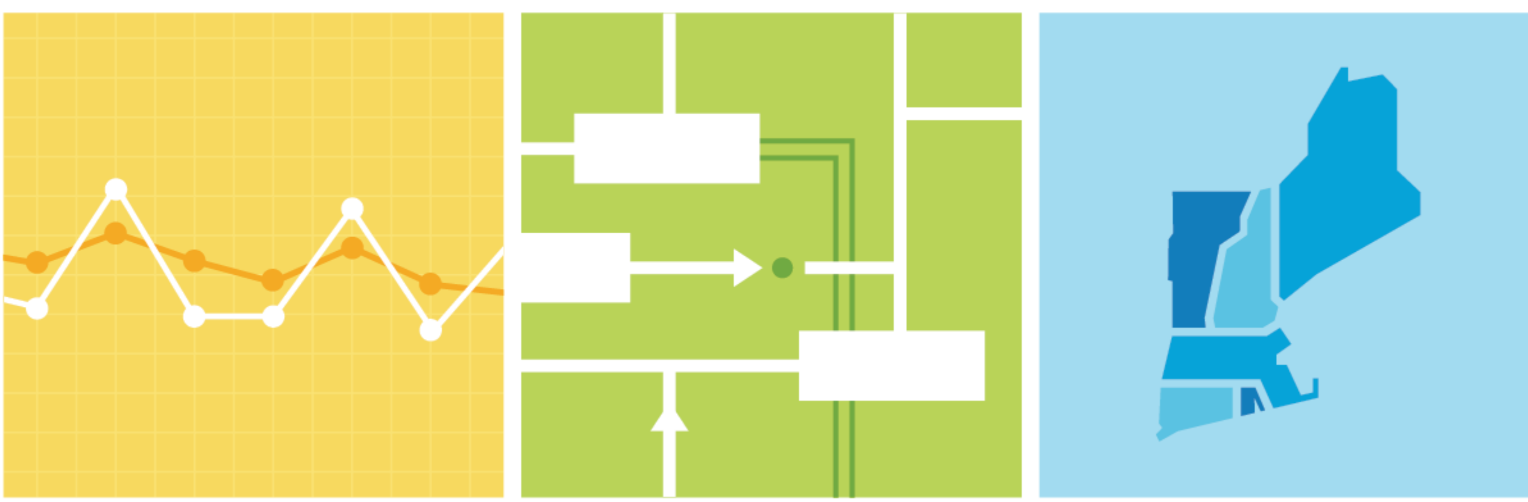
2017 Annual Markets Report

Internal Market Monitor

MAY 17, 2018

ISO-NE PUBLIC



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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 *2017 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2017. 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 2017. 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 2 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):

ICE Global markets in clear view

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

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

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Section 1
Executive Summary

The *2017 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 2017. 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 relative shortage of energy and reserves impacted price, and overall price-cost markups in the day-ahead energy market were within a reasonable range for a competitive market. For the fourth 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 2017, at $9.1 billion, was considerably higher than 2016, increasing by 20%, or by $1.5 billion. This increase was substantially due to higher capacity market costs associated with the eighth forward capacity auction (FCA 8), which took effect during the second half of 2017. Capacity costs increased by $1.1 billion, or by 93%, on 2016 costs. Up until FCA 8, capacity prices were relatively low and set administratively at the market floor prices due to surplus capacity conditions. Capacity costs represent an increasing share of overall wholesale costs (increasing from 15% in 2016 to 25% in 2017) and will increase further in 2018, to an estimated $3.5 billion, as higher capacity prices from FCA 9 take effect.

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. The market responded to lower clearing prices in FCA 12 by temporarily removing capacity. A total of 1,430 MW from 30 resources dynamically de-listed for a period of one year. Two dynamic de-list bids from Mystic 7 and 8, located in the NEMA/Boston load zone and SENE capacity zone, were rejected for reliability reasons. Their combined 1,278 MW was held in the auction, even though the dynamic de-list bid prices were above the auction clearing price.

Energy costs totaled $4.5 billion in 2017, up 9% on 2016, and accounted for the remaining $0.4 billion increase in overall wholesale costs. The increase in energy costs was driven by higher natural gas prices. Natural gas prices averaged $3.72/MMBtu, up 19% on 2016 prices.[4] The upward pressure of natural gas prices on energy costs was mitigated by lower wholesale electricity demand, particularly in the third quarter (Q3) of 2017.

The trend of declining wholesale electricity demand continued in 2017, down 2% or by an hourly average of 341MW, on 2016 demand. In 2017, Q3 demand was down by 8%, or by almost 1,280 MW on average per hour, compared to the prior year. The downward trend was driven primarily by

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

the increase in state-sponsored energy efficiency measures, and to a lesser but growing extent, the increase in behind-the-meter photovoltaic installations.

In March 2017, the ISO implemented fast-start pricing rules to better reflect the costs of operating fast-start resources through the real-time price and to strengthen performance incentives. Market pricing outcomes under fast-start pricing are as expected; real-time LMPs have better reflected the costs of committing fast-start resources. The changes have had the effect of increasing real-time LMPs, reducing uplift (or NCPC) payments and increasing operating reserve payments. Also, since fast-start pricing mechanics are not applied in the day-ahead market it is expected that higher real-time LMPs may increase the opportunity for virtual demand to converge day-ahead and real-time prices. Since the implementation of fast-start pricing, offered and cleared virtual demand bids increased.

During 2017, the ISO and stakeholders made significant progress in developing a mechanism designed to protect competitive capacity market pricing while accommodating the entry of state-sponsored renewable resources. The rules underpinning this initiative, known as Competitive Auctions with Sponsored Policy Resources (CASPR), were recently approved by FERC and will be implemented for FCA 13. The design will continue to rely on the minimum offer price rule (MOPR), with the intention of protecting competitive pricing in the primary auction. A new secondary auction will follow the running of the primary auction, in which the MOPR will not be applied. In the secondary auction resources that are willing to exit the capacity market will trade their CSO position with new state-sponsored resources that did not receive a CSO in the primary auction. Concern remains about how effective CASPR will be in protecting competitive capacity market prices over time and will need to be analyzed and monitored closely.

The FCM and the energy market exhibited competitive outcomes despite the 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 the market 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, a number of areas require further evaluation.

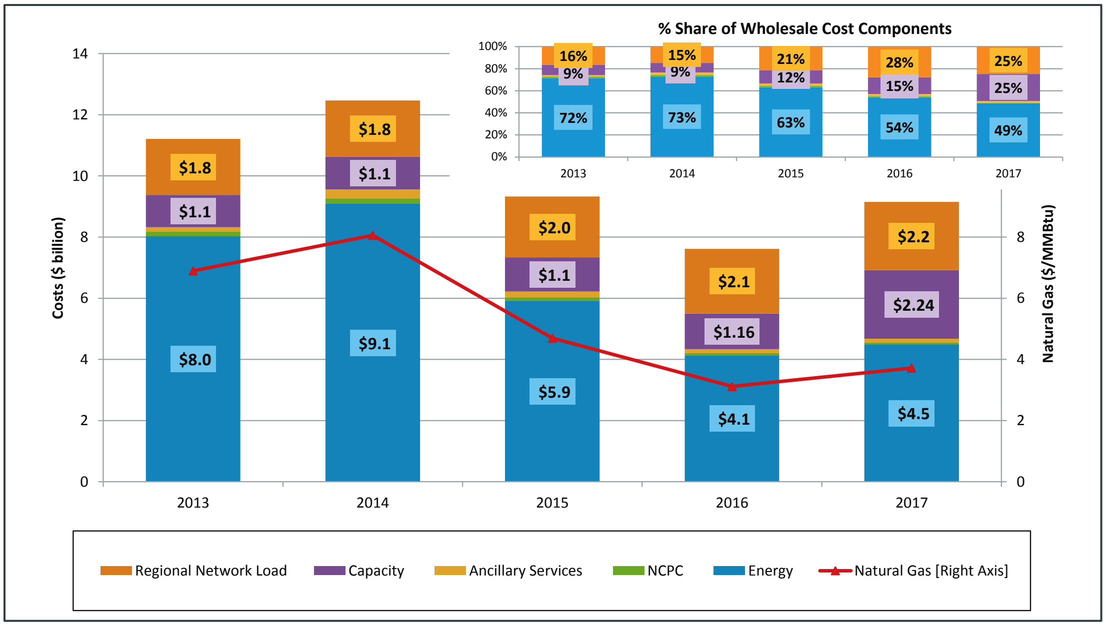
First, the forward reserve market does not currently have any active market power mitigation provisions and, as highlighted in this report, has structural market power issues. These issues are currently being evaluated. Second, the energy market has rules to identify and mitigate seller-side market power. In general, the real-time market has produced 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. There are energy supply portfolios that have structural market power in almost half of the hours in the real-time market. The potential impact of structural market power in the real-time market and the effectiveness of existing mitigation thresholds will be further evaluated this year.

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 2017, we have added an additional recommendation to address the current limitations of how multi-stage generators are modelled in the energy market. Currently, the rules do not accurately account for the constraints and costs of multi-stage generators, which can lead to potential price distortion and higher uplift payments.

1.1 Wholesale Cost of Electricity

In 2017, higher capacity market costs and natural gas prices resulted in higher total wholesale costs. The estimated cost of wholesale electricity was $9.1 billion, an increase of $1.5 billion, or 20%, compared with 2016 costs. The cost equates to $76/MWh of wholesale electricity demand, an increase of 23% on the average 2016 wholesale cost of $61/MWh. 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.[5] The percentage share of each cost component is shown in the inset graph.

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, dollar per MWh of load served, along with the percentage contribution of each category to the overall wholesale cost in 2017 is shown in parenthesis.

Energy ($4.5 billion, $37/MWh, 49%): Energy costs are a function of energy prices (the LMP) and wholesale electricity demand (megawatt hours, or MWh).[6]

- Day-ahead and real-time LMPs averaged $33.35 and $33.94/MWh, respectively (simple average). Compared with 2016, prices were up by between 12-17%, or by $3.58 to $4.99/MWh, in the day-ahead and real-time market, respectively.

[5] 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.

[6] MWh stands for megawatt-hours; MW stands for megawatts; and MMBtu stands for million British thermal units. The LMP presented here is the Hub LMP, a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace.

- 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.
- Natural gas prices continued to be the primary driver of LMPs. Prices averaged $3.72/MMBtu, representing an increase of 19%, or $0.61/MMBtu, compared with 2016. The upward pressure of gas prices on energy costs was partially offset by lower demand levels, particularly in the third quarter (Q3) of 2017.
- Demand (or real-time load) was at its lowest level in the past 18 years.[7] Demand was down by 2% in 2017, or by 341 MW per hour, compared to 2016. The largest reduction was observed in Q3, when demand was down by 8%, or by almost 1,280 MW on average per hour, compared to the prior year. The trend of declining load can be explained by three main factors: seasonal temperature differences year-over-year, the increase in energy efficiency programs, and the strong growth in behind-the-meter solar generation.

Regional Network Load Costs ($2.2 billion, $18/MWh, 25%): Regional Network Load (RNL) costs cover the use of transmission facilities, reliability, and certain administrative services. Costs increased by 5% compared to 2016. The regional transmission rate increased by approximately 8% in 2017 over the 2016 rate, moving from $104.10 kW/yr to $111.96 kW/yr.[8] The cost increase was the result of 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.

Capacity ($2.2 billion, $19/MWh, 25%): Capacity costs almost doubled in 2017 (increasing by 93% or $1.1 billion), in line with auction clearing prices. The overall share of capacity costs as a percentage of wholesale costs has increased from 15% in 2016 to 25% in 2017. June 2017 marked the beginning of the FCA 8 capacity commitment period (CCP), which had tighter system conditions due to a number of generator retirements. Capacity payments to existing resources outside of NEMA/Boston increased by 123%, from $3.15/kW-month in FCA 7 to $7.03/kW-month in FCA 8. Capacity payments to new and existing resources in NEMA/Boston are based on a price $15.00/kW-month. Capacity costs are estimated to increase even further in 2018, to about $3.5 billion, as higher prices from FCA 9 take effect.

NCPC ($0.1 billion, $0.4/MWh, 1%): Net Commitment Period Compensation costs, also known generically as "make-whole" or "uplift" payments, are the portion of production costs in the energy market not recovered through the LMP. NCPC payments decreased significantly in 2017 compared to 2016: $52 million in 2017 versus $73 million in 2016, a reduction of $21 million. The reduction was primarily driven by fewer reliability commitments in local areas, particularly in NEMA/Boston, and by impact of the fast-start pricing rules that were implemented in March 2017.

Ancillary Services ($0.1 billion, $1.1/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. Ancillary service costs, which include reserve payments, regulation payments, and winter reliability costs, totaled $128 million in 2017, a decrease of 2% compared to 2016.

[7] Demand data predating 2000 was not available to draw longer historical comparisons.

[8] The formula rate inputs for the regional transmission rate are updated annually with FERC by the New England Participating Transmission Owners on June 30th.

1.2 Overview of Supply and Demand Conditions

Key statistics that summarize 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

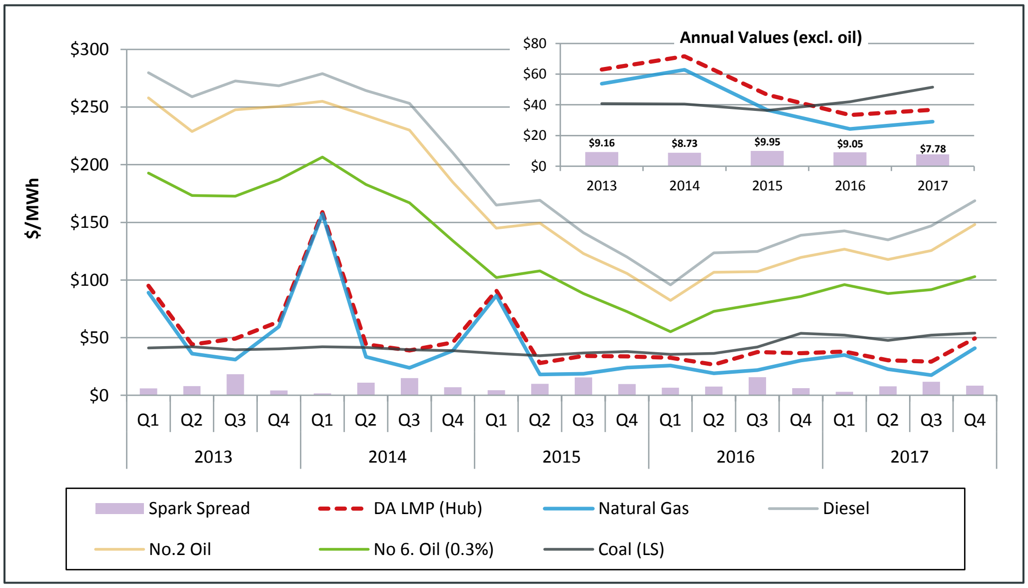
Statistic	2013	2014	2015	2016	2017	% Change 2017 to 2016
Demand (MW)						
Real-time Load (average hourly)	14,769	14,518	14,493	14,165	13,824	-2%
Weather-normalized real-time load (average hourly)[a]	14,584	14,511	14,358	14,111	13,775	-2%
Peak real-time load (MW)	27,379	24,443	24,437	25,596	23,968	-6%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	53.80	62.87	36.62	24.29	29.02	19%
Coal	40.76	40.45	36.34	41.97	51.57	23%
No.6 Oil	181.42	172.38	92.63	73.34	94.76	29%
Diesel	269.91	251.49	148.68	120.78	148.36	23%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	56.42	64.56	41.90	29.78	33.35	12%
Real-time (simple average)	56.06	63.32	41.00	28.94	33.94	17%
Day-ahead (load-weighted average)	59.71	69.26	45.03	31.74	35.23	11%
Real-time (load-weighted average)	60.27	68.58	44.64	31.56	36.16	15%
Estimated Wholesale Costs ($ billions)						
Energy	8.0	9.1	5.9	4.1	4.5	9%
Capacity	1.1	1.1	1.1	1.2	2.2	93%
Net Commitment Period Compensation	0.2	0.2	0.1	0.1	0.1	-29%
Ancillary Services	0.1	0.3	0.2	0.1	0.1	-3%
Regional Network Load Costs	1.8	1.8	2.0	2.1	2.2	5%
Total Wholesale Costs	**11.2**	**12.5**	**9.3**	**7.6**	**9.1**	**20%**
Fuel Mix (% of native New England Generation)						
Natural Gas	45%	43%	49%	49%	48%	-1%
Nuclear	33%	34%	30%	31%	31%	0%
Other[c]	6%	7%	7%	7%	7%	0%
Hydro	7%	8%	7%	7%	8%	1%
Coal	6%	5%	4%	2%	2%	-1%
Wind	2%	2%	2%	2%	3%	1%
Oil	1%	2%	2%	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 within +/- 1%

As can be seen from Table 1-1, costs for the major fuels increased significantly in 2017 and were the key driver of the increase in electricity prices. The supply side continues to be highly dependent on natural gas, accounting for almost half of the fuel mix.

Energy Market Supply Costs: The trend in quarterly estimated generation costs for each major fuel along with the day-ahead on-peak[9] LMP over the past five years is shown in Figure 1-2 below.[10] The inset graph shows annual values and excludes oil prices to better illustrate the long-term trend. The strong positive correlation between natural gas prices (blue line) and the LMP (dashed red line) is evident.

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



A year of relatively low volatility in quarterly natural gas and energy prices continued from 2016 into 2017. The average cost of a natural gas-fired generator was $29/MWh in 2017, compared to $24/MWh in 2016. The average natural gas cost ranged from $18/MWh in Q3 to $41/MWh in Q4 2017.

In Q1 2017, natural gas and energy prices were higher than in Q1 2016, but still well below 2013-2015 levels. In the past two winters average temperatures have been higher than the preceding three years. The average temperature in Q1 2017 was 32° F, compared to 34°F in 2016 and 24° F in 2015. Lower temperatures in March 2017 were the primary driver of the 35% increase in gas prices in Q1 year-over-year (from $3.32 in 2016 to $4.48/MMBtu in 2017). Similarly, cold weather and high gas prices in December 2017 drove the 36% increase in Q4 prices (from $3.88 in 2016 to $5.26/MMBtu 2017). While this is high in percentage terms, the change in terms of dollars per MMBtu was not as extreme as prior years.

Spark spreads (the difference between the LMP and the estimated cost of a gas-fired generator) were highest again during Q3 2017, when more expensive, or less efficient, generators are dispatched to meet higher system demand. However, spark spreads were down overall in 2017, as were market implied heat rates[11], consistent with lower average and peak demand levels.

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

[10] 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.

[11] The market implied heat rate is the breakeven heat rate for a gas-fired generator. A lower implied heat rates infers a lower gross margin, or a lower spark spread. It equals LMP divided by the gas price.

The difference between average generation costs for natural gas-fired generators and competing fuels (coal and oil) was relatively large in 2017, and increased since 2016. Coal prices increased year-over-year by 23%. According to a recent article from the Energy Information Administration, the increase was driven by strong domestic and international coal demand.[12] Oil prices also increased, due to actions by OPEC and non-OPEC countries leading to a decrease in international crude oil production.[13] No. 6 oil prices rose 29% from 2016 levels. On average, coal and No.6 oil were higher than natural gas by $23 and $66/MWh, respectively. Coal and oil, together, continued to make up only about 3% of the native generation mix.

Emissions costs are not included in the generation cost estimates in Figure 1-2 above, but do impact generation costs. 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 2017, CO_2 prices declined in the first half of the year and rebounded in the second half, resulting in an overall reduction of about 30%. The continued reduction (from 2016) in the first half of the year was in the midst of continued uncertainty about the Clean Power Plan. However, on August 23, 2017, the RGGI review led to a 30% reduction to the cap by 2030, relative to 2020 levels. In reaction to the news, the spot market price for RGGI allowances increased nearly 40% from $3.30/short to $4.60/short ton.[14] In 2017, the estimated contribution of CO_2 costs to the variable fuel costs of generation for gas, coal and No.6 oil was $1.64, $3.69 and $3.28/MWh, respectively, ranging from 3% to 7% of short-run costs.

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 FCM is a critical component of a developer's decision to move forward with a new project. 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. The revenue required from the capacity market is often referred to as the net cost of new entry, or Net CONE.

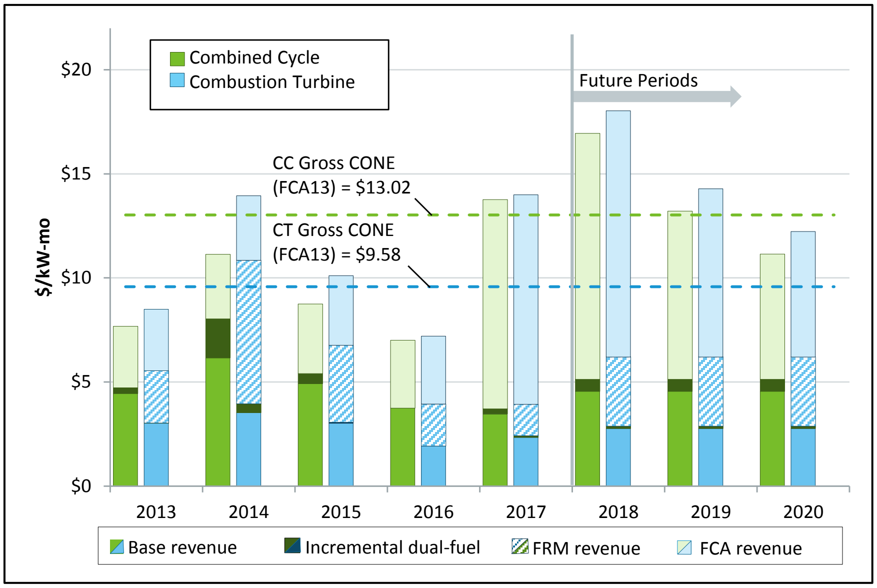
A simulation analysis was conducted to assess if historical energy and capacity prices are sufficient to cover CONE. The results are presented in Figure 1-3 below. Each stacked bar represents revenue components by generator type and year. The analysis enables a comparison of total expected net revenue to the estimated CONE for combined cycle (CC) and combustion turbine (CT) resources. If the height of a stacked bar rises above the relevant CONE estimate, overall market revenues are sufficient to recover total costs.

[12] US Energy Information Administration. *U.S. Coal production, exports, and prices increased in 2017.* https://www.eia.gov/todayinenergy/detail.php?id=34992

[13] US Energy Information Administration. *Crude oil prices increased in 2017, and Brent-WTI spread widened* Washington, DC: US Department of Energy, January, 2018. https://www.eia.gov/todayinenergy/detail.php?id=34372

[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/Press-Releases/2017_08_23_Announcement_Proposed_Program_Changes.pdf

Figure 1-3: Estimated Net Revenue from 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.

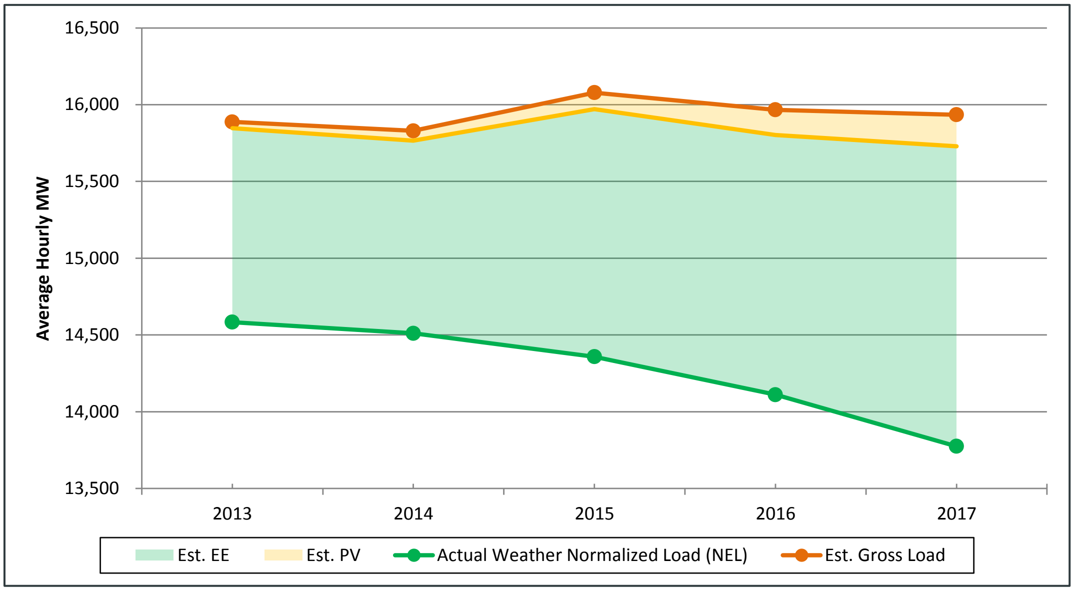
The results indicate that prior to 2017 capacity prices were generally too low to incent investment in new gas-fired generation because the system was long on capacity. For 2017 onward, the situation changed with generation retirements moving the system into a state where it is not long on installed 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.[15]

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, or "NEL", averaged 13,824 MW per hour in 2017, down 2% on 2016, and was at its lowest level of at least 18 years. The estimated impact of energy efficiencies and behind–the-meter photovoltaic generation on wholesale demand over the past five years is shown in Figure 1-4 below. NEL is shown on a weather-normalized basis.[16]

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

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

Figure 1-4: Net Wholesale Load and Impact of Energy Efficiency and Photovoltaic Generation



Energy efficiency has had the largest impact of the three factors; the average hourly reduction has grown from 1,100 MW in 2013 to 1,900 MW in 2017. Behind-the-meter solar generation has had less of an impact and, on average, reduced load by an estimated 200 MW per hour in 2017.

Operating Reserve Requirement: The bulk power system needs reserve capacity in order to respond to contingencies, such as those caused by unexpected outages. Operating reserves are provided by the unloaded capacity of generators, either online or offline, which can deliver energy within 10 or 30 minutes. The ISO procures both system-wide reserve, and local reserve for import-constrained areas. The system reserve requirement has been relatively constant over the past four years, with a total ten-minute reserve requirement of about 1,718 MW and total thirty-minute reserve requirement of about 2,534 MW in 2017.

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.

New England was a net importer of power in 2017, with net imports meeting about 2,300 MW on average each hour, or 17% of total native electricity demand. Net interchange with neighboring balancing authority areas in the real-time market has been fairly consistent over the past four years, meeting between 15% to 17% of demand.

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 almost always flow. About 80% of day-ahead transactions across the Canadian interfaces were fixed-priced in 2017. In real-time the percentage increases to 84%.

Real-time imports and exports across the New York North interface are subject to the Coordinated Transaction Scheduling (CTS) rules, which went into effect in December 2015. The CTS design is intended to improve the frequency with which power moves from the lower- to higher-cost region and increase the utilization of interface transfer capability to better converge prices between the regions.

Overall, the bids submitted at New York North in 2017 allowed power to flow consistent with forecasted price differences 68% of the time – an improvement from 63% in 2016. However, due to price forecast error in the CTS clearing process, power only flowed in the correct direction 61% of the time (compared with 56% in 2016) based on actual price differences.

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. There continues to be a consistent bias[17] in the ISOs' (ISO-NE and the New York ISO) internal price forecasts which may reduce the effectiveness of CTS. CTS price forecast accuracy was worse in 2017 than in 2016. In 2017, the average ISO-NE forecast error rose by $0.54, from $0.80 to $1.34.[18] Meanwhile, the average NYISO forecast error improved by $0.50, from -$1.58 to -$1.08. The resulting average price spread forecast error in 2017 was $2.42, slightly worse than $2.38 in 2016.[19] Biases in ISO-NE and NYISO forecasts continue to be in opposite directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. Further, participants who submit competitive bids to profit from price differences across the interface will face a non-trivial risk of settlement losses as a result of forecast errors. We recommend that the ISO assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved.

The ability to schedule real-time power efficiently under the CTS design is also dependent on the bids submitted by market participants. In 2017 there was a large increase in price-sensitive export bids, compared with 2016. This behavioral change, on average, provided the CTS process with an aggregate transaction curve that allowed the direction of flows to be more consistent with price differences. In 2017, on average, market participants were willing to bring energy into New England when New England prices were at least $2 higher. In 2016, market participants, as a whole, required a much larger price spread, around $25/MWh.

Capacity Market Supply and Demand: As with energy prices, there is also a strong link between capacity prices and natural gas-fired generators, which accounted for 86% (about 4,600 MW) of new generation additions since FCA 2. 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 87% of total capacity (about 29,400 MW), with the remainder comprising import (4% or about 1,200 MW) and demand response (9% or about 3,040 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.

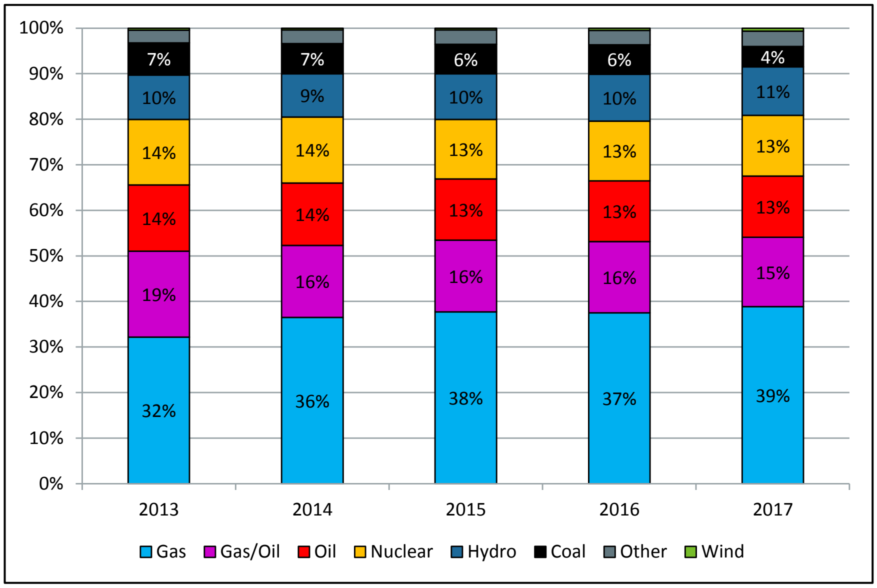
[17] The term "bias" here relates to attributes of the modelling and mechanics of CTS that result in measureable differences between forecast and actual outcomes. It is not intended to refer to human-driven bias.

[18] Forecast error is: Forecast minus Actual.

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

[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 units 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 and gas/oil dual-fuel generators has increased slowly over the past few years with the retirement of generators of other fuel types. Combined, gas and gas/oil dual-fuel generators accounted for 54% of total average generation capacity. Coal generation had the largest year-over-year decrease due to the retirement of Brayton Point in June 2017. Coal accounted for 1,350 MW in 2017, down from 2,000 MW in the previous four years. Similar to 2016, in 2017 nuclear generation accounted for 4,000 MW (13%) of the capacity fuel mix. The retirement of the Pilgrim nuclear facility (about 690 MW) in 2019 will reduce nuclear capacity and energy further.

Demand: The system installed capacity requirement (NICR) has been declining slightly over the past three FCAs, ranging from 34,151 MW in FCA 10 (for delivery in the capacity commitment period 2019/20) to 33,725 MW in the most recent auction, FCA 12.[21] NICR in FCA 12 value was roughly 350 MW lower than Net ICR for FCA 11. A primary driver for the reduction was changes to the ISO's behind-the-meter solar photovoltaic forecast methodology.[22] In the last two auctions, two zones (in addition to the rest-of system) have been modelled: the Southeastern New England (SENE) zone as a potential import-constrained zone and the Northern New England (NNE) as a potential export-constrained zone.[23] However, the import and export limits did not bind for either zone and therefore there was no separation from the rest-of-pool price.

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

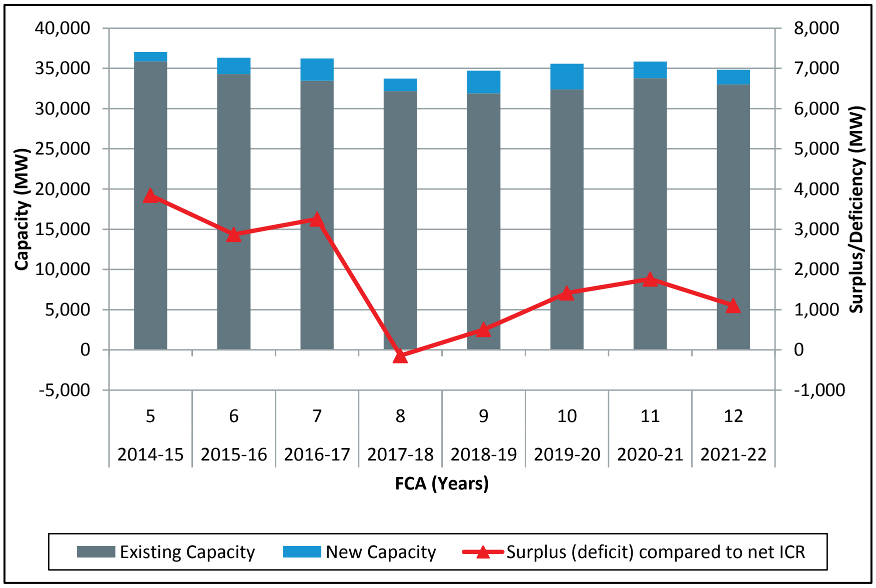
[21] The Net Installed Capacity Requirement (NICR) is the amount of capacity (MW) needed to meet the region's reliability requirements (after accounting for tie benefits with Hydro-Quebec). Due to transmission limitations there are also local sourcing requirements (LSR) for import-constrained areas and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

[22] While energy efficiency (EE) has been the biggest driver of lower wholesale energy demand, it participates on the supply side in the capacity market and therefore has little to no impact on capacity demand (NICR).

[23] The SENE capacity zone includes the NEMA/Boston, Southeastern Massachusetts, and Rhode Island load zones. The NNE export-constrained zone comprises the Maine, New Hampshire, and Vermont load zones.

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 5 through FCA 12



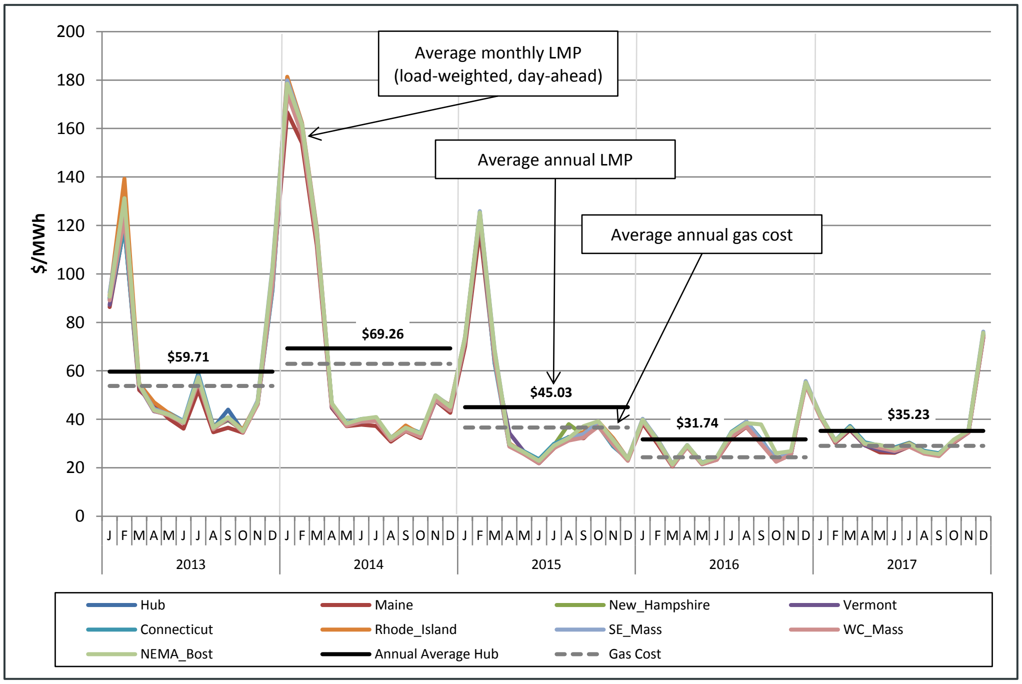
Following resource retirements of 2,700 MW in FCA 8 (and an increase in NICR), the surplus capacity in FCA 7 of over 3,000 MW was quickly eroded. However, higher clearing prices brought new capacity to the market in the three subsequent auctions; in FCA 9 -11, 4,100 MW of new generation and demand response resources cleared. 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, primarily due to one-year dynamic delists totaling 1,200 MW, bringing the surplus of capacity above NICR down to about 1,100 MW.

1.3 Day-Ahead and Real-Time Energy Markets

Prices: Price differences among the load zones were relatively small in 2017, reflecting modest levels of both marginal losses and congestion. The average absolute difference between the Hub and load zone prices was $0.23/MWh in the day-ahead energy market and $0.71/MWh in the real-time energy market – a difference of approximately 0.7-2.1%.

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 month, but not by load zone. From 2013 through 2015 constraints on the natural gas system resulted in large price spikes in natural gas and electricity prices in the months of January and February. Extreme pricing did not occur in Q1 over the past two years. The highest prices in 2017 were in December, with day-ahead (load-weighted) prices of $75 and real-time prices of $84/MWh. This was driven by extremely cold weather and high natural gas prices of up to $28/MMBtu towards the end of the month.

On average, electricity prices in the day-ahead and real-time markets were relatively close, with an average real-time price premium of $0.93/MWh in 2017, a reversal of the day-ahead premium in 2016 of $0.18/MWh. The average annual real-time premium was driven by the aforementioned premium in December.

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. As a result, only 20% to 30% 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. Cleared virtual transactions declined from over 2,000 MW per hour in 2008 and 2009 to less than 500 MW per hour in 2013 through 2016, but increased to about 800 MW in 2017. In 2017, virtual transactions set the LMP in the day-ahead market during 50% of pricing intervals, a significant increase compared to the average of about 32% in the previous four years. However, it is important to note that most of this increase is due to price-setting in local export-constrained areas of the system. Virtual transactions set price for the whole system in 10% of hours in 2017. The increase in virtual supply is largely attributable to virtual supply clearing in the expectation of lower real-time prices in areas of the system with higher levels of wind generation. The activity coincides with the implementation of the Do-Not-Exceed (DNE) dispatch rules in May 2016, which incorporated intermittent wind and hydro generation into the economic scheduling and pricing process. The increase in virtual demand activity in 2017 coincides with the implementation of the fast-start pricing rules. It reflects participant expectations of higher prices in the real-time market compared to the day-ahead market, since the fast-start pricing mechanics (and their upward impact on LMPs) only apply to the real-time market.

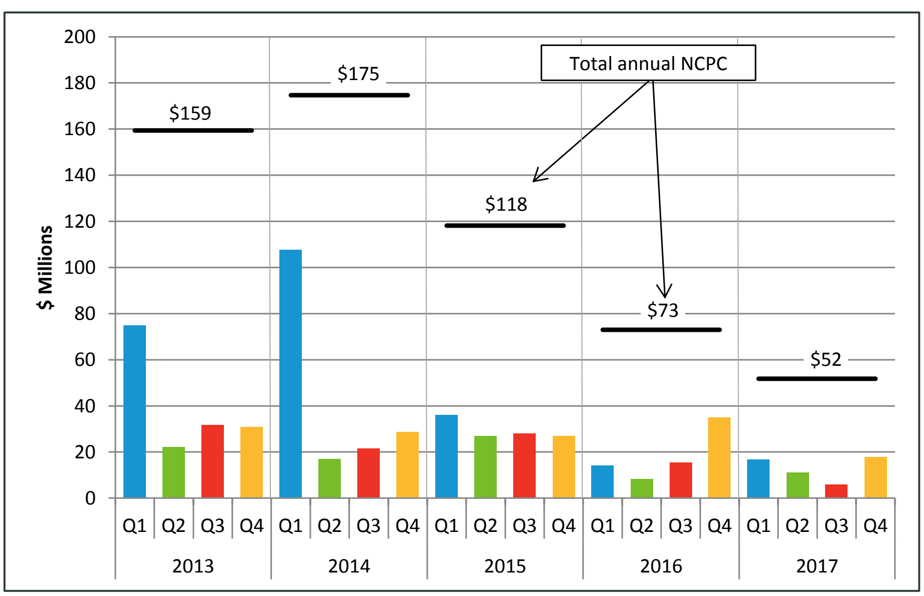
The relatively low volume of cleared virtual transactions, coupled with the high percentage of time these transactions set the market clearing price in the day-ahead market, is an indicator of the low volume of price-sensitive offers from other (non-virtual) supply sources. Generators set price only 35% of the time in the day-ahead market 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 64%. There was a noticeable increase in the number of intervals during which wind generators set prices, increasing from under 4% in 2016 to 19% in 2017. This is due to the DNE market rules changes referenced above. Similar to a large amount of virtual supply, it is important to note that wind predominantly sets price in small local export-constrained areas of the system, as opposed to setting price for large parts of the system. Though wind was marginal 19% of the time in 2017, it was generally marginal in a very local congested area and did not directly impact system price. At the system level, wind was the marginal fuel type less than 1% of the time.

The fast-start pricing rules also increased the amount of generation capable of setting price by an average of 200MW per hour, and by as much as about 470 MW in peak hours. This is as a result of relaxing the economic minimum limit of fast-start generators to zero in the pricing process.

Net Commitment Period Compensation (NCPC): NCPC payments decreased significantly in 2017 compared with 2016, falling to $52 million from $73 million (a reduction of almost 30%). NCPC payments represented 1.2% of total energy payments in 2017, down from the previous four years which ranged from 1.8-2.0%. 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



There were two primary drivers behind the decrease in NCPC. First, there were fewer local reliability commitments in NEMA/Boston due to progress of the Greater Boston Reliability project, which increased the transfer capability of the Boston import interface. Local second-contingency protection resource ("LSCPR") NCPC payments fell by $18.6 million (from $31.1 to $12.5 million) between 2016 and 2017. Second, the fast-start pricing rule changes, which took effect in March 2017, had the intended effect of increasing real-time LMPs and reducing NCPC. Overall, we estimate that NCPC was reduced by $11.9 million in 2017 as a result of fast-start pricing.

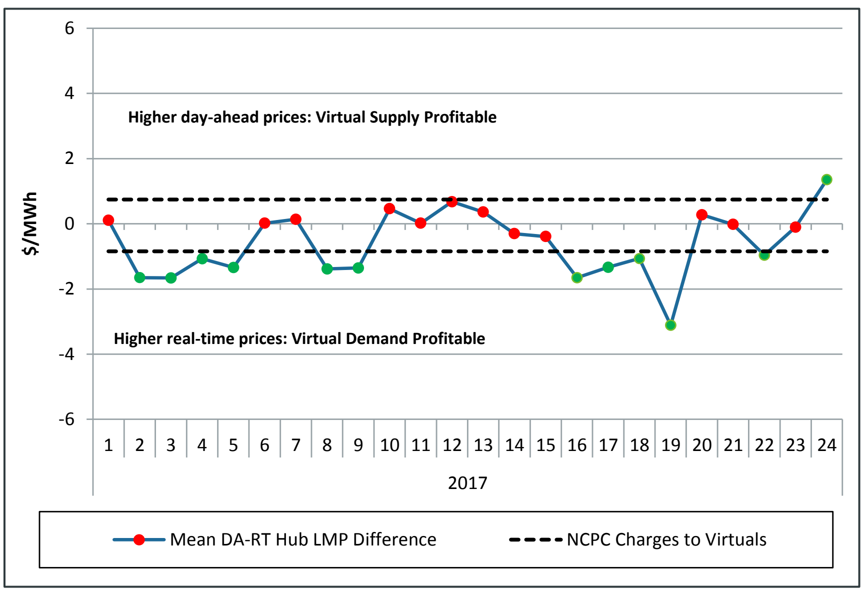
Without these factors there would likely have been an increase in 2017 NCPC payments, consistent with the increase in overall energy and fuel prices.

Virtual Transactions: Although there had been a general decline in virtual transactions since 2008, a combination of lower NCPC charges and market rule changes, namely DNE and fast-start pricing, resulted in an increased virtual trading activity in 2017. Virtual transaction volumes were 71% higher than in 2016. The volume increase is expected, as the market rule changes 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 there continues to be opportunities for virtual transactions to profit from hourly differences between day-ahead and real-time prices, the allocation of NCPC limits this opportunity. In 2017 the average per-MW real-time NCPC charge rate was $0.74/MW, down from $1.25 in 2016 and from $2.74 in 2015 due to the lower NCPC payments to generators as discussed above.

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. This is illustrated in Figure 1-9 below, which shows the average (mean) difference between the day-ahead and real-time Hub price by time of day during 2017. The dashed black lines correspond to the average NCPC deviation charges for incremental offers and decremental bids. Where the blue line falls within the dashed-black lines (red dots), it is not profitable to clear virtual supply or demand, on average, as NCPC charges are greater than the day-ahead to real-time price difference.

Figure 1-9: Day-Ahead to Real-Time Price Differences and NCPC Charges, 2017



The graph shows that, on average, in some hours it is not profitable for a virtual participant to help converge prices. For example, in hours ending (HE) 10 through 15, the average gross profit to be made from a virtual bid is less than the NCPC costs it would be charged. While a participant will not know in advance what the allocated NCPC will be, this expectation of a loss (or a higher possibility of a loss) diminishes the incentive for a virtual participant to arbitrage these price differences.

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.

Financial Transmission Rights: The traded volumes and prices in the FTR market have been declining in recent years as the amount of congestion declined due to new transmission investments. In 2017, the total profit to FTR holders was $13.5 million, which was a 54% increase from 2016. FTRs were fully funded in 2017, meaning the congestion revenue fund was sufficient to cover FTR positions.

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 protect the market from the potential exercise of market power.

The following metrics were calculated for the real-time energy market:[24]

- *C4 for supply-side participants*
  The C4 value expresses the percentage of real-time supply controlled by the four largest companies. In 2017, the C4 value was 48%, a slight increase compared to 43% in 2016. The top four suppliers were the same in 2016 and 2017, and a large driver of the increase was from one of the four largest suppliers controlling four additional 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 2017 was 52%, similar to 2016. 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.

- *Residual Supply Index (RSI) and Pivotal Supplier Test (PST)*[25]
  Results from the RSI and pivotal supplier analysis for 2017 indicate that there have been supply portfolios with market power in about 58% of hours. This represents a reduction in

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

[25] 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.

structural competitiveness compared to 2016, which can partially be explained by the reduced level of available supply observed in year 2017.

In the absence of effective mitigation measures, participants may have the ability to unilaterally take action that would increase prices above competitive levels. While 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, particularly for pivotal supplier mitigation.

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.[26] In a perfectly competitive market, all 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 results show that competition among suppliers limited their ability to increase price by submitting offers above estimates of their marginal cost. For 2017, the Lerner Index for the day-ahead energy market was 4.9%. This indicates that offers above marginal cost increased the simulated day-ahead energy market price by less than 5%. These results are consistent with previous years and within an acceptable range given modeling and estimation error.

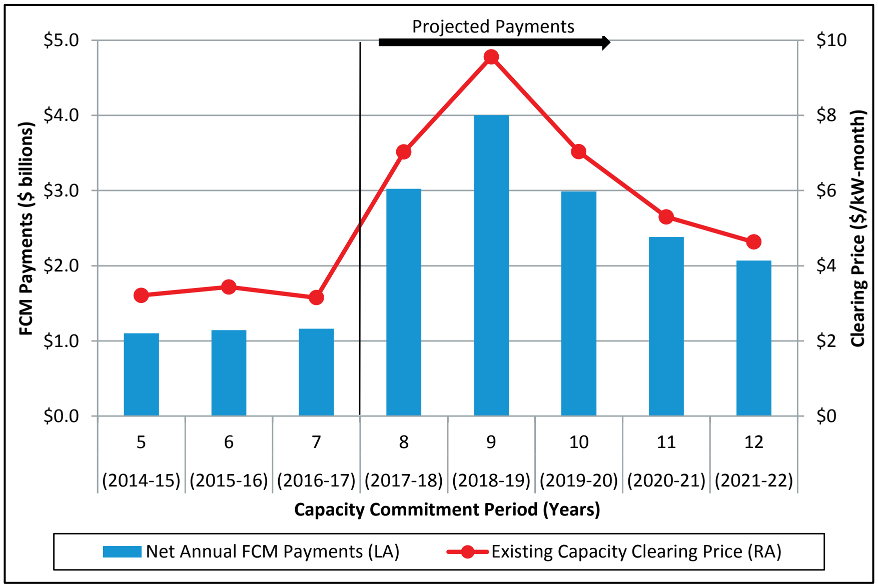
1.4 Forward Capacity Market (FCM)

FCM Prices and Payments: Rest-of-Pool clearing prices along with actual and projected payments from the fifth capacity commitment period (CCP 5) through CCP 12 are shown in Figure 1-10 below.[27]

[26] 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.

[27] Payments for future periods, CCP 8 through CCP 12, have been estimated as: $FCA\ Clearing\ Price\ \times Cleared\ MW\ \times 12$ for each resource.

Figure 1-10: FCM Payments by Capacity 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 volatility and delivered efficient price signals to maintain the region's long-run reliability criteria.

The system was relatively long on capacity until *FCA 7*, with prices clearing at an administrative floor price averaging $3.26/kW-month. Despite the decline in the rest-of-pool clearing price in *FCA 7*, payments increased due to higher zonal prices in NEMA/Boston due to the auction falling short of the local sourcing requirement.[28]

Capacity payments are expected to more than double 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 is expected to result 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 led to increased projected payments in *CCP 9* ($4 billion) compared to *CCP 8* ($3 billion).

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 declined. System-wide clearing prices fell from $7.03/kW-month in *FCA 10* and $5.30/kW-month in *FCA 11*, to $4.63/kW-month the most recent auction, *FCA 12***.** Lower clearing prices are expected to cause a 48% decrease in projected payments, from a high of $4 billion in *CCP 9* down to $2.1 billion in *CCP 12*.

In FCA 12, the auction fell below the dynamic de-list bid threshold for the second consecutive auction. The large amount of capacity that was dynamically bid below the threshold, totaling 2,772

[28] Prices in NEMA/Boston were $14.99 and $6.66/kW-month for new and resources and existing resources, respectively.

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

MW, required reliability reviews by the ISO. Two dynamic de-list bids, from Mystic 7 and 8, were rejected for reliability reasons in the NEMA/Boston load zone, which is located in the SENE capacity zone. These two resources—with a combined 1,278 MW of capacity—submitted dynamic de-list bids that were above the clearing price and were then rejected due to the ISO's determination that the resources needed to be retained for reliability. After accounting for the two rejected bids, a total of 1,430 MW from 30 resources were able to dynamically de-list. Over 1,200 MW of the dynamic de-lists were from natural gas resources.

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).[30] The results of these two complementary measures indicate that the New England capacity market can be structurally uncompetitive at both the zonal and system levels. The extent of structural competitiveness has fluctuated widely across capacity zones over the last five auctions as the 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 12) no pivotal supplier submitted a de-list bid, which is the mechanism a supplier may use when it wants to attempt to withdraw capacity in an auction.

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), regulation and the winter reliability program. The cost of these programs totaled $128 million in 2017, down by 2% from 2016 costs.

Real-time Reserves: The implementation of the fast-start pricing rules had the expected impact of increasing the magnitude and frequency of operating reserve prices and increasing payments. Fast-start pricing more accurately reflects the cost of operating higher cost fast-start generators and, on average, has increased the price of energy.[31] Because the price of 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.

Total real-time operating reserve payments increased by 75% from $20.5 million in 2016 to $35.8 million in 2017. Without fast-start pricing, we estimate that real-time reserve payments would have been approximately $13 million in 2017. The largest increase was to the spinning reserve product, which had 1,440 hours of non-zero pricing at an average price of $18/MWh in 2017.

Forward Reserves: Costs associated with the Forward Reserve Market (FRM) totaled about $40 million in 2017, down by 25% on 2016 costs, consistent with auction clearing prices. In general, auction clearing prices declined in 2017 relative to 2016 for the respective summer and winter

[30] Both metrics include three important assumptions as calculated: 1) respect system constraints such as capacity transfer limits, 2) take into account the affiliations between suppliers to accurately reflect all the capacity resources under the supplier's control, and 3) consider only existing resources due to an inability to predict intra-auction new supply behavior.

[31] 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

periods despite an increase in system-wide requirements. Reduced FRM offer prices in 2017 explain the reduction in auction clearing prices. However, for zonal pricing, there have been four instances of significant price separation during the five-year period. In the summer periods for 2015, 2016 and 2017 and the winter period for 2017-18, 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 2017-18 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 2013 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. Additional analysis is being undertaken to determine if the presence of pivotal suppliers has resulted in uncompetitive prices.

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 $29.7 million in 2017, a 12% increase from the $26.5 million in 2016. The increase in payments reflects three factors: 1) an increase in the requirement in 2017 relative to 2016, as the implementation of NERC standard BAL-003 (Frequency Response and Frequency Bias Setting) for the full year resulted in an additional 7% increase in the average regulation capacity requirement for 2017, 2) higher energy market prices increased regulation market opportunity costs and payments, and 3) an increase in regulation service, leading to an overall increase in service 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 about $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. 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 will end 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 '17 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 planned implementation date for a new methodology for determining demand-resource baselines is June 1, 2018, at which time new market rules will become 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 after it is implemented.	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
Treatment of multi-stage generation Due to the ISO's current modeling limitations, multi-stage generator	New recommendation from analysis	Medium

Recommendations	Status as of the AMR '17 Publication Date	Priority Ranking
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 modelling capability* – More dynamic approach to modelling operational constraints and costs of multiple configurations	presented in the recent Fall 2017 Quarterly Markets Report. Not in the scope of the ISO's current work plan.	
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
Limited energy generator rules: The ISO modify the market rules as necessary when EMOF is introduced 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

[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 units in a single turbine configuration when that 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.

Section 2
Overall Market Conditions

This section provides an overview of the key trends in wholesale market outcomes over the past five years (2013 through 2017). 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 2017, the total estimated wholesale market cost of electricity was $9.1 billion, an increase of about 20% compared to $7.6 billion in 2016.[35] This equates to $76/MWh of wholesale electricity demand served, an increase of 23% on the average 2016 wholesale cost of $61/MWh. This increase was substantially due to higher capacity market costs associated with the eighth forward capacity auction (FCA 8), which took effect during the second half of 2017. Capacity costs increased by $1.1 billion, or by 93% on 2016 costs. Energy costs totaled $4.5 billion, up 9% on 2016, and accounted for the remaining $0.4 billion increase in overall wholesale costs. The increase in energy costs was driven by higher natural gas prices. The wholesale cost estimate is made up of three general categories: energy, capacity and transmission.

The first general category, energy, includes costs to load from the energy and reserves markets. Energy and reserves markets can be further broken down to energy (associated with Locational Marginal Prices or "LMPs"), Net Commitment Period Compensation ("NCPC", also called uplift payments) and Ancillary Services (operating reserve for contingencies, regulating reserve and the winter reliability program) costs. This category comprised about 49% of total wholesale costs in 2017.

The second category, capacity, reflects the cost to attract and retain sufficient capacity to meet energy and ancillary service requirements. The capacity category represented about 25% of the total wholesale cost.

