capacity from the FCA. Depending on whether the clearing price is positive (negative), cleared supply offers are compensated (charged), and cleared demand bids are charged (compensated).

There was limited participation in the substitution auction. Many of the supply offers were removed for two reasons. First, resources that cleared the FCA have capacity removed from the offers beginning with their lowest price-quantity pair. Second, offers that exceed the applicable FCA clearing price are removed.[180] The substitution auctioned cleared 54 MW at a price of $0/kW-month. This means the state-sponsored resource will receive $0/kW-month in FCA 13, and clear subsequent auctions as an existing capacity resource. The resource that shed 54 MW was a dual-fuel oil/gas-fired generator and will receive their full FCA 13 payment for that capacity. The resource will also be retired, partially or fully, from all New England markets starting June 1, 2022.[181]

[178] See Attachment C of the following: https://www.iso-ne.com/static-assets/documents/2019/02/fca_13_results_filing.pdf

[179] For more information, see Section III.13.2.8 of the tariff.

[180] See Section III.13.2.8.2.3. of the tariff for more information on supply offers entered into the auction.

[181] See Section III.13.2.8.3.1 of the tariff for more information on entering demand bids into the auction.

6.4 Forward Capacity Market Outcomes

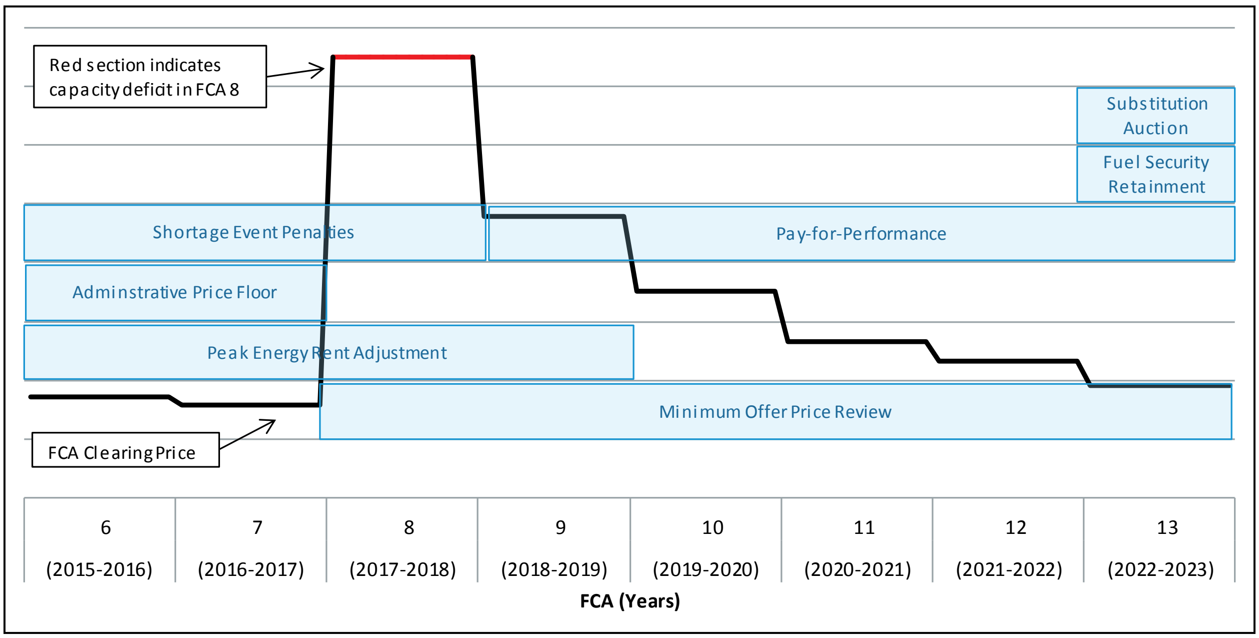
This section reviews the overall trends in prices and volumes in the FCM. It covers both the primary auction (FCA), as well as secondary trading of capacity in the substitution auction, reconfiguration auctions, and bilateral transactions.

6.4.1 Forward Capacity Auction Outcomes

FCM prices are determined by the interaction of capacity supply and demand. When capacity is in relatively short supply, like in FCA 8, we expect prices to be higher. 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



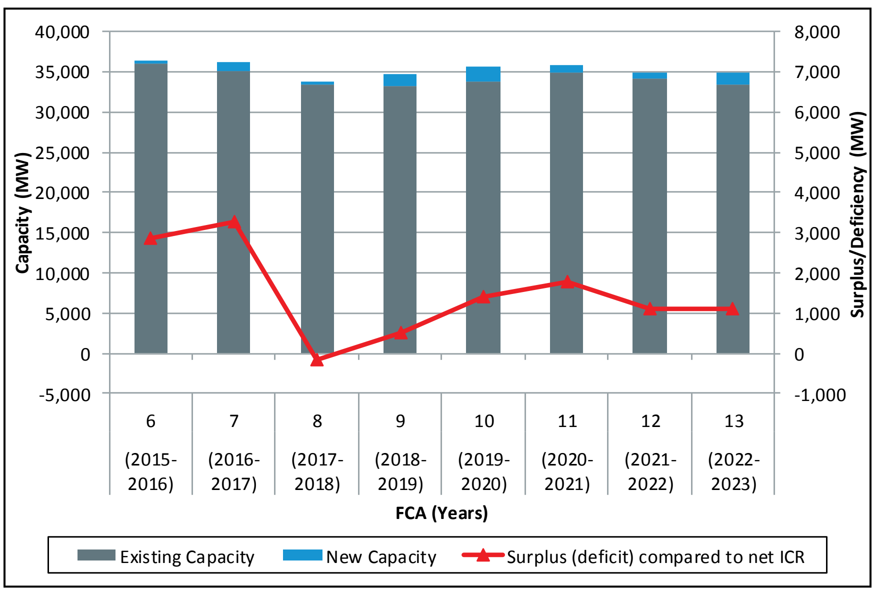
The first seven auctions cleared at the administrative market price floor. The price floor protected supply from low prices in a market environment with excess supply and a vertical (fixed) demand curve. Capacity prices under the vertical demand curve construct were subject to large year-to-year changes as the result of under- and over-supply. Administrative pricing was the mechanism to price capacity when supply did not equal demand. Such a large swing in price occurred in *FCA 8*, when a number of large resources retired and cleared capacity fell short of Net ICR. By contrast, the sloped demand curve implemented for *FCA 9* improved price formation and reduced price volatility.[182] When there is a surplus of supply relative to Net ICR, as happened in *FCA 13*, a sloped demand curve results in a price below Net CONE.

Starting with FCA 8, there were a number of significant changes to the capacity market design. The minimum offer floor price rules were implemented, which are intended to protect the market from the exercise of buyer-side market power (i.e. the ability to decrease prices below competitive levels). From FCA 9, the new Pay-for-Performance (PFP) market rules replaced the shortage event penalty rules (see Section 6.1). Combined, these rules delivered a greater degree of active participation in the auctions, with more new and existing resources offering prices in the auction.

In the most recent auction, two rules were implemented with conflicting impacts on FCA clearing prices.[183] First, the ISO agreed to a cost-of-service agreement with Mystic 8 and 9, citing system-wide fuel security. The Mystic resources account for 1,413 MW of CSO, and were treated as price-takers in the FCA. This had a downward impact on prices in FCA 13. The second rule, CASPR, reduces the price-suppressing impact of state-sponsored resources in the FCA. High amounts of pre-existing renewable-technology exemptions limited the amount of participation in the substitution auction.

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 in FCAs 6 through 13



Prior to FCA 8, the auction was largely dominated by price-insensitive supply and an administrative price floor. The auction clearing price could not go below the floor price, which led to some price

[182] 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 level. 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.

[183] Both rules are discussed in Section 6.1 above.

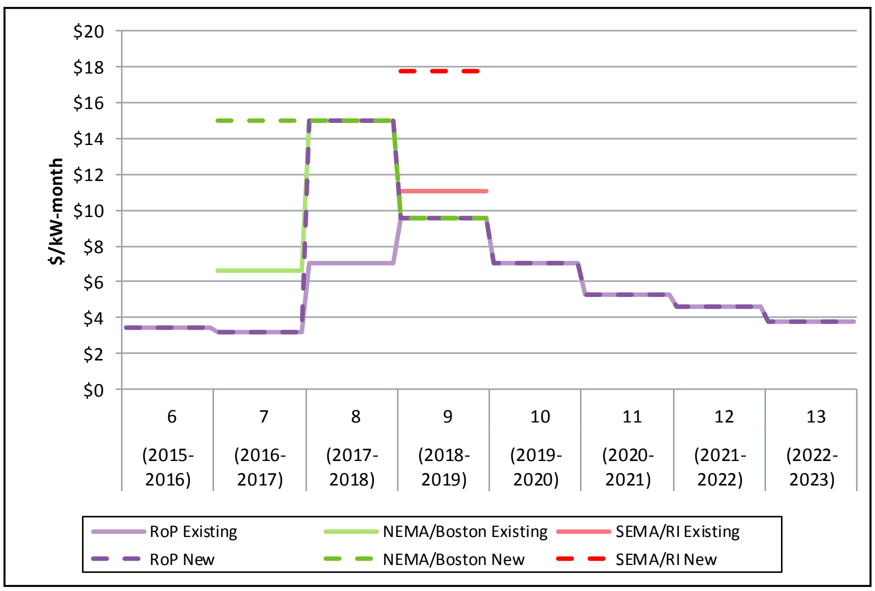
certainty for existing resources. With these auction conditions, there was at least 2,000 MW of excess cleared capacity in the early FCAs.[184] In FCA 8, cleared capacity fell below Net ICR for the first time due to a higher Net ICR (up 900 MW from FCA 7) and 2,700 MW of retirements.

In the subsequent three auctions (FCA 9, 10, 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 into a 1,800 MW surplus in the span of three auctions.

The surplus declined in FCA 12 and 13, primarily due to one-year dynamic de-list bids. Once the auction price went 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. In FCA 13, the dynamic de-lists comprised of 742 MW of oil-fired resources, 95 MW of coal-fired resources, and 29 MW of other resources. The surplus fell 700 MW from roughly 1,800 MW in FCA 11 to 1,100 MW in FCAs 12 and 13.

The changes in new and existing capacity clearing prices for each FCA are illustrated in Figure 6-6 below. The solid lines represent the price paid to existing resources. Dashed lines represent the price paid to new resources.

Figure 6-6: Forward Capacity Auction Clearing Prices



Clearing prices did not separate by capacity zone in FCA 6, with clearing prices equal to the floor price. In FCA 7, the NEMA/Boston zone cleared at $15.00/kW-month for new capacity when a newly qualified resource submitted a bid in the first round. Existing capacity in NEMA/Boston was paid an administrative price of $6.66/kW-month. That price was set by administrative pricing rules.[185] New and existing capacity across the rest of the system cleared at the floor price of $3.15/kW-month.

[184] Cleared capacity in this figure represents the cleared MW value from the FCA. It does not account for any proration or specific resource caps.

[185] See Attachment B of the FCA 7 results filing to FERC: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/feb/er13_992_000_2_26_13_7th_fca_results_filing.pdf

FCA 8 concluded in the first round when a new resource submitted a bid to withdraw capacity at $14.99/kW-month. In this case, the auction closed during the first round and various administrative prices were triggered.[186] New capacity resources in Rest-of-Pool (RoP) and all resources in NEMA/Boston received $15.00/kW-month. Existing resources in RoP were paid an administrative price of $7.03/kW-month.

The higher capacity prices in FCA 8 sent a signal to market participants that load is willing to pay for more capacity that will improve system reliability. Clearing prices fell steadily from FCA 9 through FCA 11. As new capacity entered the market, the system-wide clearing price in FCA 9 fell to $9.55/kW-month.[187] Clearing prices continued to fall in FCAs 10 and 11.

In FCAs 12 and 13, the dynamic de-list bid threshold (DDBT) had a significant impact on the clearing 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, and $3.80/kW-month in FCA 13.

6.4.2 Secondary Forward Capacity Market Results

The 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.[188]

The IMM has observed a number of combined-cycle (CC) and gas turbine (GT) resources taking on additional Capacity Supply Obligations (CSOs) during CCP 9, and not offering the acquired capacity in the day-ahead and real-time energy markets.[189] The unoffered capacity was particularly pronounced in October 2018, as the FCM transitioned from the summer period (June through September) to the winter period (October through May). As the FCM transitions to winter, resources receive higher qualified capacity values.

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. We estimate that in October, about 650 megawatts (MW) of CSOs were undeliverable (not offered into the energy market) due to ambient conditions.

The IMM believes that generators should not take on additional CSOs that they are unable to offer in the energy market. Further, the IMM recommends that the ISO explore changes to the FCM

[186] See page 2 for more information: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/feb/er14_1409_000_fca8_results_filing_2_28_2014.pdf

[187] Within SEMA/RI, the price separated due to inadequate supply. The administratively-set prices were $17.73/kW-month for new resources and $11.08/kW-month for existing resources.

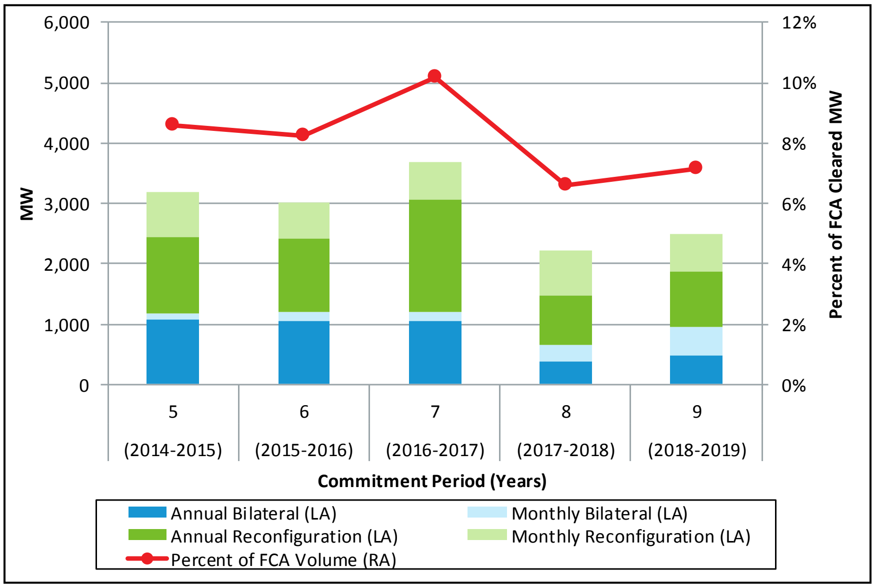
[188] There are many opportunities for participants to adjust their obligations. Immediately after the FCA occurs, the ISO holds a substitution auction. Leading up to the commitment period, there are three annual reconfiguration auctions (ARAs) to acquire one-year commitments are held prior to the commitment period. 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.

[189] Combined cycle (CC) and gas turbine (GT) generators are the focus of this section as their maximum capacities are heavily impacted by ambient air conditions.

qualification rules that would better align the determination of qualified capacity values with expected ambient temperatures.[190]

The average annual volume by secondary market product (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.[191] Monthly and annual *reconfiguration auction* volumes are shown in green colors and monthly and annual *bilateral transaction* volumes in blue colors.

Figure 6-7: Traded Volumes in FCA and Reconfigurations[192]



Historically, the traded volume in the secondary markets has been much lower than the primary auctions. From CCP 5 through CCP 9, secondary traded volumes averaged about 8% of the primary auction volumes, with a high of 10% occurring in CCP 7 (roughly 3,700 MW). The majority of the secondary trading occurs during annual bilateral periods and reconfiguration auctions. The monthly reconfiguration auction volumes are affected by seasonal temperatures. During the winter periods many thermal generators have additional capability that can be traded in the monthly auctions.

Prices in the secondary markets are set through ISO administered reconfiguration auctions or through bilateral agreements between parties. Unlike the first seven primary auctions, there was no floor prices in Annual Reconfiguration Auctions (ARAs), which lead to low clearing prices during periods when the system is long. The absence of a floor price means that the clearing price can be set below the FCA floor price in any reconfiguration auction. The difference between the FCA and

[190] See Fall 2018 Quarterly Markets Report at https://www.iso-ne.com/static-assets/documents/2019/03/2018-fall-quarterly-markets-report.pdf

[191] Volumes are shown as average annual weighted values. For example, a monthly product gets a weight of 1/12th, an annual product a weight of 1 etc.

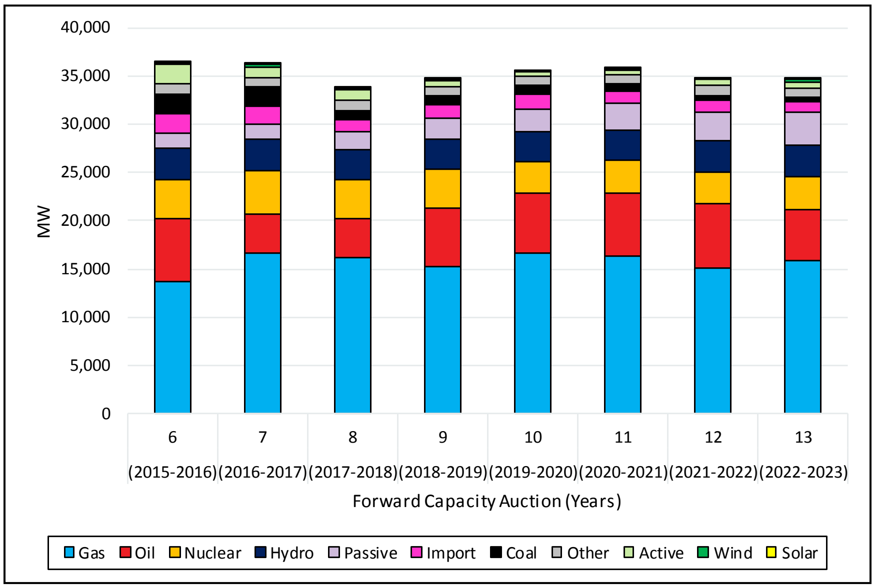
[192] The graph has been updated from 2017 AMR. The 2017 AMR graph had incorrect horizontal axis labels. They were one-year off (i.e. Commitment Period 2017-2018 should have been labeled 2016-2017).

ARA prices represents an opportunity for participants that obtained an obligation in the FCA and shed it in the ARA to profit (i.e. they receive the FCA clearing price minus the ARA price).

6.5 Trends in Capacity Supply Obligations

This section discusses trends and major changes in capacity since the inception of the FCM. 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 as a percentage of cleared capacity in each FCA.

Figure 6-8: Capacity Mix by Fuel Type from FCA 6 through FCA 13



The most substantial movements over the past eight FCAs were made by passive and active Demand Response (DR) resources. Between FCA 6 and 13, active demand response fell from 2,002 MW to 686 MW. Meanwhile, passive demand response more than doubled from 1,643 MW to 3,355 MW. This is in line with state policy goals to increase passive DR, and federal regulations that impacted certain emergency generators' ability to participate as active DR. More recently, oil-fired generation decreased 1,290 MW from 6,589 MW in FCA 12 to 5,298 MW in FCA 13. This was driven by the retirement of Mystic 7, and dynamic de-lists of two Yarmouth resources.

6.5.1 Retirement of Capacity Resources

A participant can choose to retire its resource by submitting a retirement request to the ISO.[193] This is an irrevocable request to retire all or a portion of a resource.[194] Up to FCA 11, this request was not contingent on market clearing prices; it was known as a non-price retirement. Starting in FCA

[193] The FCA retirement permanently sheds the CSO; however, a resource may effectively retire before the CSO retirement, if it sheds its obligation through secondary markets and the retirement does not trigger reliability concerns.

[194] 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 to operate it until the reliability need has been met. Once the reliability need has been met, the resource must retire.

11, non-price retirements have been replaced by priced-retirements and go through a cost-review process to establish if the bid may be an attempt to inflate clearing prices above competitive levels.

The retirement of generators with CSOs exceeding 50 MW from CCP 6 are shown in Table 6-1 below.

Table 6-1: Generating Resource Retirements over 50 MW from FCA 6 to FCA 13

FCA # (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 7 (2016/17)	AES Thames	Coal	Connecticut	184
FCA 8 (2017/18)	Brayton Point 1	Coal	SEMA	228
FCA 8 (2017/18)	Brayton Point 2	Coal	SEMA	226
FCA 8 (2017/18)	Brayton Point 3	Coal	SEMA	610
FCA 8 (2017/18)	Brayton Point 4	Coal	SEMA	422
FCA 8 (2017/18)	Bridgeport Harbor 2	Oil	Connecticut	130
FCA 8 (2017/18)	Norwalk Harbor 1	Oil	Connecticut	162
FCA 8 (2017/18)	Norwalk Harbor 2	Oil	Connecticut	168
FCA 8 (2017/18)	Vermont Yankee Nuclear	Nuclear	Vermont	604
FCA 8 Total (resources > 50 MW)				**2,550 MW**
FCA 9 (2018/19)	Mt. Tom	Coal	WCMA	144
FCA 10 (2019/20)	Pilgrim Nuclear	Nuclear	SEMA	677
FCA 12 (2021/22)	Bridgeport Harbor 3	Oil	Connecticut	383
FCA 13 (2022/23)	Mystic 7	Oil	NEMA/Boston	575

Note: The capacity defined here is the most recent non-zero FCA cleared capacity for each resource.

Energy policy and market dynamics have been cited as reasons leading to increased pressure on nuclear, coal- and oil-fired generators to retire. Increasing emission 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. Finally, the decreasing price of natural gas has led to lower energy market prices and additional natural gas-fired capacity.

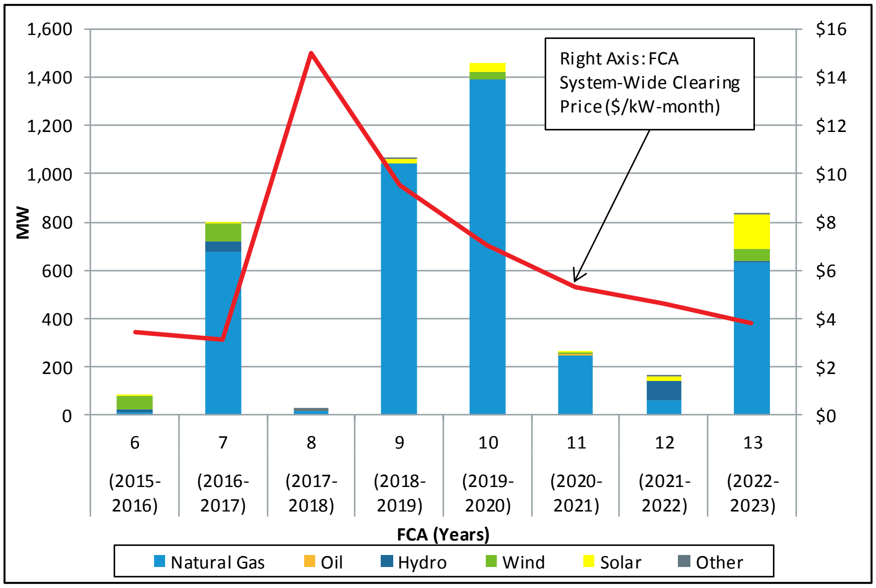
6.5.2 New Entry of Capacity Resources

This section provides an overview of major new resources entering the FCM. New entry typically implies a resource is 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.[195] Project sponsors of new capacity resources can elect to lock in the FCA clearing price for up to seven years.

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. Figure 6-9 illustrates new generation capacity by fuel type since FCA 6.

[195] See Market Rule 1, Section III.13.1

Figure 6-9: New Generation Capacity by Fuel Type from FCA 6 to FCA 13



Note: "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

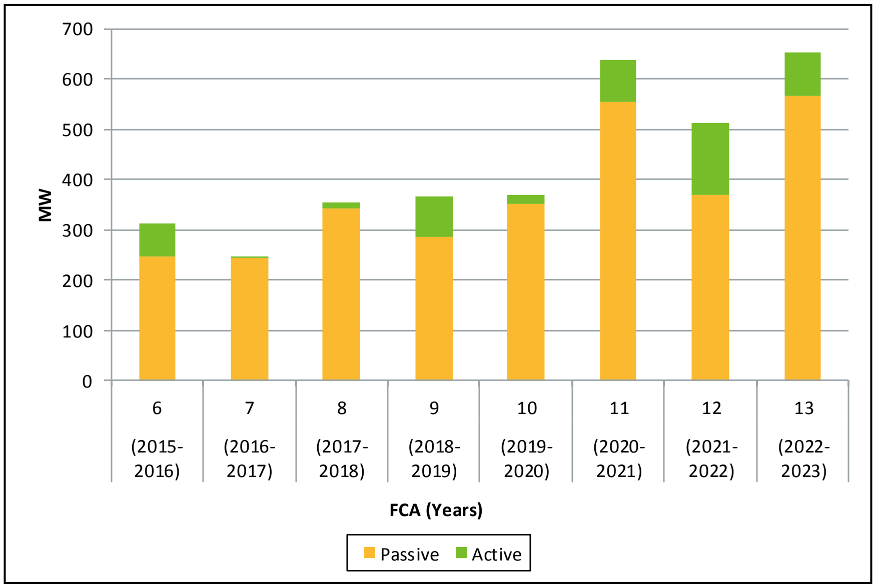
The majority of new additions since FCA 6 have been natural gas-fired resources. In *FCA 7*, Footprint (gas) added 674 MW of capacity. In *FCA 9*, over 1,000 MW of capacity was added; the largest addition was CPV Towantic, a 725 MW combined cycle resource in Connecticut. *FCA 10* saw the largest amount of new generation entry, with an additional 1,400 MW of new natural gas-fired capacity. Three natural gas-fired generators accounted for 94% of this supply: Bridgeport Harbor 6 (484 MW), Canal 3 (333 MW), and Burrillville Energy Center (485 MW).

For FCA 13, Killingly, a large dual-fuel oil/gas-fired combined cycle generator, and state-sponsored solar resources led to a significant increase in cleared new generation compared to the prior two auctions. As the auction entered the fourth round starting at $4.30/kW-month, the combined cycle was able to offer and clear its full summer-qualified capacity (632 MW). Total new and existing solar capacity increased 160%, from 86 MW in FCA 12, to 224 MW in FCA 13. A total of 65 new solar resources cleared 141 MW of capacity in FCA 13. State policies continue to be a key driver of renewable and energy efficiency resources, as discussed below.

Significant increases in new passive demand response resources have more than offset active demand response retirements. Passive demand response is defined as on-peak and seasonal-peak resources. Active demand response is broken into real-time demand response and emergency generation.[196] Figure 6-10 below shows new active and passive resources that cleared in each FCA since FCA 6.

[196] 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.

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. In FCA 13 alone, over 650 MW of new demand resources cleared. This was split between 87 MW of active demand response resources and 566 MW of passive demand resources.

6.6 Market Competitiveness

In this section two metrics are used to evaluate the competitiveness of the Forward Capacity Market (FCM):

- Residual Supply Index (RSI)
- Pivotal Supplier Test (PST)

The former measures the percent of capacity remaining in the market after removing the largest supplier of capacity. The latter is a tariff-defined metric that examines whether a supplier's capacity is needed to meet zonal capacity requirements.[197] There are similarities between the two metrics; both metrics respect system constraints. Additionally, they take into account the affiliations between suppliers to accurately reflect all the capacity under a supplier's control. The metrics also consider only existing resources due the challenges in predicting intra-auction new supply behavior.[198]

The RSI is measured on a continuous scale with a lowest possible value of zero (a pure monopoly) and an uncapped upper limit. Specifically, the RSI measures the percentage of capacity requirements (system or zonal) that can be met without capacity from the largest supplier's

[197] Section III.A.23 of the Tariff.

[198] 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)."

portfolio of qualified capacity resources. 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, in theory, increase its offer prices above competitive levels to increase the market clearing price.

While the RSI uses a continuous measure and provides a sense of the largest supplier's ability to influence clearing prices, the PST is measured on a binary scale and indicates the number of suppliers who may be able to influence prices. The PST is a portfolio-level test conducted at the system and import-constrained zonal levels for each supplier. The PST compares (1) the total existing capacity in a zone without that supplier's portfolio of existing capacity to (2) the relevant capacity requirement for that zone.[199] If the former quantity is less than the latter quantity, the supplier is deemed a pivotal supplier and any de-list bids it has submitted at prices above the dynamic de-list bid threshold may be subject to mitigation.[200] 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:

- *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.[201]
- *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). As discussed in Section 6.5.1, there were significant resource retirements leading into FCA 8. More 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. To avoid providing supplier-specific data, these are not described in any detail in this document, but should be taken into account when considering the analysis.

Residual Supply Index Results

The RSIs for the system and for each import-constrained zone over the past five FCAs are illustrated in Figure 6-11 below.[202]

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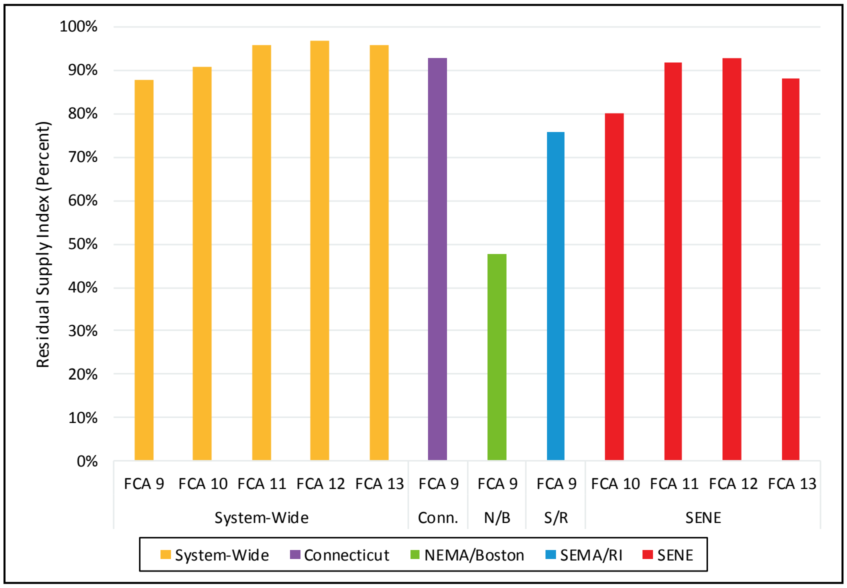
[199] The relevant requirements are the Installed Capacity Requirement net of HQICCS (Net ICR) at the system level and the Local Sourcing Requirement (LSR) at the import-constrained zonal level.