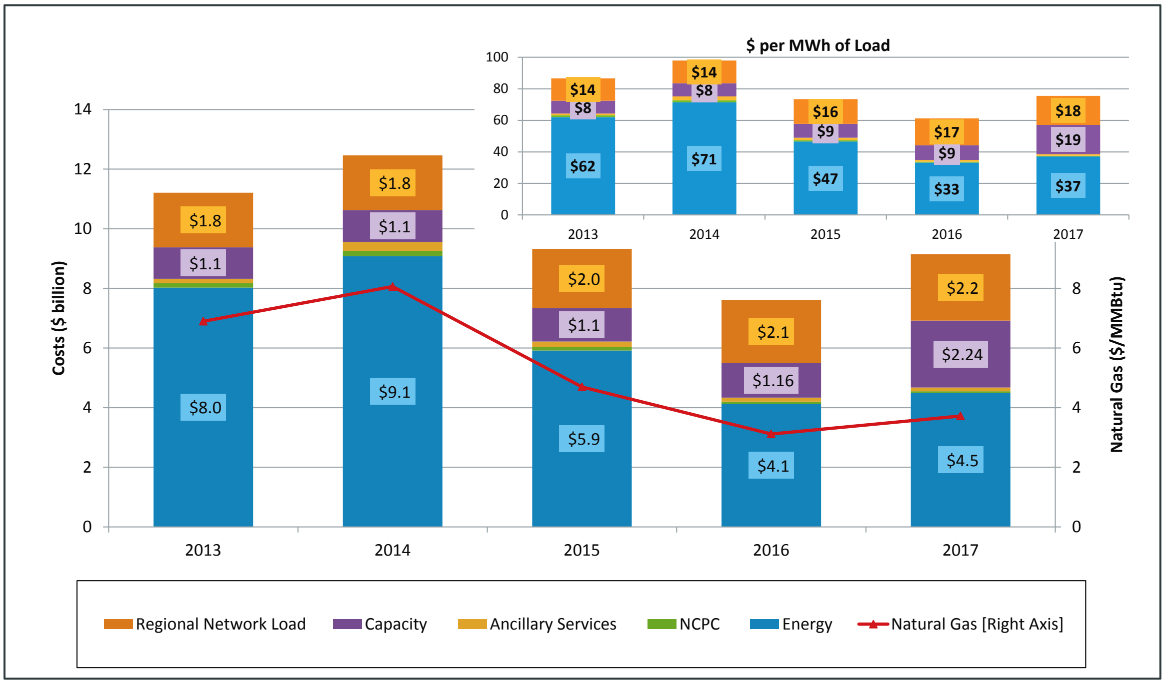
The third category, transmission, includes transmission owners' recovery of infrastructure investments, maintenance, operating and reliability costs. These costs are also referred to as Regional Network Load (RNL) costs and represented approximately 24% of total wholesale costs. [36]

The estimated wholesale electricity cost for each year by category, along with average natural gas prices, is shown in Figure 2-1 below. The percentage share of each cost component is shown in the inset graph. Natural gas prices are the primary input to electricity production and thus a key driver of energy, ancillary services and NCPC costs.

[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. Transmission network costs, known as Regional Network Load (RNL) costs, are also included in the estimate of annual wholesale costs.

[36] RNL, or Open Access Transmission Tariff (OATT), costs are associated with providing regional network service (RNS) and other services to transmission customers that collectively provide for the use of transmission facilities, reliability, and certain administrative services. Of the three costs categories included in RNL (infrastructure, reliability and administrative), infrastructure costs account for over 90%. The OATT governs the allocation of these costs, which are billed according to a transmission customer's hourly load at the time of the peak load of its local transmission network.

Figure 2-1: Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices[37]



The relationship between natural gas prices and energy costs is apparent in Figure 2-1, with annual energy costs and gas prices moving in the same direction. Natural gas prices were 19% higher in 2017 compared to the previous year, while energy costs increased by 9%.

Energy costs were $4.5 billion (or 37/MWh) in 2017, compared to $4.1 billion ($33/MWh) in 2016. to 2016, there were *increases* in energy costs in three quarters of the year in 2017. Combined, energy costs in Q1, Q2 and Q4 were 25% higher in 2017 ($3.5 versus $2.8 billion), while gas prices were 31% higher ($4.21 versus $2.58/MMBtu). The upward pressure on energy costs from higher natural gas prices during these three quarters was mitigated by materially lower load in Q3, the summer period, which typically has the highest overall demand of the year.

Energy costs in Q3 2017 *decreased* by 26% (about $340 million lower) in 2017 compared to Q3 2016. This reduction was driven by a combination of lower demand levels and lower gas prices. In 2017, Q3 demand was down by 8%, or by almost 1,280 MW on average per hour, compared to the prior year. Natural gas prices were down by almost 20%, or by $0.55/MMBtu.

The largest monthly changes occurred in December 2017 when energy costs accounted for almost 20% of total annual energy costs. Energy costs totaled almost $860 million, up by $240 million on the prior December. Average natural gas prices in December of $9.53/MMBtu were significantly higher than the rest-of-year average of $3.18/MMBtu. Extremely cold weather in late December led to very high gas prices over a 6-day period and accounted for a 9% increase in annual average gas prices alone. In other words, by excluding these 6 days from the annual average, gas prices were only 10% higher in 2017 compared to 2016. During this period, there was a greater reliance on the

[37] 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 through hour ending 11 on D+2.

region's fleet of oil-fired generation and consequently natural gas was not the primary driver of energy prices.

NCPC costs, at $52 million ($0.4/MWh) in 2017, declined by 29% relative to 2016. Ancillary service costs, which include reserve payments, regulation payments, and winter reliability costs, totaled $128 million in 2017, a decrease of 2% compared to 2016.

The overall share of capacity costs as a percentage of wholesale costs has increased from 15% in 2016 to 25% in 2017. Capacity market costs in 2017 totaled to $2.2 billion ($19/MWh), nearly double the 2016 cost. June 2017 marked the beginning of the FCA 8 capacity commitment period, which had tighter system conditions due to a number of generator retirements. Capacity payments to existing resources outside of NEMA/Boston increased by 123%, from $3.15/kW-month to $7.03/kW-month. Capacity payments to existing resources in NEMA/Boston increased from $6.66/kW-month to $15.00/kW-month.

Transmission costs totaled $2.2 billion ($18/MWh) in 2017. Costs increased by 5% compared to 2016. The regional transmission rate increased by approximately 8% in 2017 over the 2016 rate, moving from $104.10 kW/yr to $111.96 kW/yr.[38] The cost increase was the result of 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. The rate also includes regional transmission operating and maintenance costs, as well as administrative costs associated with regional network service.

2.2 Supply Conditions

This section of the report provides a macro-level view of supply conditions across the wholesale electricity markets in 2017, 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 2.2.3).

2.2.1 Generation and Capacity Mix

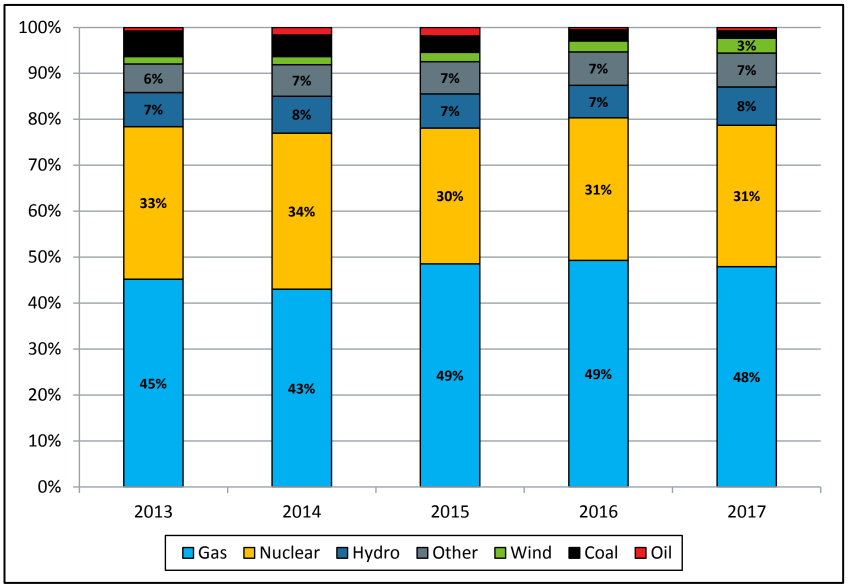
This subsection provides a summary of the generation mix in New England over the past five years. The composition of New England's native generation provides important context to overall supply conditions and market outcomes. Information about generation is provided across a series of different dimensions, 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.

[38] The formula rate inputs for the regional transmission rate are updated annually with FERC by the New England Participating Transmission Owners on June 30th.

Figure 2-2: 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 generally consistent between 2016 and 2017. In 2017, nuclear generation accounted for 31% of annual real-time energy production while natural gas-fired generation accounted for 48%. Wind's share of generation increased to 3% in 2017, which marked the first time wind generation produced more energy than oil- and coal-fired generation combined in ISO-NE. Wind capacity added in 2017 (discussed in the subsection below) explains part of the increased production. Along with the increase in wind generation, coal-fired generation's overall share decreased from 2.4% in 2017 to 1.6% in 2018. The primary driver was Brayton Point's retirement (1,490 MW) on June 1st, 2017.

Capacity Factors: In general, capacity factors for each fuel type decreased due to lower loads.[39] In 2017, nuclear generation had a capacity factor of 90%, which was 3% lower than 2016. This is due to larger nuclear units refueling in 2017. Natural-gas fired generators had an average capacity factor of 34%. Less efficient, and relatively more expensive coal- and oil-fired generation had relatively lower capacity factors, of about 14% and 2%, respectively. A detailed discussion about the effects of input fuels and supply-side participation on electricity prices can be found in Section 3.4 of this report.

Hydro power is an exception to the decrease in generation and capacity factors. Precipitation conditions in 2017 were in line with average, whereas 2016 was a dry year in the Northeast.[40] The relative improvement in drought conditions increased average hourly hydro generation output from 690 MW in 2016, to 840 MW in 2017. The average capacity factor for hydro units was 31% in 2017, up 4% from 2016.

A breakdown of energy production and consumption by state is shown in Figure 2-3 below. The state breakdown provides a general idea of where energy is being produced and consumed. Darker

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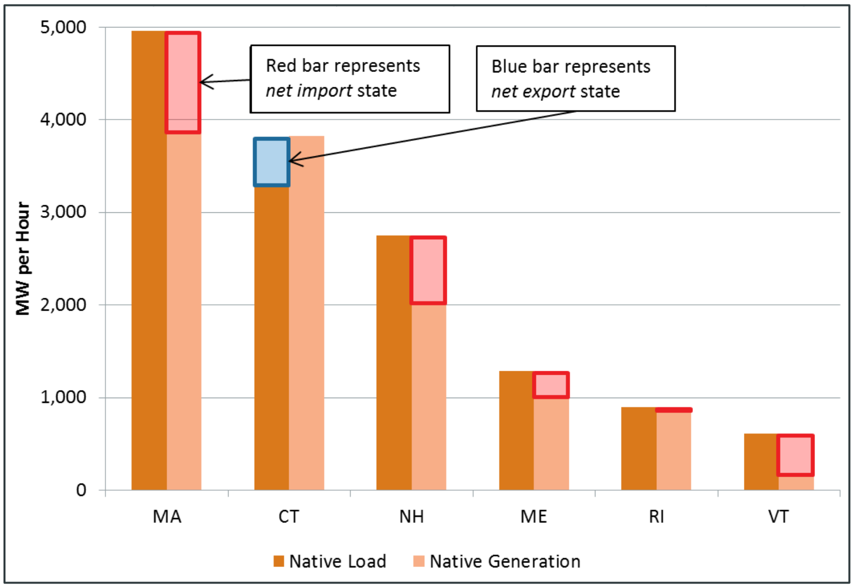
[39] A capacity factor indicates how much of the full capability of a generator is being utilized in the energy market. For example, a capacity factor of 60% for a 100MW generator means that the generator is producing 60MW on average each hour.

[40] From 2013-2017, 74% of New England by area had no drought. In 2016 the average was 52%, while in 2017 it was 75%. See http://droughtmonitor.unl.edu/Data.aspx for more information.

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, 2017

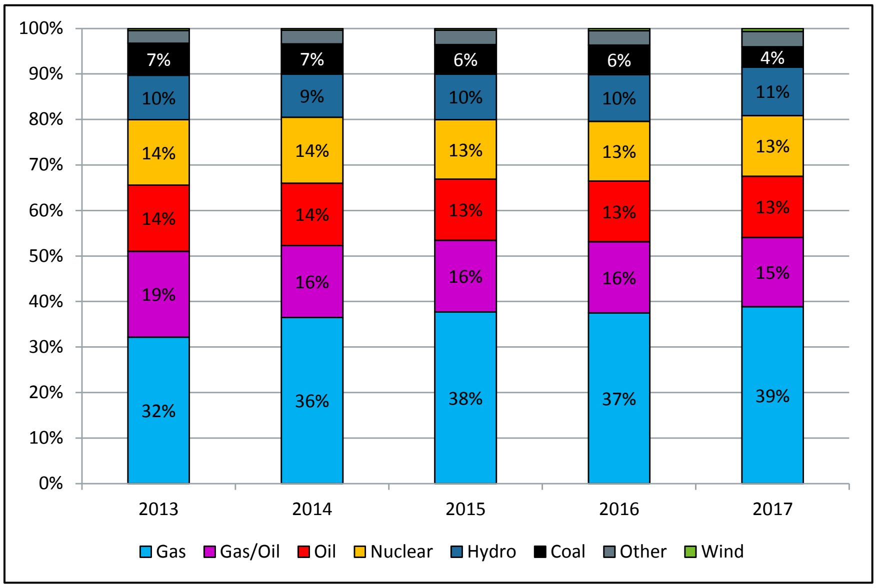


Most of the region's electricity production comes from Connecticut (33%) and Massachusetts (33%). About 60% of system load is also in these two states. Native generation in Massachusetts is about 88% of its load meaning a relatively large portion is met by production outside of the state. Connecticut is the only net exporting state, producing 4% more compared to its load. The abundance of red bars makes it clear that New England is a net importing region. In 2017, net imports averaged about 2,300 MW each hour, meeting 17% of New England's wholesale electricity demand. This is discussed at length 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.[41]

[41] 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).

Figure 2-4: Average Generator Capacity by Fuel Type



Notes: Coal category includes units capable of burning coal and dual fuel units capable of burning coal and oil. "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

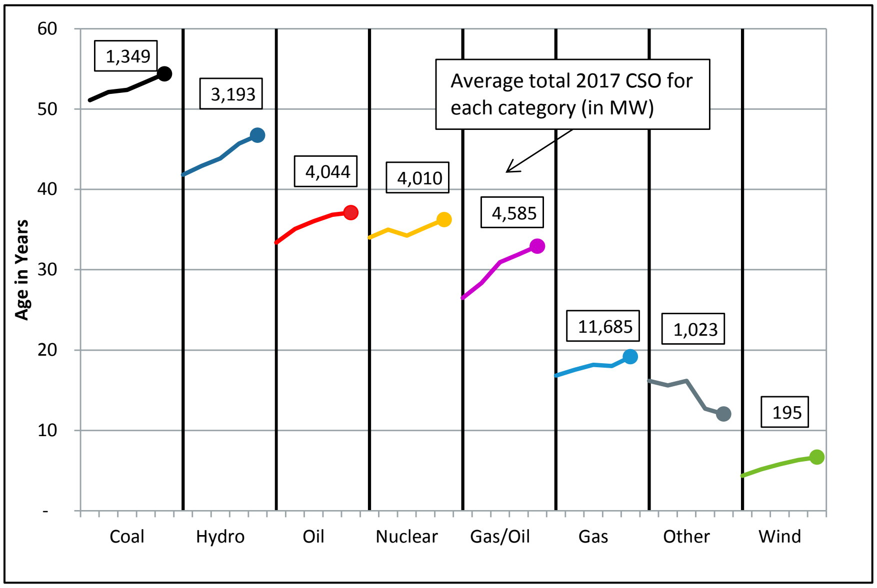
Natural gas continues to be the dominant fuel source. The percentage of capacity from gas- and gas/oil-fired dual-fuel generators has increased slowly over the past few years with the retirement of generators of other fuel types. Natural gas-fired generators accounted for 39% of capacity in 2017 while generators capable of burning either oil or natural gas (i.e., a type of dual-fuel generator) accounted for 15% of capacity. Combined, these gas- and gas/oil-fired dual-fuel generators accounted for 54% of total average generation capacity.

Capacity from coal-fired generators had the largest year-over-year decrease due to the retirement of Brayton Point in June 2017. Coal-fired capacity accounted for 1,350 MW in 2017, down from 2,000 MW in the previous four years. As a result, its share of total capacity dropped from 6% in 2016, to 4% in 2017. Similar to 2016, in 2017 nuclear generation accounted for 4,000 MW (13%) of the capacity fuel mix. The retirement of the Pilgrim nuclear facility (about 690 MW) in 2019 will reduce the capacity and energy share of nuclear generation. By 2020 the capacity of nuclear generation is expected to be about 3,350 MW.

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 generators in New England face other market dynamics, including higher emissions costs and 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 generation. 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 2013 to 2017. 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. The dot at the end of the line represents average age in 2017. Data labels above the bars show total capacity in 2017 by fuel type.

Figure 2-5: Average Age of New England Generator Capacity by Fuel Type (2013-2017)



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

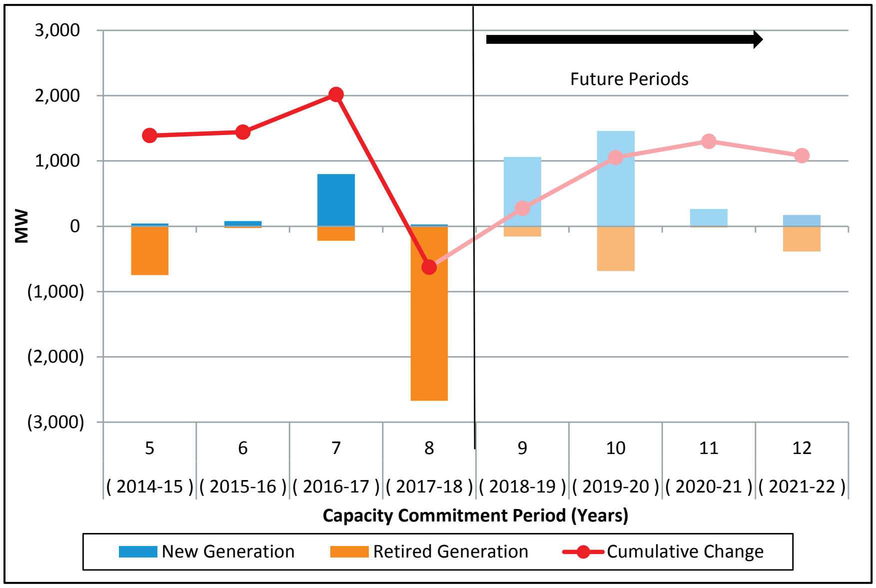
The average age of New England's generators in 2017 ranged from 7 years to 54 years, with an average total system age of 31 years. In general, the average age went up by a year due to lack of new generation. Coal-fired generators, which comprise 4% of total generation capacity, have the highest average age of 53 years. Natural gas-fired generators are relatively newer, with an average age of 19 years.

Generator additions and retirements beginning with Capacity Commitment Period 5 (CCP 5) are shown in Figure 2-6 below.[42] Blue bars represent new generation added through the capacity market. Orange bars represent generation that permanently retired.[43] Future periods are years for which the Forward Capacity Auction (FCA) has taken place, but the capacity is yet to be delivered.

[42] 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).

[43] This figure's changed after the 2015 AMR. Generator additions used to only capture new supply greater than 50 MW. It now captures all new supply regardless of size. Additionally, this figure accounts for incremental additions or significant increases from already existing generators. Retired megawatts in each CCP represent the aggregation of the last non-zero FCA cleared capacity for all resources with a full retirement in that CCP. For partial retirements, we use the analyzed MW value from the "status of non-price retirement requests and retirement de-list bids tracker" on the external website.

Figure 2-6: Generator Additions, Retirements, and Cumulative Change



There have been large swings in generation additions and retirements over eight commitment periods. During this period the first major retirement was in June 2014 (*CCP 5*), when Salem Harbor retired. Salem Harbor was a 750 MW oil/coal dual-fired power plant located in NEMA/Boston. The resource's owner cited the growing uncertainty surrounding future costs related to environmental regulations as a contributing factor to its retirement decision.[44] Two years later, the majority of the cleared capacity in *CCP 7* was attributed to the new Footprint Combined Cycle resources being built on the site of the retired Salem Harbor units. Footprint accounted for 670 MW, which was added in the NEMA/Boston capacity zone.[45]

A large volume of retirements in *CCP 8* contributed to a capacity deficiency during the FCA. Two retirements made up 78% of the capacity reduction: The Brayton Point coal-fired generation facility (1,490 MW) and Vermont Yankee Nuclear Power Station (600 MW) cited long-run economic issues as the primary reason for retirement. Entergy, the owner of Vermont Yankee, stated persistently low wholesale energy prices as the reason for the retirement. Additionally, both units spent a substantial amount on environmental upgrades (Brayton) or improving reliability (Vermont Yankee) several years prior to their retirements.[46] The retirements contributed to a large increase in capacity prices. The clearing price for the primary auction in CCP 8 was $15.00/kW-month for all new resources, signaling to the market that new supply was needed.[47]

[44] *Non-price Retirement Election for Salem Harbor Units 3 and 4.* (May 11, 2011) https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/non_prc_retremnt_lttrs/2011/salem_retirement_election.pdf

[45] The Footprint Combined Cycle deferred their CSO until June 1, 2017. This means that they will have no obligation and will not be paid until CCP 8. For more information see: https://www.iso-ne.com/static-assets/documents/2014/12/er15-60-000_12-5-14_order_granting_footprint_deferral__req.pdf

[46] The Vermont Yankee nuclear station shut down at the end of 2014. They traded out of their obligation and de-listed between their shutdown and May 31st 2017. See http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2769 for more information on reasons for retirement.

[47] The retirements of Vermont Yankee and Brayton caused an abrupt change in the supply-demand balance. This, coupled with a lack of new generation, led to high clearing prices. See Page 6 of Attachment B 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

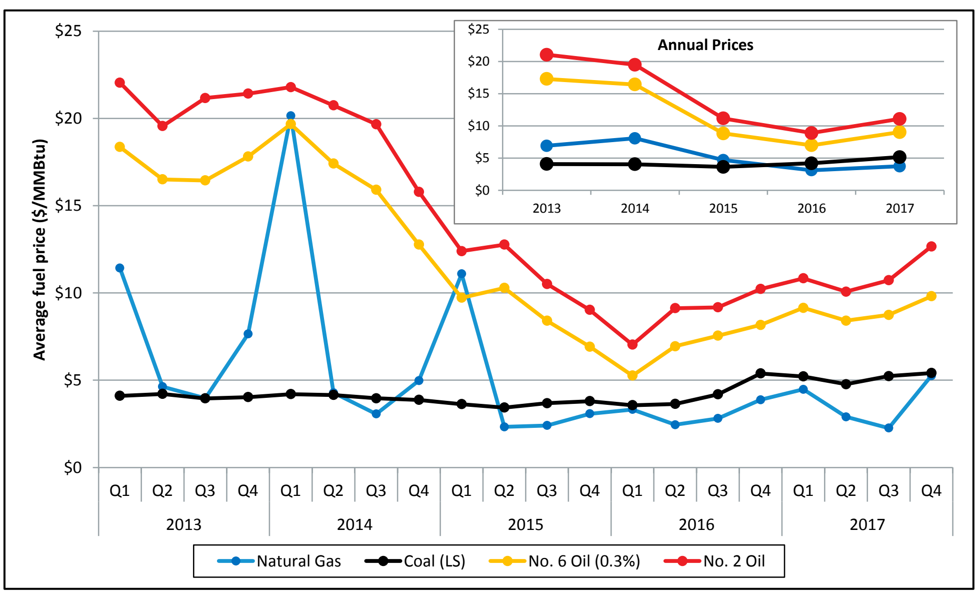
In response to price signals, nearly 1,060 MW of new generation capacity entered for *CCP 9*. The largest new resource was the Towantic 730 MW combined cycle plant in Connecticut, with dual fuel capability (gas and oil). In *CCP 10*, the Pilgrim Nuclear power station will retire. The resource accounts for roughly 680 MW of capacity. This means 1,380 MW, or 34%, of the nearly 4,000 MW of nuclear capacity will be retired by 2020. There was roughly 1,500 MW of new supply added in CCP 10. Three natural gas-fired resources accounted for 86% of this supply: Bridgeport Harbor 6(480 MW), Canal 3 (330 MW), and Burrillville Energy Center (490 MW). In *CCP 11*, 264 MW of new generation cleared. This includes the repowering of Milford Power, a 220 MW combined cycle resource.

During the most recent auction (*CCP 12*), 167 MW of new generation cleared. As the auction price declined, new generating resources exited the auction. There was also roughly 400 MW of retirements from existing resources; the majority of this came from Bridgeport Harbor 3, a 383 MW coal-fired resource.

2.2.2 Generation Input Costs

Fuel Prices: For the most part, fuel costs and the operating efficiency of combustion generators drive New England's electricity prices. Generators fueled by natural gas, coal, and oil produce roughly 50% of New England's electricity. Average 2017 prices for natural gas, oil, and coal increased year-over-year by an average of between 19% to 25%. Quarterly average cost of natural gas[48], 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.

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



Natural Gas: In 2017 natural gas prices averaged $3.72/MMBtu, an increase of 19% compared to the 2016 average price. The annual average price increase in 2017 was driven by increased Q1 and Q4 gas prices.

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

The *Q1 2017* price of $4.48/MMBtu was 35% higher than in Q1 2016. Average temperatures in March 2017 were 32°F, which was slightly lower than January and February. Average temperatures in March 2016 were milder (41°F), which led to comparably lower gas prices in Q1 2016.

The primary drivers of elevated natural gas prices in *Q4 2017* were gas delivery reductions on the Algonquin pipeline in October and cold weather in December. Average natural gas prices increased 36% from *Q4 2016*, up to $5.26/MMBtu. Due to planned maintenance at a compressor station bringing gas into New England during the month of October, operational capacity on the pipeline fell 26%, from 1.1 billion cubic feet per day (Bcf/d) to just over 0.8 Bcf/d. The constraints on the pipeline led to higher gas prices, even though weather conditions were milder than previous Octobers. Cold weather during December 2017 also contributed to elevated gas prices. This is particularly true during the last five days of the year where temperatures averaged 7°F, and gas prices averaged $22.75/MMBtu.

Although the region experienced elevated year-over-year prices, Q3 2017 had the lowest gas prices in recent history. Natural gas prices in *Q3 2017* were $2.26/MMBtu, 20% lower than Q3 2016. This outcome is the result of lower gas demand from natural gas-fired generators and increased capacity on New England pipelines. The AIM project, completed in 2016, added 0.34 Bcf/d of capacity on the Algonquin pipeline.[49] Along with increased capacity in Q3 2017, New England pipeline demand was at a four year low. This coincides with the lowest amount of power burn in Q3 since 2013.

Oil: Oil prices continued to increase in 2017. No. 6 oil prices rose 29% from 2016 levels. No. 2 oil increased 25% over the same period. Actions by OPEC and non-OPEC countries led to a decrease in international crude oil production. Production cuts are planned to continue until at least the end of 2018.[50] These actions led to higher crude oil prices and domestic production.

Coal: Lastly, coal prices increased year-over-year by 23%. According to a recent article from the Energy Information Administration, the increase was driven by strong domestic and international coal demand.[51]

Emission Prices: Emission allowances, as required by federal and state regulations, are a secondary driver of electricity production costs for fossil fuel generators. The key driver of emission costs for New England generators is the Regional Greenhouse Gas Initiative (RGGI). The RGGI is the marketplace for CO_2 credits in the Northeast, and covers all six ISO-NE states. RGGI operates as a cap and trade system, where fossil fuel generators, among other CO_2 emitters, must hold allowances equal to their emissions over a certain period.[52] Market prices for CO_2 credits impact total energy costs of fossil fuel generators that must purchase allowances to meet RGGI requirements.

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. The line series illustrate the average estimated cost of

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[49] AIM stands for Algonquin Incremental Market project. See US Energy Information Administration. *New England natural gas pipeline capacity increased for the first time since 2010* Washington, DC: US Department of Energy, December, 2016. https://www.eia.gov/todayinenergy/detail.php?id=29032

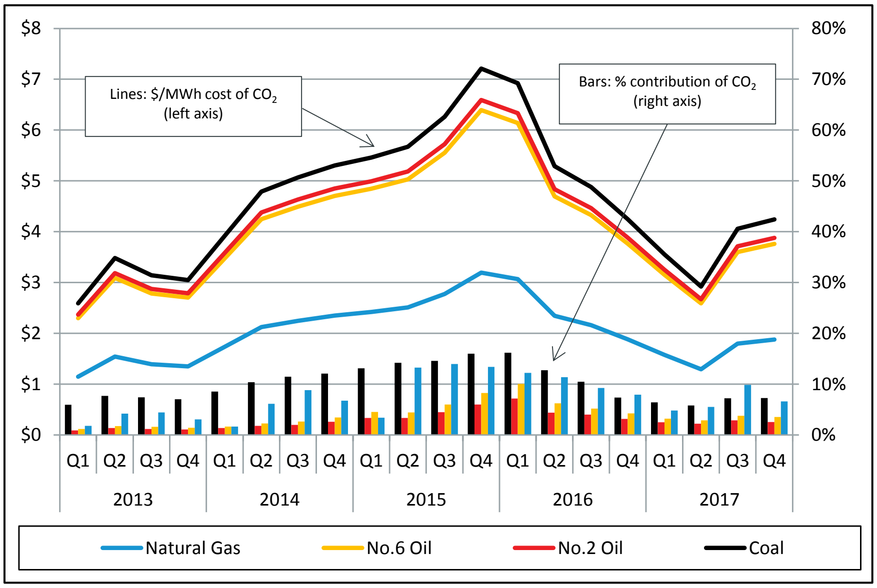
[50] US Energy Information Administration. *Crude oil prices increased in 2017, and Brent-WTI spread widened* Washington, DC: US Department of Energy, January, 2018. https://www.eia.gov/todayinenergy/detail.php?id=34372

[51] US Energy Information Administration. *U.S. Coal production, exports, and prices increased in 2017.* https://www.eia.gov/todayinenergy/detail.php?id=34992

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

emission allowances for fossil fuel for the past five years. The bar series show the proportion of average energy production costs attributable to emissions costs for the same years.

Figure 2-8: Average Cost of CO2 Allowances and Contribution to Energy Production Costs



A combination of increased permits purchased in 2015, uncertainty about the future of the Clean Power Plan after February 2016, and actual emissions falling below the market cap led to declining prices through *Q2 2017*. Natural gas-fired generators had average emissions costs of $1.29/MWh in *Q2 2017*. This was the lowest price since *Q1 2013*. After the announcement of the Clean Power Plan in 2015, demand for RGGI allowances increased. This led to higher cleared quantities and prices. In February 2016, the Supreme Court suspended the Clean Power Plan.[53] The excess allowances in the RGGI market and uncertainty about the future of the program were the primary drivers behind falling prices.

In the second half of 2017, emission prices increased on news of proposed program changes. On August 23, 2017, the RGGI review led to a 30% reduction to the cap by 2030, relative to 2020 levels. In reaction to the news, the spot market price for RGGI allowances increased nearly 40% from $3.30/short to $4.60/short ton on August 23.[54] The average emissions costs for a natural gas-fired generator was $1.80/MWh in *Q3 2017*, and $1.88/MWh in Q4.

As shown in the bar chart series portion of Figure 2-8, the relative contribution of CO_2 emissions allowance costs to generation costs fell in 2017. The maximum share was 10% of the variable production costs of a natural gas-fired generator in *Q3 2017*. The bars for all fuel types increase in *Q3* and *Q4 2017*, despite higher fuel prices. This is due to the relatively larger increase in emission costs.

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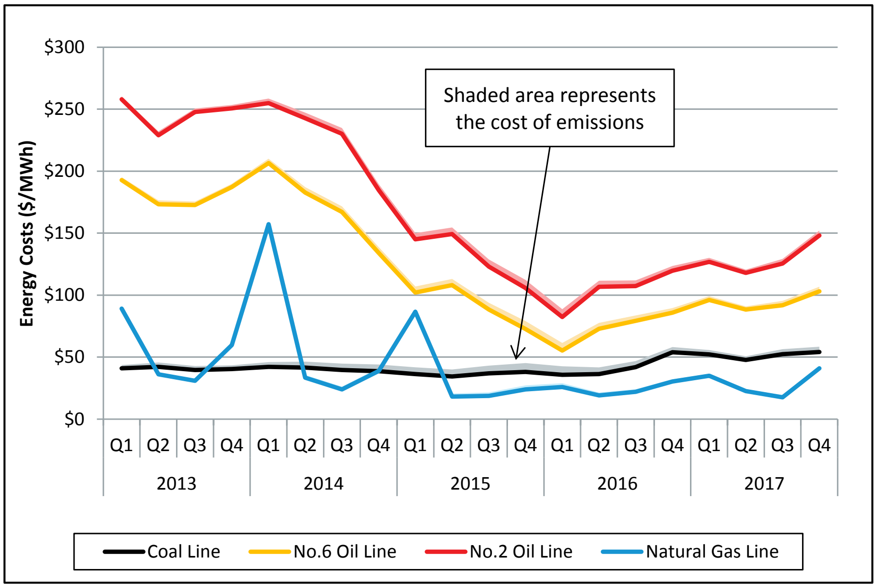
[53] US Energy Information Administration. *Regional Greenhouse Gas Initiative auction prices decline,* Washington, DC: US Department of Energy, April, 2016. http://www.eia.gov/todayinenergy/detail.php?id=26812

[54] 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/Press-Releases/2017_08_23_Announcement_Proposed_Program_Changes.pdf

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 illustrate 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.

Figure 2-9: Contributions of CO2 Allowance Cost to Energy Production Costs



The figure 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.

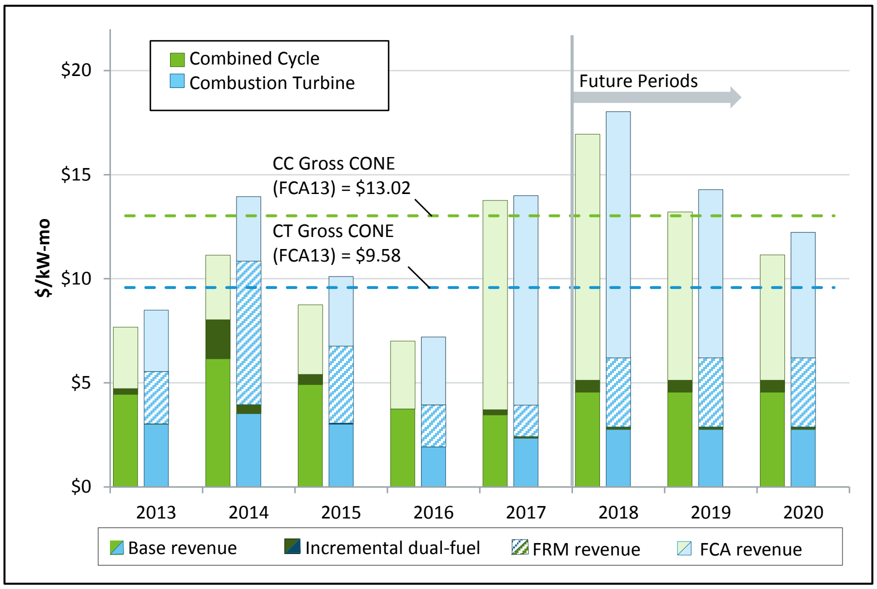
2.2.3 Generator Profitability

New generator owners rely on a combination of net revenue from energy and ancillary service markets and forward capacity payments to cover their fixed costs. Revenue from the Forward Capacity Market (FCM), which is conducted three-plus years in advance of the operation 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 (as opposed to net revenue from energy and reserve products). 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 generation project, 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.[55] Figure 2-10 shows the result of the simulations.[56] Each stacked bar represents revenue components for a generator type and year. A combined cycle unit is shown in green and a combustion turbine unit that participates in the FRM market is shown in blue. The simulation produces base revenue (energy and ancillary services) and incremental dual-fuel revenue numbers for years 2013-2017. Estimates of future years base and dual-fuel revenue are simple averages of prior year values. For all years, the FCA and FRM revenue numbers shown are calculated using the actual payment rates applied to calendar years.

Figure 2-10: Estimated Net Revenue for New Gas-fired Generators



The simulation results indicate that net revenue numbers for 2017 remained close to 2016 levels. 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 $4.54/kW-month which increases to $5.12/kW-month for generators with dual-fuel capability. Under the same conditions, new combustion turbines could expect net revenue earnings from $3.21/kW-month for single-fuel generators to $3.38/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.

A combustion turbine generator can also participate in the FRM where off-line reserves are procured prior to the reserve season. A forward reserve resource receives revenue from the forward reserve auction, but it foregoes real-time reserve payments and, in most hours where the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve.

[55] 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 resource).

[56] The Gross CONE figures for the CC and CT gas fired resources reflect Net CONE values of $7.74/kW-month and $6.45/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

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. This analysis shows that a new combustion turbine which is designated as an FRM resource could earn $2.88/kW-month more net revenue than the same resource could have accumulated in the real-time 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). However, these results are particularly sensitive to the frequency of scarcity pricing events via the Reserve-Constraint Penalty Factor (RCPF).

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 FCAs. The most recent CONE revisions filed with FERC establish net revenue components of $5.29/kW-month and $3.13/kW-month for combined cycle and combustion turbine generators respectively.[57] 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 2-10 shows that, prior to 2017, capacity prices were generally too low to incent investment in new gas-fired generation because the system was long on capacity. For 2017 onward, the situation appears to change with generation retirements moving the system into a state where it is not long on installed capacity and total revenue appears 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. 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, CONE 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.

2.3 Demand (Load) Conditions

Consumer demand for electricity is one of the key drivers of wholesale electricity prices in New England.[58] Real-time electricity load is driven primarily by a combination of weather and the economy. The following sections describe the factors affecting New England's real-time electricity load, system reserve requirements and the amount of capacity needed to meet the region's reliability needs.

2.3.1 Energy Demand

The average hourly load for electricity has declined each year since 2013. In just the past year, the average hourly load fell from 14,165 MW in 2016 to about 13,824 MW in 2017, a decline of 341 MW or 2.4%. Figure 2-11 below shows the average hourly load, by year and quarter from 2013 through 2017.[59] The orange series represents average annual hourly load and the black series represents the average quarterly hourly load. Calendar quarters are identified by different colored dots (blue

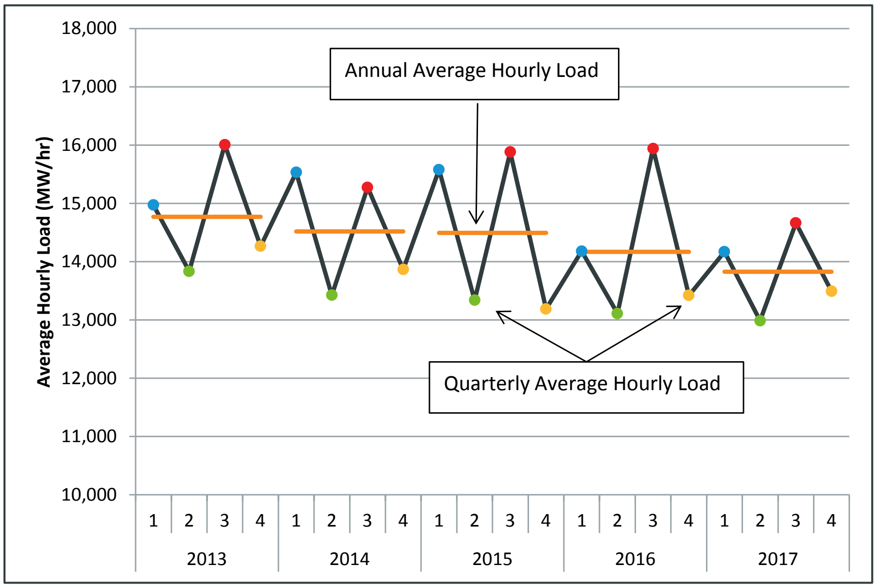
[57] These revenue components include "Pay For Performance" (PFP) revenue which this study does not.

[58] 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 macro meaning, but typically refers to demand that clears in the day-ahead energy market when used in that context.

[59] Load represents the wholesale electricity load for the New England area.

for quarter 1, green for quarter 2 etc.).

Figure 2-11: Average Hourly Load by Quarter and Year



The trend of declining load can be explained by three main factors: seasonal temperature differences year-over-year, the increase in energy efficiency programs, and the strong growth in behind-the-meter solar generation.[60] On the weather-normalized basis, average hourly load decreased by 810 MW between 2013 and 2017; this reduction can be largely attributed to the growth in the region's energy efficiency programs.

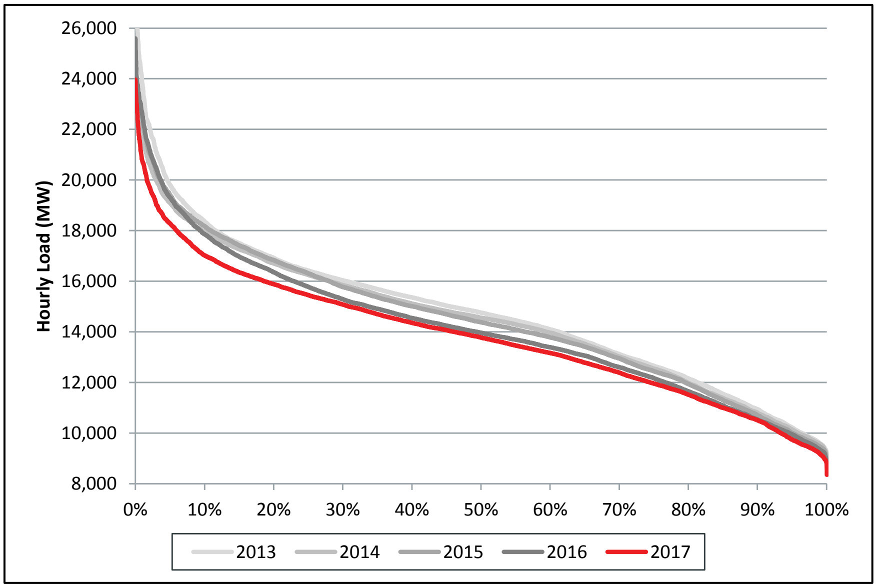
First quarter load in 2017 was consistent with 2016, but because of higher temperatures experienced in 2016 and 2017, was significantly lower when compared to prior years. For example, the average temperature was 33°F during Q1 2017 and 34°F in 2016, which was ten degrees higher than the average temperature of 24°F for Q1 2015. Consequently, Q1 2017 average load decreased by nearly 1,400 MW (from 15,580 MW to 14,170 MW) compared to Q1 2015.

Load is typically the highest during the summer period, which is the third quarter (red dots). In 2017, average Q3 temperatures were 3 degrees lower compared to 2016 and 2 degrees lower compared to 2015. In 2015 and 2016, average Q3 load was similar due to similar weather conditions. Temperatures averaged 69°F in Q3 2017, comparable with an average temperature of 72 °F in Q3 2016. Q2 and Q4 average hourly load (green and yellow dots, respectively) have been trending lower since 2013 with exception of a slight increase in Q4 2016 and 2017 due to lower temperatures compared to previous years.

The system load for New England over the last five years is shown as load-duration curves in Figure 2-12. The load duration curves order hourly load levels from highest to lowest, and show the relationship between load levels and the frequency the load levels occur.

[60] Total nameplate capacity of solar generation installed in New England is estimated at 1,918 MW. It includes FCM resources, non-FCM energy-only generators and behind-the-meter solar resources. Estimated behind-the-meter solar generation summer peak load reductions are 575 MW. See Final 2017 PV Forecast Details, https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf

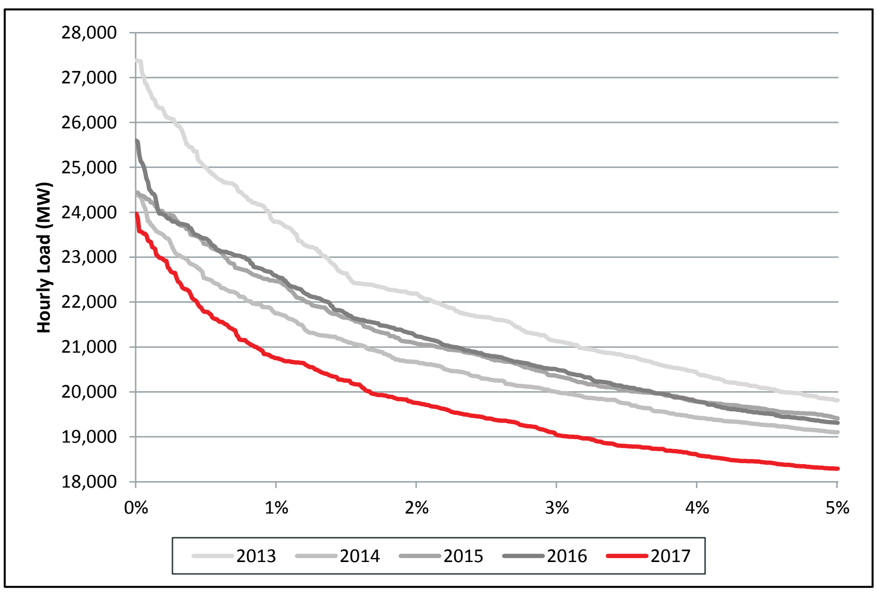
Figure 2-12: Load Duration Curves



The separation of the 2017 curve (red series) from the preceding four years is evident from Figure 2-12 above, with load 2.4% lower in 2017 compared with 2016.

We take a closer look at the load duration curves for the top 5% of hourly observations in order to compare the peak load changes from year to year, as shown in Figure 2-13.

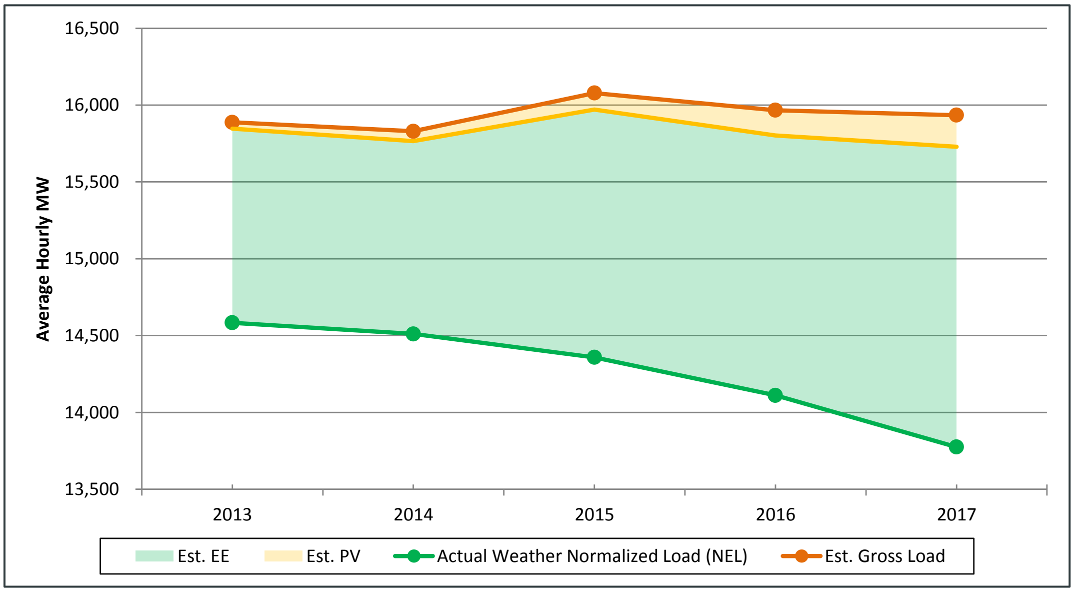
Figure 2-13: Load Duration Curves - Top 5% of Hours



It is evident that the peak load in 2017 was lower compared to previous years. The contributing factors of lower peak load during the past few years are milder summers, the growth in state-sponsored energy efficiency programs[61], and the increase in behind-the-meter solar generation. The installation of energy efficiency and behind-the-meter solar generation has contributed to a general reduction in electricity load and to a larger reduction in peak load.

Figure 2-14 shows the estimated growth of behind-the-meter solar generation and energy efficiency measures and the associated impact on weather-normalized NEL.

Figure 2-14: Net Wholesale Load and Impact of Energy Efficiency and Photovoltaic



Weather-normalized NEL has been declining since 2013. Energy efficiency (EE, green shaded area) has had the largest impact as the average hourly reduction grew from 1,100 MW in 2013 to 1,900 MW in 2017. Behind-the-meter solar generation (PV, yellow shaded area) has had less of an impact and, on average, reduced load by an estimated 200 MW per hour in 2017. The orange line, 'estimated gross load', reconstitutes what gross load would have been if there had been no behind-the-meter solar generation or energy efficiency measures. As seen, gross load has been relatively constant since 2013, but has seen a slight decline since 2015. This is consistent with the national trend of total U.S. electricity sales; New England has also seen a decrease in its share of the total U.S. gross domestic product.[62]

2.3.2 Reserve Requirements

All bulk power systems need reserve capacity in order to respond to contingencies. ISO New England's operating reserve requirements are designed to allow the bulk power system to serve

[61] 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.

[62] See draft 2018 CELT ISO-NE Annual Energy and Summer Peak Forecast for more information: https://www.iso-ne.com/static-assets/documents/2018/03/a3_draft_2018_celt_iso_ne_annual_energy_and_summer_peak_forecast.pdf

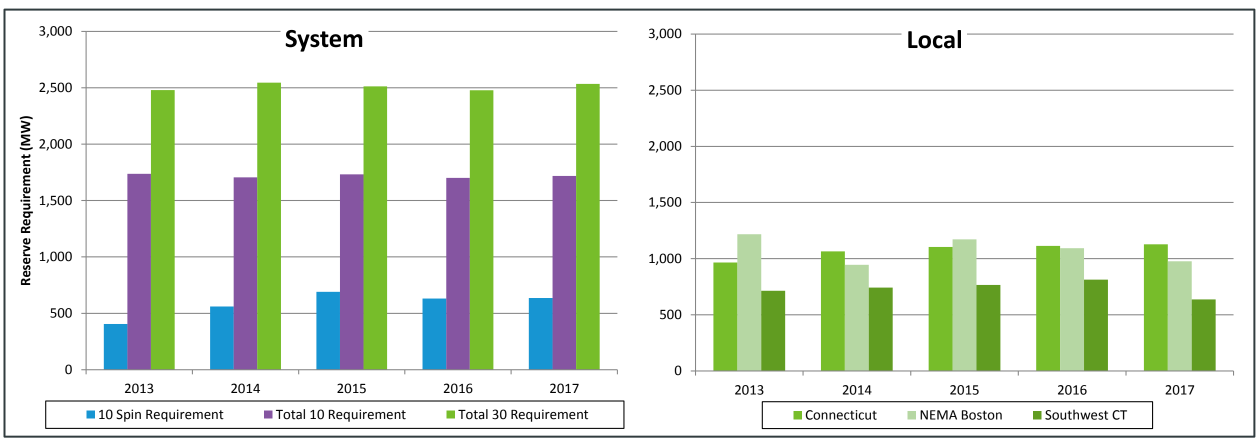
load uninterrupted if there is a loss of a major generator or transmission line.[63] The ISO maintains a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency (N-1) within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. Additionally, reserves must be available within 30 minutes to meet 50% of the second-largest system contingency (N-1-1). Adding this additional requirement to the total 10-minute reserve requirement comprises the system total reserve requirement.

Operating reserves are provided by the unloaded capacity of generating resources, either online or offline, which can deliver energy within 10 or 30 minutes. 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 spinning reserve (TMSR) requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute non-spinning reserve (TMNSR). The remainder of the total reserve requirement can be served by 30-minute operating reserves (TMOR). Starting in October 2013, in addition to the total reserve requirement, a replacement reserve requirement was added.[64]

In addition to the system-wide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas. Currently, local TMOR requirements exist for the region's three local reserve zones – Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABSTN).

Average annual system reserve and local reserve requirements are shown in Figure 2-15 below.

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



[63] Operating Procedure No. 8, *Operating Reserves and Regulation* (January 17, 2017), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

[64] The replacement reserve requirement adds 160 MW to the total reserve requirement in the summer and 180 MW to the requirement in the winter. 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.

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 only be satisfied by resources located within a local reserve zone. Requirements can vary year-to-year based on the size of the contingencies; however, rules changes have also had an impact. 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.[65] 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

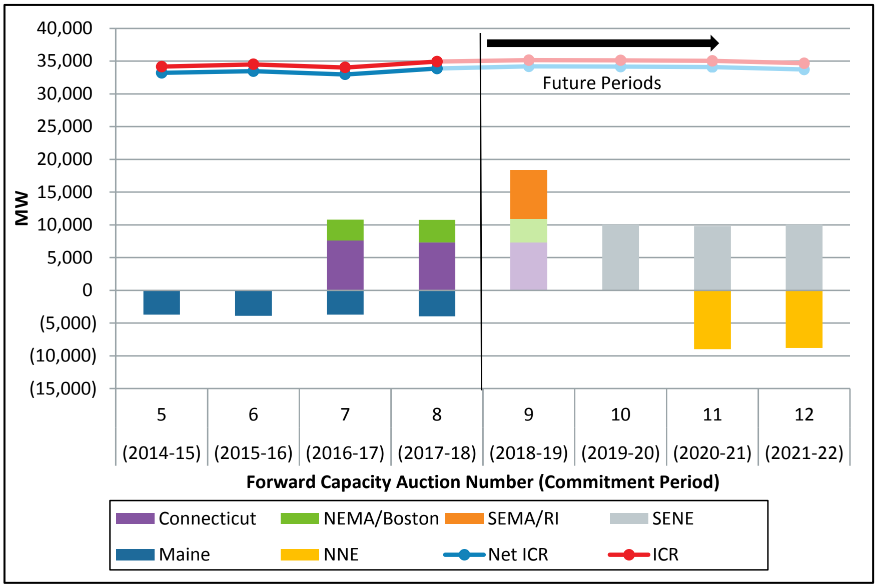
The Installed Capacity Requirement (ICR) is the amount of capacity (expressed in megawatts) needed to meet the region's reliability requirements (including energy and reserves). The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than once every ten years. The ISO develops the ICR through a stakeholder and regulatory process with review and action by various NEPOOL committees, state regulators, and the New England States Committee on Electricity.

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

Trends in system capacity requirements, ICR and Net ICR, since the inception of the FCM are shown below in Figure 2-16. The system ICR and Net ICR are represented as line series. LSRs (positive bars) and MCLs (negative bars) are also shown.

[65] 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.

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



The Net ICR for FCA 12 was 34,683 MW. This value is roughly 350 MW lower than Net ICR for FCA 11. A primary driver for the reduction was changes to the ISO's behind-the-meter solar PV forecast methodology. Updating the forecast reduced Net ICR by 335 MW.[66]

LSRs are placed on import-constrained zones due to limited import capability and generation-load imbalances. As zonal capacity approaches and falls below the LSR, additional capacity within the zone becomes more and more valuable due to declining reliability in the local area. Starting in FCA 10, Southeast New England (SENE) was the only import-constrained zone.[67] The SENE capacity zone was modeled again in FCA 12, and had an LSR of roughly 10,000 MW.

Maximum capacity limits are placed on export-constrained zones due to limited export capability. These zones may procure more generation capability than can be exported to the rest of the system. Surplus capacity within the export-constrained zone becomes less and less valuable due to its declining contribution to system reliability. Northern New England (NNE) was modeled as an export-constrained zone for the first time in FCA 11.[68] The export limit for NNE fell from 8,980 MW in FCA 11 to 8,790 in FCA 12.[69]

2.4 Imports and Exports (External Transactions)

New England buys and sells power with its neighboring control areas of New York, Hydro Québec, and New Brunswick over the transmission lines that interconnect the regions. Market participants can buy power in one region and sell it in another using external transactions in the day-ahead and real-time markets. Market participants can buy power at a low price in one region and sell it to

[66] The methodology changes from the reliability hours methodology to the hourly profile methodology. For more information on the differences, please refer to https://www.iso-ne.com/static-assets/documents/2017/11/icr_2017_fca_12.pdf

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

[68] Northern New England consists of the Maine, New Hampshire, and Vermont load zones.

[69] For more information on FCA 12 requirements see https://www.iso-ne.com/static-assets/documents/2017/11/icr_2017_fca_12.pdf

another region at a higher price – profiting from the price difference (spread). Market participants can also use external transactions to fulfill other contractual obligations to buy or sell power (such as a power purchase agreement) or to import and collect a premium for renewable power.

External transactions allow competitive wholesale markets to deliver load at a lower cost. Importing ISOs are able to serve demand at lower production costs than could be achieved using only native supply, by displacing more expensive native generation when imported power is available at lower cost. 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.