[200] 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.

[201] For instance, Connecticut and NEMA/Boston were modeled as separate capacity zones in FCAs 7 through 9. In FCA 10, Connecticut was rolled into the Rest-of-Pool (ROP) capacity zone. Likewise, NEMA/Boston was rolled into the Southeast New England (SENE) zone, along with Southeast Massachusetts/Rhode Island (SEMA/RI), that same year.

[202] 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 auctions periods for consistency.

Figure 6-11: Capacity Market Residual Supply Index, by FCA and Zone



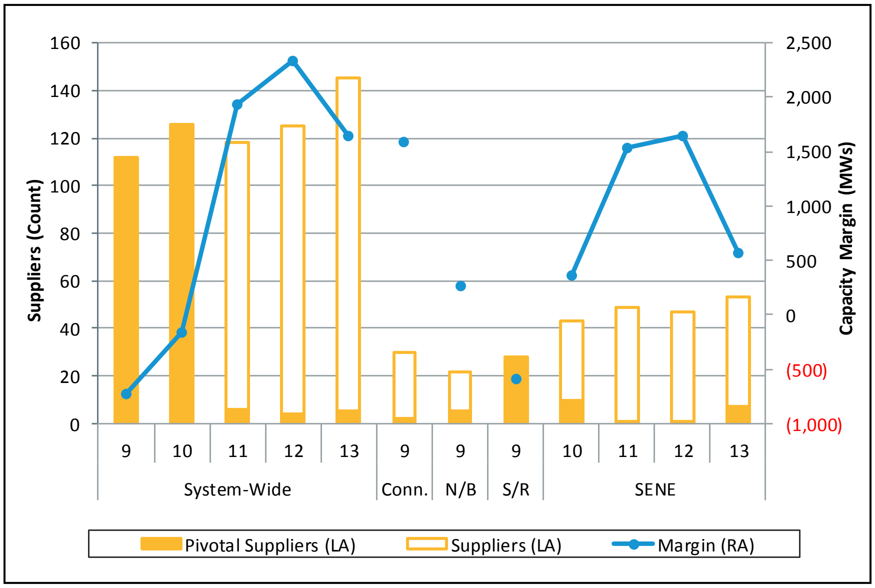
The RSI was below 100% in every auction since FCA 8, at both the system and zonal level, indicating that there was at least one pivotal supplier. The system-wide RSI (yellow) increased from 88% in FCA 9 to a high of 97% in FCA 12. The RSI decreased slightly to 96% in FCA 13. The changes can be attributed to a variety of factors, including changes to the largest supplier (there were three over the study period) resulting from resource retirements, acquisitions, and sales; the steady procurement of new generation in recent FCAs; and changes in Net ICR.

Another factor contributing to the RSI changes was the consolidation of capacity zones. Prior to FCA 10, transmission constraints in both the NEMA/Boston and SEMA/RI areas necessitated two capacity zones. Starting with FCA 10, planned transmission improvements in the SEMA/RI zone eliminated the need to model SEMA/RI separately from NEMA/Boston. The two zones were consolidated into a single zone named SENE, since there are still transmission constraints potentially limiting power flows between the newly created SENE zone and the System-wide zone. With the consolidation of NEMA/Boston and SEMA/RI into a single zone for FCA 10, the relative competitiveness of the new SENE zone increased with an RSI of approximately 80%. This change represents a significant increase compared to the relatively low RSI of approximately 48% for the NEMA/Boston zone in FCA 9. After three years of increasing RSI's, the value fell to 88% in FCA 13. The decrease is due to a higher LSR value 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 the capacity exceeded or fell below the relevant capacity requirement. For example, consider the SENE capacity zone in FCA 13. The amount of capacity exceeded the LSR, resulting in a capacity margin of approximately 573 MW (right axis – blue marker). Consequently, only suppliers with a portfolio of greater than 573 MW in this zone were pivotal in FCA 13. Of the 53 suppliers in SENE in FCA 13 (left axis – yellow bar), only 7 (highlighted in yellow) were pivotal.

Figure 6-12: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone



At the system level, the slight excess of capacity in FCA 8 turned negative in FCAs 9 and 10, causing all suppliers to be deemed pivotal for these two auctions.[203] The capacity margin increased significantly and remained high over the next three FCAs. In FCA 13, a supplier needed a portfolio of over 1,650 MWs to be deemed pivotal.[204] Consequently, there have been few pivotal suppliers at the system level since FCA 11.

Both the Connecticut and NEMA/Boston capacity zones (active during FCAs 7 through 9) had excess capacity in FCA 9 – the former with over 1,500 MWs and the latter with over 250 MWs. All suppliers in the SEMA/RI capacity zone were pivotal in FCA 9 (the only auction with this capacity zone) given the area's shortfall against the LSR.

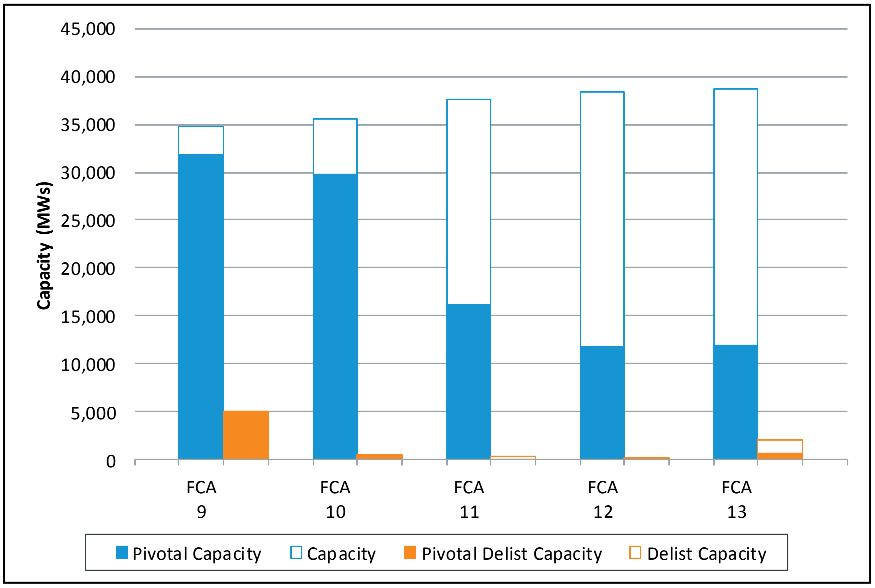
The SENE capacity zone capacity margin fell in FCA 13 due to a higher LSR value and retirements within the capacity zone. The capacity margin fell 1,100 MW, from 1,650 MW in FCA 12 to 550 MW in FCA 13. The tighter capacity margin led to seven pivotal suppliers in FCA 13, up from just one pivotal supplier in the previous two auctions.

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.

[203] Refer to Section 6.5.1 for a discussion of large resource retirements that resulted in this change.

[204] This was driven, in part, by significant increases in new capacity procured during FCAs 9 and 10. See Section 6.5.2 for an overview of new and incremental generation added in recent years.

Figure 6-13: Overview of Resources, Pivotal Resources, De-lists, and Pivotal De-lists



There have been significant swings in de-list bids and their pivotal status. In FCAs 9 and 10 when system conditions were tight, all of the de-list capacity was deemed pivotal. As the capacity margin turned positive in FCAs 11 and 12, not only did the number of pivotal resources decrease, but there were no active de-lists from pivotal suppliers during either auction. 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 total of de-list capacity. Ultimately, mitigation did not apply to any de-list capacity in FCA 13, since resources either withdrew their bid or lowered their price below the IMM mitigated price.

The results of these two complementary measures (the residual supply index and the pivotal supplier test) indicate that the New England capacity market can be structurally uncompetitive at both the zonal and system levels. 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 mitigation measures employed in the FCM, as well as summary statistics on the number and impact of these measures. To address market changes, this section presents summary information for FCA 9 through FCA 13.

The FCM is monitored for two forms of market power: supplier-side and buyer-side.

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. 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 costs, the IMM reviews de-list bids above a proxy competitive offer threshold called the dynamic de-list threshold (DDBT) price.[205] 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 is 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.

While there are a variety of de-list bid types, only a few require review by the IMM. Prior to FCA 11, reviewable de-list bid types included general static de-list bids, import and export bids, and permanent de-list bids.[206,207]

As of *FCA 11*, permanent de-list bids were replaced by "retirement and permanent de-list bids" for resources greater than 20 MW. Between *FCAs 8* and *11*, there were no permanent de-list bids or retirement de-list bids for resources greater than 20 MW, and there was only one export de-list bid. In *FCA 12*, the lead participant for 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. In *FCA 13,* over 1,400 MW of retirement de-list bids came from Mystic 8 and 9. While their bids were mitigated down, they were denied for reliability and treated as existing capacity in FCA 13. This is discussed in more detail in Section 6.3.3.

For *FCA 9* through *FCA 13*, the IMM reviewed 200 general static de-list bids from 15 different lead participants, totaling roughly 16,300 MW of capacity (an average of 3,300 MW per auction).[208] Generation resources accounted for 15,400 MW of the total capacity, even though they only accounted for 79 of the 200 general static de-list bid submissions. Demand response resources made up the other 121 resources, but only 900 MW of the total capacity. This is consistent with the smaller size of demand response resources compared to generation resources. Separate from the aforementioned statistics, the IMM reviewed over 26 supply offers from new import capacity resources without transmission investments, totaling approximately 6,200 MW.

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

[205] 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 $3.94/kW-Month in FCA 9, $5.50/kW-month in FCAs 10, 11, and 12, and $4.30/kW-month in FCA 13

[206] Starting in FCA 9, certain types of new import capacity resources were also reviewed for supplier-side market power. As of FCA 10, various changes were made, including limiting this review to new import capacity resources without transmission investments.

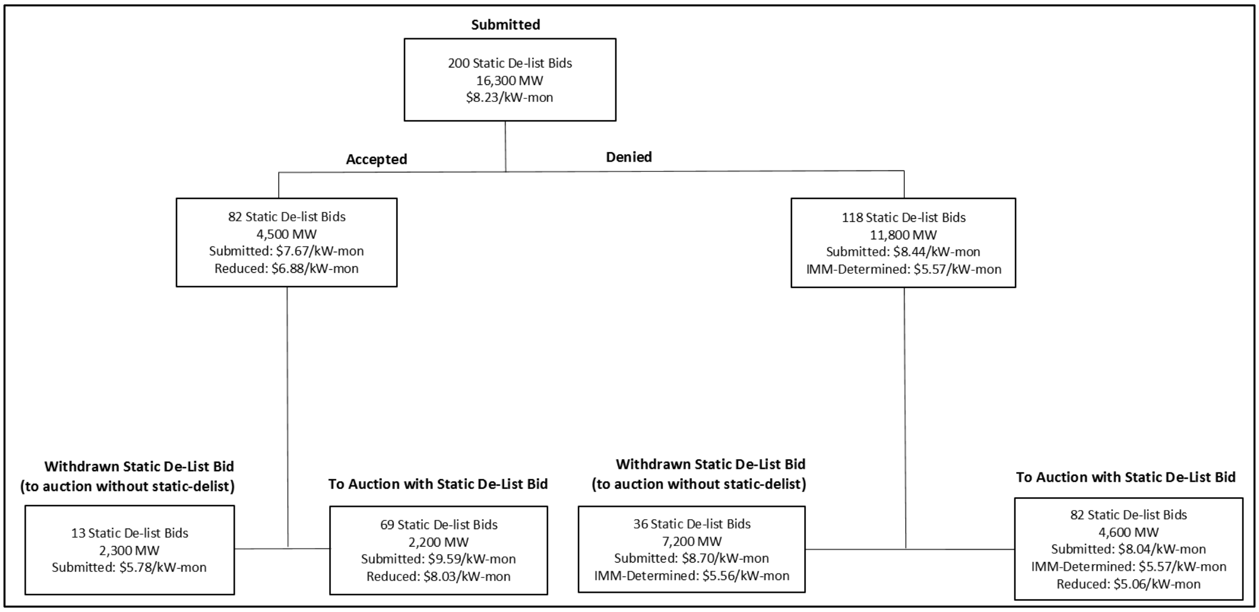
[207] The term "general" is used to differentiate between other types of static de-list bids, including ambient air static de-list bids and ISO low winter static de-list bids, which are not subject to IMM review.

[208] 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.

premium, and opportunity costs. This process resulted in mitigations for approximately 59% of the general static de-list bids (73% of de-list MW capacity).[209]

Summary statistics for static de-list bids from *FCA 9* through *FCA 13* 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.[210]

Figure 6-14: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCA 9 – 13)



Roughly 41% of bids were approved by the IMM without any changes (left box, second level). Of the static de-list bids that were mitigated, many were voluntarily withdrawn or the bid price further reduced prior to the auction. Withdrawn in this context means that the existing resource is entered into the auction but can delist its capacity only when the auction prices fall below the dynamic de-list bid threshold. For resources that were mitigated and went to the auction (box furthest to the right, third level), the weighted-average price of *mitigated* static de-list bids was $2.98/kW-month less than the market participant's originally submitted price. The weighted-average bid reduction from the IMM-determined price was $0.52/kW-month.

6.7.2 Buyer-Side Market Power

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. A depressed clearing price benefits capacity buyers, not necessarily capacity suppliers. 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

[209] If a supplier is pivotal, the IMM-determined value is entered into the auction; if not, the participant-submitted bid is entered.

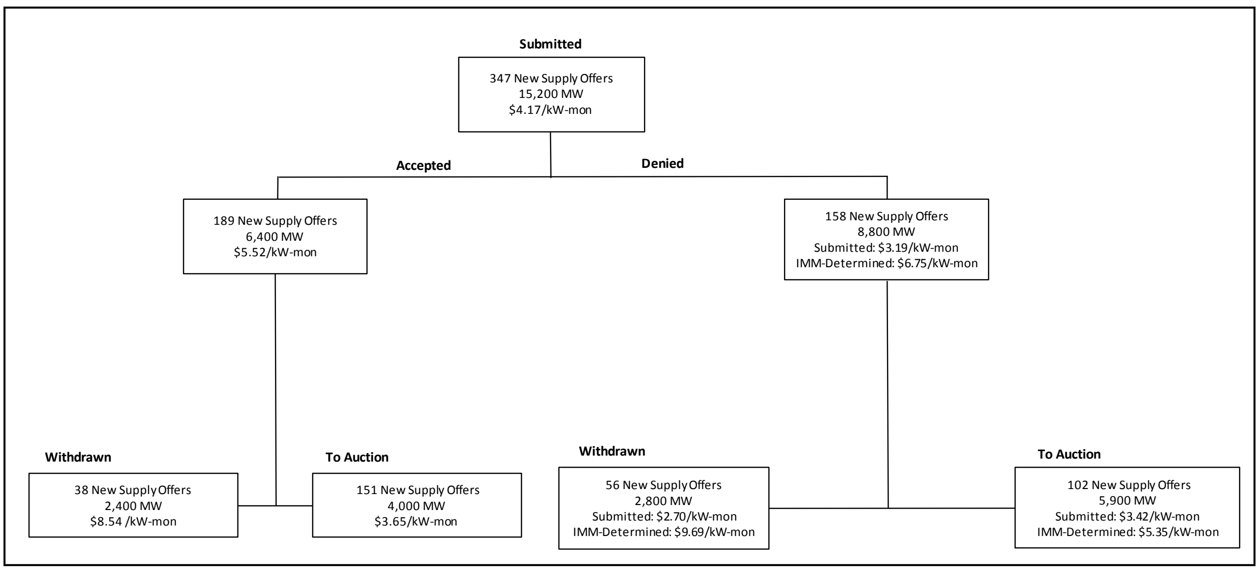
[210] Price calculations are not presented for new import capacity resources because, depending on the circumstances, the direction of the price difference can vary for price-quantity pairs within the same supply offer. Consequently, the resulting price difference summary statistics are less meaningful.

participant to offer capacity below cost.[211] 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 9 through 13, the IMM reviewed nearly 350 new supply offers from participants requesting to offer below the ORTP.[212] These offers came from 73 different lead participants and totaled 15,200 MWs of qualified capacity, of which 9,900 MW (~65%) entered the auction.[213] Generation resources accounted for the majority of the new capacity reviewed, with 91% of the total (13,850 MW). Demand response resources accounted for the remaining 9% (1,300 MW). No new import capacity resources with transmission investments completed the review process.

Summary statistics from resources requesting to offer below their respective ORTP in FCAs 9 through 13 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 (FCA 9 – 13)



The IMM mitigated approximately 45% of the new supply offers that it reviewed, or approximately 57% of the new supply capacity.[214] Similar to supplier-side mitigation, the degree of buyer-side 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

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[211] Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

[212] 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.

[213] 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.

[214] Note that the number of mitigated new supply offers also includes 27 projects that went on to elect the Renewable Technology Resource (RTR) exemption, which exempts the associated capacity from the ORTP process. The IMM-determined price for these resources reflects the mitigated price and not the resulting auction treatment value, so as not to distort the summary statistics.

offer price of $3.57/kW-month (from a submitted price of $3.19/kW-month to an IMM-determined price of $6.75/kW-month).

Section 7
Ancillary Services

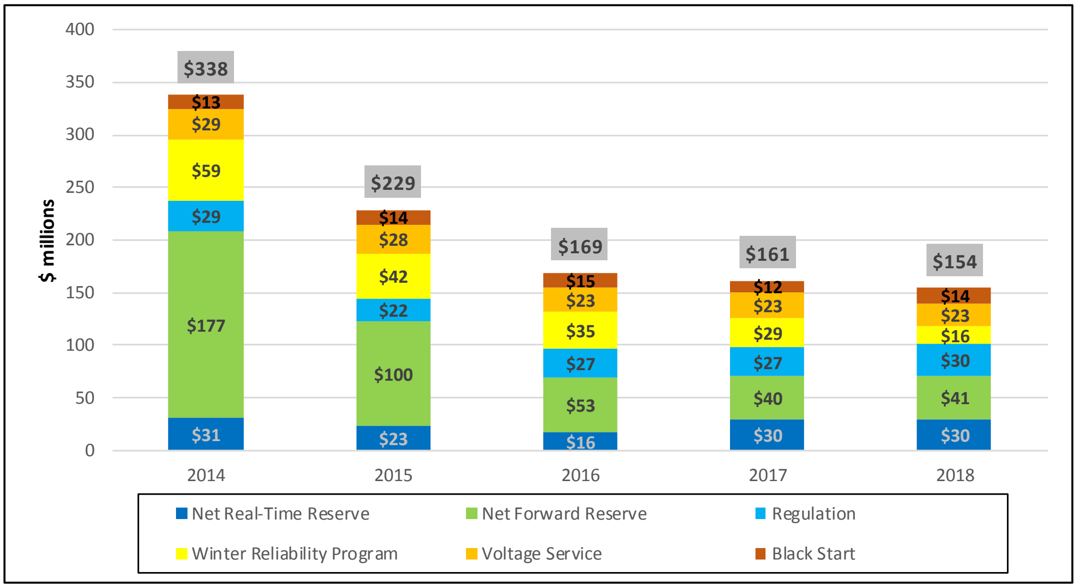
This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. In 2018, the costs of most ancillary service products and their associated make-whole payments were similar to 2017 costs. Winter Reliability Program payments were lower in 2018 because the ISO ended the program in March 2018, and therefore there were no payments in December 2018 unlike prior years.

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 the 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 ISO implemented the *Winter Reliability Program* 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 in early 2018.
- *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.
- The ISO selects and compensates strategically located generators for providing *blackstart service*. Blackstart generators must be able to restart quickly without an outside electrical supply. 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 displayed in Figure 7-1 below.

Figure 7-1: Ancillary Service Costs (in $ millions) 215



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 energy market. The following section reviews real-time operating reserve products and analyzes real-time reserve outcomes in 2018.

7.1.1 Real-Time Operating Reserve and Pricing Mechanics

There are four types of reserve products that can be provided by generators, dispatchable asset related demand, and demand response resources:

- **Ten-minute spinning reserve (TMSR):** TMSR is the highest-quality reserve product. It is provided by on-line resources that can convert reserves to energy within 10 minutes. For example, a synchronized generator that can increase its output within 10 minutes could provide TMSR. This gives the system a high degree of certainty that it can recover from a significant system contingency.
- **Ten-minute non-spinning reserve (TMNSR):** TMNSR is the second-highest quality reserve product. It is provided by off-line units that require a successful startup (e.g., a generator that can electrically synchronize to the grid and increase output within 10 minutes).
- **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).

[215] Net real-time reserves are defined as total real-time reserve payments minus total forward reserve obligation charges. The net forward reserve credit is equal to forward reserve credits minus the failure-to-activate and failure-to-reserve penalties. The Winter Reliability Program costs presented in Figure 7-1 are calculated for the calendar year (for example, January, February, and December 2017 constitute 2017 costs).

- **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.

Real-time prices for each of the above reserve products are determined by the ISO dispatch and pricing software. The software co-optimizes energy and reserves together. That is, it solves for the least-cost dispatch, while meeting energy demand and satisfying the reserve requirements (see Section 2.3.2 for information on reserve requirements), and generates energy and reserve prices. A reserve price above zero occurs when the software must re-dispatch resources in order to satisfy the reserve requirement and by doing so, imposes additional costs on the system. When this happens, the reserve price is set by the resource with the highest re-dispatch cost or opportunity cost to provide the reserves, but is capped by the Reserve Constraint Penalty Factor (RCPF).

The software will not re-dispatch resources to meet reserves at any price. When the re-dispatch costs exceed the RCPF, the price will be set equal to the RCPF and the market software will not continue re-dispatching resources to meet reserves. RCPFs are thus limits on the re-dispatch cost the system will incur to satisfy reserve requirements.[216] These RCPFs are then reflected in the energy price due to the interdependence in procurement. The RCPFs also serve as a pricing mechanism that signals scarcity in real-time through high reserve prices. Each reserve constraint has a corresponding RCPF, as shown below in Table 7-1.

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)		1,500
System TMOR (30-min)	Minimum TMOR	1,000
	Replacement Reserve	250
Local TMOR		250

Although the TMSR is the highest-quality reserve product, it has the lowest RCPF (Table 7-1). On average, the cost incurred to re-dispatch online 10-minute operating reserve resources is lower than the cost incurred to re-dispatch less flexible resources to provide 30-minute operating reserves. This is because there are additional costs associated with offline resources that are not already online and operating in merit like those providing TMSR. This is why the RCPFs associated with TMSR are less than the TMNSR and TMOR RCPFs; RCPFs are designed to 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 reserve provided as follows:

[216] 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 resources to obtain the needed reserves, if possible.

10-Minute Spinning (TMSR) ≥ 10-Minute Non-Spinning (TMNSR) ≥ 30-Minute (TMOR)

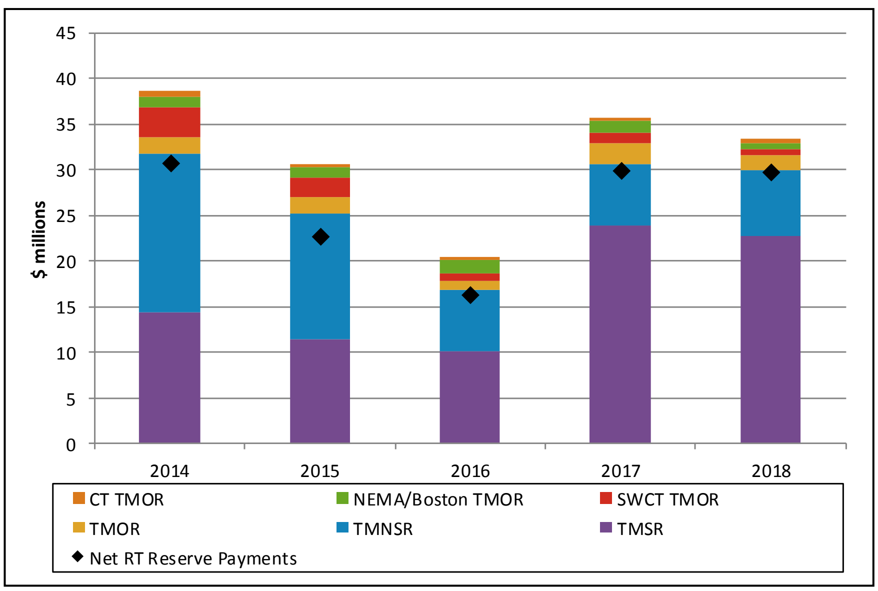
The price of higher-quality reserve products must be at least as high as the price of lower-quality reserve products. For example, if the ISO alters the dispatch to provide TMOR at a cost of $40/MWh, the prices for TMSR and TMNSR both must be equal to or greater than $40/MWh. The ordinal ranking of reserve 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 – the sum of the two reserve products' RCPFs – thereby preserving the ordinal ranking of the reserve product prices.

7.1.2 Real-Time Operating Reserve Payments

Although real-time operating reserve payment totals may change significantly on a percentage basis from year to year as a result of changes in operating reserve requirements, fuel prices, and system conditions, total payments are relatively small compared with overall energy market and capacity market payments. Reserve payments for all reserve products are shown in Figure 7-2 below. Total payments are based on each resource's real-time reserve designation and the reserve market clearing prices.

Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. Section 7.2 provides additional details on the Forward Reserve Market. Net real-time reserve payments are shown as black diamonds in Figure 7-2.

Figure 7-2: Real-Time Reserve Payments



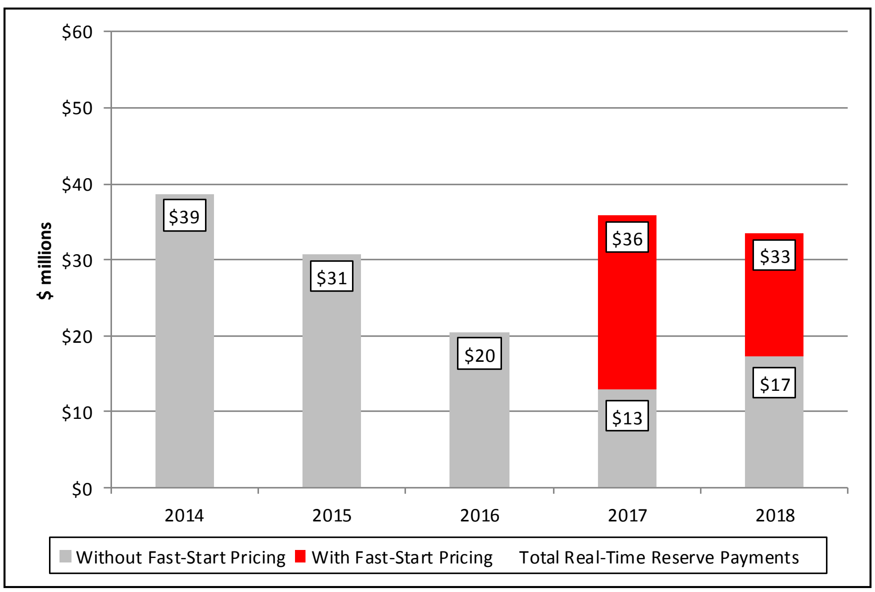
Total gross real-time reserve payments for 2018 were $33.4 million, a decrease of $2.4 million (or 7%) from 2017. This decline reflects a fall in TMSR and TMOR payments of $1 million (4%) and $1.7 million (33%), respectively. Net real-time reserve payments were $29.8 million, slightly under the 2017 value of $29.9 million. Shortage conditions and scarcity pricing on September 3, 2018, accounted for $9.1 million, or 27%, of total annual gross payments. The 2018 gross reserve payment total of $33.4 million was less than 1% of total wholesale market costs in New England.

TMSR payments declined primarily due to a lower average TMSR requirement in 2018 compared to 2017 (see Section 2.3.2). The 33% drop in TMOR payments resulted from lower average TMOR prices and fewer hours in which the system TMOR and NEMA/Boston TMOR reserve products were binding. TMSR payments made up the majority (68%) of total payments due to the frequent need to re-dispatch the system to meet the requirement.

Impact of Fast-Start Pricing on operating reserve payments

The uptick in reserve payments in 2017 and 2018 relative to prior years is due to the implementation of Fast-Starting Pricing rules. Fast-start pricing, which was discussed in detail in the Summer 2017 Quarterly Markets Report[217], was implemented in March 2017 to improve price formation and performance incentives in the real-time energy market. Figure 7-3 below shows the impact fast-start pricing has had on real-time reserve payments over the past two years.