External transactions are submitted for specific locations known as external nodes, also referred to as interfaces. The nodes represent trading and pricing points for a specific neighboring area. A pricing node may correspond to one or more transmission lines. 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 corresponding transaction on the other side of the interface is settled separately with the neighboring area.

New England's six external nodes are listed in Table 2-1 below along with the common "interface name" used to refer to them 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 ratings may be different due to how power transfers in each direction impact various reliability criteria in each region. For example, 1,000 MW can be safely imported from New Brunswick into New England, but only 500 MW can be safely exported from New England to New Brunswick.

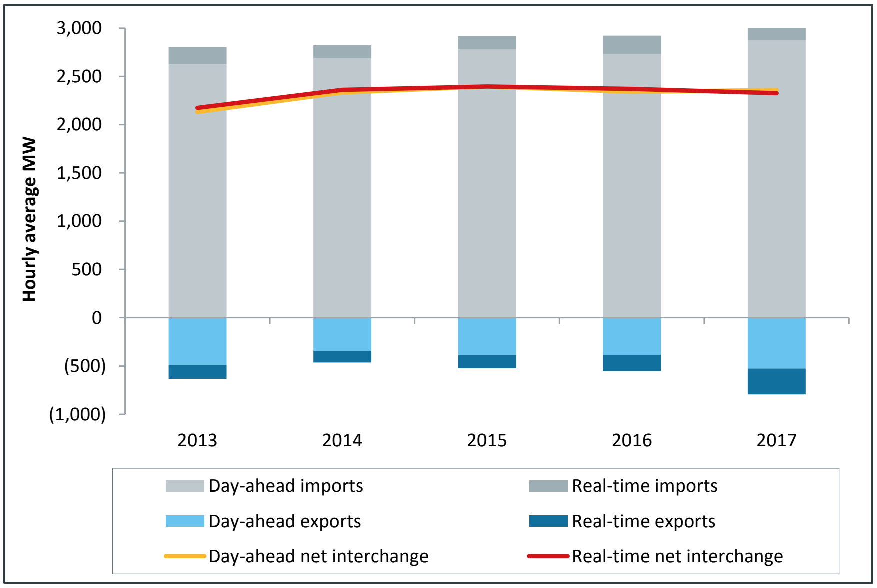
Table 2-1: External Interfaces and Transfer Capabilities

Neighboring area	Interface name	External node name	Import capability (MW)	Export capability (MW)
New York	New York North	.I.ROSETON 345 1	1,400	1,200
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	218	0-75
New Brunswick (Canada)	New Brunswick	.I.SALBRYNB345 1	1,000	550
Total			**5,164**	**3,480-3,555**

In 2017, New England remained a net importer of power. Over the year, net imports during real-time averaged 2,326 MW each hour, meeting 17% of New England's wholesale electricity demand. Total net interchange was only 2% lower than during 2016 and has been relatively steady since 2014. A 240 MW increase in average export transactions over the prior year was mostly offset by a 196 MW increase in average imports, resulting in similar average net interchange as 2016. The hourly average net interchange amounts in the day-ahead and real-time markets for 2013 through

2017 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 four years and mostly unchanged for 2017 as shown by the red line series. However, real-time energy exports increased by 43%, or by 240 MW per hour on average, compared to 2016. The increase in export transactions occurred primarily at the New York North interface, although there were also small increases at the New Brunswick and Cross Sound Cable interfaces.

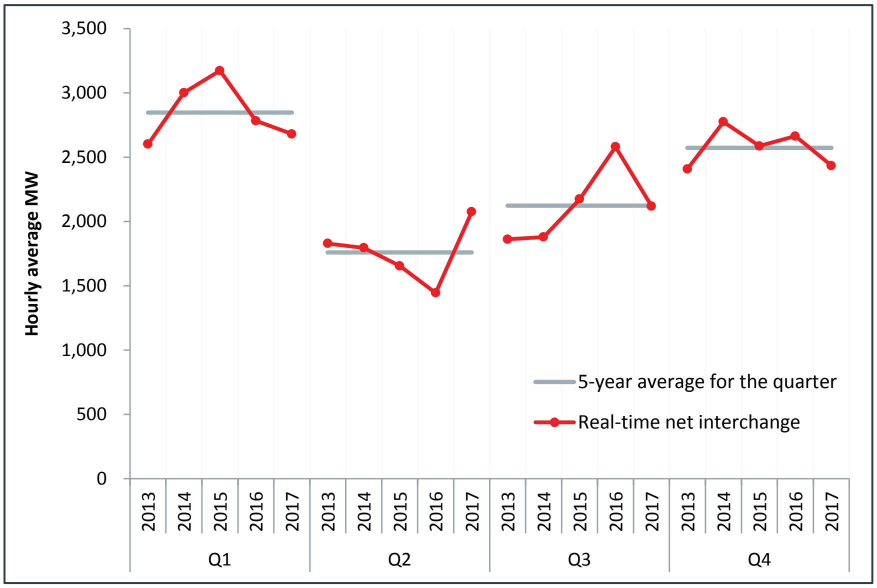
The close proximity of the day-ahead net interchange (orange) and real-time net interchange (red) line series highlights that day-ahead market outcomes across the external nodes do, on average, closely predict the real-time scheduled flows.[70] Although additional import and export transactions are scheduled 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 less than day-ahead by 1% during 2017 (*i.e.*, slightly less power was imported in real-time than planned for in the day-ahead). For the remainder of this section, only the real-time values are presented since they align so closely with day-ahead.

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 winter months when the natural gas network becomes constrained and also in mid-summer during peak load periods. New England's higher energy prices created opportunities for market participants to profit by importing lower cost power to New England. Fuel prices are discussed more in Section 2.2.2.

[70] 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 hourly average real-time pool-wide net interchange value is plotted by quarter for 2013 through 2017 in Figure 2-18 below. Note that the annual observations are grouped by calendar quarter in the chart. Each year'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, although New England is consistently a net importer throughout the year. 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.

Relative to 2016, the 2017 quarterly average net interchange was similar in both Q1 and Q4. New England imported more power in Q2 2017 than in Q2 of previous years. In Q2 2017, New England imported over 600 MW more per hour than in Q2 2016. The average net interchange in Q2 2016 was impacted by a planned outage of Phase II from April 1 through May 30. Compared with 2013-2015, Q2 2017 had slightly higher net interchange across a few interfaces, including New Brunswick, Phase II, and Highgate.

In Q3 2017 real-time interchange decreased substantially compared with 2016. The main driver was an increase in price-sensitive exports during Q3 2017 at the New York North interface and above-average import volumes in 2016. Q3 2017 volumes were consistent with previous years as the increase in export volumes over New York North was offset by an increase in imports over Phase II. New York North implemented Coordinated Transaction Scheduling (CTS) in December 2015, which is discussed in further detail in Section 5.5.

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 2,145 MW per hour in 2017, which was 193 MW greater than the imported volumes during 2016. The net real-time interchange across the three interfaces with New York (New York North, Cross Sound Cable and Northport-Norwalk) averaged 180 MW per hour in 2017, 236 MW less than 2016 net imports. 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 2017, total day-ahead and real-time energy payments reflected changes in underlying primary fuel prices, most notably natural gas.

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. However, there were energy supply portfolios that had structural market power in the real-time market in over half of the hours in 2017. 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) (see Section 6) 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.[71] 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 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.

[71] 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.

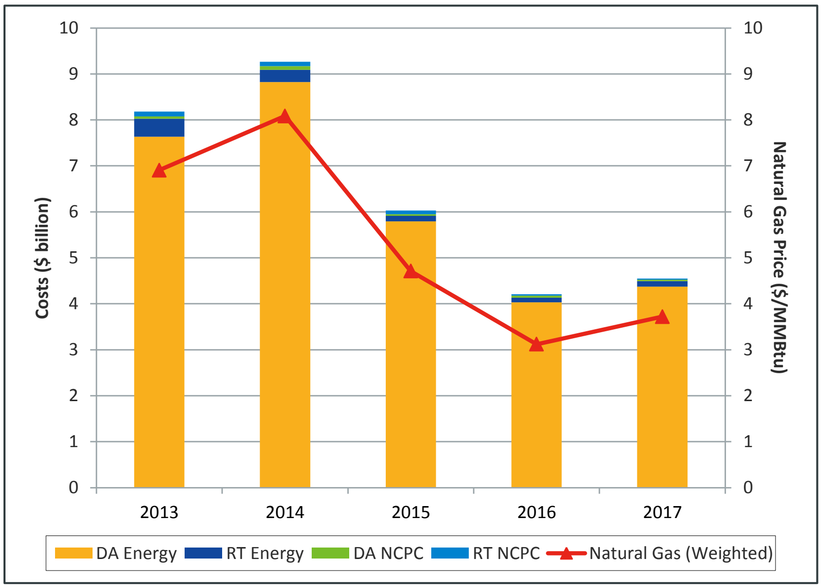
3.2 Energy and NCPC (Uplift) Payments

In 2017, total estimated energy and NCPC payments increased by 8% compared to 2016 ($4.5 billion in 2017 compared with $4.2 billion in 2016).

The majority of energy and NCPC payments in 2017 were made in the day-ahead market. Energy payments in the day-ahead market accounted for approximately 97% of total energy market payments, and day-ahead NCPC payments accounted for 53% of total NCPC payments. Section 3.5 discusses NCPC in detail.

Energy and NCPC payments for each year (billions of dollars), by market, along with the average natural gas price ($/MMBtu[72]), 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 illustrated in Figure 3-1, specifically how natural gas prices were the primary driver behind the year-to-year changes in energy and NCPC payments. The increase in energy costs was driven by higher natural gas prices. Natural gas prices averaged $3.72/MMBtu, up 19% on 2016 prices. The upward pressure of natural gas prices on energy costs was mitigated by lower wholesale electricity demand, particularly in Q3 2017. The significant natural gas price increase was also driven by a cold snap period at the end of December 2017, when oil-fired generation became cheaper than gas-fired generation. When these six days are excluded, natural gas prices only increased by 10%, on average, compared to 2016.

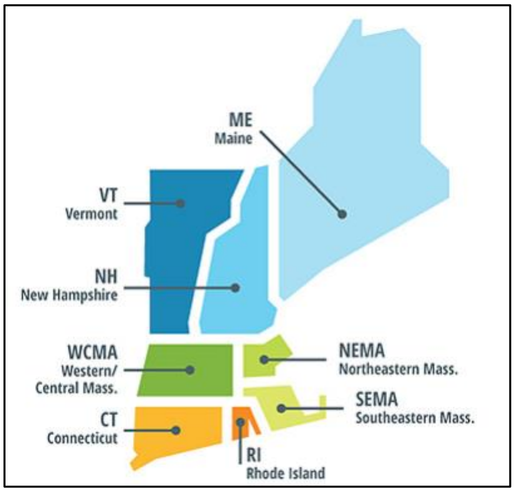
3.3 Energy Prices

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 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation [NERC]

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

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”.

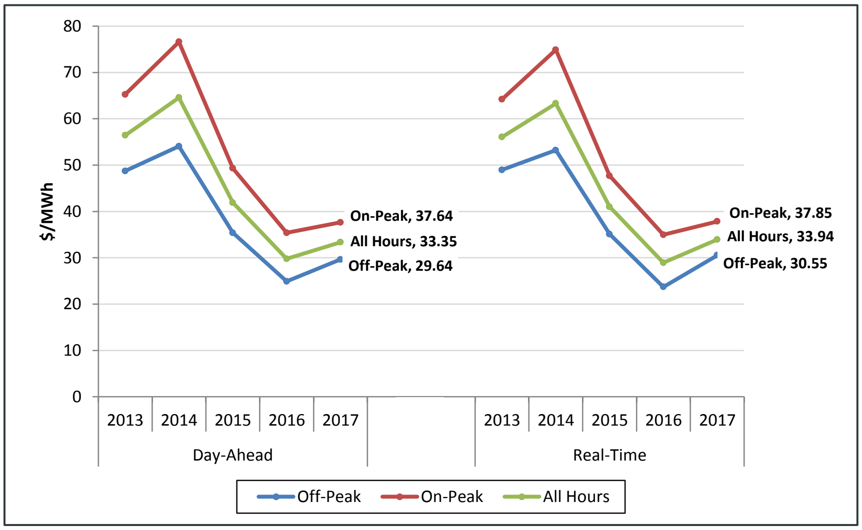
Figure 3-2: ISO New England Pricing Zones



3.3.1 Hub Prices

An illustration of energy market price trends, from 2013 to 2017, is provided in Figure 3-3 below.

Figure 3-3: Annual Simple Average Hub Price



In 2017, the average Hub price (in all hours) was $33.35/MWh in the day-ahead market and $33.94/MWh in the real-time market. Hub prices were up approximately 12% in the day-ahead market and 17% in the real-time market compared to 2016 prices.[73]

Pricing by time-of-day (i.e., on-peak and off-peak) in 2017 exhibited the same trend when compared with 2016: on-peak prices increased by 6% in the day-ahead market and 8% in the real-

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

time market while off-peak prices increased by 19% in the day-ahead market and 29% in the real-time market.

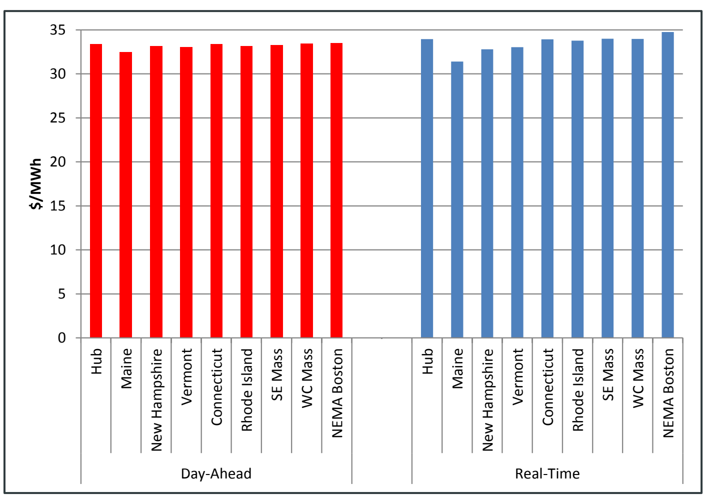
These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Factors influencing the increase in LMPs include an increase in fuel prices and related colder winter weather in 2017. Fuel prices increased significantly in 2017 compared to 2016, particularly natural gas and fuel oil which increased by approximately 19% and 28%, respectively.[74] This increase in 2017 LMPs was somewhat moderated by slightly lower loads relative to 2016.

Average real-time prices were slightly higher than day-ahead prices in 2017: 3% off-peak, 1% on-peak, and 2% overall. The higher average real-time prices reverse a longer-run trend of average day-ahead prices slightly exceeding real-time prices. The 2017 change resulted primarily from relatively high real-time prices in December 2017. While both day-ahead and real-time prices were relatively high that month, as a result of cold weather and elevated fuel prices, tight system conditions and unexpected factors in the real-time market resulted in higher overall prices. These factors included reductions in imports in mid-December because of a partial transmission outage, and very cold weather and high loads levels, combined with unexpected generator outages, during the final week of the month. These factors resulted in an average real-time premium of $9/MWh in December 2017. A review of the system and market outcomes during the December 2017 and January 2018 Cold Snap is provided is Section 3.4.7.

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.[75] In 2017, 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, 2017



[74] Fuel Oil No 2 and No 6 (3% and 5% sulfur content) were used to estimate the average increase in fuel oil prices.

[75] 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).

There was very little price difference between the load zones – 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 $0.23/MWh in the day-ahead energy market and $0.71/MWh in the real-time energy market – a difference of approximately 0.7-2.1%.

The Maine load zone had the lowest average prices in the region in 2017. Maine's prices averaged $0.86/MWh and $2.55/MWh 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.

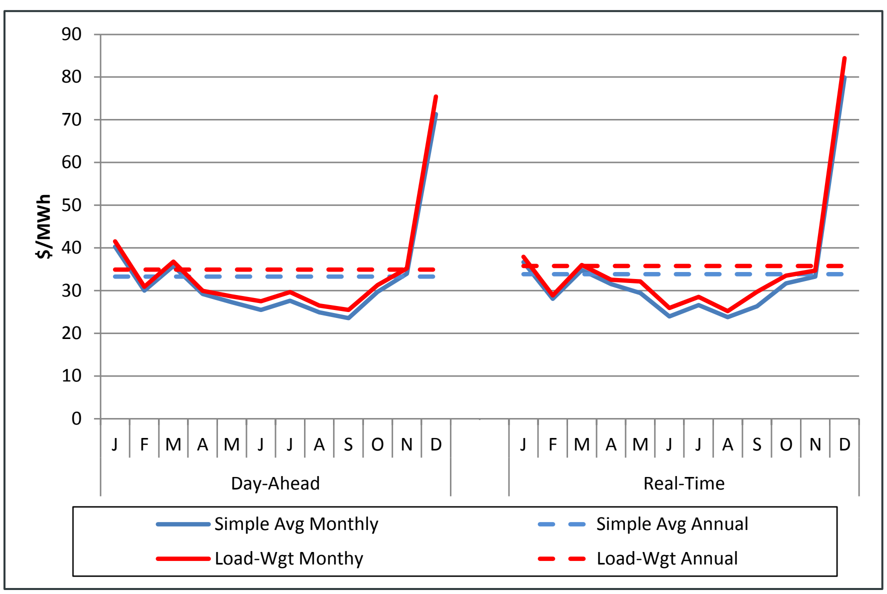
Conversely, NEMA had the highest average prices in both the day-ahead and real-time markets. NEMA average prices were slightly higher than the Hub's prices, by $0.10/MWh and $0.83/MWh, respectively. NEMA is import-constrained at times, with the transmission network limiting the ability to import relatively 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 LSEs pay for energy.[76] The amount of energy consumed in the markets can vary significantly by hour and energy prices are not uniform throughout the day. 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.

Monthly load-weighted and simple average prices for 2017 are provided in Figure 3-5.

Figure 3-5: Load-Weighted and Simple Average Hub Prices, 2017

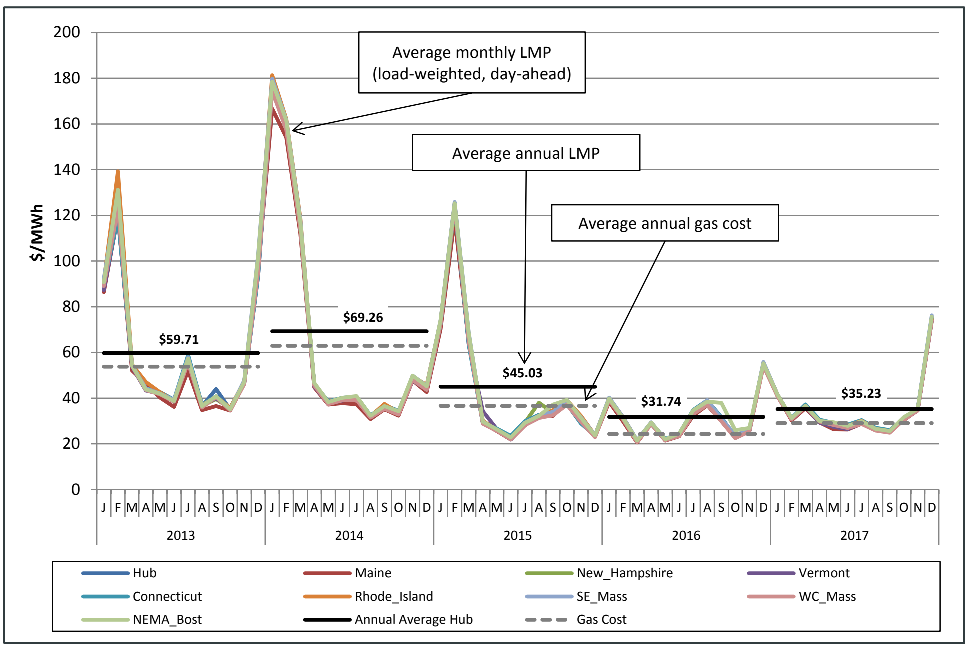


[76] While a simple average price weights each energy market price equally across the day, load weighting reflects the proportion of energy consumed in each hour: load-weighted prices give higher weighting to high-load consumption hours than to low load consumption hours, with each hour being weighted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

As expected, simple average electricity prices in 2017 were less than the load-weighted average prices. The difference ranges from approximately 2% to 11%, 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 2017, load variability during the day had the least impact on the average prices paid by wholesale consumers in April and February, when simple and load-weighted average prices differed by just 2% to 3% 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 12% (real-time market) in September.

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 2013 to 2017 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 the exception of May 2017, monthly average prices did not exhibit significant price differences across load zones over the review period.[77] Extreme pricing in the months of January and February occurred in 2013 to 2015 due to high natural gas prices. This is consistent with varying weather patterns and natural gas prices over the period, and reasonably uniform load shapes across load zones. Recent winter

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

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 describes how price convergence (the difference between day-ahead and real-time prices) can be a useful measure of market efficiency. It also explores some of the practical limitations that should be considered when interpreting this metric.

Expectation of Price Convergence

The energy market is based on a two-settlement approach that is standard in electricity and forward commodity markets. That is, a supplier can sell energy in the day-ahead *forward* market at a specific clearing price (i.e. the day-ahead LMP). Likewise, an LSE can buy energy at the clearing price. Megawatt deviations between the day-ahead obligation and real-time production or consumption are settled on the real-time *spot* price (i.e. the real-time LMP). For example, if a supplier delivers on its obligation, it has no deviation and therefore no exposure to the real-time *spot* price. On the other hand, if the supplier produces less than its *forward* day-ahead obligation, it must buy back the difference at the real-time price.

If the supplier expects a higher real-time price than day-ahead price, it would only be willing to sell at a price at least equivalent to the real-time price, or otherwise it would wait until real-time to produce electricity. Similarly, if an LSE expects a lower real-time price, it would only be willing to buy at, at most, the real-time price, or it would wait until real-time to buy the electricity it consumes. Therefore, in an efficient market, prices in the day-ahead and real-time markets should converge and make the supplier indifferent (no worse off) between selling in the day-ahead or real-time markets. Stated differently, the day-ahead offers of suppliers and bids of LSEs should reflect their expectations of real-time conditions and pricing outcomes.

As long as the day-ahead market represents real-time conditions, the day-ahead market provides a means to produce a least-cost schedule to reliably meet expected load. Creating a production schedule in the day-ahead market that is consistent with real-time conditions is important from a system operations and reliability perspective. Generators have operational and fuel procurement constraints that can be better managed when the obligation is received in the day-ahead market. Scheduling generators in the day-ahead market allows for more flexibility in unit selection. After the day-ahead market closes and the actual operating interval approaches, the list of generators that can be deployed shrinks, as longer-lead time generators are unable to start up in time. Therefore, there is a greater reliance on more expensive fast-start generators in real-time.

Factors Impacting Price Convergence

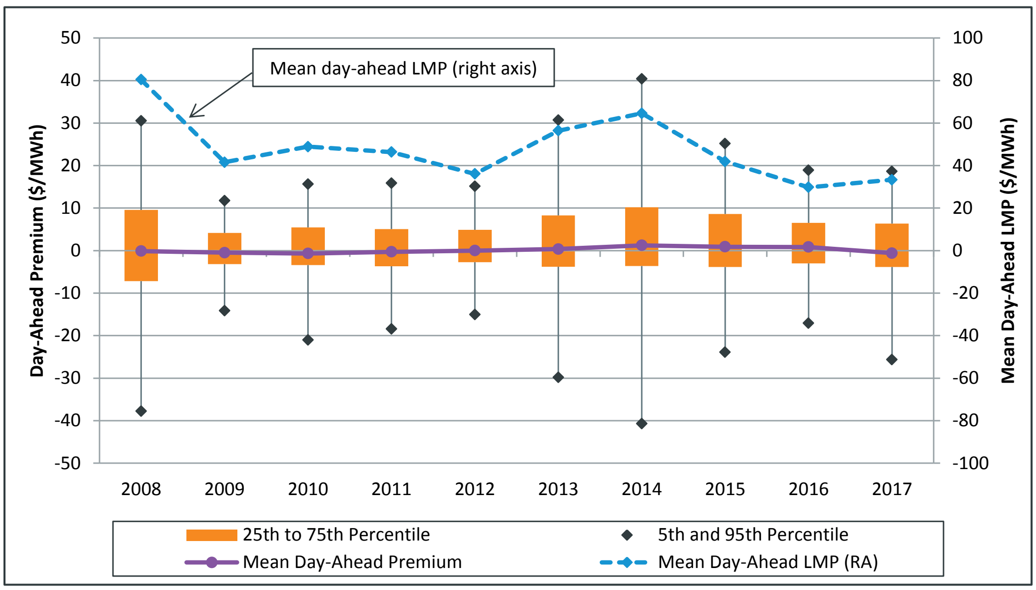
There are a number of practical issues that need to be considered when interpreting price convergence as a measure of market efficiency. The day-ahead market is not a perfect proxy for real-time conditions as there are times when convergence is not practical due to unforeseen circumstances. Real-time pricing is dependent on many variables. For example, real-time prices can be affected by the dispatch of higher cost units for reliability, load forecast error, forced outages, or other unpredictable system conditions. Also, obligations in either market have different risks and so a participant may have 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 physical delivery is expected allows the supplier to better manage buying and scheduling natural gas for the following day. This certainty can be valuable when the gas network is stressed and there is uncertainty about intra-day gas volumes and prices. 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.

Although price differences between the day-ahead and real-time markets can materialize in any given hour due to unforeseen circumstances, opportunities to profit from day-ahead and real-time differences exist, especially when price differences are predictable and measurable. Virtual transactions can be used to profit from those opportunities. They add to the market's liquidity, which is especially needed when physical producers and consumers may be reluctant to change behavior to converge prices. By moving day-ahead prices and adjusting the day-ahead schedule, virtual transactions contribute to efficient price convergence. Virtual transactions are discussed in more detail in Section 4.

Analysis

To begin the analysis of price convergence, Figure 3-7 below shows the distribution of the day-ahead price premium and the mean (average) day-ahead LMP from 2008 through 2017. A longer time series is shown for context due to changes in NCPC allocation rules in 2008 that impacted the ability of virtual transactions to profit from price differences (*i.e.* profitably converge prices).

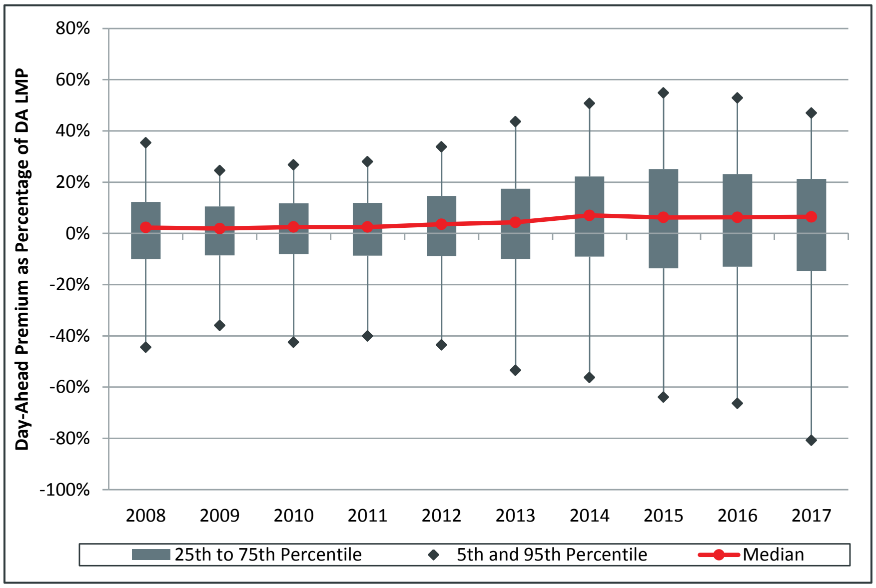
Figure 3-7: Day-Ahead Hub LMP Premium and Mean Day-Ahead LMP



In 2017, the mean day-ahead price premium (purple line in Figure 3-7) was -$0.58/MWh. This is down from $0.84/MWh in 2016. In other words, in 2017, a generator's revenue (or an LSE's cost) would have been $0.58/MWh less by selling into the day-ahead market in every hour versus selling in the real-time market (not accounting for the impact the sale may have on the day-ahead price). As discussed in Section 3.3.1, the annual average real-time premium was driven by outcomes in December 2017 when real-time prices at the Hub were $9/MWh higher than day-ahead prices.   In half of the hours in 2017, the price difference was between -$3.84 and $6.34/MWh. The distribution of differences between the day-ahead and real-time prices has generally been proportional to the average LMP level (i.e. the size of the orange boxes generally follows the blue line). Average LMPs are primarily driven by natural gas prices and 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 more pronounced when gas prices are higher.[78]

To account for changing fuel and energy prices the day-ahead price premium, as a percentage of the day-ahead LMP, is shown in Figure 3-8 below. The median is shown, as opposed to the mean, to account for outliers that result from dividing the premium by a very low day-ahead LMP.[79]

Figure 3-8: Day-Ahead Hub LMP Premium as Percent of Hub LMP



The median day-ahead price premium, as a percentage of the day-ahead LMP, has increased as a percentage of the day-ahead LMP since 2008. In 2017, the median day-ahead price premium as a percentage of the day-ahead LMP was 6%. The *range* of day-ahead price premiums as a percent of the day-ahead LMP has also increased. This may indicate that the day-ahead market is not reflecting real-time conditions as well as it has in the past. Additionally, the length of the bottom whisker has increased over time. Although in most hours the day-ahead LMP is higher, when the real-time price is higher, the difference is often higher in magnitude, as shown by the length of the bottom whisker in 2017. Improvements to increase market liquidity by increasing the volume of virtual transactions can help improve price convergence between the day-ahead and real-time markets.

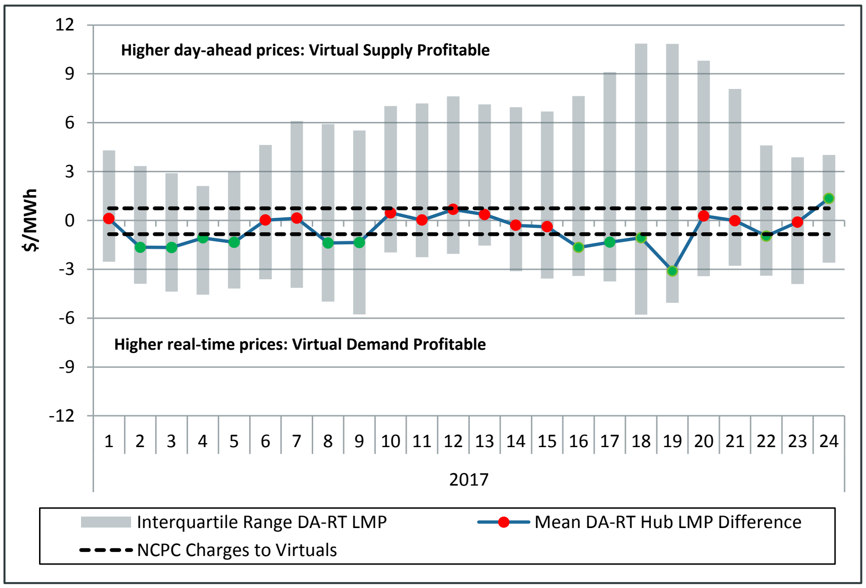
Although hourly price differences continue to offer profitable opportunities for virtual transactions, Net Commitment Period Compensation (NCPC) charges allocated to virtual transactions diminish the profitability and frequency of arbitrage opportunities. This is demonstrated in Figure 3-9 below which shows average hourly trends in the day-ahead and real-time price differences in 2017, together with average NCPC charges. The gray bars show the interquartile range (the middle 50%)

[78] For example, assume a gas-fired generator with a heat rate of 7 MMBtu/MWh is marginal during period 1 and period 2 in the day-ahead market. Also assume that a difference gas-fired generator with a heat rate of 10 MMBtu/MWh is marginal in the real-time market during the corresponding periods. If the gas price is $5/MMBtu for both generators in period 1, the day-ahead LMP is $35/MWh and the real-time LMP is $50/MWh, a difference of $15/MWh. If the gas price in period 2 is $10/MMBtu, then the day-ahead price is $70/MWh and the real-time price is $100/MWh, a difference of $30/MWh. Price divergence has doubled between period 1 and period 2 as gas prices doubled.

[79] In other words, the median was used because when the day-ahead LMP approaches zero, the day-ahead premium as a percentage of the day-ahead LMP approaches infinity, resulting in a misleading mean.

of day-ahead to real-time price differences. The blue line shows the mean 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, 2017



A couple of interesting observations can be made from Figure 3-9. First, the mean price difference was significantly influenced by outliers, particularly during hours ending (HE) 15 through 20. This can be seen in the position of the blue line within the interquartile range. For example, in HE 19 the majority of the gray bar is above the x-axis indicating that there was typically a day-ahead premium in that hour. However, the circle in that hour falls below the x-axis, indicating that high real-time prices, when they did occur, pulled the average down, causing the average day-ahead premium in that hour to be negative. The mean would be more reflective of a typical hour if only five hours (outliers) are removed. In other words, a virtual supplier that placed virtual supply offers in every hour would have been profitable in *most* hours; but, because their losses were larger than their gains, they would have been unprofitable *overall*. Therefore, a virtual participant could have taken advantage of systematic differences in price if they avoided placing bids or offers in the most extreme unprofitable hours.

Second, Figure 3-9 shows that in some hours it was not profitable for a virtual participant to help converge prices, on average. For example, in hours ending (HE) 10 through 15, the average gross profit to be made from a virtual bid is less than the NCPC costs it would be charged. While a participant will not know in advance what the allocated NCPC will be, this expectation of a loss (or a higher possibility of a loss) diminishes the incentive for a virtual participant to arbitrage these price differences.

NCPC charges to cleared virtual transactions make arbitraging differences in day-ahead and real-time prices less profitable, as the NCPC charges are often larger than the price differences. Although price formation is complex, and is dependent on many variables, a portion of the divergence may be attributed to a decrease in virtual transactions. In January 2017 the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rule changes (NOPR) regarding uplift cost allocation. FERC proposed that uplift cost allocations to deviations be consistent with cost-causation principles. That is to say, deviations that create the need for uplift should be charged.[80]

3.4 Drivers of Energy Market Outcomes

There are many factors that 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)

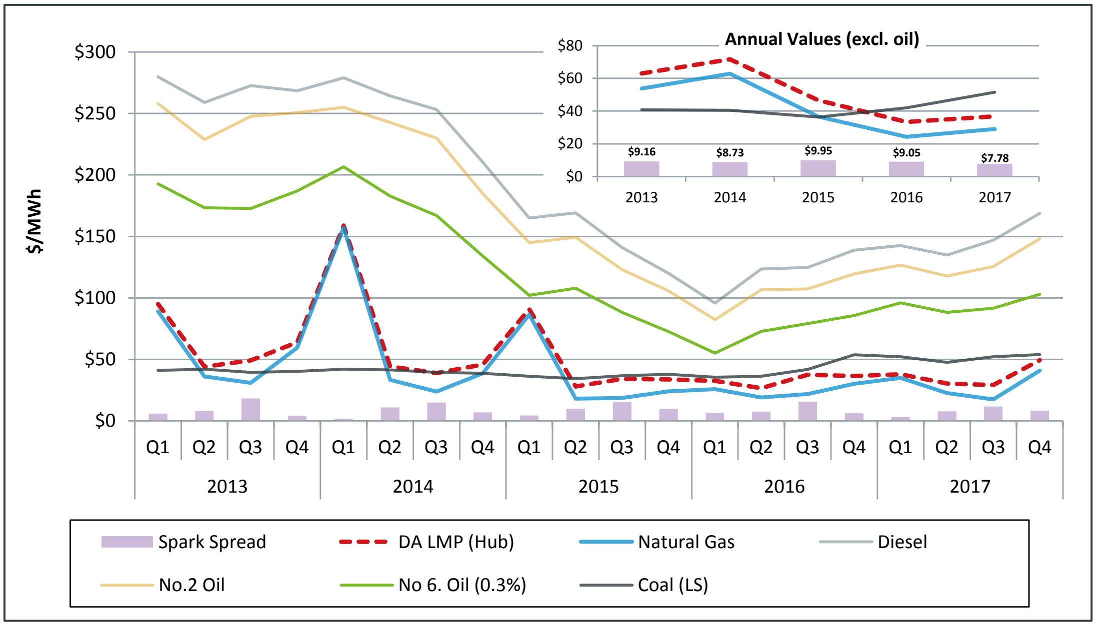
3.4.1 Generation Costs

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 thermal 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, we would expect New England electricity prices to be positively correlated with the estimated marginal costs of a typical natural gas-fired generator.

One way to understand the relationship between electricity prices and fuel costs is to compare the variable costs of generating electricity with different fuels to the wholesale price (LMP). The 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). 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. The red line represents day-ahead electricity prices, while other colors represent different fuel generation costs. Annual values are shown in the inset graph to better illustrate the long-term trend.

[80] *FERC Proposes Reforms to Uplift Cost Allocation and Transparency*. https://www.ferc.gov/media/news-releases/2017/2017-1/01-19-17-E-1.asp#.WOpYf2edzWw

Figure 3-10: Estimated Generation Costs and LMPs during Peak Hours[81]



Day-ahead and real-time electricity prices are, on average, closely correlated with the estimated costs of operating a natural gas-fired generator. The demand for electricity is typically higher during the summer months than in the winter months. During the summer months it is often necessary to operate less efficient natural gas-fired generators and/or generators that burn more expensive fuels – such as oil - to serve the load. During the summer periods (Q3), efficient natural gas-fired generators typically earn higher margins (commonly referred to as spark spreads) compared with the winter months.[82]

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.[83]

[81] 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

[82] During the winter months, coal- and oil-fired generators can displace natural gas-fired generators in the 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.

[83] During the 1990s, the region's electricity was produced primarily by oil, coal, 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 plants produced about 18% of New England's electricity. In contrast, by 2017, oil-fired plants produced 0.7% of electricity consumed in New England. Approximately 48% of electricity was produced by gas-fired generation and 2% by coal.

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

- An aging and declining fleet of nuclear, coal- and oil-fired generators, many of which were constructed during the 1960s and 1970s. These generators have been displaced by more efficient gas-fired generators in recent years.
- 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. As a consequence, the reliability of New England's wholesale electricity grid is dependent, in part, on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. 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 rise to levels that exceed the price of oil. 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 generators fueled by natural gas.[84] 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, set to begin June 1st, 2018.
- Introducing the Winter Reliability Programs, which will be needed until PFP becomes fully effective June 1, 2018.
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generators with the operating personnel of the interstate natural gas pipeline companies serving New England.
- Introducing changes to the energy market design, including improving price-signals for fast-start resources, accelerating the closing time of the day-ahead energy market (May 2013) and introducing energy market offer flexibility in December 2014
- Increasing ten-minute non-spinning reserve to be procured in the Forward Reserve Market to account for generator non-performance.

Relationship between natural gas and electricity prices

Average day-ahead LMPs and natural gas prices from 2012 to 2017 are shown in Figure 3-11 by quarter. Given the recent history of the highest natural gas and electricity prices occurring in the first quarter (Q1) of the year, Q1 is shown separately from the remainder of the year. The red bars represent average day-ahead LMPs corresponding to the left axis. The blue line represents average natural gas prices corresponding to the right axis.

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

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

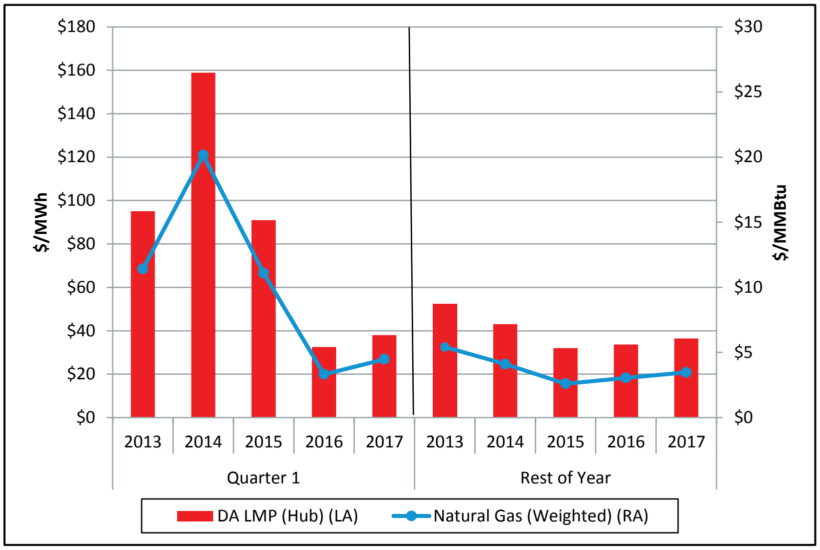
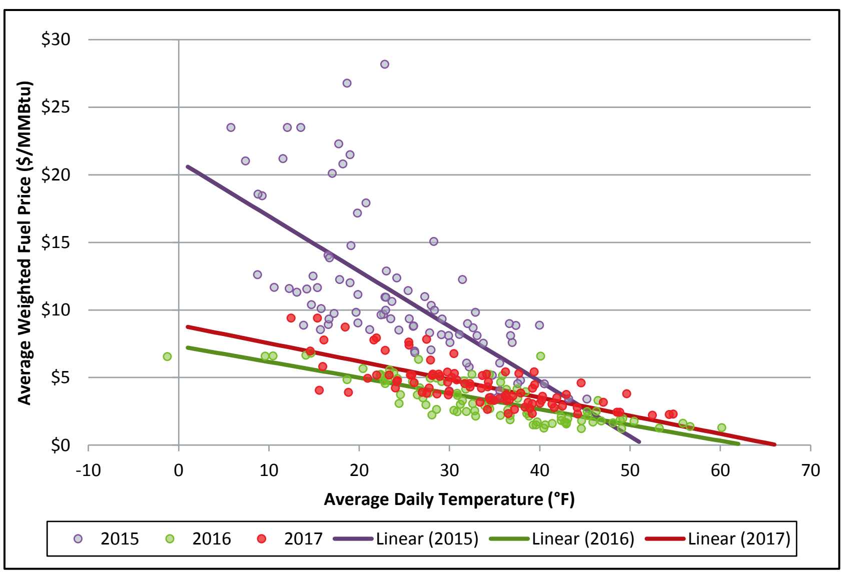


Figure 3-11 shows that during the first quarter of 2017, natural gas and electricity prices were higher than in 2016, but still well below 2013-2015 levels. Like 2016, the 2017 winter was warmer than usual, except for March.[85] The lower temperatures in March led to a 126% increase in gas prices year-over-year (from $1.96/MMBtu to $4.43/MMBtu), which was the driver of Q1 2017 increase.

Within each quarter there is variation in natural gas prices. When temperatures are low in the winter, gas-fired generators must compete with heating demand for 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 2015, 2016, and 2017 is illustrated in Figure 3-12. The observations and trend line for Q1 2017 are represented in red.

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



[85] See Section 3.4.3 for a detailed discussion on temperature.

The trend lines in Figure 3-12 show a negative correlation between gas prices and temperature; the lower the temperature the higher the gas price. The graph illustrates two trends. First, Q1 2017 gas prices were slightly higher than Q1 2016 prices, but still significantly lower than 2015 prices. The mean temperature in Q1 2017 was 32° F, compared to 34°F in 2016 and 24° F in 2015. The lower temperatures in Q1 2015 led to higher and more volatile gas prices.

Second, gas prices remained relatively stable in Q1 2017. On days with similar temperatures, natural gas prices in Q1 2017 were comparable to prices in Q1 2016 but significantly lower than Q1 2015 prices. For example, when the daily average temperature was less than 20°F in Q1 2017 and Q1 2016, gas prices averaged about $6.99/MMBtu and $6.32/MMBtu, respectively. For the same temperature range in 2015, prices averaged $14.96/MMBtu. The Algonquin Incremental Capacity (AIM) project may also have contributed to lower gas prices in Q1 2017. Spectra Energy completed the AIM project at the end of 2016, which added an additional 342 million cubic feet per day (MMcf/d) of capacity into New England. Increased capacity reduced the exposure to pipeline constraints during periods of high demand.[86]

3.4.2 Supply-Side Participation

Throughout 2017, about 80% of the supply (importers, generators) clearing in the day-ahead and real-time markets was unpriced. Unpriced supply is willing to sell (clear) in the market at any price (i.e., they are *price-takers* and not eligible to set clearing prices). 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. As a result, on average, only a small portion of the total supply clearing each day continues to be economically dispatched based on price.

The unpriced portion of the supply curve is made up of three types of unpriced transactions, including fixed imports, self-scheduled generation, and generation up to a resource's economic minimum limit.

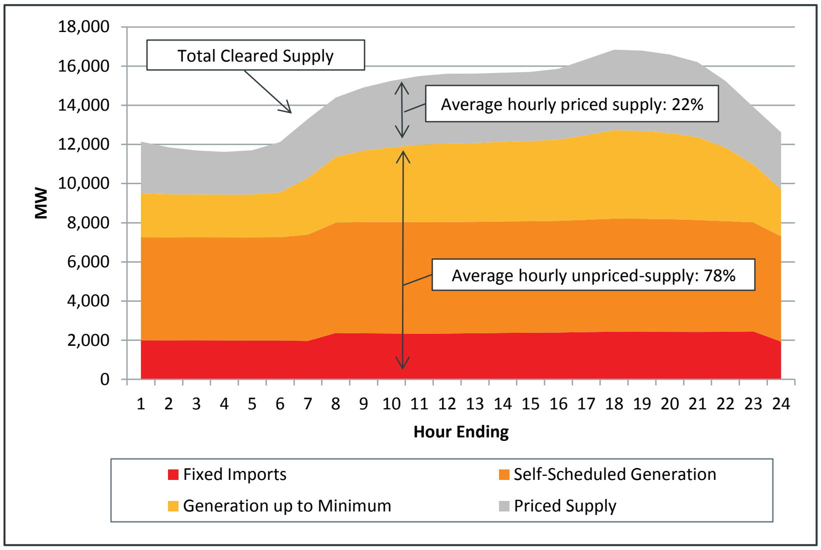
- **Fixed imports** refer to generation scheduled to flow into New England on the external interfaces regardless of price.
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum limit.[87]
- **Generation up to economic minimum** is fixed and cannot be dispatched down by the dispatch software without shutting down a generator. Generators committed economically and operating at economic minimum are included in the unpriced portion of the supply curve because their output up to (and including) their economic minimum limit is non-price setting in the energy market. However, unlike the other two categories, these generators are offering a price and are entitled to NCPC, should LMPs be insufficient to cover their as-offered costs.

[86] US Energy Information Administration. *New England natural gas pipeline capacity increased for the first time since 2010* Washington, DC: US Department of Energy, December, 2016. https://www.eia.gov/todayinenergy/detail.php?id=29032

[87] In the day-ahead market generators can self-schedule up to their economic minimum limit. In the real-time market, generators can self-schedule up to their economic minimum limit for each hour up to 30 minutes before the start of that hour. After this 30 minute deadline has passed, generators can then call the control room directly and request to be self-dispatched for that hour to any desired output level, as long as it does not cause or worsen a reliability constraint.

A breakdown of hourly average supply by its priced and unpriced components is shown Figure 3-13 below. The three subcomponents of the unpriced portion of supply listed above, **fixed imports**, **self scheduled generation** and **generation up-to economic minimum**, are shown as colored areas; supply that is **economically** dispatched is shown in gray.

Figure 3-13: Hourly Average Unpriced Day-Ahead Generation by Type, 2017

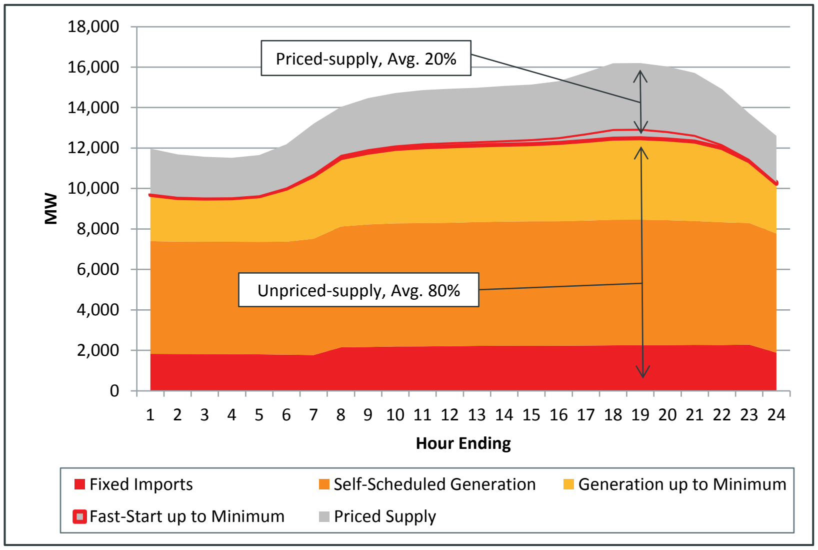


Note: Hour ending (HE) denotes the preceding hourly time period. For example, 12:00 a.m. to 12:59 a.m. is hour ending 1. Hour ending 6:00 p.m. is the time period from 5:00 p.m. to 5:59 p.m.

On average, 78% of the day-ahead supply cleared during each hour is from unpriced generation. Of this, fixed imports comprise 16%, self-scheduled generation makes up 38%, and economically committed generation up to economic minimum accounts for 24%, on average. Generation economically dispatched, with the ability to set price, accounts for only 22% of total supply, on average, over each day-ahead market day.

Frequently, participants choose to represent their day-ahead schedules as fixed schedules in the real-time market. This helps them manage some of the risk associated with fuel procurement. The increase in unpriced generation further decreases the amount of generation economically dispatched and able to set price in real-time. Figure 3-14 shows a breakdown of the hourly average real-time generation by price setting ability along with average hourly cleared supply. In real-time, non-self-scheduled fast-start generation up to economic minimum is shown as an additional category. In March 2017, the ISO implemented fast-start pricing to allow fast-start resources to set price in a broader range of circumstances. Fast-start pricing logic relaxes the economic minimum limits of online ISO-committed fast-start generators to zero for pricing purposes. Before March 2017, the generation shown inside the red lines would have been fixed (part of the yellow area). It is no longer fixed supply for pricing purposes – it is shown here to illustrate how fast-start pricing decreased the volume of unpriced real-time generation.

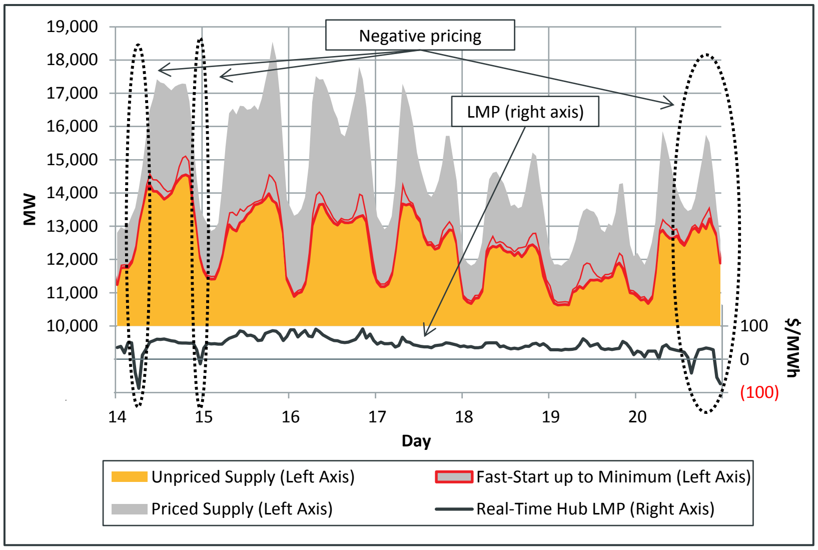
Figure 3-14: Hourly Average Unpriced Real-Time Generation by Type, 2017



On average, over 80% of the supply cleared during each hour in real-time is from unpriced generation. Comparing Figure 3-13 and Figure 3-14, on average, the amount of generation economically dispatched in real-time is slightly lower, but consistent with the day-ahead. On average, 20% of the total cleared supply is comprised of dispatchable generation. Self-scheduled generation makes up a larger percentage of cleared supply in the real-time market than in the day-ahead market (42% versus 38%). Both fixed imports and non-self scheduled generation up-to economic minimum make up about 1% less cleared supply in the real-time market when compared with day-ahead. The fast-start pricing rules increased the amount of generation capable of setting price by an average of 200MW per hour, and by as much as about 470 MW in peak hours (gray area).

A decrease in the supply of economically dispatched generation increases the likelihood of low or negative prices, as shown in Figure 3-15 below. The graph shows a breakdown of total supply by unpriced and priced supply alongside the real-time Hub LMP during this period.

Figure 3-15: Unpriced Real-Time Generation by Type and Hub Real-Time LMP, Mar. 14-20, 2017



The example shows how a large amount of unpriced generation contributed to negative pricing during the early morning hours over the period of March 14–20, 2017. Negative pricing occurred when cleared supply was substantially comprised of unpriced generation. During these times, very little generation with price-setting capability was economically dispatched — these times are highlighted by the oval shapes.

The small amount of generation economically dispatched had offered into the market with negative offers, resulting in negative prices. Such negative-pricing situations tend to only occur when the system is approaching a point of over-supply due to the limited downward dispatchability and price-setting capability of on-line resources.

An example of real-time negative pricing is shown below in Figure 3-16. The figure shows an estimate of the real-time pricing supply curve on March 20, at 3:30PM. Generation is shown in ascending order of price. Fixed generation up to economic minimum (EcoMin) is shown in yellow at -$150, the ISO offer floor, for convenience. The gray line denotes non-fixed, non-fast-start generation. The red line shows fast-start generation below economic minimum. In this case, most of the online fast-start generation was intermittent resources priced at -$150. The figure shows a 500MW portion of the supply curve, from 10,450MW to 10,950MW. Supply up to 10,500 MW is fixed. About 10,775 MW of generation cleared in this interval.

Figure 3-16: Real-Time Supply Curve, March 20, 2017, 3:30 PM

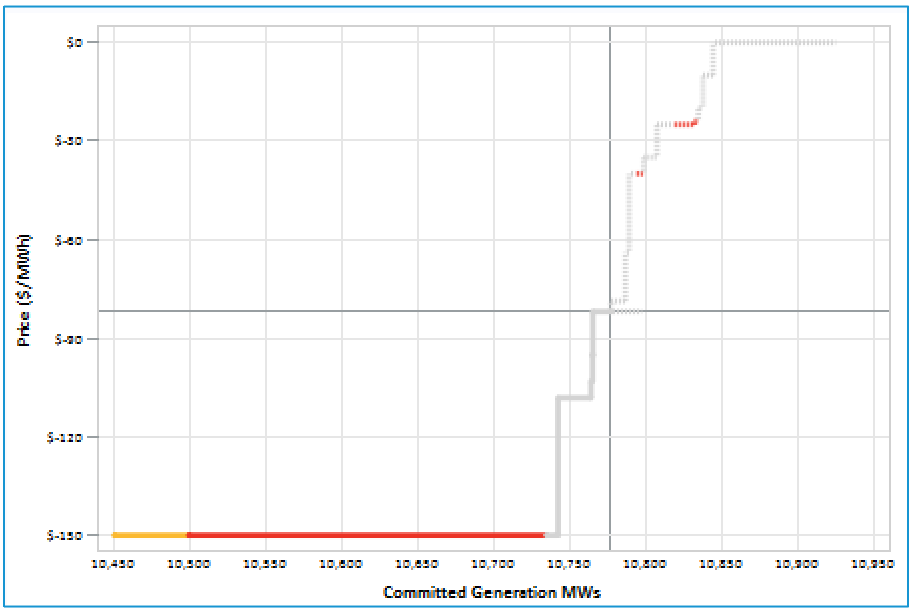


Figure 3-16 An example of real-time negative pricing is shown below in Figure 3-16. The figure shows an estimate of the real-time pricing supply curve on March 20, at 3:30PM. Generation is shown in ascending order of price. Fixed generation up to economic minimum (EcoMin) is shown in yellow at -$150, the ISO offer floor, for convenience. The gray line denotes non-fixed, non-fast-start generation. The red line shows fast-start generation below economic minimum. In this case, most of the online fast-start generation was intermittent resources priced at -$150. The figure shows a 500MW portion of the supply curve, from 10,450MW to 10,950MW. Supply up to 10,500 MW is fixed. About 10,775 MW of generation cleared in this interval.