Figure 7-3: Impact of Fast-Start Pricing on Reserve Payments



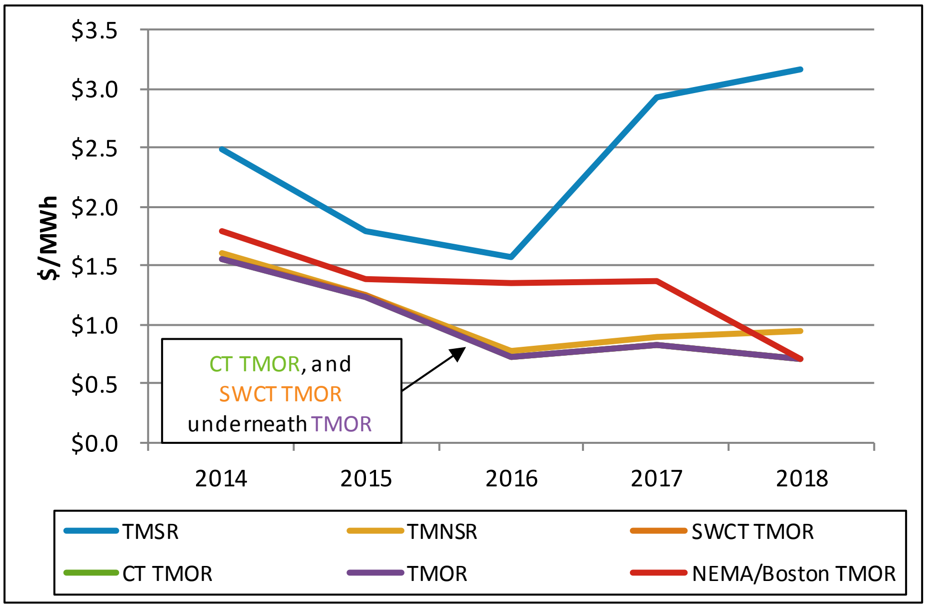
Without fast-start pricing, real-time reserve payments would have been approximately $17 million in 2018, compared to about $33 million. As intended, fast-start pricing more accurately reflects the cost of operating higher-cost fast-start generators and, on average, has increased the price of energy. Because the price of energy has increased, so too has the opportunity cost of holding back resources to provide reserves rather than energy, which has resulted in higher and more frequent reserve pricing.

[217] 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

7.1.3 Real-Time Operating Reserve Prices: Frequency and Magnitude

Average TMSR and TMNSR prices increased by 8% and 7%, respectively, in 2018 relative to 2017. Note that despite the rise in the average TMSR price, total TMSR payments fell compared to 2017. This is because the average designated TMSR level was lower in 2018 due to a drop in the average TMSR requirement compared to 2017 (573 MW compared to 652 MW). Average prices for TMOR products fell by 14%, with the exception of NEMA/Boston TMOR, which fell by 48% from 2017. Average real-time prices for each reserve product over all intervals (both zero- and non-zero pricing intervals) are illustrated in Figure 7-4 below.

Figure 7-4: Average Real-Time Reserve Prices for all Intervals



The average reserve prices shown in Figure 7-4 are a function of two factors. The first is *frequency*, which represents how often (i.e., percentage of the time) a reserve product has a positive price (a price above $0/MWh). The second factor is *magnitude*. Magnitude is the average real-time reserve price for only the intervals where reserve prices were above zero. Figure 7-5 below illustrates both the frequency (left panel) and magnitude (right panel) of non-zero reserve prices by reserve product over time.

Figure 7-5: Frequency and Average of Non-Zero Reserve Prices

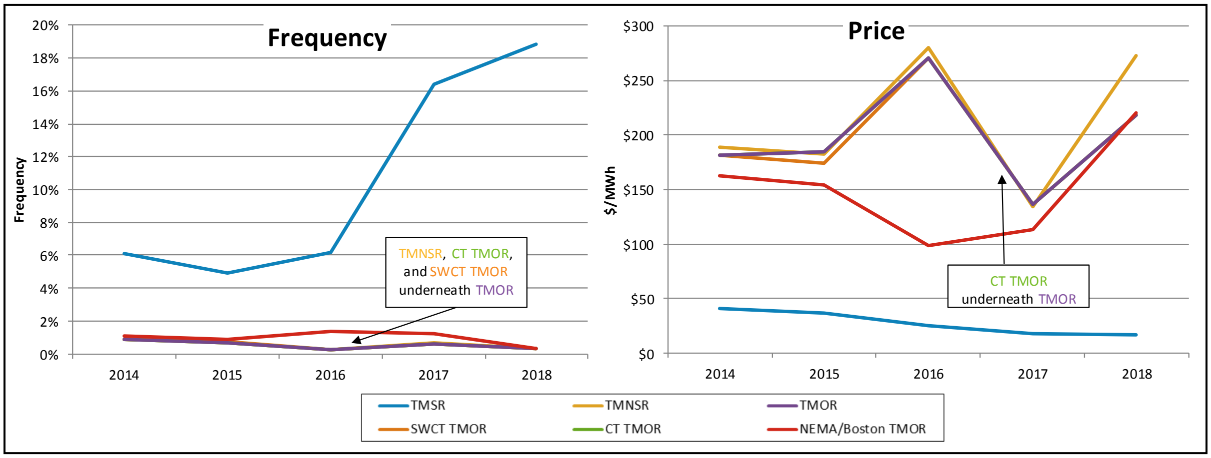


Figure 7-5 shows that TMSR price was non-zero (i.e., above $0/MWh) for about 19% of all hours in 2018, a slight increase from 2017. For those hours in which the TMSR price was above zero, it averaged nearly $17/MWh, a decrease from an average of about $18/MWh in 2017 (right panel of Figure 7-5.) The uptick in the frequency of non-zero TMSR pricing outweighed the small decline in average non-zero TMSR price, which resulted in a rise of the average TMSR price across all hours (Figure 7-4).

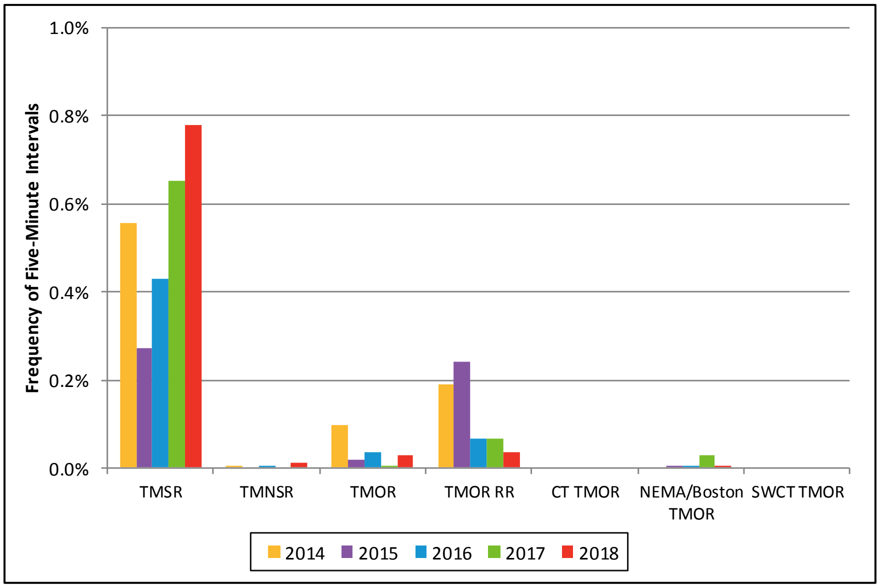
Although the frequency of non-zero TMNSR price fell by half in 2018 relative to 2017, the average non-zero TMNSR price more than doubled, resulting in an increase in the average TMNSR price (across all hours). The relatively high non-zero TMNSR price was driven by the capacity scarcity event on September 3, 2018, which saw the cascaded TMNSR price reach $2,500/MWh when the TMNSR RCPF was triggered for 45 minutes.

Similarly, the frequency of non-zero pricing for system-wide, SWCT, CT, and NEMA/Boston TMOR products decreased from 2017. This led to a fall in the average TMOR prices (across all hours); this is despite there being an increase in the average non-zero TMOR prices, which was a result of the $1,000/ MWh TMOR prices during the September 3, 2018 event.

Reserve Constraint Penalty Factors

During 2018, the RCPFs for several reserve constraints were triggered due to either a shortage of available capacity to meet the reserve requirements or re-dispatch costs that exceeded the RCPF values. As outlined above, RCPFs are the maximum re-dispatch costs the system will incur to meet each reserve constraint. The number 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



The TMSR RCPF had the highest frequency of triggering with 817 five-minute intervals (0.8% of total intervals), or about 68 hours over the year. The TMOR replacement reserve RCPF was triggered in 37 intervals (0.04%), or just over 3 hours. The NEMA/Boston TMOR RCPF was the only local TMOR RCPF triggered during 2018, and it occurred for just 15 minutes, a large drop from 2017 when the RCPF was triggered for more than 7 hours.

The TMNSR RCPF was triggered for 55 minutes during 2018, 45 minutes of which occurred in the afternoon of September 3, 2018 during the capacity scarcity event. The only time the TMOR RCPF was in effect during 2018 was for 3 hours and 40 minutes (3:20PM to 6:15PM) on September 3.

The TMSR RCPF had the highest frequency of activations due to the higher frequency of TMSR non-zero pricing intervals and its relatively low RCPF value ($50/MWh) compared to the other products. This means the dispatch software will stop trying to re-dispatch the system much sooner than for the other reserve products with significantly higher RCPF values. The TMSR RCPF activation frequency was higher in 2018 and 2017 than prior years due to an increase in the frequency of TMSR pricing and the opportunity costs due to fast-start pricing.

When the RCPFs are triggered because of a shortage of available reserves to meet the requirements, the reserve price will directly impact the energy price. During these times, the RCPF value is added into the energy price since satisfying any additional increment of load will decrease the amount of reserves available on the system by the same amount. The RCPF value determines the price of reserves during scarcity events. Thus, the LMP will reflect the total cost of serving an additional increment of load including the value of the loss of reserves.

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. However, 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 every day 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.[218]

Until the Summer 2016 FRM auction, the FRM payment rate (or price) was reduced by the contemporaneous delivery period's FCA clearing price. This "netting" was done to avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity. Netting was eliminated starting with the Summer 2016 delivery period. This eliminated the unintended consequences of netting which, under certain circumstances, resulted in uneconomic resource selection and zero (or nearly zero) FRM compensation for auction participants.[219]

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 offered 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 generator 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. Failure to assign a generator they

[218] As indicated below, the auction price cap was reduced to $9,000/MW-month beginning with the Summer 2016 auction, when "price netting" (i.e., subtraction of the FCA compensation from the FRM compensation) was terminated. Prior to the Summer 2016 auction, the auction price cap was $14,000/MW-month.

[219] ISO New England and New England Power Pool, Docket No. ER16-921-000; *Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting*. https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf See Section IV of the ISO's filing for a description of the unintended consequences and undesirable effects of the netting mechanism.

control or the transfer of the obligation to another participant results in the assessment of a "failure-to-reserve" penalty.

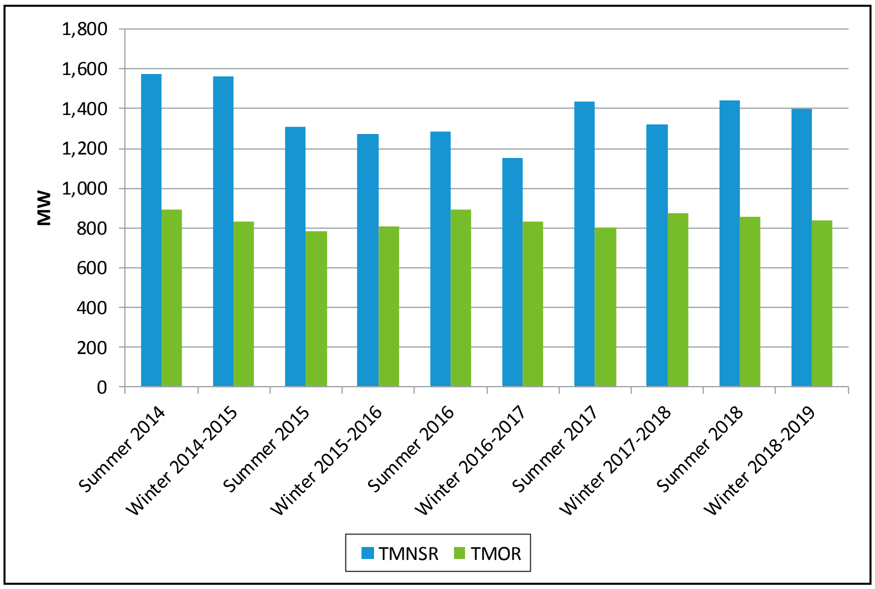
Allocation of the costs for paying resources to provide reserves is based on real-time load obligations in load zones. These obligations are price-weighted by the respective forward-reserve clearing prices of the reserve zones that correspond to each load zone.

7.2.1 Market Requirements

The FRM auction is intended to ensure adequate reserves to meet 10- and 30-minute 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 2014 through Winter 2018-19 are shown in Figure 7-7 below.

Figure 7-7: Forward Reserve Market System-wide Requirements



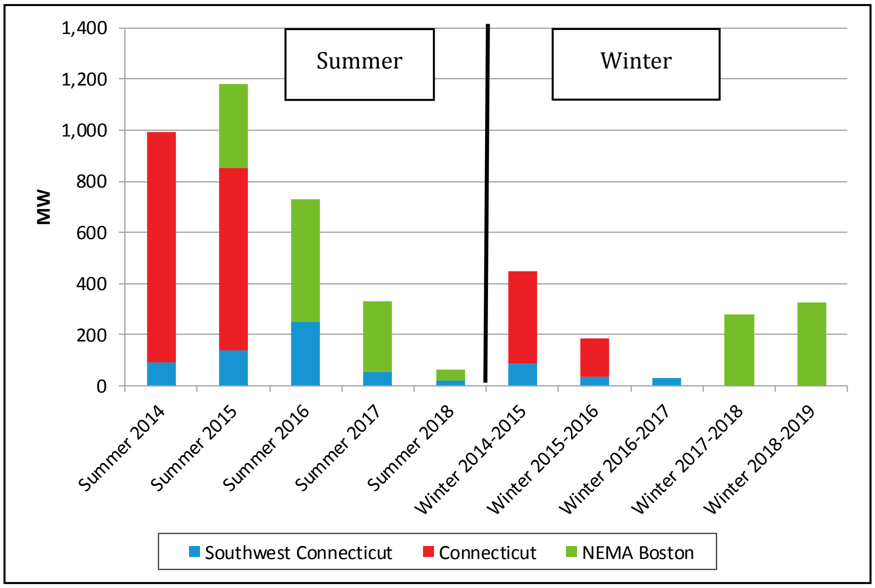
Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9 or Seabrook.[220] Therefore, the requirements have been relatively consistent at 1,200-1,400 MW for TMNSR and 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 about non-spinning reserve needs (affecting TMNSR), replacement reserve needs (affecting TMOR), and generator performance when called upon for system contingencies.

[220]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.

Some zones are constrained in terms of how much power they can import from other zones and can 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 10 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 thirty-minute operating reserve (TMOR) requirement, which can be met through 10- or 30-minute reserve supply offers in each local reserve zone.

Figure 7-8: Aggregate Local Forward Reserve (TMOR) Requirements



Local forward reserve requirements (which account for both local second contingency and external reserve support (ERS) MWs) for the reserve zones reflect the need for a 30-minute contingency response to provide support in import-constrained areas. The local forward reserve requirement for each applicable reserve zone is based on the 95th percentile value from historical requirements data for the previous two-like forward reserve procurement periods.[221] Resources within a local region as well as operating reserves available in other locations, through external reserve support, can satisfy second contingency capacity requirements.

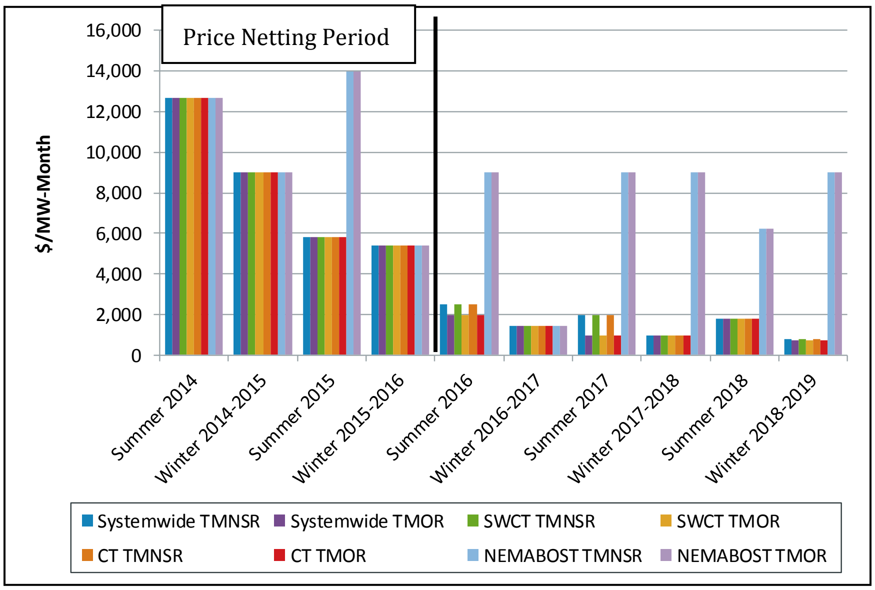
At the local level, the summer procurement period has experienced a significant reduction in aggregate local FRM requirements, as illustrated in Figure 7-8. This results from a considerable increase in ERS for Connecticut due mainly to transmission upgrades; Connecticut's local requirement has declined to zero in the past three summer and winter periods as a result of increased ERS. Meanwhile, NEMA/Boston has had positive local requirements for the last four summer and two winter periods as a result of decreased ERS.

[221] 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.

7.2.2 Auction Results

This section covers FRM auction pricing outcomes from the Summer 2014 auction through the Winter 2018-19 auction. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-9 below.[222]

Figure 7-9: Forward Reserve Prices by FRM Procurement Period



With the exception of Summer 2018 and local reserve prices for NEMA/Boston, auction prices for reserve products generally have declined by product and delivery season over the review period. In the Summer 2018 auction, higher TMOR offer prices resulted in higher clearing prices, compared to earlier summer periods. Changes in offer prices may reflect, in part, factors such as delivery risks as a result of higher or lower "forward reserve heat rates" for a delivery period, and expected energy market opportunity costs for the delivery period.[223] In NEMA/Boston, forward reserve supply shortfalls have resulted in very high auction clearing prices, including clearing prices at the offer cap (discussed below).

Prices for the 2016 and later auctions are not readily comparable to earlier periods, since the FRM prices are no longer adjusted for FCA prices (i.e., price-netting was eliminated beginning with the Summer 2016 auction). The decline in prices in 2016, relative to earlier periods, is consistent with the elimination of price-netting.

The relatively uniform historic clearing prices for TMOR and TMNSR indicate that, in many auctions, some TMNSR was 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

[222]Forward reserve auction clearing prices are calculated for each reserve product in each reserve zone, and the requirements for the Connecticut reserve zone can be partially fulfilled by the requirements for Southwest Connecticut. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the 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.

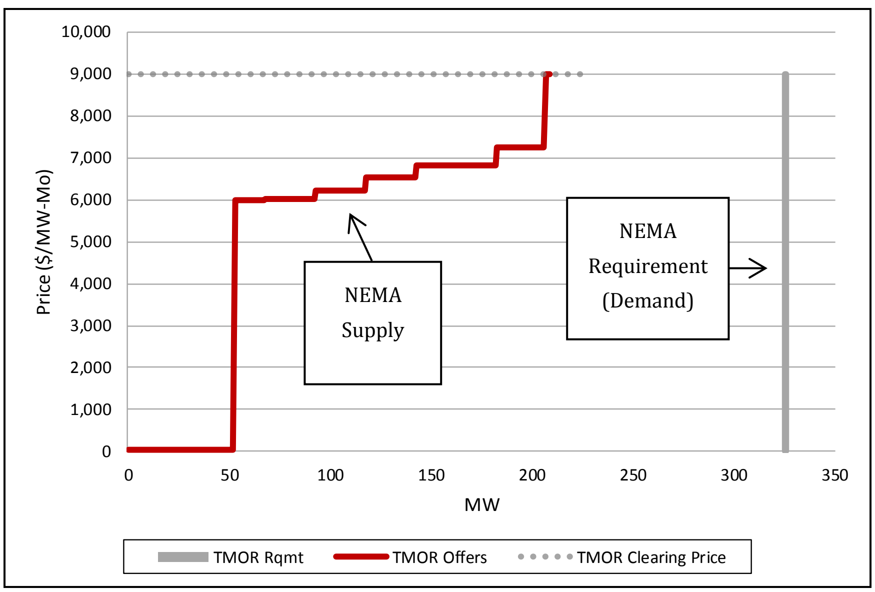
[223] Forward Reserve Heat Rates are ISO-derived values that are used in the determination of the Forward Reserve Threshold Price. Section III.9.6.2 of Market Rule 1 indicates the derivation of the heat rate values and the formulation of the Forward Reserve Threshold Price.

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.[224] 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 than TMOR. In four instances during the review period, TMNSR cleared the auction at higher prices than TMOR.

For zonal pricing, there have been six instances of significant price separation during the five-year period, as illustrated in Figure 7-9. In the summer periods for 2015 through 2018 and the winter periods for 2017-18 and 2018-19, there was price separation between NEMA/Boston and all other zones. In these instances (with the exception of Summer 2018), supply was inadequate to satisfy the local TMOR requirement, and pricing reached the auction offer cap. The 2015 NEMA/Boston summer period price exceeded the 2016 and 2017 summer prices, because the cap was reduced in 2016 (from $14,000/MW-month to $9,000/MW-month), when FCA price netting was eliminated.[225] In Summer 2018, there was adequate supply to meet the local requirement at a price of $6,225/MW-month.

Figure 7-10 below shows NEMA/Boston's supply and demand curves for the 2018-19 Winter FRM auction.

Figure 7-10: Supply and Demand for the TMOR Product in NEMA/Boston for the Winter 2018-19 Auction



With zonal supply approximately 115 MW less than zonal demand, the zonal clearing price was set to the auction price cap, resulting in a $9,000/MW-month price for local TMNSR and TMOR. Higher

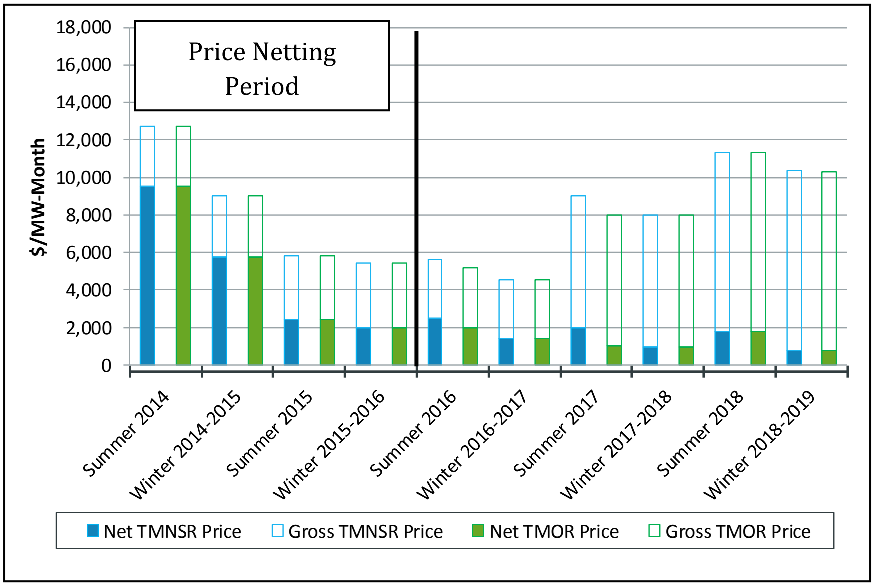
[224] See Market Rule 1, Section III.9.4, Forward Reserve Auction Clearing and Forward Reserve Clearing Prices; and, Manual M-36, Forward Reserve and Real-Time Reserve, Section 2.6, Forward Reserve Auction Clearing.

[225] ISO New England and New England Power Pool, Docket No. ER16-921-000; *Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting*. https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf .

FRM prices in NEMA/Boston over the past number of years have not been effective in delivering new fast-start capability to the region.

Finally, the gross and net forward reserve prices for TMNSR and TMOR are shown in Figure 7-11 below and illustrate the price-netting concept as if it had applied to all periods (not just prior to Summer 2016). The gross price indicates the FRM auction price inclusive of the FCA price, while the net price shows the FRM-only price. The net price provides the effective TMNSR and TMOR compensation rates for FRM rest-of-system resources for all periods in the graph. The gross price represents the FRM auction clearing price for 2015 and earlier periods. The net price represents the auction clearing price for the Summer 2016 auction and beyond.

Figure 7-11: Gross and Net FRM Clearing Prices for Rest-of-System TMNSR and TMOR



For comparison, the graph includes the Summer 2016 and later auctions and provides an estimated gross price for these auctions; the contemporaneous FCA period clearing price has been added to the FRM auction clearing prices for rest-of-system TMNSR and TMOR to create "gross" FRM clearing prices. For prior periods, when the FRM price includes the FCA payment rate (or price) the net price represents the FRM price minus the FCA price. As noted earlier, TMNSR and TMOR prices have generally fallen in 2018 relative to earlier periods.

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.[226] 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 through assigning obligations to generators in 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

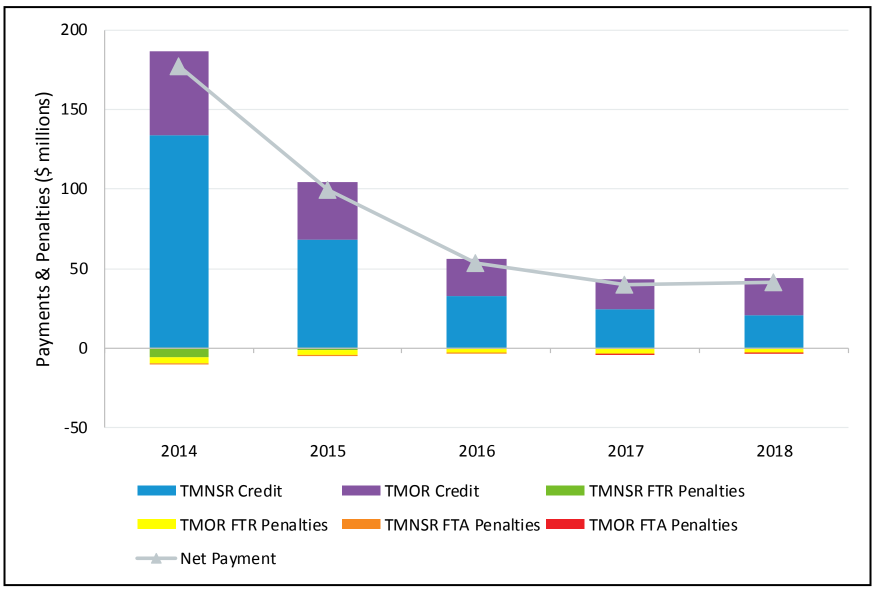
[226] Hourly FRM obligations may be transferred by participants on a daily basis up to two days after the delivery period. These transfers take place through "internal bilateral transactions" that allow the ISO to determine whether the holder of the obligation delivered the physical capacity needed to back the obligation in the real-time energy market. See ISO Manual M-36, Forward Reserve and Real-Time Reserve, Section 3.1.2.

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 generators 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 participant fails to provide energy (when called upon by the ISO) from a generator that has been assigned an FRM obligation. The failure to activate penalties are separate from failure to reserve penalties assessed to a participant.

Annual FRM payment data by year are provided in Figure 7-12 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. Payments are strongly related to FRM requirements and auction clearing prices.

Figure 7-12 FRM Payments and Penalties by Year



As indicated above, total reserve requirements have been relatively stable over the past three years. However, auction prices have declined significantly from the highs of 2014 and 2015. This trend is consistent with the net prices in Figure 7-11 above. Penalties have tended to be low relative to gross payments and have been fairly stable in the 5% to 8% range of total payments over the period. These penalties have been predominately for failing to reserve (99.6%). Total penalties have declined as auction prices have declined over time, since failure to reserve penalties result in forfeiture of auction-based payments for unassigned obligations.

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 FRM portfolio offer. If the requirement cannot be met without the largest supplier then that supplier is pivotal. The RSI is calculated based on the 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. 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 still 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 2014	96	124	85	51	N/A
Winter 2014-15	107	186	84	139	N/A
Summer 2015	117	158	69	79	12
Winter 2015-16	109	154	228	382	N/A
Summer 2016	112	139	76	N/A	23
Winter 2016-17	148	222	302	N/A	N/A
Summer 2017	110	197	183	N/A	21
Winter 2017-18	127	209	N/A	N/A	24
Summer 2018	112	214	438	N/A	34
Winter 2018-19	127	244	N/A	N/A	21

Table 7-2 shows that there were pivotal suppliers in one out of the ten FRM auctions for TMNSR. There were also pivotal suppliers in eight out of ten auctions for TMOR in at least one of the reserve zones.

Generally, the RSI values fluctuate significantly from auction to auction. These fluctuations can be partly explained by the significant variation in the local reserve requirements. For instance, the TMOR RSI value for the SWCT zone jumped from 76 (structurally uncompetitive levels) in the Summer 2016 auction to 302 (structurally competitive level) in the Winter 2016-17 period. For the same zone and time period, the TMOR local requirement decreased from 250 MW to 32 MW.

For the recent 2017 and 2018 procurement periods, the TMNSR RSI values were greater than 100. These values suggest that the TMNSR offer quantities in the auctions during these years were consistent with a structurally competitive level. Similarly, the TMOR RSI values for the Rest-of-System (ROS) zone were consistent with a structurally competitive level over the same period. The

RSI value for the NEMA zone, however, has been significantly below a competitive level for every auction procuring local supply over the review period. In these auctions, every participant who offered forward reserves in NEMA was pivotal in that auction because the total offered quantity was significantly below the local requirement.[227]

7.3 Regulation

This section presents data about the participation, outcomes, and competitiveness of the regulation market in 2018. Overall, the available supply of regulation service in 2018 far exceeded the regulation requirements, resulting in a competitive market.