Figure 3-16shows how negative prices can result from large volumes of online fixed supply. In this interval, 10,775 MW of generation cleared, 10,500 MW of which was fixed at or below economic minimum. Additionally, there was 240 MW of fast-start generation below economic minimum that was offered into the market at the floor price, which was -$150/MWh. These generators were not fixed, but offered at the lowest price possible. This may due to these generators having off-take contracts, with limited exposure to real-time LMPs and an incentive to clear their contracted volumes at any price. There was only about 25 MW of dispatchable generation priced above the offer floor that cleared. The supply offer of the marginal unit, and the market clearing price, was -$82.50/MWh.

Negative pricing can typically only occur if there are entities offering at a negative price that are online and capable of setting price. Before energy market offer flexibility was implemented in December 2014, generators could not offer at negative prices and system level negative LMPs could only occur in emergency conditions. Since then, LMPs have been negative in about 1.5% of hours. Additionally, Section 3.4.10 (marginal resources) discusses energy market price-setting and Do-Not-Exceed (DNE) dispatch rules that went into effect in May 2016, which increased the number of intermittent resources eligible to set price. Intermittent generators are generally inexpensive, and often offer at negative prices. The frequency of negative pricing has increased in Maine and New Hampshire as a result of DNE rules and the offer behavior of generators for which those rules apply.

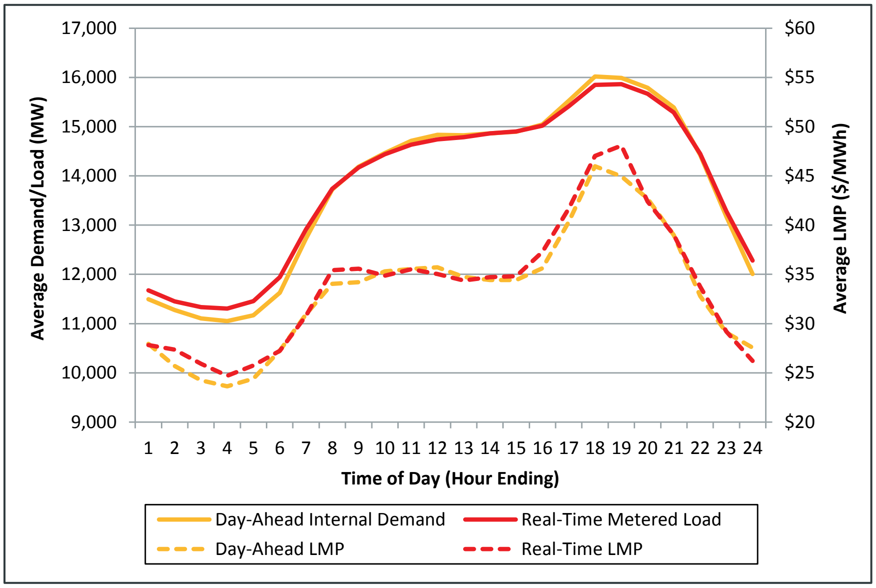
3.4.3 Load and Weather Conditions

Wholesale electricity load trends are driven by a number of factors, including weather, economic changes, energy efficiency measures, and time of day. Behind-the-meter photovoltaic generation, albeit relatively small, is also having an increasing (downward) impact on wholesale load levels. Load is one of the most important drivers of energy prices. Higher load generally leads to higher prices when other factors, such as fuel prices and outages, are similar. This is particularly evident within an operating day, with the highest-priced hours typically coinciding with the highest load levels – see Section 3.3.3 on load-weighted prices.

Demand/Load Statistics

The average time-of-day profile of day-ahead demand, real-time load and LMPs in 2017 are shown in Figure 3-17 below.

Figure 3-17: Demand Vs. LMP



The figure shows a clear positive correlation between demand levels and prices in both the day-ahead and real-time markets. It also shows that most demand clears in the day-ahead market, with relatively small demand deviations settled in the real-time market. The average difference between day-ahead cleared demand and real-time load was less than 1% in 2017.

New England's native electricity load is shown in Table 3-1 below.[88] The table includes total and hourly average load in actual and weather-normalized terms.

Table 3-1: Load Statistics

	NEL (GWh)	NEL (average hourly MW)	Recorded Peak Demand (MW)	Normalized NEL (GWh) [(a)]	Normalized NEL (average hourly MW)
2013	129,377	14,769	27,379	127,754	14,584
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	121,097	13,824	23,968	120,668	13,775

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

NEL in 2017 was the lowest of the five-year period shown above, at 121,097 GWh, equivalent to an average hourly value of 13,824 MW. This is a reduction of 2%, or 341 MW per hour, on 2016 NEL. In fact, NEL was at its lowest level in the past 18 years.[89] Average load levels have declined since 2005 when total consumption peaked. The major contributing factors to the reduction in load in

[88] Load in this analysis refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation and net interchange (imports minus exports). It excludes pumped-storage demand.

[89] Demand data predating 2000 was not available to draw historical comparisons.

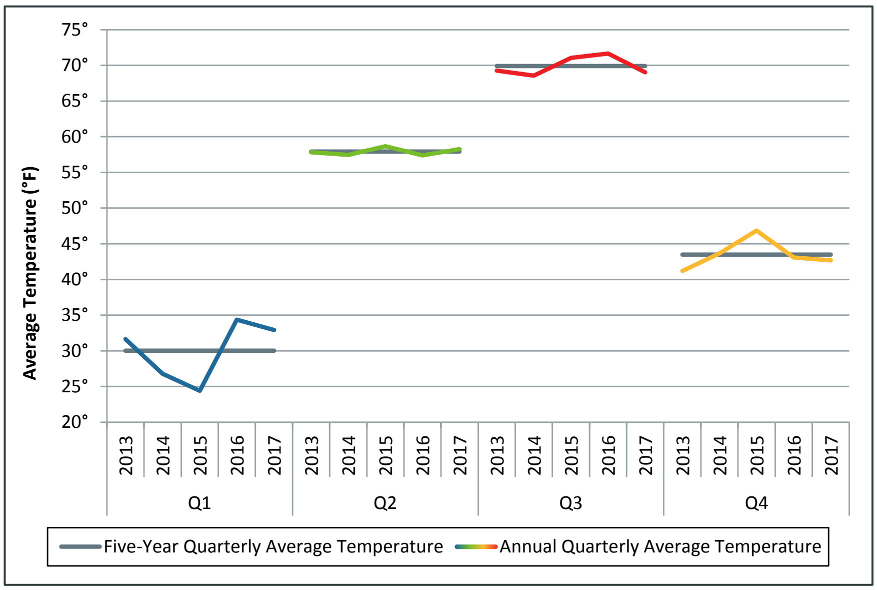
2017 were mild weather, energy efficiency programs and the growth in behind-the-meter solar generation in New England.[90]

The 2017 annual peak load of 23,968 MW was set on June 13 during hour ending 17. There was a heat wave from June 11-13, with high temperatures of over 90°F. Loads exceeded 23,000 MW for five hours on the June 13 and three hours on June12. This was the first year since 2000 in which loads did not exceed 24,000 MW at any time.

Impact of Weather

New England weather in 2017 was marked by relatively average temperatures throughout most of the year. Quarterly average[91] and five-year average temperatures for 2013 through 2017, are provided in Figure 3-18 below. Throughout this section, seasons are denoted by color to highlight the seasonality of weather and load trends. **Q1**, which includes a majority of the winter, is shown in blue, **Q2** (spring) is green, **Q3** (summer) is red, and **Q4** (fall) is yellow.

Figure 3-18: Actual and Normal Temperatures



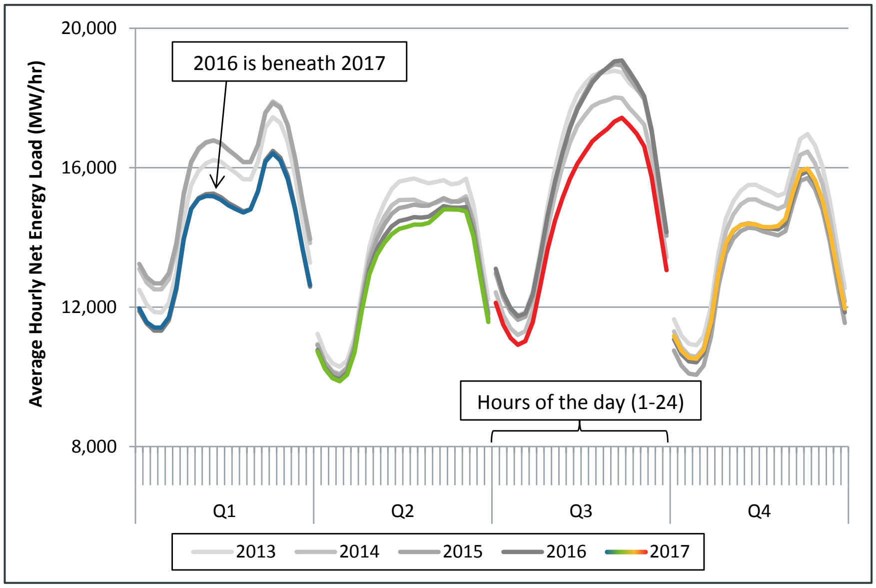
Temperatures were relatively warm in the first quarter of the year. Q1 temperatures were about 3°F warmer than average, although they were about 1°F colder than in 2016. Temperatures during Q3 were slightly lower than the five-year average. Compared with 2016, the average Q3 temperature was milder, falling 3°F from 72°F to 69°F.

Average hourly load by quarter for the last five years is shown in Figure 3-19 below. Each curve shows an aggregated hourly load curve from the quarter shown on the x-axis and the year shown by each line. Load curve shapes differ 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.

[90] The impact of energy efficiency on demand is discussed in more detail in Section 2.3.

[91] 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 3-19: Average Hourly Load by Quarter



Q1 2017 had relatively low loads, and nearly identical average load to 2016. The lower load levels were driven by relatively high temperatures. During Q2 and Q4, load was relatively low, but consistent with 2016. Q3 2017 load was exceptionally low compared with previous third quarters. The average temperature in Q3 2017 was only about 1°F cooler than the average Q3 temperature in the previous three years, and 3°F cooler than Q3 2016. As discussed above, energy efficiency programs and behind-the-meter solar have led to a reduction in load in the past few years. These programs have a greater impact on load in the summer when loads are generally higher, and solar panels have more hours of unimpeded sunlight.

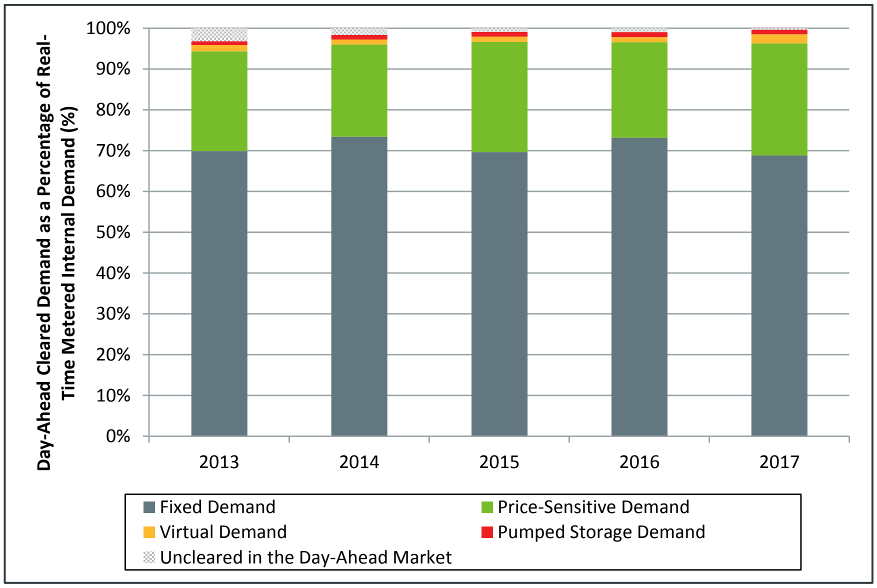
3.4.4 Demand Bidding

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.[92]

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 3-20 below.

[92] Reserve Adequacy Assessment (RAA) ensures 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 3-20: Components of Cleared Demand in the Day-Ahead Market

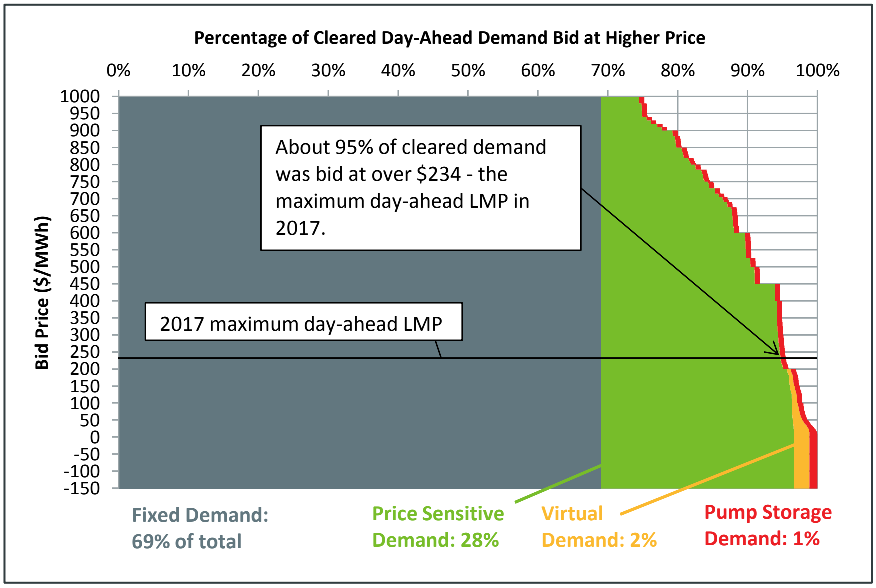


Total fixed demand bid volumes decreased from 73% of real-time load in 2016 to 69% of real-time load in 2017. Fixed bids indicate that participants are willing to pay the market clearing price, regardless of cost. Participants substituted to price-sensitive demand, which increased as a percentage of real-time load from 23% to 27%. In 2017, virtual demand bids increased from 1% to 2% of total real-time load. Virtual transactions are discussed more 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 3-21 below. Price levels are shown on the y-axis. On the x-axis, the percentage of cleared bids that were willing to clear at each price level is shown. For example, about 95% of cleared day-ahead demand was willing to pay more than $234/MWh, the maximum day-ahead hub LMP that was observed in 2017.

Figure 3-21: Components of Day-Ahead Cleared Demand as a Percentage of Real-Time Demand



Generally, demand cleared in New England is price insensitive. Almost 70% of total day-ahead demand was fixed and would have cleared at any price. Additionally, 93% of price-sensitive demand, the second most significant bid type in terms of volume, cleared with a bid above the maximum day-ahead LMP in 2017. Small jumps are visible at $600 and $450/MWh, where large volumes of price-sensitive demand bids were offered during the year. Although pumped-storage demand accounted for a much smaller percentage of day-ahead cleared demand in 2017, most was bid as fixed energy. About 66% of pumped storage demand that cleared in the day-ahead market was self-scheduled. Overall, about 95% 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 2017.

3.4.5 Load Forecast Error

The ISO produces multiple load forecasts, ranging from several days in advance of the operating day to short-term forecasts within the operating day. The following analysis focuses on the final forecast made before 11:00AM prior to the operating day, which is the final estimate of expected real-time load that is available before the day-ahead market is cleared.[93] The ISO's load forecasts before the operating day are used in reserve adequacy assessments to make generator commitment decisions. Additionally, each morning the day before the operating day, the load forecast is published and available to the market, and likely informs participant bidding positions in the day-ahead market.

The ISO's load forecasts will inevitably differ from actual loads. There are many unanticipated factors that affect load, including unexpected weather, behind-the-meter generation, and industrial customer processes. These factors contribute to load forecast error. Forecast error can provide insight into energy market outcomes, including day-ahead and real-time price divergence, extreme real-time prices, and reserve pricing.

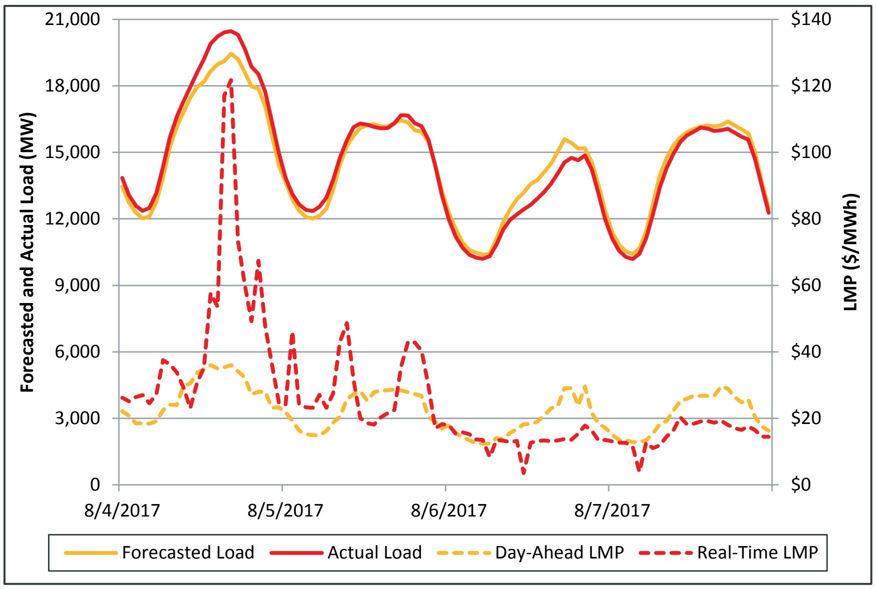
For instance, if the ISO forecasts loads that are significantly greater than actual loads, more resources will be committed than needed in the day-ahead market. This can result in real-time

[93] This forecast was made within 15 minutes of 9:30AM 96% of the time.

prices that are lower than day-ahead prices because more expensive resources are backed down from their day-ahead positions. Alternatively, if actual loads are greater than the forecast, fewer resources will likely be committed in the day-ahead market than will be 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 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.

A four-day stretch in which there were times of over- and under-forecasting is shown in Figure 3-22 below to illustrate how forecast error can impact price. August 4, when actual loads were greater than forecasted loads, is shown along with August 6 and 7, when actual loads were lower than forecasted loads, and August 5, when there were times of each during the day. Day-ahead and real-time Hub LMPs are shown with dotted lines.

Figure 3-22: Forecasted and Actual Load vs. Day-Ahead and Real-Time LMPs



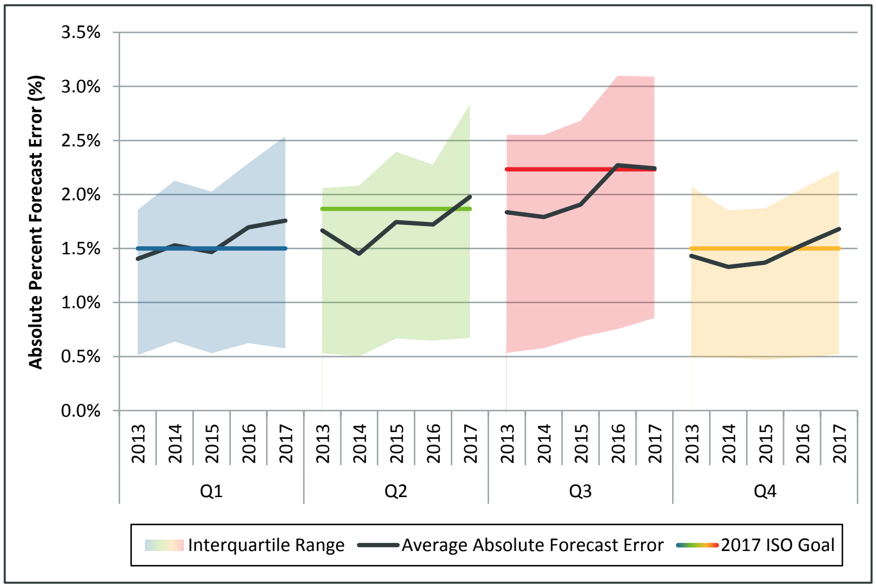
On August 4, the actual peak load was 20,470 MW, over 1,000 MW higher than the forecasted peak load of 19,450 MW. At noon, load forecast error jumped to over 1,000 MW, and remained above that level until 6PM EST. The average forecast error during that time was 1,142 MW, and the average difference between real-time and day-ahead prices was about $40/MWh.

There were periods of over- and under-forecasting on August 5. The forecast error was not as pronounced as the previous day, but real-time prices were directionally correlated with the forecast error. Before 1PM, the actual load was above the forecasted load by an average of 300 MW, and the real-time prices were greater by about $9/MWh. From 1PM to 5PM, the actual load was under the forecast by an average of about 75 MW and real-time LMPs were less than day-ahead LMPs by an average of $8/MWh. From 5PM until 9PM, real-time prices were again higher as actual loads exceeded the forecast.

August 6 and 7 loads were consistently under the forecast. Hourly actual load never exceeded the forecast, and the average hourly load was almost 400 MW lower than forecast. Similarly, real-time LMPs were lower by an average of $5.44/MWh, and were lower in every hour after 6AM on the August 6.

These four days illustrate the relationship between forecast error and price. To quantify the accuracy of the ISO's load forecast error, Figure 3-23 shows the mean absolute percent forecast error (MAPE) by quarter for the last five years. Also shown is the 25th through 75th percentile of absolute percent load forecast error[94] to illustrate the general range of ISO forecast errors. The colored lines represent the 2017 ISO goals for the MAPE.

Figure 3-23: Load Forecast Error by Quarter



Overall, in 2017 ISO load forecast error was 1.9% — slightly higher than the 2017 ISO target of 1.8%. Load forecast error, and the ISO forecasting targets, vary seasonally. Forecast error tends to be higher in the summer when loads are higher and behind-the-meter solar generation depresses wholesale demand. Recently, forecasting load has become more difficult, largely due to an increase in behind-the-meter photovoltaic generation.

3.4.6 Supply/Reserve Margin

The supply margin measures the additional available capacity over the 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 LMPs. Additionally, the energy market is more susceptible to market power when system conditions are tight.

We use the reserve margin as a proxy for the capacity margin because the reserve margin is the difference between available capacity and demand. The equations below illustrates this relationship:

i. $Gen_{Energy} + Gen_{Reserves} + [Imports - Exports] = Demand + [Reserve\ Requirement]$

Equation i. is equivalent to:

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

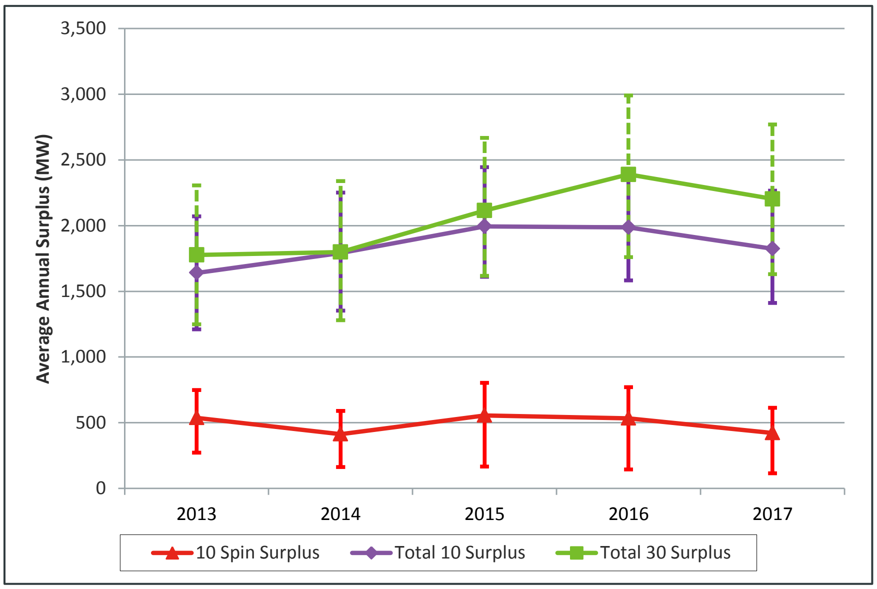
[94] The forecast used in these analyses is the forecast generated between 7AM and 11AM on the day before the Operating Day.

$$Supply + Reserve\ Margin = Demand$$

The reserve margin is the only difference between supply and demand, and represents the additional capacity 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 bars branching off of each line show the 25th and 75th percentiles for each reserve margin. 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 by Product



In 2017, the average reserve surplus for each product was lower than in 2016. The total 30-minute reserve surplus decreased by 186 MW in 2017 relative to 2016. Demand was lower in 2017, which resulted in less online generation and lower available reserves. The requirements for each reserve type also increased slightly, which contributed to the decrease in surplus relative to 2016.

3.4.7 System Events during 2017

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 2017 bear specific mention.

October 30, 2017

The first system event occurred on October 30, when a storm brought strong winds and rain to New England[95]. Heavy rain caused destructive flash flooding, and 70 mph wind gusts downed trees across the region. That morning, the ISO declared a Master/Local Control Center Procedure No. 2

[95] Additional details on the October 30th system event are available in IMM's 2017 Fall Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2018/02/2017-fall-quarterly-markets-report.pdf.

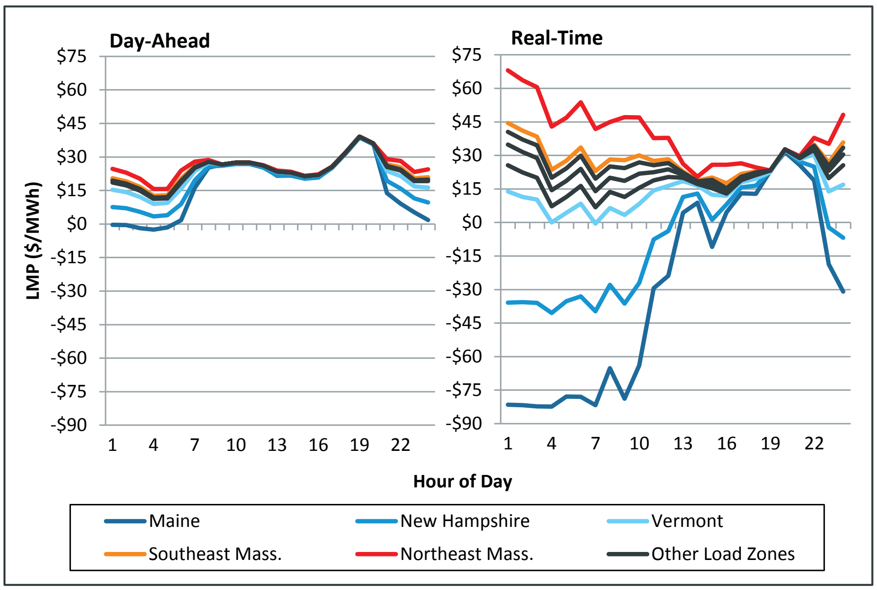
(M/LCC2), signaling abnormal conditions due to severe weather. The storm caused equipment outages that left 1.2 million customers (about 1 out of every 6) without power. This affected load patterns and zonal pricing.

Customer outages resulted in actual loads that were significantly lower than early load forecasts. On October 30, actual loads were over 1,500 MW lower than the day-ahead load forecast for 13 hours. The forecast was adjusted down at 4AM EST on that day, but this forecast still overestimated actual load by an average of about 1,000 MW for 12 hours. A more accurate forecast was then generated at 8AM. While the ISO's early forecasts were inaccurate, some error is to be expected given the extreme weather conditions and unplanned outages.

During the system event, the total decrease in system-wide demand was about 10%, or about 1,200MW, on average, throughout the day. About 750 MW of that was attributable to decreases in Maine, New Hampshire and Rhode Island, areas where the storm had the most severe impact. The three largest load zones by consumption (Connecticut, Northeast Massachusetts, and Western/Central Massachusetts) experienced the smallest percentage decreases in demand.

There was also significant price separation between load zones during the system event. Price separation occurred in the day-ahead market due to a planned equipment outage, and then became much more pronounced in real-time. Day-ahead and real-time prices by load zone on October 30, 2017 are shown in Figure 3-25 below.

Figure 3-25: Zonal Price Separation in the Day-Ahead and Real-Time Energy Markets



Prices were the lowest in Maine, Vermont, and New Hampshire due to several factors. First, these three states saw a 620 MW or 21% reduction in their combined demand from day-ahead to real-time on average, due to customers losing power. Second, the strong winds of the storm resulted in even more real-time renewable generation, which had not cleared in the day-ahead market. This additional inexpensive generation also had a price-suppressing effect in real-time.

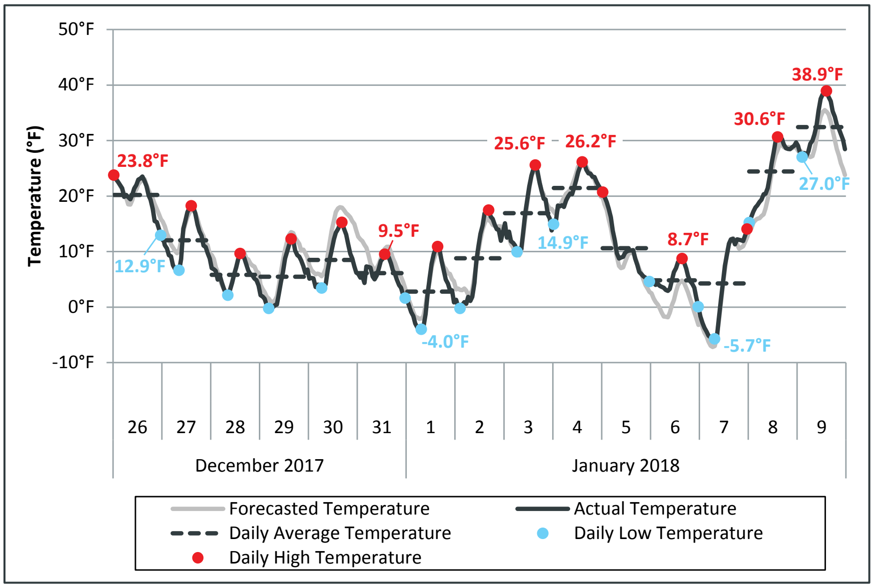
The other load zones did not experience the same dramatic reduction in real-time prices. The average decrease in demand between the day-ahead and real-time markets was 575 MW on average in the remaining zones). Though this reduction was similar in volume to the 620 MW demand decrease in Maine, New Hampshire, and Vermont, it represented a much smaller portion of cleared day-ahead demand in the remaining zones (6% compared to 21%). In the morning of October 30, a large generator in Connecticut had to reduce its capability in real-time by approximately 300 MW. This reduction had an offsetting impact on the effect of the decrease in load in the remaining New England load zones.

December 2017-January 2018 Cold Snap[96]

The system experienced abnormal conditions from December 26, 2017 through January 9, 2018 as a result of cold weather, constrained natural gas and oil systems, and the switch in economic merit order between gas- and oil-fired generation. December 26 through January 7 was the coldest 12-day stretch observed in New England since 1980. In addition to the extreme cold, a blizzard known as "the bomb cyclone" brought snow and ice into the region on January 4 and 5, causing severe coastal flooding. The ISO issued a Cold Weather Watch on several days, and implemented an M/LCC 2 (Abnormal Conditions Alert) event from January 3 through January 9.

Hourly New England forecasted and actual temperatures from December 26 through January 9 are shown in Figure 3-26. Forecasted temperatures are shown by a light gray line, and actual temperatures are represented by a solid black line. Red dots signify actual daily highs, blue dots show daily lows, and average daily temperatures are shown by horizontal dotted lines.

Figure 3-26: Hourly New England Temperatures during Cold Snap

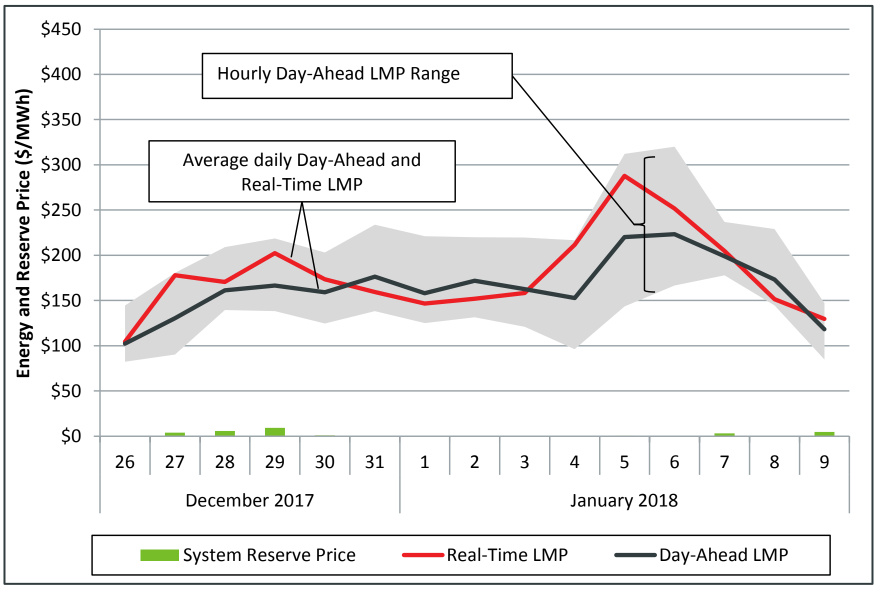


On December 26, peak load was about 18,500 MW, the lowest peak load until January 9 (18,100 MW). The average real-time load from December 27 through January 8 was 17,200 MW, 18% above the season average from the past three winter seasons. The highest load during the period was 20,600 MW on January 5, when the temperature dropped rapidly from a high of 21°F in the first hour of the day to a low of 4.6°F in the last hour of the day. It was the highest winter peak load observed since January 2014.

[96] A detailed report on market performance during the Cold Snap can be found in the Winter 2018 Quarterly Markets Report. See https://www.iso-ne.com/static-assets/documents/2018/05/2018-winter-quarterly-markets-report.pdf

Prices during the Cold Snap were high, reflecting high load levels and fuel prices. Average daily day-ahead prices during the 15-day period were between $103 and $220/MWh. Over the past three winters, the nine highest-priced days in the day-ahead market and the ten highest-priced days in the real-time market were observed during the Cold Snap. Day-ahead and real-time Hub energy prices, as well as system reserve prices, are shown below in Figure 3-27. Day-ahead prices are shown with a solid black line. The range of day-ahead prices is also shown by the gray area. The red line shows real-time Hub LMPs. The green bar at the bottom shows the system reserve price. Average reserve prices during the Cold Snap were very low and comprised entirely of spinning reserve (TMSR) pricing.

Figure 3-27: Day-Ahead and Real-Time Energy and Reserve Prices



The highest prices during the Cold Snap were observed on January 5 and 6 as temperatures averaged about 8°F. These days experienced the highest natural gas prices of the Cold Snap, at over $60 and about $47/MMBtu, respectively. Additionally, peak loads on January 5 and 6 exceeded 20,000 MW, and generator outages were significant with over 3,000 MW of capacity out of service. Generator outages were largely a result of mechanical issues, rather than fuel procurement problems. Real-time prices were significantly higher than day-ahead prices on January 4 and 5 as a large nuclear generator was forced out of service in real-time.

Natural gas prices exceeded oil and coal prices during the Cold Snap due to tight pipeline conditions. This, in turn, impacted generation costs. Generation costs for natural gas-fired generators averaged $211/MWh during the Cold Snap. On average, natural gas generation costs were 285%, 92%, and 27% higher than coal, No 6. oil, and No 2. Oil costs, respectively. Elevated natural gas prices impacted the merit-order of natural gas-fired generation. This, in turn, caused many dual-fuel generators to switch from natural gas to their alternate fuel source.

Overall, the fuel mix of generators providing supply throughout the period reflected the change in relative fuel prices. At the start of the Cold Snap on December 26, natural gas-fired generators supplied, on average, 4,500 MW per hour or 31% of the total supply. As natural gas prices rose, natural gas-fired generators provided a declining share of supply, with its supply reduced to 2,500 MW per hour, on average, (15% of total supply) by January 5, the peak of natural gas prices.

Oil-fired generators, which typically have higher dispatch costs than natural gas-fired generators, became in-merit more frequently during the Cold Snap, displacing the supply from some natural gas-fired generators. While oil-based generators provided just 435 MW of supply per hour on average on December 26, output from oil-fired generators rose to about 5,000 MW per hour on average, or 30% of total supply, from January 5 through 7. In addition to displacing natural gas-fired generation, oil-fired generation also offset a 650 MW per hour average reduction in nuclear generation resulting from an outage on January 4.

Despite fuel system constraints and high loads, there were no scarcity issues in the electricity market. Average reserve surpluses were healthy, at 500, 2,400, and 3,000 MW for 10-minute spinning, 10-minute non-spinning, and 30-minute operating reserves, respectively. There were 28 hours of (non-zero) spinning reserve pricing, but no instances of non-spinning reserve pricing. By the end of the Cold Snap, oil-fired generators had depleted stocks to about 20% of full inventory, with many large generators only having enough oil left to operate for a few more days.

3.4.8 Reliability Commitments

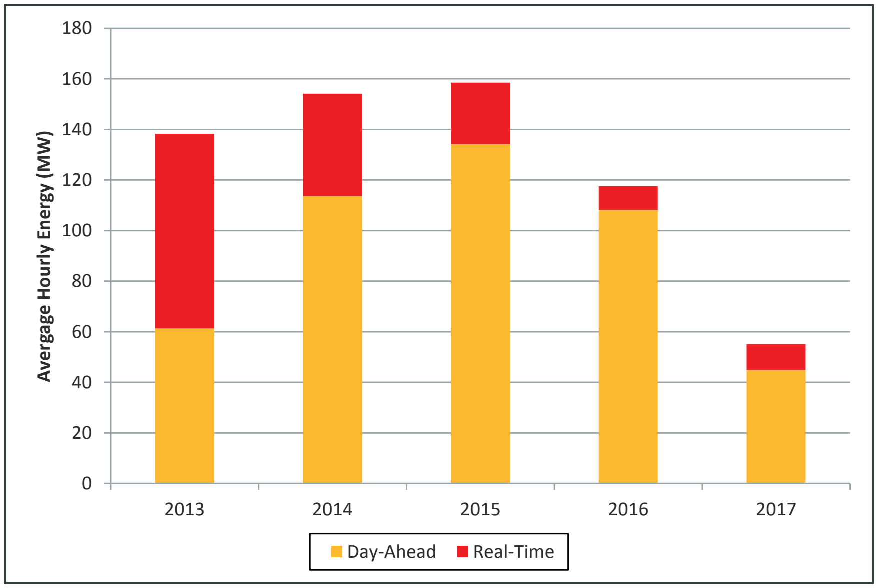
The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[97] To meet these requirements, 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.

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 did not exist) 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. These generators are typically combined cycles that can be run in multiple configurations, and are discussed at the end of this section.

In 2017, the amount of ISO reliability commitments decreased. The real-time average hourly energy output (MW) from reliability commitments during the peak load hours (hours ending 8-23) for 2013 through 2017 is shown in Figure 3-28. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

[97] 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 during Peak Load Hours (HE 8-23)



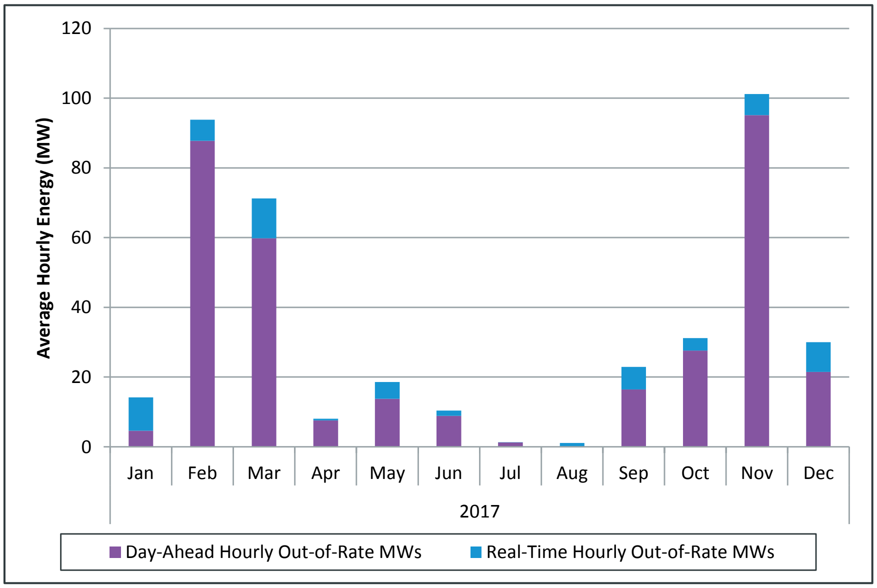
Reliability commitments remain a relatively small component of total system generation, at less than 0.5%, on average. The average hourly energy from reliability commitments during the peak load hours increased over time prior to 2016, but decreased substantially in 2016 and 2017. Commitments in the day-ahead market have become more common as a percentage of total reliability commitments.

The reduction in overall reliability commitments in 2017 was due to significantly less local second contingency reliability commitment output from September through November. In 2017, 67% (37 MW/hr) of the output from reliability commitments was for second contingency reliability protection (LSCPR), with 58% (22 MW) of that output in the NEMA/Boston area. Although LSCPR comprised a large portion of the reliability commitment output, LSCPR commitment output decreased by 65% compared to 2016. The completion of planned transmission work that required must-run generation in the Boston area in 2016 contributed to this reduction. In both 2016 and 2017, equipment outages were required to upgrade the transmission capability in NEMA/Boston. Although the upgrades continued in 2017, the specific equipment that was out-of-service did not require LSCPR commitments to maintain stability in as many instances as in 2016.

From May 2013, there was a shift from reliability commitments being made in the real-time market to the day-ahead. The reduction in real-time reliability commitments can be seen by the decrease in the height of the red bar from 2013 to 2014. This 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. The ISO's rationale for this is discussed further below.

A closer look at reliability commitments made during 2017 is shown in Figure 3-29 below. The figure shows the out-of-merit energy for reliability commitments during the peak load hours in 2017, 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 during Peak Load Hours (HE 8-23)



Of the roughly 55 MW of average hourly output from generators committed for reliability, about 34 MW was out-of-rate. This is a relatively small amount of out-of-rate energy (in the context of average hourly load of 13,824 MW in 2017) that is being served by more expensive generation to meet a reliability need. Figure 3-29 shows that the greatest amounts of out-of-rate energy output from reliability commitments occurred in February, March, and November. Reliability commitments in these months were predominantly made for voltage support and LSCPR. Approximately 57% of the output from reliability commitments in February and March of 2017 was for low voltage support in Western Central Massachusetts. Another 22% was for LSCPR in the NEMA/Boston area.[98] In November 2017, 97% of reliability commitment output was for LSCPR in NEMA/Boston. Prior to 2013, there was ample supply of in-merit economic generation available in the NEMA/Boston area. Beginning in 2013, however, due to changing fuel prices, these generators have become out-of-rate for significant periods of time.

As shown in the two figures above, a large majority of the reliability commitments in 2017 were made in the day-ahead market. This helps minimize excess surplus capacity and the amount of economic generation that is displaced on the system from these generators 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

[98] 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.

Reliability Commitments of Multi-stage Generators

Multi-stage generators are combined cycle units that can operate in multiple configurations. In 2006, the ISO established voluntary rules that allowed participants with multi-stage generators to model their resources as multiple independent assets in the energy market, based on the number of gas turbines. While this approach, known as Pseudo-Combined Cycle or "PCC", resolves some issues, it does not model the operational constraints of multi-stage generators. Not all multi-stage generators have adopted the PCC rules. Some multi-stage generators tend to offer their generator's highest-output configurations (full configurations) into the market, even though they could operate at lower-output configurations as well. The IMM found that this offer behavior can result in the systematic over-commitment of certain resources, excess NCPC payments, and price distortion.[99]

Key observations from the day-ahead market in 2015 through 2017 include:

- *When multi-stage generators offer at their highest-output configuration (maximum configuration[100]), excess NCPC costs may occur.*

Generators committed for local reliability don't typically recover their three-part offer price (start-up, no-load and energy) through the LMP and subsequently require NCPC payments to make them whole. Multi-stage generators tend to offer their maximum configuration, or maximum possible output, into the market, even though they could also operate under a configuration that uses only one turbine, or a "minimum configuration". When operators commit multi-stage generators at their maximum configurations, the generators incur higher commitment costs, which results in higher NCPC payments. These payments would decrease if ISO operators could choose which generator configuration to commit, rather than committing the one configuration that the generator offered. We estimate that from 2015 through 2017, there were 37 reliability commitments of multi-stage generators on their maximum configurations, when the minimum configuration would have satisfied the local reliability need. This resulted in an estimated $6.1 million in additional NCPC payments to multi-stage generators.

- *Excess out-of-merit energy from multi-stage generators has a price-suppressing effect.*

If the ISO commits multi-stage generators for reliability on their maximum configurations, and if a lower-output configuration would have satisfied the reliability need, then there is excess supply coming from multi-stage generators. In other words, it is producing energy that would otherwise be produced by a lower-cost generator. The generator is typically dispatched at the higher economic minimum associated with the maximum configuration. Generation at economic minimum does not have the ability to set price; it is treated as must-run or price-taking supply. This has a price-suppressing effect, which distorts market signals. For days with such reliability commitments, market simulation results showed that the average day-ahead Hub LMP would have been

[99] The full analysis can be found in the 2017 Fall Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2018/02/2017-fall-quarterly-markets-report.pdf

[100] For example, the highest output (economic maximum) for a multi-stage generator with two gas turbines and one steam turbine is a 2x1 configuration. We refer to the highest-output configuration as the "maximum configuration". The minimum output configuration is typically one gas turbine and one steam turbine, or a 1x1 configuration. We refer to the minimum-output configuration as the "minimum configuration".

$1.22/MWh higher ($40.91 vs. $39.69) if multi-stage generators had offered the ISO more options (i.e., all of their configurations), rather than just their maximum configuration.

- *The ISO should evaluate alternative approaches to modeling multi-stage generators*

The current approach leads to additional production costs and impacts price formation, which could be prevented with different rules or a new model. One option is to make PCC modeling mandatory for all multi-stage generators. Alternately, the ISO could implement a more dynamic approach that models specific configurations and accounts for transition times and costs between them. However, the latter approach is complex and may be costly to implement. The chosen approach should rely on a cost-benefit analysis.

3.4.9 Congestion

This section addresses transmission congestion in New England and its effect on price, including locational price differences, and changes in total congestion in the last five years.

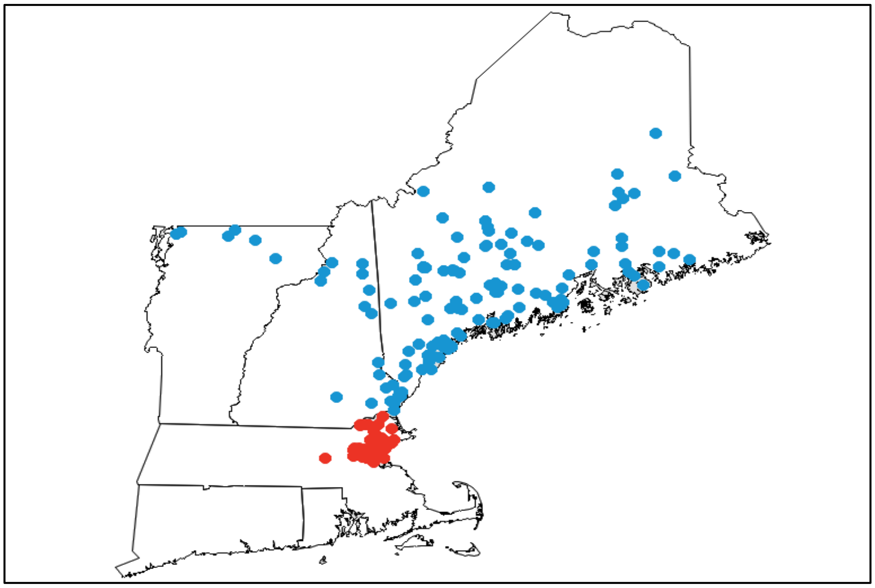
At every node in the New England system, LMPs reflect the cost of delivering the next megawatt (MW) of energy at the lowest cost to the system. The LMP is then divided into three components for the purpose of settling Financial Transmission Rights (FTRs): the energy component, congestion component, and loss component.

The congestion component of the LMP is the marginal cost of congestion caused by supplying an increment of load at a location relative to the reference bus. The congestion component can be positive or negative, with a negative congestion component signaling an export-constrained area, and a positive congestion component signaling an import-constrained area. Congestion components of LMPs are only important relative to each other, and only differences between locational values are used in settlements.

Due to significant investments in the transmission system, congestion in New England is relatively infrequent and small in magnitude. Congestion during any given time interval is reflected in the congestion component of the LMP, and the total amount of congestion in New England is reflected in the congestion revenue fund.

Nodes in New England most affected by congestion are shown in Figure 3-30. Nodes in blue represent export-constrained areas, and nodes shown in red represent import-constrained areas. Real-time data was used to produce the map, although day-ahead congestion patterns are very similar.

Figure 3-30: New England Pricing Nodes Most Affected by Congestion

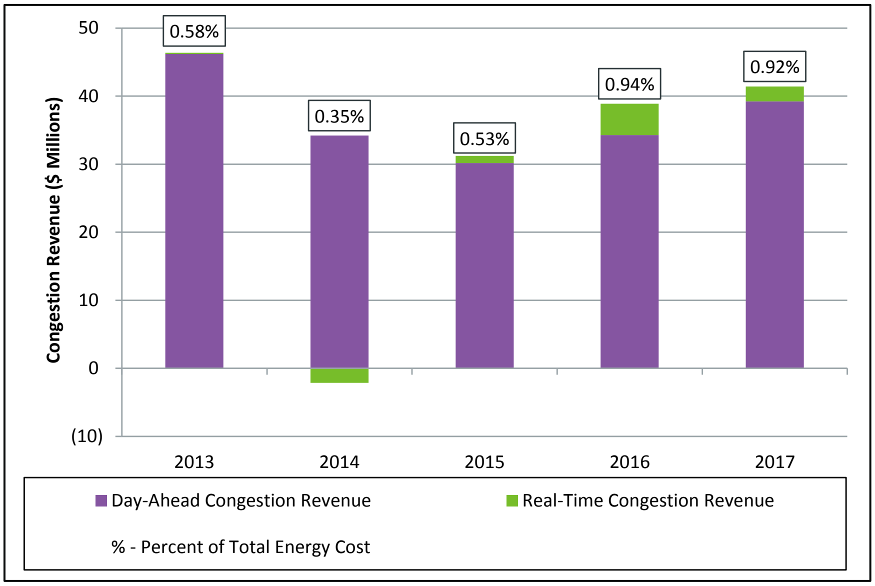


Two main congestion patterns are highlighted in Figure 3-30. First, areas on the system with a high concentration of renewable generation have lower prices, on average, than the rest of the system. In 2016, areas in Northern Maine, New Hampshire, and Vermont were export- constrained. Not only were these areas frequently export-constrained, but often the magnitude of the congestion component in the LMP was high. Many renewable generators offer at very low, even negative, prices. When transmission lines connecting these areas to the rest of the system reach the maximum amount of power allowed, the transmission line is said to "bind". When a transmission line connecting areas with low-cost generators 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. Marginal resources are discussed in more detail in Section 3.4.10. The second pattern of note is the higher pricing in NEMA/Boston relative to the rest of the region. In 2017, the transmission lines connecting NEMA/Boston 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.

One way to place a dollar value on congestion in New England is to examine congestion revenue. Congestion revenue is collected in both the day-ahead and real-time markets and is the amount available for payment to FTR holders or congestion paying load serving entities. Congestion revenue is calculated as the collection of congestion costs measured by the difference between congestion components of the LMPs at different locations on the system. Congestion costs occur when load pays a different price for energy at a location than generation serving that load is compensated. For example, in an export-constrained area, the LMP at the generation location will be lower due to a negative congestion component and the LMP at the load will be higher given a positive congestion component. In this example, load pays more than generation is compensated and the congestion cost is the difference between payment by load and compensation to generation. This congestion cost then gets allocated as congestion revenue.

Congestion revenue and its share of the total energy cost in New England are shown in Figure 3-31 below. The purple bar represents the day-ahead congestion revenue, and the green bar represents the real-time congestion revenue.

Figure 3-31: Congestion Revenue Fund Components, Balances, and Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue in 2017 was $41.4 million. This represents a 7% increase from $38.9 million dollars in 2016. As a percentage of total energy cost (labels) the congestion revenue represents less than 1% and was in line with 2016, but slightly higher when compared to other years since 2013. Day-ahead congestion revenue is much higher than real-time congestion revenue because approximately 97% of the energy transacted in New England is settled in the day-ahead market. Day-ahead congestion revenue is a function of many different factors impacting many constraints, but two large drivers of day-ahead congestion revenue in 2017 were the frequency in which both the New York–New England (importing power to New England) and Seabrook South interfaces bound, for reasons discussed below. The magnitude of congestion revenue associated with a particular constraint is dependent upon the degree of price differences between source and sink locations as well as the size of the particular constraint. Because the New York – New England and Seabrook South interfaces are two large interfaces on the New England system, it makes sense that these two interfaces would be large drivers of congestion revenue if system conditions caused the constraint(s) to bind frequently.

The New York–New England interface is a collection of seven lines that control flows between the New York and New England control areas. The average day-ahead congestion revenue (system-wide) in the 659 hours that the New York–New England interface was binding was $17,135 per hour compared to the average revenue of $3,447 per hour in which it was not binding. Although the interface was only binding in 7.5% of hours, the congestion revenue within these hours comprised 29% of the total day-ahead congestion revenue. The implementation of CTS and increased transparency of scheduling flows between New York and New England is one reason for the number of intervals that the New York North interface was binding.

The Seabrook South interface consists of two lines that control flows through the Seabrook bus; Seabrook Station is a 1,200 MW nuclear generator located in New Hampshire and is the largest individual generator on the New England system. The Seabrook South interface typically delivers power from northern New England to areas of southern New England where there are higher concentrations of load. The average day-ahead congestion revenue in the 191 hours the Seabrook South interface was binding was $33,816 per hour compared to the average revenue of $3,822 per hour in which it was not binding. Although it was only binding in 2.2% of hours, the congestion revenue within these hours comprised 16% of the total day-ahead congestion revenue. Transmission work that took one of the interface's lines out of service for 20 days was one reason for the number of intervals in which the Seabrook South interface was binding.

3.4.10 Marginal Resources

The LMP at a 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 resource that sets price is "marginal". Analyzing marginal resources by transaction type can provide additional insight into day-ahead and real-time pricing outcomes. If supply offers are sorted from lowest to highest cost, the result is a supply curve or "stack". The relative position of generators in the supply stack is largely determined by fuel cost. Similarly, the demand curve is made up of bids from load serving entities (LSEs) willing to purchase electricity sorted from the highest to lowest price. If one imagines a supply curve intersecting a demand curve, the amount of supply needed to meet demand determines how far up the supply stack the market needs to go to deliver load in the least-cost way, and consequently, what fuel type is on the margin and sets price.

There will be at least one marginal resource on the system during each pricing interval. In some cases, resources are priced equally at a location and are both marginal, because the next cheapest MW could be delivered by either. Alternatively, when transmission constraints are binding, energy cannot flow freely. If a resource is setting price in an export-constrained area, transmission limitations will not allow it to deliver the next increment of load outside of its area. In those cases, there will be more than one marginal resource – one inside the export-constrained area, and another for the locations that cannot get the inexpensive energy because of the transmission limitations.

In the day-ahead market, a greater number of transaction types can be marginal; including virtual bids and offers, fixed and priced-demand, generator supply offers and external transactions. By contrast, only physical supply, pumped storage demand, and some external transactions can set price in the real-time market. In practice, marginal resources in the real-time market are typically generators (predominantly natural gas-fired generators) and pumped storage demand.

A visual example of a marginal resource is shown in Figure 3-32 below. Figure 3-32 represents an estimate of the day-ahead supply and demand curves on June 8, hour ending (HE) 12. The supply stack is shown in ascending order of price, and the demand curve is shown in descending order of price. The lines are colored by fuel type. Note that although oil and price demand are the same color, oil will only be a component of the supply stack and price demand will only be a component of demand. The graph on the left shows the supply and demand curves in their entirety, with fixed supply at -$150/MWh (the offer floor) and fixed demand at $1,000/MWh (the offer cap) for simplicity. The graph on the right side is a zoomed-in portion of the curve on the left. It shows the quantities from 14,250 MW to 15,000 MW and the prices from $18 to $25/MWh.

Figure 3-32: Day-Ahead Supply and Demand Curves - June 8, 2017, HE 12

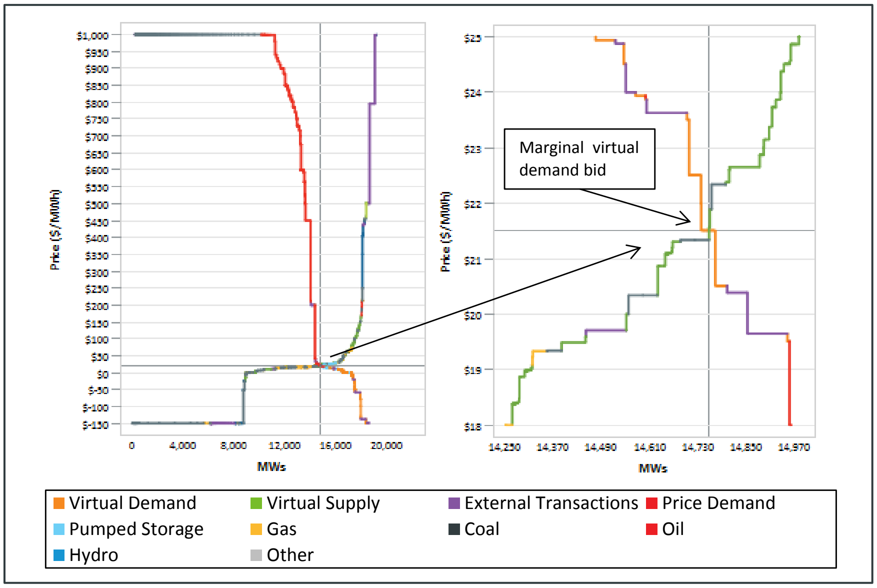


Figure 3-32 illustrates the meaning of a marginal resource and the liquidity of the day-ahead market supply and demand curves. In this illustration, virtual demand is the marginal resource. To serve one more increment of load, the ISO would instruct the virtual demand bid to not consume one MW, at a cost to the system of about $21.50/MWh.[101] To deliver the next MW from supply, the ISO would instruct a gas-fired generator to produce the next MW, which would cost $21.89/MWh. Between $18 and $25/MWh there are many different fuel or transaction types that could set price, including: virtual demand, virtual supply, imports, exports, price-sensitive demand, and gas. On the graph on the left, the supply curve is relatively flat (elastic) from just over 8,000MW to about 16,000MW, ranging in price from $0 to $50/MWh in that space.

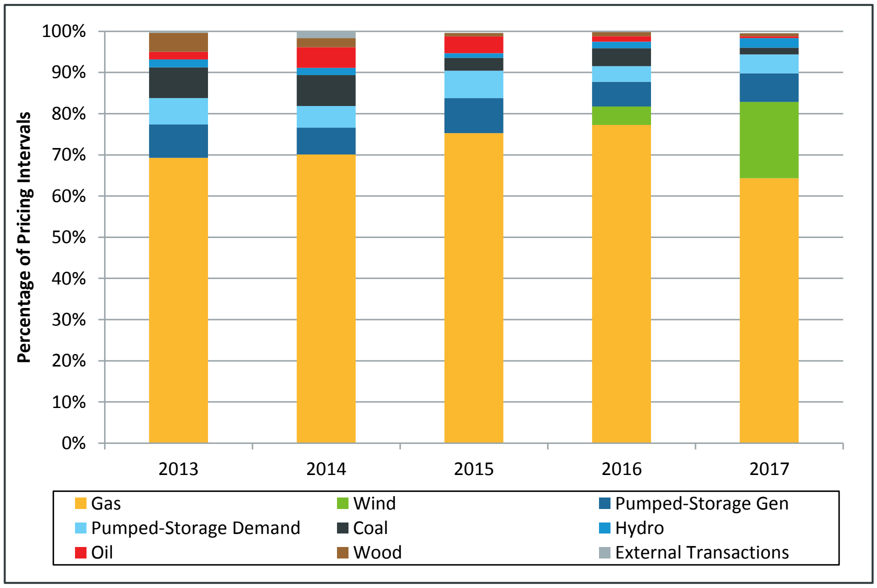
Marginal resources in the real-time market

The marginal fuel mix in the real-time market over the past five years is shown in Figure 3-33 below.[102]

[101] The loss of virtual demand consumption is a cost because it is the lost value of the virtual demand bid.

[102] 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.

Figure 3-33: Real-Time Marginal Fuel-Mix Percentages



Natural gas was the marginal fuel for 64% of all pricing intervals in the real-time market in 2017. This is a decrease compared with 2016 (77%). One reason for this decrease is that wind displaced gas as the price-setting fuel in a large percentage of intervals. Wind set price in 19% of intervals, an increase from 4% in 2016. The increase is driven by the Do-Not-Exceed (DNE) dispatch rules, which went into effect on May 25, 2016.[103] DNE incorporates wind and hydro intermittent generators into the unit dispatch and pricing process, making the generators eligible to set price. Previously, these generators had to self-schedule their output in the real-time market and, therefore could not set price.

Most of the marginal wind generators in 2017 were located where the transmission system is regularly export-constrained. This means that the wind generators frequently set price within their constrained regions while another resources(s) set price for the rest of the system. Though wind was marginal 19% of the time in 2017, wind was the single marginal fuel type on the system in <1% of all five-minute pricing intervals. Another notable trend is the displacement of coal and oil over the past few years. This is driven by lower natural gas prices and the retirement of a large amount of coal-fired generation.

Marginal resources in the day-ahead market

Unlike the real-time market where generators set price 95% of the time, generators of all fuel types set price only 35% of the time in the day-ahead market in 2017. This is because generators in the day-ahead market compete with other physical and financial price-setting entities. Many of these entities either do not exist or are not eligible to set price in the real-time market. Virtual supply and

[103] *ISO New England Inc. and New England Power Pool*, Do Not Exceed ("DNE") Dispatch Changes, ER15-1509-000 (filed April 15, 2015); Order Conditionally Accepting, In Part and Rejecting, In Part, Tariff Revisions and Directing Compliance Filing*,* 152 FERC ¶ 61,065 (2015). In a subsequent filing, the Filing Parties modified the DNE Dispatch changes to remove the exclusion of DNE Dispatchable Generators from the regulation and reserves markets, to comply with the Commission's order on the original rule changes. The Commission accepted the ISO's compliance filing in a subsequent order. *ISO New England Inc. and New England Power Pool*, Compliance Filing Concerning DNE Dispatch Changes, ER15-1509-002 (filed August 21, 2015); Letter Order Accepting DNE Dispatch Compliance Filing, ER15-1509-002 (issued October 1, 2015).

demand, for example, are financial products that only exist in the day-ahead market.[104] Similarly, price-sensitive demand only exists in the day-ahead market. In real-time, the only demand that is price-sensitive is pumped storage demand.

External transactions are marginal much more often in the day-ahead market than in the real-time market. In the real-time market only CTS transactions at the New York North interface can set price. External transactions at New York North can also set price in the day-ahead market. In the day-ahead market, external transactions at other non-CTS interfaces can also be marginal, but the marginal external transactions only determine the flow over the interface; they do not set 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. The price cannot separate in the real-time market because cleared external transactions are treated as fixed when real-time prices are calculated at non-CTS interfaces. External transactions are discussed more in Section 5.

The percentage of time that each entity set price in the day-ahead market over the past five years is illustrated in Figure 3-34 below. Beginning in 2015, the graph illustrates a breakdown of the generation by category (large gray bar, years 2013 and 2014) by generator fuel type (colored bars outlined in black).[105]

Figure 3-34: Day-Ahead Marginal Fuel-Mix Percentages

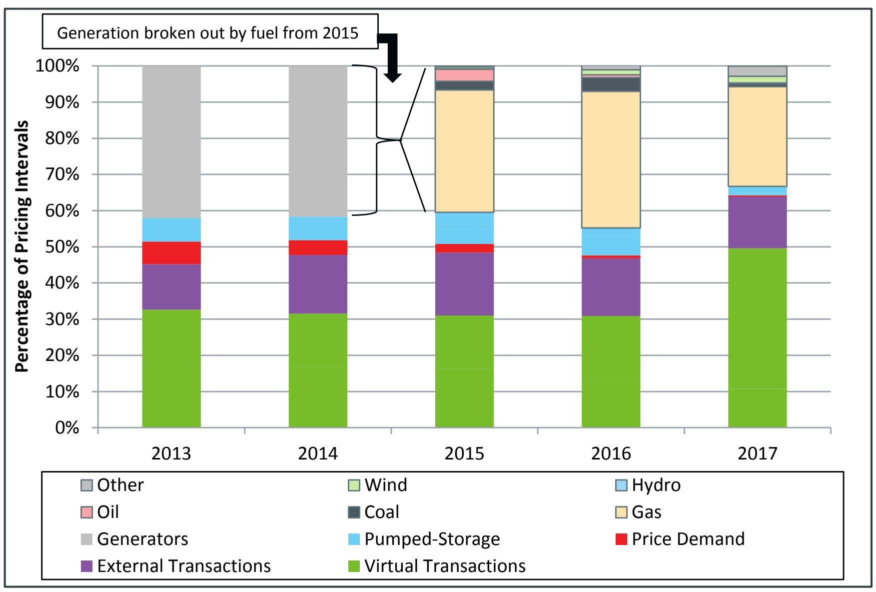


Figure 3-34 illustrates a 20% increase in marginal virtual supply offers (from 19% to 39%) between 2016 and 2017. This increase is due to a higher frequency of virtual supply offers being marginal in export-constrained areas. These export-constrained areas are typically in the same location as wind generators. Many of these generators do not clear in the day-ahead market but operate in real-time, depressing the real-time price. This creates an opportunity for virtual supply offers to profit from the higher day-ahead prices at these nodes. In most of these intervals, virtual

[104] See Section 4 on virtual transactions.

[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. The metric has been adjusted accordingly from 2015.

supply offers were not the only marginal transaction on the system. Virtual transactions set price for the whole system in 10% of hours in 2017. Aside from virtual transactions, generators set price approximately 35% of the time in the day-ahead market. Similar to the real-time market, gas-fired generators set price more than generators of all other fuel types combined in 2017. This shows that even though other entities affect the supply curve, natural gas is typically needed more than any other generator fuel type to serve the next increment of demand.

3.5 Net Commitment Period Compensation

Net Commitment Period Compensation ("NCPC") payments are designed to make generators that follow the ISO's operating instructions no worse off financially than the generator's best alternative.[106] For example, a generator's revenue from providing energy and ancillary services may be insufficient to recover some portion of its start-up and other short-run production costs. In this case, the generator's best alternative, instead of following the ISO's operating instruction and incurring a financial loss, may be to not operate at all (thereby incurring no loss). As this generator would be reluctant to operate when costs are expected to exceed revenues, NCPC is provided to it in order to strengthen the incentive for it to follow ISO commitment and dispatch instruction.

The majority of NCPC payments, such as the one given in the example above, can be described as "make-whole" payments because they are paid to generators that were unable to recover their operational costs in the day-ahead and real-time energy markets. Generally, generators following ISO instruction can expect to receive energy market payments that cover their as-offered costs. However, marginal cost markets do not ensure cost recovery of fixed or sunk commitment production costs in all cases, and there are a number of circumstances in which a generator may not be able to recover its as-offered costs through energy market revenues. In these cases, NCPC payments are necessary to make generators "whole" to their as-offered costs.

There are other NCPC payments given to generators for "lost opportunities." These credits result from situations in which generators forego opportunities for additional energy market revenue by following ISO instruction. This typically occurs when the ISO restricts a generator's output below its economically optimal level. For example, a generator that is postured by the ISO (i.e., has its output reduced from its economic dispatch level) in order to maintain system reliability may lose out on an opportunity to earn additional revenue by ignoring ISO instruction and producing additional energy. In order to incent the generator to follow the ISO posturing instruction, NCPC is given 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).

NCPC payments decreased significantly in 2017 compared to 2016; $52 million in 2017 versus $73 million in 2016, a reduction of $21 million. One of the primary reasons for this decrease was because of the reduction in local second-contingency protection resource (LSCPR) NCPC payments, which fell by $18.6 million between 2016 and 2017. Additionally, the fast-start pricing changes that took effect in March 1, 2017, reduced the reliance of fast-start resources on NCPC to ensure cost recovery. Overall, we estimate that NCPC was reduced by $11.9 million in 2017 as a result of fast-start pricing.

[106] 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:[107]

- **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 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.[108]

3.5.2 NCPC Payments for 2013 to 2017

NCPC payments have steadily declined for the last four years, falling from $175 million in 2014 to $52 million in 2017. Many factors have led to the decrease in NCPC payments over this period. These include varying system conditions (e.g., instances of load forecast and generator commitment error, instances of local transmission issues and the resulting local reliability needs), fuel prices, generator offer behavior, and changes in NCPC payment rules. For example, the total NCPC payments for 2015 reflect changes in payment rules that allowed generators to collect more NCPC than under prior NCPC rules. This rule change and other NCPC rule changes are discussed in more detail below.

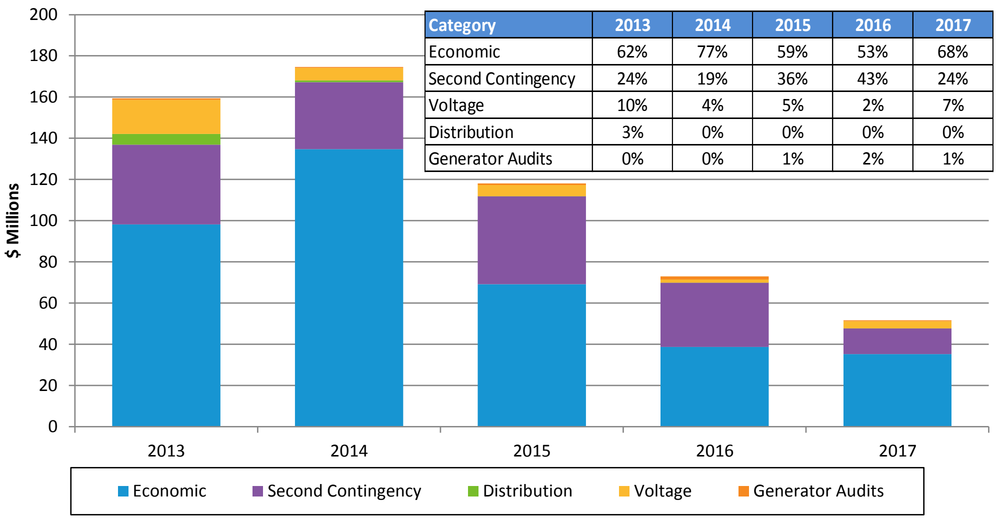
NCPC Payments by Category

Most NCPC payments are for economic (or first contingency) needs, as shown in Figure 3-35, 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.

[107] 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.

[108] 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 3-35: Total NCPC Payments by Year and Category



Category	2013	2014	2015	2016	2017
Economic	62%	77%	59%	53%	68%
Second Contingency	24%	19%	36%	43%	24%
Voltage	10%	4%	5%	2%	7%
Distribution	3%	0%	0%	0%	0%
Generator Audits	0%	0%	1%	2%	1%

Total economic payments reached a high of $134.8 million in 2014 and have fallen every year since.[109] In 2017, total economic payments totaled $35.3 million, which represents a 74% decrease from the 2014 total. However, after falling the two previous years, economic payments as a percent of total NCPC payments actually rose in 2017, when they accounted for 68% of total NCPC payments.

A significant reason for the reduction in total NCPC payments in 2017 was the decrease in LSCPR payments. In 2017, LSCPR payments totaled $12.5 million, accounting for 24% of total NCPC payments. The 2017 total is 60% less than the LSCPR payments that were made in 2016 ($31.1 million). Prior to 2017, second contingency payments were generally increasing as a proportion of total payments. These payments accounted for 19% of total NCPC payments in 2014, before growing to 36% in 2015 and 43% in 2016.

The majority of LSCPR payments in recent years have been paid to generators in the NEMA/Boston load zone (66% over the 5-year period). In part, the need for these commitments stemmed from transmission work associated with the Greater Boston Reliability project. As this project has returned transmission elements to service and increased the transfer capability of the Boston import interface, the need for local second contingency resources has fallen, which, in turn, reduced total LSCPR payments in 2017. Other types of NCPC payments have been relatively small each year.

NCPC Payments Relative to Energy Market Costs

It is worth noting that total NCPC payments represent a small fraction of compensation provided to generators in the energy market. To add perspective on the relative size of NCPC payment amounts, total day-ahead and real-time NCPC payments, as a percent of energy costs, are shown in Table 3-2.[110]

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[109] The factors that contributed to this sizable decrease in economic NCPC payments, particularly the NCPC rule changes, are explored in more detail later in this section.

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

Table 3-2: NCPC Payments as a Percent of Energy Costs

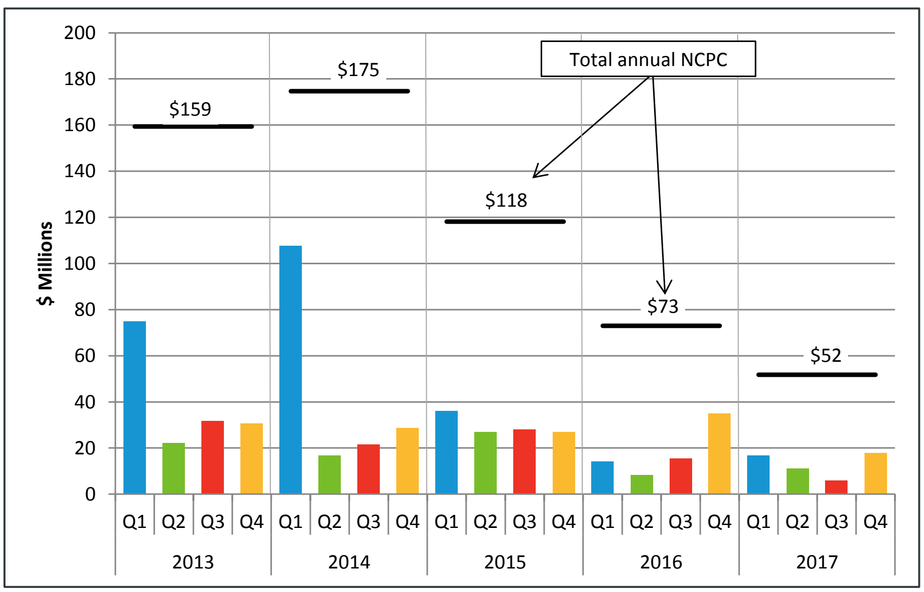
	2013	2014	2015	2016	2017
Day-Ahead NCPC	0.6%	0.9%	0.6%	1.1%	0.6%
Real-Time NCPC	1.4%	1.0%	1.4%	0.7%	0.5%
Total NCPC as % Energy Costs	**2.0%**	**1.9%**	**2.0%**	**1.8%**	**1.2%**

NCPC payments as a percent of energy costs were at their lowest level in the five-year review period in 2017, accounting for only 1.2% of the $4.5 billion that generators received in direct energy market revenues. As a share of energy costs, NCPC payments have been relatively consistent over the past five years; day-ahead NCPC payments have ranged from 0.6% to 1.1% over the 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 2013 and 2017 are shown in Figure 3-36 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.

Figure 3-36: Total NCPC Payments by Quarter



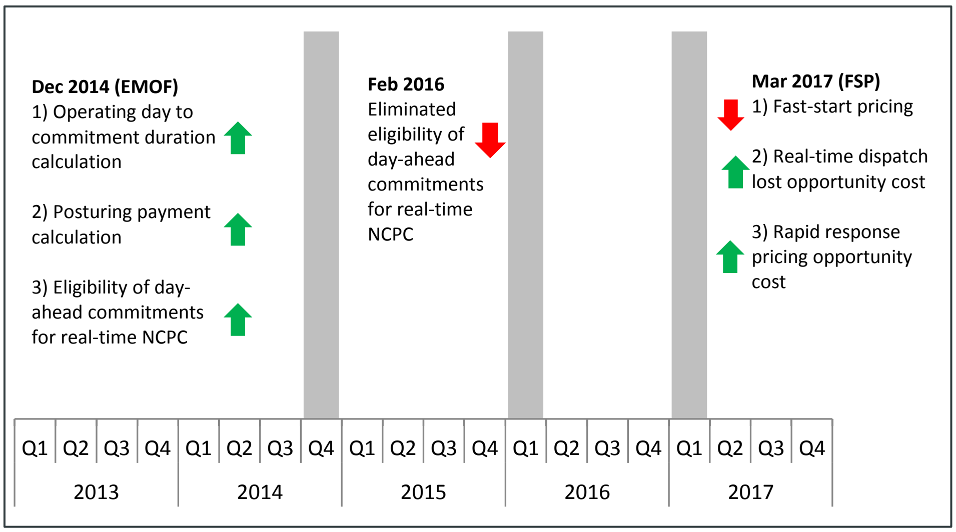
As shown in Figure 3-36, the highest NCPC payments tend to occur in winter months (Q1 and Q4 of each year). This largely reflects increased economic and LSCPR NCPC payments during the winter months. Generators that are committed for LSCPR are often more expensive units that would not otherwise operate based on economics. The higher Q1 NCPC payments in 2013 and 2014 explain a significant portion of the overall increase in NCPC payments in those years. Warmer than normal winters in 2016 and 2017, combined with relatively low fuel prices, resulted in reduced NCPC payments in the last two winters.

Looking more narrowly at 2017, the highest payments also occurred in Q1 and Q4. Over 80% of the LSCPR payments made in 2017 occurred in these two quarters. The elevated LSCPR payments in these quarters reflect local reliability needs, predominately in the NEMA/Boston area. A total of $9.9 million was paid to generators in NEMA/Boston for local reliability NCPC in Q1 and Q4. The payments in NEMA/Boston support on-going transmission outages (needed to upgrade transmission capabilities in that area) that limited the availability of imports into the area and caused the need for local reliability commitments. However, and as noted above, the total LSCPR payments in 2017 were greatly reduced from levels observed in recent years.

Impact of Market Rule Changes on NCPC

In addition to fuel costs and local reliability commitments, revisions to NCPC rules, implemented since December 2014, have influenced recent NCPC payments. The changes, along with their direction impact on NCPC, are shown in Figure 3-37 below.

Figure 3-37: Directional Impact of Market Rule Changes on NCPC



First, NCPC payments are now calculated over the hours a generator is committed (e.g., 6 hours), rather than over the 24-hour operating day. This means that a profitable commitment no longer offsets an unprofitable commitment that occurs during the same operating day. Instead, separate commitments are reviewed independently of one another in regard to NCPC, which has the effect of strengthening generators' incentives to follow ISO dispatch instructions during unprofitable commitment periods.[111]

Second, the NCPC compensation structure was improved to account for the lost opportunity costs of generators postured to meet system reliability needs (i.e., dispatched away from their economically optimal output by the ISO in order to maintain sufficient operating reserves). This credit acknowledges that postured resources incur a cost (i.e., foregone revenue) by following the ISO posturing instruction rather than optimizing their energy production. In practice this applies frequently to limited energy generators, that is, generators that are unable to operate continuously at full output on a daily basis because of fuel limitations, design considerations or other reasons. In

[111] For a detailed description of NCPC payment rules, see the ISO's training material for WEM 101: https://www.iso-ne.com/participate/training/materials.

2015, 2016, and 2017, NCPC to postured generators amounted to $5.2 million, $5.4 million, and $1.5 million, accounting for 4.4%, 7.5%, and 3.0% of total NCPC, respectively.[112] It is worth noting the drop in magnitude of posturing NCPC credits over this three-year period can be largely explained by the reduction in the number of unit-hours that generators were postured each year, falling from 1,332 hours in 2015, to 993 hours in 2016, to 733 hours in 2017.[113]

Third, in February 2016, the ISO eliminated an NCPC rule that had been in effect since December 2014 that provided additional real-time NCPC for commitment costs that had already been evaluated and compensated in the day-ahead energy market. It is estimated that this factor resulted in NCPC payments of approximately $68 million from December 2014 through February 2016. For 2015, the payments are estimated to total almost $58 million, or almost half of total NCPC payments; in 2016, these payments totaled approximately $5 million before being discontinued. The payment of uplift in both the day-ahead and real-time markets for the same day-ahead commitment was eliminated in February 2016, after the ISO determined that the real-time payment was not necessary to incent resources to provide the energy they had committed to provide day-ahead.

Fourth, there were two new types of NCPC credits – real-time dispatch lost opportunity cost NCPC credits and rapid response pricing opportunity cost NCPC credits – that were implemented on March 1, 2017. The real-time dispatch lost opportunity cost NCPC credit was added as part of the Subhourly Settlements Project, which changed the real-time settlement interval from hourly to five minutes. Modifying the real-time settlement period from one hour to five minutes exacerbated an existing gap in NCPC rules in situations where a generator's desired dispatch point ("DDP") is below its economic dispatch point ("EDP').[114] A generator's EDP is the point at which the resource would choose to operate based on its supply offers, its physical operating characteristics, and the real-time price of energy. Generators in these circumstances have an incentive to deviate from their DDP because it is more profitable to operate at their EDP. The real-time dispatch lost opportunity cost NCPC credit is provided to resources in these circumstances in order to align their incentives with ISO dispatch instruction by making them indifferent to operating at their DDP or EDP. Dispatch lost opportunity cost NCPC credits totaled $2.8 million in 2017.

The rapid response pricing opportunity cost NCPC credit was added as part of the fast-start pricing project, which aimed to improve price formation and performance incentives in the real-time energy market when fast-start resources are committed and dispatched.[115] Fast-start resources are typically inflexible and have to operate at or near their maximum output. This means that when a fast-start resource is dispatched to meet additional demand in the real-time energy market, other online resources must often be simultaneously re-dispatched to output levels below their EDPs. Similar to the resources that had a DDP below their EDP in the preceding paragraph, resources that are dispatched below their EDP in order to accommodate fast-start resources have a strong

[112] $3.1 million of NCPC posturing credits were paid out on August 11, 2016, when the system experienced extremely tight conditions.

[113] For this count, each hour that an individual generator was postured is counted as one unit-hour. For example, if a single generator was postured for five hours, the count would be five unit-hours. If a second generator was postured for the same five hours, the count would be 10 unit-hours.

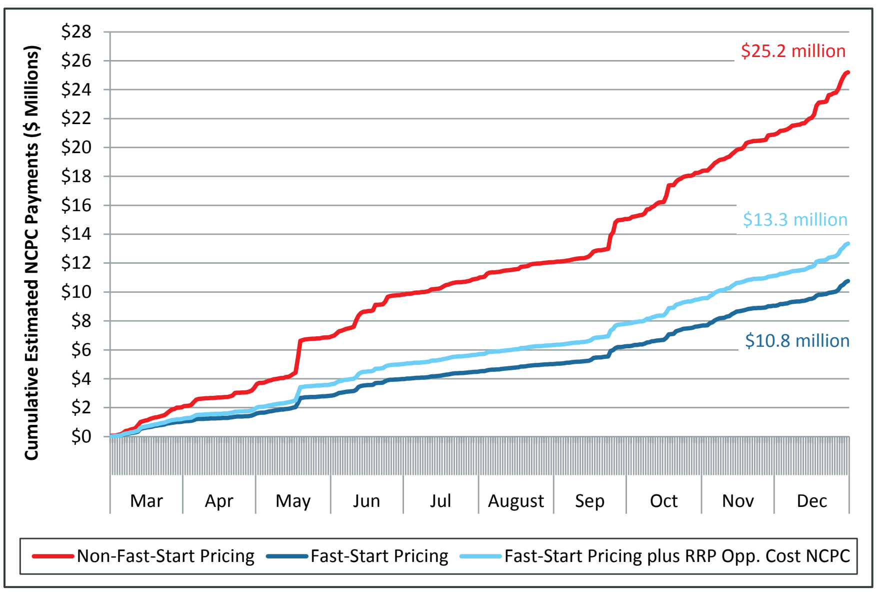
[114] The DDP is the ISO-instructed dispatch level that a generator is expected to follow. It can be different from the optimal dispatch level for a profit-maximizing generator. One example of how this arises is due to the fast-start pricing mechanics, whereby DDPs are determined by a dispatch process, while higher LMPs can be determined in the pricing process. A generator would be incented to generate more than the DDP in light of higher prices, unless compensated for the lost opportunity.

[115] The Fast-Start Pricing project was released concurrently with the Subhourly Settlements Project on March 1, 2017.

incentive to deviate from their dispatch instruction in order to maximize their profits. This financial incentive is eliminated through the payment of rapid response pricing opportunity cost NCPC, which makes them indifferent to operating at their DDP and EDP. This form of NCPC amounted to $2.6 million in 2017.

Prior to the implementation of the fast-start pricing project, fast-start resources could generally not set price after their initial commitment interval. This meant that fast-start resources typically did not cover their operating costs through energy market revenue and had to be made whole through NCPC. The fast-start pricing project increased the ability of fast-start resources to set real-time prices, which allowed these resources to cover their costs through energy market payments more frequently and reduced their reliance on out-of-market NCPC payments. The estimated impact of fast-start pricing on commitment and dispatch NCPC is shown in Figure 3-38 below.[116] The red line represents NCPC that would have been paid without fast-start pricing. The dark blue line shows actual commitment and dispatch NCPC payments. A light blue line is also shown that represents actual rapid response pricing NCPC in addition to the actual commitment and dispatch NCPC payments. The difference between the light blue and red lines represents the impact of fast-start pricing on NCPC.

Figure 3-38: Comparison of 2017 NCPC Payments Using Pricing and Dispatch LMPs



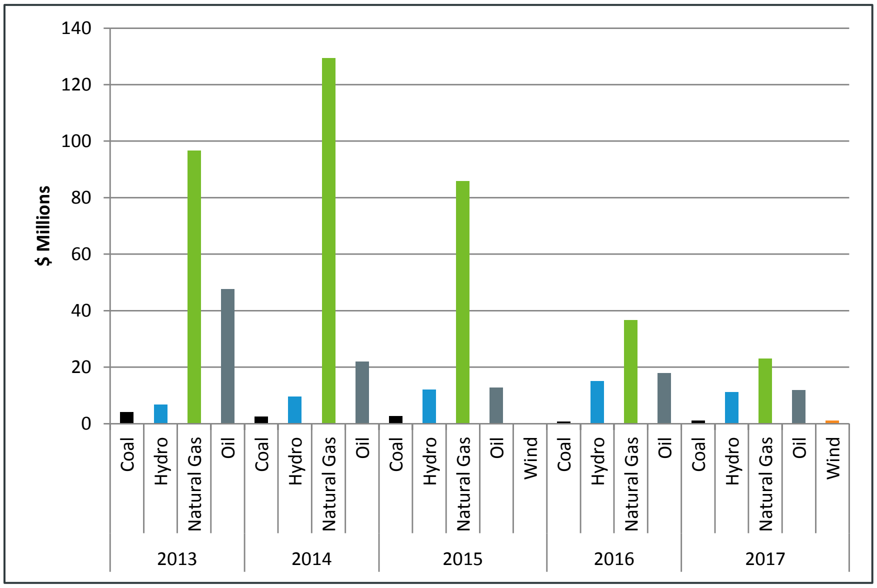
A significant reduction in NCPC payments is apparent. Overall, it is estimated that NCPC was reduced by $11.9 million ($25.2 minus $13.3m). The estimated reduction in commitment and dispatch uplift payments is $14.4 million ($25.2m minus $10.8m), a reduction of more than half.

NCPC by Fuel Type

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

[116] This is an updated version of a chart contained in the Summer 2017 Quarterly Markets Report. More information about the impact of Fast-Start Pricing on market outcomes can be found in the analysis contained within that report, which can be found here: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

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



Natural gas, fuel oil, and hydro generators receive the majority of NCPC payments. These fuel types receive the majority of NCPC payments because of their locational importance, both in the supply stack and geographically. These generators are often neither the least- nor most-costly generators, but are needed to ensure the reliable operation of the power system and are more economic to commit than very costly generators. Given some operational inflexibility (such as minimum run times), these generators may need to operate during hours when energy market pricing does not allow the generators to fully recover production costs. The large payments to natural gas-fired generators in 2013-2015 represent the high fuel cost for operating these generators during winter months.

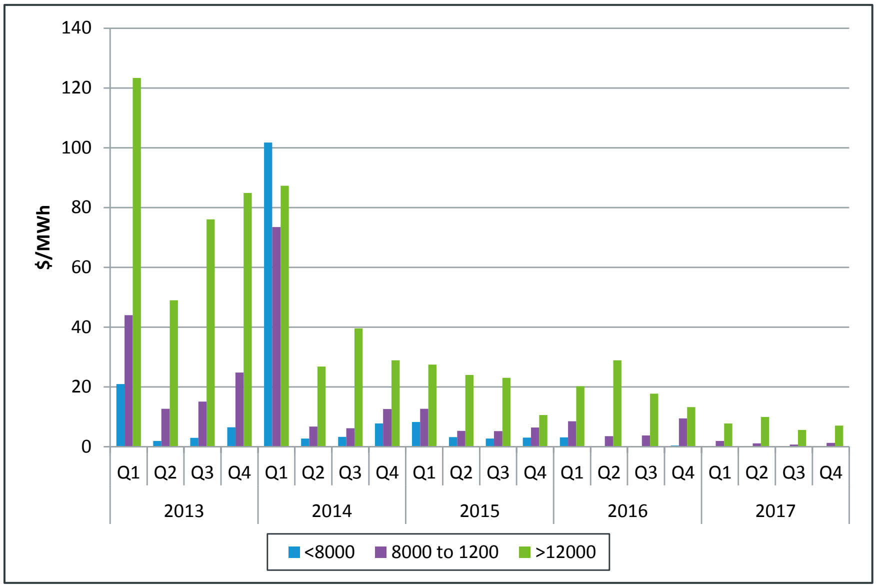
NCPC by Heat Rate

To examine NCPC payments further, we classified average payments for real-time economic NCPC by generator heat rate.[117] 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.[118] Figure 3-40 below indicates the average real-time NCPC payments ($/MWh) to generators according to generator heat rate categories.

[117] 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.

[118] 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, fuel oil-fired generators with heat rates greater than 8,000 Btu/kWh.

Although generators with high heat rates receive relatively high average NCPC payments, these generators received only approximately 16% of total real-time economic NCPC payments from 2013 to 2017. These generators were committed less frequently than lower heat rate generators. Average payments to these generators have generally been declining over time, and represented just 14% of total real-time economic NCPC payments in 2017.

3.6 Demand Resources in the Energy Market

Demand resources currently participate in the energy market through the Transitional Price-Responsive Demand (TPRD) Program. The TPRD program allows market participants with Real Time Demand Response (RTDR) resources to receive payments for load reductions offered in response to day-ahead LMPs, although the resources are not integrated in the day-ahead energy market. Market participants are paid the day-ahead LMP for their cleared load reductions and are obligated to reduce load by the amount cleared day-ahead. The participant is then charged or credited at the real-time LMP for any deviations in real-time compared with the amount cleared day-ahead.

The TPRD program was designed to "transition" demand response resources to full integration into the wholesale energy, reserve, and capacity markets. On June 1, 2018 the ISO will fully integrate price responsive demand 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). Full integration will allow demand response resources to submit demand reduction offers into day-ahead and real-time energy markets. Demand resources will be committed and dispatched in the energy market based on economics and will be eligible to set price. Demand resources will also provide operating reserves, in a manner similar to traditional generation resources.

Participation in TPRD program during 2017 was limited to 220 MW and four participants.

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 and 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 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 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. 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 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 and Section 7, respectively.

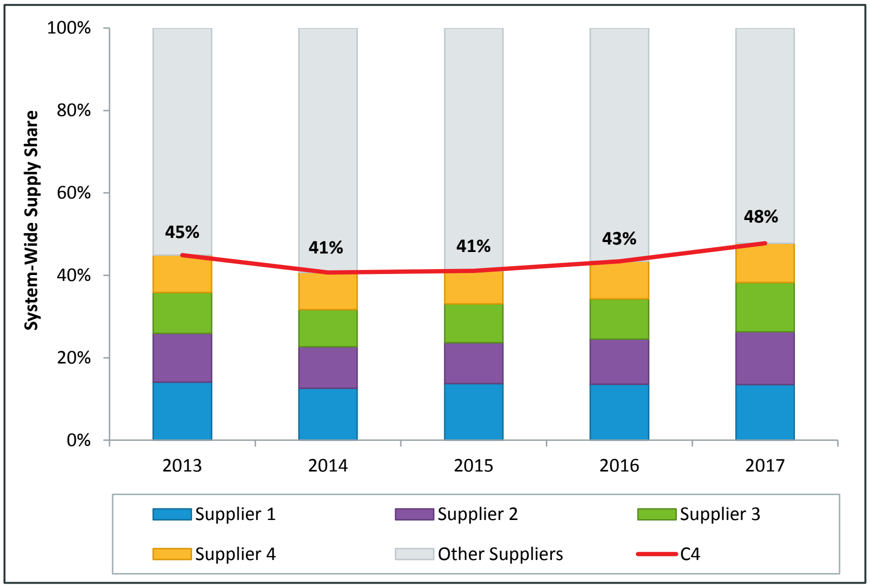
3.7.1 C4 Concentration Ratio for Generation

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.[119] 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 3-41 below, the C4 value of 48% for 2017 is a slight increase relative to the values observed in years 2013 through 2016.

[119] 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 3-41: System-wide Supply Shares of the Four Largest Firms



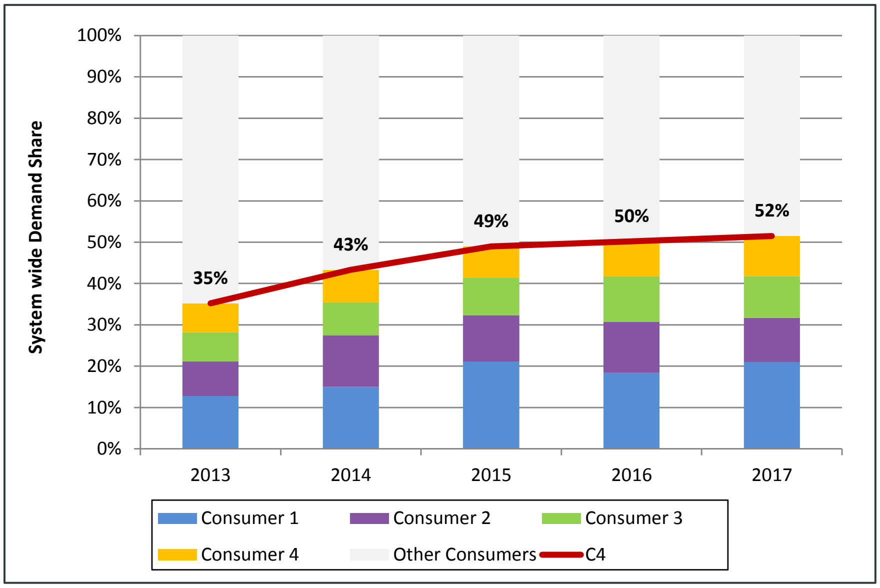
Note: The firms labeled "Supplier 1," "Supplier 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

In 2017, the total supply of generation and import transactions in all on-peak hours was, on average, 16,300 MW per hour. The four largest suppliers provided, on average, 7,800 MW, or 48%, of the total energy during these hours. As illustrated by the red C4 trend line in Figure 3-41, the aggregate amount of supply from the four largest suppliers in 2017 is an increase compared to observations in prior years. The top four suppliers were the same in 2016 and 2017 and a large driver of the increase was from one of the four largest suppliers controlling four additional generators in 2017. While a slight increase was observed in 2017, the observed C4 values in the range of 41% to 48% indicate low levels of system-wide market concentration in a relatively small market. In addition, the individual shares are not highly concentrated in any one company.

3.7.2 C4 Concentration Ratio for Load

This section applies the same C4 metric discussed in the previous section to the demand side. 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 3-42 below, which shows the market shares of the top four firms and the combined market share of all remaining firms.

Figure 3-42: 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 2017, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 65,536 GW.[120] Overall, the four largest load-serving market participants served 52% of the total system load for the 2017 on-peak hours. As shown by the red C4 trend line in Figure 3-42, the load share of the four largest firms increased by 14% from 2013 to 2015 as a result of the merger of two participants. Since 2015, the load share of the four largest firms has remained relatively constant at approximately 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. Also, 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. First, the vast majority of demand clears in the day-ahead market, averaging 97% in 2017. Second, the day-ahead aggregate demand curve is relatively inelastic, with effectively about 5% of price-sensitive demand on average (see Section 3.4.4).

3.7.3 Residual Supply Index

The Residual Supply Index (RSI) identifies instances when the largest supplier has market power.[121] Specifically, the RSI measures the percentage of real-time demand that can be met without energy from the largest supplier's portfolio of generators. The RSI focuses only on the largest supplier. When the RSI is below 100, a portion of the largest supplier's generation is required to meet

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

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

demand. In such instances, the largest supplier is considered a "pivotal supplier" and has market power. The pivotal supplier 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 a competitive price level. When the RSI exceeds 100, there is enough supply available in the market to meet demand excluding the supply from the largest supplier. In such cases no individual supplier is pivotal and sufficient competition exists in the market.

An RSI analysis was conducted using data from 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. The test results are used in conjunction with the energy market mitigation system and processes. The data used in the calculation of 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 6-7 UDS runs each hour. Table 3-3 shows the average RSI values and the percentage of hours with at least one pivotal supplier for years 2013 to 2017.

Table 3-3: RSI and Pivotal Supplier Statistics, 2013 - 2017

Year	RSI	% of Hours with a Pivotal Supplier
2013	95.7	66.0%
2014	95.5	61.6%
2015	96.8	53.9%
2016	100.6	46.8%
2017	99.1	57.9%

There were more hours with a pivotal supplier in year 2017 than in the last two years. This indicates that during year 2017 suppliers faced relatively lower competition compared to the previous two years. The reduction in the structural competitiveness can be partially explained by the reduced level of available supply observed in year 2017 compared to 2016 reporting periods (see Section 3.4.6. on the supply/reserve margin). A duration curve for RSI shows the level of RSI over the year arranged in a descending order. Figure 3-43 shows the percent of hours, on an annual basis, when the hourly RSI was above or below 100 between 2013 and 2017. There is at least one pivotal supplier when the RSI is below 100.

Figure 3-43: System-wide Residual Supply Index Duration Curves (Years 2013 - 2017)

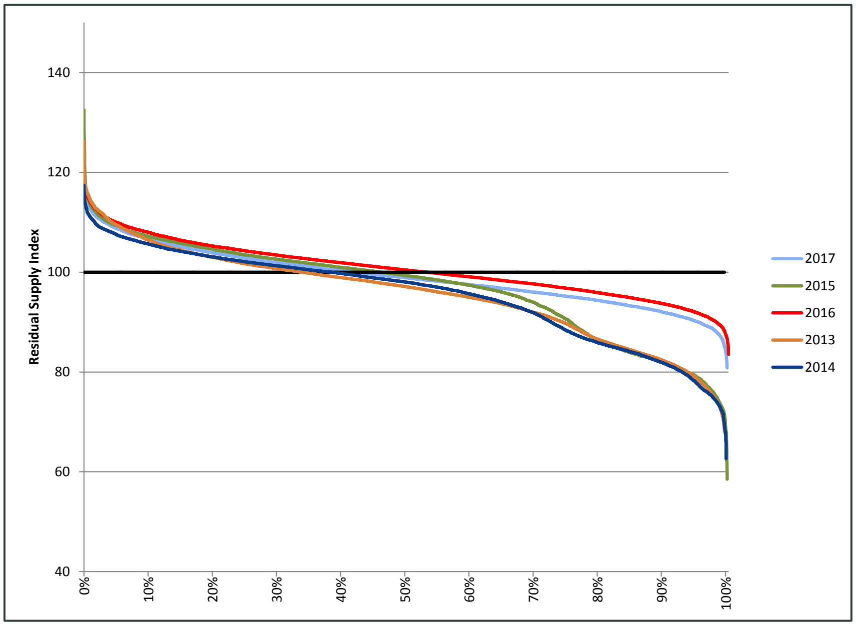


Figure 3-43 shows that there was less availability of competitive supply in 2017 than in 2016. In addition to reduced available supply, the average size of the largest supplier was also at the lowest level in 2017 compared to 2015 and 2016.

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 impact 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:[122]

- 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.[123]

[122] 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.

[123] 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.

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 2017 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%. These results are consistent with previous years and within normal year-to-year variation given modeling and estimation error.[124] Table 3-4 shows the annual Lerner Index values.

Table 3-4: Lerner Index for Day-Ahead Energy

Year	Lerner Index
2013	4.3
2014	9.0
2015	8.3
2016	8.2
2017	4.9

The 2017 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 their marginal cost.

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 to 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

[124] 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.

level. Generator reference levels are determined in consultation with the participant and are designed to reflect a competitive offer.[125]

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 scenarios in which mitigation may occur 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 online generators that are dispatched by the market software or by operator manual instructions.

Depending on the applicable scenario, determining whether a participant's supply offer must be mitigated involves up to three tests: 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 situations. The first is when they are a *pivotal supplier* controlling resources needed to meet system-wide load and reserve requirements. The second is when their resource is in an import *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 situation 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 thresholds, expressed as a percentage or dollar amount, depend on the type of market structure test that applies in the scenario. The threshold values are tightest for scenarios where opportunities to exercise market power are most frequent.

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.

Table 3-5 below provides an overview of the primary types of mitigation and each of the tests applied for the scenario. 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.

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[125] 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 Internal Market Monitor 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.

Table 3-5: 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 3-5. 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 directly discernable from 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.

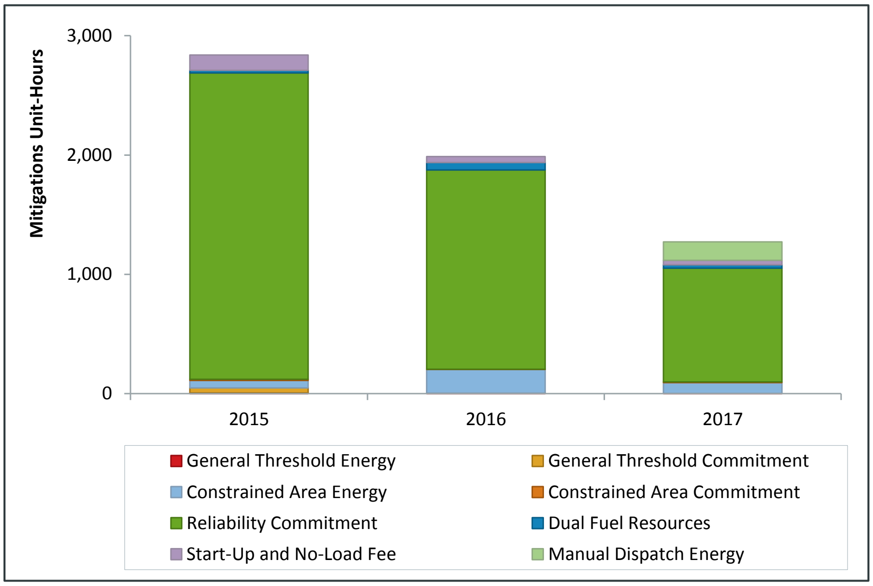
There is one additional mitigation type specific to dual-fuel resources not listed in Table 3-5. Dual-fuel mitigation occurs after-the-fact when the supply offer indicates a generator will operate on a higher-cost fuel than it actually uses (*e.g.*, if offered as using oil, but the generator actually runs using natural gas). This mitigation will affect the amount of NCPC payments the generator is eligible to receive in the market settlement.

3.8.2 Mitigation Event Hours

In this section, the occurrences of mitigations in the energy market are summarized for 2017 and compared with prior years. 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 (that is, the totals 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 day would then be eight unit-hours.

The total amount of mitigations continued to decline in 2017. There were 1,273 unit-hours when some form of mitigation was applied. This is 36% lower than the 1,987 total unit-hours of mitigation that occurred in 2016. For context, if every available generator was mitigated in every hour in the day-ahead and real-time market, then there would be 5.1 million unit-hours of mitigation. The amount of 2017 mitigations is 0.025% of this total. Figure 3-44 below presents the annual count of mitigations by type for each year between 2015 and 2017.[126]

Figure 3-44: Mitigation Events by Annual Period



The number of energy (i.e., non-commitment) mitigations increased year-over-year during 2017. This occurred as a result of the March 2017 implementation of what is called "manual dispatch energy" mitigation; overall, other energy mitigation types decreased in 2017.[127] Although down in 2017 compared to 2016, constrained area energy and general threshold energy mitigations were slightly higher in 2017 when compared with 2015.

Reliability commitment mitigations in 2017 remained the predominant type, accounting for 75% (952) of mitigation occurrences. The frequency of reliability commitment mitigations is consistent with the hourly markets rule changes that expanded the application of this mitigation test to scenarios where a generator remains online beyond the end its scheduled commitment. During 2017, the reliability commitment mitigations occurred relatively evenly throughout the year.

[126] The reporting period for mitigations has been revised to begin in 2015. Prior to 2015, the rules governing mitigations were materially different, and lead to mitigation counts that are not comparable to counts during the reporting period. For example, prior to 2015, commitment mitigations lasted for the duration of the operating day, once applied; under current rules, commitment mitigation only applies to the commitment period.

[127] Manual Dispatch Energy Mitigation (MDE) 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.

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. The volume of virtual transactions has declined since 2008 primarily due to increased “transaction costs” in the form of NCPC charges. However, over the past year virtual transactions have increased as total NCPC charges have decreased. This trend is related to the implementation of two notable and recent market rules changes: Fast-start Pricing and Do-Not-Exceed (DNE) dispatch rules. Both changes have created more opportunities for virtual players to converge day-ahead and real-time prices. Fast-start pricing has also reduced the amount of economic NCPC in the real-time market.

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. The traded volumes and prices in the FTR market have declined in recent years as the amount of congestion declined. The amount of congestion on the system has declined due to new transmission investments.

4.1 Virtual Transactions

This section addresses participant use of virtual transactions and their potential influence on the day-ahead market, as well as how transaction costs, in the form of NCPC charges, can inhibit the ability of virtual transactions to converge prices.

Although there was a general decline in virtual transactions since 2008, market rule changes in 2016 and 2017 led to year-over-year increases in virtual transaction volumes. The volume increase is expected, as the market rule changes 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. Transaction costs reduce a virtual transactions 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.

4.1.1 Virtual Transaction Impact and Mechanics

In the New England day-ahead energy market, participants submit virtual bids (demand) and offers (supply) 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 participant's 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 better 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 arbitrage 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 arbitrage the price difference, resulting in more generation being committed and prices converging.

Price convergence signals that the day-ahead market is an accurate representation of real-time conditions, and allows the energy market to satisfy real-time load in the least-cost way. Virtual bids and offers can be submitted at any pricing location on the system during any hour. Virtual transactions are settled 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 real-time price is lower than the day-ahead price (sell high, buy back low), and cleared virtual demand bids make a profit if the real-time price is higher (buy low, sell back high). However, all cleared virtual transactions (supply and demand) are also obligated to pay a per-MW charge to contribute towards the payment of real-time economic NCPC to generators. The total profit after these charges are levied will be referred to as "net" profit in this section.[128]

Real-time economic NCPC is charged to real-time deviations from the day-ahead schedule. Virtual supply is always treated as its own real-time deviation, and receives an NCPC charge equal to the number of cleared MWs multiplied by the daily "charge rate."[129] Virtual demand is included as a part of load obligation deviation, and can therefore increase or decrease deviations.[130]

4.1.2 Analysis of Virtual Transactions and Price Convergence

In this section we present an analysis of the relationship between transaction costs, virtual transactions, and price convergence. As mentioned above, beginning in 2008, a nontrivial increase in NCPC charges to virtual transactions led to a reduction of virtual activity. Figure 4-1 shows NCPC charges to virtual transactions, the volume of virtual transactions and the average NCPC charge rate ($/MW) over the past nine years. It shows the per-MW NCPC charge rate for deviations, the hourly average system deviation (MW), and the hourly average economic NCPC payments which are

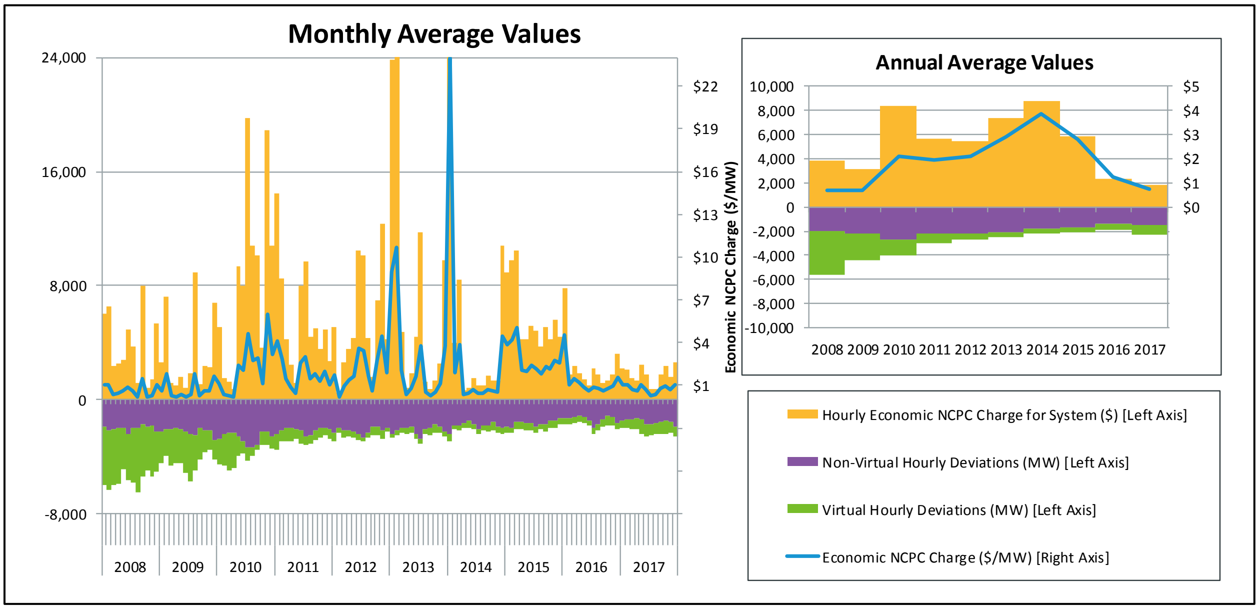
[128] Virtual transactions can also receive NCPC for relieving congestion at the external interfaces. These payments are transfers between the participants causing the congestion and those relieving the congestion and are only applied to transactions that clear at the external interfaces. Because they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

[129] 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.

[130] The methodology for estimating NCPC charges to virtual demand bids accounts for each participant's hourly virtual demand bids' effect on load obligation, and in-turn, their virtual demand bids' effect on their allocation of NCPC charges. The adjustment had a small impact on the NCPC calculations, and did not alter the conclusions of the analysis.

recovered over the deviations. Given the volatility of the monthly average values, the inset graph shows annual average values to better illustrate the long-term trend.

Figure 4-1: Monthly (and Annual) Average Economic NCPC Payment, Deviation, and NCPC Charge Rate



There are several key observations:

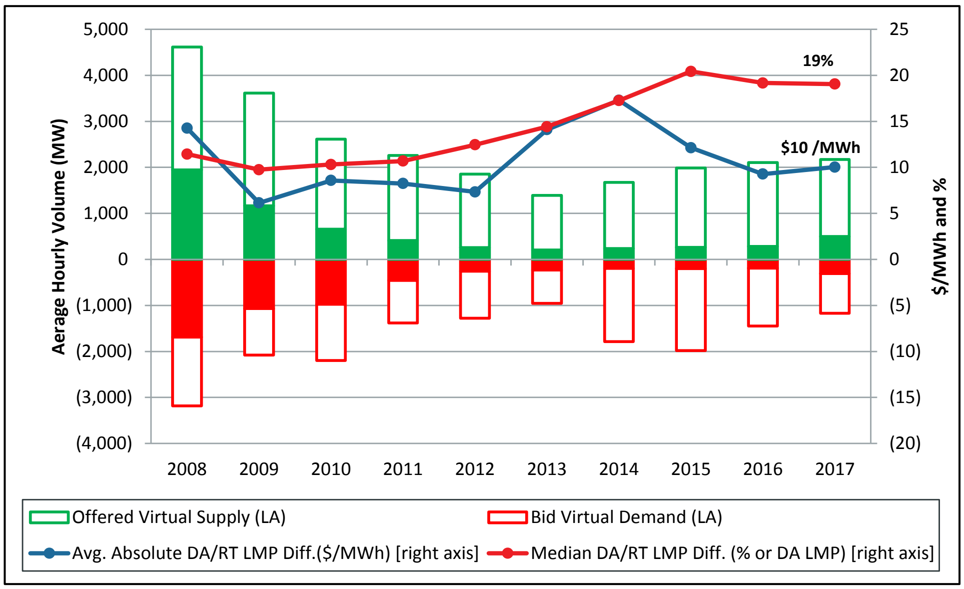
- Economic NCPC and associated deviation charges can be extremely volatile, even on a month-to-month basis.
- The volume of virtual deviations (green bar) has declined since 2008, while the volume of non-virtual deviations (purple bar) has remained relatively constant.
- Economic NCPC deviation charges have increased over the years, with a relatively large increase occurring in 2010.
- The increase in NCPC deviation charges resulted in an increase in the average NCPC (transaction) charge rate since 2008. The NCPC charge rate is a function of the NCPC charges ($) and the total volume of deviations over which to allocate the charges. Decreasing virtual transaction volumes have contributed to the decrease in total deviations, which has led to higher per-MW transaction charges. As the volume of deviations decreased, the economic NCPC charges were divided among a smaller volume and the NCPC charge rate tended to increase.

For example, in 2017, approximately 800 MW/hour of virtual transactions cleared, compared with about 3,600MW/hour in 2008. The average per-MW real-time NCPC charge rates during these years were $0.76 and $0.67, respectively. Although this difference in per-MW economic NCPC charges only represents a 14% increase, the change was less pronounced in 2017 than in previous years, as relatively little real-time economic NCPC was paid. In 2017, virtual volumes were 71% higher than in 2016 and the per-MW real-time NCPC charge decreased 40% ($1.25 in 2016 to $0.77 in 2017). The decrease in real-time NCPC in 2017 is discussed in detail in Section 3.5.

Participants have reduced their virtual activity in response to higher NCPC costs, which contributes to the increasing transaction cost. As more participants elect not to submit virtual transactions, the few remaining virtual transactions that clear the market incur higher NCPC charges, which hinder participants' ability to arbitrage smaller price differences. For example, if there is a $5 per-MW NCPC charge, a virtual transaction will only be profitable if the price difference is greater than $5. In 7% of hours in 2017 there was no trade at the ISO Hub that could have been profitable because the per-MW NCPC charge was greater than the price difference.[131] This may lead traders to structure their virtual bids and offers to clear only if the anticipated day-ahead to real-time price differences are extreme. In the presence of high and volatile NCPC charges, we expect that virtual volumes would decrease and the number of hours that virtual transactions are profitable would decrease.

The decline in submitted and cleared volumes between 2008 and 2017 is evident in Figure 4-2 below. The figure also shows the median absolute difference between real-time and day-ahead prices, as a percentage of the LMP (red line series). In this metric, the price difference is normalized by the day-ahead Hub LMP. Although there are many variables that determine how well prices converge, in normalizing by the day-ahead LMP, the price difference better represents the accuracy of day-ahead scheduling. The median is used to reduce the influence of outliers on the analysis.

Figure 4-2: Virtual Transaction Volumes and Mean and Median Absolute Price Difference



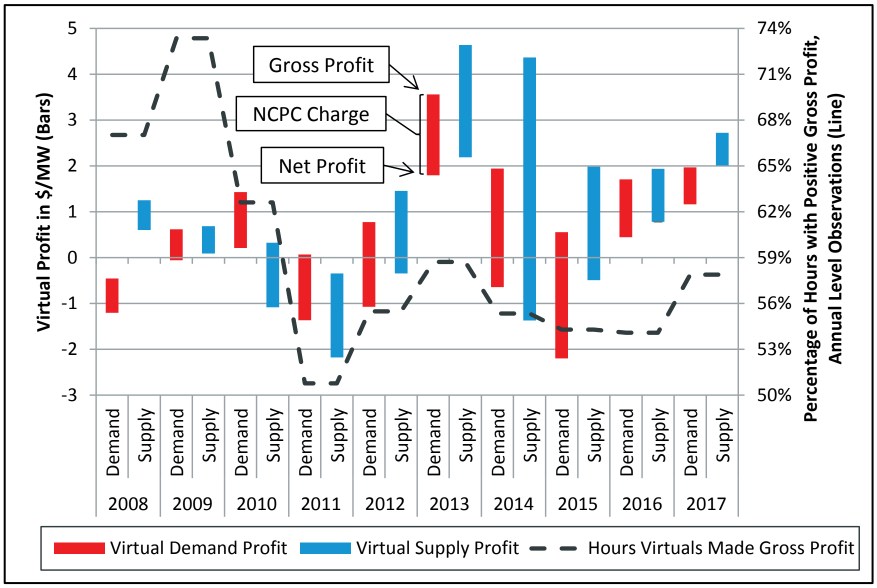
Cleared virtual transactions declined from over 2,000 MW per hour in 2008 and 2009 to less than 500 MW per hour in 2013 through 2016, but increased to about 800 MW in 2017 (see discussion below). During this time, the average price difference fluctuated between $6.14/MWh in 2009 and $17.30/MWh in 2014 (blue line). Overall price convergence has declined since 2008 as illustrated by the increasing median price difference between day-ahead and real-time prices (red line). The median difference (as a percentage of day-ahead prices) increased to approximately 19% in 2017 from about 11% in 2008, and less than 10% in 2009.[132] Price convergence is discussed in depth in Section 3.3.4. Figure 4-3 provides additional detail on the impact of NCPC charges on the profitability of virtual transactions. It also highlights the impact of NCPC charges on the opportunity to profitably trade virtual electricity. The figure displays the annual average net and gross profit of

[131] This number is in hindsight, and does not account for changes in per-MW NCPC or the DA LMP due to additional virtual transactions.

[132] 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.

virtual transactions since 2008. The bars are categorized by year and type (i.e. virtual demand in red and virtual supply in blue). The top of each bar represents gross profit, the bottom represents the net profit; the height of the bar represents the per-MW NCPC charge. 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: Virtual Net and Gross Profits and Percentage of Hours Profitable (Gross)



Other than virtual demand in 2008 and virtual supply in 2011, virtual transactions have, on average, had positive gross annual profits. The per-MW gross profits between 2013 and 2017 were substantially greater than in 2008 and 2009. In 2008 and 2009, virtual transactions made $0.53/MW before NCPC charges. In 2013 to 2017, virtual transactions made $2.55/MW.

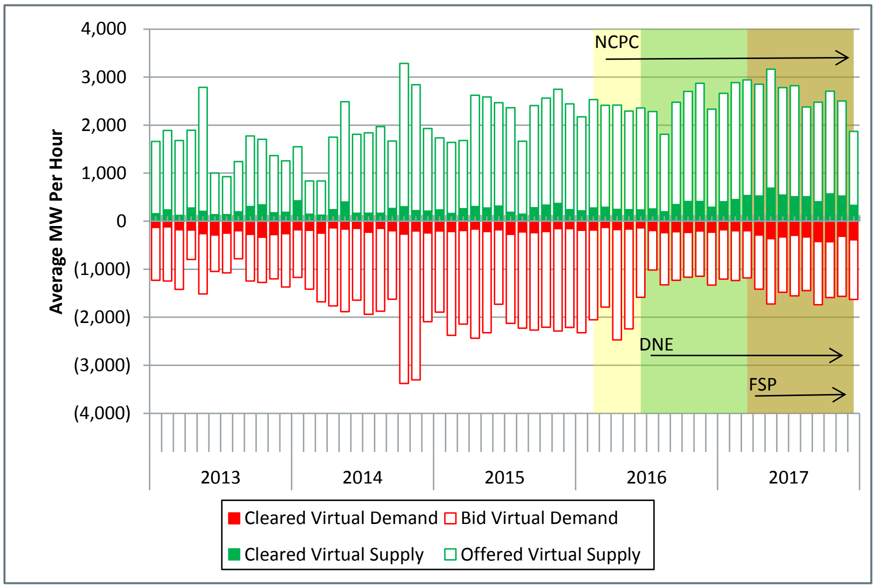
Despite the increase in per-MW gross profit, the percentage of hours that virtual transactions are profitable on a gross basis (and helped converge prices) has decreased since 2009. Virtual transactions were profitable on gross basis in 67% of hours in 2008. This number increased to 73% in 2009; in 2017, virtual transactions helped converge price in only 58% of hours, despite having net profits of $1.75 per-MW during the year. The increase in net profit per-MW and decrease in the percentage of hours that virtual transactions were profitable may indicate that traders are structuring bids and offers to take advantage of larger price differences in fewer hours, rather than consistently capturing small differences. Capturing small differences can be risky because of relatively large NCPC charges.

During years when virtual transactions have been profitable on a gross basis, they have often incurred net losses after accounting for NCPC charges. Net profit per-MW is shown by the bottom of the bars in Figure 4-3. The reduction in profitability due to the increase in the magnitude of per-MW NCPC charges can be seen as the bars increase in length over the study period. In 2017, virtual transactions remained profitable after NCPC charges were levied. This was due in large part to a decrease in overall economic NCPC, discussed in Section 3.5.

4.1.3 Volumes of Virtual Transactions

Monthly virtual transaction volumes from 2013 through 2017 are shown in Figure 4-4 below. Incremental offers are shown in green and decremental bids in red. In the timeline, a number of market rules changes that have likely had a significant impact of virtual trading are highlighted.

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



In 2017, submitted virtual demand bids and supply offers averaged about 2,500 MW per hour, which was an 18% decrease from about 3,100 MW in 2016. Total 2017 volumes of cleared virtual transactions averaged 810 MW per hour compared to 470 MW in 2016, representing a 71 % increase.

Beginning mid-way through 2016, the average offer prices of virtual transactions began converging towards actual LMPs, resulting in higher percentages of virtual transactions clearing. Three notable changes may have contributed to this behavior: (i) reduced NCPC, (ii) the implementation of Do-Not-Exceed (DNE) dispatch rules, and (iii) the implementation of Fast-Start Pricing (FSP).

Reduced NCPC

In February 2016 (yellow 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 $0.77 in 2017 versus $2.79 in 2015. It is estimated that NCPC deviation charges were as much as $2/MW higher in 2015 due to the NCPC rules. The reduction in NCPC is discussed in further detail in Section 3.5. 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 (green 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 (red 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 FSP mechanics are not applied in the day-ahead market. It is expected that higher real-time LMPs may increase the opportunity for virtual demand to converge price under certain conditions. Since the implementation of FSP, offered and cleared virtual demand bids increased.

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 generation 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 generation in real-time.

4.1.4 Top Locations of Virtual Transactions by Net Profit

The top 10 profitable locations for virtual demand in 2017 are shown in Table 4-1.

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

Location	Submitted MW	Cleared MW	Net Profit ($MM)	% of Total Net Profit	Net Profit Per MW	# of Participants
.Z.NEMASSBOST	970,000	400,000	$1.4	38%	$3.4	21
.Z.CONNECTICUT	790,000	320,000	$0.8	21%	$2.4	16
.Z.RHODEISLAND	260,000	160,000	$0.4	12%	$2.8	10
.H.INTERNAL_HUB	1,310,000	920,000	$0.4	11%	$0.4	23
.Z.WCMASS	220,000	170,000	$0.3	7%	$1.5	6
.I.SALBRYNB345 1	960,000	10,000	$0.3	7%	$20.6	8
.Z.SEMASS	220,000	160,000	$0.2	7%	$1.6	10
UN.BERLN_NH13.8BURG	70,000	10,000	$0.1	4%	$11.8	6
LD.W_AMESBY13.2	30,000	10,000	$0.1	3%	$7.1	5
LD.WARD_HIL23	40,000	20,000	$0.1	1%	$2.3	1

The NEMA/Boston zone (.z.NEMASSBOST) accounted for the most net profit (i.e., profit after transaction costs and NCPC) for virtual demand participation in 2017. The NEMA/Boston zone continues to be an area that is frequently import-constrained in the real-time market leading to higher LMPs. While profitable, the NEMA/Boston location has a high level of competition with 21 participants, which is the most competitive location other than the Hub (.H.INTERNAL_HUB).

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

Location	Submitted MW	Cleared MW	Net Profit ($MM)	% of Total Net Profit	Net Profit Per MW	# of Participants
UN.BINGHAM 34.5BNGW	360,000	160,000	$2.6	24%	$16.0	13
UN.OAKFIELD34.5OAKW	520,000	260,000	$1.9	18%	$7.3	12
.Z.MAINE	1,670,000	450,000	$0.8	7%	$1.8	17
UN.STETSON 34.5STE2	80,000	50,000	$0.7	6%	$12.4	7
UN.ROLLINS 34.5ROLL	110,000	90,000	$0.6	5%	$6.8	9
LD.KEENE_RD46	70,000	50,000	$0.5	5%	$10.6	5
UN.BULL_HL 34.5BLHW	110,000	40,000	$0.5	4%	$10.7	13
UN.POWERSVL115 GNRT	280,000	80,000	$0.3	3%	$3.5	8
.I.SALBRYNB345 1	160,000	60,000	$0.3	3%	$4.7	10
UN.SHEFIELD34.5SHEF	450,000	140,000	$0.3	3%	$2.0	15

As discussed previously, we have observed an increase in the volume of virtual supply participation at locations impacted by DNE resources. These locations also tend to be the most profitable given the opportunity to take advantage of the difference between day-ahead and real-time supply offers by DNE resources. The two locations accounting for the most net profit, UN.BINGHAM 34.5BNGW and UN.OAKFIELD34.5OAKW, are nodes located in Maine and are associated with a high concentration of DNE generation. These locations were competitive with 13 and 12 participants, respectively.

4.2 Financial Transmission Rights

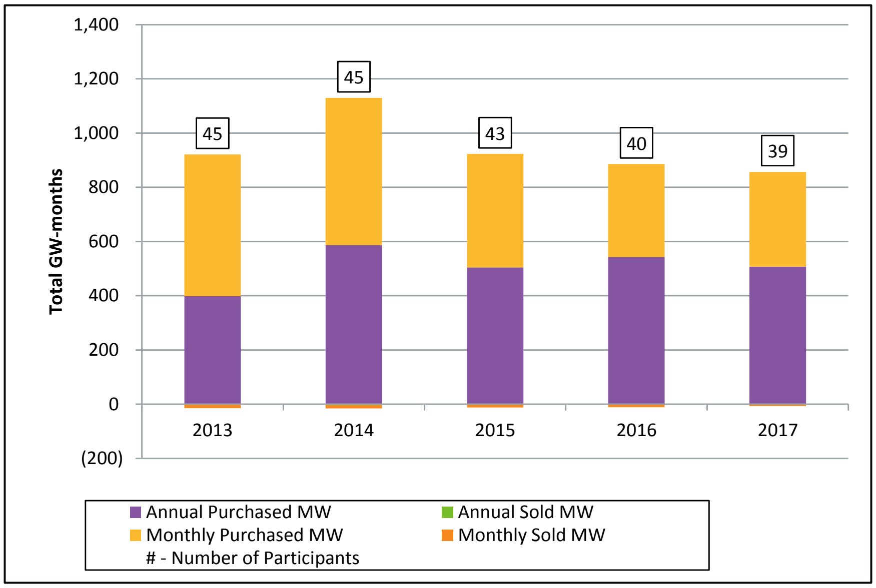
In this section we discuss the purpose of financial transmission rights (FTRs) and the performance of the FTR market. FTRs allow participants in the New England energy market to hedge the cost of transmission congestion and arbitrage differences between expected and actual day-ahead congestion costs.

FTRs can be purchased between any two nodes, zones or Hub on the system. For each pair of nodes there are two paths, one in each direction. An FTR holder receives revenue when the sink congestion component is greater than the source congestion component. Alternatively, the path obligates the holder to pay when the source congestion component is greater than the sink congestion component. Payments to FTR holders are provided from the congestion revenue fund (see Section 3.3.4).

Similar to virtual transactions, there can be various motives driving activity in the FTR market. FTRs can be purchased to arbitrage the difference between the expected and actual day-ahead congestion (for example, by pure financial players that can also provide liquidity to the auction) or to hedge physical positions.

Participants purchase and sell FTRs in annual and monthly auctions. There are two auctions for annual FTRs that occur before the start of the year, and twelve auctions for monthly FTRs each year. FTRs are purchased in all auctions, and sold in the second annual auction and each monthly auction, because only FTR paths that are owned (i.e. have been purchased) can be sold by participants. Figure 4-5 shows the volume purchased during each year between 2013 and 2017.

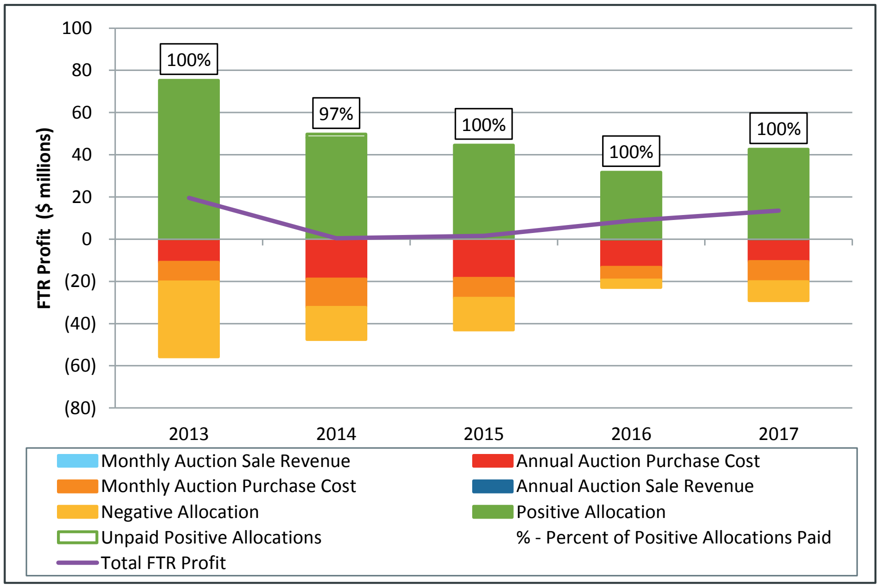
Figure 4-5: Financial Transmission Rights Purchased and Sold



In 2017, 39 participants purchased approximately 857 GW-months of FTRs. About 59% were purchased in annual auctions, which is consistent with previous years. Very few FTRs are sold by FTR holders 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 2017 annual auction, 18% of the MW volumes bid into the auction cleared, while 32% of bids by MW cleared in the monthly auctions.

Paths can be purchased at a negative price if congestion is expected in the "counter-flow" direction (when congestion at the source is expected to be greater than congestion at the sink location). When the source congestion component is greater than the sink congestion component, the FTR holder is obligated to pay the difference in the congestion components for each MW held. When congestion moves in the direction of a path held by a participant, the payment is referred to as a "positive allocation." Conversely, a participant must pay when congestion moves opposite of the path they own, referred to as a "negative allocation." Total system profit in the FTR market is the sum of the positive allocations and the revenue from sales, minus negative allocations and the cost of purchases. While total profit is provided, in practice the surplus (or shortfall) is allocated back to FTR holders through a monthly and annual true-up process. These components, as well as total profit (purple line) can be seen in Figure 4-6.

Figure 4-6: Financial Transmission Profits and Costs



In 2017, the total profit from FTRs was $13.5 million (purple line), which was a 54% increase from 2016. During 2017, there were approximately 850 GW-months of FTRs owned, profiting $15.82/MW-month on average compared to approximately 875 GW-months of FTRs owned in 2016, which profited $10.02/MW-month on average. As shown in Figure 4-6, both positive and negative allocations increased relative to 2016, but were less when compared to other years since 2013.

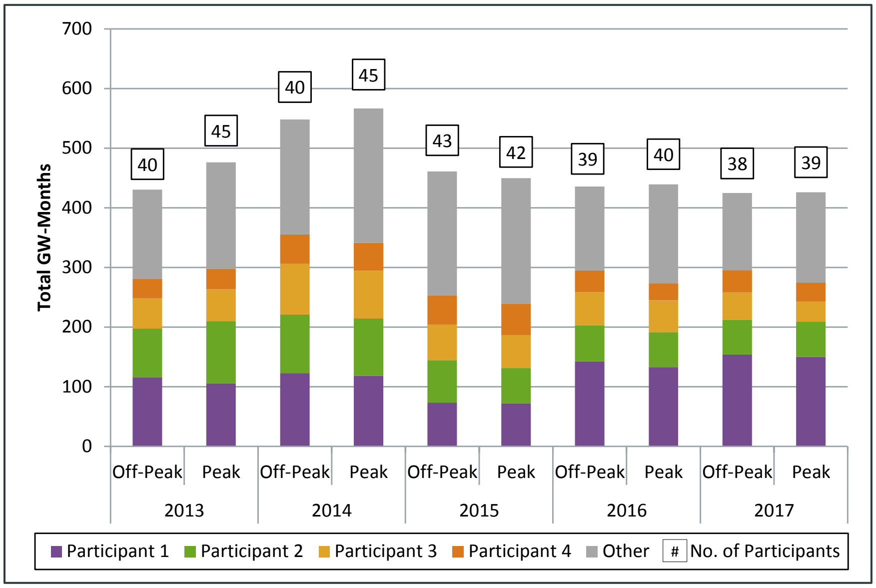
The increase in both allocations and profit coincides with increased congestion that materialized in the day-ahead market relative to expectations reflected in the auction(s). While 2017 FTR MW volumes were similar to 2016, auction participants as a whole undervalued the congestion on the system. FTR auction prices in 2017 were higher compared to 2016, but still significantly lower than 2015. Participants in the FTR market paid, on average, $23 per MW-month in the auctions, compared to about $22 in 2016, and $30 in 2015. The total allocations to the FTR holders increased to $39 per MW-month (profit of $15) from $32 (profit of $10) in 2016 and $31 in 2015 (profit of $1). Although profit in 2017 was larger than the previous two years, the $13.5 million total profit in the FTR market is still relatively modest. Significant investment in transmission infrastructure over the past ten years has reduced congestion in the New England footprint, which has contributed to lowering the value of the FTR market.

FTRs are paid from the congestion revenue fund, which was discussed in Section 3.4.9. If there are shortfalls in the congestion revenue fund, only the portion that has been funded is paid. FTRs were fully funded in 2017.

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.[133]

[133] 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 Six Holders of Financial Transmission Rights



In 2017, a similar amount of on-peak and off-peak MW were purchased. The volume purchased in 2017 was consistent with the previous four years. Three participants owned 57% of the on-peak FTRs, which was consistent with previous years.

To ensure that participants with FTR portfolios are not manipulating congestion with virtual transactions, the ISO tariff stipulates FTR capping rules, which are applied by IMM mitigation software.[134]

[134] See Market Rule 1, Appendix A, Section III.A.12.

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-schedule 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 doesn't 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 the 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.[135]

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

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.[136]

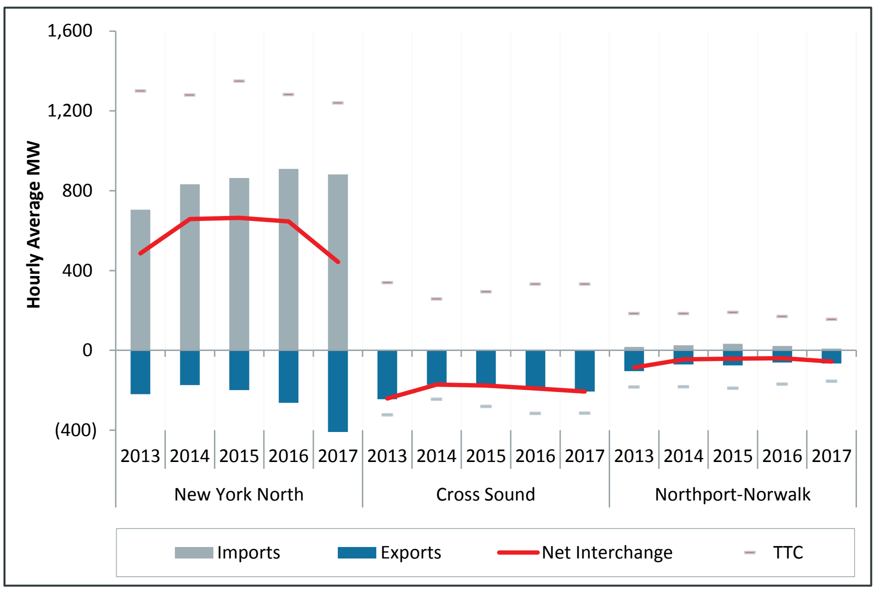
5.2 External Transactions with New York and Canada

In 2017, New England remained a net importer of power with net imports during real-time averaging 2,326 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 2013 and 2017 in Figure 5-1 below. Note that the annual observations are grouped by interface.

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 181 MW per hour in 2017, making New England a net importer of power from New York. . The New York North (NYN) interface is comprised of seven AC lines between New York and New England. It has the largest import and export transfer capacities (1,400 MW import and 1,200 MW export) among the New York interfaces and facilitates the majority of power transactions between the two markets. 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. The average hourly values of the real-

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

time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted in Figure 5-1 using the gray dash lines. The TTC ratings are included to indicate typical transmission capacity utilization at each interface. Except for Cross Sound Cable exports, the New York interfaces are not typically near their full capability ratings. Note that 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.

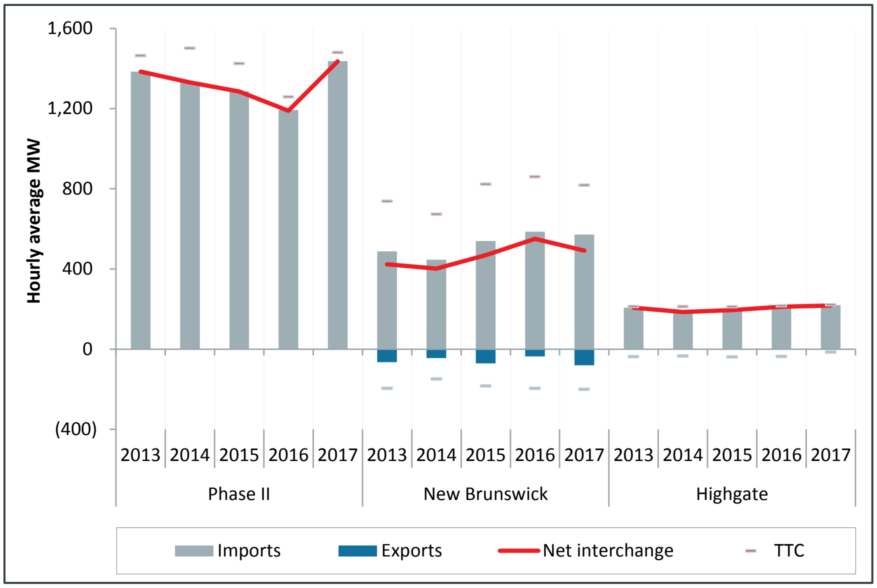
It is notable that exports at the New York North interface increased by 66% in 2017 relative to 2016 (from 263 MW to 439 MW per hour), and increased 121% relative to 2015. The introduction of interface congestion pricing with CTS in December 2015, has improved both day-ahead and real-time price signals at New York North. Since the change, participants have increased the volume of export bids to be more consistent with average price differences (in 2017 the average New England price at NYN was $32.02 – slightly less than the average New York price at the interface of $32.37).

Import volumes at this interface decreased slightly in 2017 relative to 2016 but are still considerably larger than exports. The resulting decrease in real-time net interchange compared with 2016 was 32%. The New York ISO and ISO-NE implemented CTS at the New York North interface in mid-December 2015 to improve the efficiency of real-time power flows between the two control areas. Since the implementation of CTS, participants have increased the bid volume of price-sensitive exports. In 2013-2016, New England imported power 90% of the time over New York North even though New England prices were typically only higher than New York's 49% of the time. In 2017, New England prices were higher than New York prices 53% of the time. New England imported power more often than was efficient based on price signals, but the percentage of time New England was a net importer at the New York North interface decreased to 80% of the time. Section 5.5 of this report discusses the observed impacts of this market change in further detail.

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 2013 and 2017 in Figure 5-2 below. New England imports significantly more power from the Canadian provinces 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 2,145 MW per hour in 2017, which was an increase of 10% relative to the imported volumes during 2016.

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



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 80 MW per hour in 2017. Two major factors contributed to the increase in imports over Phase II in 2017. First, there was a planned outage at Phase II from April 1, 2016 through May 30, 2016 to replace and test the interface protection and control equipment. The average total transfer capability in 2017 was about 135 MW higher than in 2016 due to the completion of the outage. The other factor was an increase in real-time priced import transactions that allowed the TTC to be better utilized. New England's neighboring control areas often limit the transfer capability at Phase II to mitigate the risk of a large contingency. In 2017, neighboring control areas permitted the TTC to be set closer to its physical limit more frequently resulting in the highest average import TTC since 2014. The average volume of offered imports was 1,670 MW, about 200 MW higher than the average volume of hourly offered imports in 2013 through 2016.

5.3 External Transaction Types

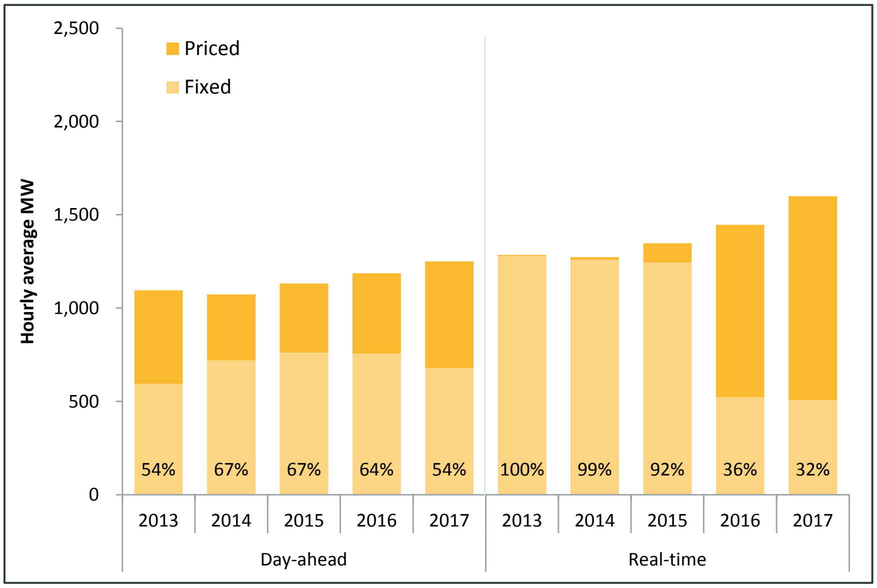
In this section, we examine the external transactions that underlie the transacted energy volumes discussed in the preceding section and in Section 2. We consider the make-up of the transactions that participants utilized to transact power. Specifically, where and when participants elect to use priced 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 2013 and 2017.[137] 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 are presented as the average MW per hour annually.

[137] Refer to Section 2 for details of the external nodes associated with the New York, Québec, and New Brunswick areas.

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. The shift was 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. There was an 11% increase in total real-time scheduled energy in 2017 compared to 2016. As discussed in Section 5.5, there was a 66% increase in scheduled exports at the New York North interface. The day-ahead volumes of fixed and priced transactions in 2017 were consistent with prior years, with priced transactions making up 46% 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 were 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.

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

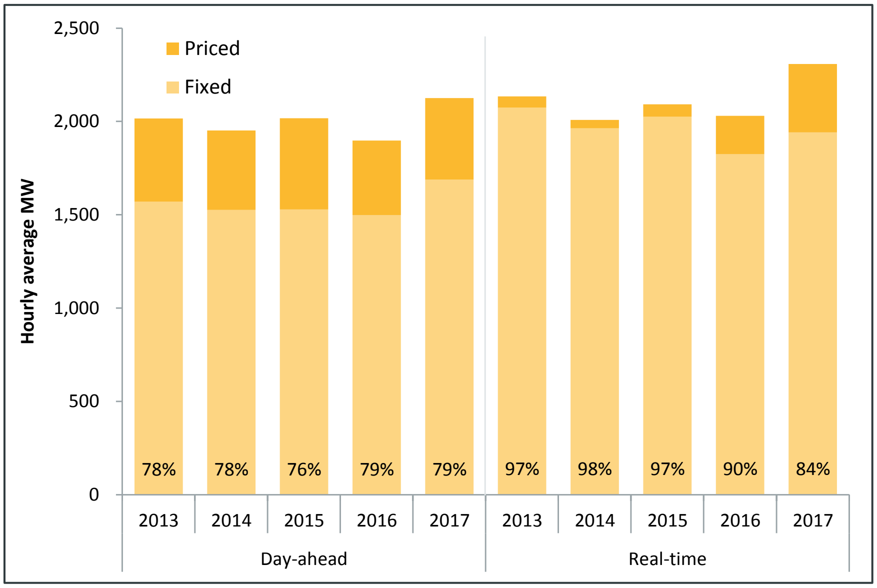
Market	Direction	Type	2013	2014	2015	2016	2017
Day-ahead	Import	Priced	80	63	89	133	195
		Fixed	533	687	700	709	577
		Percent Priced	13%	8%	11%	16%	25%
	Export	Priced	422	291	281	298	375
		Fixed	61	33	61	48	101
		Percent Priced	87%	90%	82%	86%	79%
Real-time	Import	Priced	5	13	70	651	657
		Fixed	721	845	827	281	234
		Percent Priced	1%	2%	8%	70%	74%
	Export	Priced	0	0	32	272	436
		Fixed	558	413	418	242	272
		Percent Priced	0%	0%	7%	53%	62%

Comparing the percentages of fixed transactions in the day-ahead among imports and exports using Table 5-1 highlights that the majority of priced-type transactions at the New York interfaces are export transactions. For example, the 2017 value of 46% priced transactions in the day-ahead discussed previously was composed of 195 MW of imports and 375 MW of exports, on average, hourly. Reading down the 2017 column of Table 5-1, the percentage of priced import transactions in the day-ahead was 25% whereas priced transactions made-up 79% of export transactions. Participants importing power to New England generally behave as significantly less price-sensitive than those that export and submit greater volumes of transactions. This contributes to New England predominately importing power from New York despite variations in price differences between the control areas.

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 2013 and 2017 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 cleared volumes are presented as the average MW per hour annually.

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 2,300 MW each hour are scheduled over the Canadian interfaces compared with around 1,600 MW at the New York interfaces. The very high volumes of fixed transactions are also evident; in 2017 almost 80% of day-ahead and 84% 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 2017 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 75% each year since 2013.

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	2013	2014	2015	2016	2017
Day-ahead	Import	Priced	446	420	486	399	418
		Fixed	1,564	1,517	1,509	1,491	1,677
		Percent Priced	22%	22%	24%	21%	20%
	Export	Priced	0	6	3	2	18
		Fixed	6	9	20	6	11
		Percent Priced	1%	42%	12%	22%	61%
Real-time	Import	Priced	61	42	64	203	354
		Fixed	2,009	1,919	1,955	1,788	1,871
		Percent Priced	3%	2%	3%	10%	16%
	Export	Priced	0	3	2	4	13
		Fixed	64	44	70	35	69
		Percent Priced	0%	7%	3%	10%	16%

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

5.4 External Transaction Net Commitment Period Compensation Credits

The high volumes of day-ahead fixed transactions at the external 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.[138] 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 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 is when fixed import or export transactions

[138] 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 the CTS implementation.

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 2013 through 2017 are presented in Table 5-3 below.

Table 5-3: NCPC Credits at External Nodes

Year	Day-ahead credits ($million)	Real-time credits ($million)
2013	$2.83	$0.31
2014	$10.03	$0.59
2015	$3.05	$1.15
2016	$0.90	$1.28
2017	$0.56	$1.92

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. We typically see these payments occur when there is an unexpected or large decrease in the 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 37% in 2017 compared to 2016. The vast majority (84%) was paid at the New Brunswick interface. However, total day-ahead credits at this interface in 2017 ($469k) decreased by 46% from their total in 2016 ($873k). 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. Nearly 90% of the day-ahead NCPC paid out at external nodes in 2017 went to virtual transactions.

Real-time NCPC credits at external nodes are paid to priced transactions scheduled during real-time that turn out to be out-of-merit for the hour, similar to generator out-of-merit credits.[139] As Table 5-3 shows, total real-time credits during 2017 were 51% higher than in 2016. The increase was primarily due to an increase in NCPC credits at the New Brunswick interface during Q2 2017. Real-time NCPC payments to external transactions can only be paid to priced transactions – fixed transactions are willing to clear at any price, and can therefore not clear out-of-merit. Compared with Q2 2016, there was a large increase in price sensitive transactions that cleared at the New Brunswick interface in Q2 2017, from 86MW/hour to 260MW/hour. Similar to the day-ahead, the majority (64%) of real-time external transaction NCPC credits paid in 2017 were at the New Brunswick interface. NCPC payments at the New Brunswick interface increased 193% in 2017

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

relative to 2016. The external interface with the second-most NCPC paid out in 2017 was the Phase II interface, where over $0.43 million was paid. In December 2014, the NCPC design changes for hourly market offers modified the real-time credit for external transactions to consider all MW scheduled in real-time based on a price evaluation rather than just the MW 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.[140]

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 flows, and eliminated fees on transactions.[141] 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 schedules flow in the correct direction 61% of time in 2017

From January through September, average imports declined while average exports increased. New England prices were, on average, $0.71/MWh lower than New York prices in the first nine months of the year. In the final three months, imports increased as gas prices in New England increased. New England prices were $0.71/MWh higher than New York prices, on average, during this time.

Annual forecasted and actual price spreads and flows between New England and New York are summarized in Table 5-4 below. The percentage of intervals where forecasted and actual prices signaled exporting or importing are shown ("Price Signal" column), along with the number of intervals that flows were actually scheduled in each direction ("Flow" column). Additionally, there are columns provided to show the percentage of intervals that flows were scheduled in the correct (economically efficient) direction based on price forecasts and actual prices. These values are shown based on the ISOs' price forecast and based on actual price differences.

[140] 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

[141] 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/

Table 5-4: Summary of CTS Outcomes

Year	Forecasted Price Differences					Actual Price Differences				
	Net Exports		Net Imports		Flows in Correct Direction	Net Exports		Net Imports		Flows in Correct Direction
	Price Signal	Flow	Price Signal	Flow		Price Signal	Flow	Price Signal	Flow	
2016	40%	6%	59%	94%	**63%**	50%	6%	50 %	94%	**56%**
2017	45%	20%	53%	79%	**68%**	46%	20%	54 %	79 %	**61%**

Overall, bids submitted at New York North in 2017 allowed power to flow consistent with forecasted price differences 68% of the time – an improvement from 63% in 2016. However, due to price forecast error in the CTS solution, power only flowed in the correct direction 61% of the time (compared with 56% in 2016).

New York and New England prices signaled that importing into New England was efficient in 54% of intervals in 2017. Power was imported more often, in 79% of intervals. Although New England imported 25% more often than was efficient in 2017 (79% actual minus 54% efficient), this was an improvement on 2016. In 2016, prices signaled that importing was efficient in half of intervals, but power was imported 94% of the time – CTS schedules resulted in net imports 44% more often than was efficient.

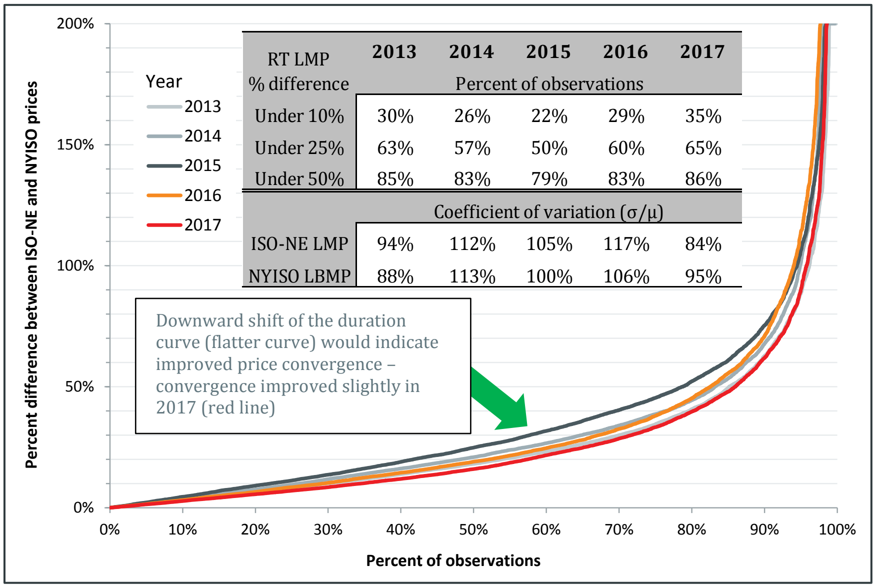
At a quarterly level, the effect of forecast error is more pronounced. In Q1 2017 through Q3 2017, market participants generally submitted transactions that allowed CTS to generate efficient schedules. In this period, 70% of CTS schedules were in the economic direction (i.e. importing when New England prices are higher and exporting when New York prices are higher). However, due to forecast error, only 58% of CTS schedules were in the efficient direction based on actual prices. In Q4 2017, participants changed their offer behavior by increasing insensitive import offers while decreasing export bids. CTS generated an efficient schedule based on forecasted prices less often, 61% of the time, and the flow was in the correct direction more often (68% of the time). Although CTS created schedules that were less efficient based on price forecasts, forecast error resulted in schedules that were more efficient based on actual prices. These numbers indicate that better price forecasting could result in more efficient scheduling with the available bids and that forecast error may be stifling incentives for participants to offer in the most economically efficient way.

Price convergence improved slightly in 2017

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.[142] Percentage differences are shown to adjust for absolute price levels. 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. The line series in Figure 5-5 plot the cumulative distribution function for observations of the absolute percentage difference between the ISO-NE and NYISO real-time hourly energy prices at the New York North interface.

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

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



Each year from 2013 through 2017 is plotted in Figure 5-5 above, with the orange line series representing the year 2016 and the red line series representing the year 2017 – the first two full years in which CTS was operational. 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.[143] 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.

Although there was an improvement in convergence in 2017, overall the data do not support a firm conclusion about the contribution of CTS. Although the real-time price differences were generally lower, prices were less volatile than in previous years. In 2017, the coefficient of variation in real-time price was 84% for ISO-NE, the lowest value in the study period, and 95% at the NYISO side, the second lowest value in the last five years. Price volatility was comparable in 2013, and price differences between New York and New England were also similar, indicating that the effect of CTS on price convergence was not substantial. The probability of ISO-NE and NYISO price differences being less than 10% was lower in 2013 than in 2017; however, 25% and 50% differences were observed with nearly equal frequency. This metric indicates that no conclusion can be made regarding the effect of CTS on price differences between New York and New England.

Price forecast error *continues to inhibit CTS effectiveness*

143 The coefficient of variation is the ratio of the standard deviation to the mean.

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. Generally, interface bids are cleared 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			Forecast Error of Spread		
	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread
2016	29.86	26.60	**3.26**	28.02	29.23	**-1.22**	0.80	-1.58	**2.38**
2017	34.97	29.66	**5.31**	32.02	32.37	**-0.34**	1.34	-1.08	**2.42**

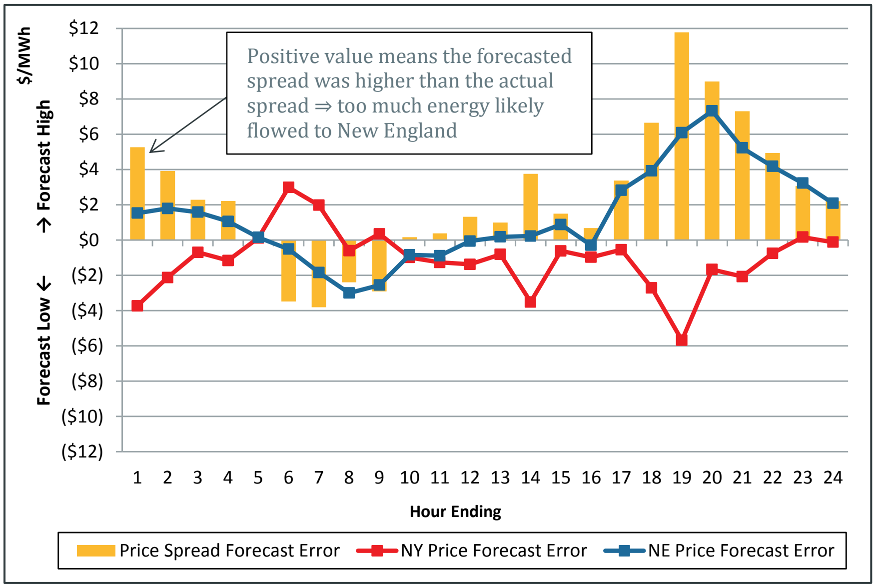
CTS price forecast accuracy was worse in 2017 than in 2016. In 2017 the average ISO-NE forecast error rose by \$0.54, from \$0.80 to \$1.34.[144] Meanwhile, the average NYISO forecast error improved by \$0.50, from -\$1.58 to -\$1.08. The resulting average price spread forecast error in 2017 was \$2.42, slightly worse than \$2.38 in 2016.[145]

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 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 December 2015 through 2017. The tendencies for New England to forecast too high 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 system ramp periods (i.e., before the morning peak and after the evening peak). New York forecast errors are most apparent in the early morning hours. There is a non-trivial reversal in the forecast errors during the morning load ramp hours between 5:00 a.m. to 9:00 a.m. (HE 06 – HE 09). The trend is similar to that reported in the 2016 Annual Markets Report. The cause of this shift in error tendencies during the morning hours is not yet known.

[144] Forecast error is: Forecast minus Actual LMP.

[145] 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 yellow bar series is the average error in forecasting the price difference between the markets. For example, in the first hour of the day (HE 01) ISO-NE produces a forecast higher than its actual price by $1.53/MWh, on average, and NYISO forecasts lower than its actual price by $3.73/MWh, on average. Thus, the average error in the forecast of price difference between the markets is $5.26/MWh higher than actual difference.

The ISOs' forecast biases being in opposite directions 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.

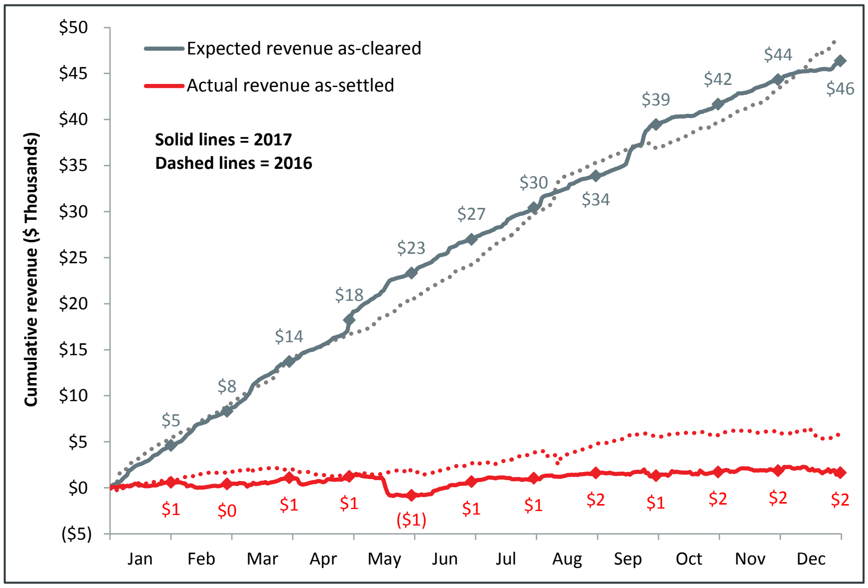
The impact of the ISO's price forecast errors

The risk of ISO price forecast error is substantial 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 2017. 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 2017 (and 2016 for comparison) is plotted in Figure 5-7 below. Solid lines depict 2017 observations, and dashed lines show 2016. The lighter dotted line series are the expected revenue based on the forecasted price differences at the time the bid is cleared. The darker solid line series are the actual revenue based on the final LMPs for market settlements. The month-end cumulative revenue totals for 2017 are displayed above the diamond line markers. As the chart shows, both the expected and actual revenues are positive, but actual revenue falls 96% short of expected over the period.

Figure 5-7: Cumulative Return on a 1 Penny CTS Interface Bid Strategy



The actual cumulative revenue of $1,623 under this hypothetical strategy produces a positive return, but that actual return is 96% below the forecasted value of $46,366. 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	44.9%	$13,975	$2,510	(82%)
Import	$0.01/MWh	53.3%	$32,392	($886)	(103%)

The results by bid direction in Table 5-6 highlight the problem caused by the ISOs' price forecast biases occurring in opposite directions. As discussed previously, ISO-NE tends to forecast its price too high and New York tends to forecast its price too low. 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 53.3% of scheduling intervals compared to 44.9% for the export transaction. However, in the intervals in which the import offer cleared, on average, exporting was a more profitable strategy. 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 expected to be 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 2017 curves and lighter colored lines show the 2016 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 2017, at a price spread of $0, 600 MW of imports would have cleared, 415 MW of exports would have cleared, and the net flow of CTS transactions would have been 184 MW if the average bid and offer curves were submitted.

Figure 5-8: Price Sensitivity of Offered CTS Transactions

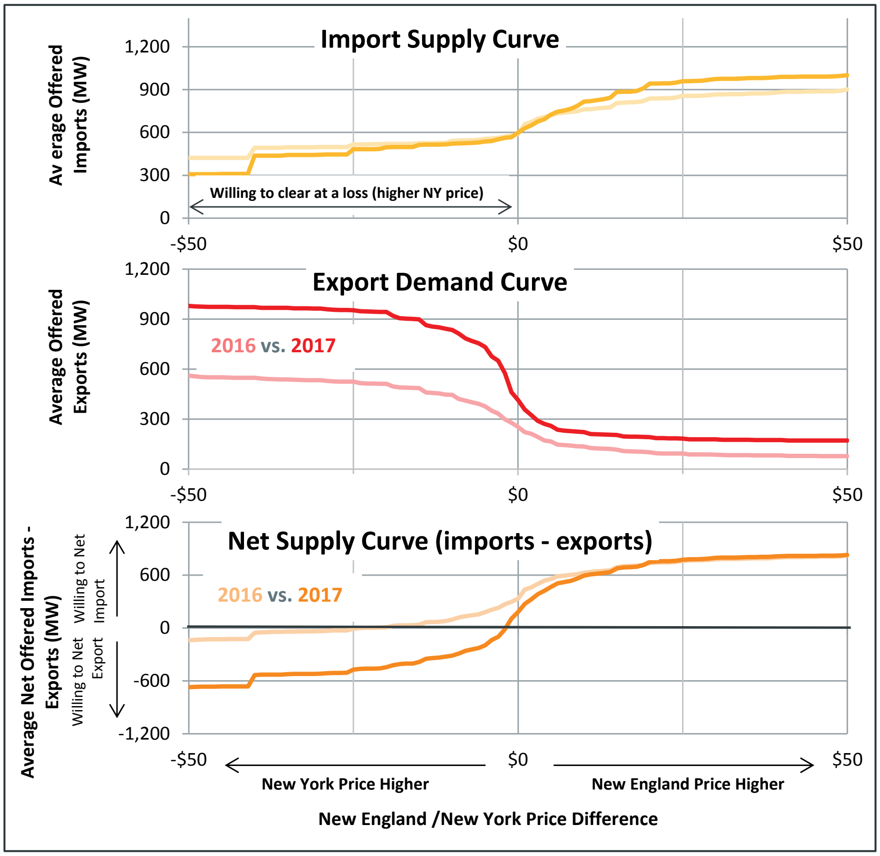


Figure 5-8 shows a large increase in price-sensitive export bids in 2017, compared with 2016. The increase is shown by the relatively high level of the darker red line (the export bid curve) to the left of $0 (the price spread at which exports become profitable) compared with the lighter red line. This behavioral change, on average, provided the CTS process with an aggregate transaction curve that allowed the direction of flows to be more consistent with price differences. In 2017, on average, market participants were willing to bring energy into New England when New England prices were at least $2 higher. In 2016, market participants, as a whole, required a much larger price spread, around $25/MWh.

Examining CTS participation on a quarterly level provides additional insight. In Q1 through Q3, market participants, on average, were willing to import if New England prices were greater than New York prices and willing to export if New York prices were greater than New England prices. The CTS process was able to create a schedule in the efficient direction 70% of the time based on forecasted prices in this time period. However, due to forecast error, power flowed in the efficient direction based on actual prices just 58% of the time.

In Q4, participant offer behavior changed. Participants were not willing to export to New York unless New York prices exceeded the New England price by more than $20/MWh. Given the reduction in average offer price sensitivity, CTS only generated an efficient schedule, based on forecasted prices, in 61% of intervals, far less than the Q1-Q3 value of 70%. But based on actual prices, flows were *more* efficient in Q4 than in the first three quarters of the year. In Q4, flows were in the correct direction 68% of the time, much more often than the 58% observed in Q1-Q3.

Efficient bidding behavior at the CTS interface may be disincentivized when market participants bear the risk of ISO forecast error.

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 FCAs have increased and decreased as the number of resources competing and clearing in the auctions and the region's surplus capacity has changed.

The first seven forward capacity auctions (FCA 1 to FCA 7), 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. Capacity payments are expected to reach $3 billion, nearly double in 2017-18 compared to the prior period.

The trend of minimal surplus and increased capacity payments will continue into 2018-19. As capacity prices increased, new suppliers entered the market in FCAs 9, 10 and 11. However, as new suppliers entered the market, the amount of capacity on the system increased resulting in declining prices. This pattern of increasing prices followed by decreasing prices is what one would expect from a competitive market. Further, planned transmission improvements, coupled with an increase in the number of resources competing in the auctions, increased the capacity market's overall competitiveness. In the most recent auction, 1,431 MW of capacity from existing resources dynamically de-listed as the clearing price of the auction fell below the dynamic de-list bid threshold.

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 and shortage event penalties.
- Section 6.3 covers the inputs and outcomes of the most recent forward capacity auction, FCA 12.
- Section 6.4 reviews key trends in primary (FCA) and secondary trading of capacity.
- 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.

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.[146] 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.[147] Up to that auction, a resource owner faced *de minimis* financial penalties if it was unable to perform during shortage conditions. The rule changes will improve the 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 replaces 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. PFP is expected to create strong incentives for resource performance. Prior to PFP the consequences of poor performance are limited. Shortage events have been rare, with only two occurring to date and each limiting penalties to a maximum of 5% of annual capacity revenues. Furthermore, the current rules include numerous exemptions, which dilute performance incentives.

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.[148] 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.[149] This helps ensure that load does not pay through the FCM to maintain a fleet of resources that meets reliability conditions and then later pay when those reliability conditions are not met and result in high real-time prices.

[146] See Section III.13.6.1. of the tariff for more information.

[147] 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.

[148] 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.

[149] Demand resources are excluded from the PER adjustment through FCA 8. The PER Adjustment will be applied to Demand Response Resources on June 1, 2018 (FCA 9) once these resources can participate in the Energy Markets.

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.[150]

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.

The demand curve used in the auction is based on resource adequacy planning criteria that establish the installed capacity requirement (ICR).[151] Load serving entities 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 12 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 the price elasticity through sloped curves reduces market 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

[150] 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.

[151] 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"

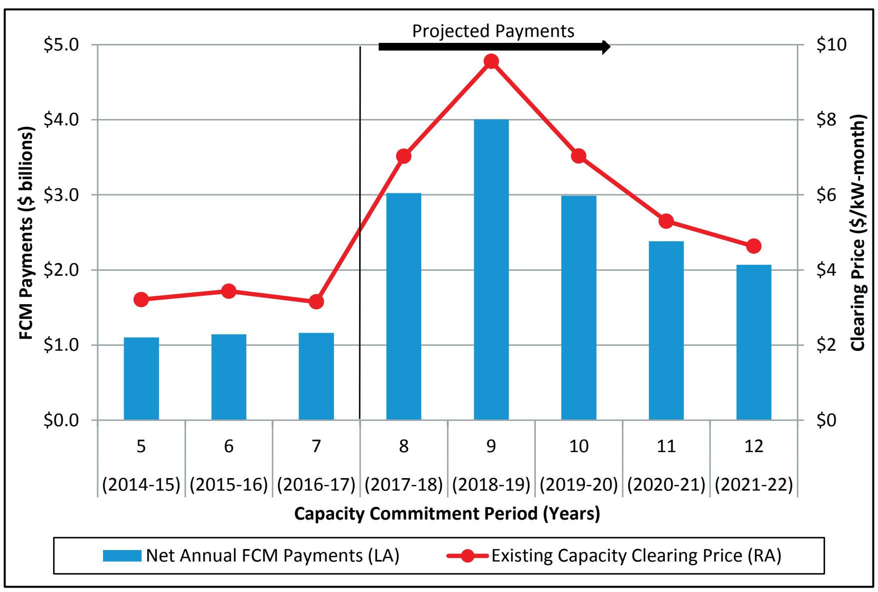
revenues to suppress capacity prices below competitive levels. A developer with a new resource wishing to remain in the auction below a benchmark minimum competitive offer price (known as Offer Review Trigger Prices) is required to provide cost justification for review and approval by the IMM.

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 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 trends in total FCM payments, which are fundamentally driven by underlying FCA clearing prices and volumes. Payments for CCPs 5 -12 are shown in Figure 6-1 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent FCM payments by commitment period. Payments for CCPs 5-7 reflect adjustments as described further below. Payments for CCPs 8-12 are projected payments based on FCA outcomes, as those periods have not been settled.[152] The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[153] Payments correspond to the left axis while prices correspond to the right axis.

Figure 6-1: FCM Payments by Commitment Period



[152] Payments for incomplete periods, CCP 7 through CCP 11, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

[153] The Rest-of-Pool capacity zone is made up of all unconstrained import/export capacity zones.

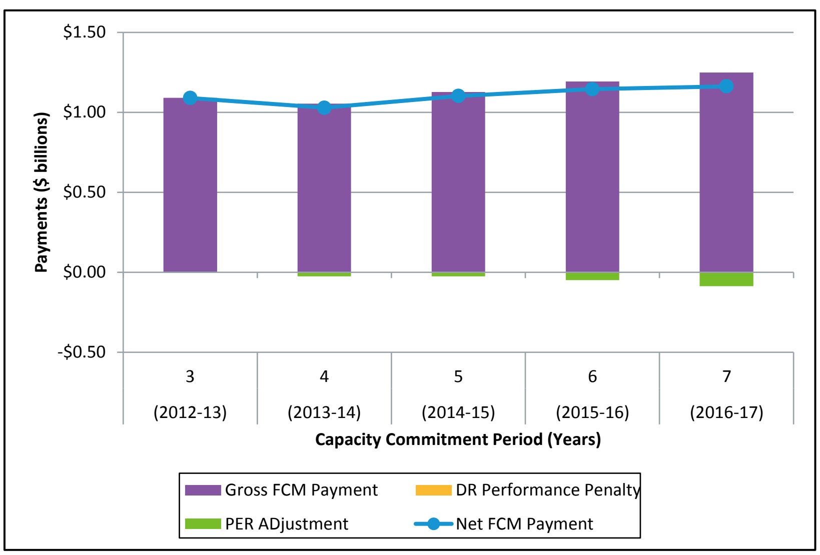
In *CCP 5* through *CCP 7*, payments remained relatively low due to system-wide surplus capacity and clearing prices set at the administrative floor price.[154] Capacity payments are expected to more than double from *CCP 7* and *CCP 8* due to higher primary auction clearing prices. FCA 8 cleared with 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 is expected to result 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).[155] The combination of higher Rest-of-Pool and SEMA/RI prices led to increased projected payments in *CCP 9* ($4 billion) compared to CCP 8 ($3 billion).

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 declined. System-wide clearing prices fell from $7.03/kW-month in *FCA 10* and $5.30/kW-month in *FCA 11*, to $4.63/kW-month in *FCA 12***.** Lower clearing prices are expected to cause a 48% decrease in projected payments, from $4 billion in *CCP 9* down to $2.1 billion in *CCP 12*.

As mentioned above, FCM annual payments are impacted by PER and, in the case of demand resources, performance penalties. Historically, FCM payment adjustments, on a percentage basis, have been relatively low. Gross payments (purple bar), PER adjustments (green bar), demand response performance penalties (yellow bar), and net payments (blue line) for the past five years (*CCP 3* through *CCP 7*) are presented in Figure 6-2 below.

Figure 6-2: Gross and Net Payments CCP 1 through CCP 6[156]



[154] In FCA 7, Northeastern Massachusetts/Boston capacity zone (NEMA/Boston) supply fell short of the local sourcing requirement. 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.

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

[156] Figure 6-2 does not show CCP 7 because the commitment period's end date is May 31, 2017.

There has been little variation in net payments from CCP 3 to CCP 7, since clearing prices were primarily set by the administrative floor price.[157] Total net payments in *CCP 7* were $1.2 billion. Peak energy adjustments increased during the commitment period, accounting for 7% of gross payments, or $90 million. During a system event on August 11 and 12, 2016, real-time LMPs exceeded the strike price for at least 10 hours in all capacity zones. The August 2016 PER adjustment was between $3.25/kW-month and $3.98/kW-month. Those prices are the highest single monthly PER values since the inception of the FCM. The August PER value is accounted for in a moving 12-month average, impacting FCM payments from September 2016 to August 2017.

6.3 Review of the Twelfth Forward Capacity Auction (FCA 12)

This section provides a closer review of FCA 12. The auction was held in February 2018. Further detail on the auction is contained in the IMM's Winter 2018 quarterly markets report.[158] This section is organized into two subsections. First, an overview of qualified and cleared capacity across a number of different dimensions is provided. Then the focus shifts to auction results, with particular emphasis on the mechanics around the demand curve in FCA 12.

The results of FCA 12 were competitive. At the start of the fourth round, bids were priced below the dynamic de-list bid threshold. Within this dynamic range, existing resources have the opportunity to remove capacity at a price that is not reviewed by the IMM. There was no single resource at the system or zonal level that could unilaterally exercise market power. Therefore, resource owners were incentivized to offer at competitive prices and the outcome of the auction was competitive.[159]

6.3.1 Qualified and Cleared Capacity

The amount of qualified and cleared capacity from new and existing resources compared to the capacity requirement provides an important indication of the level of potential competition in the auction.

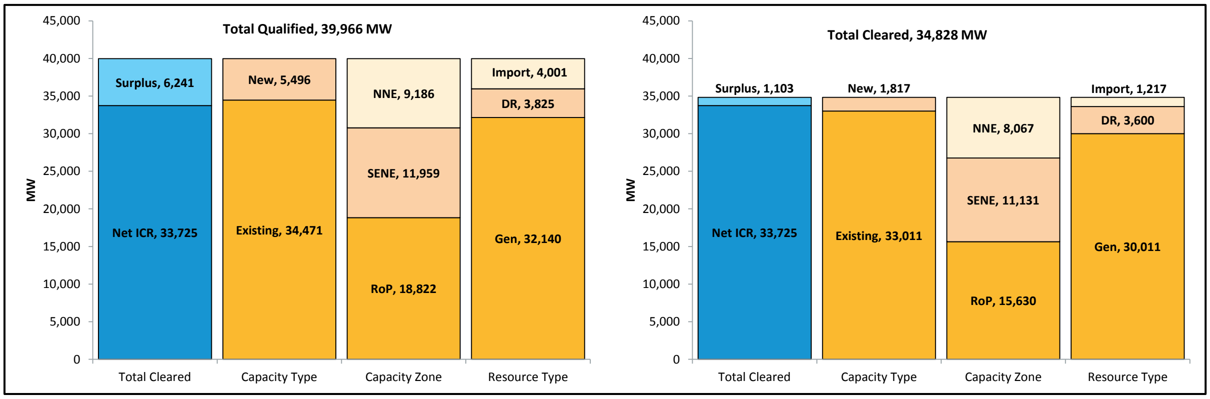
The qualified and cleared capacity in FCA 12 compared to Net ICR (blue bars) is illustrated in Figure 6-3 below. Qualified capacity is shown in the graph on the left and cleared capacity on the right. The height of the stacked bars equals total capacity. The three orange bars in each graph show the breakdown of total capacity across three dimensions: capacity type, capacity zone and resource type.

[157] In CCP 7, NEMA/Boston cleared at $6.66/kW-month for existing resources, and $14.99/kW-month for new resources. This is discussed in Section 6.4.1 below

[158] See https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

[159] See Attachment D of the FCA 12 FERC filing for more information: https://www.iso-ne.com/static-assets/documents/2018/02/fca_12_results_filing.pdf

Figure 6-3: Qualified and Cleared Capacity in FCA 12



There was a surplus of qualified capacity above Net ICR of 6,241 MW, or almost 19%. Qualified capacity from existing resources alone exceeded the Net ICR by 746 MW (34,471 MW vs. 33,725 MW). There was 5,496 MW of resources entering the auction as qualified new capacity. This comprised 850 MW of generation, 730 MW of demand resources, and 3,920 MW of import capacity.[160]

Out of the roughly 40,000 MW of qualified capacity, only 1,580 MW came from new qualified generation and demand response resources. Out of this, 514 MW of new demand response resources cleared, while only 167 MW of new generation cleared. Lower clearing prices in FCA 12 led to fewer new resources clearing 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.

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 11,959 MW of qualified capacity, 1,941 MW in excess of the local source requirement (LSR) of 10,018. At the end of the auction, 11,131 MW of supply cleared within the zone, 1,113 MW in excess of LSR. In NNE there was 9,186 MW of qualified capacity, 396 MW in excess of the maximum capacity limit (MCL) of 8,790 MW. However, 1,119 MW of capacity dropped out of the auction, resulting in the cleared amount of 8,067 MW, 723 MW below MCL. Therefore, there was also no negative price separation in NNE.

6.3.2 Results and Competitiveness

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 include the auction parameters provided by the ISO as well as participant behavior, and are summarized below for FCA 12.

FCA 12 incorporated the Marginal Reliability Impact (MRI) methodology in the calculation of the sloped system and zonal demand curves. The MRI methodology estimates how an

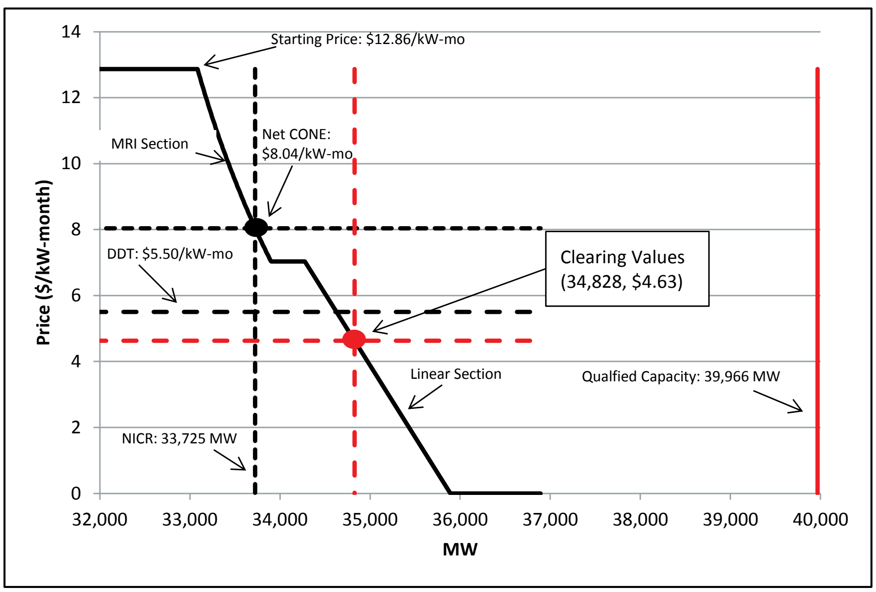
[160] For the purposes of FCA qualification, all imports are considered new resources.

incremental change in capacity impacts system reliability at various capacity levels.[161] However, the full MRI curve was not implemented for FCA 12. 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.[162]

Figure 6-4 below illustrates 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). 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 375 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 33,725 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 $8.04/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 $4.63/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 $5.50/kW-month (black dashed line).

Figure 6-4: System-wide FCA 12 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, and 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 (delist) the market during the fourth round. The DDBT also serves as an important

[161] For more information on why the ISO implemented a sloped demand curve, see Section 6.1

[162] The transition period begins 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.

threshold for market power mitigation, whereby an existing resource that submits bids above this level is subject to a mitigation review by the IMM.

During the fourth round the ISO performed reliability reviews for the submitted dynamic de-list bids, totaling 2,772 MW. Two dynamic de-list bids, Mystic 7 and 8, were rejected for reliability reasons in the NEMA/Boston load zone, which is located in the SENE capacity zone. Therefore, their combined 1,278 MW was held in the auction but were extra-marginal.[163] After accounting for the two rejected bids, a total of 1,430 MW from 30 resources were able to dynamically de-list. Over 1,200 MW of the dynamic de-lists were from natural gas-fired resources.

Three dynamic de-list bids set the clearing price when supply fell short of demand. The marginal resources de-list bids were then rationed to allow for demand to exactly equal supply. The auction cleared 34,828 MW at a price of $4.631/kW-month. As shown in Figure 6-4, supply met demand and price was set along the linear sloped portion of the transitional demand curve.

Assuming no changes in offer behavior, the transitional demand curve impacted the clearing price. If the ISO had implemented the MRI demand curve fully for this auction, then the clearing price would have been lower with less capacity cleared, assuming no change in offer behavior. This is the result of the residual shelf at $7.03/kW-month. This shelf was implemented to allow for a smoother transition to the MRI demand curve. FCA 13 will be the final auction to include this shelf.

The New Brunswick and Phase I/II interfaces 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 at a price of $3.16/kW-month for New Brunswick, and $3.70/kW-month for Phase I/II. The lower clearing prices were deemed to be competitive. The prices reflect reasonable expectations of competing opportunities in the New York ISO's spot capacity market.[164]

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 reconfiguration auctions and bilateral transactions.

6.4.1 Forward Capacity Auction Outcomes

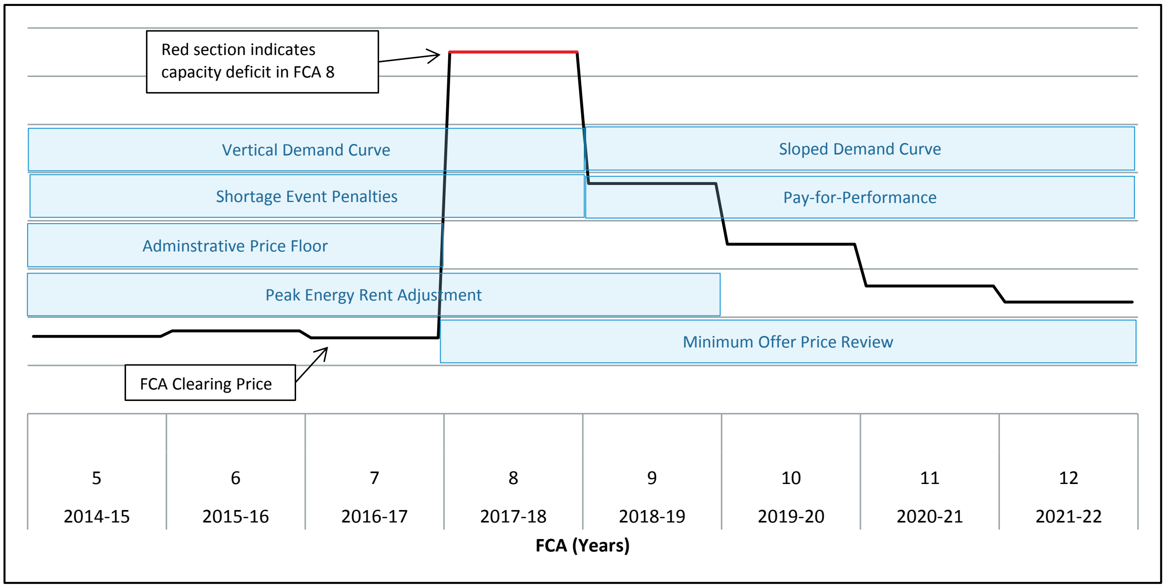
FCM prices are determined by the interaction of capacity supply and demand. When capacity is in relatively short supply, like in FCA 8, we expect prices to be higher. When supply is more abundant, we expect the opposite.

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 6-5 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.

[163] See Attachment B of the FCA 12 FERC Filing: https://www.iso-ne.com/static-assets/documents/2018/02/fca_12_results_filing.pdf

[164] See Attachment D of the FCA 12 FERC Filing: https://www.iso-ne.com/static-assets/documents/2018/02/fca_12_results_filing.pdf

Figure 6-5: FCA Clearing Prices in the Context of Market Rule Changes



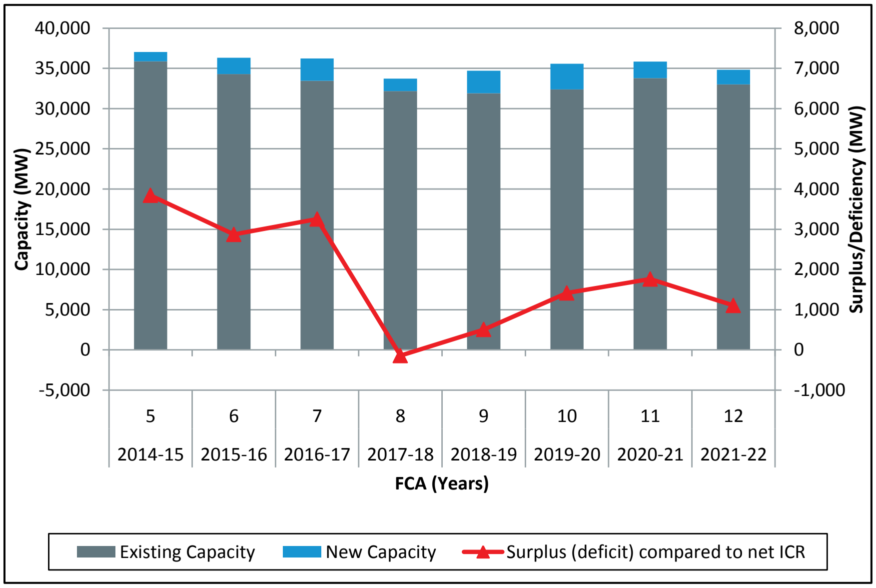
The first seven auctions cleared at the administrative market price floor. The price floor protected supply from low prices in a market environment with excess supply and a vertical (fixed) demand curve. Capacity prices under the vertical demand curve construct were subject to large year-to-year changes 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* improves price formation and reduces price volatility.[165] When there is a surplus of supply relative to Net ICR, as happened in *FCA 12*, 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.

The procured capacity relative to the Net ICR by auction is shown in Figure 6-6 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.

[165] 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.

Figure 6-6: Cleared and Surplus Capacity in FCAs 5 through 12



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 certainty for existing resources. With these auction conditions, there was at least 2,000 MW of excess cleared capacity in the early FCAs.[166] 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.

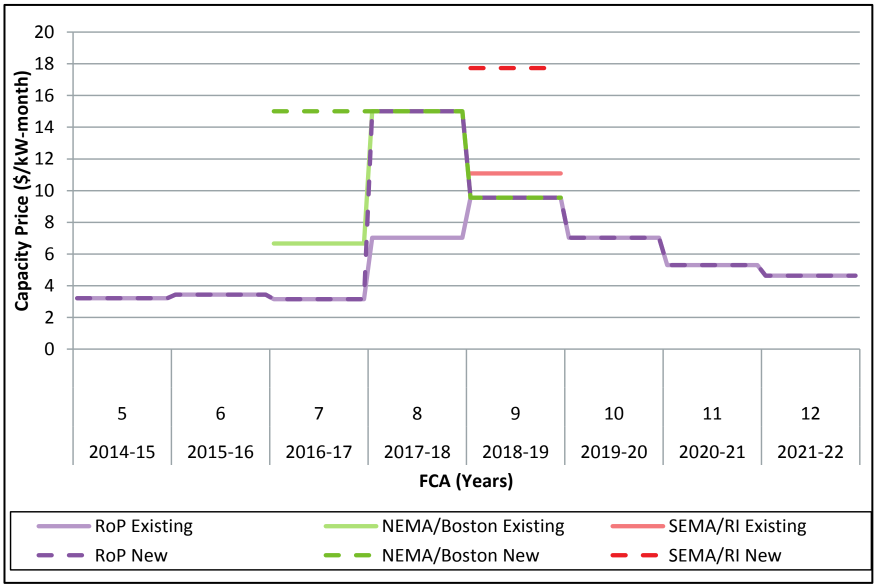
In the subsequent three auctions (*FCA 9, 10, 11*) new generation and demand response resources cleared 1,400, 1,800, and 900 MW, respectively. The new generation, along with fewer retirements, turned a 140 MW deficit into a 1,800 MW surplus in the span of three auctions.

The surplus declined in *FCA 12*, primarily due to one-year dynamic delists. Once the auction price went below the dynamic de-list bid threshold shown in Figure 6-5, resources entered de-list bids to remove their capacity for the commitment period. Over 1,400 MW of de-list bids cleared in FCA 12. That is the largest amount of cleared dynamic de-lists in an FCA, and 1,200 MW more than in FCA 11.

The changes in new and existing capacity clearing prices for each FCA are illustrated in Figure 6-7 below. The solid lines represent the price paid to existing resources. Dashed lines represent the price paid to new resources.

[166] Cleared capacity in this figure represents the cleared MW value from the forward capacity auction. It does not account for any proration or specific resource caps.

Figure 6-7: Forward Capacity Auction Clearing Prices



Clearing prices did not separate by capacity zone until FCA 7, 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 new 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.[167] New and existing capacity across the rest of the system cleared at the floor price of $3.15/kW-month.

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 administration prices were triggered.[168] 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 12*. The system-wide clearing price in FCA 9 was $9.55/kW-month.[169] Clearing prices continued to fall in FCAs 10 and 11. In FCA 12, a dynamic de-list bid set the system-wide clearing price at $4.63/kW-month.

[167] 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

[168] 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

[169] 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.

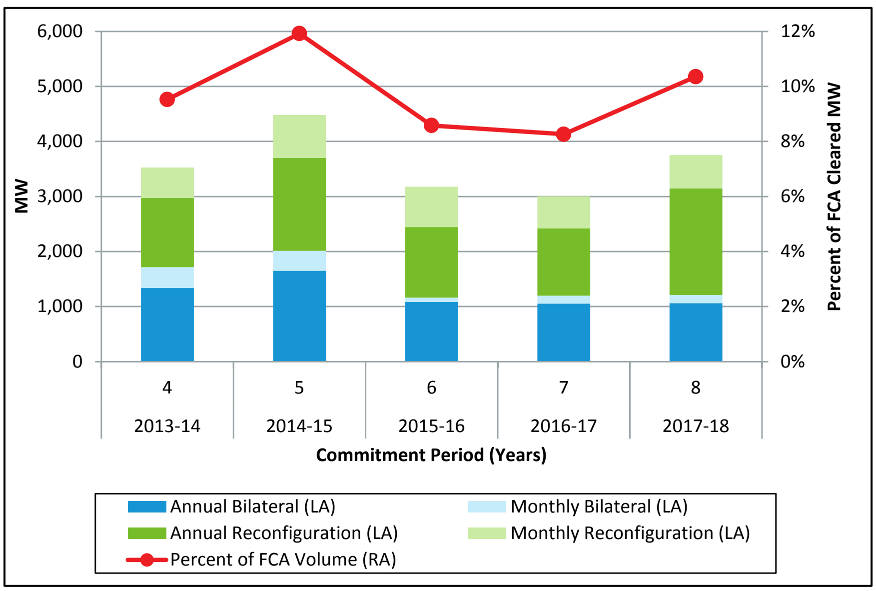
6.4.2 Secondary Forward Capacity Market Results

Reconfiguration auctions and bilateral transactions facilitate the secondary trading of CSOs. That is, they provide an avenue for participants to adjust their CSO positions after the primary FCA takes place.[170]

Historically, the traded volume in the secondary markets has been much lower than the primary auctions. From CCP 4 through CCP 8, secondary traded volumes averaged about 9% of the primary auction volumes, with a high of 12% occurring in CCP 4 (roughly 4,500 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 and some import resources have additional capability that can be traded in the monthly auctions.

Figure 6-8 below shows 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).[171] Monthly and annual *reconfiguration auction* volumes are shown in green colors and monthly and annual *bilateral transaction* volumes in blue colors.[172]

Figure 6-8: Traded Volumes in FCA and Reconfigurations



Prices in the secondary markets are set through ISO administered reconfiguration auctions or through bilateral agreements between parties. Unlike the primary auctions, there are no floor prices in Annual Reconfiguration Auctions (ARAs), which led to low clearing prices during

[170] There are many opportunities for participants to adjust their obligations. 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.

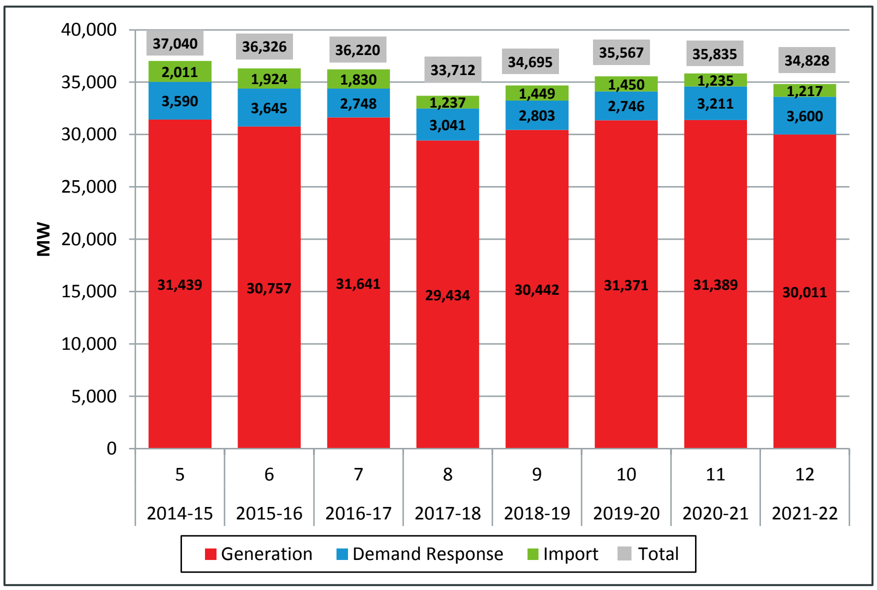
[171] Volumes are shown as average annual weighted values. For example, a monthly product gets a weight of 1/12th, an annual product a weight of 1 etc.

periods when the system was 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 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). Prior to the removal of the floor price in CCP 8, all but two clearing prices were below FCA 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 and import resources. Figure 6-9 below illustrates the relative share of these categories as a percentage of cleared capacity in each FCA.

Figure 6-9: Capacity Mix by Resource Type from FCA 5 through FCA 12



The mix of capacity by resource type has not changed significantly. In fact, while there have been annual fluctuations, the percentage shares are very similar in FCA 12 compared to FCA 5. In FCA 12 generation, demand response, and imports made up 86%, 10%, and 3% of the capacity mix, respectively. Demand response has remained relatively constant since FCA 5 due to new passive demand response entering the market, and active demand response leaving the market.[173] There will be roughly 500 MW of real-time demand response active when the price-responsive demand (PRD) project goes live on June 1, 2018.

6.5.1 Retirement of Capacity Resources

A participant can choose to retire its resource by submitting a retirement request to the ISO.[174] This is an irrevocable request to retire all or a portion of a resource.[175] Up to FCA 11, this

[173] See Section 2.3.1. for more information on passive demand response and its impact on the energy market.

[174] 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.

request was not contingent on market clearing prices; it was known as a non-price retirement. Starting in FCA 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.

Retired generating resources with capacity exceeding 50 MW from the fifth commitment period are shown in Table 6-1 below.

Table 6-1: Generating Resource Retirements over 50 MW from FCA 5 to FCA 12

FCA# (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 5 (2014/15)	Salem Harbor 1	Coal	NEMA/Boston	82
FCA 5 (2014/15)	Salem Harbor 2	Coal	NEMA/Boston	80
FCA 5 (2014/15)	Salem Harbor 3	Coal	NEMA/Boston	150
FCA 5 (2014/15)	Salem Harbor 4	Coal	NEMA/Boston	437
FCA 5 Total (resources > 50 MW)				**749**
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**
FCA 9 (2018/19)	**Mt. Tom.**	**Coal**	**WCMA**	**144**
FCA 10 (2019/20)	**Pilgrim Nuclear**	**Nuclear**	**SEMA**	**677**
FCA 11 (2020/21)	**Bridgeport Harbor 3**	**Oil**	**Connecticut**	**383**

a) The capacity period 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. Increasing emission prices and other energy polices have led to increased production costs (see Section Generator Profitability2.2.3). 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 prices and additional natural gas-fired capacity.

6.5.2 New Entry of Capacity Resources

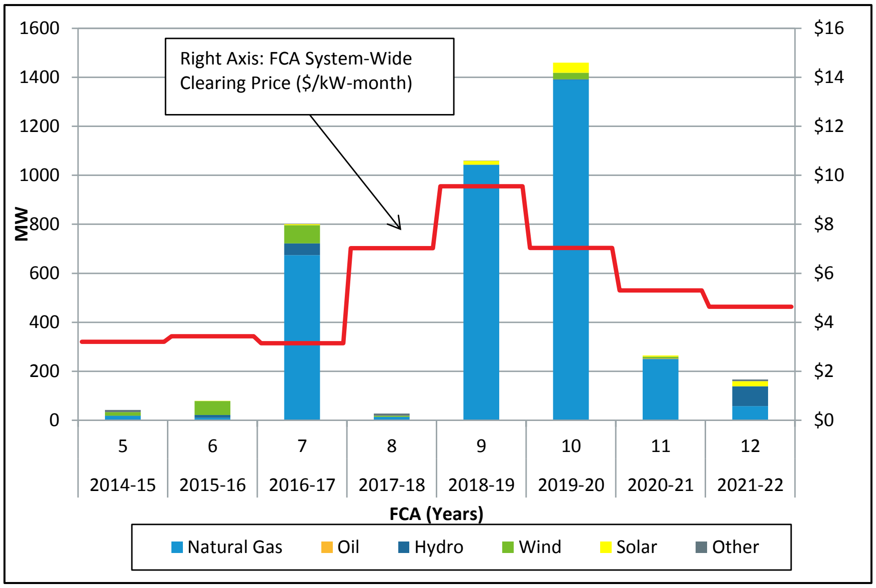
This section provides an overview of major new resources entering the FCM. New entry typically implies a resource entering the market for the first time. However, existing resources

[175] 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.

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.[176] 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 6-10 represents new generation capacity by fuel type since the FCA 2.[177]

Figure 6-10: New Generation Capacity by Fuel Type from FCA 2 to FCA 11



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

The majority of new additions since FCA 5 have been natural gas-fired resources. In *FCA 7*, Footprint (gas) added 675 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 86% of this supply: Bridgeport Harbor 6(480 MW), Canal 3 (330 MW), and Burrillville Energy Center (490 MW).

In *FCA 11* and FCA 12, there was a large decrease in cleared new capacity. There was a total of 167 MW of new generation in FCA 12. Hydro added the most capacity from incremental additions from two pumped storage resources. There was one new 58 MW simple cycle gas turbine that cleared in SENE. Lastly, 52 new solar projects cleared for a total of 21 MW. None of the projects were larger than 2 MW.

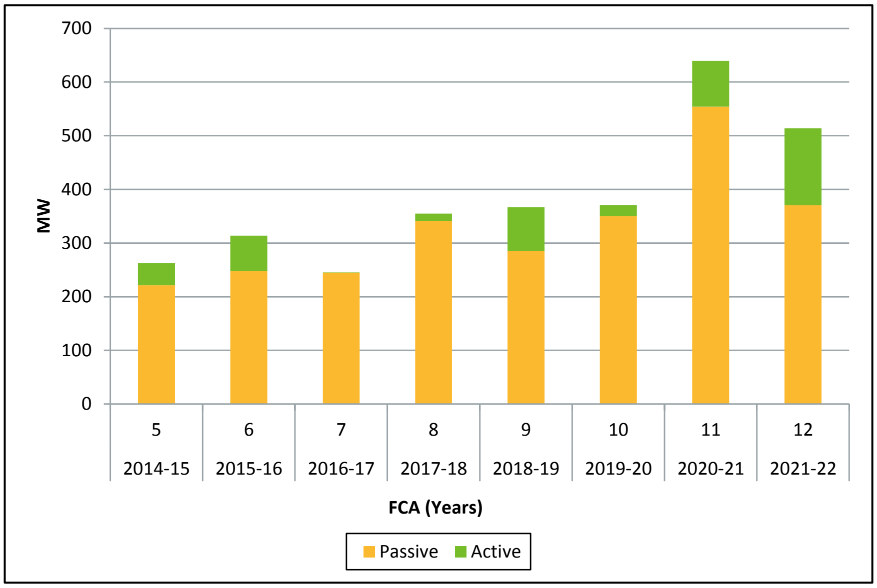
Significant increases in new passive demand response resources have more than offset active demand response retirements. Passive demand response is defined as on-peak and seasonal-peak resources. Active demand response is broken into real-time demand response and

[176] See Market Rule 1, Section III.13.1

[177] Nearly all capacity resources in FCA 1 participated as existing capacity, which was allowed under the FCM Settlement Agreement. Therefore, the figures in this section start with FCA2.

emergency generation.[178] Figure 6-11 below shows new active and passive resources that cleared in the FCA.

Figure 6-11: New Demand (Reduction) Resources with a CSO



New passive demand response resources added 2,100 MW from FCA 5 to FCA 12. 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. Over that same period, total active demand response fell nearly 1,500 MW. Tighter emission restrictions on emergency generation increased barriers to participation in the FCM.[179]

In FCA 12 alone, over 500 MW of new demand response cleared. This was split between 144 MW of active demand response resources and 371 MW of passive demand response resources. As mentioned above, the entry of these resources is less likely to be directly driven by capacity market prices, but rather by state public policy goals.

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)

[178] On-peak resources are energy efficiency and load reducing distributing generation projects provide long term peak capacity reduction. Season-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.

[179] On May, 2016, the D.C. circuit court issued an order reversing and remanding the EPA rules that provided a 100 hour exemption for operation of emergency engines during demand response events. This effectively removed emergency generations' ability to bid into the FCM as a demand response resource.

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 incorporates demand conditions by examining whether a supplier's capacity is needed to meet zonal capacity requirements.[180] Both metrics:

- respect system constraints such as capacity transfer limits,
- take into account the affiliations between suppliers to accurately reflect all the capacity resources under the supplier's control, and
- consider only existing resources due the challenges in predicting intra-auction new supply behavior.[181]

The RSI is measured on a continuous scale with a lowest possible value of 0 (a pure monopoly) and an uncapped upper limit. When the RSI is greater than 100%, suppliers other than the largest supplier have enough capacity to meet the relevant capacity requirement. This indicates that the largest supplier should have little opportunity to profitably increase the market clearing price. Alternatively, if the RSI is less than 100%, the largest supplier is needed to meet demand. Consequently, the largest supplier could, in principle, 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.[182] 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.[183] 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.

Because both metrics are concerned with the ability to meet capacity requirements in the absence of specific portfolios of capacity, the output of both metrics result from multiple factors, including:

- *Capacity requirements* – both at the system level (in the form of the net installed capacity requirement, or Net ICR) and the import-constrained area level (in the form of the 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. For instance, Connecticut and

[180] Section III.A.23 of the Tariff.

[181] 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)."

[182] 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.

[183] 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.

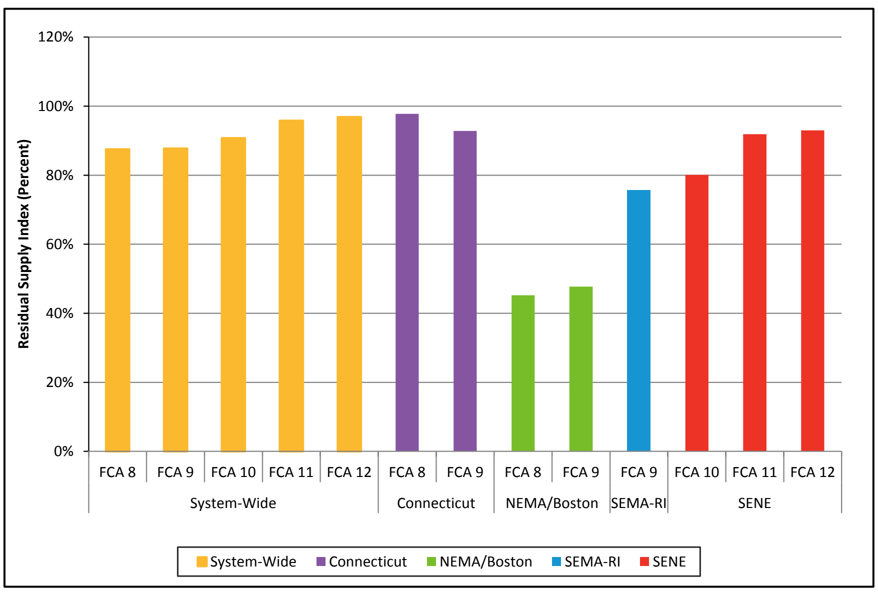
NEMA/Boston were modelled as separate capacity zones in FCAs 7 through 9. In FCA 10, Connecticut was rolled into the Rest-of-Pool (ROP) capacity zone. Likewise, NEMA/Boston was rolled into the Southeast New England (SENE) zone, along with Southeast Massachusetts/Rhode Island (SEMA/RI), that same year.

- *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 6-12 below.[184]

Figure 6-12: Capacity Market Residual Supply Index, by FCA and Zone



The RSI was below 100% in every auction since FCA8, at both the system and zonal level, indicating that there was at least one pivotal supplier. The system-wide RSI (yellow) increased in each of the past five FCAs, rising from a low of 87% in FCA 8 to a high of 97% in FCA 12. This increase 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 a reduction in the Net ICR in recent auctions.

[184] 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.

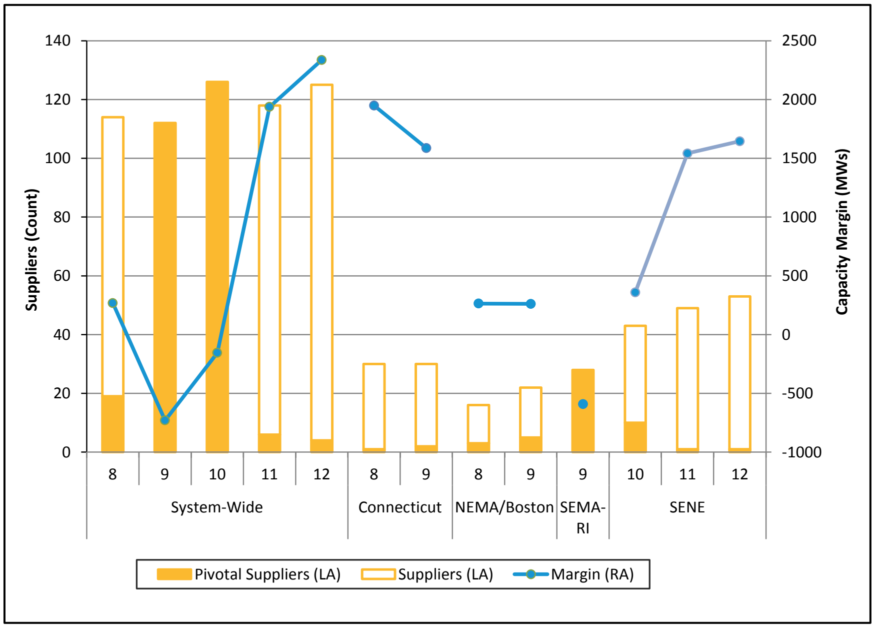
Another factor contributing to the RSI changes was the consolidation of capacity zones from FCA 9 to FCA 10. Planned transmission improvements and resource additions in Connecticut further relieved constraints that potentially limited power from flowing between Connecticut and the System-Wide (Rest-of-Pool) zones. Starting with FCA 10, the planned transmission improvements allowed the Connecticut zone to be merged into the System-wide zone which contributed to the increased competitiveness of the System-wide zone.

The NEMA/Boston and SEMA/RI zones experienced a similar outcome. 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. There are still transmission constraints potentially limiting power flows between the newly created SENE zone and the System-wide zone; hence the need for the separate SENE 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. Competition has continued to increase in the SENE zone, with an RSI of 93% in FCA 12. However, there continues to be local system needs in NEMA/Boston, which required the retention of the two Mystic generators for reliability in FCA 12. In other words, there are more localized competiveness issues in this area than the RSI in the SENE zone would suggest.

Pivotal Supplier Test Results

The number of suppliers and pivotal suppliers within each zone over the past five FCAs are presented in Figure 6-13 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. As an example of how to read the figure, consider the SENE capacity zone in FCA 10. The amount of capacity exceeded the LSR, resulting in a capacity margin of approximately 350 MW (right axis – blue marker). Consequently, a supplier with a portfolio of greater than 350 MW in this zone would be deemed pivotal in FCA 10. Of the 43 suppliers in SENE in FCA 10 (left axis – yellow bar), only 10 (highlighted in yellow) were pivotal.

Figure 6-13: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone



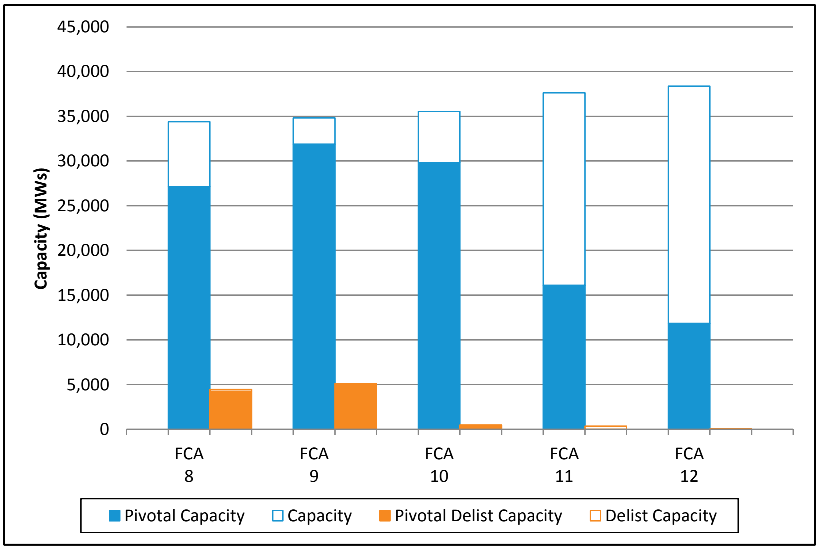
At the system level, the slight excess of capacity in FCA 8 turned negative in FCAs 9 and 10, causing all suppliers to be deemed pivotal for these two auctions.[185] The capacity margin increased decidedly over the next two FCAs. In the latter (FCA 12), a supplier needed a portfolio of over 2,300 MWs to be deemed pivotal.[186] Consequently, there were few pivotal suppliers at the system level in either FCAs 11 or 12. Both the Connecticut and NEMA/Boston capacity zones (active during FCAs 7 through 9) had excess capacity in FCAs 8 and 9 – the former with over 1,500 MWs and the latter with a flat 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. Lastly, the capacity margin in the SENE capacity zone increased by almost 1,300 MW between FCAs 10 and 12. This is primarily the result of over 1,000 MWs of new capacity added to the capacity zone in FCA 10. Consequently, the number of pivotal suppliers dropped from ten in FCA 10 to only one in FCA 12.

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 6-14 below.

[185] Refer to Section 6.5.1 for a discussion of large resource retirements that resulted in this change.

[186] 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 6-14: Overview of Resources, Pivotal Resources, De-lists, and Pivotal De-lists



Consistent with the slight capacity margin at the system level in FCA 8 (~250 MWs), approximately 80% of existing capacity was associated with pivotal suppliers at this time. While this is less than the proportion of de-list capacity from pivotal suppliers in FCA 8 (95%), it is important to note that there were a number of market changes made at this time, including the removal of a price floor.[187]

The negative capacity margins in FCAs 9 and 10 led to increases over the FCA 8 totals in both the amount and proportion of capacity associated with a pivotal supplier.[188] In FCAs 9 and 10, all de-list capacity was pivotal; however, so was the majority of all existing capacity. The total de-list capacity decreased significantly after FCA 9, from over 5,000 MWs in FCA 10 to a low of under 30 MWs in FCA 12. 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.

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 Forward Capacity Market (FCM), as well as summary statistics on the number and impact of these

[187] Refer to Section 6.4.1 for an overview of market rule changes.

[188] While all suppliers were pivotal in FCAs 9 and 10, the same does not hold true for resources. The PST is a portfolio-level test that results in supplier-specific pivotal status determinations, but resources within a pivotal supplier's portfolio may still be non-pivotal. For instance, consider an example where there is capacity in excess of an external interface's capacity interface limit (CTL). If, after removing a supplier's capacity at that interface, there is still capacity in excess of the CTL, then those import resources will be deemed non-pivotal. This is because the supplier does not have the ability to exercise market power at that interface by removing that capacity.

measures. To address market changes, this section presents summary information for FCA 8 through FCA 12.

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 (DDT) price.[189] 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.[190]

As of FCA 11, permanent de-list bids were replaced by "retirement and permanent de-list bids" for resources greater than 20 MW. Between FCA 8 and 11, there were no permanent de-list bids or retirement de-list bids for resources greater than 20 MW and 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.

[189] De-list bids priced below the DDT 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 DDT price. The DDT has undergone a number of revisions since the start of the FCM. The DDT price was $1.00/kW-month in FCA 8, $3.94/kW-Month in FCA 9, and $5.50/kW-month in FCAs 10, 11, and 12.

[190] 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.

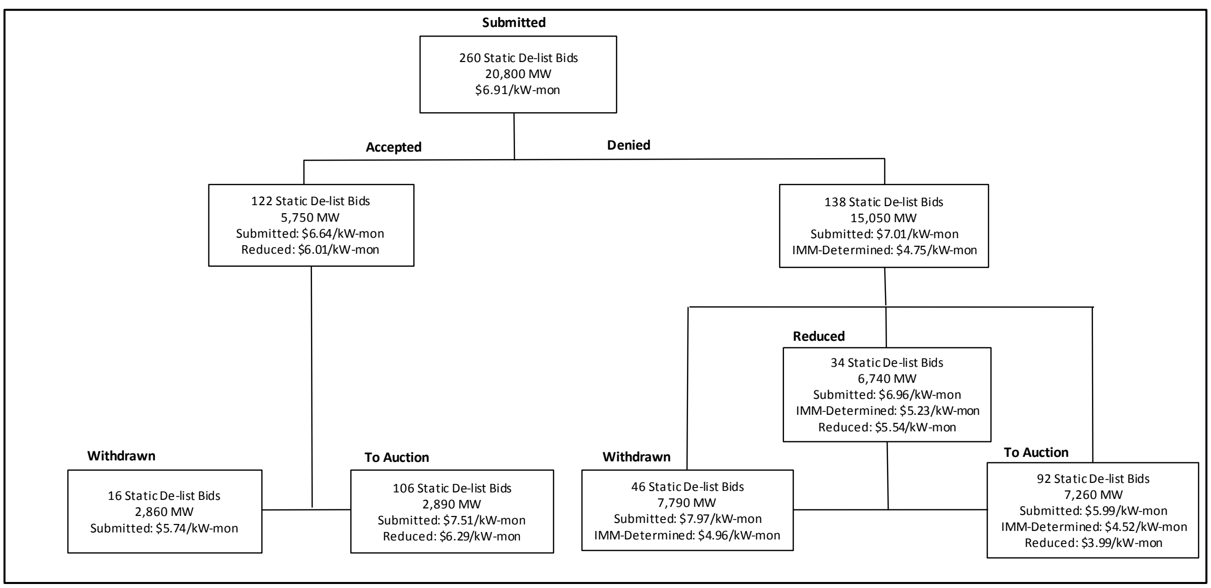
Starting in FCA 9, certain types of new import capacity resources were also reviewed for supplier-side market power. As of FCA 10, various changes were made, including limiting this review to new import capacity resources without transmission investments

For *FCA 8* through *FCA 12*, the IMM reviewed 260 general static de-list bids from 18 different lead participants, totaling over 20,800 MW of capacity (an average of 4,160 MW per auction).[191] While generation resources accounted for just over a third (102) of the total number of general static de-list bid submissions, these de-list bids totaled approximately 93% (19,400 MW) of all de-list capacity. Demand resources, which typically consist of smaller resources, accounted for 60% of the total number of submitted general static de-list bids, but only 7% of the total capacity. In addition, 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 premium, and opportunity costs. This process resulted in a lower approved auction price for approximately 53% of the general static de-list bids (72% of de-list MW capacity).[192]

Summary statistics for static de-list bids from *FCA 8* through *FCA 12* as well as the path the bids took from the time of initial submittal to the auction are provided in Figure 6-15 below. Note that all de-list bid prices are megawatt-weighted averages.[193]

Figure 6-15: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCA 8 – 12)



[191] 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.

[192] If a supplier is pivotal, the IMM-determined value is entered into the auction; if not, the participant-submitted is entered.

[193] 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.

Nearly half of all static de-list bids were approved by the IMM without any changes (no mitigation). Of the static de-list bids that were mitigated, many were voluntarily withdrawn or the bid price further reduced prior to the auction. The weighted-average bid reduction was $0.53/kW-month. The weighted-average price of *mitigated* static de-list bids that went to the auction was $2.00/kW-month less than the market participant's originally submitted price.

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 participant to offer capacity below cost.[194] 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 8 through 12, the IMM reviewed over 310 new supply offers from participants requesting to offer below the ORTP.[195] These offers came from 66 different lead participants and totaled 11,700 MWs of capacity, of which 7,300 MW (~63%) entered the auction.[196] Generation resources accounted for the majority of the new capacity reviewed, with 89% of the total (~10,300 MW). Demand response resources accounted for the remaining 11% (~1,300 MW). No new import capacity resources with transmission investments completed the review process.

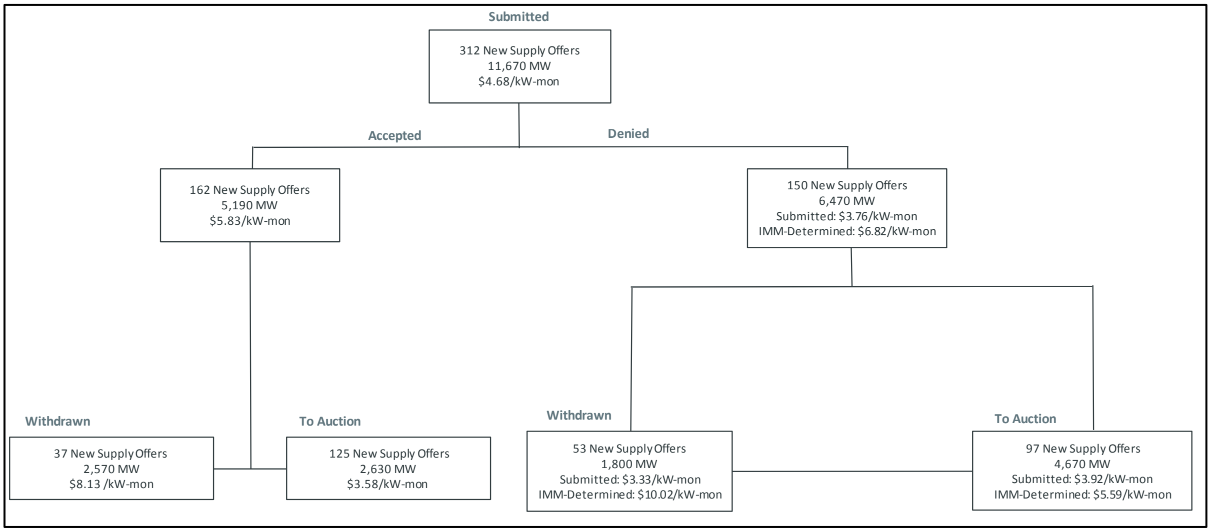
Summary statistics from resources requesting to offer below their respective ORTP in FCAs 8 through 12 are provided in Figure 6-16 below. Note that all offer prices are megawatt-weighted averages.

[194] Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

[195] 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.

[196] 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.

Figure 6-16: Reviewable Offer Request Summary Statistics, by Key Milestone Action (FCA 8 – 12)



The IMM mitigated approximately 48% of the new supply offers that it reviewed, or approximately 55% of the new supply capacity.[197] 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 resulted in an average increase in offer price of $3.06/kW-month (from a submitted price of $3.76/kW-month to an IMM-determined price of $6.82/kW-month).

[197] Note that the number of mitigated new supply offers also includes 24 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.

Section 7
Ancillary Services

This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. In 2017, the total costs of ancillary service products and their associated make-whole payments were similar to 2016 costs. There are four 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 *Winter Reliability Program* is intended to remedy fuel supply issues that can threaten reliability. The program pays market participants to purchase sufficient fuel inventories (oil or LNG) or provide additional demand response during the winter months, when it can be challenging to procure natural gas.

Ancillary service costs by submarket are displayed in Table 7-1 below.

Table 7-1: Ancillary Service Costs, 2016 and 2017 (in $ millions)

Ancillary Service	2016	2017
Total Reserve Market Costs[198]	$16.4	$29.9
Net Forward Reserve Credit	$53.2	$39.9
Regulation	$26.5	$29.7
Winter Reliability Program[199]	$35.2	$28.8
Total	**$131.3**	**$128.3**

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 levels of reserves are available to respond to such contingencies, the ISO procures several different

[198] Total reserve market costs are defined as total real-time reserve payments minus total forward reserve obligation charges.

[199] The Winter Reliability Program costs presented in Table 7-1 are calculated for the calendar year (for example, January, February, and December 2017 constitute 2017 costs). The Winter Reliability Program costs presented in Section 7.4 are calculated on a seasonal basis (for example, December 2017, January 2018, and February 2018 constitute Winter 2017-2018 costs).

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 2017.

7.1.1 Real-Time Operating Reserve and Pricing Mechanics

The ISO maintains real-time reserve requirements for the following reserve products:

- **Ten-minute spinning reserve (TMSR):** TMSR is the highest-quality reserve product. It is provided by on-line resources able to increase their output within 10 minutes. This gives the system a high degree of certainty 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 (i.e., can electrically synchronize to the grid and increase output within 10 minutes) to ensure that needed reserves will be available in response to a contingency.
- **Thirty-minute operating reserve (TMOR):** TMOR is a lower quality reserve product provided by less-flexible resources on the system (i.e., on-line resources that can increase output within 30 minutes or off-line resource that can electrically synchronize to the system and increase output within 30 minutes in response to a contingency).[200]
- **Local Thirty-minute operating reserve (Local TMOR)**: Local TMOR is a product that requires additional TMOR for each local reserve zone to meet the local second contingency in import-constrained areas. TMOR is required for the local reserve zones of Connecticut (CT), Southwest Connecticut (SWCT) and NEMA/Boston.

Participants with resources that provide reserves are compensated through the locational FRM, which offers a product similar to a capacity product (see Section 7.2), and through real-time reserve pricing. When the ISO dispatches resources in real-time, the process co-optimizes the use of resources for providing electric energy and real-time reserves. Reserve pricing occurs when the system must re-dispatch resources away from the lowest-cost solution for satisfying energy requirements and incur additional costs to meet the reserve requirements. When this happens, the reserve price is set by the resource with the highest re-dispatch cost or opportunity cost to provide the reserves, capped by the Reserve Constraint Penalty Factor (RCPF). RCPFs are limits on re-dispatch costs the system will incur to satisfy reserve constraints. The RCPFs also serve as a pricing mechanism that signals scarcity in real-time through high reserve prices. These reserve prices are reflected in the energy price due to the interdependence in procurement. Each reserve constraint has a corresponding RCPF, as shown below in Table 7-2.

[200] In addition to the Operating Reserve Requirements, the 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. Operating Procedure No. 8, *Operating Reserves and Regulation* (January 17, 2017), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

Table 7-2: 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

Reserve prices are determined using each resource's real-time energy offer. Other features of the co-optimization process include the following:

- When there are not enough reserves on the system to meet reserve product requirements, reserve constraints are said to "bind". In the presence of a binding reserve constraint, the system dispatch may reduce the output of an otherwise economic unit in the energy market to create reserves on the system. When this occurs, the opportunity cost of altering the dispatch determines the market-clearing price for the reserve product.
- The market-clearing 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.[201]
- The market software optimizes the use of local transmission interfaces to minimize the cost of satisfying all energy and reserve requirements in each region.
- On average, the cost incurred to re-dispatch online 10-minute operating reserve assets 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:

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.

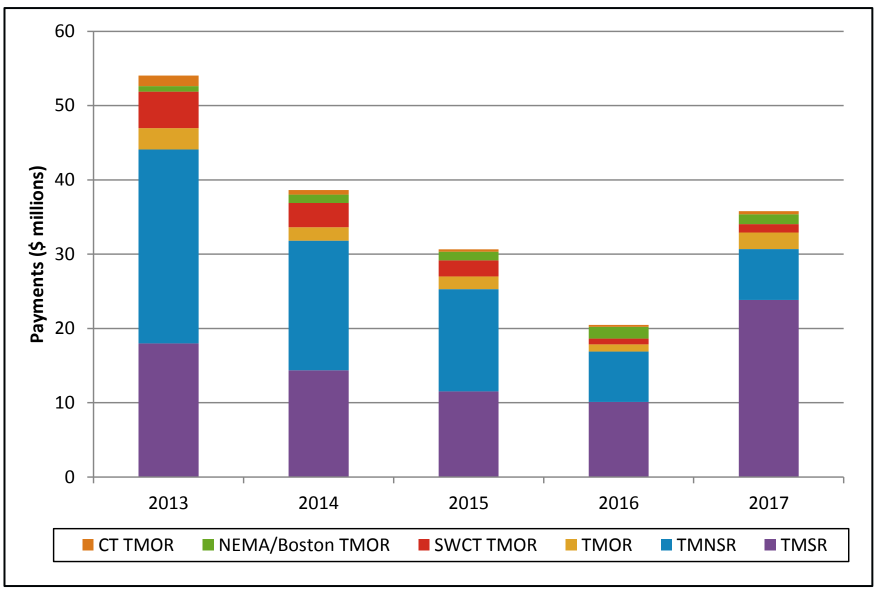
[201] When an RCPF is reached and the real-time energy market's optimization software stops re-dispatching resources to satisfy the reserve requirement, the ISO will manually re-dispatch resources to obtain the needed reserves, if possible.

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

Total real-time operating reserve payments increased by 75% from $20.5 million in 2016 to $35.8 million in 2017 due to the new fast-start pricing rules that were implemented in March 2017. 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. The 2017 value of $35.8 million was < 1% of total wholesale market costs in New England. Reserve payments for all reserve products are shown in Figure 7-1 below.

Figure 7-1: Real-Time Reserve Payments 2013 - 2017



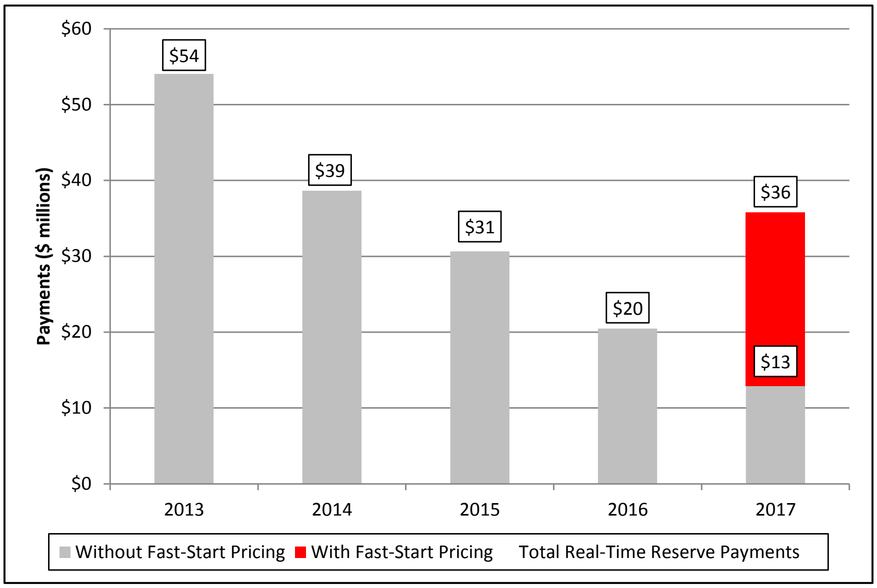
The payments presented above are a measure of the value of real-time reserves. They are based on each resource's real-time reserve designation and the reserve market clearing prices. To ensure participants are not paid twice for the same service, there is a settlements mechanism to adjust the real-time reserve payment for resources that are paid in the forward reserve market.

Overall, reserve payments in 2017 increased for all reserve products compared to 2016 with the exception of NEMA/Boston TMOR, which decreased by $237,000 or 15%. The decrease in reserve payments in NEMA/Boston was primarily driven by a decrease in the frequency of reserve pricing in the zone. The increase in 2017 payments for all other products was driven by an increase in the average real-time reserve prices.

Impact of fast-start pricing on operating reserve payments

While changes to the frequency and magnitude of reserve pricing are a function of many different factors that influence system conditions, the implementation of fast-start pricing in March 2017 had the single biggest impact in 2017. As intended, fast-start pricing more accurately reflects the cost of operating higher-cost fast-start generation and, on average, has increased the price of energy.[202] Because the price of 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. Figure 7-2 below shows the impact of fast-start pricing on real-time reserve payments.

Figure 7-2: Impact of Fast-Start Pricing on Reserve Payments



Without fast-start pricing, real-time reserve payments would have been approximately $13 million in 2017, compared to about $36 million of real-time reserve payments that occurred with the fast-start pricing rules in place since March 1, 2017.

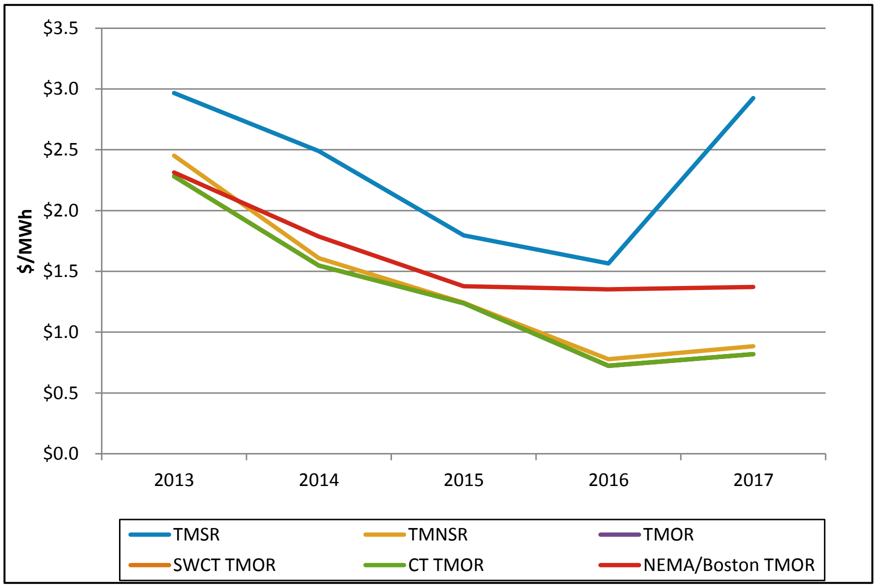
7.1.3 Real-Time Operating Reserve Prices: Frequency and Magnitude

Average real-time reserve prices are driven by the relative frequency of zero and non-zero prices. In most intervals, reserve prices are zero. An interval with a zero reserve price signifies that there was adequate reserve capacity available on the system, and that the system did not have to be re-dispatched in order to meet reserve requirements. The focus of this section is on the frequency and magnitude of non-zero reserve pricing. We show that the large changes observed in 2017 were due to the impact of the fast-start pricing rule changes.

Average real-time prices for each reserve product overall all intervals (both zero- and non-zero pricing intervals) are illustrated in Figure 7-3 below.

[202] 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

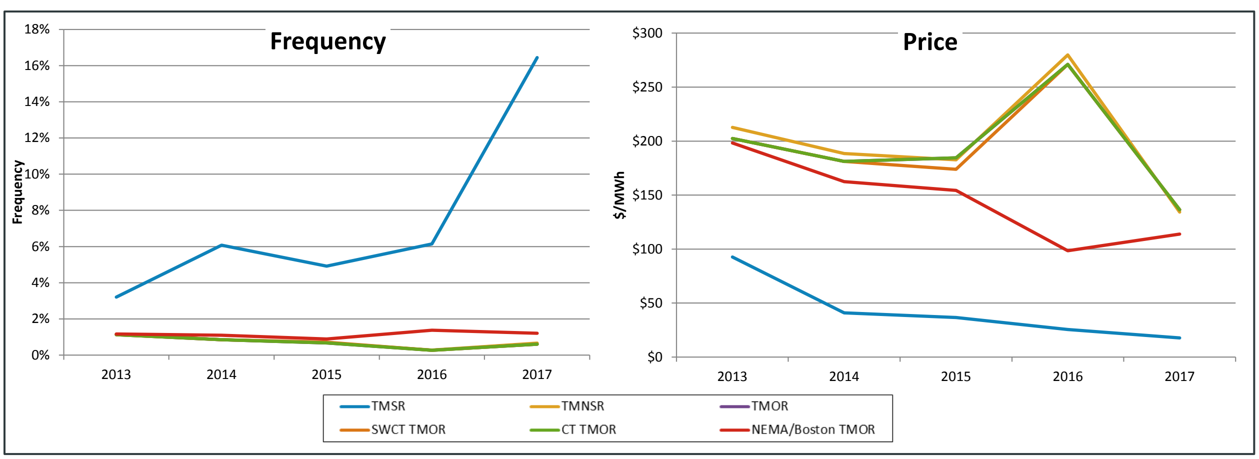
Figure 7-3: Average Real-Time Reserve Prices for all Intervals



Note: This figure includes all zero and non-zero reserve prices. Average operating reserve prices are based on preliminary prices and do not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

The average real-time reserve prices increased for all products in 2017 compared to 2016. The first of the two explanatory factors is *frequency*. Frequency represents the number or percentage of pricing intervals in which a reserve product has a positive price (a price above $0/MWh). The other factor is *magnitude*. Magnitude is illustrated by showing the average real-time reserve price for each product in intervals when there was non-zero reserve pricing. Figure 7-4 below illustrates changes in both frequency (left) and magnitude (right) of non-zero reserve prices by reserve product over time.

Figure 7-4: Frequency and Average of Non-Zero Reserve Prices



As shown in the left graph, the TMSR frequency was higher than any other reserve products in 2017, on average. TMSR pricing occurs more frequently because the TMSR reserve constraint tends to bind during times when the system is ramp-constrained, which can quickly deplete 10-minute spinning reserves. These periods tend to occur during the morning and evening hours when load naturally increases. As load increases, many generators are scheduled to increase their output. Each generator has a limited amount of ramping capacity (the amount of additional output it can provide over a period of time). As a generator ramps up to provide more energy, its ramp capacity (i.e. the capacity it can turn into energy within a specified time) is consumed in providing more energy and therefore does not retain that ramp capacity in reserve. During periods of high load ramp, a generator's ability to provide TMSR can be limited.

While the TMSR product had a higher frequency of reserve pricing in 2017 than in 2016, increasing by 167%, Figure 7-4 shows the average price for positive pricing intervals decreased by 30%. The decrease in average price occurred because the 2017 average accounts for a vast number of hours with low albeit positive TMSR prices. The large increase in frequency outweighed the slight decline in average price as TMSR payments increased by $13.8 million in 2017, or 136%.

Likewise, although the average reserve price during positive pricing intervals for TMNSR, system TMOR, SWCT TMOR, and CT TMOR decreased between 2016 and 2017, the increase in frequency of reserve pricing for these products led to an increase in payments. This means that even though the system experienced lower reserve prices for these products when there was non-zero pricing, the frequency of pricing was so high (approximately 0.7% of intervals) that there was an ultimate increase in reserve payments for these products in 2017.

The only exception to the increase in payments was NEMA/Boston as this region experienced a 16% increase in the magnitude of reserve pricing, but a 12% decrease in the frequency of reserve pricing for the local TMOR product. The decrease in frequency was primarily driven by the local reserve constraint binding less frequently due to transmission outages in and around the Boston area that affected the import capability into the load and reserve zone during 2017. The increase in the magnitude of reserve pricing is primarily due to the increase in frequency of the local TMOR RCPF binding, which is discussed in further detail below.

The impact of fast-start pricing on reserve prices

The fast-start pricing rule changes had a significant impact on both the frequency and magnitude of non-zero prices that drove the overall increase in average reserve prices and payments. The estimated impact is shown in Table 7-3 below.

Table 7-3: Impact of Reserve Prices and Payments on Real-Time Operating Reserves

Product	Zone	Actual 2017			Estimated w/o FSP			Difference		
		Avg. Price	*Hours of*	*Payment*	*Avg. Price*	*Hours of*	*Payment*	*Avg. Price*	*Hours of*	*Payment*
		$/MWh	*Pricing*	*$ millions*	*$/MWh*	*Pricing*	*$ millions*	*$/MWh*	*Pricing*	*$ millions*
TMSR	System	$18	1,440	$24	$13	712	$8	$5	727	$16
TMNSR	System	$134	58	$7	$190	15	$3	-$56	42	$4
TMOR	System	$136	53	$2	$188	14	$1	-$52	38	$1
	NEMA/Boston	$114	105	$1	$106	72	$1	$8	33	$0
	CT	$136	53	$0	$188	14	$0	-$52	38	$0
	SWCT	$136	53	$1	$188	14	$0	-$52	38	$1

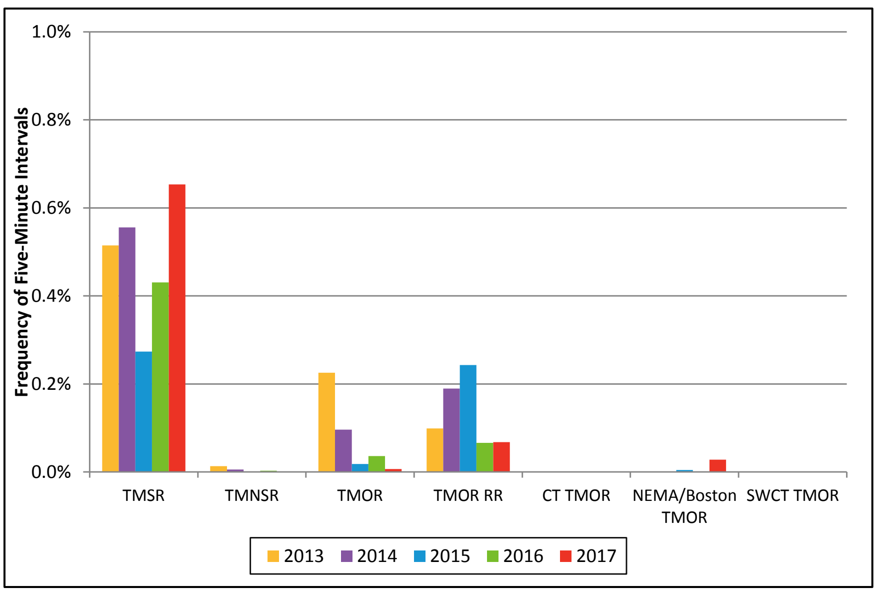
Fast-start pricing has increased the frequency of reserve pricing across all reserve products. While fast-start pricing ultimately impacts all reserve products, it has had the most impact on TMSR.

This has occurred because in times when the system is ramping, fast-start generators are often dispatched to provide energy while other generators are held down to provide reserve. Because fast-start pricing more accurately reflects the price of operating higher-cost fast-start resources, it has, on average, increased the price of energy. As the price of energy has increased, so too has the opportunity cost of providing reserves rather than energy (generators providing reserves must be indifferent between providing energy and reserve) thus TMSR pricing naturally tends to occur more frequently because under fast-start pricing an opportunity cost may exist whereas prior to the change one would not exist.

Reserve Constraint Penalty Factors

During 2016, 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 7-5 below.

Figure 7-5: Reserve Constraint Penalty Factor Activation Frequency, 2013-2017



The TMSR RCPF had the highest frequency of triggering with 686 five-minute intervals (0.7% of total intervals), or about 57 hours over the year. The TMOR replacement reserve RCPF was triggered in 71 intervals (0.07%), or about 6 hours. The only local TMOR RCPF that was triggered in 2017 was for the NEMA/Boston local reserve zone with 88 five-minute intervals (0.03%).

The TMSR RCPF had the highest frequency of activations due to the higher frequency of TMSR pricing intervals and it's 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 2017 than in 2016 due to an increase in the frequency of TMSR pricing and the opportunity costs due to fast-start pricing.

The NEMA/Boston TMOR RCPF had the second highest frequency of activations. Eighty-four of the 88 five-minute intervals that were binding occurred between May 17 and 19, 2017. During this time, New England experienced tight system conditions as temperatures were higher than average (reaching 90° F) resulting in peak loads around 20,000 MW. Additionally, an M/LCC2 was declared from 9:30 to 10:00 PM EST on May 18. The local NEMA/Boston area was particularly tight, as an outage at a gas compressor station located upstream from several local gas-fired generators occurred on May 16 resulted in several unplanned outages and reductions. As a result, more expensive generation (e.g., oil) was online to meet energy and reserve requirements leading to higher re-dispatch costs impacting that local reserve zone and ultimately triggering the local TMOR RCPF.

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 will be 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.

In June 2018, the Pay-for-Performance market rule changes will become effective for the Forward Capacity Market, which is the start of the Capacity Commitment Period associated with the ninth Forward Capacity Auction. Under this construct, capacity revenue is linked to performance during Capacity Scarcity Condition(s), which will be triggered by RCPF pricing for TMOR and TMNSR reserve products (either system-wide or local) provided that RCPF pricing is not a result of resource ramping limitations.

In 2017, on average, the impact of reserve pricing on the energy price was small. The average TMSR price in 2017 was $2.92/MWh during all intervals. This is the maximum amount that the reserve price could impact the average energy price, assuming that each instance of reserve pricing can be added to the energy price to derive the LMP (as it is when RCPF for a reserve product in binding).

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, every day during the reserve delivery period participants must assign the obligation to one or more resources. 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.[203]

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.[204]

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 control or the transfer of the obligation to another participant results in the assessment of a "failure-to-reserve" penalty.

[203] 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.

[204] 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.

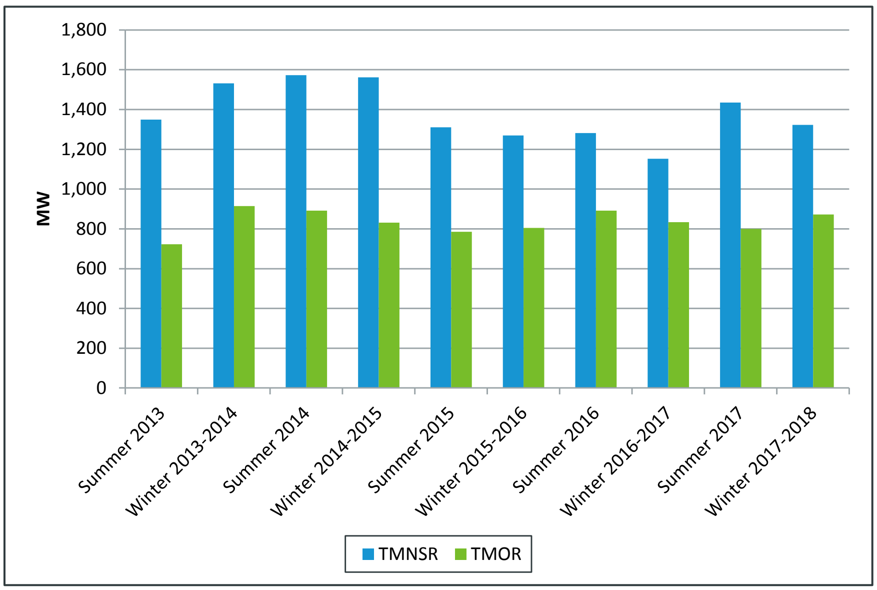
Allocation of the costs for paying resources to provide reserves is based on real-time load obligations in load zones. These obligations are price-weighted by the respective forward-reserve clearing prices of the reserve zones that correspond to each load zone.

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. 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.[205]

The system-wide forward reserve requirements from Summer 2013 through Winter 2017-18 are shown in Figure 7-6.

Figure 7-6: Forward Reserve Market System-wide Requirements

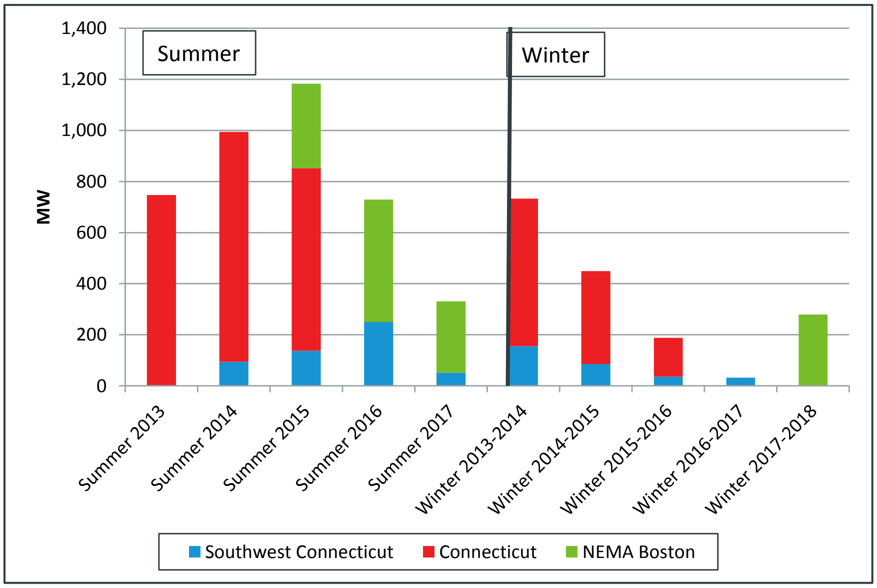


Some zones are constrained in terms of how much power they can import from other zones and can have different clearing prices. As a result, instead of having a single reserve requirement for each reserve product for all of New England, the ISO identifies requirements at a zonal level and at the system 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 7-7. 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.

[205] 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.

Figure 7-7: 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.[206] 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 winter procurement period has experienced a significant reduction in aggregate local FRM requirements, as illustrated in Figure 7-7. This results mainly from a considerable increase in ERS for Connecticut, due to transmission upgrades; Connecticut's local requirement has declined to zero in the past two summer and winter periods as a result of increased ERS. Meanwhile, NEMA/Boston has had positive local requirements for the last three summer and one winter periods as a result of decreased ERS.

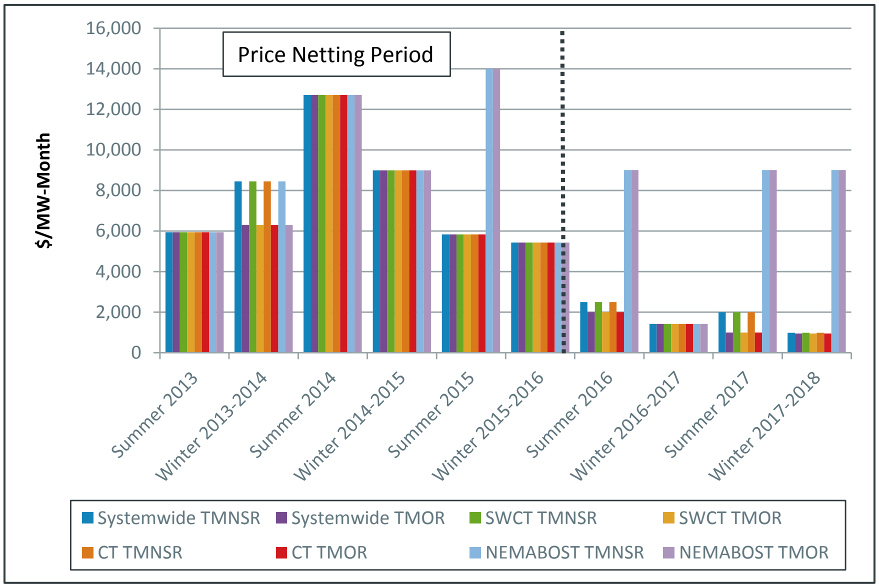
7.2.2 Auction Results

This section covers FRM auction pricing outcomes from the Summer 2013 auction through the Winter 2017-18 auction. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-8.[207]

[206] 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.

[207] 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.

Figure 7-8: Forward Reserve Prices by FRM Procurement Period



In general, auction clearing prices declined in 2017 relative to 2016 for the respective summer and winter periods despite an increase in system-wide requirements. Reduced FRM offer prices in 2017 explain the reduction in auction clearing prices. Reduced offer prices may reflect, in part, lower delivery risks as a result of higher forward reserve heat rates for the 2017 delivery periods, or participants' expectations of lower energy market opportunity costs in 2017.[208] NEMA/Boston experienced very high auction clearing prices in both 2016 and 2017, as a result of supply shortfalls (discussed below).

Prices for the 2016 and later auctions are not readily comparable to earlier periods, since the 2016 and 2017 FRM prices are no longer adjusted for FCA prices (i.e., price-netting was eliminated beginning with the 2016 auctions). The decline in prices in 2016, relative to earlier periods, is consistent with the elimination of price-netting.

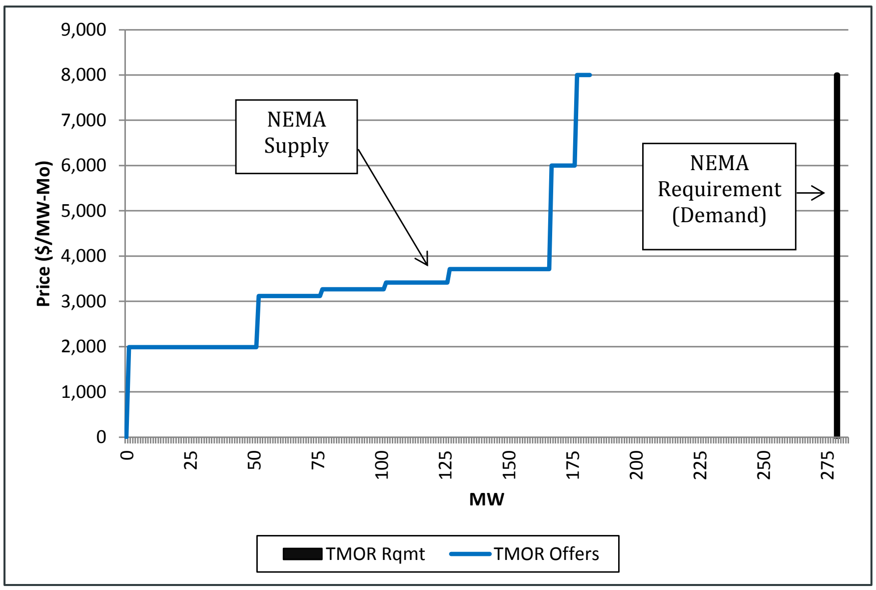
The relatively uniform historic clearing prices for TMOR and TMNSR indicate that, in many auctions, some TMNSR was cleared to meet the system-wide TMOR requirement. The auction clearing software treats the system-wide TMOR requirement as an upper limit on the amount of TMOR that can clear the auction and will select the higher-quality TMNSR reserve product to meet the TMOR requirement when it is economical to do so.[209] 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 the 30-minute product. In four instances during the review period, TMNSR cleared the auction at higher prices than TMOR.

[208] The heat rates used to determine threshold offer prices for FRM resources increased in the 2017 winter period from 19,935 Btu/KWh to 20,460 Btu/KWh and increased in the summer period from 17,539 Btu/KWh to 21,999 Btu/KWh.

[209] 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.

For zonal pricing, there have been four instances of significant price separation during the five-year period, as illustrated in Figure 7-8. In the summer periods for 2015, 2016 and 2017 and the winter period for 2017-18, there was price separation between NEMA/Boston and all other zones.[210] In these instances, supply was inadequate to satisfy the local TMOR requirement, and pricing reached the auction offer cap in each period. This is illustrated in Figure 7-9 below for the Winter 2017-18 auction.

Figure 7-9: Supply and Demand for the TMOR Product in NEMA/Boston for the Winter 2017-18 Auction

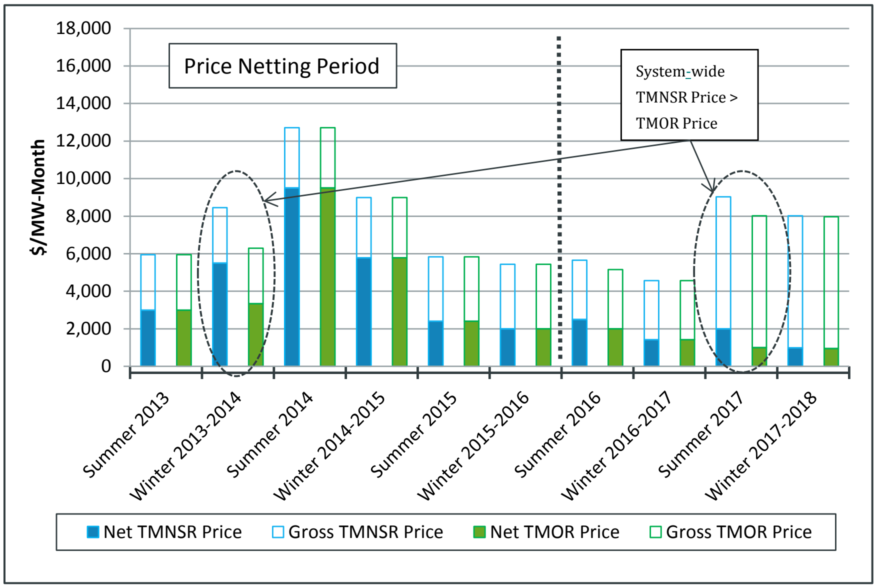


The above figure shows NEMA/Boston's supply and demand curves for the 2017-18 Winter FRM auction. With zonal supply approximately 100 MW less than zonal demand, the zonal clearing price was set to the auction price cap, resulting in a $9,000/MW-month price for local TMNSR and TMOR.

Finally, the gross and net forward reserve prices for TMNSR and TMOR are shown in Figure 7-10 below and illustrate the price-netting concept as if it had applied to all periods (not just prior to 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 2016 and 2017 auctions.

[210] 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 .

Figure 7-10: Gross and Net Forward Reserve Market Clearing Prices for Rest-of-System TMNSR and TMOR



For comparison, the graph includes the 2016 and 2017 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 fallen in 2017 relative to 2016 and earlier periods.

7.2.3 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 table 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.

Table 7-4: 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 2013	94	138	N/A	99	N/A
Winter 2013-14	89	136	58	123	N/A
Summer 2014	96	124	85	87	N/A
Winter 2014-15	107	186	84	215	N/A
Summer 2015	117	158	69	122	12
Winter 2015-16	109	154	283	382	N/A
Summer 2016	203	222	76	N/A	23
Winter 2016-17	313	308	302	N/A	N/ A
Summer 2017	240	278	183	N/A	21
Winter 2017-18	285	292	N/A	N/A	24

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 7-4 shows that there were pivotal suppliers in 3 out of the 10 FRM auctions for TMNSR. There were also pivotal suppliers in 8 out of 10 auctions for TMOR in at least one of the reserve zones. The Southwest Connecticut (SWCT) zone had an RSI less than 100 for five auctions.

Generally, the RSI values fluctuate significantly from auction to auction. These fluctuations can be partly explained by the significant variation in the reserve requirement. 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 went down from 250 MW to 32 MW.

For the 2016 and 2017 procurement periods, the TMNSR RSI values were significantly 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. Except for the Summer 2016 auction, the SWCT zone was structurally competitive in the 2016-2017 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.

Additional analysis is being undertaken to determine if the presence of pivotal suppliers has resulted in uncompetitive prices.

7.3 Regulation

This section presents data about the participation, outcomes, and competitiveness of the regulation market in 2017. Overall, the available supply of regulation service in 2017 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.[211] 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).[212] 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.[213]

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.[214] Under the prior rule, generators offered regulation at a single price. Under the new rules, generators use two-part pricing: a service price and a capacity price.[215] The pricing change was implemented effective March 31, 2015.[216]

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

[211] 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.

[212] This NERC standard can be accessed at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

[213] 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.

[214] 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 unit's opportunity costs and a service payment for performance that reflects the quantity of frequency regulation provided.

[215] 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.

[216] Market Participants providing regulation service may also qualify for make-whole or NCPC payments.

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 7-5 below.

Table 7-5: Regulation Prices, 2013 to 2017

	Regulation Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)			Regulation Capacity Clearing Price ($/MW per Hour)		
Year	**Min**	**Avg**	**Max**	**Min**	**Avg**	**Max**	**Min**	**Avg**	**Max**
2013	0.00	11.68	692.08	n/a	n/a	n/a	n/a	n/a	n/a
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

(a) Pricing rules changed on 3/31/15.

In 2017, the average service price was $0.34/mile, a $0.09 (20%) reduction compared to the average of $0.43/mile in 2016. Mileage payments represent a small share of overall regulation payments (14% or $4 million in 2017).

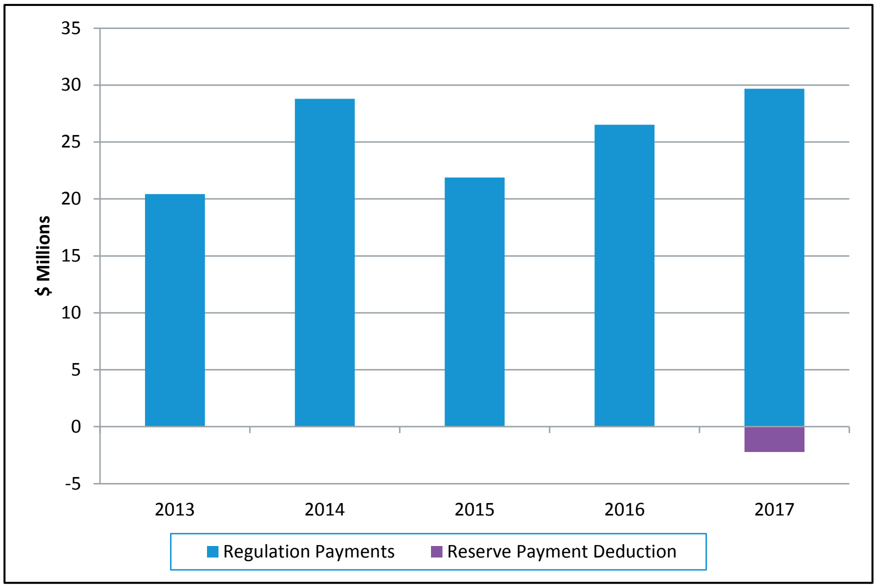
Regulation capacity prices increased by 7% in 2017 compared with 2016, reflecting increased regulation requirements and increased energy market LMPs (which affect energy market opportunity costs for regulation resources). The two-part pricing (implemented in 2015) is not comparable to prices for the 2014 and earlier periods, because two-part pricing altered regulation compensation (and bidding incentives) for resources. For the earlier periods, high winter regulation prices, associated with very cold weather, elevated fuel prices, and energy market opportunity costs, resulted in elevated regulation clearing prices in 2014 and 2015.

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, and a make-whole payment. Starting in March 2017 with the sub-hourly settlement of several market activities (including real-time operating reserves), a deduction was added to regulation payments. This deduction represents the over-compensation of regulation resources for providing operating reserves. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since 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.[217]

Annual regulation payments over the past five years are shown in Figure 7-11 below. The reserve payment deduction is shown as a negative value in the exhibit; the positive amounts represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period.

[217] The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

Figure 7-11: Regulation Payments



Payments to resources providing regulation service totaled $29.7 million in 2017, a 12% increase from the $26.5 million in 2016. (These totals exclude the reserve payment adjustment.) The increase in payments reflects at least three factors. (1) 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 has resulted in an additional 7% increase in the average regulation capacity requirement for 2017. (2) Higher energy market prices in 2017 relative to 2016, affecting regulation market opportunity costs, also have impacted regulation payments. (3) Finally, although regulation service prices decreased, an increase in regulation service volumes more than offset the price reduction, leading to an overall increase in service payments.

The significant increase in 2016 payments, compared to 2015, resulted primarily from 2 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 compared to 2015. Elevated payments in 2014 reflected elevated regulation costs during Winter 2014.[218]

7.3.2 Requirements and Performance

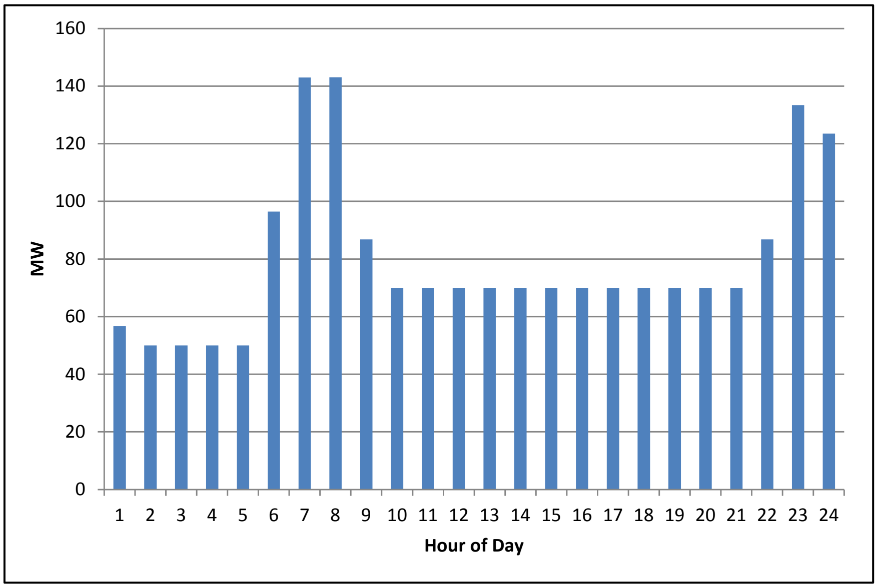
The average hourly regulation requirement of 79.6 MW in 2017 was slightly higher than the 74.3 MW requirement in 2016. The 7% increase in the average regulation requirement

[218] 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.

resulted from 2016 values reflecting only a partial implementation of the increased requirements that occurred in April 2016, as noted above.[219]

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). See Figure 7-12 below.

Figure 7-12: Average Hourly Regulation Requirement, 2017



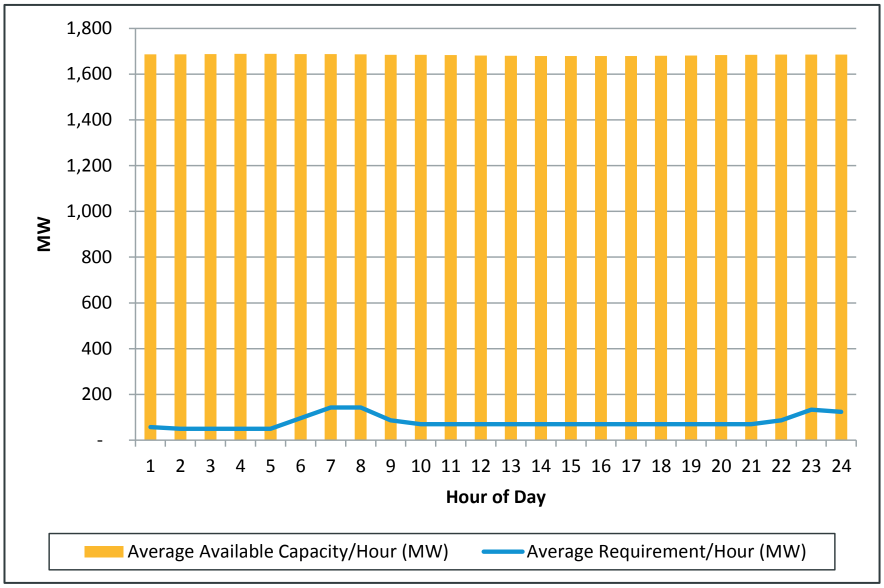
With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO now uses violations of Balancing Authority ACE Limits (BAAL) to measure performance. Violations result from exceeding ACE limits for more than 30 consecutive minutes; in 2017, there were no BAAL violations.

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 physical withholding. The regulation market was competitive in 2017. Figure 7-13 below simply plots the regulation requirement relative to available supply.

[219] In April 2016, both regulation capacity and service requirements were increased due to the modification of calculations performed in accordance with NERC standard BAL-003, Frequency Response and Frequency Bias Setting; this change has resulted in an approximately 25% increase in the average regulation requirement for 2016.

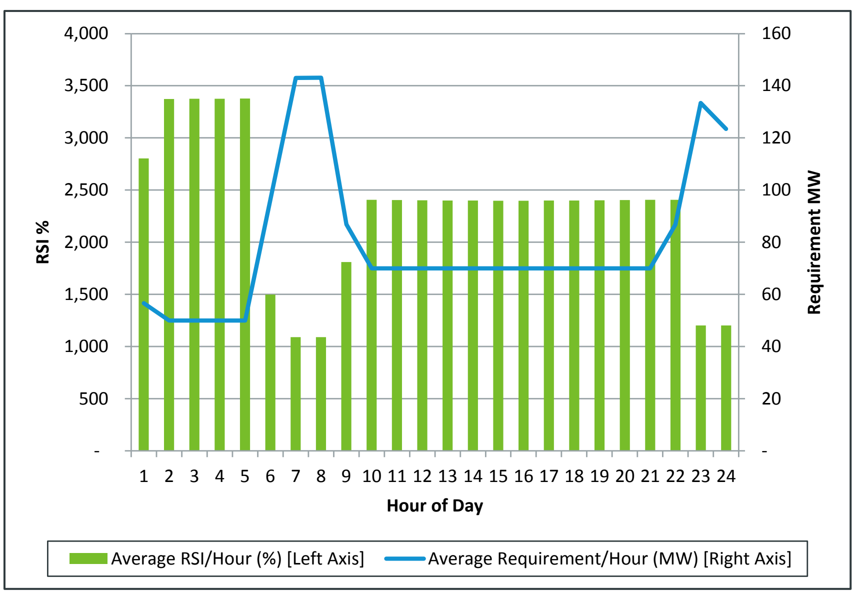
Figure 7-13: Regulation Market Average Requirement and Available Capacity, 2017



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 7-14, the regulation requirement and RSI are inversely correlated (the lower the requirement the higher the RSI).

Figure 7-14: Average Regulation Requirement and Residual Supply Index



In 2017, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system has the capability to serve 10 times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement.

7.4 Winter Reliability Program

This section provides an overview of the 2017-2018 Winter Reliability program. It includes a summary of procured volumes, level of participation, types of participation, pricing, and payments.

The 2017-2018 winter season marks the fifth year in which the ISO implemented a winter reliability program.[220] The ISO first implemented the program in the 2013-2014 winter season to deal with gas supply network constraints and the resulting electricity system reliability concerns. The program pays market participants to purchase sufficient fuel inventories (oil or LNG) or provide additional demand response during the winter months, when it can be challenging to procure natural gas. This is the last winter that the program will be in effect, coinciding with the implementation of the Pay-for-Performance (PFP) rules (i.e., through the 2017-18 winter). The PFP rules should provide stronger market incentives for participants to have sufficient fuel available to satisfy their energy supply offers and capacity supply obligations.

7.4.1 Requirements, Participation, Pricing, and Payments

Oil Fuel Service Program:

To participate in the oil program, participants must have generators capable of operating on fuel oil.[221] During Winter 2017-2018, 86 units participated in the program. Around 2.9 million barrels (bbl) of oil inventory were eligible for compensation per the winter program rules at the base set rate of $10.33/bbl.[222] The payment rate is designed to cover the carrying cost of oil over the winter period. Given the initial inventory and payment rate, the maximum oil program cost exposure was $29.6 million.

Participants in the oil program are paid based on their final oil inventory at the end of the winter at the payment rate. Some of the burned inventory was replenished, resulting in a high remaining inventory. At the end of the program, 2.6 million bbls of oil remained. The remaining amount was equal to 89% of the beginning inventory.

Liquefied Natural Gas (LNG) Service Program:

To take part in the LNG program, participants must be capable of receiving supplies of LNG. In previous years, participants included natural gas-fired generators and dual-fuel generators. There was no participation in the 2017-2018 LNG program.

Demand Response (DR) Service Program:

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[220] The rules governing the program are described in Appendix K of Market Rule 1. *See* http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

[221] Ibid.

[222] *See* 2017/2018 Winter Program Rate Memo, https://www.iso-ne.com/static-assets/documents/2017/07/2017-2018-winter-programp-payment-ratenotice.docx

In the 2017-2018 program, three demand response assets participated in the program with an aggregate interrupting capability of 7.5 MW of demand. The total cost associated with the demand response service in the 2017-18 program was $32,900.

Dual-Fuel Commissioning Service Program:

The Dual-Fuel Commissioning (DFC) program includes gas-fired generators that plan to commission oil-fired dual-fuel capability. Eligibility for this program includes gas-fired generators that have not demonstrated the ability to operate on oil on or after December 1, 2011.[223] No additional dual-fuel generators were commissioned for the 2017-2018 program. Between the 2014-15 and 2015-16 winter seasons, six generators submitted an intent to commission dual-fuel capability; four generators submitted an intent in the 2014-15 season, totaling 1,039 MW of capability, and two additional generators submitted an intent for the 2015-16 winter season totaling 735 MW of capability. Participation in this program has resulted in 1,774 MW of winter seasonal claimed capability from gas-fired generators that planned to add oil-burning capability. As of December 2016, all six generators had successfully commissioned the use of the secondary fuel.

A summary of the volume procured, the payment rates, and the costs of the four winter programs to date is provided in Table 7-6.[224]

Table 7-6: Winter Reliability Program Cost Summary

	2013-14	2014-15	2015-16	2016-17	2017-18
Contracted Volume					
Oil (bbl)	3,057,554	3,817,754	2,953,967	3,050,824	2,868,243
LNG (MMBtu)	n/a	500,000	1,277,976	171,121	0
Fuel Rate					
Oil ($/bbl)	n/a	18.00	12.90	10.21	10.33
LNG ($/MMBtu)	n/a	3.00	2.15	1.70	n/a
Remaining Inventory					
Oil (bbl) [225]	2,579,320	2,544,668	2,881,550	3,034,668	2,566,435
LNG (MMBtu)	n/a	500,000	1,277,976	171,121	0
Additional Costs					
Dual Fuel Service (includes commissioning and auditing costs)	n/a	1,081,114	539,343	782,671	0
Demand Response Service	198,489	160,857	210,316	128,220	32,901
Maximum Cost Exposure ($ millions)	**75.0**	**70.2**	**40.4**	**32.2**	**29.6**
Total Program Costs ($ millions)	**66.0**	**45.1**	**38.5**	**30.6**	**24.4**

[223] *See* Market Rule 1, Appendix K, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

[224] Winter 2011-2018 numbers are preliminary and subject to change.

[225] In the first year of the program, generators were paid up front for contracted fuel so the remaining inventory did not contribute to the total costs.

The actual total program costs were the lowest of the past five winters. In Winter 2017-18, the cost of the program as a percentage of total energy costs was 0.94%, a decrease from the previous winter when program costs comprised 2.2% of total energy costs

As the table above shows, the 2017-18 season had low remaining inventory for oil relative to the contracted volume. The lower remaining inventory compared to the prior two winters was driven by a cold snap period in Winter 2017-18. From late December 2017 through early January 2018, frigid temperatures strained natural gas supplies, and large volumes of oil-fired generation were required to meet system demand. There was also no contracted LNG inventory in the 2017-18 program.

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 been assessed, for future years.

8.1 Major Design Changes Recently Implemented

The following market rules changes were implemented during 2017.

Fast-Start Pricing *(implemented on March 1, 2017)*

On September 24, 2015, rule changes were filed to improve real-time price formation when fast-start resources are deployed.[226] With these changes, a fast-start resource is able to set the real-time LMPs under a broader range of dispatch conditions than under the previous pricing method. In addition, real-time energy prices will better reflect the costs of operating fast-start resources when they are economically committed and dispatched thereby improving price transparency. Further, the changes are intended to improve market efficiency by strengthening performance incentives for all resources during operating conditions when performance tends to matter the most.

Four changes to dispatch, pricing, and compensation when fast-start resources are committed and dispatched were made:

- Ensuring that both the commitment and dispatch processes respect the offered minimum output level of each committed fast-start resource through its run time, including the initial commitment interval;
- "Relaxing" a fast-start resource's minimum output to zero in the pricing process that calculates real-time LMPs and reserve market clearing prices ("RMCPs");
- Revising the current treatment of a fast-start resource's start-up and no-load fee in the pricing process. This is done through calculating an adjusted incremental offer by amortizing the fees over the minimum run time and maximum output, respectively;
- Providing compensation to resources that, in certain circumstances, may incur a lost-opportunity cost for following the ISO's dispatch instructions when a fast-start resource sets the LMP under the new pricing method.

The Summer 2017 Quarterly Markets Report presented our analysis of the new fast-start pricing rules.[227] The analysis indicated that fast-start pricing has worked as intended; real-time LMPs have better reflected the costs of committing fast-start resources. Key observations from March 1 through October 31 included:

[226] *ISO New England Inc. and New England Power Pool*, Revisions to Fast-Start Resource Pricing and Dispatch, Docket No. ER15-2716-000 (filed September 24, 2015); Letter order accepting Tariff Revisions to Fast-Start Resource Pricing and Dispatch, Docket No. ER15-2716-000 (issued October 19, 2015).

[227] See the *Summer 2017 Quarterly Markets Report*, December 20, 2017 at https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

- The average system LMP in all intervals increased by $2.72/MWh (11%) due to the fast-start pricing rules. Higher LMPs resulted in increased real-time energy charges by load of $5.9 million (11%). Prices increased during intervals when fast-start generators produced energy, and decreased when fast-start pumped storage demand has consumed energy. Both real-time generation and demand have stronger incentives to follow commitment instructions.

- The total number of fast-start commitments requiring NCPC decreased from 27% to 18%. NCPC also decreased by $8.8 million as a result of fast-start pricing. NCPC for committed or dispatched out-of-merit costs decreased by $10.6 million, a reduction of more than half. This decrease has been slightly offset by $1.9 million in rapid response pricing NCPC, a new category of NCPC necessitated by fast-start pricing mechanics.

- Reserve pricing has been more frequent and higher in magnitude due to fast-start pricing. The estimated increase in the average reserve price in all intervals is $2.23/MWh (192%). Additional reserve payments totaled $19.8 million, an increase of 181%. This is an expected outcome of fast-start pricing due to the tradeoffs produced when relaxing physical constraints to determine a price more reflective of total production costs. A reserve accounting approach was taken that avoids the appearance of more reserve capacity than is physically available, and ensures reserves are priced when the reserve requirement is physically binding. It has also resulted in reserve pricing in cases when a physical re-dispatch is not needed to maintain reserves.

Sub-Hourly Settlement *(implemented March 1, 2017)*[228]

Under the revised settlement rules, all assets and transactions in the real-time energy and reserve markets are settled on a 5-minute basis, rather than on hourly average prices and quantities. The rule changes align the settlement interval with the five-minute energy and reserve pricing intervals. They are intended to improve the incentive to follow price signals in the real-time energy market and to enhance the accuracy of real-time energy and reserve compensation.

Market Enhancements for Asset-Related Demand *(implemented on March 1, 2017)*

On February 17, 2016, rule changes were filed to improve the way that pumped storage hydro-generating resources are modeled and dispatched.[229] The changes established new modeling practices and bidding parameters that allow participants with pumped storage hydro-generating resources to better reflect the operating characteristics of this type of resource in its supply offer data and to better reflect those operating characteristics in the economic dispatch. The rule changes also include several modifications of the NCPC rules related to pumped storage hydro-generating resources and other resources with similar characteristics.

FCM Zonal Demand Curves *(implemented on February 6, 2017 for FCA 11)*

[228] *ISO New England Inc. and New England Power Pool*, Implementing Sub-Hourly Settlements, Docket No. ER16-1838-000 (filed June 2, 2016); Letter order accepting Implementation of Sub-Hourly Settlements, Docket No. ER16-1838-000 (issued July 26, 2016).

[229] *ISO New England Inc. and New England Power Pool,* DARD Pump Parameter Changes,ER16-954-000, (filed February 17, 2016).

On April 15, 2016, rule changes were filed to address the shortcomings of the existing set of demand curves to improve the performance of the Forward Capacity Market.[230] The new set of curves (at both the system and zonal level) are based on design principles that reflect the marginal improvement in reliability associated with adding capacity in constrained capacity zones versus the remainder of the system. The new set of demand curves will set prices that more accurately reflect the locational marginal reliability impact of capacity. At the zonal level, replacing the existing vertical demand curves with sloped demand curves addresses the price volatility and market power concerns by specifying a more gradual change in prices corresponding to shifts in supply and accounting for the partial substitutability of capacity across zones.

8.2 Major Design Changes in Development or Implementation for Future Years

The following market rule changes have been substantially, or completely, designed and will be implemented in future years.

FCM Pay-for-Performance *(to be implemented on June 1, 2018)*

In January 2014, the ISO filed proposed rule changes with FERC regarding performance incentives in the Forward Capacity Market (FCM).[231] The proposal was, to 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 take effect from the ninth forward capacity auction (FCA9). While the associated settlement rules take effect in June 2018, the impact of the rules has 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 spot market, the participant is expected to deliver its share of total system energy and reserve requirements. Deviations (in megawatts) will be settled on an administratively-determined rate, known as the performance penalty 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.

Price-Responsive Demand *(to be implemented 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 will be fully integrated into the wholesale energy market from June 1, 2018, through a set of rules commonly referred to as price-responsive demand (PRD). Demand response resources will also be eligible to provide reserves and will

[230] *Demand Curve Design Improvements* (ER16-1434-000), April 15, 2016, http://www.iso-ne.com/static-assets/documents/2016/04/er16-1434-000.pdf.

[231] *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)

participate in the capacity market in the same manner as other supply-side resources. PRD will allow demand response resources to submit demand reduction offers into the day-ahead and real-time energy markets. Demand resources will be 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.

Competitive Auctions with Sponsored Policy Resources (CASPR) *(implemented on March 9, 2018 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, CASPR, will 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.

The IMM remains concerned 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 is driven by 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. This will be addressed through an additional form of bid mitigation beginning with FCA 14.

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.

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.[232] Order 831 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 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.

The ISO currently anticipates beginning the design of the required software and process changes for the Order 831 revisions in early 2018, after completion of a set of changes to permit storage-related devices to participate in the Energy Market. Once the design phase is complete, the ISO will begin developing the required software and process changes. The development phase cannot begin until two high-priority projects are implemented in June 2018: the PRD project for full integration of demand response into the energy market and the PFP capacity market project.

Annual Reconfiguration Transactions (ARTs) for Annual FCM Auctions *(requested effective date beginning March 1, 2018)*

In February 2018, the ISO filed rule changes to implement ARTs and remove CSO bilaterals from annual reconfiguration auctions.[233] Starting in FCA 11, zonal demand curves replace fixed

[232] *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)

[233] *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

capacity requirements.[234] 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 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 due to 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.

[234] 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.

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