The regulation market is the mechanism for selecting and paying resources needed to balance supply levels with the second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[228] 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).[229] 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.[230]

7.3.1 Regulation Pricing and Payments

The Regulation Clearing Prices (RCP) are calculated in real-time and are based on the regulation offer of the highest-priced generator providing the service. During 2015, FERC required the ISO to change how regulation pricing is determined.[231] Under the prior rule, generators offered regulation

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[227] Note that some of the historical values reported in the table have changed since being reported in the 2017 Annual Markets Report (re RSIs for TMNSR, TMOR ROS, and TMOR SWCT). An error in the algorithm used to calculate the RSI was discovered, resulting in the changed values. The change in values, however, did not result in a change to earlier conclusions about the structural competitiveness of each auction. The correction resulted in reduced levels of competitiveness for some auctions, but the revised data continue to indicate that the auctions were structurally competitive.

[228] 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.

[229] This NERC standard can be accessed at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

[230] 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.

[231] The changes were instituted under FERC's Order No. 755, which required two-part bidding and for compensation of frequency regulation resources to be based on the actual service provided, including a capacity payment that includes the marginal resource's opportunity costs and a service payment for performance that reflects the quantity of frequency regulation provided.

at a single price. Under the new rules, generators use two-part pricing: a service price and a capacity price.[232] The pricing change was implemented effective March 31, 2015.[233]

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 cost, including: (1) the expected value of lost energy market opportunities when providing regulation service, (2) elements of fixed costs such as incremental maintenance to ensure a generator's continuing performance when providing regulation, and (3) fuel market or other risks associated with providing regulation.

Regulation clearing prices for the past five years are shown in Table 7-3 below.

Table 7-3: Regulation Prices

	Regulation Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)			Regulation Capacity Clearing Price ($/MW per Hour)		
Year	Min	Ave	Max	Min	Ave	Max	Min	Ave	Max
2014	0.00	19.04	1,407.43	n/a	n/a	n/a	n/a	n/a	n/a
2015[(a)]	2.86	18.27	381.13	0.00	0.30	10.00	2.44	25.26	1,172.47
2016	n/a	n/a	n/a	0.00	0.43	10.00	1.33	27.33	1,384.57
2017	n/a	n/a	n/a	0.00	0.34	10.00	0.00	29.23	1,010.16
2018	n/a	n/a	n/a	0.00	0.25	10.00	0.00	28.30	2,331.55

(a) Pricing rules changed on 3/31/15.

In 2018, the average service price was $0.25/mile, a $0.09 (27%) reduction compared to the average of $0.34/mile in 2017. Mileage payments represent a small share of overall regulation payments (8% or $2.6 million in 2018).

Regulation capacity prices decreased modestly (by 3%) in 2018 compared with 2017, reflecting a decline in the "incremental cost saving" component of regulation capacity pricing.[234] The two-part pricing (implemented in 2015) is not comparable to prices for the 2014 and earlier periods, because two-part pricing altered regulation compensation (and bidding incentives) for resources.

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

[232] For convenience, the offers are described as two-part. Technically, participants have the ability to specify an intertemporal opportunity cost in their offers, in addition to service and capacity prices; intertemporal opportunity costs, however, are combined with capacity prices, when offers are evaluated for regulation commitment.

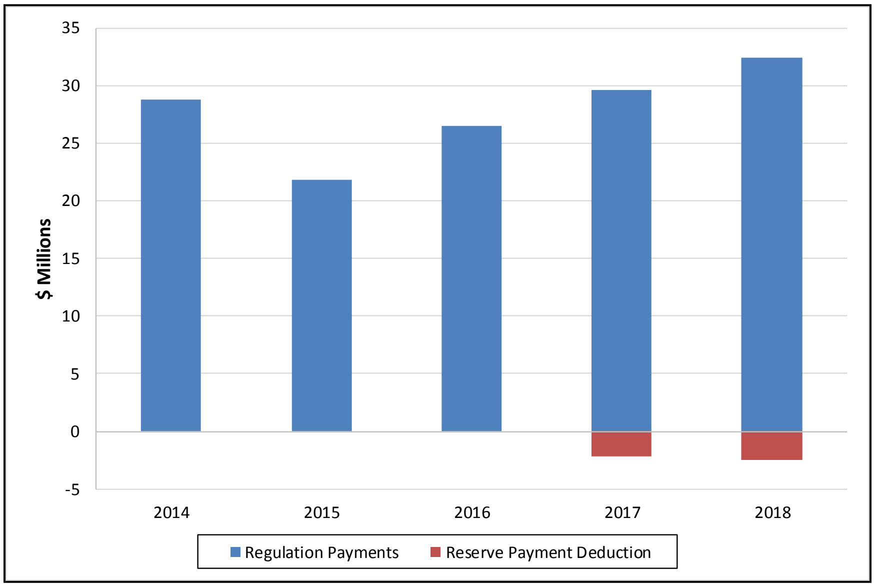
[233] Market Participants providing regulation service may also qualify for make-whole or NCPC payments.

[234] Incremental cost saving represents the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer. This compensation replicates a "Vickery" approach to compensating lumpy "supply," and is intended to provide regulation resources with payments approximating the system opportunity cost of obtaining regulation. See Peter Cramton's testimony (April 26, 2012) to the Federal Energy Regulatory Commission, Re: Docket Nos. RM11-7-000 and AD10-11-000; Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets.

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 operating reserves are not actually provided 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 for providing operating reserves.[235]

Annual regulation payments over the past five years are shown in Figure 7-13 below. The reserve payment deduction is shown as a negative value in the exhibit; the positive amounts represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period.

Figure 7-13: Regulation Payments



Payments to resources providing regulation service totaled $32.5 million in 2018, a 9% increase from the $29.7 million in 2017. (These totals exclude the reserve payment adjustment.) In 2018, the average regulation requirement increased by 12% (as noted below), which also led to a commensurate increase in regulation capacity utilization. The 3% decrease in average regulation capacity prices helped to moderate the increase in overall regulation payments.

In 2017, the increase in payments reflected several factors: an increase in regulation requirements, an increase in energy market opportunity costs, and an increase in regulation service volumes.[236] The significant increase in 2016 payments, compared to 2015, resulted primarily from two factors. The implementation of BAL-003 in April 2016 resulted in an approximately 25% increase in the average regulation requirement for 2016. Also, the manual selection of large regulation resources by the ISO during the summer months increased regulation payments by approximately $2 million

[235] The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

[236] Regulation requirements increased in 2017 relative to 2016, as the implementation of NERC standard BAL-003 (Frequency Response and Frequency Bias Setting) affected all 12 months of 2017 compared to 9 months of 2016; for example, this change resulted in an additional 7% increase in the average regulation capacity requirement for 2017.

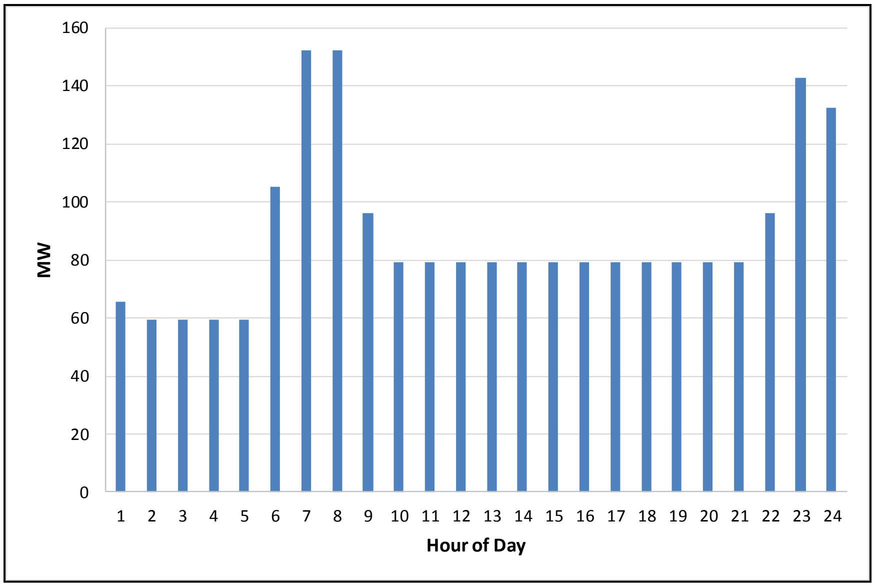
compared to 2015. Elevated payments in 2014 reflected elevated regulation costs during Winter 2014.[237]

7.3.2 Requirements and Performance

The average hourly regulation requirement of 88.8 MW in 2018 was higher than the 79.6 MW requirement in 2017. This 12% increase in the average regulation requirement reflects operational needs in 2018; given increased variability in ACE, the regulation requirement was increased beginning in July 2018. The increased requirement ensures that the ISO can maintain ACE within acceptable tolerance levels.

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 2018 is shown in Figure 7-14 below.

Figure 7-14: Average Hourly Regulation Requirement, 2018



With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO now uses violations of Balancing Authority ACE Limits (BAAL) to measure performance. Violations result from exceeding ACE limits for more than 30 consecutive minutes; in 2018, there were no BAAL violations.

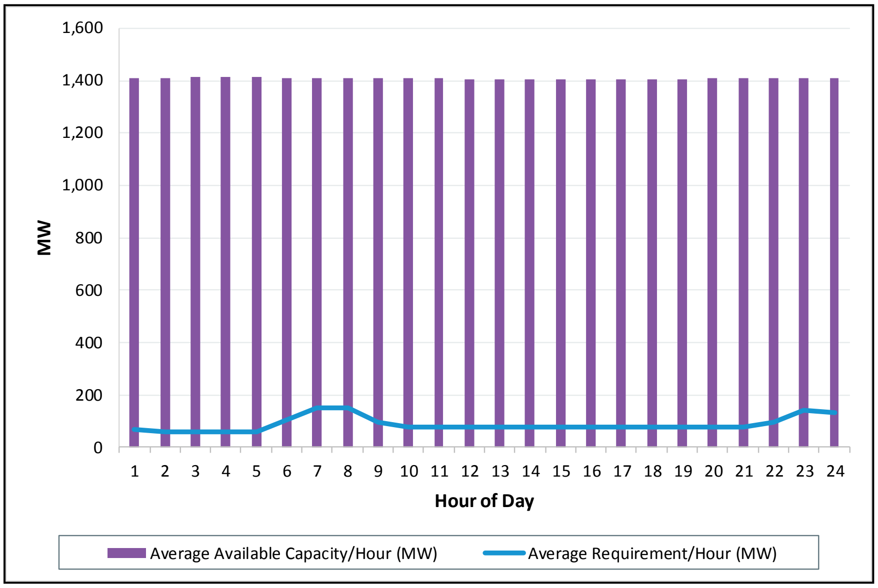
7.3.3 Regulation Market Structural Competitiveness

The competitiveness of the regulation market was reviewed by examining market structure and resource abundance. The abundance of regulation resources, and relatively unconcentrated control of that supply, implies that market participants have little opportunity to engage in economic or

[237] See the Spring 2016 Quarterly Markets Report, available at https://www.iso-ne.com/static-assets/documents/2016/08/q2_spring_2016_qmr_final.pdf, for a detailed discussion of regulation payments in 2015 and earlier years. Note that the data presented in Quarterly reports uses a "seasonal" quarter, which differs from calendar quarters. As such, annual and quarter totals will not match when comparing a Quarterly Markets Report to the Annual Markets Report.

physical withholding. The regulation market was competitive in 2018. Figure 7-15 below simply plots the regulation requirement relative to available supply.

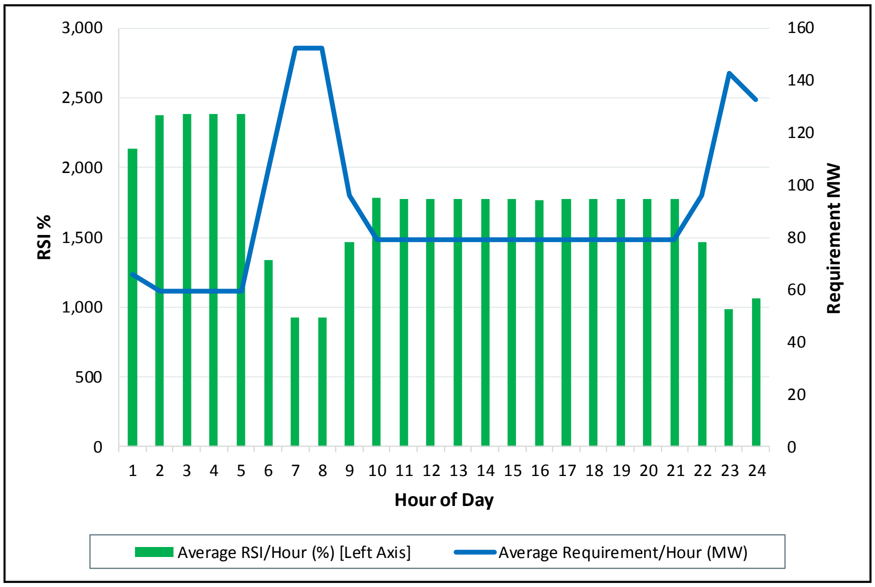
Figure 7-15: Regulation Market Average Requirement and Available Capacity, 2018



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an available abundance of 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 available supply relative to need, after removing the largest regulation supplier in the market. As shown in Figure 7-16, the regulation requirement and RSI are inversely correlated (the lower the requirement the higher the RSI).

Figure 7-16: Average Regulation Requirement and Residual Supply Index



In 2018, the lowest hourly average RSI did not fall below 900%, implying that, on average, the system has the capability to serve nine times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement.

Section 8
Market Design Changes

This section provides an overview of the major market design changes that were recently implemented and those that are planned, or are being assessed, for future years. Table 8-1 below lists (and includes links to) the design changes summarized in this section.

Table 8-1: Market Design Changes

Major Design Changes Recently Implemented	Major Design Changes in Development or Implementation for Future Years
FCM Pay-for-Performance	Energy Security Solutions
Price-Responsive Demand	Energy Market Offer Caps
Energy Market Opportunity Costs	Annual Reconfiguration Transactions (ARTs) for Annual FCM Auctions
Revisions to Operating Procedure 21	Enhanced Storage Participation
Retaining Resources for Fuel Security ("Chapter 2")	
Competitive Auctions with Sponsored Policy Resources (CASPR)	

8.1 Major Design Changes Recently Implemented

The following market rules changes were implemented during 2018.

FCM Pay-for-Performance (commenced on June 1, 2018)

In January 2014, the ISO filed proposed rule changes with FERC regarding performance incentives in the Forward Capacity Market (FCM).[238] The proposal was, to a large extent, accepted by FERC, with a number of changes that were subsequently addressed by the ISO and stakeholders. The so-called Pay-for-Performance (PFP) rules took effect from the ninth forward capacity auction (FCA9). While the associated settlement rules took effect in June 2018, the impact of the rules had already been incorporated into participant bids and capacity clearing prices since FCA 9, which was held in February 2015.

PFP is intended to strengthen the incentives for capacity resources to deliver on their capacity supply obligations (CSOs) when most needed for system reliability. The rules are based on a two-settlement design, whereby participants take on a forward position in the capacity market for a capacity resource. During shortage conditions in the real-time energy market, the participant is expected to deliver its share of total system energy and reserve requirements. Deviations (in megawatts) are settled on an administratively-determined rate, known as the Performance Penalty

[238] *ISO New England Inc. and New England Power Pool,* Filings of Performance Incentives Market Rule Changes; Docket No. ER14-1050 -000 (filed January 17, 2014)

Rate (PPR). In other words, if a resource over-delivers in real-time, it will be paid for its additional performance at the PPR; conversely if it under-delivers it will buy out of its position at the PPR.

The first shortage condition under the PFP rules occurred on September 3, 2018 as a result of the combined effect of unanticipated higher load during hot and humid conditions and unplanned generation outages. That shortage condition lasted for 2 hours and 40 minutes and another hasn't occurred to date since. An analysis of the event was covered in detail in the Summer 2018 Quarterly Markets Report.[239]

Price-Responsive Demand *(commenced on June 1, 2018)*

FERC Order No. 745 (Demand-Response Compensation in Organized Wholesale Energy Markets) required organized wholesale energy markets to pay demand-response providers the market price for electric energy for reducing consumption below expected levels. In compliance with this order, demand response resources were fully integrated into the wholesale energy market on June 1, 2018, through a set of rules commonly referred to as Price-Responsive Demand (PRD). Demand response resources are also eligible to provide reserves and participate in the capacity market in the same manner as other supply-side resources. PRD allows demand response resources to submit demand reduction offers into the day-ahead and real-time energy markets. Demand resources are committed and dispatched in the energy market when economic, as well as designated to provide operating reserves, in a manner similar to traditional generation resources.

An analysis of the participation of PRD in the energy markets is covered in Section 3.6 of this report.

Energy Market Opportunity Costs *(implemented on December 1, 2018)*

This winter, energy offer reference levels began including an Energy Market Opportunity Cost (EMOC) adder for resources that maintain an oil inventory. The update was motivated by concerns that during sustained cold weather events generators would be unable to make energy supply offers that incorporate the opportunity costs associated with the depletion of their limited fuel stock. Such an event arose during the previous winter - 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.

ISO staff developed a mixed-integer programming model which produces the generator-specific EMOC numbers. For a given forecast of LMP and fuel prices, the model seeks to maximize a generator's net revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and operational characteristics. Opportunity costs produced by the model are available to participants an hour before the day-ahead market closes, allowing time for participants to update their offers.

Revisions to Operating Procedure 21: Energy Inventory Accounting and Actions during an Energy Emergency *(implemented for Winter 2018/19)*

In response to fuel availability concerns, particularly those experienced in January 2018, the ISO introduced a new energy forecasting and reporting framework. The ISO began publishing a 21-day

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[239] The report is available at https://www.iso-ne.com/static-assets/documents/2018/12/2018-summer-quarterly-markets-report.pdf

look-ahead energy forecast accounting for the inventories of oil, coal, natural gas, and other fuels at New England power plants, as well as anything that could limit their availability, such as emissions restrictions. The forecasts describe expected conditions, from normal to conditions requiring declaration of an energy alert or an energy emergency.

This operational energy forecast is designed to raise the awareness of resource owners and other market participants, government officials, and regulators when the region's power system may start running low on oil and other fuels. With sufficient advance notice, it's hoped that resource owners will evaluate their fuel supplies and take action to ensure they have enough fuel to operate or will lock down arrangements to have more fuel delivered in time.[240]

Retaining Resources for Fuel Security ("Chapter 2") *(effective from October 30, 2018)*

In May 2018, the ISO filed a petition for waiver of certain tariff provisions to allow for the retention of two retiring generators owned by Exelon Generation Company, LLC, Mystic Units 8 and 9, for the 2022/23 and 2023/24 winter periods in order to maintain fuel security.[241] In its July 2 Order, FERC rejected the petition for waiver. FERC directed the ISO to submit tariff revisions by August 31 to provide for short-term, cost-of-service agreements to address demonstrated fuel security concerns. It also directed the ISO to submit by July 1, 2019 (subsequently revised to October 15, 2019), permanent tariff revisions reflecting improvements to its market design to better address regional fuel security concerns (or to show cause as to why the tariff remains just and reasonable absent those filings).

In August 2018, the ISO filed revisions to establish, inter alia, generally-applicable provisions that allow for the retention of a resource for fuel security reasons for FCAs 13 through 15, and addressed how such retentions should be treated in the FCM; as price-takers. FERC accepted the proposed revisions with effect from October 30, 2018.

Competitive Auctions with Sponsored Policy Resources (CASPR) *(first auction conducted in February 2019 for FCA 13)*

New resources are subject to a Minimum Offer Price Rule (MOPR) which sets their floor price based on a competitive offer benchmark for a given resource's technology type. The MOPR mechanism is intended to prevent subsidies from depressing prices in the Forward Capacity Auction (FCA). However, many state-subsidized resources will be built regardless of obtaining a Capacity Supply Obligation (CSO). As a result, the region will purchase more capacity than it requires to meet its demand. Throughout 2017, the ISO worked with stakeholders to address this problem by developing a mechanism that would accommodate the entry of state-sponsored renewable resources into the Forward Capacity Market (FCM) over time and limit the extent to which those resources will artificially suppress capacity market prices. The result of this effort, Competitive Auctions with Sponsored Policy Resources (CASPR), is intended to achieve these objectives by adding a secondary auction stage to the FCA process. The primary auction function will not change, with state-sponsored resources subject to the MOPR. A secondary auction then follows in which resources that are willing to exit the capacity market will trade their CSO with new state-sponsored resources that did not receive a CSO in the primary auction and are no longer bound by the MOPR in the secondary auction.

[240] See ISO Newswire at http://isonewswire.com/updates/2018/11/2/iso-ne-is-implementing-near-term-changes-in-both-operations.html

[241] ISO New England, Petition for Waiver, Docket No. ER18-1509-000, (filed May 2, 2018).

The IMM has expressed concern about how effective CASPR will be in protecting competitive capacity market prices over time. Two potential effects, in particular, could exert downward pressure on capacity prices.

The first was recently addressed through an additional form of bid mitigation beginning with FCA 14. The rules changes address concerns about the incentive for retiring resources to submit FCA offers below their true cost in order to improve their chances of receiving a CSO in the primary auction which they then can shed for a severance payment in secondary auction.

The second effect concerns the impact of state-sponsored resources on clearing prices in capacity auctions after they have initially cleared in a substitution auction. When resources first clear as "new" resources in a capacity auction they become "existing" resources in subsequent auctions. Existing resources do not have MOPR mitigation applied to limit the minimum price they can offer into the primary auction. Consequently, because an existing state-sponsored resource is no longer subject to the MOPR, it can offer into subsequent FCAs at a price that reflects the subsidy and is below a competitive market level. Further, state-sponsored resources are often renewable resources with low variable cost of producing energy (e.g., wind and solar). The low variable cost of production results in higher net revenue from the electricity market and thus reduces the "missing money" payment that these resources would need from the capacity market to operate profitably from year to year. This positions state-sponsored resources to offer a lower bid price in the FCM in years subsequent to their first clearing via the CASPR mechanism, which can have the effect of reducing auction clearing prices over time. Those state-sponsored resources would not otherwise have had the opportunity to suppress the FCA clearing price because, with sufficiently high construction costs, they would not have cleared as new resources and they would not have subsequently become existing resources (where MOPR does not apply) in the FCM.

This "subsequent year" effect does have the potential to suppress capacity market prices, however, it is a byproduct of the decision to create a mechanism that allows such resources to enter the capacity market and become existing capacity resources. Applying a MOPR-type rule to existing state-sponsored resources could result in either removing the resources once they have cleared through CASPR, which undermines the purpose of CASPR, or could be inconsequential due to the low "missing money" requirement for state-sponsored resources once they are built.

In FCA 13, the substitution auctioned cleared 54 MW at a price of $0/kW-month. This means that a state-sponsored resource will receive $0/kW-month in FCA 13, and clear subsequent auctions as an existing capacity resource. The resource that shed 54 MW was a dual-fuel oil/gas-fired generator and will receive their full FCA 13 payment for that capacity. The resource will also be retired, partially or fully, from all New England markets starting June 1, 2022.

8.2 Major Design Changes in Development or Implementation for Future Years

The following market rule changes are either currently in the design phase or have been completely designed. The planned implementation date is in in future years.

Energy Security Solutions *(planned implementation in 2023 for the interim solution, unknown for the long-term solution)*

Interim solution for Winters 2023/2024 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).[242] 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 allow resources to sell up to 72 hours (3-days) of inventoried energy to be held during trigger conditions[243] 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. If a resource sells inventoried energy forward, it must either (i) maintain this amount of inventoried energy during each trigger condition or (ii) buy out of any shortfall at the spot rate, during the relevant winter month. 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 allows generators to reflect such revenue stream in their bidding strategies for FCA 14 and FCA 15.

Long-term market-based solution

The ISO and stakeholders are currently working on a long-term solution to address regional fuel security in its market design. At a conceptual level, the ISO is developing three design components[244]:

- a multi-day ahead market, which optimizes energy (including stored fuel energy) over a multi-day timeframe
- new ancillary services products in the day-ahead market that value flexibility of energy "on demand" to manage uncertainties in each operating day
- a seasonal forward market that provides asset owners with incentives to invest in supplemental arrangements for the winter period

Energy Market Offer Caps *(planned implementation date of October 1, 2019)*

In May 2017, the ISO filed proposed market rule changes to comply with FERC Order No. 831.[245] The Order addresses the potential issue, primarily when fuel is scarce, for energy market offers to reach and exceed the current $1,000/MWh energy market offer cap that is in place in the majority of organized energy markets. The Order is intended to improve energy market price

[242] ISO New England Inc., Docket No. ER19-1428-000; Inventoried Energy Program (filed March 25, 2019)

[243] A trigger condition occurs when the average of the daily high and low temperature is 17°For lower.

[244] See ISO New England presentation to the NEPOOL Markets Committee, entitled Energy Security Improvements: Market-based Approaches. Discussion of a market-based solution to improve energy security in the region, April 10, 2019. https://www.iso-ne.com/committees/markets/markets-committee/

[245] *ISO New England Inc. and New England Power Pool,* Market Rule 1 Revisions to Modify Energy Market Offer Caps in Compliance With Order No. 831; Docket No. ER17-1565-000 (filed on May 8, 2017)

formation by reducing the likelihood that offer caps will suppress LMPs below the marginal cost of production, while compensating resources for the costs they incur to serve load. This will enable RTOs/ISOs to dispatch the most efficient set of resources when short-run marginal costs exceed $1,000/MWh, by encouraging resources to offer supply to the market when it is most needed, and by reducing the potential for seams issues between RTO/ISO regions.

The Order requires RTOs/ISOs to cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer, and further imposes a hard cap of $2,000/MWh on incremental energy offers used in pricing calculations. In addition, there is a provision that allows a participant to request after-the-fact recovery of costs that it did not recover through the market either because it was precluded from doing so by the existing $1,000/MWh offer cap or because its offer was mitigated.

Annual Reconfiguration Transactions (ARTs) for Annual FCM Auctions (*will apply from the 2nd Annual Reconfiguration Auction for CCP 11, to be conducted in August 2019)*

In February 2018, the ISO filed rule changes to implement Annual Reconfiguration Transactions (ARTs) and remove CSO bilaterals from annual reconfiguration auctions.[246] Starting in FCA 11, zonal demand curves replaced fixed capacity requirements.[247] CSO bilaterals cannot be used in conjunction with zonal demand curves because they are allowed only when capacity is deemed fully substitutable. Within an import-constrained zone capacity becomes more valuable as total capacity declines. Conversely, capacity becomes less valuable as total capacity increases within an export-constrained zone.

The proposed ART mechanism provides price certainty to participants, addresses concerns with substitutability, and improves competition in the annual reconfiguration auctions. At a high level, ARTs are an agreement between two parties that meet a participant's desire for a fixed price transfer, while accounting for impacts to system reliability. ARTs are tied to the annual reconfiguration auction (ARA), since they are settled against auction outcomes. A major benefit of ARTs is their simplicity. Participants agree on:

1. The acquiring and transferring parties
2. The transaction amount
3. A set price and capacity zone to settle against

Increased participation and more efficient market outcomes in the ARAs are two anticipated improvements from replacing CSO bilaterals. Participants enter into an ART with the intent to participate in the ARA. Increased participation leads to more liquidity. More liquidity in turn decreases market concentration and the potential for market power.

[246] *ISO New England Inc. and New England Power Pool,* Order Accepting ART Revisions and FCM Market Enhancements, ER18-455-001, (filed February 28, 2018). https://www.iso-ne.com/static-assets/documents/2018/02/er18-455-000_2-28-18_order_accept_art_rev.pdf

[247] The MRI-based demand curves are structured to procure the most cost effective combination of capacity levels among the zones that meets the system's resource adequacy objective. The auction will clear capacity in a constrained zone based on the incremental value of capacity inside the zone, and will meet the resource adequacy objective by determining the most cost efficient mix of capacity from the various zones.

Enhanced Storage Participation *(requested effective date of April 1, 2019)*

In October 2018, the ISO filed proposed rule changes to enable emerging storage technologies to more fully participate in the New England markets and to comply with FERC Order 841.[248,249] The revisions are intended to allow emerging storage technologies to be dispatched in the real-time market in a manner that more fully recognizes their ability to transition continuously and rapidly between a charging state and a discharging state and that provides a means for their simultaneous participation in the energy, reserves, and regulation markets.

[248] *ISO New England Inc. and New England Power Pool;* Docket No. ER19-84-000; Enhanced Storage Participation Revisions (filed October 10, 2018). https://www.iso-ne.com/static-assets/documents/2018/10/er19-84-000_enhanced_storage_revisions.pdf

[249] See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule, 162 FERC ¶ 61,127 (February 15, 2018) ("Order No. 841").

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	NERC's *Real Power Balancing Control Performance Standard*
BAL-003	NERC's *Frequency Response and Frequency Bias Setting Standard*
bbl	barrel (unit of oil)
Bcf	billion cubic feet
Btu	British thermal unit
C4	market concentration of the four largest competitors
CC	combined cycle (generator)
CCP	capacity commitment period
CO_2	carbon dioxide
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DARD	dispatchable asset related demand
DDG	do-not-exceed dispatchable generators
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor

Acronyms and Abbreviations	Description
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GWh	gigawatt-hour
GW-month	gigawatt-month
HE	hour ending
HQ	Hydro-Québec
HQICCS	Hydro-Québec Installed Capacity Credit
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOLE	loss- of-load expectation
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MCL	maximum capacity limit
ME	State of Maine and Maine load zone

Acronyms and Abbreviations	Description
M/LCC 2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MRA	monthly reconfiguration auction
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NICR	net Installed Capacity Requirement
NNE	northern New England
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay for performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PURA	Public Utilities Regulatory Authority
Q	quarter
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price

Acronyms and Abbreviations	Description
RCPF	Reserve Constraint Penalty Factor
RGGI	Regional Greenhouse Gas Initiative
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RSI	Residual Supply Index
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
RTDR	real-time demand response
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts