ISO New England's Internal Market Monitor

2016 Annual Markets Report

Internal Market Monitor
May 30, 2017

Preface

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 *2016 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2016. 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 2016. 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" (December 3, 2014), 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 is furnished by the Intercontinental Exchange (ICE):

ICE Global markets in clear view

Underlying oil and coal pricing data is 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 *2016 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 ISO-administered forward and real-time markets buy and sell operating reserve products, regulation service, 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 in 2016. The capacity market procured additional new capacity in the tenth and eleventh forward capacity auctions at competitive prices. The day-ahead and real-time energy markets performed well, with electricity prices closely reflecting changes in underlying primary fuel prices. 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.

The total wholesale cost in 2016, at $7.6 billion, was considerably lower than 2015, decreasing by 18%, or by $1.7 billion. This was due to the decline in energy costs of $1.8 billion (30%) compared to 2015, which continue to be driven primarily by natural gas prices. Natural gas prices averaged $3.12/MMBtu, a 34% reduction on 2015 prices.[4] This significant decline in annual average natural gas prices and energy costs was driven by the price and cost declines in the first quarter of 2016. Due to milder weather, natural gas prices were down 70% in the first quarter compared to the same quarter in 2015, which resulted in $2 billion in lower energy costs quarter-over-quarter. For the remaining three quarters of the year natural gas prices and energy costs increased moderately compared to 2015.

Total wholesale costs to date have been influenced by low capacity market prices that ranged from $2.95 to $4.50/kW-month. Low capacity prices will continue until the 2017-18 capacity commitment period (associated with the eighth forward capacity auction, or FCA 8) when capacity market prices will increase, reflecting the end of a period when the New England system was structurally long on capacity. In FCA 8, this trend reversed when a significant amount of capacity retired from the capacity market, contributing to the auction clearing less than the resource adequacy requirement. The next two auctions (FCA 9 and FCA 10) produced market prices sufficient to attract new investment to replace retired capacity. The most recent auction (FCA 11) cleared surplus capacity of almost 1,800 MW relative to the capacity requirement, at a price of $5.30/kW-month. Capacity prices and purchases from the past four auctions will increase the capacity component of the total wholesale cost of electricity from a historical annual average of about $1.2 billion (for the first seven delivery periods) to a projected annual average of about $3.1 billion from June 2017 through May 2021.

The ISO implemented a number of important market rule changes in both the energy and capacity markets over the past year. In the energy market, changes were made to improve the

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

incentives and outcomes in the dispatch and pricing of electricity. First, in May 2016 the Do-Not-Exceed (DNE) dispatch rules were implemented. The DNE changes incorporate intermittent wind and hydro resources into the economic dispatch and pricing software. Rather than manually curtailing wind generators to manage congestion, the changes provide a market solution to this reliability issue and allow congestion to be reflected in real-time prices. More recently, in March 2017 new rules regarding fast-start pricing and sub-hourly settlements were implemented. Fast-start pricing is intended to better reflect the costs of operating fast-start resources through the real-time price and to strengthen performance incentives. The sub-hourly settlement changes align the settlement interval with five-minute real-time energy and reserve market prices, rather than with hourly average prices and quantities. The rules should improve the incentive to follow price signals in the real-time energy market, and enhance the accuracy of real-time energy and reserve compensation.

In the capacity market, the ISO implemented retirement reforms that address the potential for a capacity supplier to uneconomically retire a resource and raise capacity prices above competitive levels. The changes will also provide the market with additional time to provide a signal to potential new entrants that additional capacity may be needed. Lastly, from FCA 11, zonal sloped demand curves replaced vertical demand curves. The zonal curves reflect the marginal improvement in reliability associated with adding capacity in constrained capacity zones versus the remainder of the system. The sloped curves also address price volatility and market power concerns associated with a vertical demand curve.

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 artificially lower the market clearing price. Both mitigation processes for the energy and capacity markets have functioned reasonably well and resulted in competitive outcomes. However, a number of areas require further evaluation.

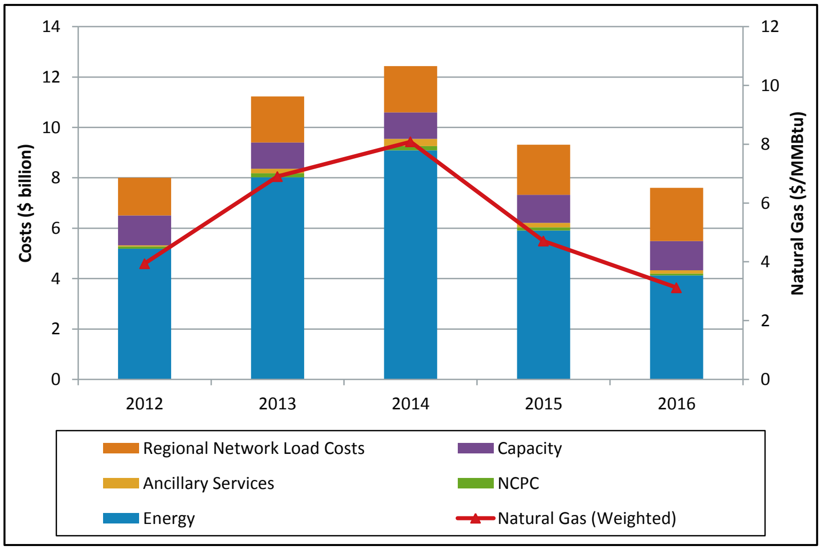
First, the forward reserve market does not currently have any active market power mitigation provisions and, as highlighted in this report, has structural market power issues. These issues are currently being evaluated. Second, the energy market has rules to identify and mitigate seller-side market power. There are energy supply portfolios that have structural market power in the real-time market in almost half of the hours. 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. 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.

1.1 Wholesale Cost of Electricity

In 2016, lower natural gas prices resulted in lower wholesale electricity prices and a significant decrease in the overall wholesale cost of electricity. Natural gas prices at the Algonquin Citygates trading hub were at the lowest level in the past 16 years. Average wholesale energy prices (or Locational Marginal Prices, "LMPs") were at the lowest level since the implementation of standard market design in 2003.

The estimated cost of wholesale electricity of $7.6 billion represented a decrease of $1.7 billion, or 18%, compared with 2015 costs. The components of the wholesale cost over the past five years (on the left axis, "LA") along with the average annual natural gas price (on the right axis, "RA") are shown in Figure 1-1 below.[5]

Figure 1-1: Wholesale Market 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 dollar amount and percentage contribution of each category to the overall wholesale cost in 2016 is shown in parenthesis.

Energy ($4.1 billion, 54%): Energy costs are a function of cleared demand (megawatt hours, or MWh) in either the day-ahead or real-time energy markets and the market clearing prices (the LMP).[6] The reduction in total wholesale costs in 2016 was driven by significantly lower energy prices in the first quarter of the year – the result of a milder winter and resulting lower natural gas prices. While overall annual energy costs declined by $1.8 billion in 2016 compared to 2015, Q1 costs declined by $2 billion. There was a slight increase of $0.2 billion in energy costs year-over-year over the remaining quarters.

- The 2016 annual electricity demand in New England was at its lowest level in the past 17 years.[7] Annual demand in 2016 was down by 2% on 2015 levels. Due to milder weather

[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 through 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.

[7] Based on available electricity demand data back to January 2000.

demand was down 9% in Q1 2016 compared to Q1 2015.

- Day-ahead and real-time LMPs averaged $29.78/MWh and $28.94/MWh, respectively (simple average). Prices were at their lowest since standard market design was implemented and were down by 29%, or by more than $12/MWh, compared with 2015. Day-ahead LMPs in Q1 2016 averaged $29.71/MWh, down 66%, or by $56.34/MWh, compared to Q1 2015 prices.

- Supply and demand-side participants continued to exhibit a strong preference towards the day-ahead market, with approximately 98% of the cost of energy settled on day-ahead LMPs.

- Natural gas prices continued to be the primary driver of LMPs. Prices averaged $3.12/MMBtu, representing a reduction of 34%, or $1.59/MMBtu, compared with 2015. Gas prices in Q1 2016 were down by 70%, or by $7.96/MMBtu, compared to Q1 2015.

Regional Network Load Costs ($2.1 billion, 28%): Regional Network Load (RNL) costs cover the use of transmission facilities, reliability, and certain administrative services. Of the three cost categories included in RNL (infrastructure, reliability and administrative), infrastructure costs make up over 90%. RNL costs rose by 6% in 2016 as a result of investment in new regional transmission infrastructure to address deficiencies in meeting reliability criteria, as well as investment to address deficiencies in the condition of existing regional transmission assets.

Capacity ($1.2 billion, 15%): Capacity costs were up about 5% compared with 2015, in line with auction clearing prices. Capacity costs in 2016 are primarily the product of the clearing prices associated with the FCAs 6 and 7 and the capacity requirements in those auctions.[8] The capacity requirements for the sixth and seventh auctions were 33,456 MW and 32,968MW, respectively. The Rest-of-Pool clearing prices of $3.43 and $3.15/kW-month for the two auctions were set at the administrative price floor due to a surplus of capacity in the market. However, in FCA 7 the NEMA/Boston capacity zone was import-constrained, with cleared capacity falling short of the local sourcing requirement. The NEMA/Boston price was administratively set at $14.99/kW-month for new resources, and $6.66/kW-month for existing resources. This results in projected payments associated with FCA 7 to be slightly higher, despite the decline in the Rest-of-Pool clearing price.

NCPC ($0.1 billion, 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 costs decreased by 38% in 2016 in line with the reduction in underlying fuel prices. The majority of NCPC (60%) was paid in the day-ahead market in 2016.

Ancillary Services ($0.1 billion, 2%): These are costs of additional services procured to ensure system reliability, including operating reserve (real-time and forward markets) and regulation. In addition, the costs associated with the out-of-market winter reliability program are included in this cost category. These costs have decreased by 30% in line with lower fuel input costs.

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[8] The capacity commitment period associated with an auction is an annual period beginning on June 1 each year and therefore spans two years calendar years. The sixth and seventh FCAs were for commitment periods 2015/16 and 2016/17 respectively. The capacity required is known as the Installed Capacity Requirement.

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

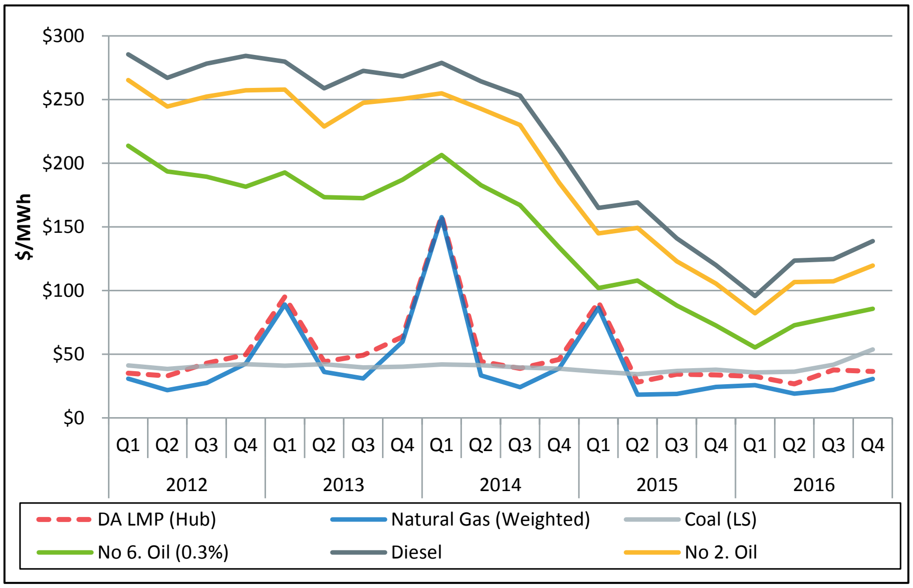
Statistic	2012	2013	2014	2015	2016	% Change 2016 to 2015
Demand (MW)						
Real-time Load (average hourly)	14,581	14,769	14,518	14,486	14,143	-2%
Weather-normalized real-time load (average hourly)[a]	14,600	14,584	14,511	14,358	14,111	-2%
Peak real-time load (MW)	25,880	27,379	24,443	24,437	25,521	4%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	30.72	53.86	63.05	36.73	24.34	-34%
Coal	40.70	40.76	40.45	36.34	41.97	15%
No.6 Oil	194.54	181.42	172.38	92.64	73.34	-21%
Diesel	278.88	269.92	251.49	148.69	120.78	-19%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	36.08	56.42	64.56	41.90	29.78	-29%
Real-time (simple average)	36.09	56.06	63.32	41.00	28.94	-29%
Day-ahead (load-weighted average)	38.08	59.71	69.26	45.03	31.74	-30%
Real-time (load-weighted average)	38.40	60.27	68.58	44.64	31.55	-29%
Estimated Wholesale Costs ($ billions)						
Energy	5.2	8.0	9.1	5.9	4.1	-30%
Capacity	1.2	1.0	1.1	1.1	1.2	5%
Net Commitment Period Compensation	0.1	0.2	0.2	0.1	0.1	-38%
Ancillary Services	0.0	0.2	0.3	0.2	0.1	-30%
Regional Network Load Costs	1.5	1.8	1.8	2.0	2.1	6%
Total Wholesale Costs	**8.0**	**11.2**	**12.4**	**9.3**	**7.6**	**-18%**
Fuel Mix (% of native New England Generation)						
Natural Gas	52%	45%	43%	49%	49%	1%
Nuclear	31%	33%	34%	30%	31%	1%
Other[c]	6%	6%	7%	7%	7%	0%
Hydro	7%	7%	8%	7%	7%	0%
Coal	3%	6%	5%	4%	2%	-1%
Wind	1%	2%	2%	2%	2%	0%
Oil	1%	1%	2%	2%	1%	-1%

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] The "Other" fuel category includes landfill gas, methane, refuse, solar, and steam
⇨ denotes change is within a band of +/- 1%

As can be seen from Table 1-1, costs for the major fuels have declined significantly in 2016 and have been the key driver of the decrease in electricity prices. The supply side continues to be highly dependent on natural gas, accounting for almost one half of the fuel mix. Coal prices were the exception, increasing by 15%. With the increase in coal costs relative to natural gas, there was a corresponding decline of about 1% in its share of the fuel mix.

Energy Market Supply Costs: The trend in quarterly estimated generation costs for each major fuel along with the day-ahead LMP over the past five years is shown in Figure 1-2 below.[9] The strong positive correlation between natural gas prices (blue line) and the LMP (red line) is evident.

Figure 1-2: Estimated Generation Costs and Day-Ahead LMP



Average natural gas and oil prices declined significantly in 2016 compared to 2015. The decline is particularly evident in the first quarter, after which prices began to rebound. The difference between average natural gas generation costs and competing fuels (coal and oil) was relatively large in 2016. While in 2015 the costs of natural gas and coal were within 1% of each other ($36.73 vs. $36.34/MWh), coal was over 70% ($17.62/MWh) more expensive than natural gas in 2016. The average difference between No.6 oil and natural gas was about $49/MWh (or about 200%) in 2016 compared to $55.90/MWh (about 150%) in 2015.

In the first quarter of 2016 the region did not experience the same levels of high natural gas prices as it had in the preceding three years. Warmer-than-usual weather resulted in lower gas demand (for direct heating and electricity generation) causing the New England gas system to be less stressed. The mean temperature in Q1 2016 was 34°F, compared to 24° in 2015 and 27° in 2014.

[9] 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.

The average natural gas price was $3.12/MMBtu in 2016, compared to $4.71/MMBtu in 2015. While gas prices were down by 70% (by $7.79/MMBtu) in Q1 2016 compared to Q1 2015, for the remaining three quarters gas prices actually increased by 17% in 2016 compared to 2015. This was likely attributable to a partial outage of a compressor station which brings gas from New York to Connecticut. The compressor capacity was reduced by 700,000 dekatherms, or by 50% of its full capacity. Much lower temperatures in December 2016 also led to a significant increase in natural gas prices compared to the same month in 2015.

Global Crude oil prices reached a 13-year low in the first quarter of 2016, but increased for the remainder of the year due to greater demand and decreased supply. This is reflected in the price of the three oil products (No. 6, No. 2 and diesel) shown in Figure 1-2 above. Oil made up only 1% of the native generation fuel mix in 2016.

Coal prices fell during the first two quarters of 2016, but rebounded in quarters three and four. The decline is largely due to increased gas generation, elevated coal stockpiles, and reduced winter 2015-16 electric demand nationwide.[10] In the second half of the year, stockpiles began to fall and temperatures rose, which led to higher electric demand. The combination of lower supply and higher demand led to increased coal prices in quarters three and four.

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 2016, CO_2 prices declined by 13%, which according to the EIA, coincided with the suspension of the Clean Power Plan in February 2016.[11] In 2016, the estimated contribution of CO_2 costs to the variable costs of generation for gas, coal and No.6 oil was $2.36, $5.33 and $4.73/MWh, respectively.

Generator Profitability: New generator owners rely on a combination of net revenue from energy and ancillary service (E&AS) markets and forward capacity payments to cover their fixed costs. 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 chart falls below the relevant CONE estimate, overall market revenues are insufficient to recover total costs.

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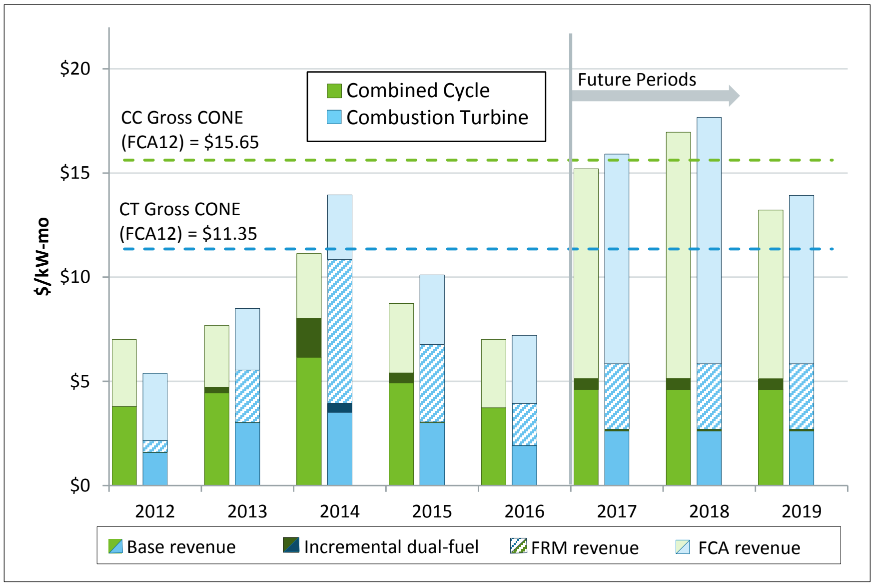
[10] US Energy Information Administration. *Coal production declines in 2016, with average coal prices below their 2015 level* Washington, DC: US Department of Energy, April, 2016. www.eia.gov/todayinenergy/detail.php?id=29472

[11] EIA is the US Energy Information Administration. See https://www.eia.gov/todayinenergy/detail.php?id=26812

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 market prices (at a system level) coupled with net revenue from energy and ancillary service sales were generally not sufficient to incent new generation. Capacity market prices, prior to 2017 (FCA 8) were low because there was a larger amount of capacity available to the market to meet demand (the system was relatively long on capacity).[12,13] When compared with the latest CONE benchmarks, total revenue appears sufficient to support the new entry of gas-fired resources. Recent FCM auction outcomes support this observation, with a number of both types of gas-fired generators clearing for the capacity commitment periods FCA 9 (2018) and FCA 10 (2019).

Energy Market Demand: The demand for electricity is weather-sensitive and contributes to the seasonal variation in energy prices. New England's native electricity demand, referred to as net energy for load, or "NEL", averaged 14,143 MW per hour in 2016, down 2% on 2015. The growth in the installation of energy efficiency measures, together with the increase in behind-the-meter generation such as rooftop solar, have contributed to lower NEL.

Operating Reserve Requirement: The bulk power system needs reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are provided by the unloaded capacity of generating resources, 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 1,700 MW and total thirty-minute reserve requirement of about 2,500 MW in 2016.

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[12] This analysis looks at system-level pricing. In FCA 7 the NEMA/Boston capacity zone was short and cleared a new combined cycle resource at just under $15/kW-month. The price impact was limited to new entry in that capacity zone, so the remainder of the system did not exhibit a price signal that would be sufficient for new generation.

[13] The FCM prices represent (blended) prices over a calendar year (January to December) as opposed to a capacity period (June to May).

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.

External transactions (imports and exports) can represent a significant share of either the supply stack (when importing) or additional demand on the system (when exporting). New England was a net importer of power in 2016, with net imports meeting almost 2,400 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 New England 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. Almost 80% of day-ahead transactions across the Canadian interfaces were fixed-priced in 2016. In real-time the percentage increases to 90%.

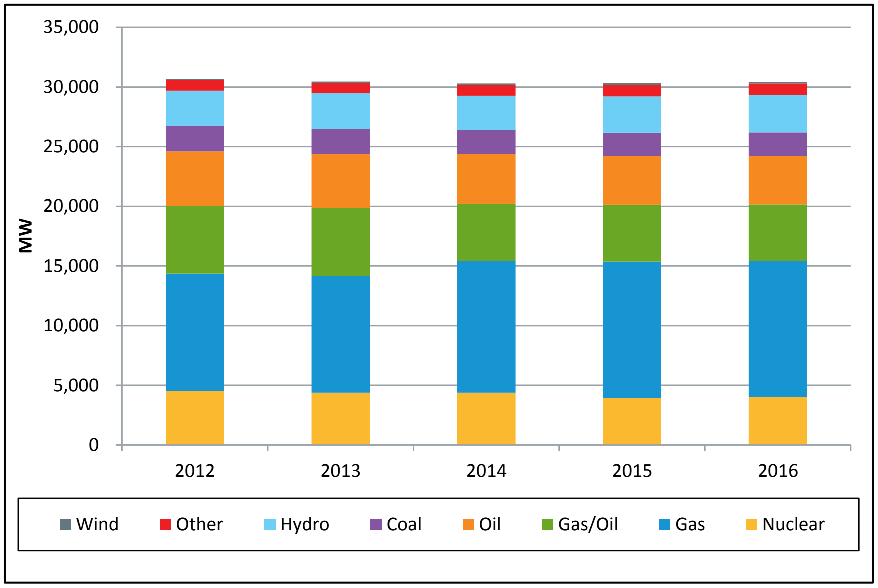
For the New York North interface new rules came into effect in December 2015, known as Coordinated Transaction Scheduling (CTS). The CTS design is intended to improve the frequency with which power moves from the lower- to higher-cost region and increase the utilization of interface transfer capability to better converge prices between the regions. Economic scheduling and price convergence between the markets appears to have improved under CTS. However, greater levels of participation from companies willing to transact power at market prices (as opposed to price-insensitive bids) would add to the bid liquidity necessary for CTS to shift real-time power flows in the economically efficient direction and further converge market prices.

In addition, 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 has been 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. 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.

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 87% (about 4,600 MW) of new generation additions to capacity in the past ten FCAs. 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 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 combined cycle gas turbine.

A breakdown of capacity supply obligations in the capacity market by fuel type is shown in Figure 1-4 below.

Figure 1-4: 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.

The retirements of nuclear generation and older dual fuel gas/oil generation in recent years has largely been offset by the increase in new natural gas-fired generation. The distribution of capacity by fuel type did not change significantly from 2015 to 2016. In 2016 gas- and gas/oil-fired generators (generators capable of firing on gas and oil) comprised 53% of overall generation capacity (or almost 16,200 MW). Nuclear and oil-fired generators were the next largest by capacity share, with 13% each (26% in total) of generation capacity. The visible decrease in nuclear capacity (by 600 MW) in 2015 was due to the retirement of the Vermont Yankee nuclear station. The retirement of the similarly-sized Pilgrim nuclear facility (about 690 MW) in 2019 will further reduce the capacity and energy share of nuclear fuel in future years. By 2020 the capacity of nuclear generation is expected to be about 3,350 MW, compared to 4,500 MW in 2012.

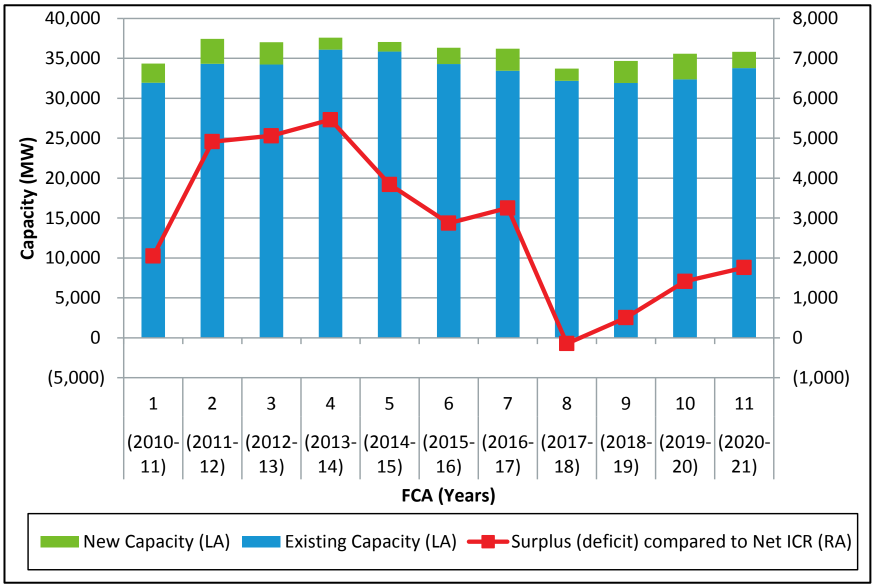
The system installed capacity requirement for the past three forward capacity auctions has been relatively flat, ranging from 34,075 MW in FCA 11 (for delivery in the capacity commitment period 2020/21) to 34,189 MW in FCA 9.[14] In the two most recent auctions the Southeastern New England (SENE) zone has been modelled as a potential import-constrained zone. Most recently, Northern New England (NNE) has been modelled as a potential export-constrained zone.[15] However, the LSR and MCL did not bind for either zone and therefore there was no separation from the Rest-of-Pool price.

[14] 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.

[15] 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.

The supply and demand balance in the FCM has gone through a number of shifts since the first auction. The volume of capacity procured in each auction relative to the NICR is shown in Figure 1-5 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 1-5: Cleared and Surplus Capacity in FCA 1 through FCA 11



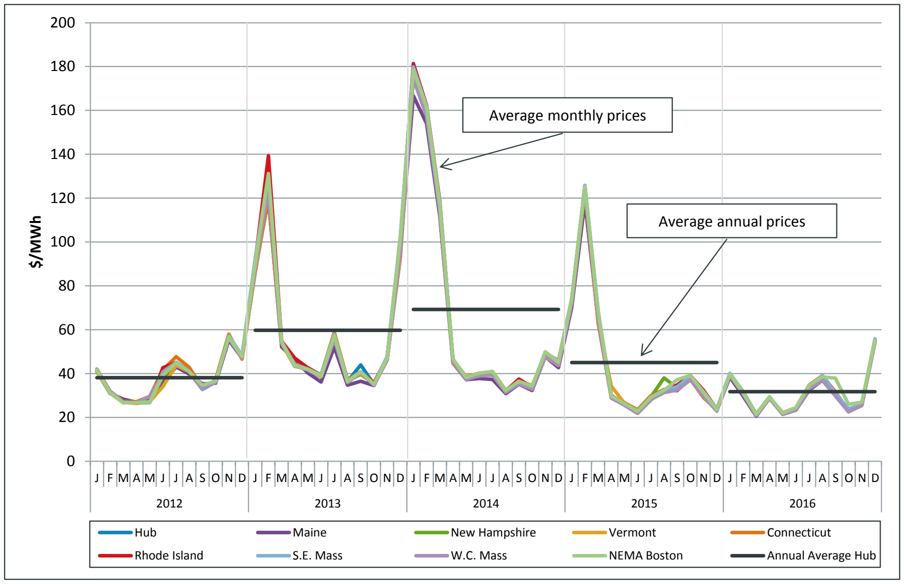
Following resource retirements of 2,700 MW in FCA 8 (and an increase in NICR), the surplus capacity in FCA 7 of over 3,000 MW was quickly eroded. However, higher clearing prices have brought new capacity to the market in the past three auctions, resulting in a surplus in the most recent auction (FCA 11) of almost 1,800 MW.

1.3 Day-Ahead and Real-Time Energy Markets

Prices: Price differences among the load zones were again relatively small in 2016, reflecting modest levels of both marginal losses and congestion.

The average absolute difference between the Hub and load zone prices was $0.27/MWh in the day-ahead energy market and $0.37/MWh in the real-time energy market – a difference of approximately 0.9-1.3%. The monthly load-weighted prices across load zones over the past five years are shown in Figure 1-6 below. The black line shows the average annual load-weighted hub price.

Figure 1-6: Day-Ahead Energy Market Load-Weighted Prices



Load-weighted energy prices by load zone from 2012 to 2016 indicate a pattern that varies considerably by year and month, but not by load zone. From 2013 through 2015 constraints on the natural gas system have resulted in large price spikes in natural gas and electricity prices in the months of January and February. Extreme pricing did not occur during the winter months in 2016 due to milder weather and less stress on the New England gas network. Similar to 2012, in 2016 average electricity prices in January were comparable to prices during the summer months, with summer prices reflecting higher load levels rather than high natural gas prices.

On average, electricity price in the day-ahead and real-time markets were relatively close, with an average difference of $0.84/MWh in 2016, down from $0.90/MWh in 2015. While there are many factors that can cause divergence in price between the two markets, price convergence between the two markets can be viewed as a rough indicator of the day-ahead market's ability to predict real-time conditions.

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 falls to about 2% on the demand side when very high-priced bids (whereby the bids always clear) are taken into account.

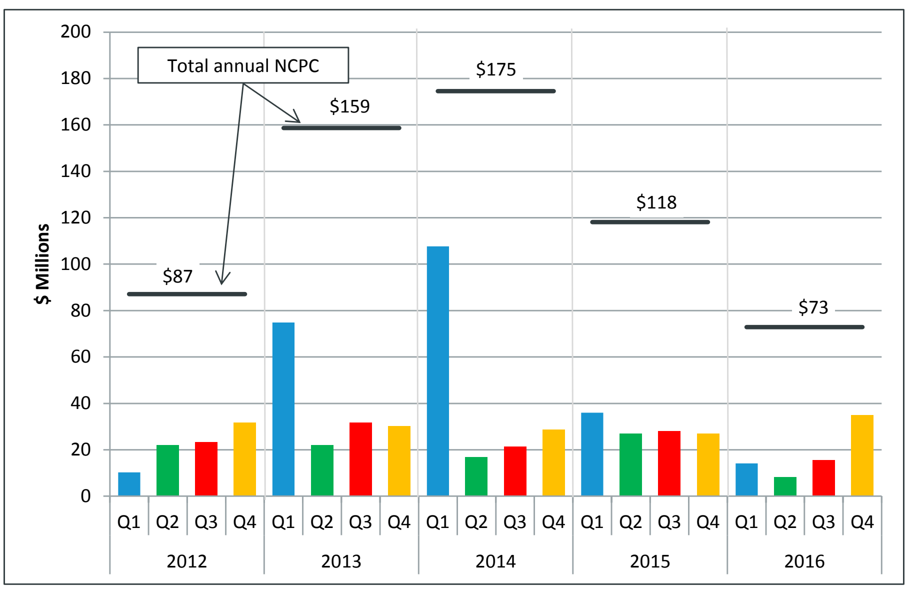
In this context of limited price-setting ability, virtual demand and supply tend to serve an important price-discovery role in the day-ahead market. Although volumes have declined in recent years, in 2016 virtual transactions (demand and supply) set the LMP in the day-ahead market during 31% of intervals. This is comparable to previous years, ranging from 27% to 33% between 2012 and 2015. However, in 2016 there has been a noticeable shift towards virtual supply setting price more frequently than virtual demand. The increase is 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 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 44% of the time in the day-ahead market in 2016.

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) resources. Consequently, the price-setting intervals for natural gas resources are significantly higher in the real-time at 77%. The percentage of price setting intervals for oil fell from 4% to 1% in 2016. This displacement was, in part, due to lower gas prices in 2016 as gas generators were in-merit more often compared with oil, especially during the winter months. There was also a noticeable increase in the number of intervals during which wind generators set prices, increasing from under 1% to 4%. This is due to the DNE market rules changes referenced above.

Net Commitment Period Compensation (NCPC): NCPC payments decreased significantly in 2016 compared with 2015, going to $73 million from $118 million (a reduction of 38%). NCPC payments to generators represented approximately 2% of their total energy payments in 2016. Quarterly (colored bars) and annual total NCPC payments (black lines) are shown in Figure 1-7 below.

Figure 1-7: Total NCPC Payments by Quarter and Year



The year-over-year changes are generally consistent with changes in fuel costs (especially natural gas) over this time period.[16] The high NCPC payments in the first quarter in 2013 and

[16] Other factors also influence NCPC payments. These include varying system conditions (i.e., instances of load forecast and generator commitment error, instances of local transmission issues and resulting local reliability needs, etc.) 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. These rules were subsequently changed in February 2016.

2014 explain a significant portion of the overall increase in NCPC payments in those years. This largely reflects higher natural gas costs during the winter months (i.e., higher operating costs for generators) and concerns about natural gas scarcity and system reliability impacts. A warmer-than-normal winter and relatively low fuel prices resulted in reduced NCPC payments for Q1 2016.

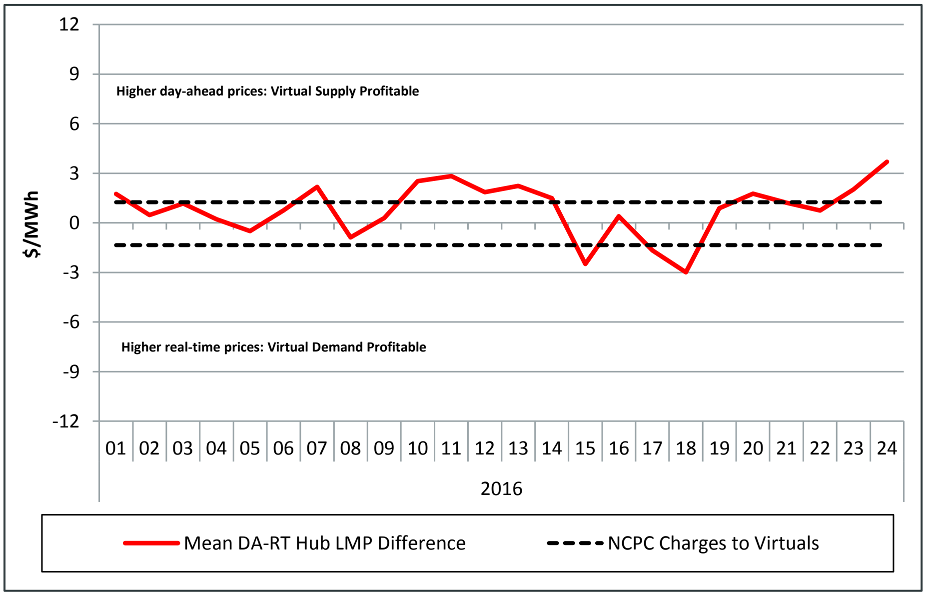
Another factor contributing to lower NCPC payments relates to market rule changes. From December 2014 through February 2016, a generator scheduled in the day-ahead market was eligible for both day-ahead and real-time NCPC. When real-time prices were lower than day-ahead prices, a generator could receive real-time NCPC even when the generator's supply offer and dispatch schedule did not change between the two markets. The additional real-time NCPC payments were deemed unnecessary because the generator was fully compensated in the day-ahead market, including any necessary day-ahead NCPC payments. It is estimated that this factor resulted in NCPC payments of approximately \$68 million from December 2014 through February 2016. In 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. These payment rules were not applicable for most of 2016.

The overall impact of lower fuel prices and changes to market rules was offset by the need for reliability commitments of relatively more expensive generation in Q4 2016 in the NEMA/Boston area. The reliability commitments support on-going transmission outages (needed to upgrade transmission capabilities in that area) that limited the availability of imports into the area. Generators in NEMA/Boston received \$22 million of the total \$35 million in Q4 NCPC payments.

Virtual Transactions: In 2016, cleared virtual transactions averaged 475 MW per hour. This volume has been consistent over the past six years but represents a material reduction from years prior to 2011. The allocation of economic NCPC among fewer day-ahead/real-time deviations has increased the per-megawatt charge to cleared virtual transactions and is likely the key driver of the reduced volumes. 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 2016 the average per-MW real-time NCPC charge rate was \$1.22, down from \$2.93 in 2015 due to the lower NCPC payments to generators as discussed above.

Although lower in 2016, the NCPC charges continue to limit the extent to which virtual transactions can converge day-ahead and real-time prices. This is illustrated in Figure 1-8 below, which shows the mean (average) of day-ahead and real-time price differences by time of day during 2016. The dashed black lines correspond to the average NCPC deviation charges for incremental offers and decremental bids. Where the the red line falls within the dashed-black lines, 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 1-8: Day-ahead to Real-time Price Differences and NCPC Charges in 2016



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 2 through 6, the average gross profit to be made from a virtual demand bid (difference between the day-ahead and real-time LMP) is less than the NCPC costs it would be charged.

We have 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. We also note that in January 2017 the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking (NOPR) regarding uplift (NCPC) cost allocation. Specifically, FERC proposed that uplift cost allocations to deviations that are inconsistent with cost causation be changed to better reflect the transactions that are reasonably expected to have caused the costs.[17]

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.

[17] In January 2017 the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking (NOPR) regarding uplift cost allocation. Specifically, FERC proposed that uplift cost allocations to deviations that are inconsistent with cost causation be changed to better reflect the transactions that are reasonably expected to have caused the costs. The suggested changes align with the recommendation of the IMM. See *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, 158 FERC ¶ 61,047 (2017).

The following metrics were calculated for the real-time energy market:[18]

- *C4 for supply-side participants*
  The C4 value expresses the percentage of real-time supply controlled by the four largest companies. In 2016, the C4 value was 43%, similar to the values observed over the prior four years. 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 2016 was 50%, similar to 2015. 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)*[19]
  Results from the RSI and pivotal supplier analysis for 2016 indicate that there have been supply portfolios with market power in about 50% of hours. This represents an improvement in structural competitiveness compared to 2014 and 2015, which can partially be explained by the lower load levels observed in 2016.

  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.[20] 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.

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

[19] 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.

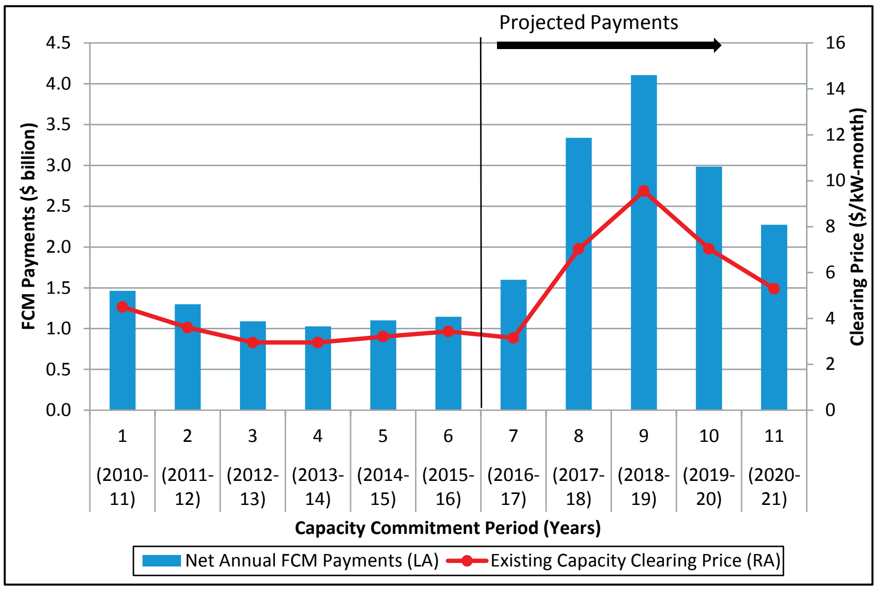
[20] The Lerner Index is calculated as the percentage difference between the annual generation-weighted LMPs between two scenarios. The first scenario calculates prices using actual supply offers, while the second scenario uses marginal cost estimates in place of supply offers.

The results show that competition among suppliers limited their ability to increase price by submitting offers above estimates of their marginal cost. For 2016, the Lerner Index for the day-ahead energy market was 8.2%. This indicates that offers above marginal cost increased the simulated day-ahead energy market price by approximately 8.2%. 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 for the first capacity commitment period (CCP 1) through CCP 11 are shown in Figure 1-9 below.[21]

Figure 1-9: 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 for the first seven auctions, clearing at administrative floor prices ranging from $2.95/kW-month to $4.50/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.[22]

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

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

Capacity payments are expected to more than double from CCP 7 and CCP 8. There was a capacity deficiency of 143 MW in FCA 8, primarily due to retirements. Administrative pricing rules were triggered due to the shortfall, resulting in a price of $7.03/kW-month for existing (non-NEMA/Boston) resources and a price of $15.00/kW-month for new and existing resources in NEMA/Boston.

In FCA 9 a system-wide sloped demand curve was applied for the first time. The clearing price was $9.55/kW-month for all capacity resources, with higher prices in the import-constrained zone of Southeastern Massachusetts/Rhode Island (SEMA/RI).[23] The combination of higher Rest-of-Pool and SEMA/RI prices leads to an increase in projected capacity payments of almost $1 billion compared to FCA 8.

In FCA 10 the market procured 35,567 MW of capacity, about 1,400 MW above NICR of 34,151 MW. The rest-of-pool clearing price was $7.03/kW-month, with no price separation among the capacity zones. More than 1,450 MW of new generation capacity cleared, of which three natural gas-fired generators made up 90%. Two external interfaces, the New York AC Ties and New Brunswick, still had excess offered capacity over the transfer capabilities of the lines at the system-wide clearing price. The interfaces cleared at lower prices of $6.26 and $4.00/kW-month, respectively, once that excess capacity dropped out.

In FCA 11, the market procured 35,835 MW, almost 1,800 MW above the NICR of 34,075 MW. The rest-of-pool clearing price was $5.30/kW-month, with no price separation among the capacity zones. There was still an excess of capacity willing to import over the New Brunswick interface at the rest-of-pool price, which resulted in a lower price of $3.38/kW-month for cleared resources at that interface.

Market Competitiveness: Two metrics were calculated to evaluate the competitiveness of the capacity market; the RSI and PST.[24] As covered above in Section 1.3, both measures 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. 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

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

[24] 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.

most recent auction (FCA 11) 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 assessment of 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 $131 million in 2016, down 30% from 2015 costs.

Real-time reserves: The frequency and average levels of real-time reserve prices remained relatively low during 2016. Over 40% of the total annual real-time reserve costs of $20.5 million were incurred on August 11, when the system experienced tight system conditions, deficiencies in thirty-minute reserves and a shortage event.

Forward reserves: Forward reserve auctions in 2015 and 2016 resulted in relatively stable Forward Reserve Market (FRM) compensation levels for system-wide reserve products, close to $2,000/MW-month. However, the NEMA/Boston reserve zone was import-constrained in the past two summer auctions and has cleared at the auction price cap due to inadequate supply. In Summer 2016, the cap was $9,000/MW-month.

The FRM was structurally uncompetitive (i.e. has at least one pivotal supplier or a RSI < 100) in six out of the ten auctions since Summer 2012 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 $26.5 million in 2016, a 21% increase from the $21.8 million in 2015. The increase in payments reflects several factors: first, a 25% increase in the average regulation requirement; second, the manual selection of large regulation resources by the ISO during the summer months; and third, an increase in the opportunity cost component of capacity offers due to higher LMPs in December 2016.

Winter reliability program: The winter reliability program covering the winter of 2016/17 cost $31 million, the lowest of the four winters to date due to lower payment rates.[25] In 2016, the Federal Energy Regulatory Commission (FERC) issued an Order on Remand directing the Internal Market Monitor (IMM) to evaluate the competitiveness of the 2013-2014 winter reliability program and whether participants exercised market power. The report, filed with FERC on January 23, 2017, found that the program's "pay-as-bid" compensation structure may have incentivized participants to place bids that exceeded their costs.[26]

The analysis showed that the auction was not structurally competitive, and provided evidence that the exercise of market power may have been responsible for a portion of the program's

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[25] The program will end with the implementation of the FCM pay-for-performance rules in June 2018.

[26] The "pay-as-bid" structure was replaced by compensation rates after the first winter period of the program.

total cost. However, there were a number of factors including variation in risk valuation, information available to participants about the market structure, and incentives provided by the chosen auction design that precluded a more conclusive analysis.

1.6 Market Enhancement Recommendations

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

Table 1-2: Market Enhancement Recommendations

Recommendations	Status as of the AMR '16 Publication Date
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 in the project planning stage to implement a new IMM market analysis system that will address this recommendation.
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.
FCM resource retirements: The ISO develop and implement the following processes and mechanisms regarding uneconomic resource retirements in the Forward Capacity Market: • A process for identifying resource retirements that appear to be pre-mature with respect to their expected economic life and can be used to exercise market power, • A mitigation measure that ensures auction clearing prices are not distorted by the exercise of market power through pre-mature retirement of capacity resources, • A more robust mechanism for existing resources to retire through competitive price discovery in the FCM rather than through administrative means, and • A timeline for the retirement process that will facilitate signaling to prospective new entry the extent of potential retirement capacity prior to the show of interest deadline for new capacity resources.	The IMM has worked with the ISO and stakeholders to address this recommendation. Proposed rule changes were filed on December 17, 2015. They were accepted by FERC in April 2016.
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.

Recommendations	Status as of the AMR '16 Publication Date
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
NCPC charges to virtuals 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.	The ISO recently filed comments related to this issue in response to a NOPR and will await FERC direction before taking action on this item.[27]
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.
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.	New recommendation from analysis presented in the Spring 2016 Quarterly Markets Report.
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.	New recommendation from analysis presented in the Spring 2016 Quarterly Markets Report.

[27] In January 2017 the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rule changes (NOPR) regarding uplift cost allocation. Specifically, FERC proposed that uplift cost allocations to deviations that are inconsistent with cost causation be changed to better reflect the transactions that are reasonably expected to have caused the costs. The suggested changes align with the recommendation of the IMM. See Docket No. RM17-2-000, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators.*

Section 2

Overall Market Conditions

This section provides an overview of the key trends in wholesale market outcomes over the past five years (2012 through 2016). 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.

New England's total wholesale cost of electricity in 2016 was considerably lower than 2015, due primarily to lower natural gas prices. Natural gas prices at the Algonquin Citygates trading hub were at the lowest level in the past 16 years. As a result, average wholesale electricity prices were at the lowest level since the start of the wholesale markets in 2003. Electricity demand in New England was at the lowest level in the past 17 years. The trend of declining load is primarily a result of seasonal temperature changes and the growth of energy efficiency programs and behind-the-meter solar generation.

Natural gas and nuclear continue to be New England's dominant fuel sources, representing 49% and 31% of the annual energy production, respectively. In contrast, coal- and oil-fired generation together accounted for 3% of energy production in 2016. New England was a net importer of power in 2016, with net imports meeting 17% of New England's total electricity demand. Market concentration levels - the extent to which the market is dominated by one or more suppliers – was reasonably low, resulting in relatively competitive prices.

The forward capacity market saw the entry of new efficient resources, the retirement of less efficient resources and created surplus capacity during the first seven commitment periods. This surplus trend was reversed during the eighth auction with the retirement of 2,700 MW of coal, oil and nuclear units that resulted in higher capacity prices. New capacity supply of 5,000 MW entered the market in the last two forward capacity auctions, FCA 10 and FCA 11.

2.1 Wholesale Cost of Electricity

In 2016, the total estimated wholesale market cost of electricity was $7.6 billion, a decrease of about 18% compared to $9.3 billion in 2015.[28] The wholesale cost estimate is made up of three general categories; energy, capacity and transmission.

The first category, energy, 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 57% of total wholesale costs in 2016.

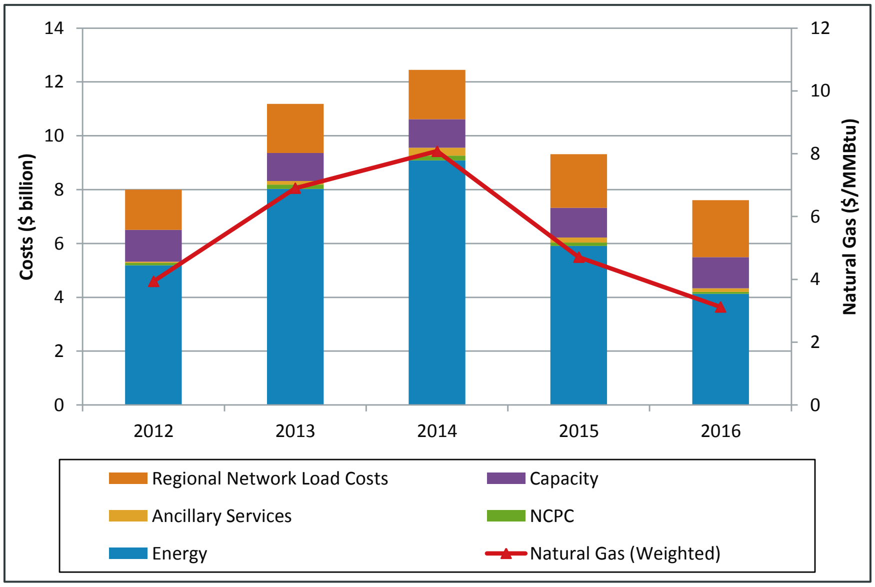
The second category, capacity, reflects the cost to attract and retain sufficient generation capacity to meet energy and ancillary service requirements. This category represented about 15% of the total wholesale cost.

[28] 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.

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 28% of total wholesale costs.[29]

A breakdown of the estimated annual wholesale electricity cost, along with average natural gas prices, is shown in Figure 2-1 below. Natural gas is the primary fuel used to produce electricity and thus a key driver of energy, ancillary services and NCPC costs.

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices



The relationship between natural gas prices and energy costs is apparent Figure 2-1, with annual energy costs and gas prices moving in the same direction. Natural gas prices were 34% lower in 2016 compared to the previous year. The decrease in average natural gas prices in 2016 resulted in a significant decrease in energy costs. Energy costs were $4.1 billion in 2016, 30% lower than 2015. NCPC costs, at $73 million in 2016, declined by 38% relative to 2015. Ancillary service costs, which include operating reserve and regulation payments, as well as winter reliability costs, totaled $131 million in 2016, a decrease of 9% compared to 2015.

Capacity market costs in 2016 totaled to $1.2 billion, an increase of 5% compared to 2015. As described in Section 6, the increase was due to high clearing prices in NEMA/Boston.

Transmission costs totaled $2.1 billion in 2016. Both costs and the regional transmission rate increased by approximately 6% in 2016 over the 2015 rate, moving from $98.07 per kW/yr to $103.30 per kW/yr. [30] The increase was the result of investment in new regional transmission infrastructure to address deficiencies in meeting reliability criteria, as well as investment to

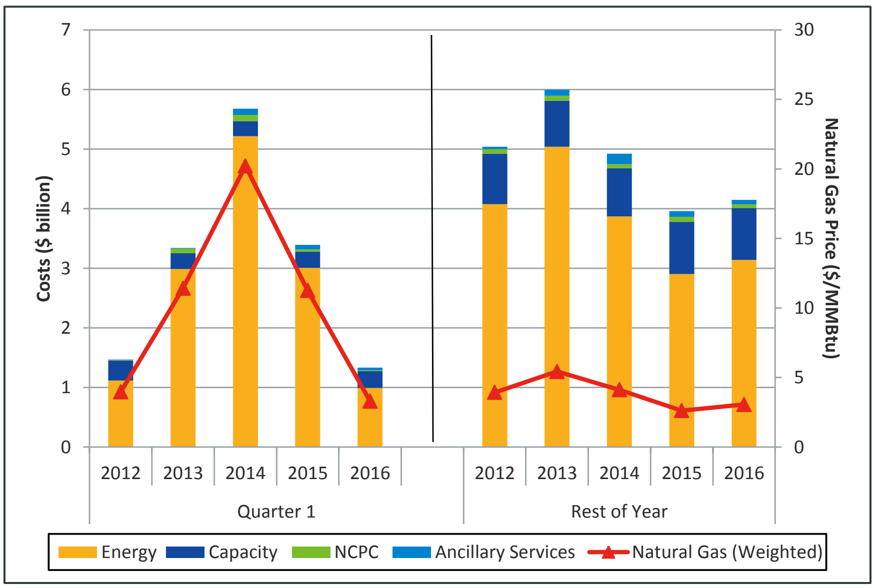
[29] RNL, or Open Access Transmission Tariff (OATT), costs are associated with providing regional network service (RNS) and other services to transmission customers that collectively provide for the use of transmission facilities, reliability, and certain administrative services. Of the three costs categories 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.

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

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.

The decrease in wholesale market costs in 2016 was driven primarily by a reduction in first quarter costs. In 2013 through 2015, gas prices were relatively high in Q1 due to low temperatures and high gas demand. However, Q1 2016 experienced milder temperatures and lower gas prices. Energy costs, capacity costs, and natural gas prices for the past 5 years are shown in Figure 2-2 below. The figure shows costs and gas prices for the first quarter of each year separately from the remainder of the year.

Figure 2-2: Wholesale Market Costs and Average Natural Gas Prices for Quarter 1 Compared with Rest of Year



In the first quarter of 2016, energy, capacity, NCPC, and ancillary service costs totaled $1.3 billion, compared to $3.4 billion in the first quarter of 2015. In the remaining quarters, however, costs increased in 2016: energy, capacity, NCPC, and ancillary service costs totaled $4.1 billion in the last 3 quarters of 2016, compared to $3.9 billion in the last 3 quarters of 2015. Additionally, average natural gas prices decreased dramatically in the first quarter of 2016 ($3.30/MMBtu) compared to the first quarter of 2015 ($11.09/MMBtu). Gas prices increased in the last 3 quarters of 2016 ($3.06/MMBtu) relative to the last 3 quarters of 2015 ($2.62/MMBtu).

2.2 Supply Conditions

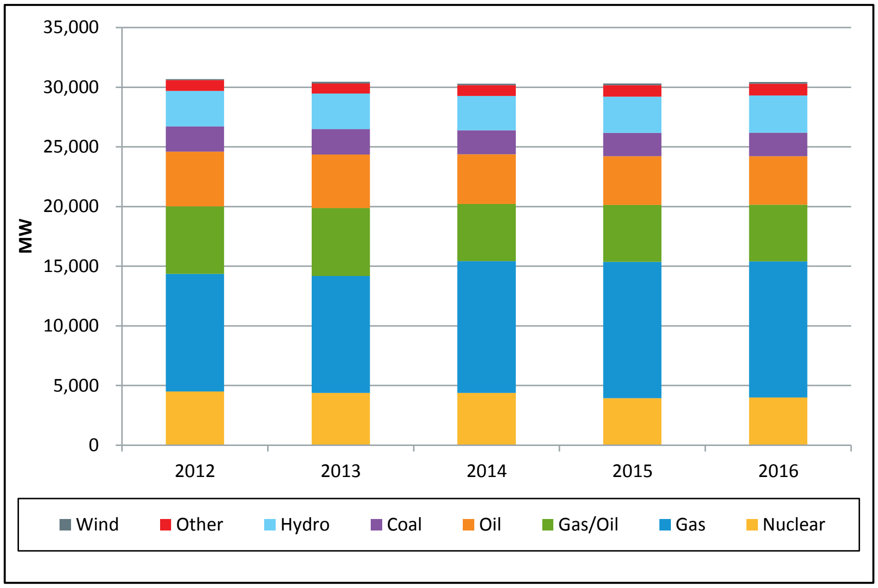
This subsection of the report provides a macro-level view of supply conditions across the wholesale electricity market in 2016, and describes how those conditions have changed over the past five years. Topics covered include the generation mix within New England, fuel and emission market prices, and estimates of generator profitability.

2.2.1 Generation and Capacity Mix

This section provides a summary of the generation mix in New England over the past five years. Information about generation is provided across a series of different dimensions, including fuel type, location, and age. The focus here is on generators native to New England and excludes external transactions (which are covered separately in Section 2.4 and Section 5). Understanding the composition of New England's native generation is key to understanding overall supply conditions and market outcomes.

Capacity by Fuel: Average generator capacity by fuel type for the past five years is shown in Figure 2-3 below.[31]

Figure 2-3: 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 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 38% of capacity in 2016 while generators capable of burning either oil or natural gas (i.e., a type of dual-fuel generator) accounted for 16% of capacity. Combined, these gas and gas/oil dual fuel generators accounted for 53% of total average generation capacity.

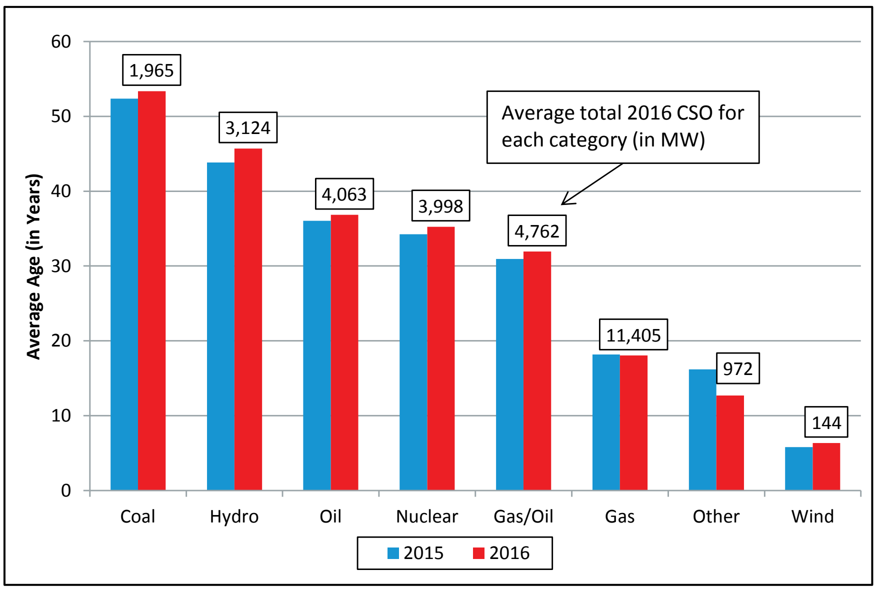
The distribution of capacity by fuel type did not change significantly from 2015 to 2016. The largest change in capacity fuel mix in 2016 was an 81 MW increase in capacity from new hydro generation that entered the capacity market on June 1st, 2017.

[31] 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).

Similar to 2015, in 2016 nuclear generation accounted for 4,000 MW (13%) of the capacity fuel mix. In 2015 the Vermont Yankee nuclear facility (about 600 MW) was permanently shut down. The retirement of the similarly-sized Pilgrim nuclear facility (about 690 MW) in 2019 will further reduce the capacity and energy share of nuclear generation. By 2020 the capacity of nuclear generation is expected to be about 3,350 MW. Coal-fired generators accounted for 2,000 MW, or 6%, of overall native generation capacity in 2016. This amount will be nearly halved in 2017 with the retirement of the Brayton Point facility.

Average Age of Generators by Fuel: The average age, in years, of New England's generation fleet is illustrated in Figure 2-4 below. Age is determined based on the generator's first day of commercial operation. The blue bars represent the average age of generators by fuel type in 2015, while the red bars represent 2016. The data labels above the bars show the capacity of generation by fuel category.

Figure 2-4: Average Age of New England Generator Capacity by Fuel Type



The average age of New England's generators by fuel category ranged from 6 years to 53 years, with an average total system age of 30 years. Coal generators, which comprise 7% of total generation capacity, have the highest average age of 53 years. The average age for oil generators is 37 years.

Natural gas generators are relatively newer, with an average age of 18 years, reflecting recent new construction. Wind and solar added a large percentage of new capacity between 2015 and 2016, resulting in an average age of 6 and 3 years, respectively.[32]

As generators age, they require increased maintenance and upgrades to remain operational. This is true for all generators, but older coal and oil 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 generators, new natural gas generators are cleaner, more efficient and generally have lower fuel costs. As a result, most new investments have been in new natural gas generators rather than in new, or upgrades to, coal or oil generators. Aging coal and oil

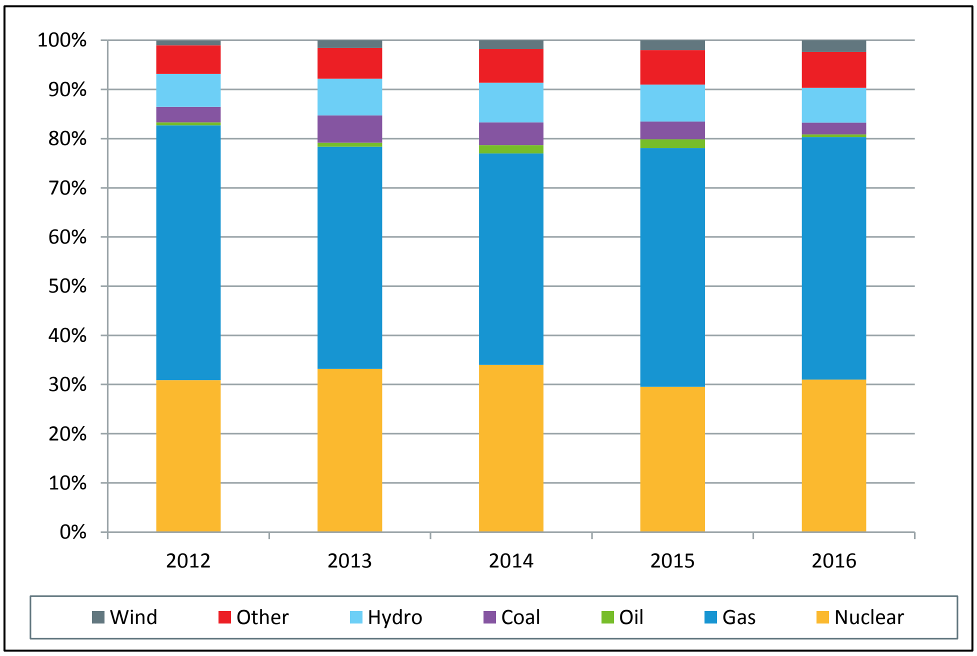
[32] The addition of new solar resources suppressed the age of the "Other" category in Figure 2-4.

generators, coupled with the aforementioned economic drivers, have contributed to generator retirements. More about generator retirements can be found in the Section 2.2.2 below.

Average Generator Output by Fuel Type: Up to this point, this section has focused on capacity. Though capacity is a useful measure to understand the generation fleet's capability, analyzing actual energy production (generation output in MWh) 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 for the past five years is illustrated in Figure 2-5 below. Unlike the capacity section above, oil and gas are broken out separately. This can be done because the actual fuel burned is specified in the generators' energy market offers.

Figure 2-5: Share of Native Electricity Generation by Fuel Type

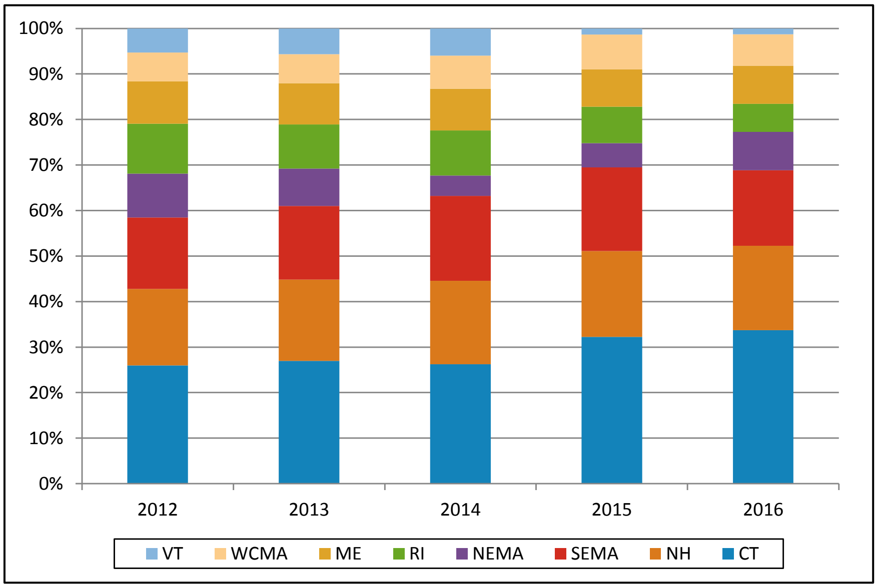


Notes: "Other" category includes landfill gas, methane, refuse, solar, steam, and wood.

Annual energy production by fuel type has been relatively consistent over the past 5 years. In 2016, nuclear generation accounted for 31% of annual real-time energy production while natural gas generation accounted for 49%. Coal and oil generation together accounted for 3% of total energy production. Oil-fired generators typically run when they are needed for local reliability or when system conditions are stressed, and on average have very low capacity factors. Increased natural gas prices can cause coal or oil-fired generators to be less expensive to run than gas-fired generators. Coal-fired generators tend to be in-merit more often than oil and, as a result, have higher capacity factors. In 2016, nuclear generation had a capacity factor of 93% and gas-fired generation 37%. In comparison, coal-fired generation had a capacity factor of about 15% and oil-fired generation about 2%. Coal-fired generation produced significantly more energy than oil-fired generation, despite the capacity supply obligations of oil and gas/oil generators being far greater.[33] 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.

A breakdown of energy production by load zone is shown in Figure 2-6 below.[34] The load zone breakdown provides a general idea of where energy is being produced.

Figure 2-6: Share of Native Electric Generation by Load Zone



Note: The ISO New England load zones are as follows: Vermont (VT), Western-Central Massachusetts (WCMA), Northeast Massachusetts (NEMA), Maine (ME), Rhode Island (RI), Southeast Massachusetts (SEMA), New Hampshire (NH), and Connecticut (CT).

Most of the region's electricity production comes from Connecticut (34%) and Massachusetts (32%). Massachusetts is broken into three different load zones: Western-Central Massachusetts (WCMA, 7%), Southeastern Massachusetts (SEMA, 17%), and Northeastern Massachusetts (NEMA, 8%). In the past few years, the energy production in Vermont (VT) has declined, mainly due to the retirement of Vermont Yankee Nuclear Power Station (604 MW) (see Section 2.2.2). The NEMA load zone, which experienced a reduction in energy production in 2014 (4%) and 2015 (5%), accounted for 8% of total energy production in 2016. The increase in NEMA energy production in 2016 was driven by an increase in self-scheduled generation.

2.2.2 New Entry and Retirements

Generator additions and retirements are shown in Figure 2-7 below.[35, 36,37] Future periods are years for which the forward capacity auction has taken place, but the capacity is yet to be delivered.

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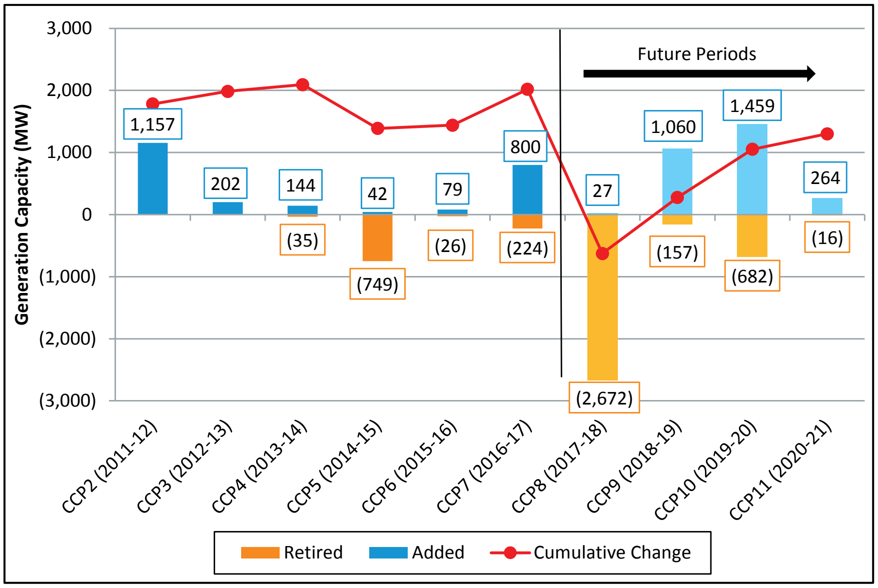
33 A capacity factor indicates how much of the full capability of a generator is being utilized in the energy market. For example, a capacity factor of 60% for a 100MW generator means that the generator is producing 60MW on average each hour.

34 Load zones are geographic areas in New England, in many cases corresponding to State boundaries, made up of an aggregation of pricing nodes.

35 Capacity Commitment Periods start on June 1st and end on May 31st of the following year. For example CCP 6 started June 1st 2015 and ended May 31st 2016.

Figure 2-7: Generator Additions, Retirements, and Cumulative Change



From the inception of the FCM through to the seventh capacity commitment period (CCP), there was a net increase of more than 2,000 MW of capacity (as shown by the red line); i.e. new entrant capacity outpaced the exit of existing capacity from the market. The increase occurred despite a relatively high surplus of capacity and low auction clearing prices. This trend was reversed in CCP 8 with the retirement of a number of large resources, which left the market short of capacity and led to higher auction clearing prices. In the last three auctions, the market reacted to the shortfall and market price signals. The most recent auctions were successful in attracting new entry to restore the system to sufficient, and even surplus, capacity.

Early additions in the FCM were largely driven by state policy goals, including a Connecticut public act intended to achieve "fuel diversity, transmission support, and energy independence in the state." [38] For example, in 2007, Kleen Energy Systems entered into a fifteen year contract with the State of Connecticut. Kleen cleared 620 MW as a new resource in the forward capacity auction for CCP 2 at the administrative floor price of $3.60/kW-month. The clearing price contrasts to the competitive threshold of new entry (CONE) price for the same period of $4.50/kW-month.[39]

Salem Harbor, a 750 MW oil/coal dual-fired power plant in NEMA/Boston, retired in CPP 5 (2014-2015). The resource's owner cited the growing uncertainty surrounding future costs related to

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[36] Capacity Commitment Period 1 is not shown because New England's entire fleet of existing and new capacity was added to the capacity market for the first time.

[37] The methodology used for this figure has changed from 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".

[38] See Public Act No. 05-1 in Connecticut for more information

[39] The competitive threshold for new entry is equal to 0.75* CONE.

environmental regulations as contributing to its retirement decision.[40] 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.[41]

There was a capacity deficiency entering CCP 8. Two retirements made up 78% of the capacity reduction. The Brayton Point coal unit (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).[42] 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.

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 natural gas combined cycle plant in Connecticut. The cumulative change in total CSO year-over-year went from negative 630 MW to positive 275 MW.

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 units accounted for 86% of this supply; Bridgeport Harbor 6(480 MW), Canal 3 (330 MW), and Burrillville Energy Center (490 MW).

In the most recent auction, FCA 11, only 260 MW of new generation capacity cleared. There were 22 generation resources that acquired a new resource obligation in the auction. The largest was Milford Power, a 220 MW combined cycle resource. Fifteen of the resources were solar projects that accounted for 4.6 MW. As the auction price declined, new generating resources exited the auction (1) when the price went below their offer floor price, or (2) when they deemed the price too low to cover their cost of new entry.

2.2.3 Generation Input Costs

This section reviews fuel and emission price trends over the past five years.

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 52% of New England's electricity. Average 2016 prices for natural gas and oil declined year-over-year, while coal prices increased slightly. Oil prices were at a 13-year low in the first

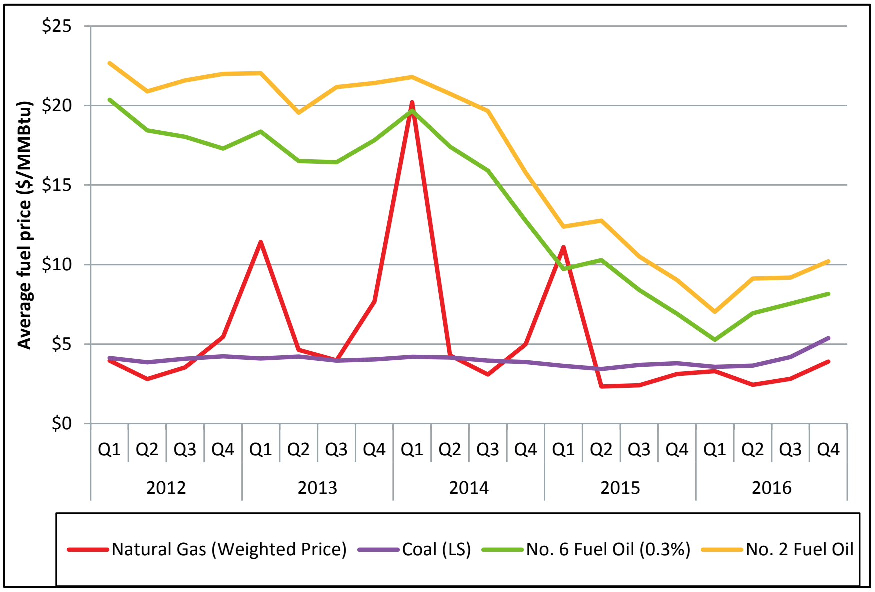
40 *Non-price Retirement Election for Salem Harbor Units 3 and 4.* (May 11, 2011) https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/non_prc_retremnt_lttrs/2011/salem_retirement_election.pdf

41 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

42 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.

quarter of 2016, but increased over the last three quarters. Quarterly average cost of natural gas[43], low-sulfur (LS) coal, No. 6 (0.3% sulfur) oil, and No. 2 fuel oil for the past five years are graphed in Figure 2-8 below.

Figure 2-8: Average Fuel Prices by Quarter



In 2016 natural gas prices averaged $3.12/MMBtu, a decrease of 34% compared to the 2015 average price. The annual average price decrease in 2016 was driven by the significant decline in first quarter prices. The 2016 first quarter price of $3.30/MMBtu was 70% lower than $11.09/MMBtu in the same quarter of 2015. The decline in first quarter gas prices was attributable toincreased gas supplies available from storage and warmer-than-usual temperatures which reduced residential heating demand.[44] According to the Energy Information Administration (EIA), natural gas in storage at the beginning of the 2015-2016 heating season (November 2015 through March 2016) was at a record high of 4,000 Bcf in the U.S. and ended at a record high of nearly 2,500 Bcf.[45]

For the remaining three quarters gas prices actually increased by 17% in 2016 compared to 2015. From Q2 to Q4 2016, natural gas prices were up 5%, 17%, and 25% over 2015 prices. A contributing factor was a force majeure on the Algonquin pipeline on August 15th, 2016. A compressor station which helps flow gas from New York to Connecticut needed to decrease capacity by 50% or 700,000 dekatherms per day. Available capacity was not restored to normal levels until November 1st. During warmer days at the end of the summer, high loads lead to increased gas demand. With limited capacity into New England gas prices increased compared to Q3 2015.

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

[44] US Energy Information Administration. *Natural gas prices in 2016 were the lowest in nearly 20 years* Washington, DC: US Department of Energy, April, 2016. http://www.eia.gov/todayinenergy/detail.php?id=29552

[45] US Energy Information Administration. *Natural gas storage ends winter heating season at record high* Washington, DC: US Department of Energy, April, 2016. http://www.eia.gov/todayinenergy/detail.php?id=25812

Lower December temperatures along with the force majeure discussed above led to the 25% natural gas price increase in Q4 2016. The average daily temperature in December 2016 was 32°. This was 11° lower than the same period in 2015. As temperatures decline heating demand increases. Increased demand on gas pipelines drives prices up, especially when capacity is constrained into the region.

Global Crude oil prices reached a 13-year low in the first quarter of 2016, but increased for the remainder of the year due to greater demand and decreased supply.[46] The index prices for the No. 6 and No. 2 distillate fuels used by most oil-fired generators in New England were the lowest observed in recent years during Q1-2016, but then rose over the course of the year.

Coal prices fell during the first two quarters of 2016, but rebounded in quarters three and four. The decline was largely due to increased gas generation, elevated coal stockpiles, and reduced winter 2015-2016 electric demand nationwide.[47] In the second half of the year, stockpiles began to fall and temperatures rose, which led to higher electric demand. The combination of lower supply and higher demand led to increased coal prices in quarters three and four.

Emission Prices: Emission allowances as required by federal and state regulations are a secondary driver of electricity production costs for combustion 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. According to the EIA, after the Clean Power Plan was suspended in February 2016, RGGI prices declined after rising for three straight years. The clearing price for the June 2016 auction was $4.53 per short ton, which is 40% below the peak value of $7.50 per short ton in December, 2015.[48]

The estimated dollar per MWh costs of CO_2 emissions and their contribution as a percentage of total costs is shown in Figure 2-9 below. The line series illustrate the average estimated cost of emission allowances for fossil fuel for the past five years. These estimated costs were calculated using the CO_2 prices utilized to set marginal cost reference levels and a benchmark full-load, average heat rate for generators of a representative technology type in each fuel category.[49] The bar series on the figure shows the proportion of the average energy production costs attributable to emissions costs for the same years.

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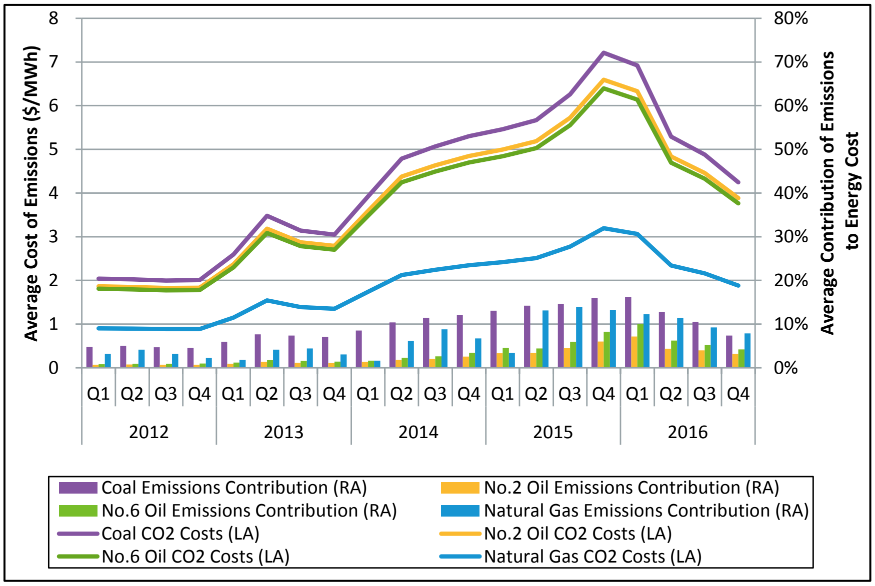
[46] US Energy Information Administration. *Energy commodity prices rose more than other commodity section in 2016* Washington, DC: US Department of Energy, April, 2016. http://www.eia.gov/todayinenergy/detail.php?id=29392

[47] US Energy Information Administration. *Coal production declines in 2016, with average coal prices below their 2015 level* Washington, DC: US Department of Energy, April, 2016. www.eia.gov/todayinenergy/detail.php?id=29472

[48] 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

[49] The full-load, average heat rate reflects incremental energy production and no load costs. Start-up fuel and variable operating and maintenance costs were excluded from this analysis.

Figure 2-9: Average Cost of CO2 Allowances and Contribution to Energy Production Costs

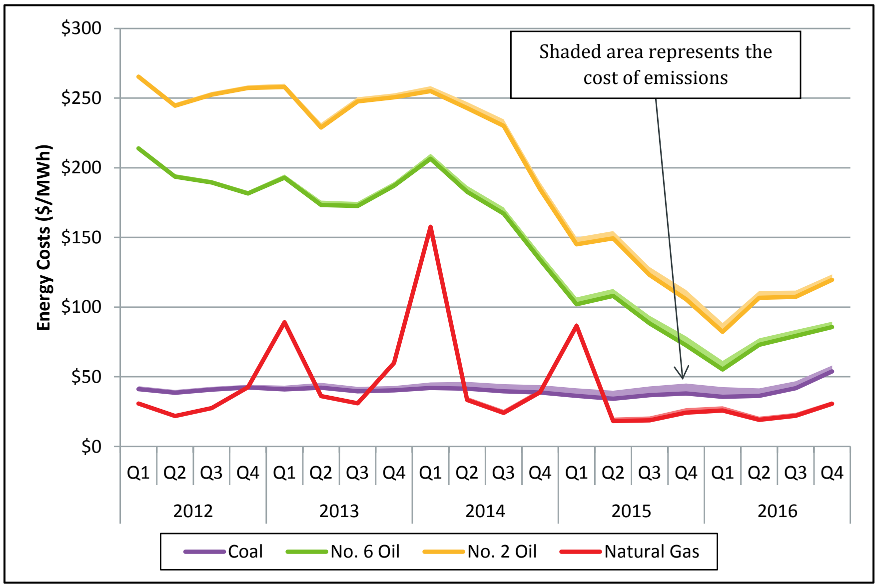


Caron dioxide emissions allowance costs fell each quarter in 2016.The line series for each of the fuel types show that between 2013 and 2015, the average quarterly cost of emissions steadily increased. The average cost of emissions declined as RGGI prices fell throughout 2016. A natural gas generator had average emissions costs of $3.19/MWh in Q4 2015. The cost fell to $1.88/MWh in Q4 2016. Coal unit emissions costs fell from $7.21/MWh to $4.25/MWh over the same period.

As shown in Figure 2-9, the relative contribution of CO_2 emissions allowance costs to generation costs fell in 2016. The bar chart series represent the quarterly average contribution of emissions allowance costs to the variable cost of producing electricity. For coal and oil-fired generators, the decline in average quarterly contributions was driven by the decrease in CO_2 allowance prices and the increase in coal and oil prices.

A wider view of the impact of CO_2 allowances on generation input costs is presented in Figure 2-10 below. The line series in the figure illustrates the quarterly estimated production cost using the average heat rate for generators of a representative technology type in each fuel category. The height of the shaded band above each line series represents the average additional energy production costs attributable to CO_2 emissions costs in each quarter.

Figure 2-10: Contributions of CO_2 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.

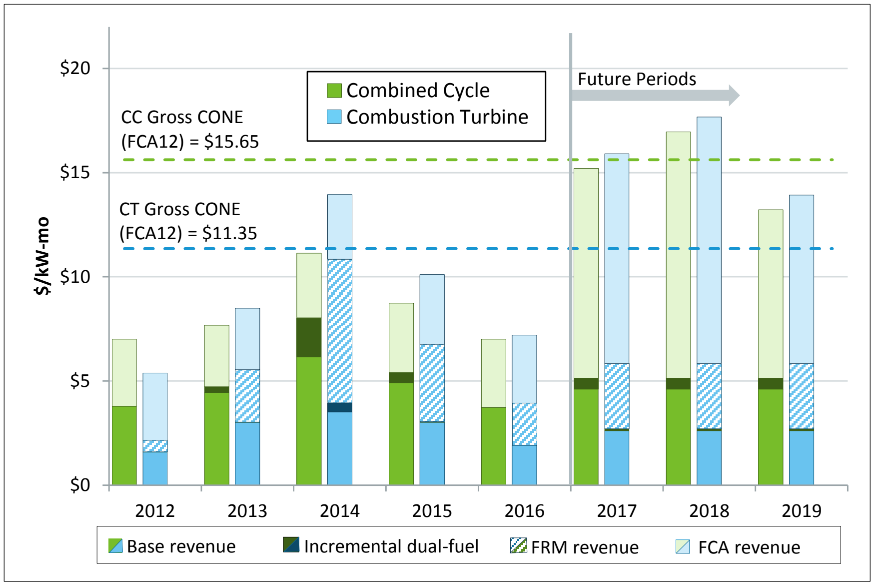
2.2.4 Generator Profitability

New generator owners rely on a combination of net revenue from energy and ancillary service markets and forward capacity payments to cover their fixed costs. Revenue from the FCM, which is conducted three-plus years in advance of the operation year, is a critical component of a developer's decision to move forward with a new project. Given the cost of a new project (CONE, or cost of new entry), developer expectations for minimum capacity revenues will be based on this cost and their expectation for net revenue from the energy and ancillary services markets. In New England, the majority of revenue to support new entry comes from the capacity market. There is an inverse relationship between expected net revenue from energy and ancillary service sales and the amount of revenue required from the capacity market in order to support new entry. As expected net revenue from energy and ancillary service sales decrease, more revenue is required from the capacity market to support new entry. The reverse is also true.

This section presents estimates of the net revenues that hypothetical new gas-fired generation units (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. While 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 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.[50] Figure 2-11 shows the result of the simulations.[51] 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 (AS)) and incremental dual-fuel revenue numbers for years 2012-2016. Estimates of future years' base and dual-fuel revenue are simple averages of these numbers. For all years, the FCA and FRM revenue numbers shown are calculated using the actual payment rates applied to calendar years.

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



The result indicate that if future market conditions remain similar to the previous five years, owners of new gas-fired combined cycle generation units can expect net revenues (not including capacity payments) to average $4.61/kW-month, which increases to $5.13/kW-month for units with dual-fuel capability. Under the same conditions, new combustion turbines can expect net revenue earnings from $3.12/kW-month for single fuel generators to $3.26/kW-month for units with dual-fuel flexibility. With higher capacity factors, combined cycle units can benefit more often from dual-fuel capability than peaking units, 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 asset can also participate in the FRM, in which off-line reserves are procured prior to the reserve season. A forward reserve resource receives revenue from the forward reserve auction, but it foregoes real-time reserve payments and, in most hours where the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve. When the energy price is abnormally high, as in the case of a scarcity event, the forward reserve resource may be dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods. This analysis shows that a new combustion turbine which is designated as an FRM

[50] 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).

[51] The Gross CONE figures for the CC and CT gas fired resources reflect Net CONE values of $10.00/kW-month and $8.04/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales. These values have been filed with FERC and are awaiting final approval.

resource could earn $2.60/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 for four of the 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 FCM auctions. The most recent CONE revisions filed with FERC contain net revenue components of $5.62/kW-month and $3.31/kW-month for combined cycle and combustion turbine units respectively.[52] However, revenue numbers in this range are clearly insufficient to support new entry without the addition of capacity payments to cover the fixed costs of a new gas-fired generator.

Figure 2-11 shows that, prior to 2017, capacity prices were generally too low to incent investment in new gas-fired 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 fact, FCM auction results show that both types of gas-fired generator have been accepted for the capacity commitment periods that cover these years. 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.

2.3 Demand Conditions

Consumer demand for electricity is one of the key drivers of wholesale electricity prices in New England. 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 14,480 MW in 2015 to about 14,140 MW in 2016, a decline of 2.4%. Figure 2-12 below shows the average hourly load, by year and quarter from 2012 through 2016.[53] 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 for quarter 1, green for quarter 2 etc.).

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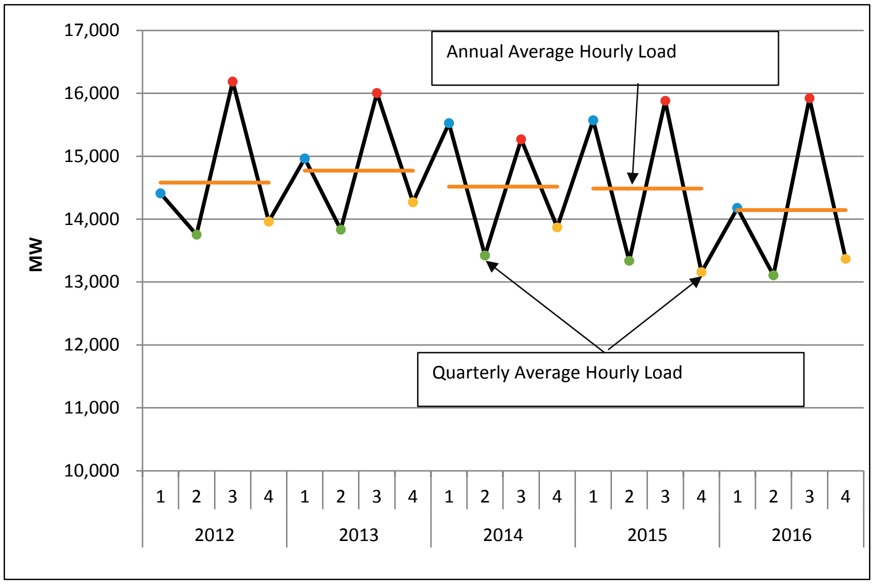
52 These revenue components include "Pay for Performance" (PFP) revenue which this study does not.

53 Load represents the wholesale electricity load for the New England area.

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



The trend of declining load can be explained by three main factors; seasonal temperature differences year-on-year, the increase in energy efficiency programs, and the strong growth in behind-the-meter solar generation.[54] The 490 MW weather-normalized load reduction in 2016 compared to 2013, can be attributed to the growth in the region's energy efficiency programs.

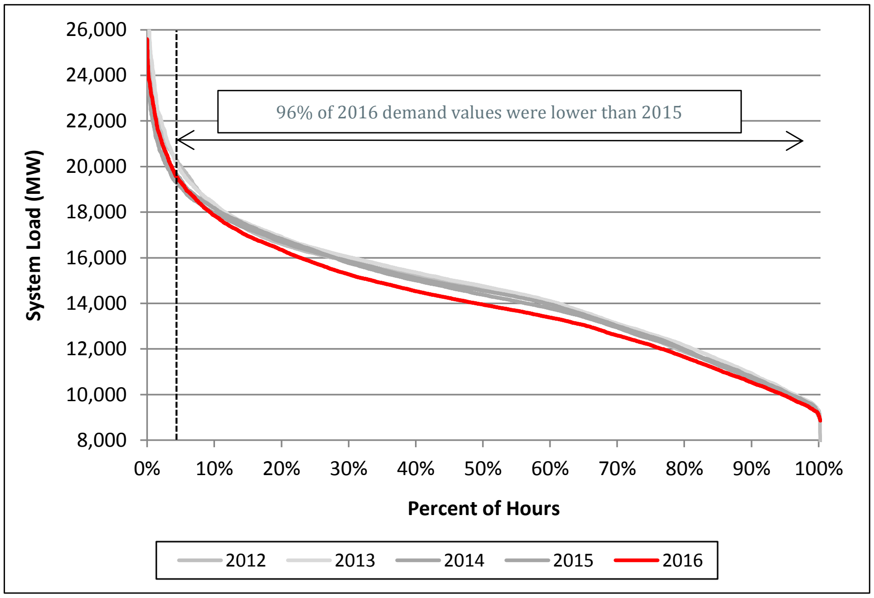
First quarter load was significantly lower in 2016 than in the previous four years as a result of higher temperatures. For example, the average temperature was 34 °F during first quarter of 2016, ten degrees higher than average temperature of 24°F for the first quarter of 2015. Consequently, 2016 first quarter average load decreased by nearly 1,400 MW (from 14,170 to 15,570 MW) compared to the first quarter in 2015.

With the exception of 2014, load is typically the highest during the third quarter (red dots). In 2014, average Q3 temperatures were 2 degrees lower compared to 2015 and 3 degrees lower compared to 2016. In 2015 and 2016, average load of the third quarter was similar due to similar weather conditions. Temperatures averaged 72 °F in the third quarter of 2016, comparable with average temperatures of 71 °F in the third quarter of 2015. Second quarter and fourth quarter average hourly load (green and yellow dots, respectively) were lower in 2015 and 2016 compared with 2012 to 2014. This change was primarily as a result of temperature differences and the growth of energy efficiency programs.

The actual system load for New England over the last five years is shown as load-duration curves in Figure 2-13. The load duration curves order hourly load levels highest to lowest, and show the relationship between load levels and the frequency the load levels occur.

[54] Total nameplate capacity of solar generation installed in New England is estimated at 1,770 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 420 MW. See Final 2016 PV Forecast Details, https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf

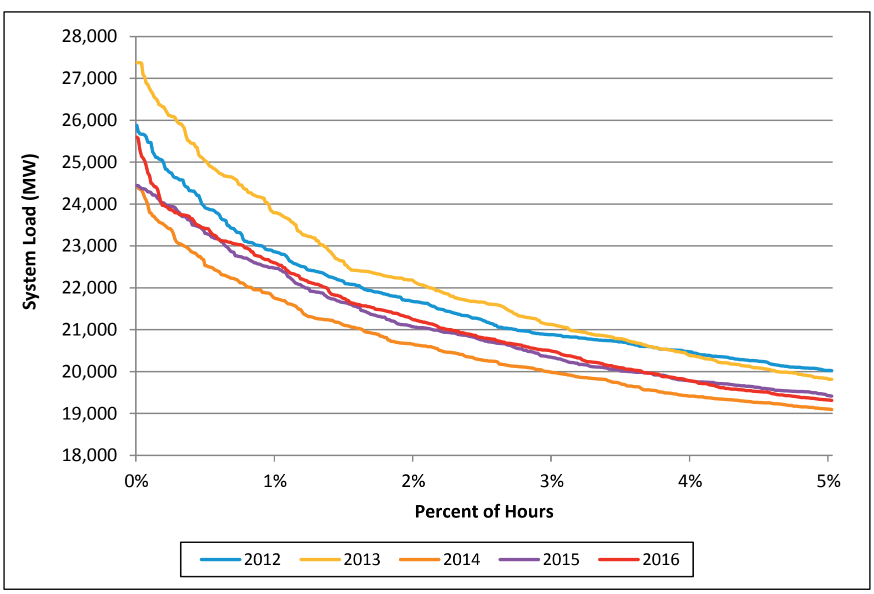
Figure 2-13: Load Duration Curves



The separation of the 2016 curve (red series) for the preceding four years is evident from the Figure 2-13 above. On average, load was 2.4% lower in 2016 compared with 2015. Load in 2016 was also below the levels for 2015 in 96% of the hours indicating that the reduction was systematic across the vast majority of hours.

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 2-14. It is evident that the peak load of the earlier years of 2012 and 2013 is significantly higher than the peak load of later years, 2014 to 2016.

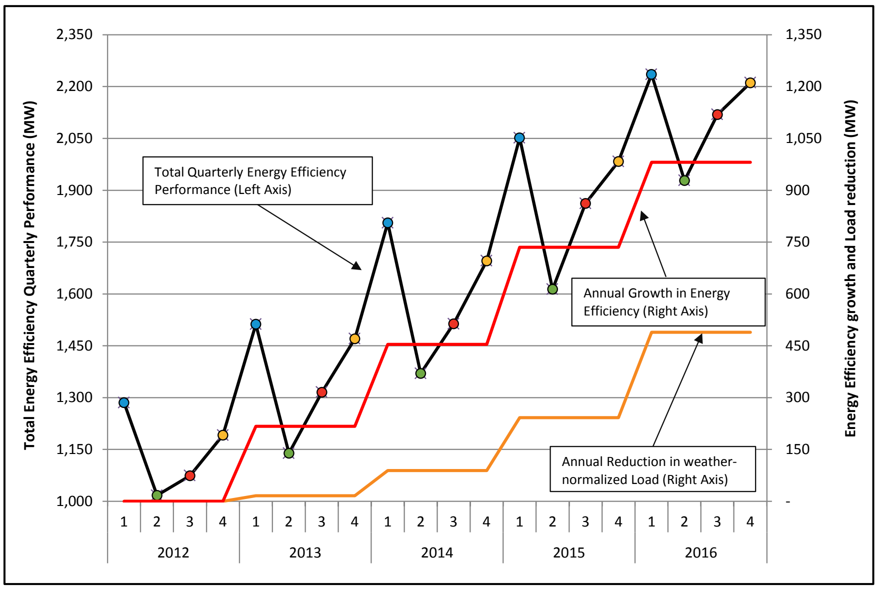
Figure 2-14: Load Duration Curves - Top 5% of Hours



The contributing factors of lower peak load during the past few years are milder summers, the growth in state-sponsored energy efficiency programs[55], 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. The energy efficiency and DG programs provide continuous demand reduction during summer peak hours ending 14 to 17 and during winter peak hours ending 18 to 19.

The growth in the energy efficiency programs that participate in the FCM (trend and weather-normalized annual average load reduction value) during the period 2012 to 2016 is shown in Figure 2-15 below. The load reductions attributable to energy efficiency and distributed generation is reported using the monthly average demand reduction values (DRV) methodology prescribed in the FCM rules.[56]

Figure 2-15: Growth in Energy Efficiency and the Reduction in Load



The graph shows that load reductions attributable to energy efficiency increased significantly over the past five years. The first quarter load reductions are higher from savings as a result of lighting and heating installed measures. Third quarter load reductions values (red dots on the black line) grew from 1,074 MW in 2012 to 2,119 MW in 2016, an increase of 1,045 MW. On an average annual

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55 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.

56 Demand Reduction Value (DRV) is monthly average performance MW of all aggregated energy efficiency measures contributing to the Resource's performance. For distributed generation measures, the performance is the monthly average of the directly measured generator output during the summer on-peak performance hour's end of 14 to 17 and winter on-peak hours of 16 to 17. Energy Efficiency and Demand Response Distributed Generation measures are aggregated to On-Peak and Seasonal-Peak resources that participate in Capacity market of ISO New England. Total performance of Demand Response Distributed Generation accounts for only 5% of energy efficiency performance. Demand Response Distributed Generation includes registered behind-the-meter solar generation. The amount of solar generation included in Demand Response Distributed Generation is a very small portion of total behind-the-meter solar generation installed in New England.

basis, the total growth in load reductions was 981 MW over the five-year period (red line). The growth in energy efficiency corresponds to a trend of reduced annual average weather-normalized load. Since 2012, annual weather-normalized load has decreased by about 490 MW.

2.3.2 Reserve Requirements

All bulk power systems, including the system in New England, need reserve capacity in order to respond to contingencies. ISO New England's operating-reserve requirements are designed to protect the system from the impacts associated with the loss of generation or transmission equipment.[57] 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. Between 25% and 100% 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 requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute nonspinning 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.[58] The replacement reserve requirement adds 160 MW to the total reserve requirement in the summer and 180 MW to the requirement in the winter.

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 requirements are shown in Figure 2-16 and average annual local reserve requirements for each local reserve zone are shown in Figure 2-17.

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[57] 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

[58] 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.

Figure 2-16: Average System Reserve Requirements

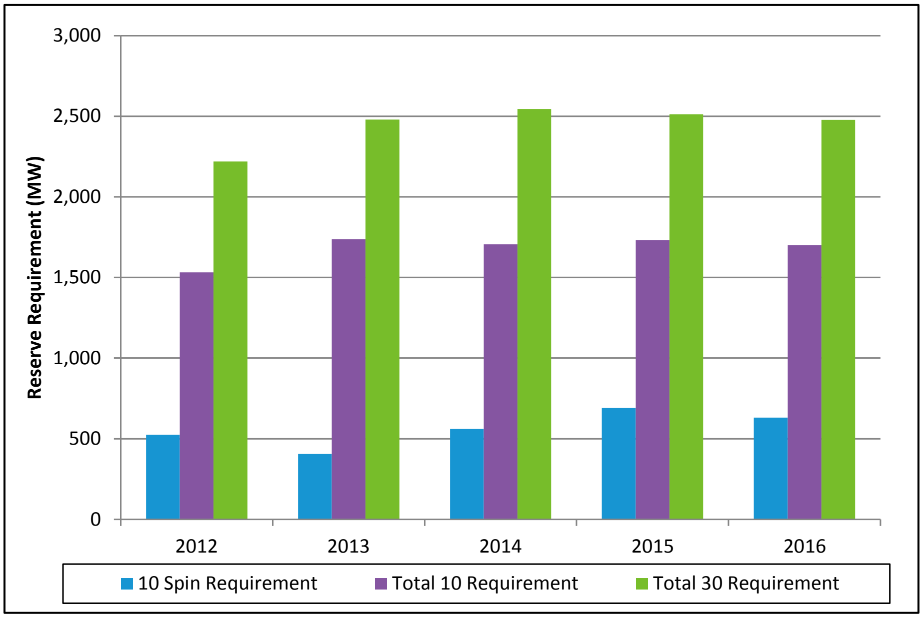
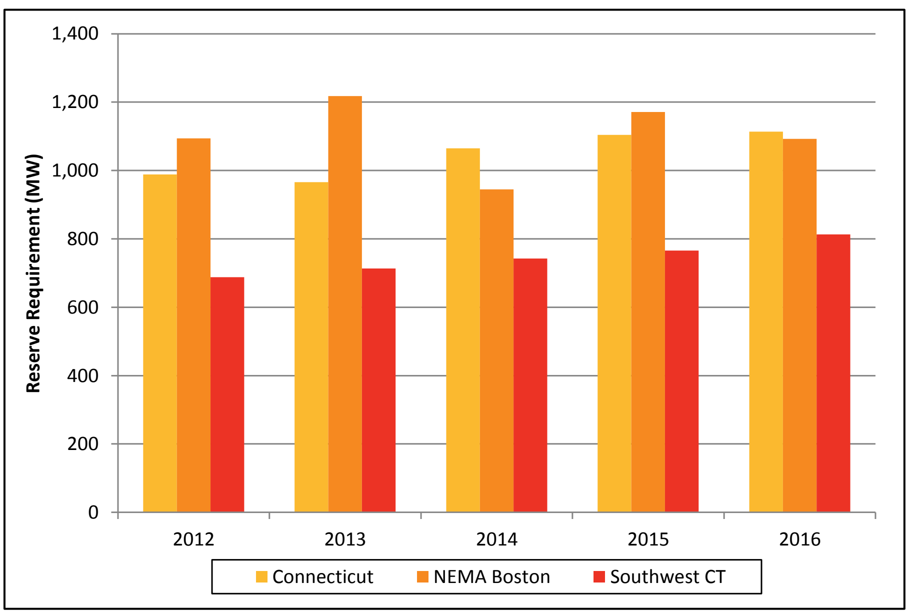


Figure 2-17: Average Local 30-Minute Reserve Requirements



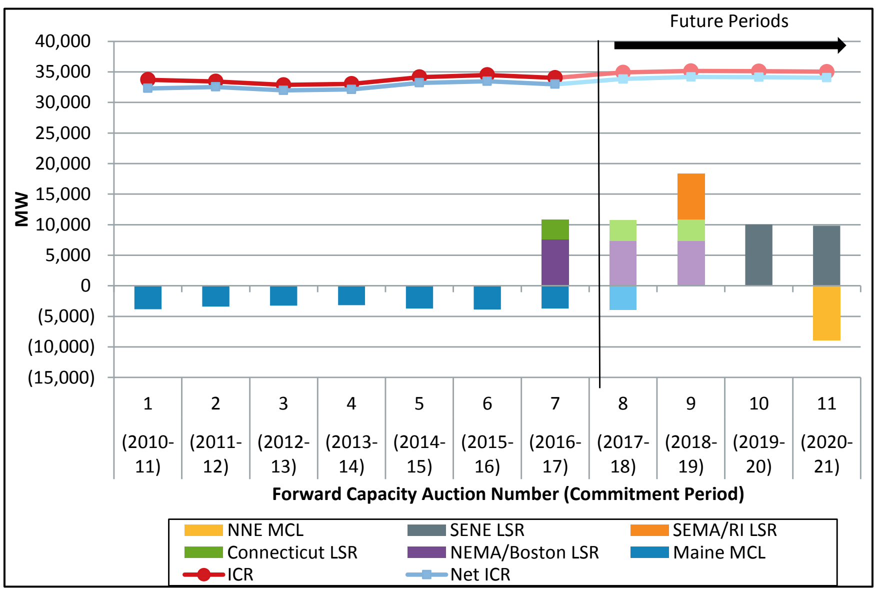
The local reserve requirements vary from year to year as the import capability into each local reserve zone varies with changing system conditions. However, rules changes have also had an impact. In July 2012, ISO New England increased the total 10-minute reserve requirement by 25% to account for generator 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 2013 auditing changes altered the way the ISO calculates Claim 10 and Claim 30 values for fast-start generators.[59] The altered auditing practices take 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. In 2013, the total reserve requirement increased due to the addition of the replacement reserve requirement.

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. The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than once every ten years. Trends in system capacity requirements, ICR and Net ICR, since the inception of the forward capacity market are shown below in Figure 2-18. It also shows the trends in local export limits, maximum capacity limits (MCLs), and local sourcing requirements (LSRs).

The system ICR and Net ICR are represented as line series. Net ICR, which accounts for the capacity benefit of the Hydro Quebec tie-lines, is the target capacity to be procured in the forward capacity auctions. The LSRs, which are the amounts of capacity to be procured within import-constrained zones, are represented by a positive bar. The MCLs – the maximum capacity to be procured within export-constrained zones - are represented by negative bars.

Figure 2-18: ICR, NICR, Local Sourcing Requirements, and Maximum Capacity Limits



The Net ICR for the Forward Capacity Auction held in 2016 (FCA 10) and 2017 (FCA 11) has decreased compared to 2015 (FCA 9). In FCA 9, the Net ICR value was 34,189 MW. The impact of behind-the-meter solar was integrated into the ICR methodology for the first time in FCA 10, and

[59] 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.

reduced loads by an estimated 370 MW.[60] The total decrease in Net ICR from FCA 9 to FCA 10 was 38 MW, down to 34,151 MW. The Net ICR declined to a value of 34,075 MW in FCA 11.

Certain load zones can be mapped together as import-constrained capacity zones. If these zones are modeled as import-constrained, then the FCA clearing prices can potentially be higher than the rest of the system. In FCA 10, the SEMA/RI and NEMA/Boston capacity zones were combined into the Southeastern New England (SENE) capacity zone. The SENE zone was created due to limited capability to import power into the region.[61] The LSR in SENE was 10,028 MW.[62] The SENE capacity zone was modeled again in FCA 11, and had an LSR of 9,810 MW.

Export-constrained zones are also modeled because the amount of power generated within the zone may be unable to reach the rest of the system when needed. The price paid to resources in these modeled zones can potentially be lower than the rest of the system. Northern New England (NNE) was considered as an export-constrained zone for the first time in FCA 10. The NNE zone consists of the Maine, New Hampshire, and Vermont load zones. The MCL was greater than the sum of existing qualified capacity and proposed new capacity. Therefore, the zone was not considered to be export-constrained in FCA 10. In FCA 11, the NNE capacity zone was considered to be an export-constrained area. The MCL associated with the NNE export constrained zone was 8,980 MW.[63]

2.4 Imports and Exports (External Transactions)

New England exchanges power with its neighboring control areas of New York, Hydro Québec, and New Brunswick over the transmission lines that interconnect the region. Participant companies can buy power in one region and sell it in another using an external transaction. Transactions can be submitted to the day-ahead or real-time markets. A participant can profit by buying at a low price in one region and selling to another at a higher price – capturing the market price spread between the two regions. Companies also use external transactions to fulfill their own contractual obligations to buy or sell power, such as a power purchase agreement. External transactions serve an important purpose in competitive wholesales markets. They allow each ISO to serve demand at lower production costs than could be achieved using only native supply, by displacing the need to use more expensive native generation when imported power is available at lower cost.

External transactions to import power to New England or export to another region 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 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 settlements only account for the leg of the transaction that occurs in the New England market. The corresponding obligation at the other side of the interface is settled separately by the neighboring area.

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60 See https://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf for more information on methodology behind calculating Net ICR.

61 For more information see Market Rule 1, Section III.12.4 (b).

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

63 For more information on FCA 11 requirements see: https://www.iso-ne.com/static-assets/documents/2016/11/icr_filing_for_2020-2021_ccp.pdf

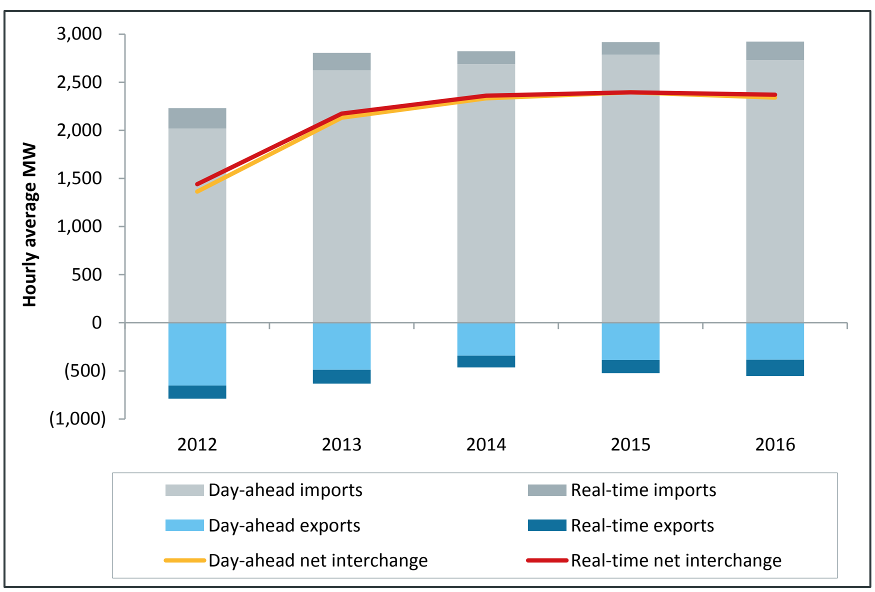
New England's six external nodes are listed in Table 2-1 below, along with the common "interface name" used throughout this report. The table also lists the import and export total transfer capacity (TTC) ratings of the transmission facilities associated with the external node. The import and export ratings of these facilities may be different due to how power transfers in each direction impact various reliability criteria. Note that there are multiple interfaces that interconnect with the New York and Hydro Québec systems.

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 2016, New England remained a net importer of power. Net imports during real-time totaled 20,809 GWh which equates to 2,369 MW imported, on average, each hour. Total net interchange was only 1% lower than 2015 and has been relatively steady since 2014. The decrease in net interchange corresponded with a 6% increase in export transactions over the prior year. The hourly average net interchange amounts in the day-ahead and real-time markets for each year 2012 through 2016 are shown in the line series of Figure 2-19 below. The figure also charts the annual 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 2-19: Day-Ahead and Real-Time Pool Net Interchange

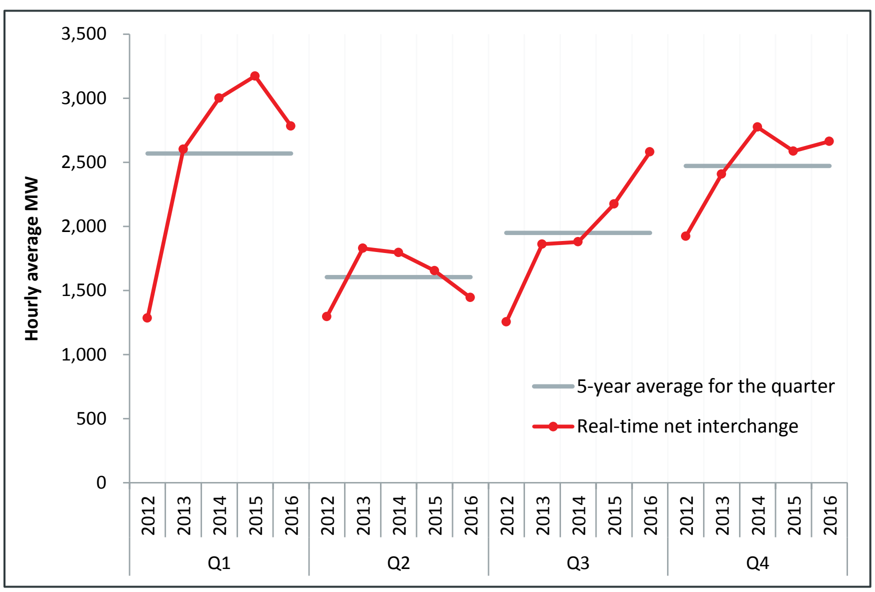


The average real-time net interchange has been relatively constant for the past three years and mostly unchanged for 2016 as shown by the red line series in Figure 2-19. However, real-time energy exports did increase by 6%, or 31 MW per hour on average, compared to 2015. The increase in export transactions occurred primarily at the New York North interface as well as the Cross Sound Cable interface. The close proximity of the day-ahead net interchange (orange) and real-time net interchange (red) line series in Figure 2-19 highlights that day-ahead market outcomes across the external nodes do, on average, closely predict the real-time scheduled flows.[64] 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 in-bound and out-bound schedules nearly offset each other. In aggregate, real-time net interchange was greater than day-ahead by 1% during 2016 (*i.e.*, slightly more 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 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 summer loads. Higher energy prices present better opportunities to profit by delivering power to New England. Participants may also adjust their contractual obligations based on seasonal demand levels or production capacity.

The hourly average real-time pool-wide net interchange value is plotted by calendar quarters for each year 2012 through 2016 in Figure 2-20 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 reference, the five-year averages for each quarter are shown with the gray line series.

Figure 2-20: Real-Time Pool Net Interchange by Quarter



As the quarterly-segmented plots in Figure 2-20 show, there is seasonal fluctuation in the system net interchange, although New England is consistently a net importer throughout the year. The

[64] Virtual transactions cleared at external interfaces in the day-ahead market have been included in the day-ahead net interchange value since they are equivalent to external transactions so far as supply and demand at these nodes.

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 when temperatures, loads, and fuel 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 in Q4 at the start of winter when heating demand once again begins to put upward pressure on natural gas and electricity prices. See Section 3.4.1 for details of fuel input costs.

Relative to 2015, the quarterly average net interchange during 2016 was down in both Q1 and Q2 by 12% and 13%, respectively. Although Q1-2016 was 8% above the five-year average (due to the low Q1 2012 net interchange), the Q1 average is below the more-recent year observations. As discussed in Section 2.2.3, compared to 2015 the average natural gas price was 70% lower in Q1-2016 which in turn corresponded to lower New England power prices (See Section 3.3 on energy prices). The below-average net interchange in Q2 2016 was impacted by a planned outage of Phase II from April 1st through May 30th. In Q3 2016, real-time interchange was up 19% compared to 2015 and 32% above the five-year average. Relative to 2015, the Q3 increase in 2016 net imports equates to 406 MW per hour, on average, of imported supply during the summer months. Half of the increase in Q3 2016 net imports occurred at the New York North interface. As shown in the figures in Section 5.5, the month of August had the highest total volume of negative-priced CTS interface bids and among the lowest volumes of export bids observed for the year. During Q4 2016, net interchange was 3% higher than 2015 and 8% higher than the five-year average for the quarter. The increase in imported energy volumes during Q3 and Q4 2016 are consistent with the year-over-year increases of 17% and 25% in average natural gas prices and 10% and 8% in average Hub LMPs in New England.

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 totaled 17,151 GWh of energy imported, or an average of 1,953 MW per hour in 2016, which was similar to the imported volumes during 2015. The net real-time interchange across the three interfaces with New York (New York North, Cross Sound and Northport-Norwalk) totaled 3,658 GWh of energy imported, or an average of 416 MW per hour in 2016, also similar to 2015 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 is 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 benefits consumers and suppliers alike.

In 2016, total day-ahead and real-time energy payments reflected changes in underlying primary fuel prices, most notably natural gas. Low natural gas prices were reflected in wholesale energy prices, both of which were at their lowest level since the introduction of standard market design in New England in 2003.

Under certain system conditions, suppliers can have local or system-wide market power. If suppliers take advantage of the 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 offers 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, remain reasonably low. However, there are energy supply portfolios that have structural market power in the real-time market in over half of the hours. The energy market has a fairly rich 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 each market.

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 electricity 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 (i.e., 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.[65] 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 benefit to both 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 5, are not explicitly purchased through the day-ahead market. Operating reserves are procured in the forward market for reserves (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, 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 load-serving entities (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 and 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 ten- or thirty-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, 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 if they do not recover their bid-on costs through the LMP.

[65] 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 load-zone LMPs are calculated as a weighted-average of all the nodes within the 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 2016, total estimated energy and NCPC payments declined by about 30% compared with 2015 ($4.2 billion in 2016 compared with $6.0 billion in 2015) and were at their lowest during the 5-year reporting period.[66]

The vast majority of energy and NCPC payments in 2016 were made in the day-ahead market. Energy payments in the day-ahead market accounted for approximately 98% of total energy market payments, and day-ahead NCPC payments accounted for 60% of total NCPC payments. (Section 3.5 discusses NCPC in detail.)

Energy and NCPC payments for each year (in billions of dollars), by market, along with the average natural gas price (in $/MMBtu), are shown in Figure 3-1 below.

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

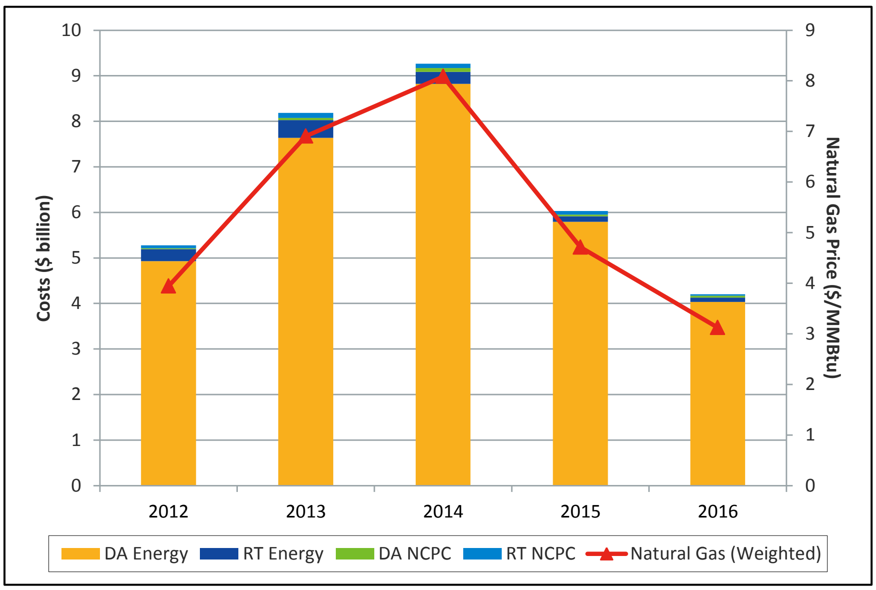


Figure 3-1 illustrates the relationship between natural gas prices and energy market payments; specifically how natural gas prices were the primary driver behind the year-to-year changes in energy and NCPC payments. The drop in the average natural gas price of 34% in 2016 compared with 2015 resulted in the decrease in total energy and NCPC payments of 30% in 2016.

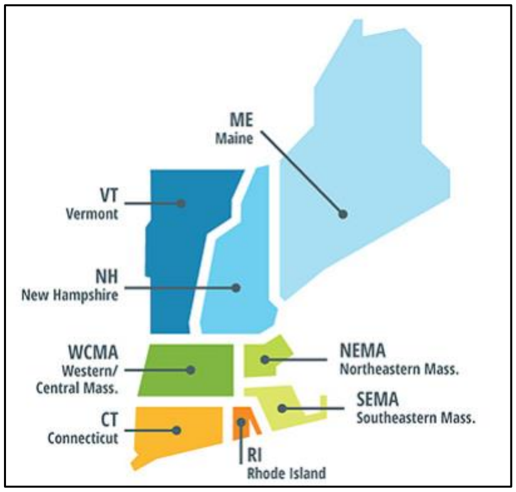
3.3 Energy Prices

Day-ahead and real-time LMPs are presented in this section. Both simple-average and load-weighted prices have been summarized by time period and location. All pricing data are summarized as either annual average or monthly average values. On-peak periods refer to weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation [NERC] holidays); the off-peak period encompasses all other hours.

[66] 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.

Pricing data are differentiated geographically by "load zone" (as shown in Figure 3-2 below) and the "Hub".

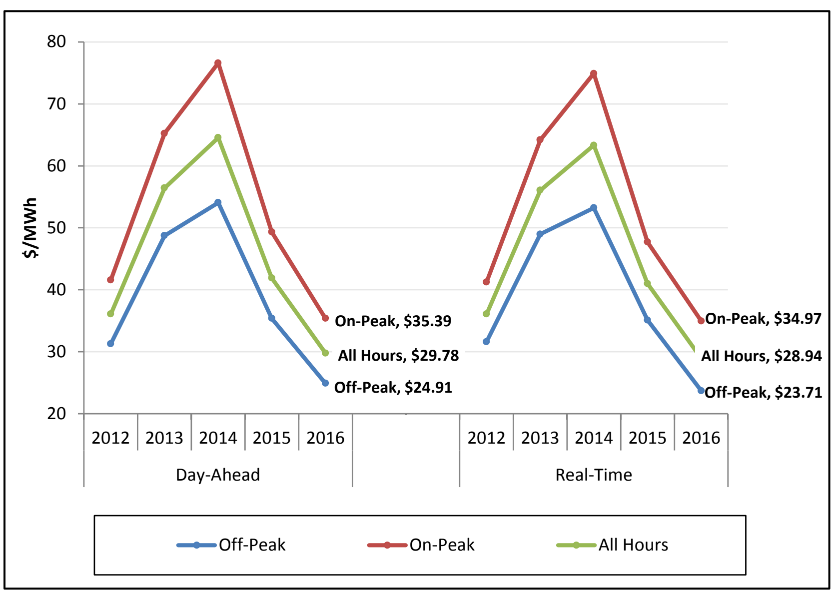
Figure 3-2: ISO New England Pricing Zones



3.3.1 Hub Prices

In 2016 the average Hub price (in all hours) was \$29.78/MWh in the day-ahead market and \$28.94/MWh in the real-time market, down approximately 29% from 2015 prices in both markets.[67] Pricing by time-of-day (i.e., on-peak and off-peak) in 2016 exhibits the same trend when compared with 2015: on-peak prices declined by 28% in the day-ahead market and 27% in the real-time market and off-peak prices declined by 30% in the day-ahead market and 32% in the real-time market. An illustration of energy market price trends, from 2012 to 2016, is provided in Figure 3-3 below.

Figure 3-3: Annual Simple Average Hub Price



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

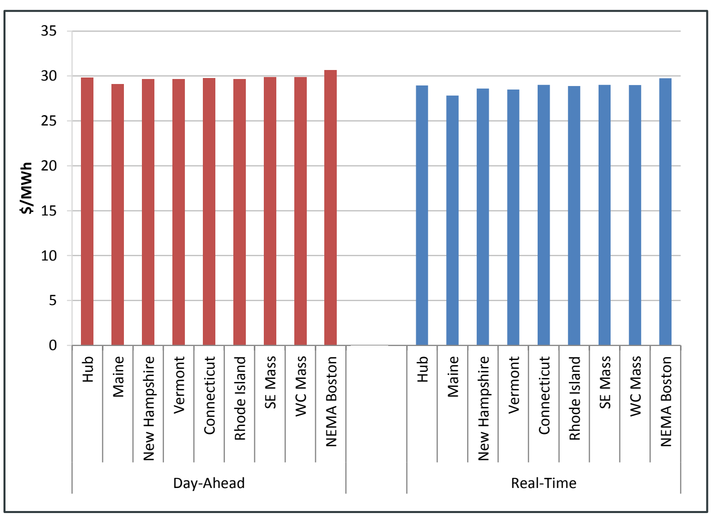
These price changes are consistent with observed market conditions, including input fuel costs, loads, and generating resource operations. Fuel prices declined significantly in 2016, in particular natural gas which declined by 34% compared with 2015. The reduction in natural gas prices, coupled with a warmer-than-normal winter, explains the significant reduction in LMPs for 2016, and led to the lowest day-ahead LMPs since the inception of standard market design in 2003.

Comparing day-ahead to real-time energy market prices for 2016, average real-time prices were slightly less than day-ahead prices: 4.8% off-peak, 1.2% on-peak, and 2.8% overall. This continues a recent trend (2013-2016) of the real-time energy market experiencing slightly decreased prices overall compared with the day-ahead market. A number of factors can influence the relationship between day-ahead and real-time prices. Random, or unsystematic, factors include load forecast error, and unforeseen system contingencies experienced in the real-time market; for example, due to forced transmission and generator outages. More systematic factors that can lead to day-ahead and real-time price separation include: market participants' willingness to pay a premium in the day-ahead market to hedge real-time price risks, ISO operator interventions such as manual out-of-market commitments and adjusted reserve requirements, and modeling differences between the day-ahead and real-time energy markets. The combination of systematic and unsystematic factors, on a day-to-day basis over the course of the year, results in the observed average price differences between the day-ahead and real-time energy markets. Section 3.3.4 of this report discusses "price convergence" (i.e., differences between day-ahead and real-time prices) in more detail.

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.[68] In 2016, 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 for 2016



68 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).

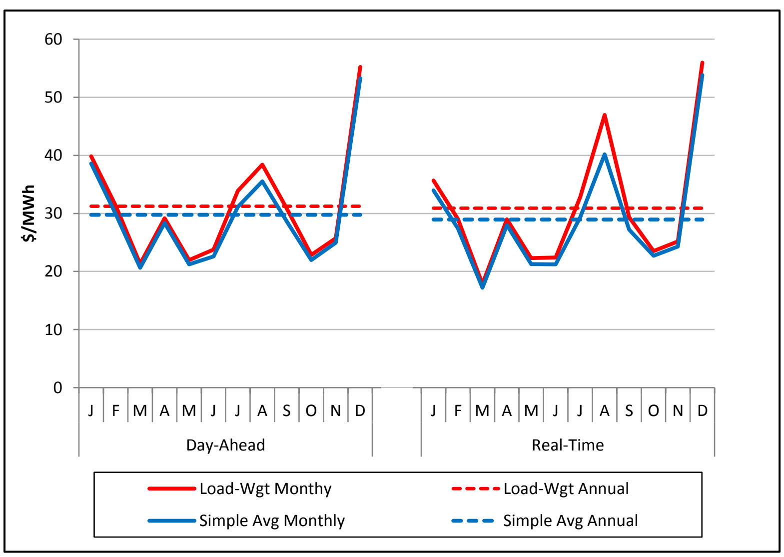
Price differences between the load zones primarily resulted from modest levels of marginal losses and congestion. The average absolute difference between the Hub annual average price and average load zone prices was $0.27/MWh in the day-ahead energy market and $0.37/MWh in the real-time energy market – a difference of approximately 0.9-1.3%. The Maine load zone had the lowest average prices in the region, while the NEMA-Boston load zone had the highest prices in both the day-ahead and real-time markets. Maine tends to be an export-constrained region. As a result, Maine cannot export all of its relatively inexpensive power to the rest of New England because of transmission constraints. Therefore, Maine prices diverge from the rest of the system prices. Conversely, NEMA-Boston is import-constrained at times, with the transmission network limiting the ability to import relatively inexpensive power into the load zone. Maine's prices averaged $0.70/MWh and $1.13/MWh lower than the Hub's prices during the year for the day-ahead and real-time markets, respectively. NEMA-Boston's average prices were slightly higher than the Hub's prices, by $0.88/MWh and $0.80/MWh, respectively.

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 wholesale load pays for energy.[69] The amount of energy consumed in the ISO's 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 will tend to be greater than simple average prices.

Monthly load-weighted average prices for 2016, and for comparative purposes, simple average prices are provided in Figure 3-5.

Figure 3-5: Load-Weighted and Simple Average Hub Prices for 2016



[69] 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.

The simple average electricity prices in 2016 were less than the load-weighted average prices. The difference ranges from approximately 3% to 17%, 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/household consumption patterns. For example, hours with low electricity consumption tend to occur overnight, when business and household activity is low and summer cooling needs are minimal. For 2016, load variability during the day had the least impact on the average prices paid by wholesale consumers in April, when simple and load-weighted prices differed by just 3% in the day-ahead market and 3.5% in the real-time market. 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 9% (July for the day-ahead market) and 17% (August for the real-time market).

Monthly load-weighted prices across load zones over the past five years in the day-ahead and real-time markets are shown in Figure 3-6 and Figure 3-7 below. The black line shows the average annual load-weighted Hub price and highlights the degree of variability in prices throughout the year.

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

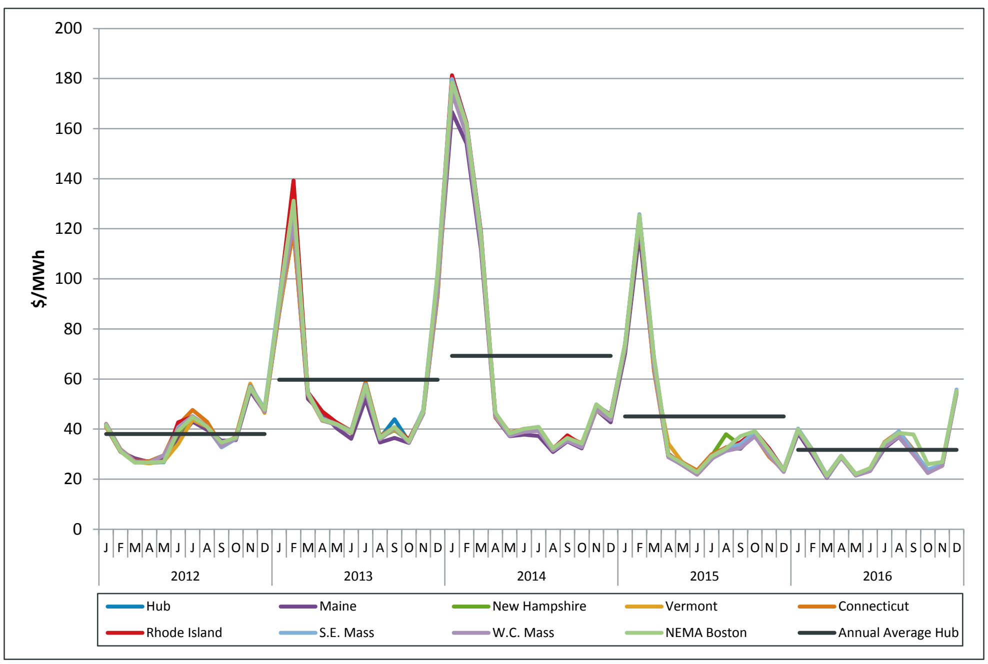
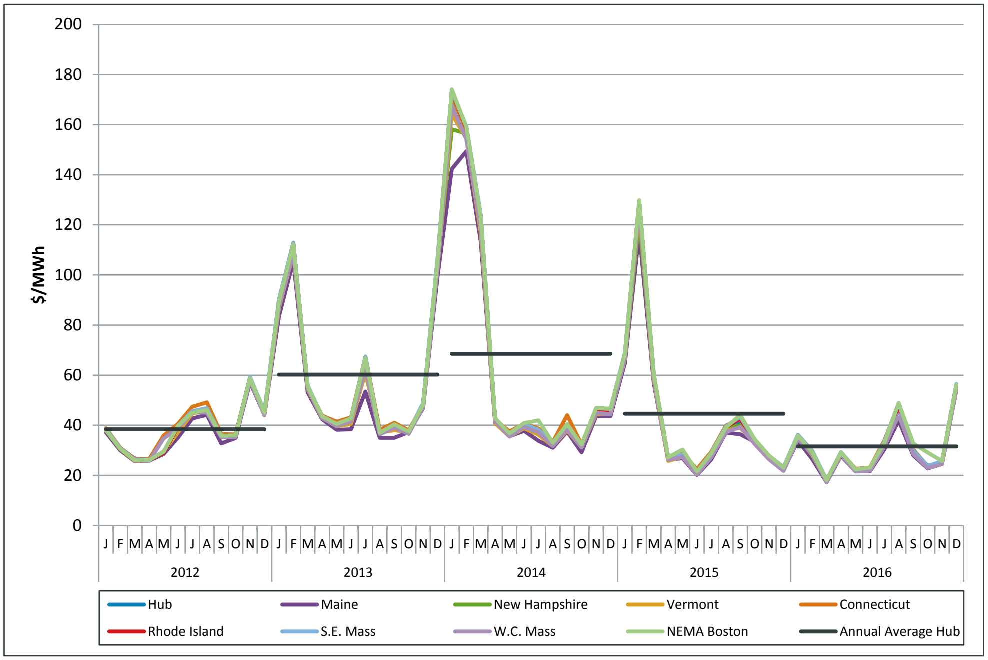


Figure 3-7: Real-Time Load-Weighted Prices



Load-weighted energy prices by load zone from 2012 to 2016 indicate a pattern that varies considerably by year and month, but not by load zone. As described above, a primary driver of material price differences between load zones is congestion and the ISO New England control area has not experienced significant congestion on internal interfaces in recent years. Extreme pricing in the months of January and February has occurred over the past three years (2013-2015) 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 periods with high fuel prices, and summer months with elevated load variability, have the highest load-weighted prices.

3.3.4 Energy Price Convergence

This section describes how price convergence (the extent to which real-time prices converge with day-ahead 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.

The energy market is based on a two-settlement approach that is standard in electricity and commodity forward markets. That is, a supplier can take on an obligation to produce energy in the day-ahead *forward* market at a clearing price (i.e. the day-ahead LMP). Likewise, a load serving entity can take on an obligation to consume 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, it would only be willing to take on a day-ahead obligation at the equivalent of the real-time price, or otherwise it would wait until real-time to produce electricity. Therefore, in an efficient market, prices in the day-ahead and real-time market should converge and make the supplier indifferent (no worse off) between selling in the day-ahead and real-time market. Stated differently, the offers of suppliers and load serving entities in the day-ahead energy market should reflect their expectations of real-time conditions and pricing outcomes.

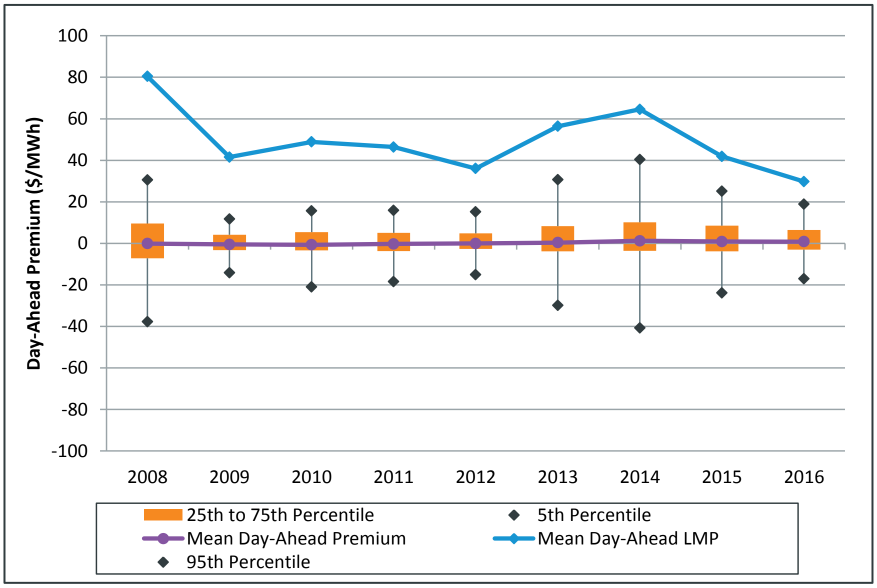
Creating a production schedule in the day-ahead market that is consistent with real-time conditions is also important from a system operations and reliability perspective. Generators have operational and fuel procurement constraints that can be better managed when the obligation is received in the day-ahead 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. 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.

There are a number of practical issues that need to be considered when interpreting price convergence as a measure of market efficiency; in other words, the ability of the day-ahead market to predict real-time conditions. 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, reserve pricing, load forecast error, forced outages, or other unforeseen system conditions. Also, obligations in either market have different risks and so a participant may have a preference for one market over another. For example, a supplier with a gas-fired generator may exhibit a preference for the day-ahead market in order to better manage its ability to buy and schedule natural gas, particularly when the gas network is stressed and intra-day gas volume and price uncertainty are high. Similarly, a load serving entity may be averse to exposure to more volatile real-time prices and prefer to purchase 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, arbitrage opportunities exist especially when price differences are predictable and measurable. Virtual transactions can be used to take advantage of those arbitrage opportunities and can help converge prices to the efficient level. Virtual transactions add to the market's liquidity, which is especially needed when physical producers and consumers may be reluctant to change behavior to converge prices. Virtual transactions are discussed in more detail in Section 4.

To begin the analysis of price convergence, Figure 3-8 below shows the distribution of the day-ahead price premium and the mean (average) day-ahead LMP from 2008 through 2016. Data are included over this extended period because a non-trivial increase in NCPC charges in 2010 coincided with a reduction in virtual transactions.

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



In 2016, the mean day-ahead price premium was $0.84/MWh. This is down from $0.90/MWh in 2015. In other words, in 2016, a generator could have made $0.84/MWh more by selling into the day-ahead market in every hour versus the real-time market (not accounting for the impact the sale may have on the day-ahead price). In half of the hours in 2016, the price difference was between -$3.02 and $6.52/MWh. Since 2010, the interquartile range (the orange box representing values in the 25th percentile to 75th percentile range, or the middle 50%) has fluctuated, increasing from $7.35 in 2009 to $13.82 in 2014, and then decreasing to $9.54 in 2016. 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 generators with different heat rates is more pronounced when gas prices are higher.[70]

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 3-9 below. The median is shown, as opposed to the mean, to account for outliers that result from dividing by a very low day-ahead LMP.[71]

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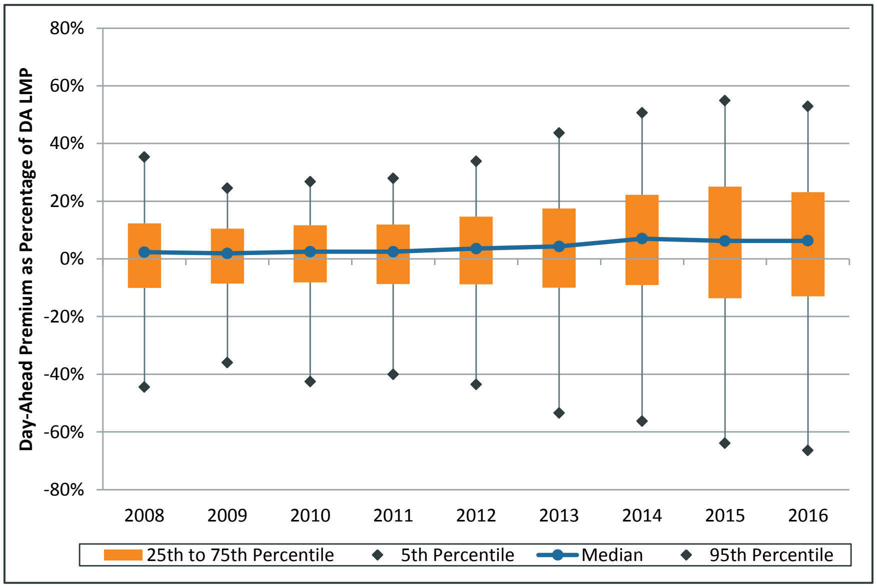
[70] For example, assume a gas-fired generator with a heat rate of 7 MMBtu/MWh is marginal during period 1 and period 2 in the day-ahead market. Also assume that a difference gas-fired generator with a heat rate of 10 MMBtu/MWh is marginal in the real-time market during the corresponding periods. If 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.

[71] 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.

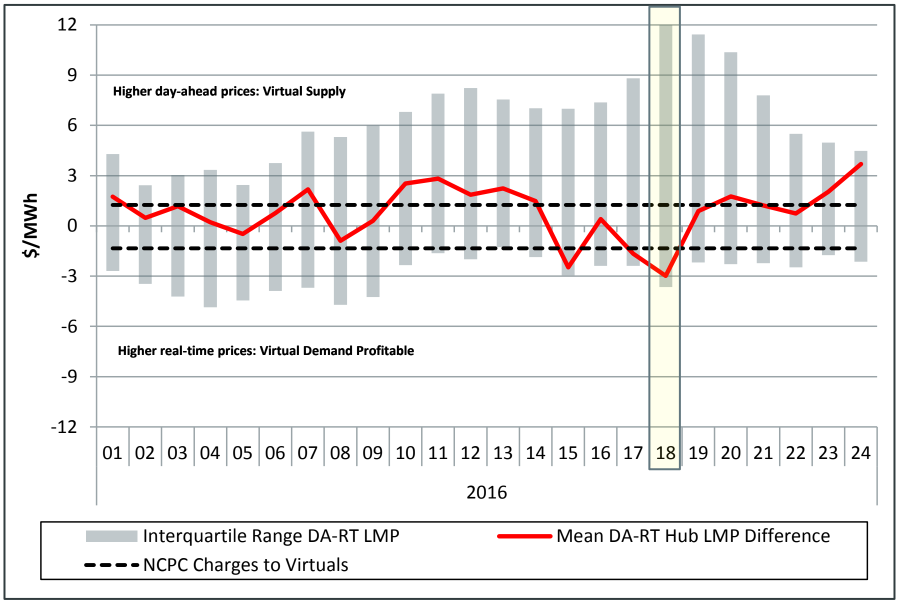
Figure 3-9: Day-Ahead Hub LMP Premium as Percent of Hub LMP



The median day-ahead price premium, as a percentage of the day-ahead LMP, has increased since 2008. In 2016, the median day-ahead price premium as a percentage of the day-ahead LMP was 6%; in 2008 this number was 2%. 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. A wide range of factors can drive the differences between day-ahead and real-time prices. As discussed above, 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 3-10 below, which shows average hourly trends in the day-ahead and real-time price difference in 2016, together with average NCPC charges. The gray bars show the interquartile range (the middle 50%) of day-ahead to real-time price differences. The red 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 red line falls between the two dashed-black lines, on average, neither virtual supply nor demand is profitable as the NCPC charges are greater than the day-ahead to real-time price difference.

Figure 3-10: Hourly Day-Ahead to Real-Time Price Differences and NCPC Charges in 2016



A couple of interesting observations can be made from Figure 3-10. First, the mean price difference is being significantly influenced by outliers, particularly during HE 15 through 20. This can be seen in the position of the red line within the interquartile range. For example, in HE 18 (highlighted above), the mean price difference is close to the 25th percentile of price differences (i.e. the red line is close to the bottom of the gray bar). Although in most of the 365 HE 18 observations during the year there is a day-ahead price premium, on average the real-time price is higher. In the case of the 365 HE 18 observations, just five hours that would be least profitable for a virtual transaction (five outliers), are significantly depressing the mean. In other words, a virtual supplier that placed virtual supply bids in HE 18 would be profitable most of the time, but if they cleared virtual supply every day during HE 18, they would be unprofitable. Therefore, a virtual participant could take advantage of systematic differences in price if they avoid placing bids or offers in the same direction in the most extreme hours.

Second, Figure 3-10 shows that in some hours it is not profitable for a virtual participant to help converge prices. For example, in hours ending (HE) 2 through 6, the average gross profit to be made from a virtual demand bid is less than the NCPC costs it would be charged. This removes the incentive for a virtual participant to arbitrage these cost 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 response to the increase in price divergence occurring between 2008 and 2016, the IMM recommends a review of the NCPC charge allocation rules. Related to our recommendation we note that in January 2017 the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking (NOPR) regarding uplift cost allocation. More specifically, FERC proposed that uplift cost allocations to deviations that are inconsistent with cost causation be changed to better reflect the transactions that are reasonably expected to have caused the costs.[72]

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 have been shown to 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)
- System events (section 3.4.6)
- Reliability commitments (section 3.4.7)
- Congestion (section 3.4.8)
- Marginal resources (section 3.4.9)

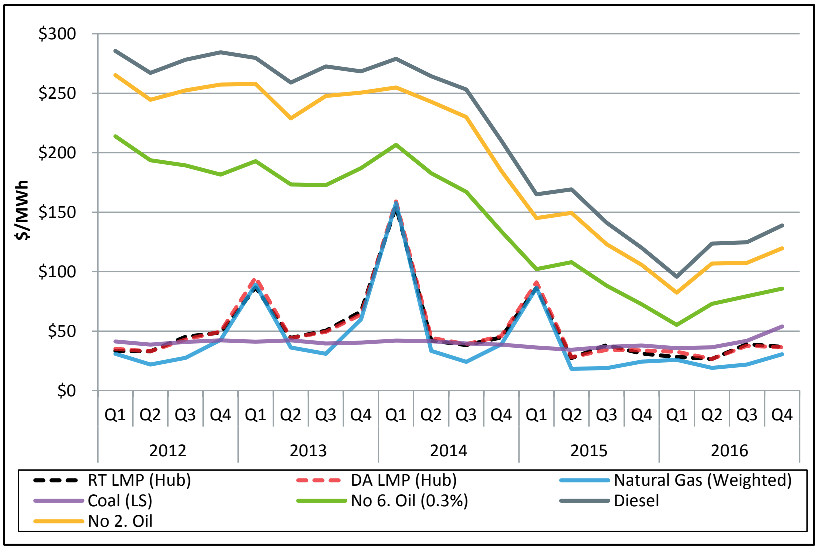
3.4.1 Generation Costs

As discussed later in Section 3.4.9 below (Marginal Resources), 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 operating costs of a typical natural gas-fired generator.

Quarterly average day-ahead and real-time LMPs, alongside the generation (variable production) costs of various fuel types assuming standard heat rates, are illustrated in Figure 3-11 below. The differences between electricity price (dotted lines) and fuel price is the average energy market spread for each generation type based on the characteristic resource for that generation type.

[72] *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Notice of Proposed Rulemaking, 158 FERC ¶ 61,047 (2017).

Figure 3-11: Estimated Generation Costs and LMPs during Peak Hours



Day-ahead and real-time electricity prices are, on average, closely correlated with the estimated costs of operating a natural-gas fired generator. During the summer months, gas generators typically earn higher margins (commonly referred to as spark spreads) compared with the winter months. For example, note the differences between Q1 and Q3 in 2016. Higher demand levels during the summer months require running less efficient gas generators and/or generators that burn more expensive fuels. This leads to a higher price being set than the generation cost of the proxy combined-cycle gas turbine with a heat rate of 7.8 MMBtu/MWh.

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.[73]
- An aging and declining fleet of oil and coal nuclear 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 the 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

[73] 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 2016, oil-fired plants produced 0.5% of electricity consumed in New England. Approximately 49% 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.

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 units are dispatched more frequently.

One of the challenges identified in the ISO's Strategic Planning Initiative was the region's reliance on generators fueled by natural gas.[74] The ISO has undertaken a number of projects aimed at improving reliability through better generator performance and fuel assurance and has been, or is addressing, the problem through the following initiatives:

- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design
- Introduction of Winter Reliability Programs, which will be needed until PFP becomes fully effective in 2018
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generation resources with the operating personnel of the interstate natural gas pipeline companies serving New England
- 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 the introduction of 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 the natural gas price from 2012 to 2016 are shown in Figure 3-12 by quarter. Given the recent history of the highest natural gas and electricity pricings occurring in the first quarter of the year, the first quarter is shown separately from the remainder of the year.

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

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

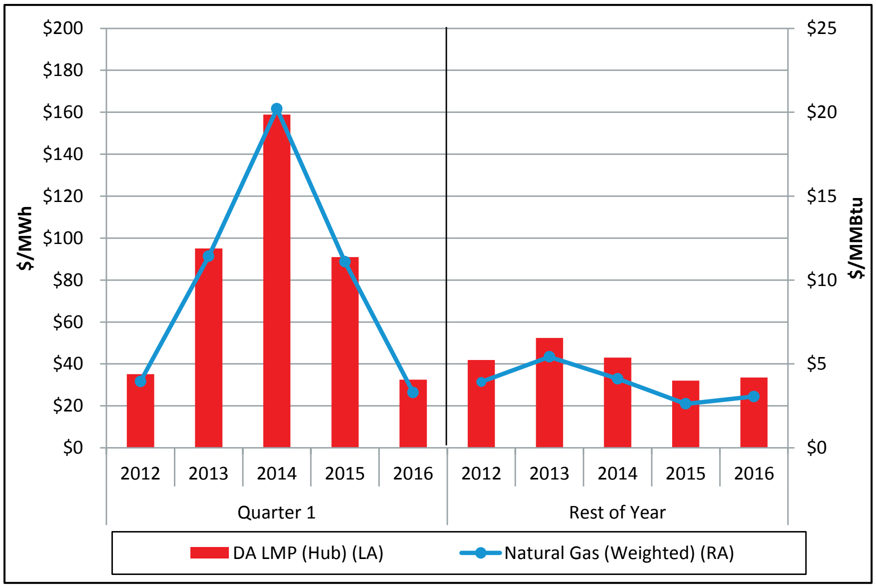
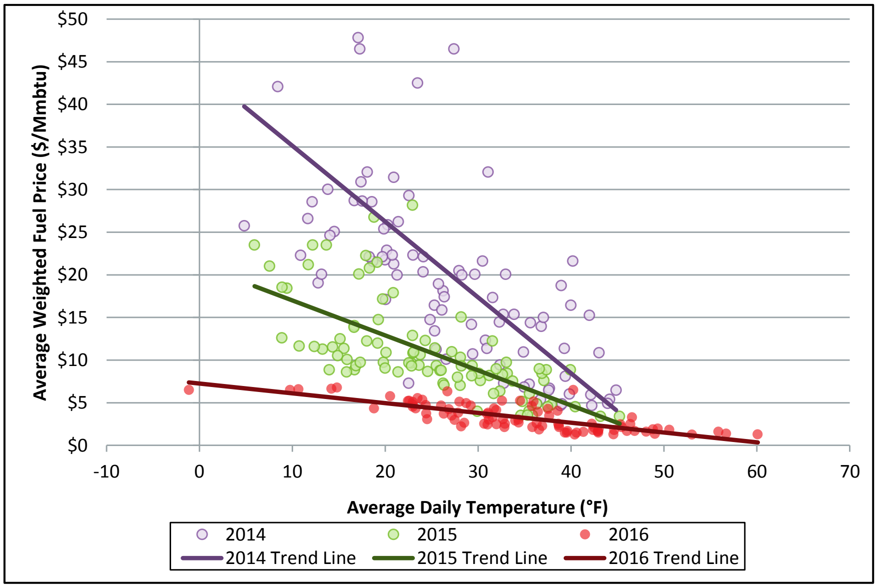


Figure 3-12 shows that during the first quarter of 2016 natural gas and electricity prices were significantly lower than the preceding three years and approximated 2012 levels. This in turn led to lower average LMPs in 2016. The combination of low natural gas prices through 2016 and a warmer-than-usual winter led to the lowest day-ahead LMPs over the same period.

In the first quarter of 2015, natural gas prices averaged $11.09/MMBtu, 70% higher than the first quarter of 2016 price of $3.30/MMBtu. In addition to low natural gas prices during the Q1 2016, average annual gas prices in 2016 were at their lowest values in 16 years (for which gas pricing data was available to us).

Within each quarter there is variation in natural gas prices. When temperatures are low during the winter, generators must compete for natural gas 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 the first quarters of 2014, 2015, and 2016 is illustrated in Figure 3-13. The observations and trend line for Q1 2016 are represented in red, 2015 in green, and 2014 in purple.

Figure 3-13: Daily Temperatures and Natural Gas Prices in Q1



The trend lines in Figure 3-13 illustrate a negative correlation between gas prices and temperature; the lower the temperature the higher the price. The graph illustrates two trends. First, lower average gas prices in 2016 were driven by a warmer-than-usual winter (and lower natural gas demand). The mean temperature in Q1 2016 was 34° F, compared to 24° F in 2015 and 27° F in 2014. Second, gas prices remained relatively stable in 2016 compared to 2014 and 2015. Even on days with similar temperatures, natural gas prices in 2016 were significantly lower than the preceding two years. Take for example gas prices when the daily average temperature was about 10°F. In Q1 2016, the gas prices averaged about $6.50/MMBtu between temperatures of 8-12°F. For the same temperature range, 2015 prices averaged $16.50/MMBtu and 2014 prices averaged $43/MMBtu.

3.4.2 Supply-Side Participation

Throughout 2016, a large percentage of the supply (importers, generators) offering into the day-ahead and real-time market 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, or the unwillingness to cycle (on and off) a generator. As a result, on average, only a small portion of the total supply clearing each day continues to be economically dispatched based on price.

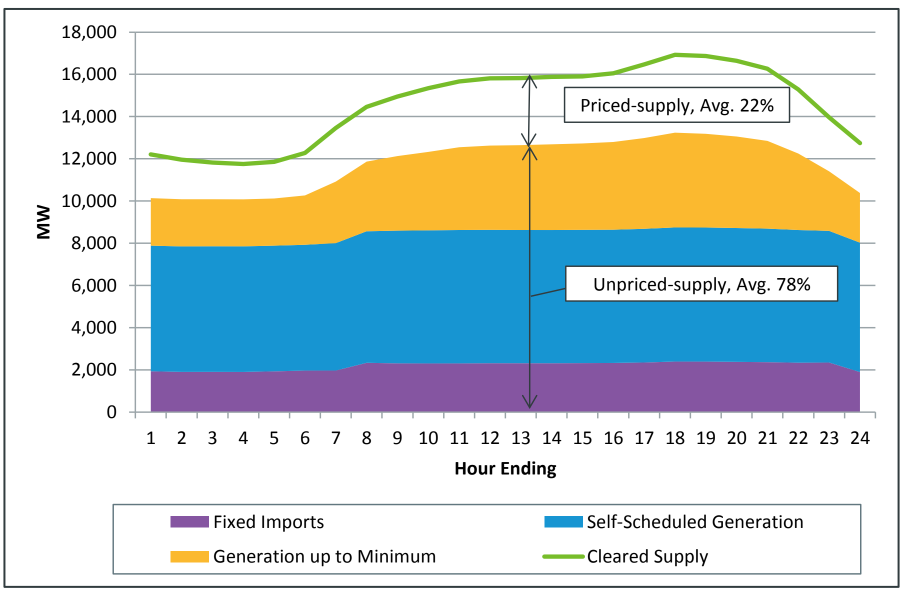
This has been the case for some time, and despite the increased flexibility provided by the introduction of hourly offers and negative priced offers in December 2014, many participants continue to self-schedule generation in both the day-ahead and real-time markets. *Self-scheduling* means that participants commit and schedule their resources, at their economic minimum limit, regardless of price or whether the ISO would have scheduled or dispatched the resource economically based on its offer price. These participants are willing to be price-takers, despite their production costs. Some are even willing to pay to remain operating if prices go negative.

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.[75]
- **Generation up to economic minimum** is fixed and cannot be dispatched down by the dispatch software without shutting down a unit. 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 entitled to NCPC, should LMPs be insufficient to cover production costs.

A breakdown of the hourly average unpriced day-ahead generation, segmented by type, along with average hourly cleared supply is shown in Figure 3-14 below.

Figure 3-14: Hourly Average Unpriced Day-Ahead Generation by Type, 2016



Note: Hour ending (HE) denotes the preceding hourly time period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1. Hour ending 6:00 p.m. is the time period from 5:01 p.m. to 6:00 p.m.

Figure 3-14 shows that, on average, during each hour upwards of 78% of the supply cleared in the day-ahead market is from unpriced generation. The space between the cleared supply curve and the total unpriced generation represents generation economically dispatched with the

[75] 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.

ability to set price, which ranges from 14% to 22% of total supply, on average, over each operating 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. This increase in unpriced generation further decreases the amount of generation economically dispatched and able to set price during real-time. Figure 3-15 shows a breakdown of the hourly average real-time generation by price setting ability along with average hourly cleared supply.

Figure 3-15: Hourly Average Unpriced Real-Time Generation by Type, 2016

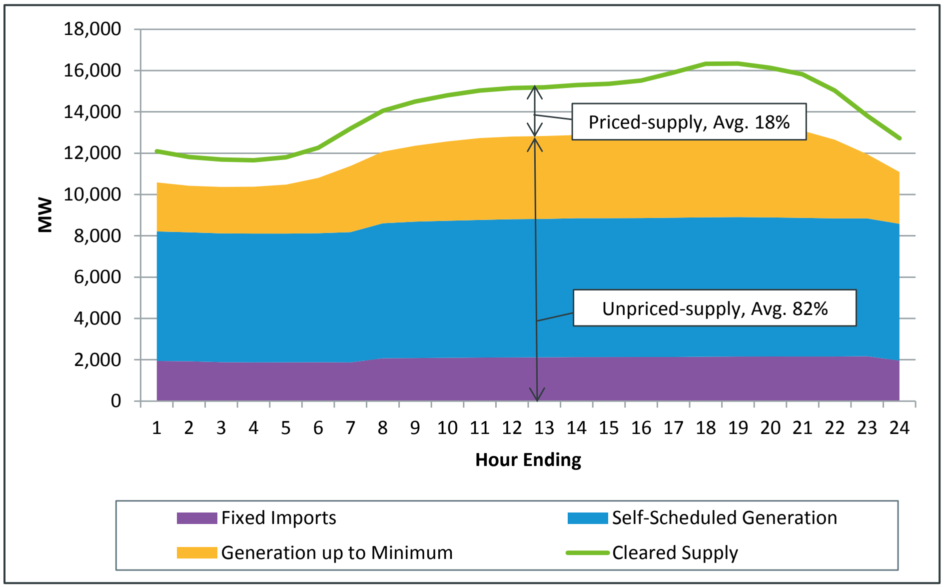
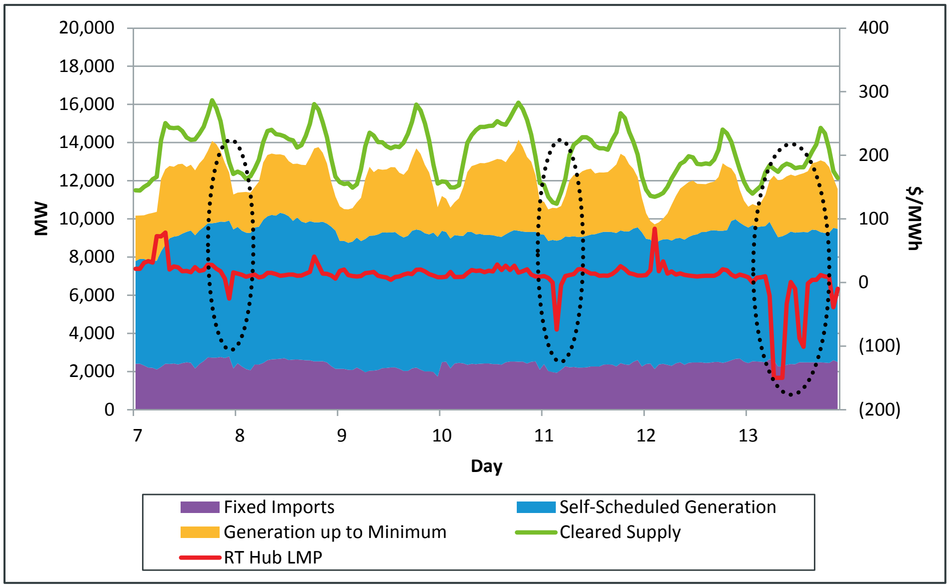


Figure 3-15 shows that each hour, on average, over 82% of the supply cleared in the real-time market is from unpriced generation. Comparing Figure 3-14 and Figure 3-15, on average, the amount of generation economically dispatched in real time decreases compared with day ahead, ranging from about 11% in the overnight hours to 18% over the peak. A decrease in the supply of economically dispatched generation increases the likelihood of low or negative prices, as shown in Figure 3-16 below.

An example of a large amount of unpriced generation contributing to negative pricing occurred during the early morning hours over the period of March 7–13, 2016. Figure 3-16 shows a breakdown of the supply curve by price-setting ability along with cleared supply and the real-time Hub LMP during this period.

Figure 3-16: Unpriced Real-Time Generation by Type and Hub Real-Time LMP, Mar. 7-13, 2016



In Figure 3-16, negative pricing occurred when the amount of total unpriced generation came very close to the cleared supply curve. 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. Negative pricing can only occur if there are entities offering at a negative price that are online and capable of setting price. Section 3.4.9 (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 units eligible to set price and the frequency of negative prices. Unpriced generation does not impair upward dispatch flexibility.

3.4.3 Load and Weather Conditions

Electricity load trends are driven by economic and demographic changes within the New England region. Load patterns are weather and time-of-day sensitive. Higher load levels generally result in higher prices. 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.

New England's native electricity load, referred to as *net energy for load* (NEL), is shown in Table 3-1 below. The table includes total and hourly average NEL 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)
2012 Annual	128,082	14,581	25,880	128,249	14,600
2013 Annual	129,377	14,769	27,379	127,754	14,584
2014 Annual	127,175	14,518	24,443	127,114	14,511
2015 Annual	126,899	14,486	24,437	125,779	14,358
2016 Annual	124,224	14,143	25,521	123,953	14,111

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

The NEL in 2016 was the lowest of the five-year period shown above, at 124,224 GWh, equivalent to an average hourly value of 14,143 MW. In fact, NEL was at its lowest level in the past 17 years. The major contributing factors to the reduced level of load in 2016 were milder weather, energy efficiency programs and the growth in behind-the-meter solar generation in the New England region.[76] The latter two factors were discussed in Section 2.3.1 above.

The 2016 annual peak load of 25,521 MW was set on August 12 during hour ending 15. The peak load was significantly higher compared to 2014 and 2015. There was a heat wave during August 11/12, with average temperature during on-peak hours of 84°F and a dew point of 72°F.[77] The temperature at the time of the peak was 93°F, with a dew point of 72°F.[78] Loads exceeded 25,000 MW for 6 hours in 2016 during August 11 and 12. Loads did not exceed 25,000 MW at any time in 2015 or 2014, but exceeded this level for 45 hours in 2013 and 17 hours in 2012.

New England weather in 2016 was marked by temperatures that were above normal throughout the year. Quarterly average actual[79] and normal[80] temperature, for 2012 through 2016, are provided by Figure 3-17 below. Notably, temperatures during the first quarter of 2016 were 4 degrees above normal, and ten degrees above Q1 2015, resulting in less heating load.

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

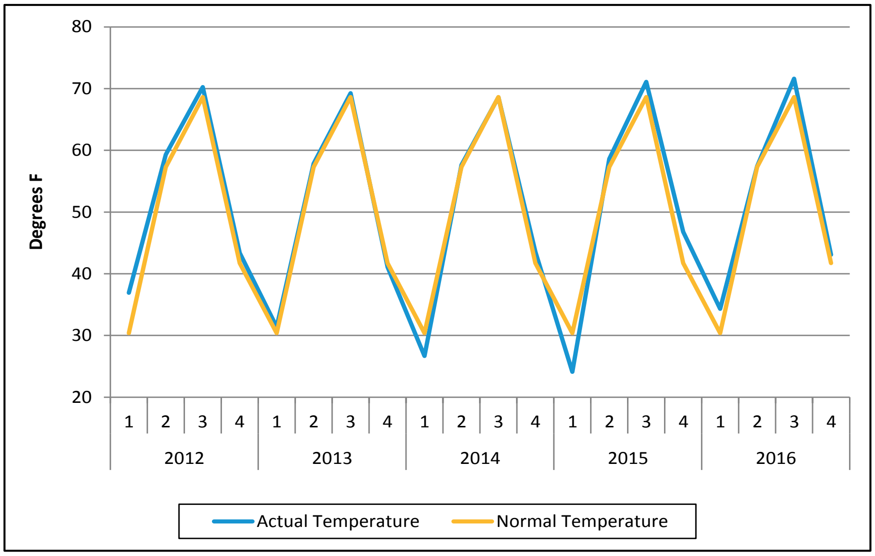
[77] See Section 3.4.6 for further detail on market outcomes during this two-day system event.

[78] *Dew point* is a measure of humidity. Dew point is the temperature at which dew forms and is a measure of atmospheric moisture. A higher dew point indicates more moisture in the air. A dew point greater than 68 °F is considered uncomfortable and greater than 72 °F is considered to be extremely humid.

[79] 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.

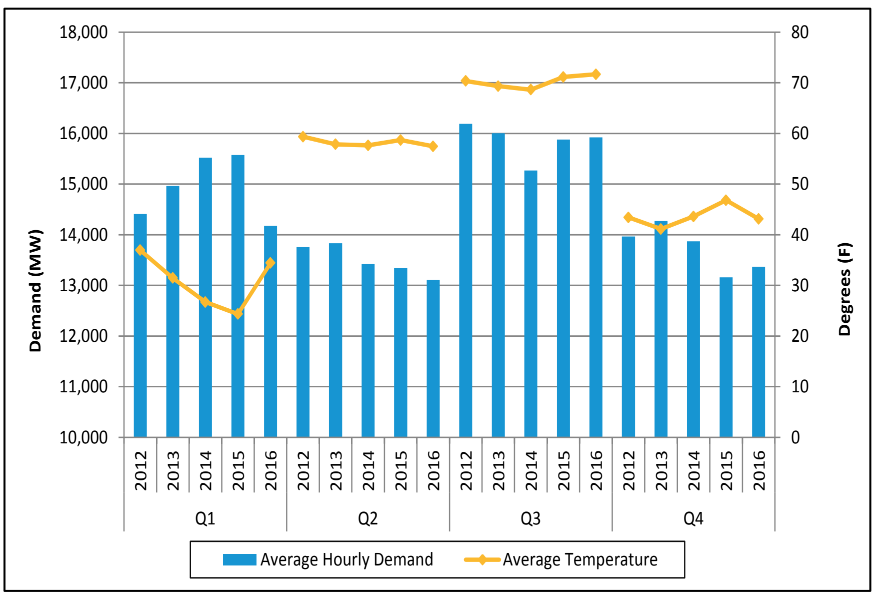
[80] The “normal” average temperature is defined as the 30-year average of temperatures from 1981 to 2010. See *1981-2010 U.S. Climate Normal,* https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data

Figure 3-17: Actual and Normal Temperatures



Average hourly load and temperatures ordered by quarter for the last five years are shown in Figure 3-18 below.

Figure 3-18: Average Load and Temperature by Quarter



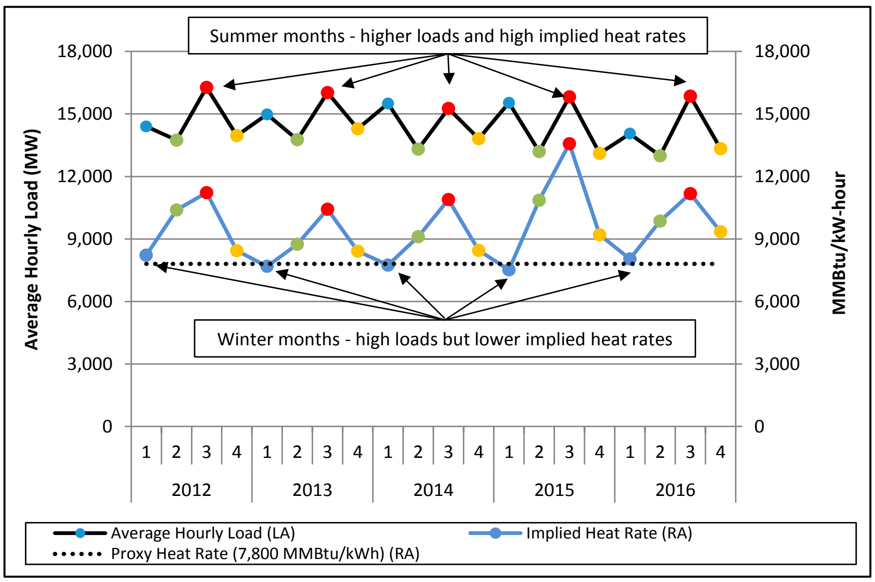
Q1 2016 was four degrees above normal temperatures and had the lowest load for that quarter in the five-year period. Q2 2016 had mild temperatures and also the lowest loads in the five-year period. Q3 2016 had similar average temperatures as Q3 2015, was above the normal temperature by 3 degrees, and had similar average loads. Average temperatures in Q4 2016 were four degrees below Q4 2015 temperatures, which resulted in higher loads.

Higher load levels generally result in higher prices. This is because generators are generally operated in economic merit order; the least expensive generators are operated first, followed by the next expensive generators and so on. In other words, the increasing demand curve intersects the supply curve at a higher and more expensive point on the curve. As load increases during the day, on average, LMPs also increase.

One way to illustrate the relationship between load and price is to use the system "implied" heat rate. The implied heat rate is a calculated value of the marginal heat rate of a hypothetical generator burning natural gas if that unit was the marginal resource setting the LMP.[81] For example, if the average LMP was $36/MWh and average natural gas price was $4/MMBtu, then the average implied heat rate would be 9,000 MMBtu/kWh. This is a reasonable, albeit high-level, assumption given that natural gas resources were the marginal resource (i.e., setting the price) during 77% of real-time intervals in 2016 (see Section 3.4.9).

To account for the impact of fluctuating gas prices on LMP, the implied heat rate is shown below, alongside average load, to more illustrate the relationship. Generally, as load increases so does the implied heat rate.

Figure 3-19: Average Hourly Load and Gas Implied Heat Rates



In the five-year period, Q3 implied heat rates were higher, consistent with higher loads in that quarter. Load levels in Q2 and Q3 are lower and have corresponding lower implied heat rates. The exception is Q1. Even though Q1 generally has the second highest load of the year, gas-implied heat rates are the lowest of all four quarters. This is because winter gas prices were high and volatile during the winter months; as a result gas generators are marginal less frequently. During these periods, oil- and coal-fired generation – with lower fuel costs – are frequently the marginal resources.

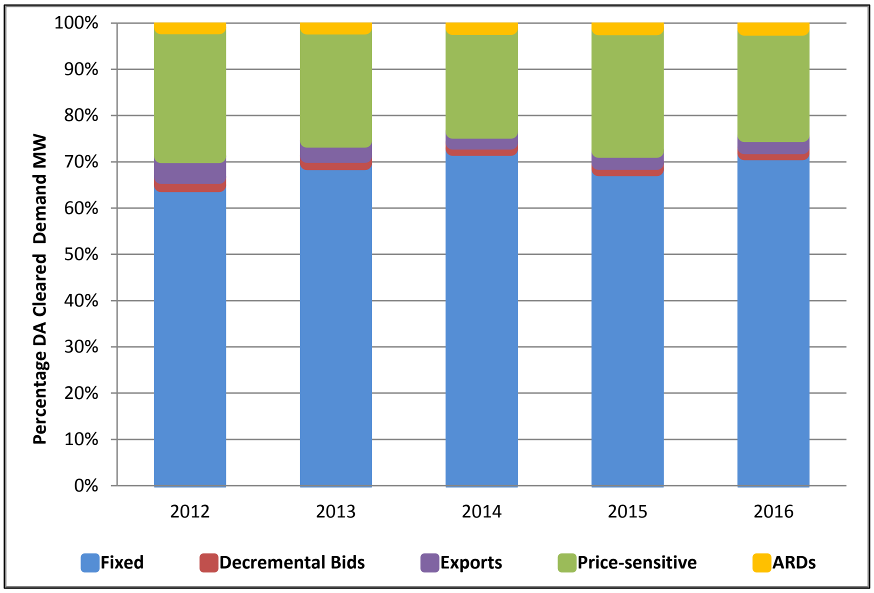
81 The implied heat rate is calculated as the ratio of the real-time hub price, divided by the day-ahead natural gas price. The implied heat rate is also known as the break-even heat rate for gas-fired combined-cycle units; if a generator has a heat rate above the implied heat rate it earns positive gross margins and vice versa. For reference, the average heat rate assumed for a combined cycle gas turbine for the purpose of calculating generation costs in Section 3.4.1 is 7,800 MMBtu/kWh, which is an accurate proxy for the average New England combined cycle fleet.

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 decisions of which generators to commit for the operating day.[82]

Day-ahead demand is comprised of fixed, price-sensitive, exports, virtual demand and asset-related demand. The components of demand clearing in the day-ahead market are shown in Figure 3-20 below.

Figure 3-20: Components of Demand cleared in the Day-Ahead Market



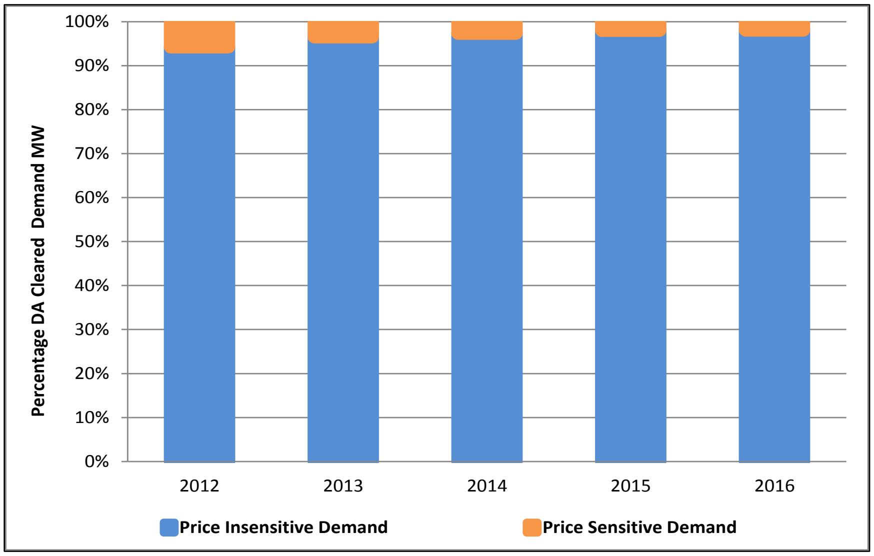
Fixed bids indicate that participants are willing to pay the market clearing price, regardless of price level. Fixed demand bids increased by 3.5% in 2016 compared to 2015, while price-sensitive bids decreased by 3.5%. In 2016, virtual demand bids decreased slightly by 0.1%; Asset Related Demand bids increased slightly by 0.1%, while export bids stayed relatively flat at 2.6% compared to 2015.

Within the "price-sensitive" category of demand bids, the majority are priced significantly above LMP, and always clears. Such transactions are, in practical terms, fixed. The same applies (generally to a lesser extent) to other non-fixed demand categories. For example, Section 5.3 of the report examines the breakdown of exports and imports between fixed and price-sensitive bids. The distinction of the overall demand bids between those that are price-sensitive and those that are *de facto* price-insensitive[83] is shown in Figure 3-21 below.

[82] 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.

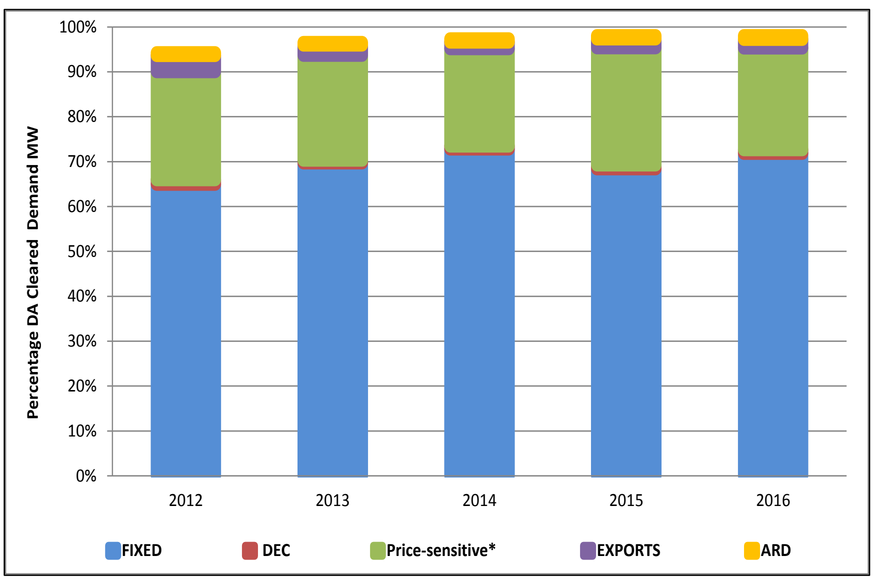
[83] The breakdown of non-fixed demand bids into price-sensitive and price-insensitive is calculated using a threshold price equal to two standard deviations above the daily average day-ahead price. When a demand bid's price is 150% or higher than the threshold price, the demand bid is considered price-insensitive. Price-sensitive* represent bids that are submitted at very high prices.

Figure 3-21: Price-sensitive and Price-insensitive Day-Ahead Cleared Demand



In 2016 approximately 98% of demand cleared as price-takers (including bids that were *de facto* price-insensitive). Overall, in the five year period there has been a gradual decline in proportion of price-sensitive demand bids, from about 6% in 2012 to 2% in 2015 and 2016. A detailed breakdown of the price-insensitive portion of cleared demand is provided in Figure 3-22 below.

Figure 3-22: Percentage Breakdown of Price-Insensitive Day-Ahead Cleared Demand

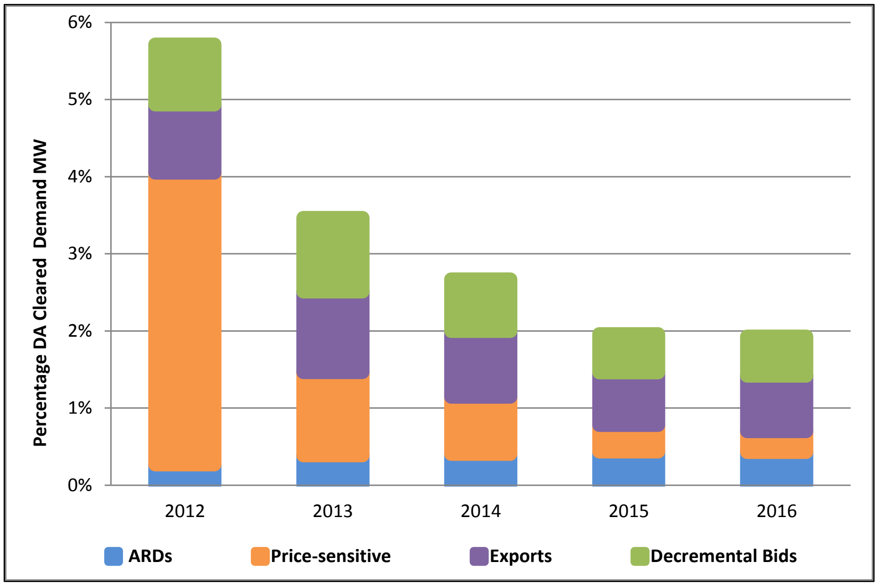


Note: Price-sensitive* denotes the transactions in the price-sensitive demand type category that offer significantly higher than the LMP and are, in practical terms, price-insensitive.

The trend in price-insensitive demand between the demand types has been relatively stable with some substitution between the fixed and price-sensitive demand types. On average, fixed demand made up about 72% of overall demand, price-sensitive* demand makes up about 23% and the remaining types make up just over 1%.

Similar to the previous figure, Figure 3-23 below shows a breakdown of the price-sensitive portion of cleared day-ahead demand.

Figure 3-23: Breakdown of Price-Sensitive Day-Ahead cleared Demand



The 2016 value of 1.9%, equates to an average hourly price-sensitive demand of only 300 MW. The portion of the price-sensitive demand type that is actually price-sensitive decreased significantly from 3.8% in 2012 to 0.3% in 2016. Price-sensitive exports, virtual demand and Asset Related Demand stayed relatively flat from 2015 to 2016.

3.4.5 Load Forecast Error

The ISO's load forecasts are used to make commitment and dispatch decisions. Additionally, many participants have come to rely on the ISO's forecasts when developing their day-ahead bidding strategies.

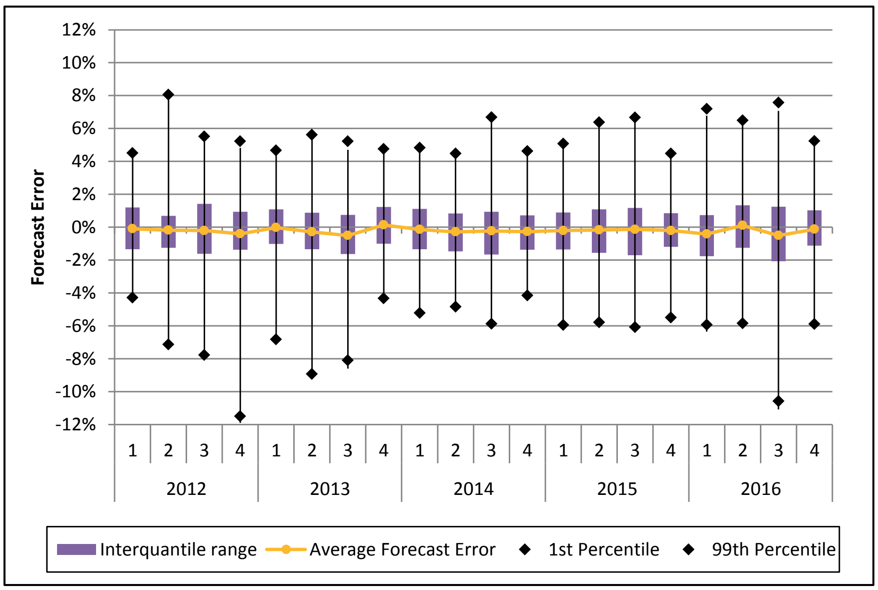
The ISO's load forecasts will inevitably differ from actual loads. There are many unanticipated factors that affect load, including for example weather, "behind-the-meter" generation and industrial customer processes. These unexpected events contribute to load forecast error and load forecast error is one of the contributing factors to deviations between day-ahead and real-time market outcomes.

For instance, if the ISO forecasts loads that are significantly greater than actual loads, then the ISO will likely commit more resources than needed in the day-ahead market. This can result in real-time prices that are lower than day-ahead prices because excess resources are operating at their economic minimum output levels and cannot set price. Further, more available online resources means less reliance on the commitment of more expensive flexible fast start or long lead-time units, which also results in lower prices. On the other hand, if the ISO forecasts loads that are significantly lower than actual loads, then the ISO will likely commit fewer resources 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 fast-start resources are required to serve actual load.

In addition to the magnitude of the forecast error, the timing of when the load forecast is produced plays a role in determining the forecast errors affect on market outcomes. If the ISO's load forecast is incorrect, but there is sufficient time to adjust commitment and dispatch decisions, then the ISO may be able to lessen the impacts of a load forecast error. However, if there is insufficient time to react to the load forecast error, then resources may be over- or under-committed, which in turn impacts real-time prices.

The average load forecast error by quarter for the last five years along with the 1st, 25th, 75th and 99th percentile of load forecast error[84] is shown in Figure 3-24. Values greater than zero indicate that actual load was greater than the forecast; values less than zero indicate actual load was less than the forecast.

Figure 3-24: Load Forecast Error by Quarter



Overall, the average forecast error is close to zero. In 2016, 77% of all the hourly intervals had forecast errors between -2.5% and +2.5%.

3.4.6 System Events during 2016

System events, such as the unexpected loss of major generation or transmission equipment, can have a significant impact on energy market outcomes. One such event in August 2016 bears specific mention. The event resulted in significant costs for under-performing resources that were unable to meet their day-ahead financial obligation, and in high scarcity pricing and rents paid to resources that were able to perform in real-time and ensure the system operating reserve margin was restored.

The system experienced tight conditions on Thursday, August 11 and Friday, August 12, 2016. During this two-day period, the ISO declared an M/LCC 2 (Abnormal Conditions Alert) event

[84] Load Forecast Error = (ISO real-time telemetered load – Forecast)/Forecast. The forecast used in these analyses is the forecast generated between 7AM and 11AM on the day before the Operating Day.

due to a forecasted operating reserve deficiency.[85] On August 11, the ISO implemented Actions 1 and 2 of Operating Procedure #4 for several hours.[86] A Shortage Event[87] was declared from 14:25 through 18:15 on Thursday, August 11.

Throughout the two-day period, generator performance issues and high load levels contributed to reduced reserve margins and high real-time prices. Five-minute real-time Hub energy prices peaked at $2,691/MWh from 14:50 to 15:00 on August 11. The following paragraphs detail the factors that contributed to the event and how event outcomes were reflected in market settlements.

Generator performance issues: The system saw significant reductions in available generator capacity during the two days. Capacity reductions can result from maintenance issues, outages, and fuel limitations. Unplanned outages can cause the ISO to start more expensive fast-start generators to provide energy and/or reserves, resulting in sharp price fluctuations in the real-time energy market.

Several generators experienced unplanned outages during the system event. On August 11, older steam turbine generators and a large nuclear generator suffered unplanned outages resulting in a loss of approximately 1,500 MW. On August 12, average availability continued to decline; average nuclear availability decreased by 180 MW and average coal and natural gas availability decreased by 400 MW and 260 MW, respectively.

Reserves: The generator outages led to reduced reserve margins and real-time price spikes during the system event. Throughout the entire event, system Thirty-Minute Operating Reserve (TMOR) pricing occurred during almost nine hours. Ten-Minute Non Spinning Reserve (TMNSR) pricing took effect during seven five-minute intervals, and Ten-Minute Spinning Reserve (TMSR) pricing occurred during 67 five-minute pricing intervals (about 5½ hours).

The highest pricing during the two-day system event occurred on August 11. On this day, re-dispatch was required to maintain reserves, resulting in frequent reserve pricing that raised energy prices. During the real-time Hub price peak of $2,691/MWh from 14:50 to 15:00, the system was deficient in the minimum TMOR and TMNSR requirements. Due to this deficiency, the Reserve Constraint Penalty Factor (RCPF) for each product was incorporated into the real-time LMP. The respective RCPFs are $1,000/MWh for the minimum TMOR requirement and

[85] When notified of an M/LCC 2 Abnormal Condition Alert, applicable power system operations, maintenance, construction and test personnel and each applicable Market Participant are expected to take precautions so that routine maintenance, construction or test activities associated with any generating station, Dispatchable Asset Related Demand (DARD), Real-Time Demand Response, Real-Time Emergency Generation, transmission line, substation, dispatch computer, and communications equipment do not further jeopardize the reliability of the power system.

[86] Operating Procedure #4 establishes criteria and guidelines for actions during capacity deficiencies, as directed by the and as implemented by ISO and the Local Control Centers (LCCs). There are eleven actions described in the procedure which the ISO can invoke as system conditions worsen. Under Action 1, the ISO notifies all resources that a capacity shortage exists and each available resource is to prepare to provide all operable capacity. Under Action 2, the ISO dispatches real-time demand response resources to respond to the deficiency. These two actions are implemented to the extent necessary to manage operating reserve requirements or provide additional dispatch options during abnormal conditions.

[87] Generally, a shortage event is a period when the New England power system is stressed and using almost all available resources to satisfy electricity demand and reserve requirements. Market Rule 1, Section III.13.7.1.1.1 (b) defines a shortage event as a period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Thirty Minute Operating Reserve during OP-4, Action 2.

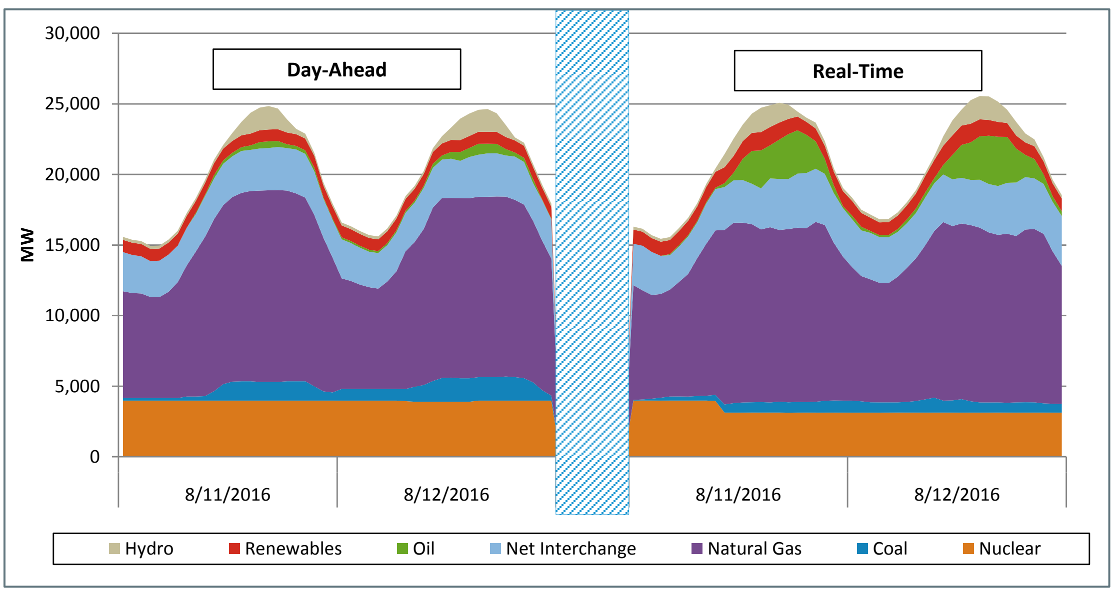
$1,500/MWh for TMNSR. The $1,000/MWh RCPF for TMOR was also incorporated into energy and reserve pricing between 17:50 and 18:00 on August 11, contributing to the high real-time Hub price of $2,001/MWh.

On August 12, the real-time Hub price reached $572/MWh between 13:55 and 14:10. Over this period, a deficiency in TMSR led to activation of the constraint penalty factor of $50/MWh. The peak real-time Hub price for August 12 occurred from 16:55 to 17:20, reaching $602/MWh. During this time, there was a system deficiency in replacement TMOR, and the constraint penalty factor of $250/MWh was incorporated into energy and reserve prices.

Forecast Error: Forecast error was not a factor in tight system conditions on Thursday, August 11, as the forecasted load was close to the actual load throughout the day. However, on Friday, August 12, there were several hours in which the forecasted demand differed significantly from the actual load. The deviation between actual and forecasted load reached as high as 1,000 MW at hour ending 15. Forecast error likely contributed to high real-time prices on August 12.

Fuel Mix: Unplanned generator outages and fuel switching led to discrepancies between real-time and day-ahead fuel mixes, particularly during peak load hours. These deviations contributed to high prices. Figure 3-25 below shows the supply mix in both the day-ahead and real-time energy markets during the two-day period.

Figure 3-25: Day-Ahead and Real-Time Cleared Generation by Fuel type with Net Interchange



As Figure 3-25 shows, the day-ahead generation fuel mix consisted primarily of natural gas generation, imports, and nuclear generation. A small amount of oil cleared in the day-ahead market. The real-time market saw decreases in gas, nuclear, coal, and hydro generation relative to the day-ahead market. Oil-fired generation compensated for most of these deficiencies. Oil was the marginal fuel type for 21% and 15% of real-time pricing intervals on August 11 and August 12, respectively. The increased use of oil played a role in the high real-time prices, as oil-fired resources have higher incremental energy costs than gas-fired, coal-fired, or nuclear generation.

Interchange: The ISO-NE system typically imports more energy than it exports. During the Shortage Event, ISO-NE was a net importer of energy from the Canadian and New York control areas. Additionally, real-time imports consistently exceeded day-ahead imports after HE 15 on August 11th. The deviation between real-time and day-ahead imports during this time was consistent with expected market behavior, as increased energy flowed to the high-priced area.

Market Settlements-Forward Capacity Market: The Peak Energy Rent (PER) is an adjustment to capacity market revenues that occurs when real-time energy prices go beyond a set strike price. The strike price is established by a proxy generator with a 22,000Btu/kWh heat rate. The adjustment protects load from high energy prices and removes the incentive to raise prices in the Real-Time Energy Market. The PER concept acknowledges that load has already paid to maintain reliability through the FCM. It helps prevent load from making additional payments when reliability conditions are not met and real-time prices are high. The August 11/12 system event caused the real-time LMP to exceed the PER strike price. On August 11, the Rest-of-Pool real-time LMP was above the strike price for six hours in all capacity zones. On August 12, the Rest-of-Pool real-time LMP exceeded the strike price for one-to-five hours, depending on the capacity zone. The cost to capacity resources that resulted from PER adjustments in August was approximately $101 million. Most of this (93%) was attributable to the system event on August 11 and 12.

Additionally, FCM rules specify a penalty rate to prevent economic withholding among resources during Shortage Events. The penalty rate, which depends on the length of the Shortage Event, was based on 5% of annualized capacity market revenues. On August 11, penalties from the Shortage Event amounted to $7.3 million, which represented about 7.2% of FCM payments for August 2016.

Market Settlements-Energy Market: Over the past five years in New England energy markets at least 95% of energy payments were made in the day-ahead market on average. Comparatively, less than 5% of energy payments were made in the real-time market. Day-ahead and real-time energy payments deviated from these averages on August 11 and 12. During the system event only 59% of energy payments were made in the day-ahead market. Deviations from the day-ahead schedule are paid or charged the real-time energy price in the real-time market.[88]

Throughout the system event, most of the deviations between real-time and day-ahead energy markets were the result of unplanned outages and the subsequent changes in generation. Generators that failed to deliver on their day-ahead schedules had to pay the real-time price to replace their real-time energy obligations. Generators that produced more energy in the real-time market than they had cleared in the day-ahead market received the real-time price for the additional energy. On August 11, the participant with the most profitable deviation made about $2.4 million, whereas the participant with the largest loss was charged around $5 million.

Over the course of the system event, NCPC totaled approximately $4 million. Of those costs, $3.5 million were incurred on August 11. Economic NCPC accounted for the majority of total costs at $3.5 million over the two days. Economic NCPC charges to deviations were small at approximately $0.2 million on August 11 and $0.1 million on August 12. Real-time economic NCPC payments for posturing generators totaled $3.1 million.

[88] Deviations that receive the real-time price include virtual demand, increases in generation or imports, and reductions in load or exports. Deviations that pay the real-time price include virtual supply, increases in load or exports, and decreases in generation or imports.

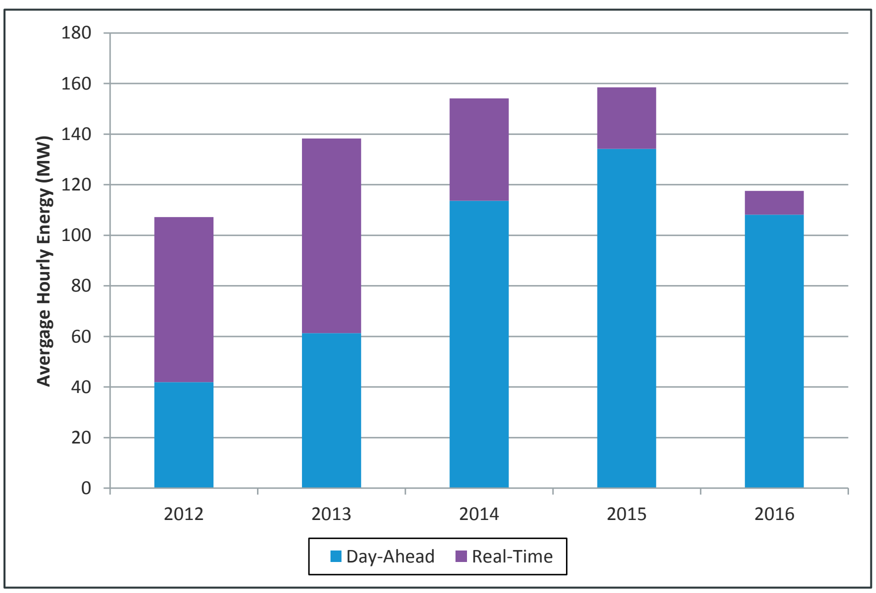
3.4.7 Reliability Commitments

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.[89] 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 resource'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 resource's costs, NCPC payments will be made to the out-of-merit resource. The impact on consumer costs (i.e. the LMP) is less straightforward as oftentimes the more-expensive generator needed for reliability will operate at its economic minimum point and be ineligible to set price.

In 2016, the amount of commitments ISO New England made for reliability reasons decreased. The real-time average hourly energy output from reliability commitments during the peak load hours (hours ending 8-23) for 2012 through 2016 is shown in Figure 3-26. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

Figure 3-26: 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 about 1% on average. However, the average hourly energy from reliability commitments during

89 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.

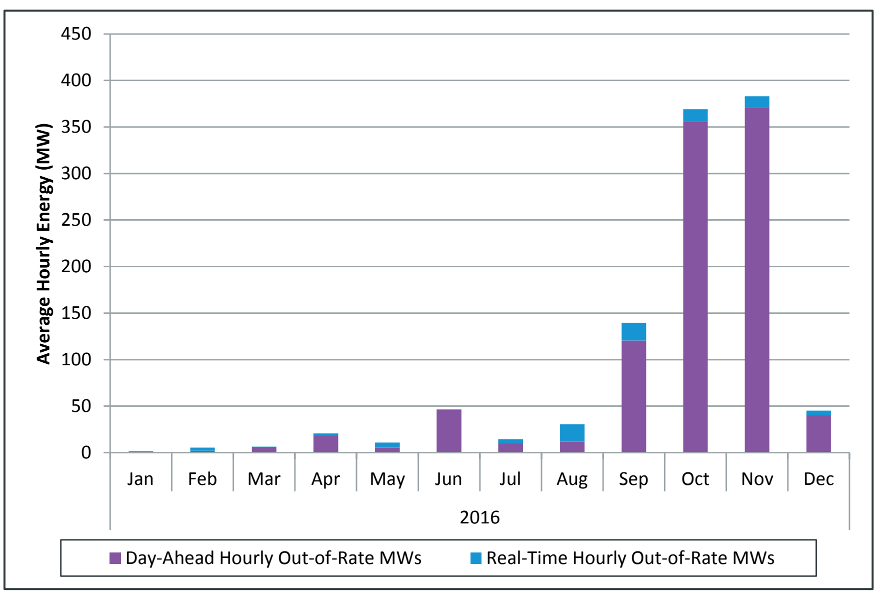
the peak load hours had been increasing over time prior to 2016, and that commitments in the day-ahead market have become more common as a percentage of total reliability commitments.

The reduction in overall reliability commitments in 2016 was due to significantly less reliability commitment output during the first four months of the year. In 2016, 89% of the output from reliability commitments was for second contingency reliability protection (LSCPR), with 74% of that output in the NEMA/Boston area. Although LSCPR comprised a large portion of the reliability commitment output, LSCPR commitment output decreased by 25% compared to 2015. An increase in self-scheduled generation in the NEMA/Boston area, and unusually mild weather contributed to this reduction. Self-scheduled units are committed as must-run generation and are not classifies as reliability commitments. If these self-schedules are located in areas with tight conditions, they may reduce the need for reliability commitments. In addition to the increase in self-scheduled generation, load in New England was approximately 1,400 MW less on average in the first quarter of 2016 than 2015. Load was discussed in more detail in Section 3.4.3 above.

From May 2013, there was a shift from reliability commitments being made in the real-time market to the day-ahead. This was primarily due to the introduction of modelling 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 area of the system to meet reliability criteria. The ISO's rationale for this is discussed further below.

A closer look at reliability commitments made during 2016 is shown in Figure 3-27 below. The figure shows the out-of-rate energy for reliability commitments during the peak load hours in 2016, 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 have been committed or dispatched in economics.

Figure 3-27: Day-Ahead and Real-Time Average Out-of-Rate Energy from Reliability Commitments during Peak Load Hours (HE 8-23)



Of the roughly 120 MW of average hourly output from generators committed for reliability, about 90 MW was out-of-rate. This is a relatively small amount of out-of-rate energy (in the context of average hourly load of 14,143 MW in 2016) that is being served by more expensive generation to meet a reliability need. Figure 3-27 shows that the greatest amounts of out-of-rate energy output from reliability commitments occurred in September through December. Reliability commitments in these months were predominantly made for LSCPR. Approximately 76% of the output from reliability commitments in the final four months of 2016 was for LSCPR in the NEMA/Boston area.[90] Prior to 2013, there was ample supply of 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 exhibits above, a large majority of the reliability commitments in 2016 were made in the day-ahead market, which helps minimize excess surplus capacity and the amount of economic generation that is displaced on the system from these units 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 these units in the day-ahead market is more desirable than in the reserve adequacy assessment (RAA) or the real-time energy market as it tends 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 units can be adjusted to accommodate the reliability commitment with more flexibility than if the commitment is made later.

For example, a local reliability need may require a unit with a relatively high economic minimum to be committed. If this requirement is known before the day-ahead market is run, other smaller units on the margin that would have otherwise been committed will not be, so the area's reliability requirement can be met without having excess supply online. This can distort price slightly by removing the other units from the supply stack and adding a large fixed quantity of energy to the supply stack. If the reliability requirement is not known before the day-ahead market, the reliability commitment will be made later, and if the units committed in the day-ahead market cannot shut down due to unit constraints, such as minimum run times, it could lead to excess generation at its economic minimum, suppressed real-time prices, and NCPC paid to units that cannot recover their commitment costs.

3.4.8 Congestion

This section addresses 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: 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.

[90] 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.

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 3-28. 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 3-28: New England Pricing Nodes Most Affected by Congestion

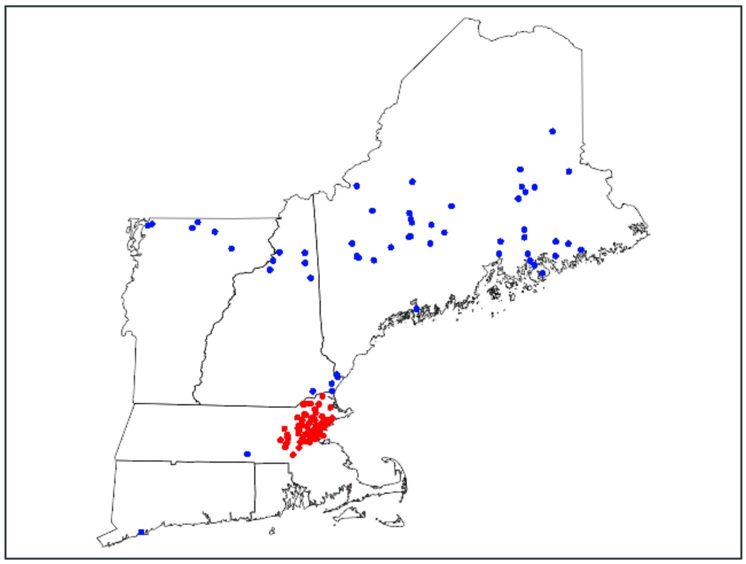
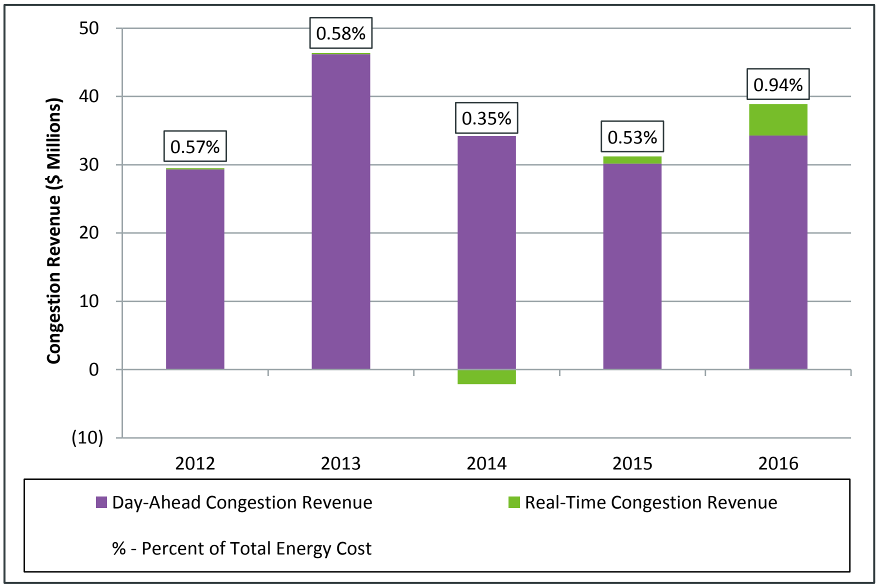


Figure 3-28 highlights two main congestion patterns. First, areas on the system with a high concentration of renewable generation have lower prices, on average, than the rest of the system. In 2016, areas in Northern Maine, New Hampshire, and Vermont were export-constrained. Not only were these areas frequently export-constrained, but often the magnitude of the difference was high. Many renewable generators offer at very low, even negative, prices. When transmission connecting these areas to the rest of the system binds, these units set the price and there is typically a significant difference between the locational prices and the system price. Marginal units are discussed in more detail in Section 3.4.9. The second pattern of note is the high pricing in NEMA/Boston. In 2016, import constraints affected the NEMA/Boston area. With the highest concentration of load in New England, the Boston area has traditionally been import-constrained, but ongoing transmission projects also affected the import capability of the area in 2016.

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. Congestion revenue is the difference between the congestion cost and revenue calculated across all locations when the system operates under constrained conditions. The congestion cost and revenue is calculated based on the congestion component of the LMP and the quantity of cleared supply and demand at each location.

Congestion revenue and its share of the total energy cost in New England are shown in Figure 3-29 below. The purple bar represents the day-ahead congestion revenue, and the green bar represents the real-time congestion revenue.

Figure 3-29: Congestion Revenue Fund Components, Balances, and Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue in 2016 was $38.9 million. This represents an increase from $31.2 million dollars in 2015; as a percentage of total energy cost (labels) the congestion revenue was slightly higher than in the previous five years. Day-ahead congestion revenue is much higher than real-time congestion revenue because approximately 98% of the energy transacted in New England is settled in the day-ahead market. The frequency with which the Boston interface (a collection of transmission lines surrounding Boston) was binding was a large driver of day-ahead congestion revenue in 2016. The average day-ahead congestion revenue in the 308 hours the Boston interface was binding was $60,495, compared to the average of $1,845 in hours in which it was not binding. Although it was only binding in 3.5% of all hours, the congestion revenue within these hours comprised 54% of the total day-ahead congestion revenue. Ongoing transmission work in the Boston area was one reason for the number of intervals in which the Boston interface was binding.

As mentioned previously, congestion is relatively infrequent in New England. Although day-ahead and real-time congestion revenue increased to 0.94% of the total cost of energy in 2016, from 0.53% in 2015, as a percentage of total energy payments, congestion remains small at under 1%.

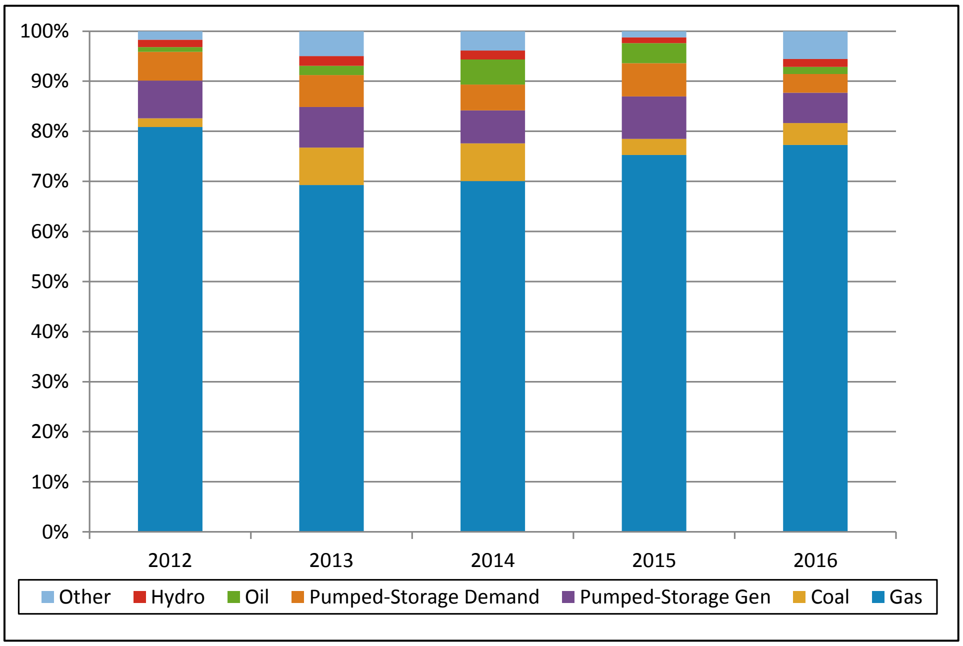
3.4.9 Marginal Resources

This section addresses the relationship between marginal (price-setting) resources and LMPs in both the real-time and day-ahead markets. The influence of differing costs of input fuels on electricity prices are evaluated by examining the percentage of time that resources of a certain fuel type are marginal. More resource types, such as demand and virtual transactions, compete in the day-ahead market, compared with the real-time market, and can therefore be marginal.

In both markets, the LMP is set by the cost of the next megawatt that the ISO would have to dispatch to meet an incremental change in load at a pricing location. The resource that sets price is called the marginal unit. The price of electricity changes as the price of the marginal unit changes and the price of the marginal generating unit is largely determined by its fuel type. Because of this, examining marginal units by fuel type helps us understand changes in electricity prices. At least one marginal unit will meet the energy requirements on the system during each pricing interval. If transmission is not constrained, we classify the marginal unit as the unconstrained marginal unit. In intervals with binding transmission constraints, an additional marginal unit exists for each binding constraint.

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 3-30 below.[91]

Figure 3-30: Real-Time Marginal Fuel-Mix Percentages



Natural gas was the marginal fuel for 77% of all pricing intervals in the real-time market in 2016. This is an increase compared with 2015 (75%). One reason for this increase is that gas helped displace oil as the price-setting fuel in a noticeable percentage of intervals. The displacement of coal and oil over the past few years is, in part, due to lower gas prices. These lower prices make gas-fired generators more economically viable than oil- and coal-fired generators, particularly in non-winter months.

The "other" category also had a noticeable increase between 2015 and 2016. Almost all of the price-setting units in the "other" category in 2016 were wind units, which set price 4% of the time. This is a significant increase compared to 2015 where wind set price <1% of the time. The increase is driven by the Do Not Exceed (DNE) dispatch rules, which went into effect on May 25,

[91] 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. Asset Related Demand (ARDs or pump) have lower offers and typically pump and set price in off-peak hours when it is generally cheaper to pump water.

2016.[92] DNE incorporates wind and hydro intermittent units into the unit dispatch and pricing process, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price.

Most of the marginal wind units in 2016 were located where the transmission system is regularly export-constrained. This means that the wind units frequently set price within their constrained regions while another unit(s) set price for the rest of the system. Though wind was marginal 4% of the time in 2016, wind was the single marginal fuel type on the system in <1% of all five-minute intervals.

Marginal resources in the day-ahead market: Unlike the real-time market, generators of all fuel types set price only 47% of the time in the day-ahead market in 2016. 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 demand, for example, are financial products that only exist in the day-ahead market.[93] 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. Lastly, even though external transactions exist in the real-time market, they set price more frequently in the day-ahead market. This is because there are more priced external transactions in the day-ahead market than in the real-time market; most real-time external transactions are fixed, or price takers, meaning they are ineligible to set price.[94]

The percentage of time that each entity set price in the day-ahead market over the past five years is illustrated in Figure 3-31 below. Beginning in 2015, the graph illustrates a breakdown of the generation by category (large gray bar, years 2012-2014) by generator fuel type (colored bars outlined in black).[95]

[92] *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).

[93] See Section 4.1 on virtual transactions.

[94] See Section 5 on external transactions.

[95] 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.

Figure 3-31: Day-Ahead Marginal Fuel-Mix Percentages

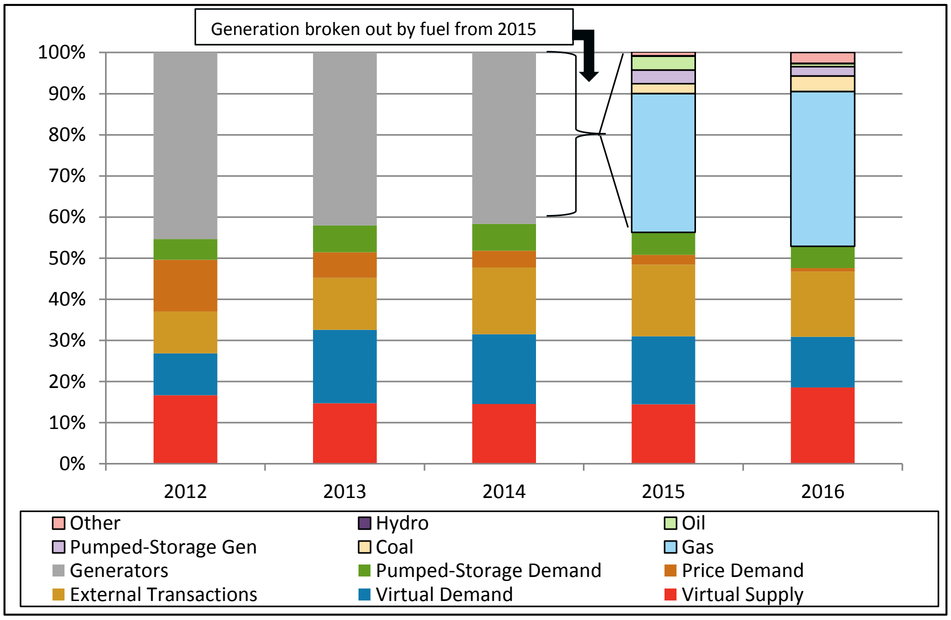


Figure 3-31 illustrates a 4% increase in marginal virtual supply offers (from 14.5% to 18.5%) between 2015 and 2016. This increase is due to a higher frequency of virtual supply offers being marginal in export-constrained areas. These export-constrained areas are typically in the same location as wind 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 arbitrage opportunity for virtual supply offers which benefit from the higher day-ahead prices at these nodes. In most of these intervals, virtual supply offers were not the only marginal transaction on the system. Virtual transactions set price for the whole system in 9% of hours in 2016. Aside from virtual transactions, generators set price approximately 47% 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 2016. 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

Generators that are unable to recover their cost of operation in the day-ahead and real-time energy markets are eligible for "make-whole payments" (sometimes also referred to as "uplift"). In these cases, a generator's revenue from providing energy and ancillary services is insufficient to recover some portion of its start-up and other short-run production costs. The make-whole payments, called "Net Commitment Period Compensation" or NCPC, are based on a comparison of a generator's revenue and its as-offered costs. The ISO provides the payments to ensure the reliable operation of the power grid, as generators would be reluctant to operate when costs are expected to exceed revenues.

3.5.1 NCPC Payments

The ISO pays NCPC to generators under a number of circumstances. Generators that operate at the ISO's instruction but do not recover their as-offered costs through energy market revenues are paid one of the following types of NCPC, depending on the reason the ISO committed the generator:[96]

- **Economic/first-contingency NCPC**: Generation is committed to satisfy system-wide load and reserves but fail to recover costs. Situations that can lead to "economic" NCPC include the following:
    - Generation committed and dispatched to provide energy on short notice or to create reserves, allowing the system to recover from the loss of the first contingency within a specified period
    - Generation providing system-wide stability or thermal support or to meet system-wide electric energy needs during the daily peak hours
    - Generation committed for peak hours that must remain on line after the peak hours to satisfy minimum run-time requirements
- **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 operating to satisfy the ISO's performance auditing requirements.[97]

3.5.2 NCPC Payments for 2012 to 2016

Total NCPC payments by year and payment category are shown below in Figure 3-32. NCPC payments decreased significantly in 2016 to $73 million, a 38% reduction compared with $118 million in 2015. In part, NCPC payments over time mirror changes in generator fuel costs (an important component of generator short-run costs). The increases in NCPC compensation observed in 2013 and 2014, and the reduction in 2015 and 2016, are consistent with changes in fuel costs (especially natural gas which declined by 34% in 2016) over this time period.[98] Another important factor for understanding the decline in NCPC payments between 2015 and 2016 was the removal of NCPC payment rules (applicable throughout 2015) that allowed generators compensated in the day-ahead market to receive NCPC payments in the real-time market under certain circumstances. This rule change is discussed below.

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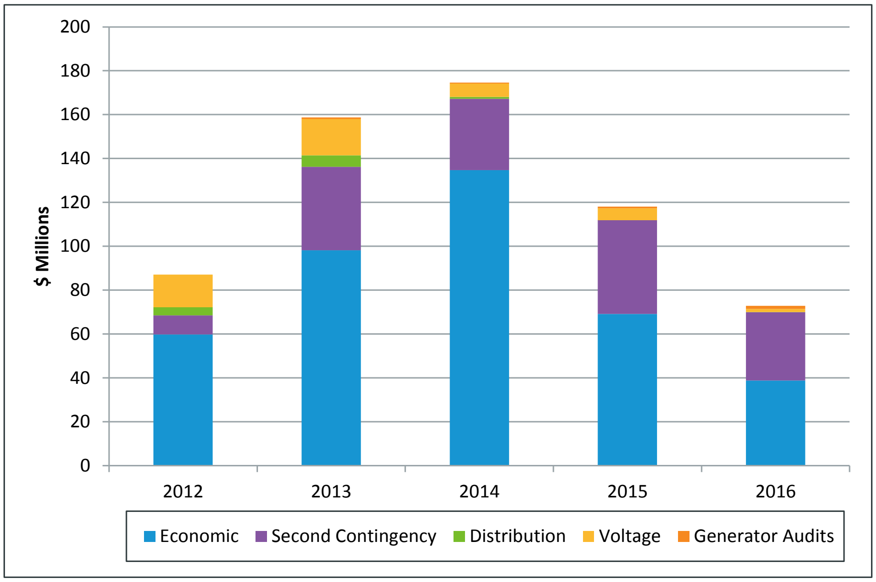
[96] A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

[97] 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.

[98] Other factors also influence NCPC payments. These include varying system conditions (i.e., instances of load forecast and generator commitment error, instances of local transmission issues and resulting local reliability needs, etc.) 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.

It is also noteworthy that total NCPC payments represent a small fraction of compensation provided to generators. For example, generators' direct energy market revenues alone totaled $4.1 billion in 2016 and $5.9 billion in 2015. NCPC payments to generators represented approximately 2% of their total energy payments.

Figure 3-32: Total NCPC Payments by Year and Category



Most NCPC payments are for economic (or first contingency) needs, as shown in Figure 3-32. These payments have ranged from a high of 77% of total NCPC payments in 2014 to a low of 53% of total NCPC payments in 2016. In recent years, second contingency payments (incurred to meet local load and reserve requirements) have increased as a proportion of total payments. This is in line with the increase in energy output from generators committed for reliability and their corresponding out-of-market rates as discussed in Section 3.4.7 above. In 2012, these payments averaged just 10% of total NCPC payments; beginning in 2013, the payments have averaged 19-43% of total payments. Other types of NCPC payments have been relatively small in each year.

To add perspective on the relative value of NCPC payment amounts, total day-ahead and real-time NCPC payments, as a percent of energy costs[99], are shown in Table 3-2.

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

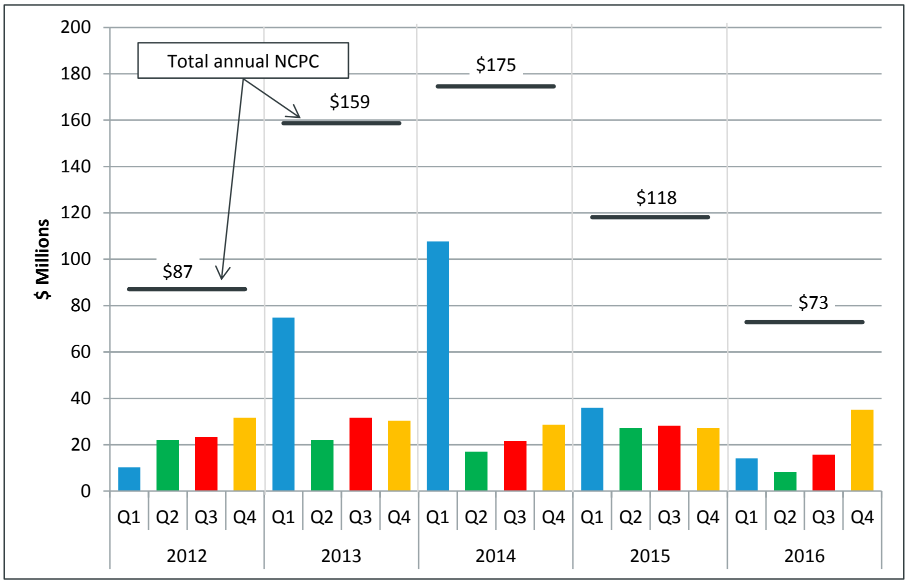
	2012	2013	2014	2015	2016
DA NCPC	0.4%	0.6%	0.9%	0.6%	1.1%
RT NCPC	1.3%	1.4%	1.0%	1.4%	0.7%
Total NCPC as % Energy Costs	**1.7%**	**2.0%**	**1.9%**	**2.0%**	**1.8%**

Total NCPC represents a relatively small portion of energy costs and have been relatively consistent over the past five years: day-ahead NCPC payments have ranged from 0.4% to 1.1% over the review period, while real-time NCPC payments have ranged from 0.7% to 1.4%.

[99] Energy cleared at the day-ahead and real-time LMPs, excluding ancillary services costs.

NCPC Payments by quarter are shown in Figure 3-33 below, with a different color assigned to each quarter. The black lines correspond to total annual NCPC payments.

Figure 3-33: Total NCPC Payments by Quarter



From 2013 through 2015 the highest NCPC payments occurred in winter months (the first quarter of each year). This largely reflects higher natural gas costs during the winter months (i.e., higher operating costs for generators) and concerns about natural gas scarcity and system reliability impacts in the day-ahead and real-time energy markets. The higher Q1 NCPC payments in 2013 and 2014 explain a significant portion of the overall increase in NCPC payments in those years.

A warmer-than-normal winter and relatively low fuel prices resulted in reduced NCPC payments for the winter 2016. The elevated NCPC payments in Q4 of 2016 reflect local reliability needs, predominately in the NEMA/Boston area. A total of $24 million was paid for local reliability NCPC in Q4; generators in NEMA/Boston received payments of $22 million. 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 increased local reliability commitments.

In addition to fuel costs and local reliability commitments, revisions to NCPC rules, implemented in December 2014, have influenced recent NCPC payments. 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 is not being offset by an unprofitable commitment, thereby improving performance incentives.[100]

Second, the NCPC compensation structure was improved to account for the lost opportunity costs of generators postured to meet system reliability needs and that are dispatched away from their economically optimal output by the ISO. In practice this applies frequently to limited

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

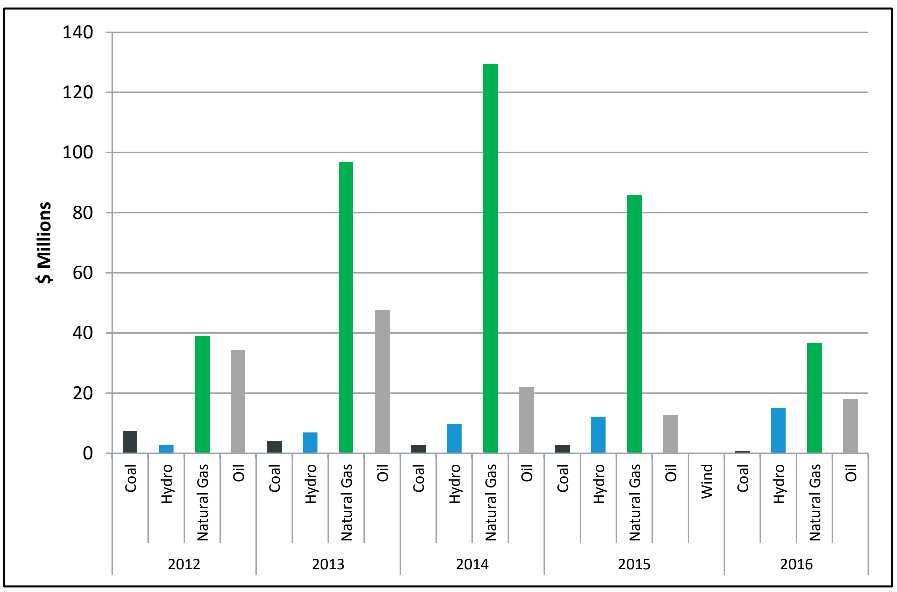
energy generators. In 2015 and 2016, NCPC to postured generators amounted to $5.2 million, and $5.5 million, accounting for 4.4% and 7.5% of total NCPC, respectively.

Third, from December 2014 to February 2016, a generator scheduled in the day-ahead market was eligible for both day-ahead and real-time NCPC. When combined with lower real-time prices compared with prices in the day-ahead energy market, this resulted in higher real-time NCPC when the underlying supply offer does not change between the two markets. It is estimated that this third 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. Adjusting the NCPC payments for the influence of this compensation structure, 2016 would have had 13% higher total NCPC payments than 2015. Although adjusted Winter 2016 payments were significantly lower than adjusted Winter 2015 payments, local reliability payments were higher in 2016 than 2015, on an adjusted basis. The increase in local reliability payments largely explains the increase for the adjusted payments.

Total NCPC payments by generator fuel type are shown in Figure 3-34; note that the chart omits fuel types that received less than $100,000 in total NCPC payments within a year.

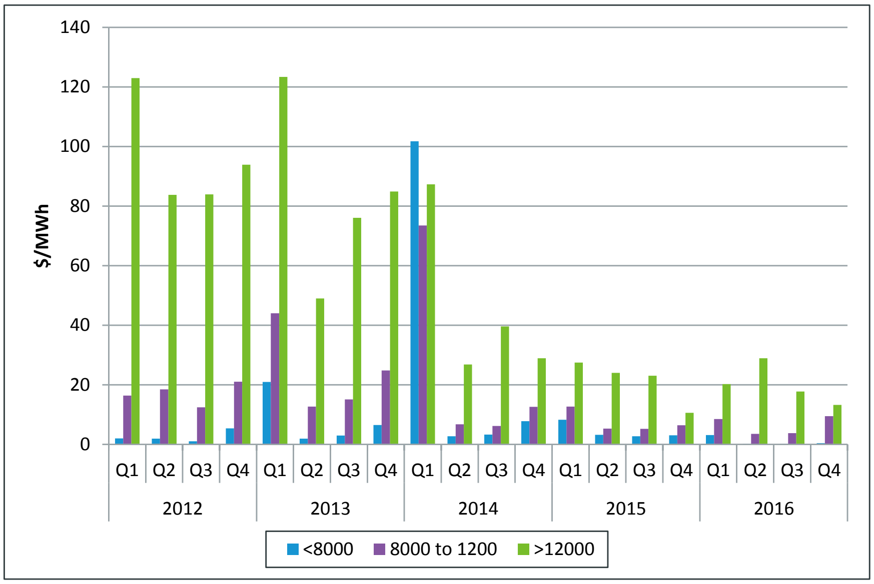
Figure 3-34: Total NCPC Payments by Generator Fuel Type



Natural gas and fuel oil generators receive the majority of NCPC payments. Occasionally, hydro generators also receive noticeable 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 typically are neither the least- or 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 generators in 2013-2015 represent the high fuel cost for operating these generators during winter months.

To examine NCPC payments further, we classified average payments for real-time economic NCPC by generator heat rate level.[101] 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.[102] Figure 3-35 below indicates the average real-time NCPC payments ($/MWh) to generators according to generator heat rate categories.

Figure 3-35: 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 sometimes not hold. For example, in Q1 2014, New England experienced very high natural gas costs; as a consequence, even fuel-efficient natural gas 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 23% of real-time economic NCPC payments from 2012 to 2016. These generators were committed less frequently than lower heat rate generators. Average payments to these generators have been declining over time, and represented just 10% of economic NCPC payments in 2016.

101 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.

102 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.

3.6 Demand Resources in the Energy Market

Demand resources 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.

Participation in TPRD program during 2016 was limited to 250 MW and three participants.

The TPRD program was designed to "transition" demand response resources to full integration into the wholesale energy market by June 1, 2018, in order to comply with FERC Order No. 745 (Demand-Response Compensation in Organized Wholesale Energy Markets). At this time demand response will also be eligible to provide reserves and will participate in the capacity market in the same manner as other supply-side resources. Full integration 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 provide operating reserves, in a manner similar to traditional generation resources.

FERC's authority to issue Order No. 745 was challenged before the United States Supreme Court. In January 2016, the United States Supreme Court ruled in a 6-2 decision upholding FERC's authority to regulate demand response programs in wholesale markets.[103]

3.7 Market Structure and Competitiveness

This section presents an evaluation of the competitiveness of the energy market. It also provides a broad view of market concentration, competitive offers and market structure that can affect competition. In addition, this section includes an overview of the market power mitigation rules in the energy market.

The competiveness of the capacity and ancillary services markets is covered in 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.[104] The C4 value expresses the percentage of real-time supply controlled by the four

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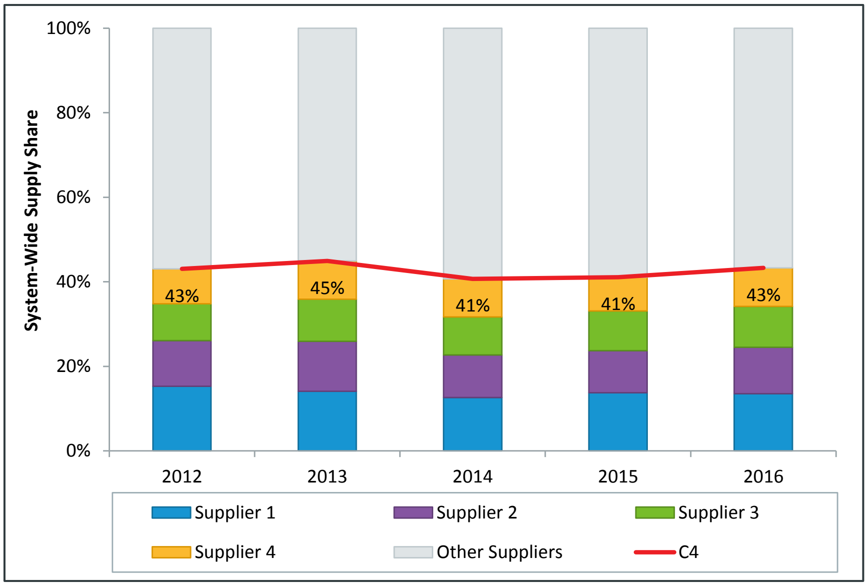
[103] Supreme Court of the United States, *Federal Energy Regulatory Commission v. Electric Public Supply Association et. al.* (January 25, 2016), http://www.supremecourt.gov/opinions/15pdf/14-840_k537.pdf

[104] 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).

largest companies. C4 values in the range of 40% 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 3-36 below, the C4 value of 43% for 2016 is similar to the values observed over the prior four years 2012 through 2015.

Figure 3-36: System-wide Supply Shares of the Four Largest Firms



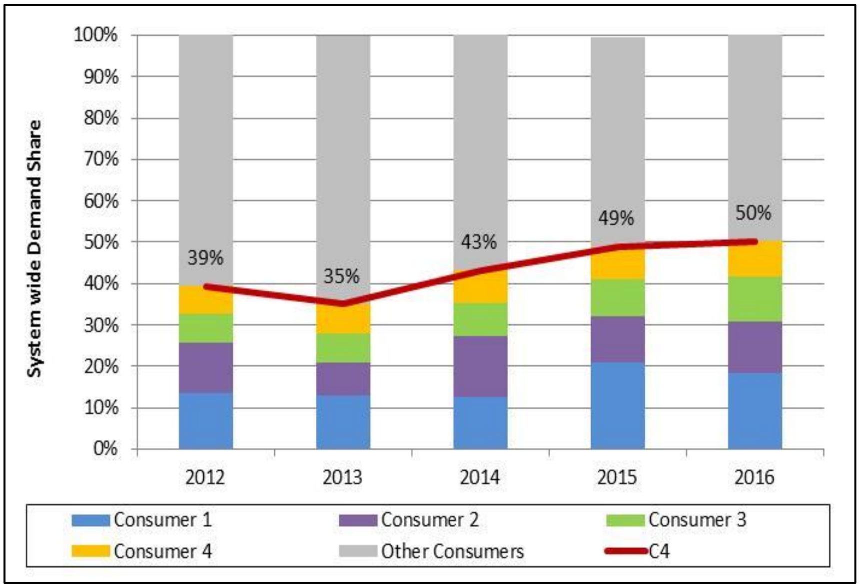
Note: The firms labeled "Supplier 1," "Supplier 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

In 2016, the total supply of generation and import transactions in all on-peak hours was 67,282 GWh. The four largest suppliers provided 29,118 GWh, or 43%, of the total energy during these hours. As illustrated by the red C4 trend line in Figure 3-36, the aggregate amount of supply from the four largest suppliers in 2016 is comparable to observations in prior years. The observed C4 values in the range of 40% to 45% 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 - 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 3-37 below, which shows the market shares of the top four firms and the combined market share of all remaining firms.

Figure 3-37: 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 2016, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 66,278 GW.[105] Overall, the four largest load-serving market participants served 50% of the total system load for the 2016 on-peak hours. As shown by the red C4 trend line in Figure 3-37, the load share of the four largest firms increased in 2015 by 14% since 2013 as a result of the merger of two participants. The load shares of the four largest firms have increased in 2016 by 1% compared to 2015 as a result of three participants adding load obligations.

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 98% in 2016. Second, the day-ahead aggregate demand curve is relatively inelastic, with only 2% of price-sensitive demand on average (see Section 3.4.4).

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

3.7.3 Residual Supply Index

The Residual Supply Index (RSI) identifies instances when the largest supplier has market power. Specifically, the RSI measures the percentage of real-time demand that can be met without energy from the largest supplier's portfolio of generation resources. 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 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 level higher than a competitive price. 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 was 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 2014 to 2016.

Table 3-3: Average System-wide Residual Supply Index for Real-Time Energy

Year	RSI	% of Hours with a Pivotal Supplier
2014	95.5	61.6%
2015	96.8	53.9%
2016	100.6	46.8%

There are fewer hours with a pivotal supplier in 2016 than the prior two years. This indicates that during 2016 suppliers faced relatively higher competition. This improvement in structural competitiveness can be partially explained by the lower load levels observed in 2016 compared to 2014 and 2015.

3.7.4 Lerner Index

The Lerner Index estimates the extent to which participants raise supply offer prices above marginal costs. This measure provides insight into market power and competitiveness, since price is the primary means of coordinating short-run production and consumption decisions. Uncompetitive offers priced above marginal cost can distort prices and impact resource allocation decisions. Thus, uncompetitive offers may lead to inefficient market outcomes.

In a perfectly competitive market, all market participants' offers would equal their marginal costs. The Lerner Index estimates the divergence of the observed market outcomes from this ideal scenario.

To calculate the Lerner Index, the day-ahead market clearing was simulated using two scenarios:[106]

- 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.[107]

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.

For 2016, the Lerner Index for the day-ahead energy market was 8.2%. This indicates that offers above marginal cost increased the simulated day-ahead energy market price by approximately 8.2%. These results are consistent with previous years and within normal year-to-year system given modeling and estimation error.[108] Table 3-4 shows the annual Lerner Index values.

[106] 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.htm.

[107] 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.

[108] 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 and 2016 Lerner Indices differs slightly from methods used in previous years.

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

Year	Lerner Index
2012	9.9
2013	4.3
2014	9.0
2015	8.3
2016	8.2

The Lerner Index calculated for 2016 is relatively low. The results show 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 avoid the potentially harmful effects of market power. When a participant's supply offer fails specific mitigation tests the offer is replaced with a competitive benchmark price known as the reference level. Generator reference levels are determined in consultation with the participant and are intended to reflect a competitive offer.[109]

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

3.8.1 Types of mitigation

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

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

Structure test. The market structure test evaluates the amount of competition faced by a participant to determine whether they possess market power. A participant is deemed to have market power in any of three conditions. The first is when they are a *pivotal supplier* controlling resources needed to meet system-wide load and reserve requirements. The second condition is when their resource is in a *constrained area* of the system and has the ability to affect local area

[109] 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.

prices. And the third is when their resource is required to meet a specific *reliability need* such as voltage support; in this scenario the resource may be the only unit, or one of very few, capable of serving the need.

Conduct test. The conduct test checks whether the participant's offer is above its competitive reference level by more than the allowed thresholds. The allowed threshold, expressed as a percentage or dollar amount, depends on the type of market structure test that applies in the scenario. The threshold values are tightest for scenarios where opportunities to exercise of market power are most prevalent.

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

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

Table 3-5 below provides an overview of the types of mitigation, except dual fuel 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.

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 relevant to commitment events. Energy and commitment mitigation types also differ in terms of the supply offer components evaluated. For energy mitigation, only the incremental energy segments of the supply offer are relevant. In commitment tests, the aggregate cost of start-up, no-load, and incremental energy at minimum output (*i.e.*, the commitment or "low load" cost) are evaluated over the commitment duration.

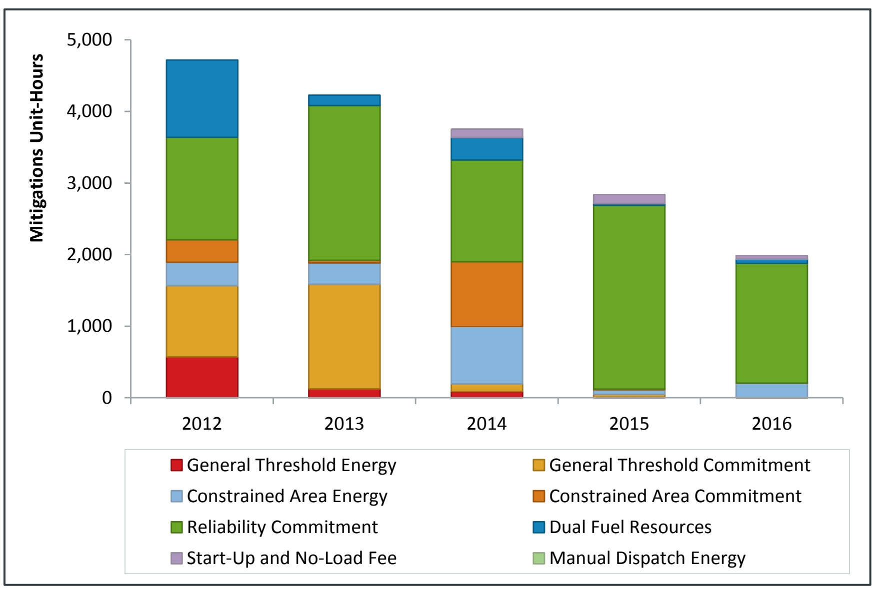
There is one additional mitigation type specific to dual fuel resources not listed in Table 3-5. Dual fuel mitigation occurs after-the-fact when the supply offer indicates a generator will operate on a higher-cost fuel than it actually uses (*e.g.*, if offered as using oil, but the unit actually runs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

3.8.2 Mitigation event hours

In this section, the occurrences of mitigations in the energy market are summarized for the year 2016 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 tallies represent unit-hours of mitigation). For example, if a single generator offer was mitigated for five hours when committed in the day-ahead market, the mitigation count for this day will be five unit-hours. If a second generator offer was mitigated on the same day for three hours during real-time, the total for this hypothetical day would then be eight unit-hours.

Throughout 2016 the total amount of mitigations continued to decline. There were 1,987 unit-hours when any one of the mitigation types was applied. This is 30% lower than the 2,838 total unit-hours that occurred in 2015. For context, the 1,987 unit-hours of mitigation that occurred in 2016 equates to less than one generator offer mitigated each hour (*i.e.*, the 1,987 mitigated unit-hours divided by 8,784 hours in 2016 equals 0.2 mitigated units per hour). Figure 3-38 below presents the annual tallies of mitigations by type for each year between 2012 and 2016.

Figure 3-38: Mitigation Events by Annual Period[110]



The number of energy mitigations continued to decline year-over-year during 2016. By categories of mitigation, there were increases in the occurrences of dual fuel resource

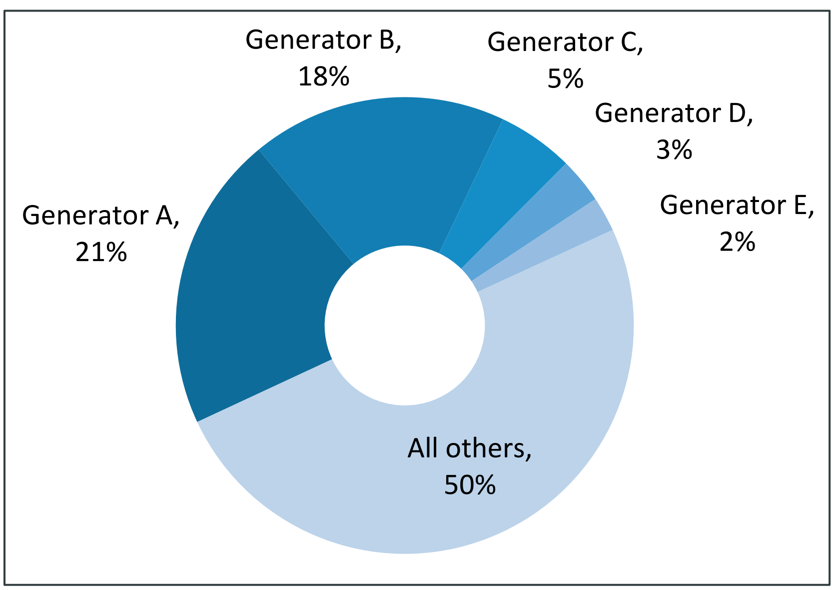
[110] Data for 2012 is for the period beginning April 19, 2012 when automated mitigation was implemented.

mitigation (dark blue) and constrained area energy mitigation (light blue). The greater frequency of constrained area energy mitigations occurred specifically in the NEMA load zone where planned transmission work frequently limited the transmission capacity to serve Boston area demand. The higher frequency of constrained area energy mitigation in 2014 was attributable to high natural gas costs during the first quarter of 2014 which made the applicable mitigation thresholds fairly tight. The totals of all other categories of mitigation declined in 2016. The overall trend of declining dual fuel resource mitigations is consistent with expectations of the hourly markets rule changes implemented in December 2014 that allow suppliers to adjust their offers hourly and specify the use of different fuel types within the operating day.

Although down in total occurrences relative to 2015, reliability commitment mitigations remained the predominant type occurring in 2016 – accounting for 84% (1,671) of mitigation occurrences. The frequency of reliability commitment mitigations is consistent with the hourly markets rules changes which expanded the application of this mitigation test to scenarios where a generator remains online beyond the end its scheduled commitment. During 2016, the majority of reliability commitment mitigations occurred from September through November when transmission work in the Boston area affected the frequency of transmission constraints and need for local reliability commitments for the NEMA zone.

To provide additional context about where and how the mitigations occurred the next two figures present breakdowns of 2016 mitigation occurrences by specific units mitigated and their location in the system. To begin, Figure 3-39 below shows the breakdown of mitigations by the top five most-frequently mitigated generators. The actual generator names are not presented, but instead they are given generic labels.

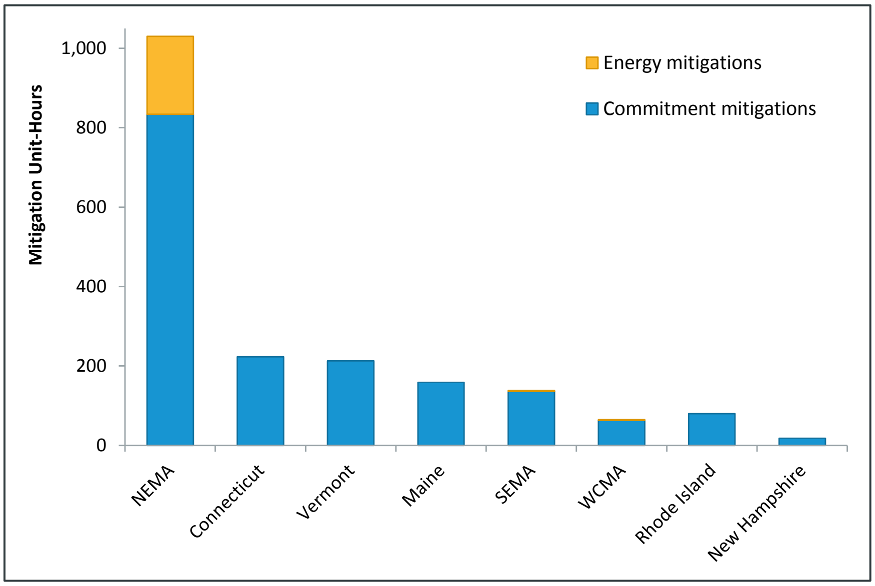
Figure 3-39: Top 5 Mitigated Generators as % of Mitigation Events



The five most-often mitigated generating units account for 50% of the mitigation unit-hours that occurred in 2016. The top two generators alone accounted for 39% of the mitigations. There were 99 generators with at least one mitigated hour during 2016. There were 374 units in total which were subject to the mitigation rules.

Finally, to illustrate the geographic concentration of mitigations across the New England system the year's mitigation occurrences are classified by the load zone where the generator is located in Figure 3-40 below. In this figure, the general threshold energy and constrained area energy mitigation types (refer to Table 2-1) are presented in the yellow "Energy mitigations" series and all other mitigation types are in the blue "Commitment mitigations" series.

Figure 3-40: Mitigation Events by Load Zone (2016)



As Figure 3-40 highlights, the majority of both energy and commitment type mitigations occurred within the NEMA load zone - about 52% of all unit-hours during 2016. The prevalence in the NEMA area during 2016 was driven primarily by the aforementioned planned transmission work, which created energy flow constraints and the need for local reliability commitments to meet local load and reserve requirements. The remainder of the mitigation occurrences had no particular concentration across the other areas of the system.

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).

Virtual transactions are purely 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, they 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.

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 has declined in recent years as the amount of congestion 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. Since 2008, "transaction" costs imposed on virtual transaction volumes have increased significantly, while volumes have decreased. 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 purely financial 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.

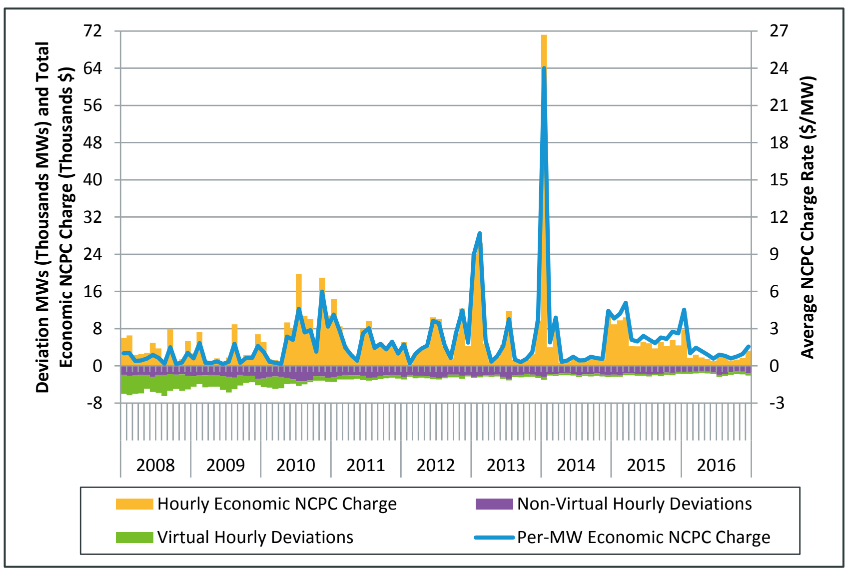
Price convergence signals that the day-ahead market is an accurate representation of real-time conditions, and allows the energy market to satisfy real-time load in the least cost way. Virtual bids and offers can be submitted at any pricing location on the system during any hour. Virtual transactions 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, and cleared virtual demand bids make a profit if the real-time price is higher. 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.[111]

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."[112] Virtual demand is included as a part of load obligation deviation, and can therefore increase or decrease deviations.[113]

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 how NCPC charges to virtual transactions, the volume of virtual transactions and the average NCPC charge rate ($/MW) have changed in the past seven years. It shows the per-MW NCPC charge rate for deviations, the hourly average deviation (MW), and hourly average economic NCPC payments which are recovered over the deviations.

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



111 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.

112 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.

113 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.

There are several key observations:

- 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.

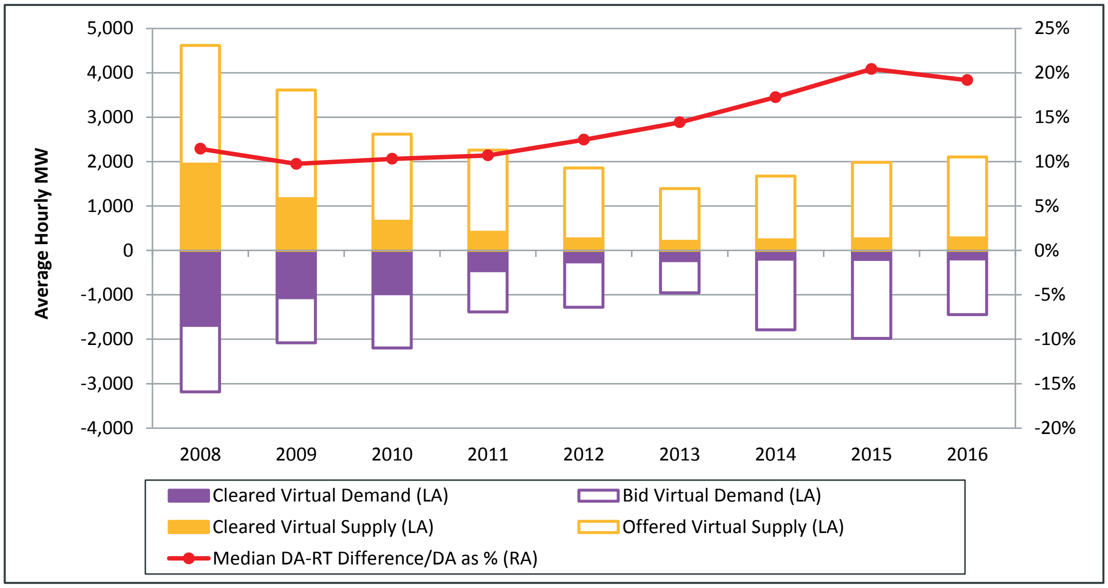
For example, in 2016, approximately 475 MW/hour of virtual transactions cleared, compared with about 3,633 MW/hour in 2008. The average per-MW real-time NCPC charge rates during these years were $1.22 and $0.67, respectively. Although this difference in per-MW economic NCPC charges represents an 82% increase, the change was actually less pronounced in 2016 than in previous years, as relatively little real-time economic NCPC was paid. In 2015, although virtual volumes were only 3% lower than in 2016, the per-MW real-time NCPC charge was $2.93, 140% higher. The decrease in real-time NCPC in 2016 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 and 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 13% of hours in 2016, 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.[114] This may lead to traders structuring their virtual demand bids and supply offers to clear only if the day-ahead price is extreme relative to the expected real-time price. 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. This is mostly the case.

The decline in submitted and cleared volumes occurring between 2008 and 2016 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, by normalizing by 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.

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

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

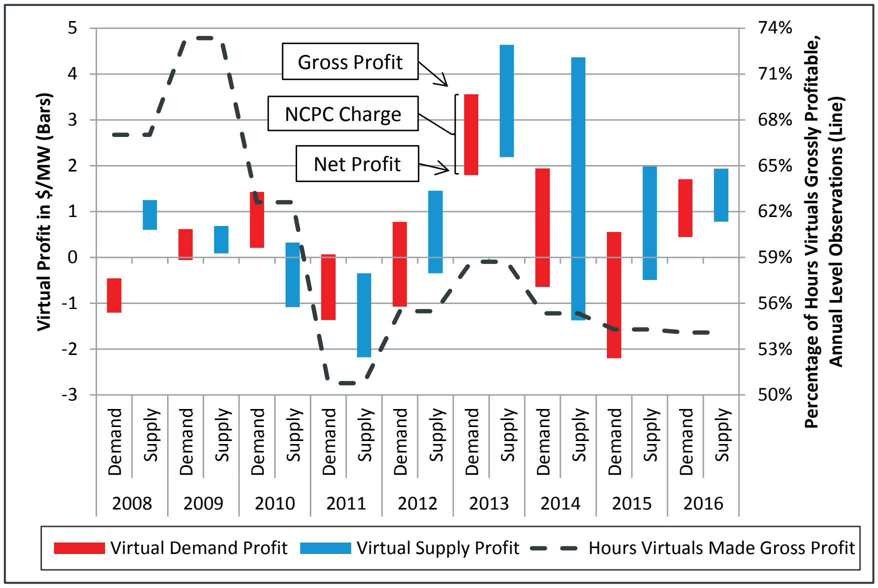


Cleared virtual transactions declined from over 2,000 MW per hour in 2008 and 2009 to less than 500 MW per hour in 2013 through 2016. During this time, the mean price difference has fluctuated between $6.14/MWh in 2009 and $17.29/MWh in 2014 (blue line). Overall price convergence has declined since 2008 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 2016 from about 11% in 2008, and less than 10% in 2009.[115] 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 virtual transactions since the beginning of 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, and 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.

115 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.

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 2016 were substantially greater than in 2008 and 2009. In 2008 and 2009, virtual transactions made $0.53/MW before NCPC. In 2013 to 2016, virtual transactions made $2.60/MWh.

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. In 67% of hours in 2008, virtual transactions were profitable on gross basis. This number increased to 73% in 2009; in 2016, virtual transactions only helped converge price in 54% of hours, despite having gross profits of $1.84 per-MW during the year. The increase in gross 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. This concept is discussed further in Section 3.3.4 on energy price convergence.

During years when virtual transactions have been profitable on a gross basis, virtual trades 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 2016, 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.

4.2 Financial Transmission Rights

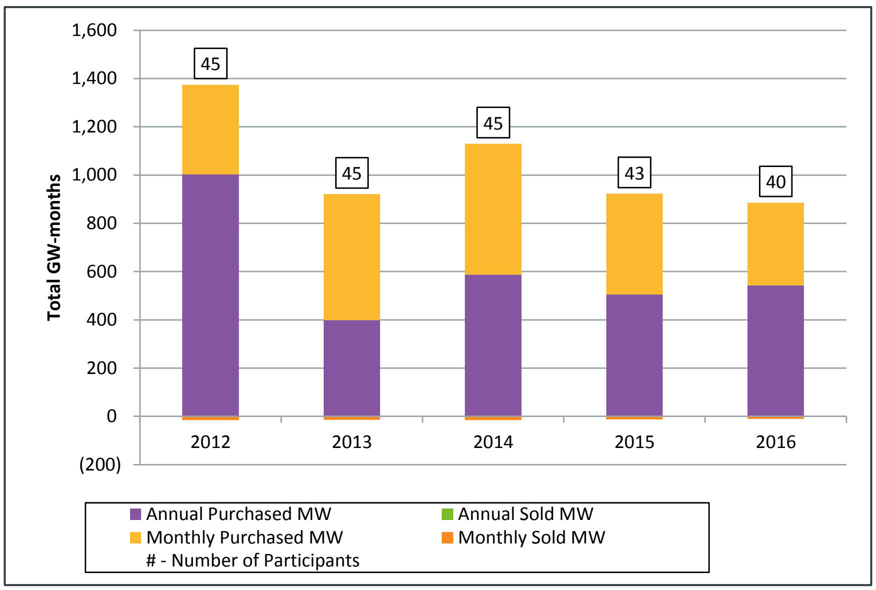
In this section, we discuss the purpose of financial transmission rights (FTRs) and the performance of the FTR market. FTRs allow participants in the New England energy market to hedge the cost of transmission congestion and arbitrage differences between expected and actual day-ahead congestion costs.

FTRs can be purchased between any two nodes 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 3.4.8). Participants purchase and sell FTRs in annual and monthly auctions.

Similar to virtual transactions, there can be various motives driving activity in the FTR market. FTRs can be purchased strictly 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 auctions 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. Figure 4-4 shows the volume purchased during each year between 2011 and 2015.

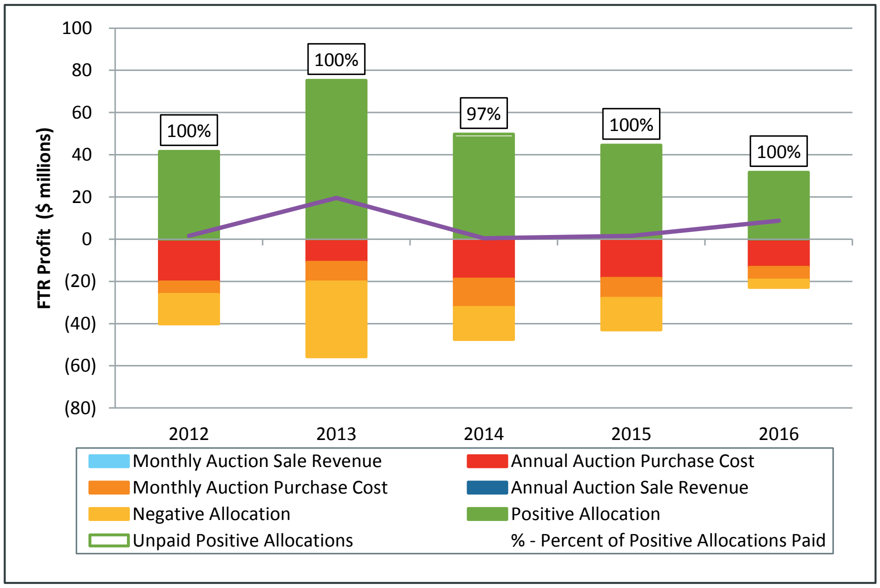
Figure 4-4: Financial Transmission Rights Purchased and Sold



In 2016, 40 participants purchased approximately 886 GW-months of FTRs. About 61% 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 4-4.The volume of bids in an auction is typically multiple times the actual cleared volume. In the 2016 annual auction, 19% of the MW volumes bid into the auction cleared, while 44% 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 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 can be seen in Figure 4-5.

Figure 4-5: Financial Transmission Profits and Costs



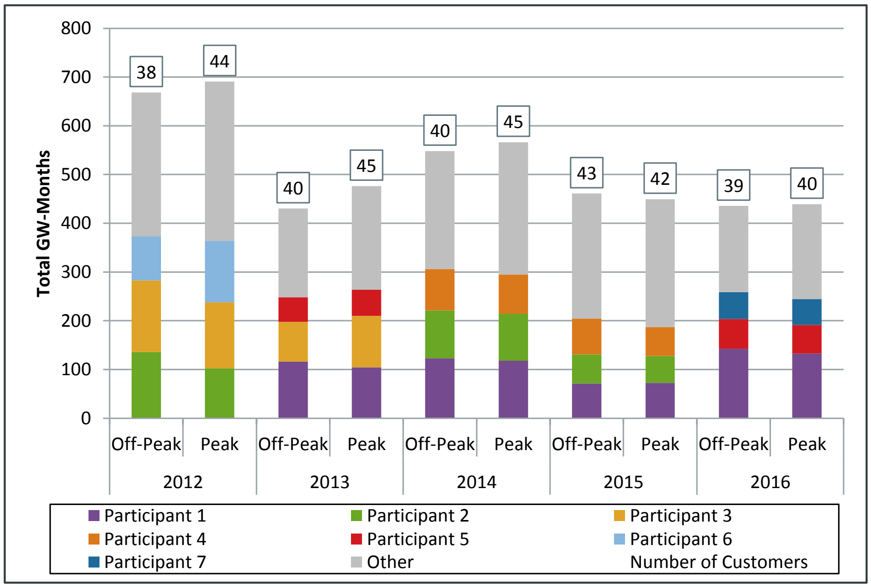
In 2016, the total profit was $8.8 million (purple line). During 2016, there were approximately 875 GW-months of FTRs owned, profiting $10.01/MW-month on average. Both positive and negative allocations, as well as the cost of FTRs in the auction were down from previous years. While FTR MW volumes were similar to 2015, auction participants as a whole undervalued the congestion on the system. As shown in Figure 4-5, both positive and negative allocations have decreased in magnitude every year since 2013.

Despite the decrease in both positive and negative allocations, the net of positive and negative allocations increased in 2016 because the decrease in positive allocations was significantly less than the decrease in negative allocations. This means that in 2016, there was a smaller obligation to be paid by participants for congestion flowing "against" their paths. In the last two years, auction prices reflected the reduction in day-ahead congestion, but were high enough to allow the pool of FTR holders to make a slight profit. This year, FTR prices were much lower. Participants in the FTR market paid on average $22 per MW-month in the auctions, compared to about $30 in 2015 and $29 in 2014. Although the prices were significantly lower, the total allocations to the FTR holders increased to $32 per MW-month (profit of $10) from $31 (loss of $1) in 2015 and $29 in 2014 (break-even). The decrease in auction price resulted in higher overall profit. Although larger than the profits in the previous two years, the $8.8 million dollar total profit in the FTR market is still relatively modest. Significant investment in transmission 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 3.4.8. If there are shortfalls in the congestion revenue fund, only the portion that can be funded is paid. In 2014, 3.6% of positive allocations were unpaid due to a shortfall in the congestion revenue fund. The unpaid portion of positive allocations in 2014 can be seen in Figure 4-5 above, where the purple line falls slightly below zero. FTRs were fully funded in 2016.

Figure 4-6 shows the amount of FTRs held by the top six participants with the most MW each year in on-peak and off-peak hours.[116]

Figure 4-6: Top Six Holders of Financial Transmission Rights



In 2016, a similar number of on-peak and off-peak megawatts were purchased. The volume purchased in 2016 was consistent with the previous four years. The slight reduction in volume may have been influenced by lower loads due to mild weather that participants anticipated would lessen congestion on the system. Three participants owned 56% of the on-peak FTRs, which was slightly more than last year but 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.[117]

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

117 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, we assess the market outcomes at the New York North interface where Coordinated Transaction Scheduling (CTS) was implemented in mid-December of 2015.

Net interchange of power with neighboring control areas was similar to the past three years, with an average of 2,369 MW imported each hour. New England imported a similar amount of energy from Canada in 2016 as compared with the prior year. A planned outage on the Phase II line caused a decrease in average hourly imports. There was a corresponding increase in imports at the New Brunswick interface over the same period.

Coordinated transaction scheduling is intended to improve the flow of power between New York ISO (NYISO) and ISO-NE. Priced transactions increased across the New York North interface after the implementation of CTS. However, many of the priced transactions were bid in at negative prices that effectively rendered the transactions fixed in price. Overall, CTS has improved scheduled power flows at the New York North interface. The implementation of CTS and congestion pricing at the New York North interface contributed to a 71% decrease in day-ahead NCPC credits at external nodes.

Improvements in the price forecasting used in the CTS scheduling process would decrease the risk of offering competitively priced transactions. Further, increasing the amount of price-sensitive bidding would produce more efficient scheduled power flows, and therefore increase price convergence between the two ISOs.

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 transaction at a single external node. These transactions may be submitted as either a priced or fixed type transaction and are allowed in both the day-ahead and real-time market. A priced transaction is evaluated for clearing based on its offer price relative to the node 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 day-ahead 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 also use wheel type transactions to ship power across New England between two external nodes. Wheel transactions are evaluated as fixed type. For CTS there is an additional real-time transaction type called an interface bid which indicates the direction of trade and minimum price spread between the New York and New England prices the participant is willing to accept to have its transaction cleared.

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. Internal generation will be re-dispatched based on scheduled tie flows. 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 deadlines to submit external transactions are specific to the transaction type. Day-ahead transactions and real-time priced type imports and exports are due by the close of the day-ahead offer period (*i.e.*, 10 am the day prior to the operating day). The offer prices of real-time priced type transactions may be modified only during the day-prior reoffer period (*i.e.*, before 2 p.m. the day prior to the operating day). Within the operating day, CTS interface bids are due by 75 minutes before the hour, fixed type transactions may be submitted until 60 minutes before the hour, and the MW offer quantities for priced type transactions may be adjusted up-to 60 minutes before the hour.

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 transactions only in real-time. When a participant submits a transaction with both day-ahead and real-time offers, that transaction is afforded some scheduling priority during real-time in the event of a tie. In particular, the MW amount cleared in the day-ahead is scheduled as if it were offered as a fixed type transaction in real-time, unless the participant alters the offer price or withdraws the transaction in real-time.[118]

In the day-ahead market, external transactions are cleared for whole hour periods based on economics, subject to 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 every 15 minutes for 15-minute schedules.

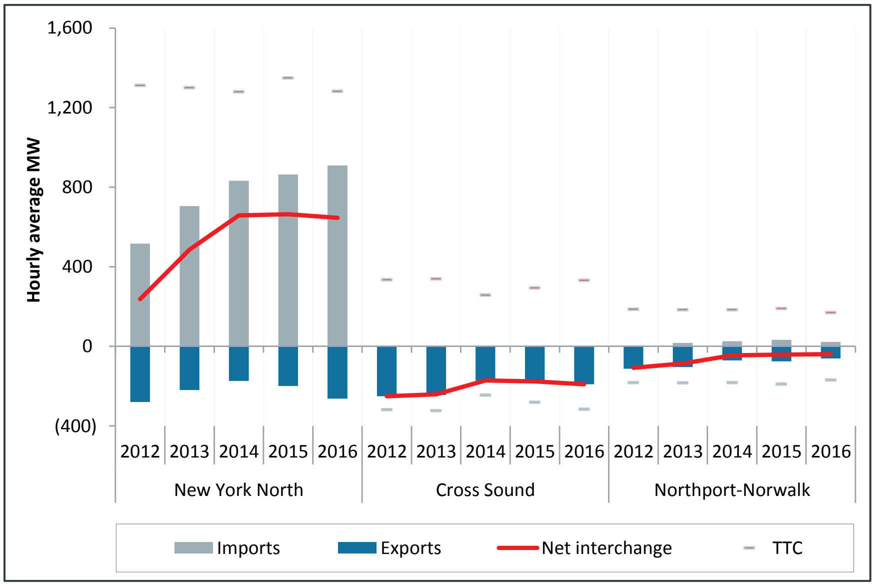
5.2 External Transactions with New York and Canada

In Section 2 of the report total or aggregated energy interchange statistics were presented and discussed. In 2016, New England remained a net importer of power, with net imports during real-time totaling 20,809 GWh, which equates to 2,369 MW imported, on average, each hour. This section provides a detailed breakdown of the total flows across each of the six interfaces with New York and Canada (see Table 2-1 in Section 2).

In aggregate, New England is a net importer of power from both New York and the Canadian provinces. However, 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 the New York control area are shown for each year between 2012 and 2016 in Figure 5-1 below. Note that the annual observations are grouped by interface in this chart, and in Figure 5-2 for the Canadian interfaces, which is further below.

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

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



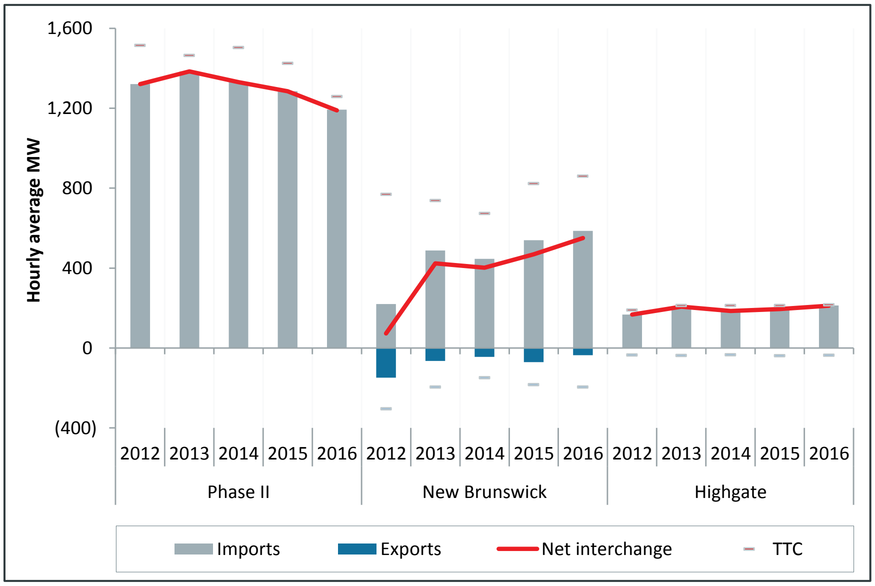
New England predominately imports power over the New York North interface and exports power at both the Cross Sound and Northport-Norwalk interfaces. Combining flows at all three interfaces, the real-time net interchange with New York totaled 3,658 GWh of energy imported, or an average of 416 MW per hour in 2016.

The New York North interface is comprised of seven AC lines between New York and New England. It has the largest import and export transfer capacities (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 hourly average values of the real-time total transfer capacity (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 capacity 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 in 2016, exports at the New York North interface increased by 33% relative to 2015. Imports at this interface also increased, by 5%, and are considerably larger in absolute volume, but the increase in exports was enough to reduce the real-time net interchange 3% compared to 2015. The New York ISO and ISO-NE implemented Coordinated Transaction Scheduling at the New York North interface in mid-December, 2015, to improve the efficiency of real-time power flows between the two markets. Section 5.5 of this report discusses the observed impacts of this market change in further detail.

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 2012 and 2016 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 totaled 17,151 GWh of energy imported, or an average of 1,953 MW per hour in 2016, which was similar to the imported volumes during 2015.

Figure 5-2: Real-Time Net Interchange at Interfaces with Canada



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 36 MW per hour during 2016. There was a shift in the location of import transactions between the Phase II and New Brunswick interfaces during 2016. The net interchange at Phase II declined 95 MW per hour, on average, between 2015 and 2016. This reduction was caused primarily by the planned outage of Phase II from April 1st through May 30th to replace and test the interface protection and control equipment. There was a corresponding increase in the New Brunswick net interchange of 82 MW per hour, on average, in 2016 relative to 2015. It appears that during the Phase II outage many suppliers routed power sourced from other Canadian provinces over to the New Brunswick interface in order to deliver energy to New England.

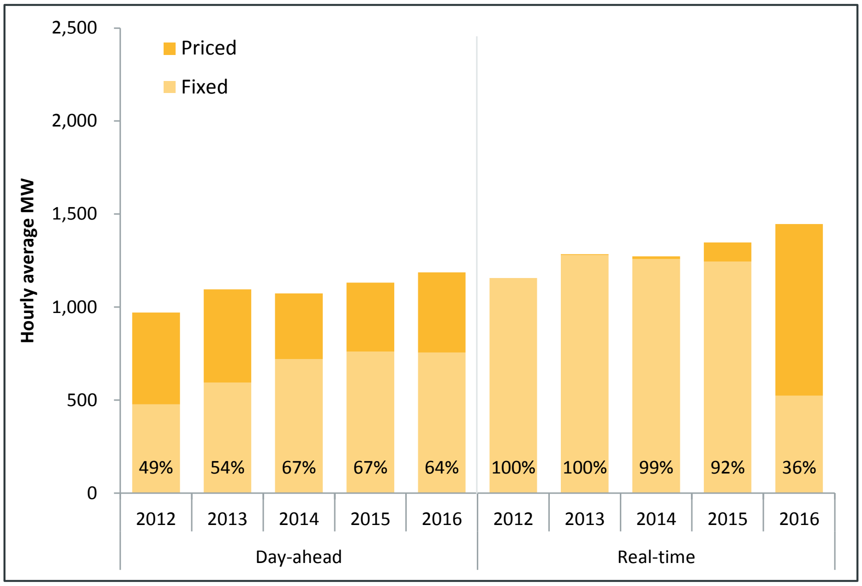
5.3 External Transaction Types

In this section, we examine the external transactions that underlie the transacted energy volumes discussed in the preceding section and in Section 2.4. 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 type transactions.

The composition of transactions cleared in the day-ahead and real-time markets at New York interfaces are charted in Figure 5-3 below for each year between 2012 and 2016.[119] The lighter yellow series is the total volume of fixed type transactions and the percentage value is the share of overall cleared transactions that were fixed type. The darker yellow series is the volume of priced type transactions cleared. The cleared volumes are presented as the average MW per hour annually.

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

Figure 5-3: Transaction Types Cleared at New York Interfaces



The most apparent change in 2016 shown in Figure 5-3 is the large increase in real-time priced type transactions which had previously been only a small fraction of real-time transactions. The shift to priced transactions at New York interfaces is due to implementing CTS in December, 2015. All real-time transactions at New York North are now evaluated based on price, although participants may (and often did) offer prices as low as negative $1,000 MWh to effectively have the transaction scheduled as fixed. In Section 5.5, we examine the price bidding behavior of CTS transactions further. There was a 7% increase in total real-time scheduled energy in 2016 compared to 2015. As discussed in Section 2.4 there was a 33% increase in scheduled exports at the New York North interface. The day-ahead volumes of fixed and priced transactions in 2016 were consistent with prior years, with priced transactions making up only 36% of cleared volumes in day-ahead.

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 segregated by import and export transactions at the New York interfaces in Table 5-1 below. Here again the values presented are for cleared transactions and the volumes are the average MW per hour.

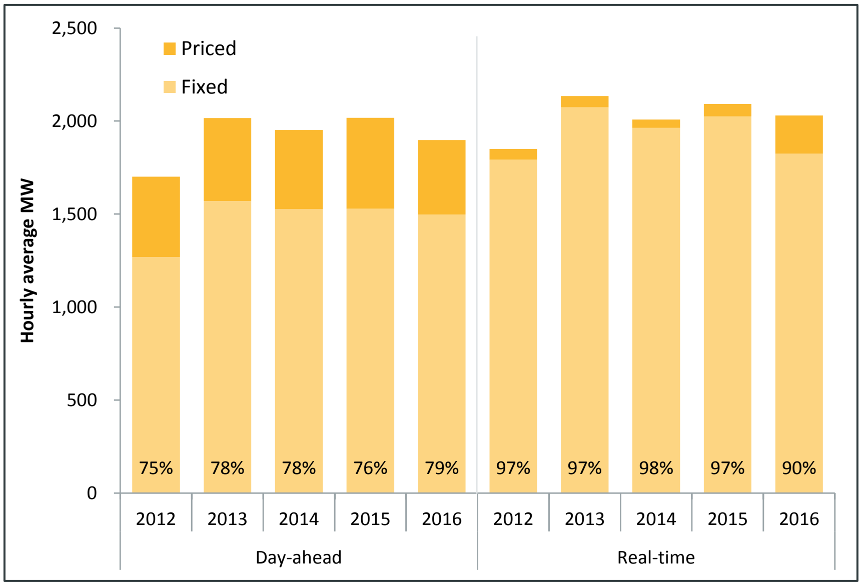
Table 5-1: Transaction Types by Direction at New York interfaces (MW per hour)

Market	Direction	Type	2012	2013	2014	2015	2016
Day-ahead	Import	Priced	27	80	63	89	133
		Fixed	372	533	687	700	709
		Percent Fixed	93%	87%	92%	89%	84%
	Export	Priced	468	422	291	281	298
		Fixed	104	61	33	61	48
		Percent Fixed	18%	13%	10%	18%	14%
Real-time	Import	Priced	1	5	13	70	651
		Fixed	520	721	845	827	281
		Percent Fixed	100%	99%	98%	92%	30%
	Export	Priced	0	0	0	32	272
		Fixed	634	558	413	418	242
		Percent Fixed	100%	100%	100%	93%	47%

The majority of priced type transactions at the New York interfaces are export transactions. For example, the 2016 value of 36% priced transactions in the day-ahead discussed previously was composed of 133 MW of imports and 298 MW of exports, on average, hourly. Reading down the 2016 column of Table 5-1, the percentage of fixed import transactions was 84%, whereas fixed transactions made-up only 14% 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 markets.

The composition of transactions cleared in the day-ahead and real-time markets at interfaces with the Canadian provinces are charted for each year between 2012 and 2016 in Figure 5-4 below. The lighter yellow series is the total volume of fixed type transactions and the percentage value is the share of overall cleared transactions that were fixed type. The darker yellow series is the volume of priced type transactions cleared. 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 is highlighted by comparing Figure 5-4 and Figure 5-3. On the order of 2,000 MW each hour are scheduled over these interfaces compared with around 1,500 MW at the New York interfaces. The very high volumes of price-insensitive fixed transactions are also evident; in 2016 almost 80% of day-ahead and 90% of real-time scheduled volumes were fixed type transactions. As discussed above, a real-time transaction will be scheduled as-if 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 90% of the real-time priced type transactions in 2016 were scheduled as-if they were fixed type transactions. The ratio of priced type transaction power scheduled as-if fixed in real-time has been above 80% each year since 2013.

The breakout of fixed and priced type 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	2012	2013	2014	2015	2016
Day-ahead	Import	Priced	421	446	420	486	399
		Fixed	1,200	1,564	1,517	1,509	1,491
		Percent Fixed	74%	78%	78%	76%	79%
	Export	Priced	12	0	6	3	2
		Fixed	69	6	9	20	6
		Percent Fixed	85%	99%	58%	88%	78%
Real-time	Import	Priced	47	61	42	64	203
		Fixed	1,655	2,009	1,919	1,955	1,788
		Percent Fixed	97%	97%	98%	97%	90%
	Export	Priced	10	0	3	2	4
		Fixed	138	64	44	70	35
		Percent Fixed	93%	100%	93%	97%	90%

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

5.4 Net Commitment Period Compensation Credits

The high volumes of day-ahead fixed type transactions occurring 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.[120] Instead, the cost of relieving the congestion is reflected in a transfer of NCPC between those causing the congestion and those reliving 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 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. In other words, a total volume of import transactions or virtual supply offers can be cleared that exceeds the import transfer capability if offsetting export transactions or virtual demand bids are available and in economic merit. 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

[120] 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 and very high-priced offers are cleared to create counter-flow for the fixed transactions to clear. The participant with the high-priced offer which created the counter-flow receives the NCPC and participants with the fixed transactions that were thus allowed to clear are charged for 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 2012 through 2016 are presented in Table 5-3 below.

Table 5-3: NCPC Credits at External Nodes

Year	Day-ahead credits ($M)	Real-time credits ($M)
2012	$0.78	$2.88
2013	$2.83	$0.31
2014	$10.03	$0.59
2015	$3.05	$1.15
2016	$0.90	$1.28

The total amounts of NCPC credits paid at external nodes are very small compared with other types of NCPC (See Section 3.5 for coverage of NCPC). 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.

In 2016, day-ahead credits decreased 71% compared to 2015. At the New York North interface, day-ahead credits decreased by $1.2 million since congestion pricing has been implemented at this node under the CTS design.[121] At the Phase II interface, day-ahead credits decreased by $1.1M relative to 2015. During the extended outage of Phase II in April and May of 2016, external transactions were not allowed at this location, which prevented clearing day-ahead offsetting transactions that would have no impact on market outcomes except to create NCPC and spot market deviations.

Real-time credits are paid to priced type transactions scheduled during real-time that turn out to be out of economic merit for the hour, similar to generator out-of-merit credits.[122] As Table 5-3 shows, total real-time credits during 2016 were comparable to 2015. 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 in 2015 and 2016 relative to the preceding years.

[121] Under the CTS design, day-ahead transactions at the New York North location also are not eligible for NCPC credits.

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

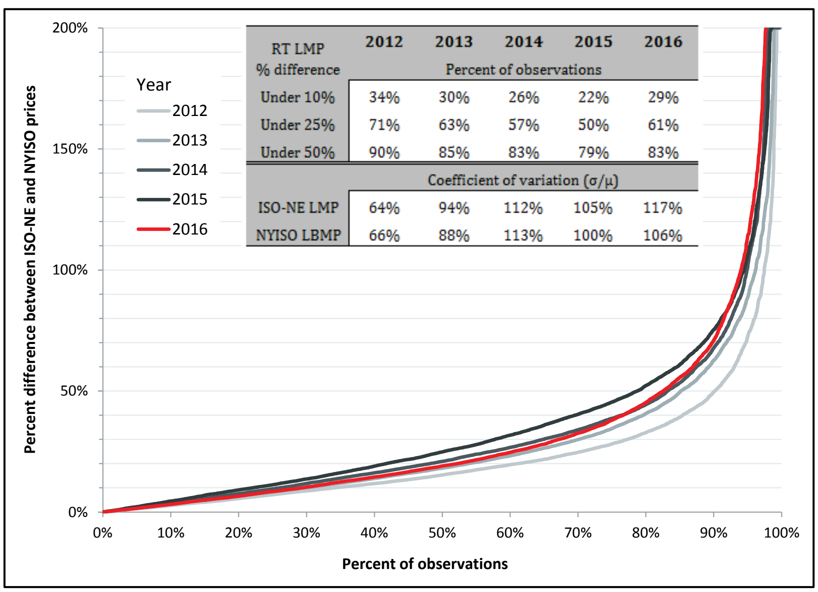
5.5 Coordinated Transaction Scheduling

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 new measures of real-time price convergence and the risk of ISO internal price forecast errors born by competitive arbitrage bidders. In addition, metrics on price forecast accuracy and bidding behavior originally reported in our analysis on CTS in the 2016 Spring Quarterly Markets Report have been updated with the a full year of observations.[123]

CTS was implemented by ISO-NE and the New York Independent System Operator (NYISO) on December 15, 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.[124] The CTS design is 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.

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 hourly prices at each ISO's respective pricing location for the New York North interface and present the results in Figure 5-5 below.[125] 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 respective external nodes.

Figure 5-5: New York North real-time price difference between ISO-NE and NYISO



RT LMP % difference	2012	2013	2014	2015	2016
	Percent of observations				
Under 10%	34%	30%	26%	22%	29%
Under 25%	71%	63%	57%	50%	61%
Under 50%	90%	85%	83%	79%	83%
	Coefficient of variation (σ/μ)				
ISO-NE LMP	64%	94%	112%	105%	117%
NYISO LBMP	66%	88%	113%	100%	106%

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123 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

124 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/

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

Each year between 2012 and 2016 is plotted by a separate line series in Figure 5-5 above, with the red line series representing the year 2016 which is the first full year with CTS 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 have 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 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.[126] If price volatility were 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 divergence between the regions is expected unless a scheduling system like CTS is frequently adjusting the interface flow.

The data presented in Figure 5-5 does not support a firm conclusion about improvement in real-time price convergence with CTS. However, the data do indicate a comparable degree of convergence during a year when price volatility was highest for ISO-NE and second highest for NYISO over the five year period. The coefficient of variation in real-time price was 117% for ISO-NE and 106% at the NYISO side during 2016. Although price variability was comparable to 2014 and 2015, in 2016 the probabilities of price differences falling below 10% and 25% both increased relative to the preceding years. The probability of ISO-NE and NYISO price differences being less than 10% were greater during both 2012 and 2013 than in 2016; however, note that the coefficient of variation values also are considerably lower for both markets in 2012 and 2013. This metric indicates that using CTS to schedule interface flows more frequently and for shorter periods (*i.e.*, 15-minutes) appears to improve tie flows and price differences as market conditions and internal generation costs change.

As we reported previously, we also evaluate the relative performance of CTS compared to the prior transaction scheduling mechanics with metrics on the frequency and degree of intuitive power flows (*i.e.*, from the lower- to higher-priced region), and of counterintuitive flows (*i.e.*, too much power is scheduled and market price differences invert at the margin). To measure these we use the actual real-time scheduled flows and prices when one ISO is producing electricity at higher cost and the interface is unconstrained.[127] The actual real-time scheduled flow and price difference occurrences between regions in each of four possible states are presented in Figure 5-6 below.

The first two states are the intuitive outcomes based on real-time prices: (1) when the New England price is higher and net tie flow is toward New England (the top right quadrant), and (2) when the New York price is higher and net tie flow is toward New York (the bottom left quadrant). These intuitive quadrants are highlighted green. These instances appear intuitive because the importing region has a higher native generation cost. However, the large price differences between the regions during unconstrained intervals indicate that the amount of power delivered to the importing ISO should be further increased to achieve a more efficient tie schedule. That is, the

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

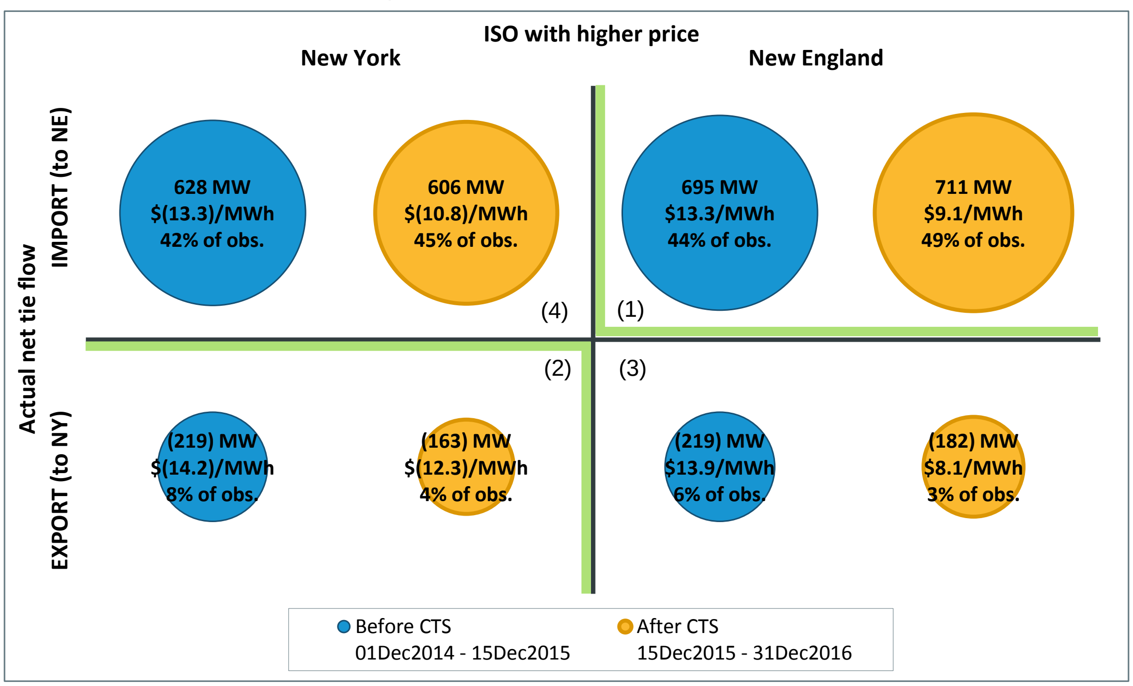
127 For this analysis, the interface was characterized as constrained in the period before CTS if the scheduled power flow was within 2% of the total transfer capability (TTC) applicable for the hour. The interface was constrained for 22% of observations in the before CTS period. For the period after CTS, the interface schedule is identified as constrained if a reliability limit (*e.g.*, TTC, interface ramp limit, system reserve requirement) was binding for the 15-minute scheduling interval; this occurred during 20% of observations.

interface would be utilized to deliver more lower-cost power from the exporting region and the importing region would back down its more expensive generation, up to the point that the market prices are equal.

The other two states are counterintuitive outcomes where the exporting ISO has a higher cost of energy at the margin than the importing ISO. These outcomes are: (3) when the New England price is higher and the net tie flow is toward New York (the bottom right quadrant), and (4) when the New York price is higher and net power flow is toward New England (the top left quadrant). In these instances it would be more efficient to reduce the tie flow (toward zero), backing down higher-cost generation in exporting region and dispatching up lower cost generation in the importing region up to the point that the market prices are equal.

Within each quadrant of Figure 5-6, the following measures are presented for the periods before CTS (blue) and after CTS (yellow): the average tie flow[128] on the top line (the bubbles are sized according to this value); the average real-time price difference on the middle line (calculated as the ISO-NE price minus the NYISO price[129]); and the frequency that each condition occurred before or after CTS as the percent of observations ("obs.") on the bottom line. As an example of how to read the chart, consider the top right quadrant where the New England price is higher and the direction of tie flow is an import to New England. Here we observe that, on average, 695 MW were delivered to New England before CTS whereas 711 MW went to New England after CTS; the New England price was higher by $13.30/MWh before CTS and higher by $9.10/MWh after CTS; and that this scenario (New England having the higher price and net tie flow being to New England) was observed 44% of the time before CTS and 49% of the time in the period after CTS.

Figure 5-6: Real-time tie scheduling measures before and after CTS at NYN, unconstrained intervals



128 A positive value of average tie flow indicates a net import of power to New England and a negative value indicates a net export of power to New York.

129 A positive value of average price difference indicates the ISO-NE price is higher and a negative value indicates the NYISO price is higher.

The results presented in Figure 5-6 indicate a mixed change in performance measures after the CTS implementation. In the intuitive condition when the New England price is higher and power is flowing to New England (top right quadrant), there was an increase in the frequency of observations (from 44% to 49%) and slightly more power is being imported – on average, 711 MW after CTS compared to 695 MW before CTS. After CTS the average price difference also decreased to $9.10/MWh from $13.10/MWh.[130] Nevertheless, there is ample capability to increase flows to New England, on average, and price differences are nearly $9/MWh. More lower-cost New York power could be used to offset higher-cost New England power in these instances.

In the other intuitive condition when the New York price is higher and net power flow is an export to New York (the bottom left quadrant in Figure 5-6), the results indicate worse scheduling performance. The frequency of observations decreased from 8% before CTS to 4% after CTS and the volume of power being exported decreased from 219 MW exported before CTS to 163 MW after CTS. Here the average price difference is also lower between the two regions after CTS, but not of a magnitude that appears to explain the average decrease in economic power flow to New York.

Taken together, the results in the two intuitive conditions reveal that power flow is in the economically efficient direction 53% of the time (49% + 4%) in the period after CTS, which is about as often as 52% before CTS (44% + 8%). The large price differences between the regions indicate the tie is on average under-utilized during unconstrained intervals. Too little power is flowing in the intuitive direction. The importing ISO is operating higher-cost generation at the margin that could otherwise be offset by delivering more power across the interface.

For the counterintuitive scenarios, the results with CTS show improvement. The counterintuitive observations are when the exporting region is using higher-cost generation to deliver power to the lower-cost region, which has native generation that is less expensive at the margin. Again looking at Figure 5-6, when the New York real-time price is higher, but net power flow is to New England (the top left quadrant), the average flow has decreased from 628 MW before CTS to 606 MW after CTS, and the premium paid for NYISO power at the margin fell from $13.30/MWh to $10.80/MWh. However, the market price differences are still large and New England is importing too much New York power in 45% of intervals after CTS implementation. When the New England real-time price is higher but net power flow is to New York (the bottom right quadrant in Figure 5-6) the results are overall more positive: average flow decreased (from 219 MW before CTS to 182 MW after CTS), the frequency of occurrences dropped by 3%, and the premium for New England power delivered to New York at the margin decreased from $13.90/MWh before CTS to $8.10/MWh after CTS.

The measures presented in Figure 5-6 are intended to provide insight into the relative performance of CTS compared with the prior transaction scheduling system. However, this analysis has its limitations. To thoroughly evaluate the cost of under-utilization and counterintuitive flows would require analyzing each ISO's supply curve and the interface bids to determine the optimal tie schedules ex-post. The NYISO internal supply curve data is not currently provided to ISO-NE. ISO-NE should acquire the additional data necessary to perform a more detailed assessment of the CTS scheduling solution and sources of deviation between actual flows and optimal flows.

Price forecast accuracy: The efficiency of CTS schedules can be greatly impacted by the accuracy of the ISOs' internal price forecasts of the marginal cost of energy at the external node. Price forecasts are calculated for each 15-minute interval and used to determine the direction of price differences

[130] The narrowed regional price spreads are likely driven by the lower natural gas and electricity prices in both regions that occurred coincident with the period after CTS.

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.

The last time we reported on the ISOs' price forecast accuracy in the 2016 Spring Quarterly Markets Report the analysis considered the period December 15, 2015 through June 30, 2016. Over that period, the NYISO forecast was lower than its actual settlement price by ($1.93)/MWh and the ISO-NE forecast was higher than its actual price by $1.17/MWh, on average.[131] Over the remainder of 2016 the price forecasts of both ISOs demonstrated greater accuracy. Extending the observation period through December 31, 2016, the NYISO forecast error shrank to ($1.57)/MWh below its actual price, on average. The average ISO-NE forecast error similarly shrank to $0.86/MWh above its actual price.

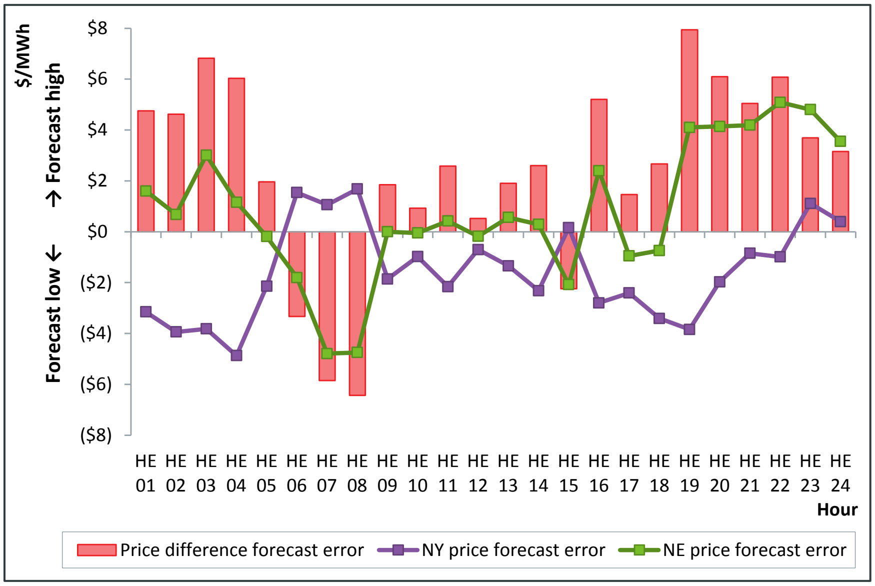
However, the ISOs' average forecast errors are still in the opposite direction, which will overestimate the actual price difference between the regions. Because each ISO's forecast error tends to occur in the opposite direction, the forecasted difference between the two market prices is higher than actual differences by $2.42/MWh, on average.[132] And forecast performance remains inconsistent for both ISO-NE and NYISO across the 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.

We updated a previously published exhibit showing the simple average of forecast errors calculated by hour of the day with data through the end of 2016 in Figure 5-7 below. 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 8:00 a.m. (HE 06 – HE 08). The cause of this shift in error tendencies during the morning hours is not yet known.

131 Forecast error is: Forecast minus Actual.

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

Figure 5-7: Average Real-Time ISO Price Forecast Errors, By Hour



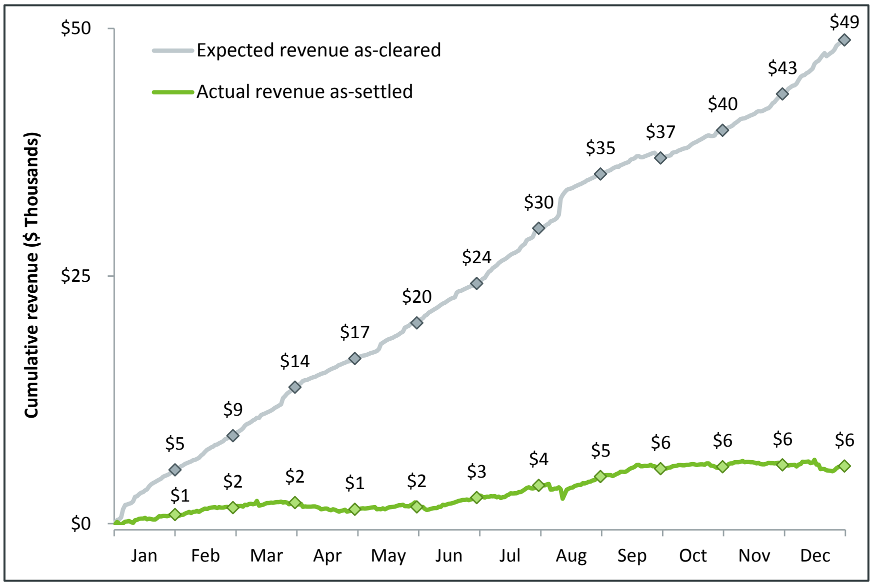
A positive observation in Figure 5-7 indicates the forecast is higher than the actual price and a negative observation indicates the forecast is lower than actual price. The purple line series represents the average error in the NYISO price forecast for each hour and the green line series represents the average error in the ISO-NE price forecast each hour. The red 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 $1.60/MWh and NYISO forecasts lower than its actual price by $3.15/MWh, on average. Thus, the average error in the forecast of price difference between the markets is $4.75/MWh higher than the actual difference.

The ISOs' forecast biases being in opposite directions may consistently produce inefficient tie schedules. When forecasted price differences are under-estimated, too few interface bids may clear and the interface may be underutilized. 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. The risk of ISO price forecast error is born 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 2016. 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 2016 is plotted in Figure 5-8 below. The gray line series is the expected revenue based on the forecasted price differences at the time the bid is cleared. The green line series is the actual revenue based on the final LMPs for market settlements. The month-end cumulative revenue totals are displayed above the diamond line markers. As the chart shows, both the expected and actual revenue are positive, but actual revenue falls 88% short of expected revenue over the period.

Figure 5-8: Cumulative Return on a 1 Penny CTS Interface Bid Strategy



The actual cumulative revenue of $5,795 for each MW transacted under this hypothetical strategy produces a positive return, but that actual return is 88% below the forecasted value of $48,826. We observe similar disparities in actual earnings relative to forecast using other bid prices for this analysis. 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 5-4 below. Notably, the import bid produces a loss at settlement.

Table 5-4: Gain or Loss on a 1 penny CTS Interface Bid Strategy by Bid Direction

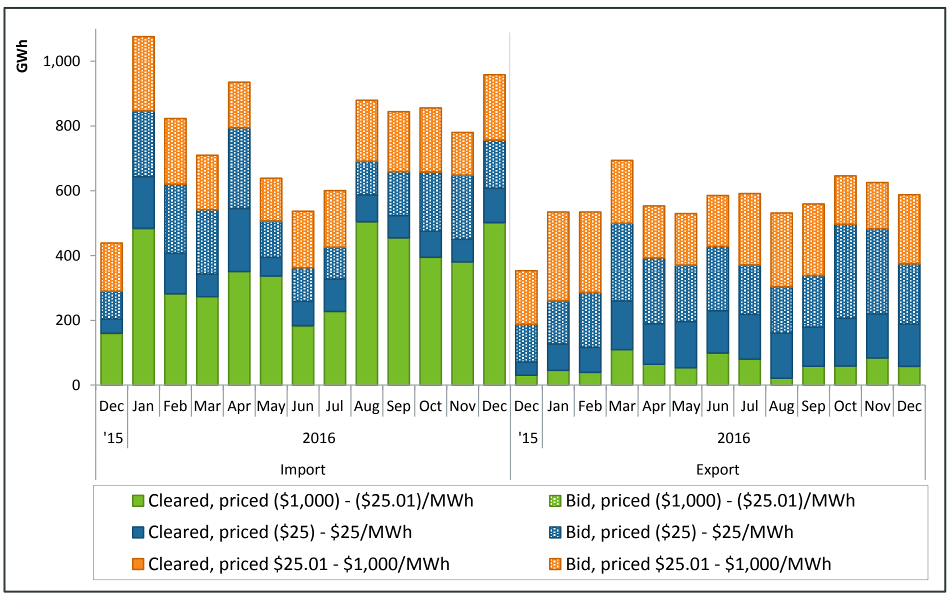
Bid direction	Bid price	Frequency cleared	Expected revenue as-cleared	Actual revenue as-settled	Gain or Loss at settlement
Export	$0.01/MWh	40.1%	$19,268	$8,172	(58%)
Import	$0.01/MWh	58.6%	$29,558	($2,377)	(108%)

The results by bid direction in Table 5-4 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; *i.e.*, 58.6% of scheduling intervals compared to 40.1% for the export. However, on average, the final New England LMP ends up lower than forecast and the New York LMP is higher than forecast. In these instances the interface schedule should have been adjusted in the opposite direction. 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.

CTS bidding observations: The ability to schedule real-time power in the economically efficient direction under the CTS design is also dependent on the bids submitted by market participants. CTS can only schedule import and export volumes up to the amount of the bid MW volumes submitted and at prices below the forecasted price spread between the two markets. Bid prices can be positive, negative, or zero. A positive bid price indicates the participant is willing to trade power when, as forecasted, the price in the source market is lower than the price in the destination market by at least the bid price (buy low and sell high). A negative bid price indicates a willingness to counterintuitively buy high and sell low; *i.e.*, to trade power when the energy price is expected to be higher at the source than the destination, by as much as the negative bid price. Over the period beginning December 15, 2015, through 2016 import transactions accounted for 71% of the power transacted at the interface and 90% of scheduled imports were bid at negative prices. Among export transactions, negative-priced bids accounted for 78% of the scheduled power.

The total energy volumes (GWh) of submitted and cleared interface bids are shown in Figure 5-9 below using three ranges of bid price: the price-insensitive bids offered at prices between ($1,000)/MWh and ($25.01)/MWh, a plausible range of competitive offers between ($25)/MWh and $25/MWh, and an opportunistic range of offers between $25.01/MWh and $1,000/MWh.

Figure 5-9: Interface Bid and Cleared Volumes (GWh) in Price Ranges



The monthly totals of submitted and cleared interface bids in Figure 5-9 shows the predominance of price-insensitive bids (green bars) contributing to cleared transaction volumes. Over the entire period, the largest share of scheduled power comes from negative-priced import bids. Only 38% of the competitive bids between ($25)/MWh and $25/MWh (blue bars) are being cleared in either direction. Only 0.1% of the cleared energy is from offers between $25.01/MWh and $1,000/MWh (orange bars), although these are 28% of bid MW. Also apparent from the chart is the overall lower volumes of submitted exports, which account for only 42% of bid MW compared to 58% bid as imports.

The overall lower submitted volume of export bids provides less flexibility for the CTS solution to schedule power flow to New York. Ideally, the CTS software would have large volumes of bids offered to flow in each direction and at prices closer to zero in order to adjust the power flow between the regions as market conditions change.

The additional data available to us now have not changed the initial findings reported in the 2016 Spring Quarterly Markets Report. Overall, we observe that improved price forecasts and greater price-sensitive bidding could enhance the effectiveness of CTS. The large volumes of price-insensitive bids, particularly to import power to New England, suggest the parties primarily utilizing the interface capability are fulfilling contractual obligations or are unwilling to deviate from their day-ahead cleared awards for other reasons. Greater levels of participation from companies willing to make additional power transactions at spot prices would add to the bid liquidity necessary for CTS to shift real-time power flows in the economically efficient direction and further converge market prices. Although, additional participation may be stymied by the ISOs' price forecast biases, which create a persistent risk of out-of-merit clearing.

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 older, 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 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 coal, oil and nuclear units eliminated the region's capacity surplus and produced higher capacity prices.

Capacity payments are expected to nearly double in 2017-18, exceeding $3.0 billion, compared to the prior period. The trend of minimal surplus and increased capacity payments is expected to continue into 2018-19. As expected, increased capacity prices attracted new entrants. The most recent auctions, FCA 10 and FCA 11, saw a decline in capacity prices as approximately 5,000 MW of new supply entered the market, returning the region to capacity surplus conditions. Further, planned transmission improvements, coupled with an increase in the number of resources competing in the auctions, increased the capacity market's overall competitiveness.

This section is structured as follows:

- Section 6.1 provides a high-level overview of the design of the market, 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 input and outcomes of the two most recent forward capacity auctions, FCA 10 and FCA 11.
- 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 are shaping 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 provides resource owners with reasonable certainty about future capacity revenues. A developer or owner will know the 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 declining 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 contribute towards the recovery of fixed costs, reasonable profits, and return on capital investments. 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 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.[133] Second, changes were made to the FCM rules starting with the ninth FCA to improve resource performance. The changes are known as the "pay-for-performance" (PFP) rules.[134] 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 shortage 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 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.[135] 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.[136] 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.

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

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

[134] The pay-for-performance rules have been in effect since the ninth FCA, which means that the settlement rules will be effective from the CCP beginning on June 1, 2018.

[135] The PER threshold is based on revenues that would be earned in the energy market by a hypothetical peaking unit 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.

[136] 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.

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.[137]

On March 6, 2015, the ISO filed market rule changes to eliminate PER on a prospective basis starting with the capacity commitment period 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 capacity commitment period, 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 megawatt 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).[138] 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 eleven forward capacity auctions 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 a resource can safely and reliably deliver to the system; this establishes the resource's "qualified capacity". Second, new resources are subject to buyer-side market power mitigation rules, which are administered by the IMM. This is done through a cost-review process, which mitigates the potential for new resources that receive out-of-market revenues to suppress capacity prices below competitive levels. A developer with a new resource wishing to remain in the auction below a benchmark minimum competitive offer price (known as Offer Review Trigger Prices) is required to provide cost justification for review and approval by the IMM.

[137] 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.

[138] 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"

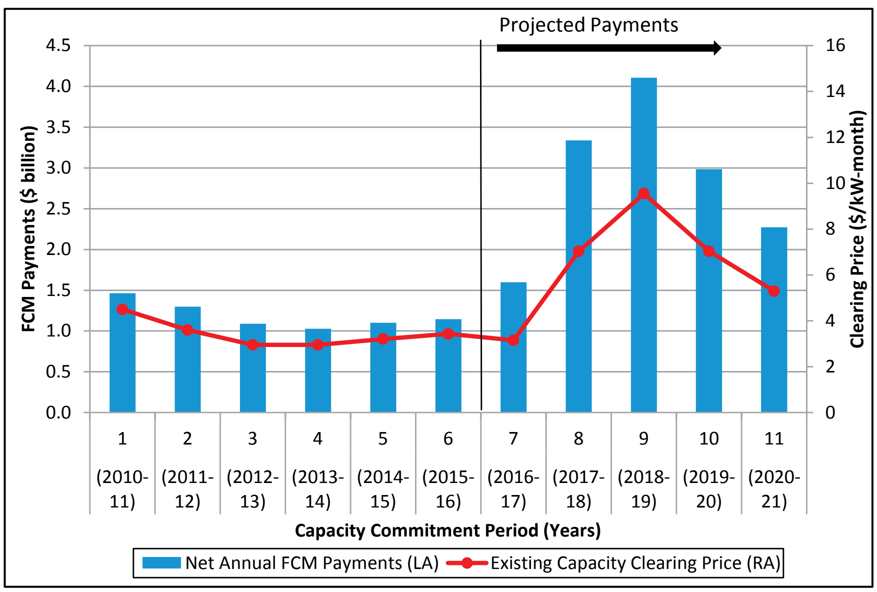
Once a new resource clears in a primary auction it becomes an existing resource and goes through a different qualification process. Similar to new resources the process, at high level, comprises two parts. First, a resource's qualified capacity for an auction is based on actual measured performance.

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, with adjustments such as peak energy rent and shortage event penalties. Payments for the capacity commitment periods CCP 1 through CCP 11 are shown in Figure 6-1 below, alongside the Rest-of-Pool clearing price. The blue bars represent FCM payments by commitment period. Payments for the first six CCPs reflect adjustments as described further below. Payments are estimated for CCP 7 to CCP 11, as those periods have not yet been settled.[139] The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[140] Payments correspond to the left axis while prices correspond to the right axis.

Figure 6-1: FCM Payments by Commitment Period



In the first six commitment periods payments remained relatively low due to surplus capacity and clearing prices set at the administrative floor price. Payments began to increase when capacity within the Northeastern Massachusetts/Boston capacity zone (NEMA/Boston) fell short of the local sourcing requirement in FCA 7. The price in this import-constrained zone was administratively set

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

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

at $14.99/kW-month for new resources, and $6.66/kW-month for existing resources. This caused the projected payments for CCP 7 to be slightly higher than CCP 6, despite the decline in the Rest-of-Pool clearing price.

Capacity payments are expected to more than double from CCP 7 and CCP 8 due to higher FCA clearing prices. The FCA did not clear enough capacity for CCP 8, primarily due to a large amount of retirements. Since the system was short, administrative pricing set the clearing price for existing resources at $7.03/kW-month and for new resources at $15/kW-month. This was the first FCA in which new and existing resource received a different clearing price, with 1,500 MW of new capacity receiving the higher $15 price. 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).[141] The combination of higher Rest-of-Pool and SEMA/RI prices led to a $981 million increase in projected capacity payments.

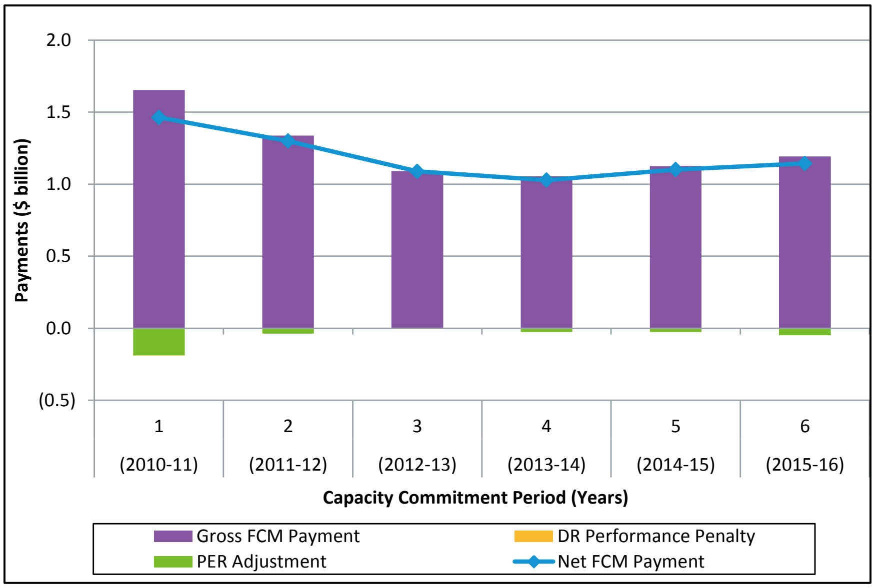
More recently, clearing prices have declined in FCAs 10 and 11, resulting in lower projected payments. Clearing prices fell by 26% to $7.03/kW-month in FCA 10, compared to FCA 9. The projected payments fall from $4.0 billion in CCP 9 to $3.0 billion in CCP 10. The system-wide clearing price declined further to $5.30/kW-month in FCA 11, resulting in projected payments of approximately $2.4 billion, which is the lowest total since FCA 7.

As mentioned above, FCM annual payments are impacted by a number of adjustments including PER and, in the case of demand resources, performance penalties. Historically, FCM payment adjustments, on a percentage basis, have been relatively low. Over the past six years, the largest adjustment to gross annual FCM payments occurred during CCP 1. In that year, the $189 million PER adjustment resulted in an 11% reduction to gross payments.[142] Gross payments, net payments, PER adjustments, and demand response performance penalties for CCPs 1 through 6 are presented in Figure 6-2 below.

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

[142] On December 1, 2010, the fuel used to calculate the PER threshold was changed from the lower price of natural gas and No. 2 fuel oil to the higher price of the two. As a result, the threshold increased from approximately $116/MWh on November 30, 2010, to $425/MWh on December 1, 2010. Because the amount of the PER adjustment is calculated from a moving 12-month average, the change in threshold affected the PER adjustment through November 2011.

Figure 6-2: Gross and Net Payments CCP 1 through CCP 6[143]



Although not shown in the figure above it is worth mentioning that PER adjustments were significant in the last quarter of 2016, which will be reflected in CCP 7 and 8 payments. 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 and therefore will result in adjustments over the 12-month period following the August 2016 event. See Section 3.4.6 for further details on the August system event.

6.3 Review of the Tenth and Eleventh Forward Capacity Auctions (FCA 10 and FCA 11)

This section provides a closer review of the two most recent forward capacity auctions, FCA 10 and FCA 11. The auctions were held in February 2016 and February 2017, respectively. Further detail on these auctions is contained in the IMM's winter 2016 and 2017 quarterly markets reports, which are available on the ISO website.[144] This section is organized into three subsections. First, an overview of qualified capacity across a number of different dimensions is provided. Second, the results of the auctions are covered, with particular emphasis on the mechanics around the demand curve in FCA 11. Third, an overview of cleared capacity, across the same dimensions as qualified capacity in the first subsection, is provided.

Before turning to the first subsection, the following is a high-level overview of the outcomes of the two auctions.

FCA 10 covers the commitment period from June 1, 2019 to May 31, 2020. In FCA 10, the market procured 35,567 MW of capacity, which is about 1,400 MW above the net installed capacity requirement (NICR) of 34,151 MW. Two capacity zones were modeled: Southeast New England

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

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

(SENE) and Rest-of-Pool (RoP).[145] The system-wide clearing price was $7.03/kW-month, with no price separation among the capacity zones. More than 1,450 MW of new generation capacity cleared, of which three natural gas-fired generators made up 90%. Two external interfaces, the New York AC Ties and New Brunswick, still had excess offered capacity over the transfer capabilities of the lines at the system-wide clearing price. These interfaces cleared at lower prices of $6.26 and $4.00/kW-month, respectively, once that excess capacity dropped out.

FCA 11 covers the commitment period from June 1, 2020 to May 31, 2021. In FCA 11, the market procured 35,835 MW, almost 1,800 above the NICR of 34,075 MW. Three capacity zones were modeled: Southeastern New England (SENE), Northern New England (NNE), and Rest-of-Pool (RoP).[146] The system-wide clearing price was $5.30/kW-month, with no price separation among the capacity zones. There was still an excess of capacity willing to import over the New Brunswick interface at the system-wide price, which resulted in a lower price of $3.38/kW-month for cleared resources at that interface.

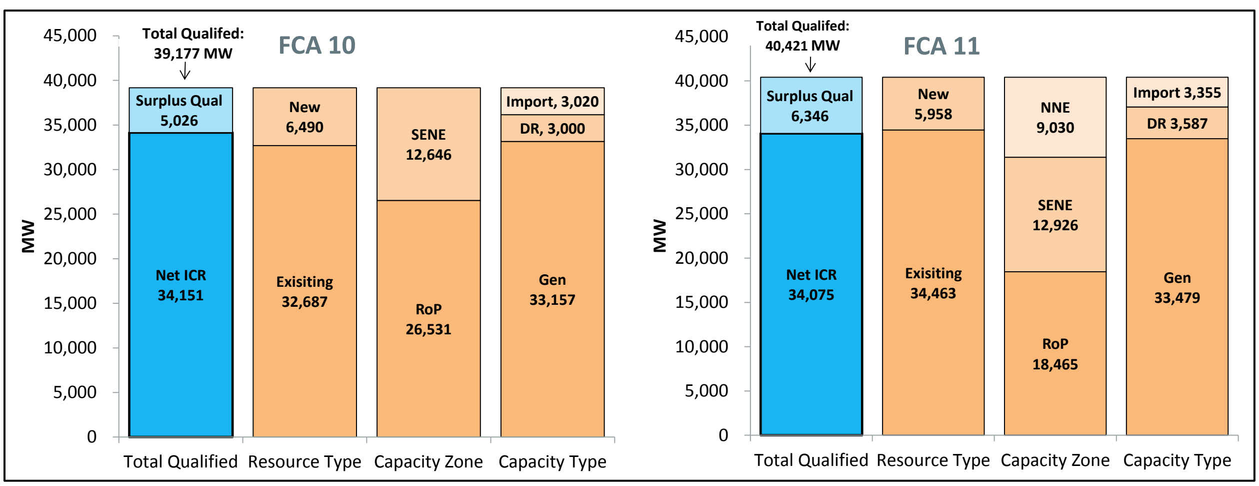
There was a sufficient amount of qualified resources participating in the auctions so that the outcomes of both FCA 10 and FCA 11 were competitive. In addition, the rigorous qualification process, including the application of mitigation rules to existing and new resources, adequately protects against the potential exercise of market power, helping to ensure a competitive outcome.

6.3.1 Qualified Capacity

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

Figure 6-3 below illustrates the qualified capacity that participated in the auctions compared to NICR (blue bars). FCA 10 data is shown in the graph on the left and FCA 11 on the right. The height of the stacked bars equals the total qualified capacity; in FCA 10 and 11 this was 39,177 MW and 40,421 MW, respectively. The three orange bars in each graph show the breakdown of total qualified capacity across three dimensions; resource type, capacity zone and capacity type.

Figure 6-3: Qualified Capacity in FCA 10 and FCA 11



[145] In FCA 10 the SENE capacity zone included the NEMA/Boston, Southeastern Massachusetts, and Rhode Island load zones.
[146] In FCA 11 the SENE capacity zone included 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 FCA 10 (left graph), there was a surplus of qualified capacity of over 5,000 MW, or almost 15%, above NICR. However, the amount of qualified *existing* capacity was not enough to meet NICR; the first orange bar illustrates that existing qualified capacity was lower than NICR by 1,500 MW. Existing qualified capacity fell primarily due to the 700 MW non-price retirement of the Pilgrim nuclear station. This deficiency caused all existing resources to be considered pivotal for the purposes of the mitigation rules. This is discussed further in Section 6.7.

Increased prices from prior auctions attracted new resources. In FCA 9 the clearing price was $9.56/kW-month, and in the SEMA/RI capacity zone the price was $17.73/kW-month for new resources due to inadequate supply. In FCA 10, about 6,500 MW of new capacity qualified, of which more than 2,200 MW was in the SENE capacity zone. This meant that total qualified capacity from both new and existing resources was well above NICR. The second orange bar shows the qualified capacity by capacity zone. The amount of qualified capacity in SENE was 2,600 MW over the local sourcing requirement (LSR), mainly due to qualified new generation.

In FCA 11 (right graph), there was a surplus of qualified capacity of about 6,350 MW, or almost 19%, above NICR. The first orange bar (by resource type) shows that the qualified capacity from existing resources exceeded the NICR by about 400 MW. While there were several pivotal suppliers, none had active static de-list bids or offers from new import capacity resources (that are treated similarly to existing resources) and therefore were not subject to mitigation. Like FCA 10, there was a significant amount of interest from new resources, at about 6,000 MW.

There was sufficient qualified capacity in SENE compared to the LSR, at about 12,900 MW, which was roughly 3,100 MW over the local requirement. The NNE capacity zone had roughly 9,000 MW of qualified capacity, which was slightly over (by about 50 MW) the maximum capacity limit.

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 10 and FCA 11.

Like FCA 9, FCA 10 utilized a system-wide sloped demand curve, unlike the vertical demand curve used in previous auctions. Under the sloped demand curve construct, at prices below the FCA starting price (of $17.30/kW-month), the system-wide quantity demanded increases linearly as the price decreases. The auction can procure capacity above and below NICR at different price levels.[147]

FCA 10 procured enough capacity to exceed NICR and cleared at a price of $7.03/kW-month, with some constrained interfaces clearing at a lower price. The price ranged in the fourth round of the auction between $8.50 down to $5.50/kW-month. The system-wide price was set after a new capacity offer withdrew in the fourth round at $7.03/kW-month. At the clearing price, the New York AC Ties and New Brunswick interface still had excess offered capacity over the capacity

147 The shape of the sloped curve is based on both financial and reliability parameters. These parameters include the estimated cost of a new resource (Cost of New Entry or "CONE") and well-established system planning design criteria.

transfer limit.[148] Because of this, the New York AC Ties cleared at $6.26/kW-month in round four. The auction continued for one additional round for the New Brunswick ties imports, closing at $4.00/kW-month. The auction concluded after all the interfaces and capacity zones cleared.

FCA 11 was the first auction to incorporate the Marginal Reliability Impact (MRI) methodology in the calculation of the sloped system and zonal demand curves. The MRI methodology estimates how an incremental change in capacity impacts system reliability at various capacity levels. However, the full MRI curve was not implemented for FCA 11. 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.[149]

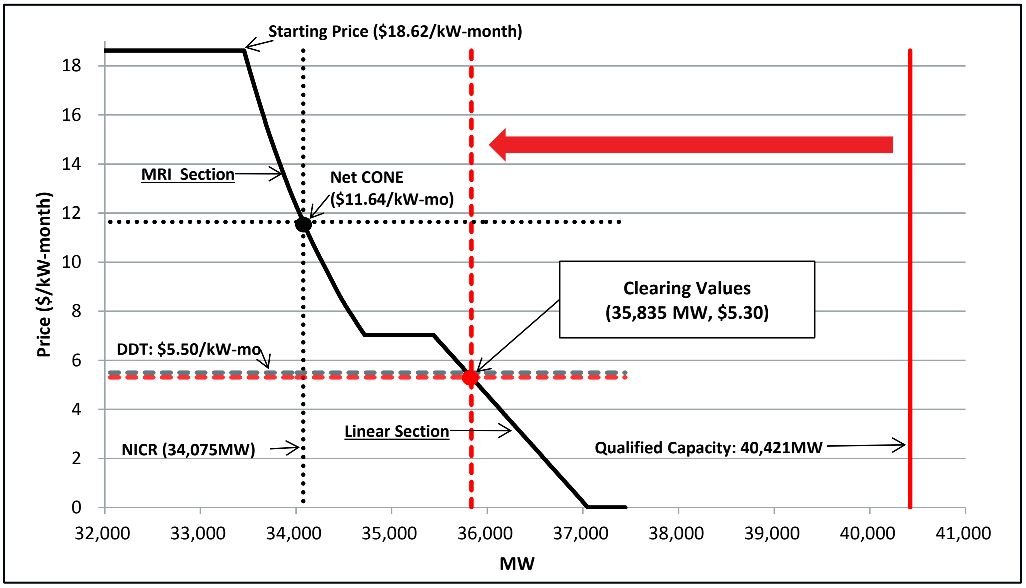
Figure 6-4 below illustrates the systemwide transitional demand curve (black solid line), which is the combination of the convex MRI curve and a linear demand curve (labeled as the MRI Section and the Linear Section). The first sloped section of the demand curve, which begins at the starting price and 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 720 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 NICR value of 34,075 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 $11.64/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 $5.30/kW-month is shown at the intersection of the cleared MW (dotted red line) and the demand curve. This is just below the dynamic de-list bid threshold price of $5.50/kW-month. When clearing prices fall below this threshold, existing resources (that do not have a static or permanent de-list bid in the auction) can actively submit prices in the auction. It also serves as an important threshold for market power mitigation, whereby an existing resource that submits bids above this level is subject to a mitigation review by the IMM.

148 When offered capacity exceeds the transfer limit, the external interfaces are treated as if they are a separately modeled export-constrained capacity zone. See Attachment C page 12 for more information: https://www.iso-ne.com/static-assets/documents/2016/02/er16-___-000_2-29-16_fca_10_results_filing.pdf

149 The transition period begins with the eleventh FCA and can last for up to three FCAs, unless certain conditions relating to NICR growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

Figure 6-4: Systemwide FCA 11 Demand Curve, Prices, and Quantities



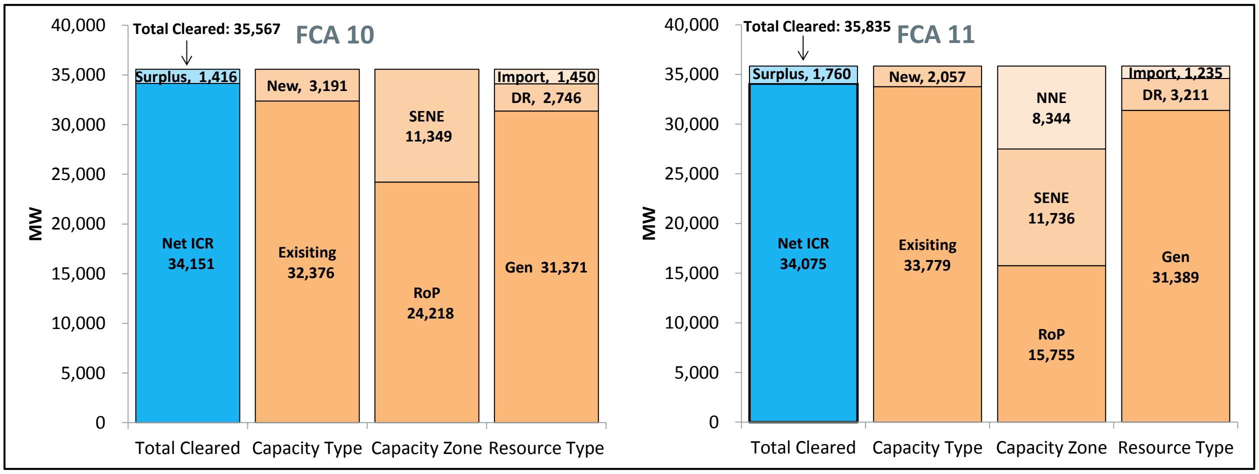
The descending clock auction closed in the fifth round for the Rest-of-Pool, SENE and NEE zones, as qualified capacity exited, and the solid red line moved towards the dotted red line. The auction cleared below the dynamic de-list threshold of $5.50/kW-month when a resource dynamically de-listed and caused supply to fall short of demand, thereby setting the marginal clearing price. The marginal resource submitting the dynamic de-list bid was then rationed to allow for demand to exactly equal supply. The auction cleared 35,835 MW at a price of $5.30/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. 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.

There was no price separation between the Rest-of-Pool, the SENE and the NNE zones. There was price separation at the New Brunswick interface, which still had 700 MW of excess capacity over its capacity transfer limit participating in the auction at the end of round five. The auction continued into the sixth round and cleared at a price of $3.38/kW-month. New Brunswick was similarly export-constrained in the prior auction, FCA 10. The New York AC ties interface was also export-constrained in FCA 10 but was not in FCA 11. In FCA 11, only 530 MW cleared behind the interface, even though the capacity transfer limit was 1,400 MW. This may be due to the expectation of higher prices in New York during the FCA 11 commitment period.

6.3.3 Cleared Capacity

The amount of cleared capacity in FCA 10 and FCA 11 exceeded system-wide and capacity zone requirements as can be seen by the blue bars in Figure 6-5 below. FCA 10 data is shown in the graph on the left and FCA 11 on the right. The orange bars show the breakdown of cleared capacity across several dimensions: constraints, capacity type, and resource type. The height of the stacked bars is equal to the total amount of capacity cleared.

Figure 6-5: Cleared Capacity in FCA 10 and FCA 11



In FCA 10 (left graph) cleared capacity exceeded NICR by 1,400 MW, or roughly 4%. The first orange bar shows that new resources accounted for about 3,200 MW, or roughly 9% of total cleared capacity. Three natural gas resources accounted for 1,300MW of new generation capacity. By capacity zone (the second orange bar), SENE cleared 11,350 MW in SENE, which was roughly 1,300 MW over the LSR.

In FCA 11 (right graph) cleared capacity exceeded NICR by nearly 1,800 MW, or by over 5%. By capacity type (first orange bar), new resource capacity accounted for 6%, or about 2,000 MW, of total cleared capacity. By capacity zone (second orange bar), the cleared amount in NNE was roughly 600 MW short of the maximum capacity limit, and therefore the zonal export constraint was not binding. Neither was the SENE import-constraint; cleared capacity located within the SENE zone was roughly 1,900 MW over the LSR.

The highest ratio of qualified to cleared new capacity was among demand response resources. New demand response resources qualified 800 MW of capacity, and cleared 640 MW. Of the 640 MW, passive demand response resources cleared 555 MW of capacity, and active demand response cleared 85 MW.[150] There was 1,800 MW of qualified new capacity from generation, and only 260 MW cleared in the auction. One generating resource, which accounted for 200 MW, was a repowering project, and qualified as a new capacity resource having met the relevant capital expenditure provisions in the Tariff.[151] Repowering projects typically have lower avoidable fixed costs than new generators.

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 (the FCA), as well as secondary trading of capacity in reconfiguration auctions and bilateral transactions.

150 Passive resources include energy efficiency and load reducing distributing generation projects that provide long term peak capacity reduction. Active demand response resources are dispatchable resources that provide reliability during demand response events.

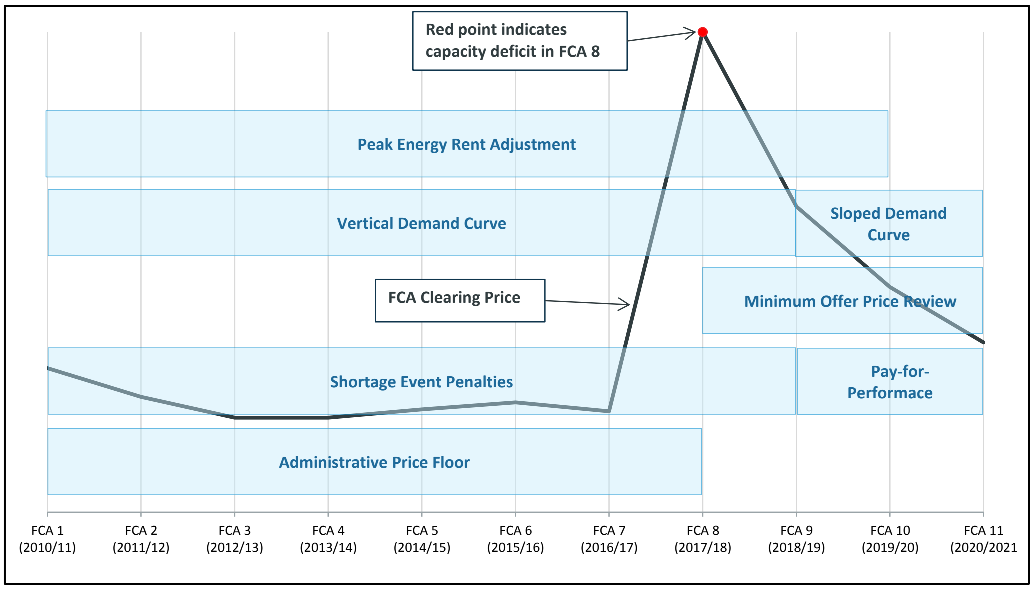
151 Repowering involves a large incremental increase in capacity due to upgrades. Once the resource clears new supply, the existing capacity will be permanently de-listed at the start of the commitment period. See Market Rule III.13.2.3.2 (e) for more information

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, like in the last two auctions discussed in the previous section.

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 6-6 below, which shows the trend in Rest-of-Pool FCA clearing prices against the backdrop of some of the major parts of the FCM rules that were in effect for some, but not for all, auctions.

Figure 6-6: 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. Under the vertical demand curve construct, market prices were subject to large swings in instances of under- and over-supply, since there was no means, other than administratively, to place a value on 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 NICR. By contrast, the sloped demand curve that was implemented from FCA 9 improves price formation and reduces price volatility.[152] When there is a surplus of supply relative to NICR, as happened in FCA 10 and 11, the price was no longer set at an administrative floor price, but by the demand curve at prices lower than the net cost of new entry.

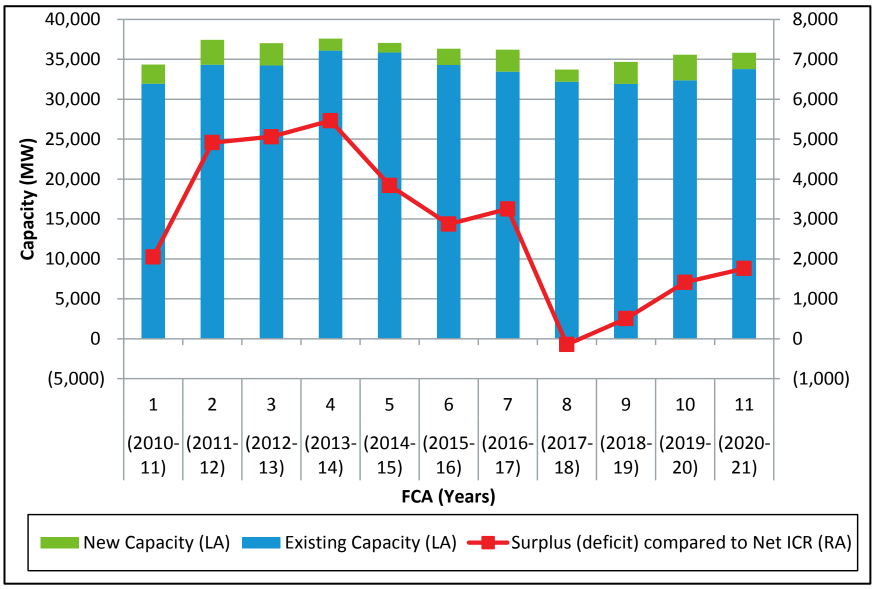
Starting with FCA 8, there were a number of significant changes to the capacity market design. The minimum offer floor price rules were implemented, which are intended to protect the market from

152 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.

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. Up to this point, the auction was largely dominated by price-insensitive supply. From FCA 10 the Peak Energy Rent reduction rule was eliminated, with many of the intended design incentives having been met through PFP.

The trend in the volume of capacity procured in each auction relative to the NICR is shown in Figure 1-5 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 deficit relative to NICR.

Figure 6-7: Cleared and Surplus Capacity in FCAs 1 through 11

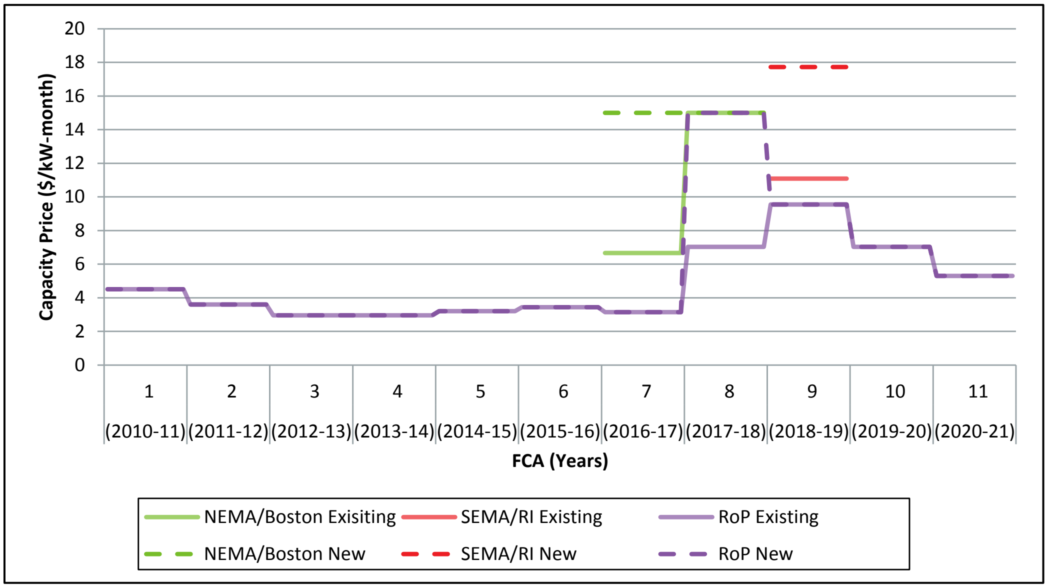


Until the eighth auction there was a surplus of cleared capacity of at least 2,000 MW.[153] The first decrease in surplus was FCA 5, when Salem Harbor retired roughly 750 MW. Even though there was a loss of cleared capacity, the system was still long compared to NICR.

The impact of surplus capacity in auctions with a floor price is that the auction will never fall below the floor price. Figure 6-8 below illustrates the changes in new and existing capacity clearing prices for each FCA. The solid lines represent the price paid to existing resources. Dashed lines represent the price paid for new resources.

153 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 6-8: 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 $14.99/kW-month for new capacity. The price was administratively set due to insufficient competition within that import-constrained zone. Existing capacity in NEMA/Boston was paid $6.66/kW-month, which was also an administrative price.

In FCA 8, cleared capacity fell below NICR for the first time due to a higher NICR (up 900 MW from FCA 7) and retirements. There were 2,700 MW of retirements. FCA 8 was the first auction where the clearing price was set by a capacity resource. The clearing price was set when a resource submitted a bid to withdraw from the auction if the price fell below $15.00/kW-month. This action set price for new resources in Rest-of-Pool (RoP) and all resources in NEMA/Boston at $15.00/kW-month.[154] 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. In the subsequent three auctions (FCA 9, 10, 11) new generation and demand response resources cleared 1,400, 1,800, and 900 MW, respectively. As seen in Figure 6-7 above, this helped turn a 140 MW deficit into a 1,800 MW surplus in the span of three auctions.

Clearing prices fell steadily from FCA 9 through FCA 11. FCA 9 was the first auction to utilize the linear sloped demand curve discussed in Section 6.3. The system-wide clearing price in FCA 9 was $9.55/kW-month, when a new supply offer withdrew from the auction. This was paid to both existing and new resources outside of the SEMA/RI capacity zone. 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.

As covered in Section 6.3 above, there was no price separation between zones in FCAs 10 and 11 because there was enough new and existing capacity to meet zonal requirements. In FCA 10, the

[154] 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

system cleared at $7.03/kW-month, which was 26% lower than the Rest-of-Pool price in FCA 9. Prices in FCA 11 fell another 25% to $5.30/kW-month.

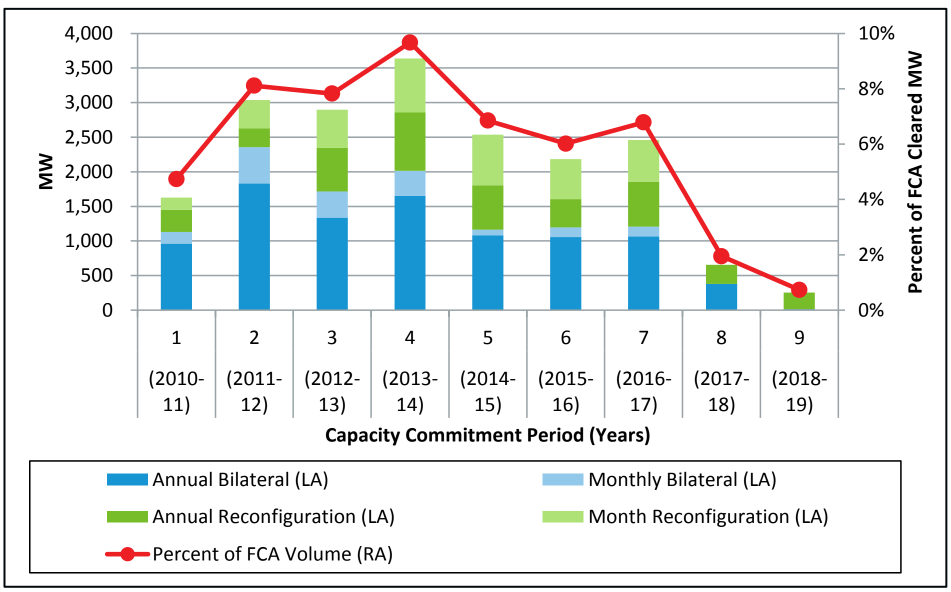
6.4.2 Secondary Forward Capacity Market Results

Reconfiguration auctions and bilateral transactions facilitate the secondary trading of capacity supply obligations. That is, they provide an avenue for participants to adjust their CSO positions after the primary forward capacity auction takes place.[155]

Historically, the traded volume in the secondary markets has been much lower than the primary auctions. Over the past six years, the secondary traded volumes averaged about 7% of the primary auction volumes, with a high of 10% occurring in CCP 4 (over 3,600 MW). The majority of the secondary trading is done through annual bilateral transactions. 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 6-10 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). Monthly and annual *reconfiguration auction* volumes are shown in green colors and monthly and annual *bilateral transaction* in blue colors.

Figure 6-9: Traded Volumes in FCA and Reconfigurations[156]



[155] 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.

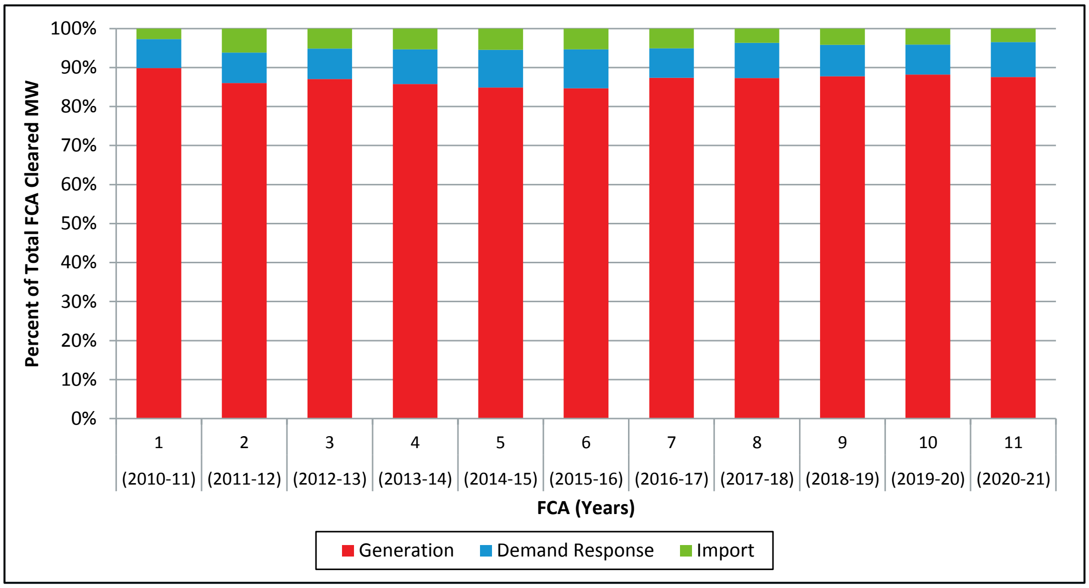
[156] There have been two annual auctions/bilaterals periods for CCP 8, and one in CCP 9.The average cleared demand and supply differs in the CCP 9 annual reconfiguration auction. This is because the sloped demand curve was incorporated into the system-wide clearing process.

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 (ARA), which led to low clearing prices during 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 6-10 below illustrates the relative share of these categories as a percentage of cleared capacity in each FCA.

Figure 6-10: Capacity Mix by Resource Type from FCA 1 through FCA 11



The mix of capacity by resource type has not changed significantly since the start of the FCM. In fact, while there have been annual fluctuations, the percentage shares are very similar in FCA 11 compared to FCA 1. In FCA 11 generation, demand response, and imports made up 88%, 9%, and 3% of the capacity mix, respectively.

6.5.1 Retirements of Capacity

A participant can choose to retire its resource by submitting a retirement request to the ISO. This is an irrevocable request to retire all or a portion of a resource.[157] Up to FCA 11, this request was not contingent on market clearing prices; it was known as a non-price retirement. Starting in FCA 11,

[157] 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.

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.

Table 6-1 below shows, by commitment period, retired generating resources with a capacity exceeding 50 MW.

Table 6-1: Generating Resource Retirements over 50 MW from FCA 2 to FCA 11

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 MW**
FCA 7 (2016/17)	AES Thames	Coal	Connecticut	184
FCA 8 (2017/18)	Brayton Point 1	Coal	SEMA	228
FCA 8 (2017/18)	Brayton Point 2	Coal	SEMA	226
FCA 8 (2017/18)	Brayton Point 3	Coal	SEMA	610
FCA 8 (2017/18)	Brayton Point 4	Coal	SEMA	422
FCA 8 (2017/18)	Bridgeport Harbor 2	Oil	Connecticut	130
FCA 8 (2017/18)	Norwalk Harbor 1	Oil	Connecticut	162
FCA 8 (2017/18)	Norwalk Harbor 2	Oil	Connecticut	168
FCA 8 (2017/18)	Vermont Yankee Nuclear	Nuclear	Vermont	604
FCA 8 Total (resources > 50 MW)				**2,550 MW**
FCA 9 (2018/19)	Mt. Tom.	Coal	WCMA	144
FCA 10 (2019/20)	Pilgrim Nuclear	Nuclear	SEMA	677

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 coal, oil, or nuclear plants. Increasing emission prices and other energy polices have led to increased production costs (see section 2.2.3). 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 capacity.

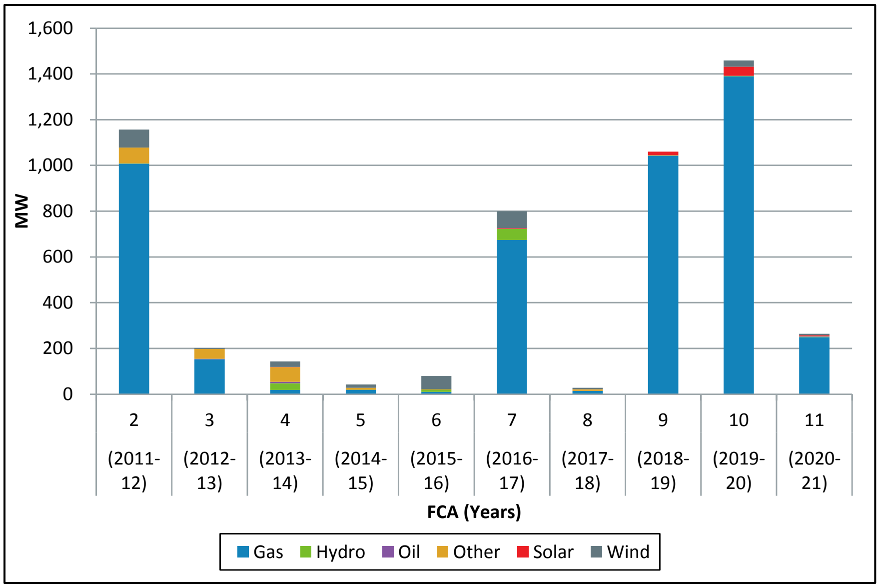
6.5.2 New Entry of Capacity Resources

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 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.[158] Project sponsors of new capacity resources can elect to lock in the FCA clearing price for up to seven years.

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

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 generators. Figure 6-11 represents new generation capacity by fuel type since the second FCA.[159]

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



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

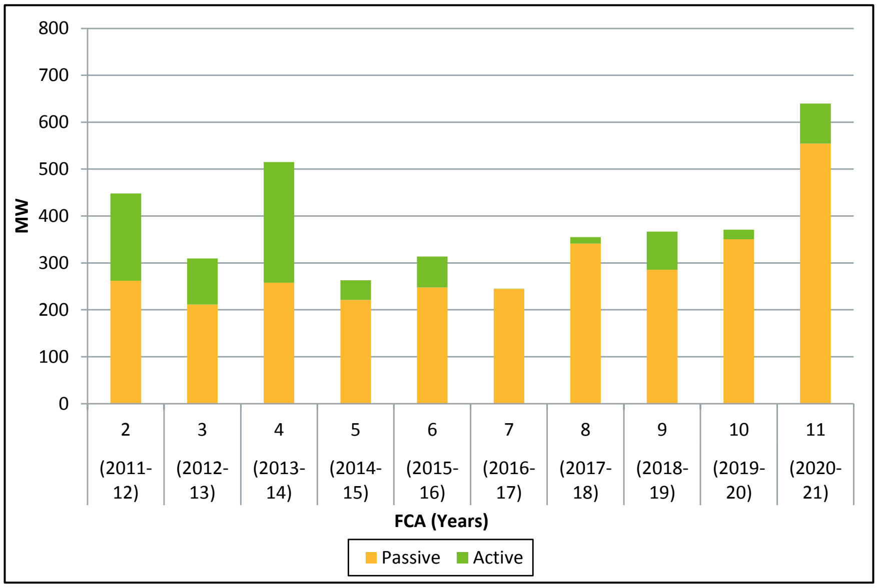
The majority of new additions have been natural gas and wind resources. Natural gas generating resources account for 87% of new additions to generator capacity since CCP 2. In FCA 2, 1,000 MW of gas and peaking unit capacity were added in Connecticut. In FCA 7, Footprint (gas) added 675 MW of capacity. In FCA 9, over 1,000 MW of capacity was added in Connecticut and Southeastern Massachusetts. In FCA 10, there was an additional 1,400 MW of new natural gas capacity. Canal 3 added 333 MW in Southeastern Massachusetts, Bridgeport Harbor 6 added 484 MW in Connecticut, and Burrillville added 485 MW in Rhode Island. The largest generator added in FCA 11 was Milford Power. This was a repowering project, which means that the entire resource qualified with new capacity of 202 MW.

Wind capacity is the second largest amount of added new capacity, totaling 292 MW. That accounts for 6% of all resources added since FCA 2. More recently, solar resources have entered the FCM. Prior to FCA 9 only 5.5 MW of new solar entered the market. Over the past three FCAs, 61 MW have been added. That includes 12 solar projects out of the 22 new generating resources to clear in FCA 11. There was a considerable decrease in added new generation from FCA 10 to FCA 11. Even with the repowering of Milford Power, new gas generation was down 82%. New solar and wind capacity was down 89% and 76%, respectively. Two drivers of the decrease in new generation were lower clearing prices and new demand response capacity that stayed in the auction.

[159] 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.

Demand response can be separated into three categories; on-peak, seasonal-peak, and real-time resources.[160] Figure 6-12 below shows new demand resources by FCA.

Figure 6-12: New Demand (Reduction) Resources with a CSO



The annual additions of new demand resources in the FCM is primarily driven by state-sponsored energy efficiency programs that participate in the FCM as passive (on-peak or seasonal-peak) supply resources. The entry of these resources therefore is less likely to be directly driven by capacity market prices, but rather by state public policy goals. This can be seen in the FCA 11 results, whereby there was a 73% increase in the amount of new cleared demand response, mostly from passive resources, despite the decline in capacity prices compared to the prior auctions.

6.6 Market Competitiveness

In this section two metrics are used below to evaluate the competitiveness of the Forward Capacity Market (FCM):

- Residual Supply Index (RSI)
- Pivotal Supplier Test (PST)

The former measures the percent of capacity remaining in the market after removing the largest supplier of capacity. The latter is a tariff-defined metric that incorporates demand conditions by

[160] 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. 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.

examining whether a supplier's capacity is needed to meet zonal capacity requirements.[161] 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.[162]

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 percent, 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 percent, 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 zone 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.[163] 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.[164] 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 NICR) and the import-constrained area level (in the form of the local sourcing requirement, or LSR). The NICR 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 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

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

[162] 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)."

[163] 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.

[164] 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.

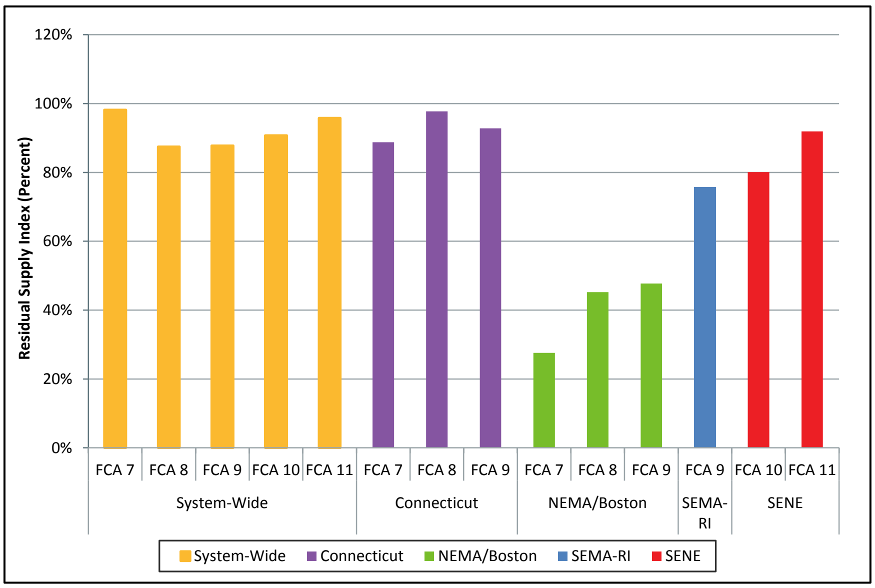
was rolled into the Southeast New England (SENE) zone, along with Southeast Massachusetts/Rhode Island (SEMA/RI), that same year.

- 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 1.6.1, 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 1.6.2).
- 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

Figure 6-13 presents the RSI for the system and for each import-constrained zone over the past five FCAs.[165]

Figure 6-13: Capacity Market Residual Supply Index, by FCA and Zone



While the system-wide RSI (in yellow) fell by approximately 11% between FCAs 7 and 8, it increased in each of the last three FCAs, including a 5% rise between FCAs 10 and FCA 11.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 NICR in recent auctions.

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

[165] 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.

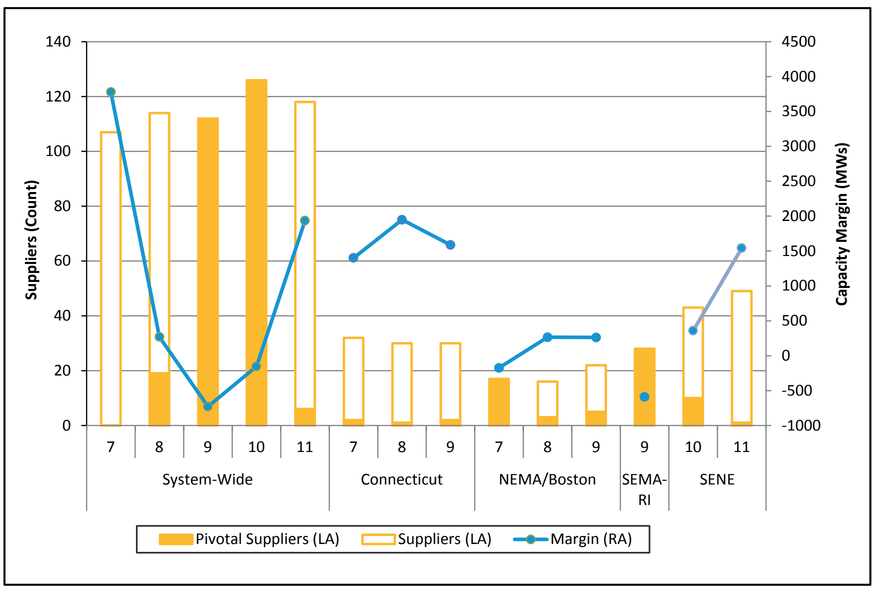
System-Wide (Rest-of-Pool) zones. Starting with FCA 10, the planned transmission improvements allowed the Connecticut zone to be merged into the System-wide zone which contributed to the increased competitiveness of the System-wide zone.

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 49% for the NEMA/Boston zone in FCA 9.

Pivotal Supplier Test Results

The number of suppliers and pivotal suppliers within each zone over the past five FCAs are presented in Figure 6-14 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 6-14: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone



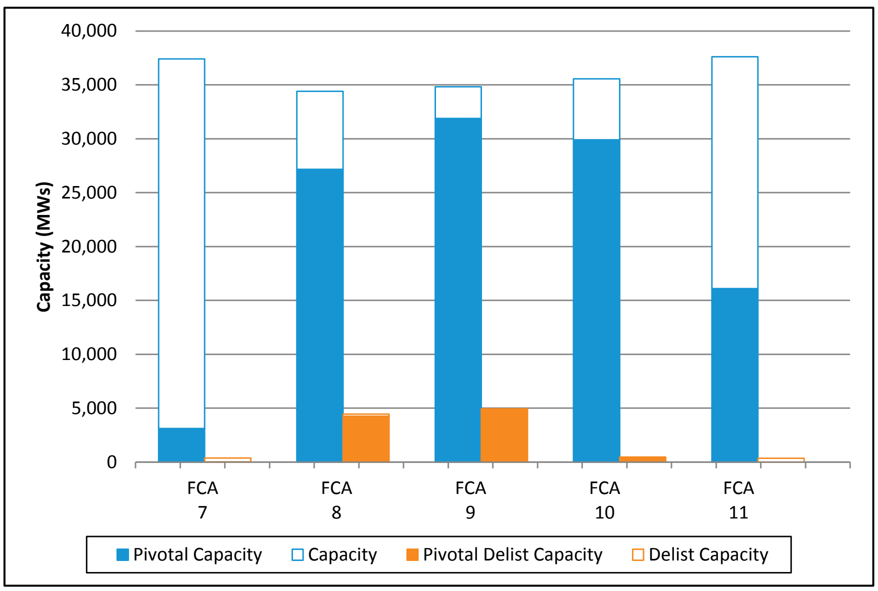
At the system level, the large capacity margin present in FCA 7 tightened significantly prior to FCA 8 before eventually turning negative in FCAs 9 and 10, causing all suppliers to be deemed pivotal at the system level for these two auctions.[166] The capacity margin increased decidedly for FCA 11,

[166] Refer to section 1.6.1 for a discussion of large resource retirements.

where a supplier needed a portfolio of over 1,900 MW to be deemed pivotal.[167] Consequently, there were few pivotal suppliers at the system level in FCA 11. For the Connecticut capacity zone (active during FCAs 7 through 9), a capacity margin of over 1,400 MW resulted in the determination of only a couple pivotal suppliers. In NEMA/Boston, the capacity shortfall present in FCA 7 resulted in pivotal determinations for every supplier in that zone. The capacity margin increased over the subsequent two auctions. Concurrently, the proportion of total existing capacity owned by the largest supplier in NEMA/Boston fell from 71% in FCA 7 to 56% in FCA 9, indicating the zone's strong and likely continued reliance on this supplier. All suppliers in the SEMA/RI capacity zone were pivotal in FCA 9 given the area's shortfall against the LSR. Lastly, the capacity margin in the SENE capacity zone increased by almost 1,200 MW between FCAs 10 and 11, resulting primarily from the addition of over 1,000 MW of new capacity in the capacity zone and a year-over-year reduction in the LSR. Consequently, the number of pivotal suppliers dropped from ten in FCA 10 to only one in FCA 11.

While a pivotal designation may indicate the ability to influence clearing prices, a de-list bid is necessary to exercise it. Figure 6-15 presents 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.

Figure 6-15: Overview of Resources, Pivotal Resources, De-lists, and Pivotal De-lists



Consistent with the ample system-wide capacity conditions, but negative capacity margin in the NEMA/Boston capacity zone, approximately 8.3% of capacity was associated with pivotal suppliers in FCA 7. This is significantly greater than the proportion of de-list capacity from pivotal suppliers (<1.0%), providing one indication that pivotal suppliers did not use de-lists to exercise market power. As system conditions tightened for FCA 8 we saw a 10-fold increase in the de-list capacity entering the auction over the prior auction. It is important to note that there were a number of

[167] 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.

market changes made at this time, including the removal of a price floor, which likely played a key role in this outcome.[168]

The negative capacity margins in FCA 9 led to increases over FCA 8 totals in both the amount and proportion of capacity associated with a pivotal supplier.[169] In FCA10, all de-list capacity was pivotal; however, the total de-list capacity decreased significantly compared to the prior auction. Finally, as the capacity margin increased in FCA 11, not only did the number of pivotal resources decrease, but there were no active de-lists from pivotal suppliers during this auction. As a result, no mitigation was applied to existing resources in the FCA 11 auction.

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 measures. To address market changes, this section presents summary information for FCA 8 through FCA 11.

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 competitive offer threshold called the dynamic de-list threshold (DDT) price.[170] A competitive de-list bid is consistent with the market participant's net going forward costs, expected

168 Refer to Section 8 for an overview of market rule changes.

169 While all suppliers were pivotal in FCAs 8 and 9, 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.

170 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 and 11.

capacity performance payments, risk premium and opportunity cost. 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.[171]

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.

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 FCAs 8 through 11, the IMM reviewed almost 250 general static de-list bids from 15 different lead participants, totaling over 18,500 MW of capacity (an average of 4,625 MW per auction).[172] While generation resources accounted for just over a third (91) of the total number of general static de-list bid submissions, these de-list bids totaled approximately 92% (~17,100 MW) of all de-list capacity. Demand resources, which typically consist of smaller resources, accounted for 63% of the total number of submitted general static de-list bids, but only 8% of the total capacity. In addition, the IMM reviewed over 25 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% general static de-list bids (69% of de-list MW capacity).[173]

Figure 6-16 provides summary statistics for static de-list bids from FCAs 8 through 11 and illustrates the path the bids took from the time of initial submittal to the auction. Note that all de-list bid prices are megawatt-weighted averages.[174]

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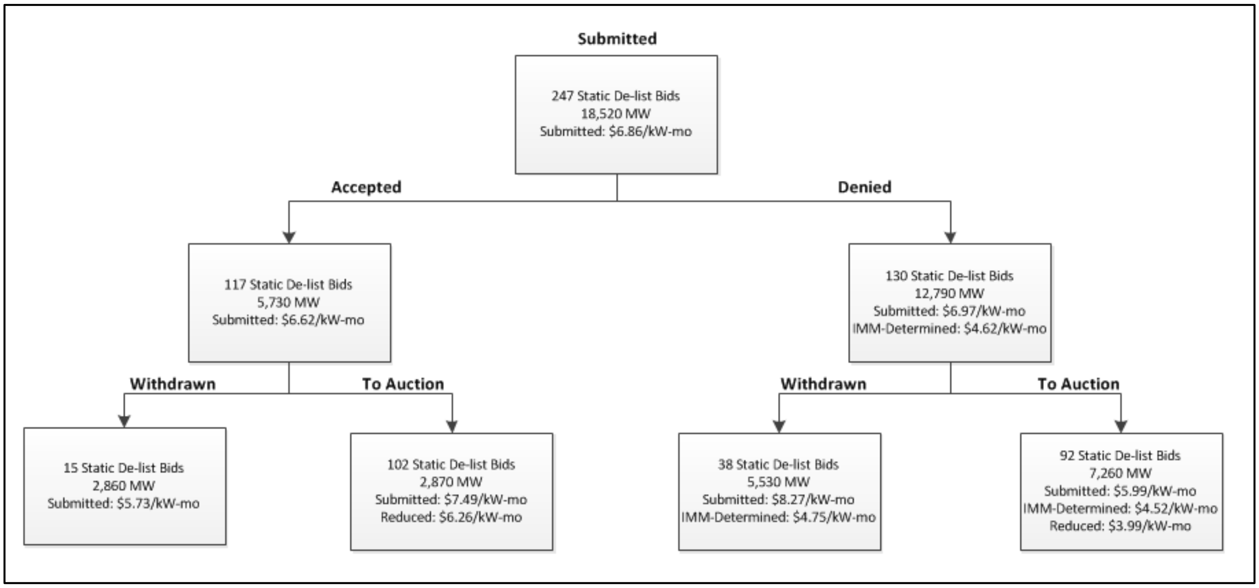
171 The term "general" is used to differentiate between other types of static de-list bids, including ambient air static de-list bids and ISO low winter static de-list bids, which are not subject to IMM review.

172 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.

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

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

Figure 6-16: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCA 8 – 11)



Nearly half of all static de-list bids (47%) 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.[175] 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 11, the IMM reviewed over 265 new supply offers from participants requesting to offer below the ORTP.[176] These offers came from 62 different lead participants and totaled over 10,300 MWs of capacity, of which almost 6,500 MW (~63%) entered the auction.[177] Generation resources accounted for the majority of the new capacity reviewed, with 88% of the total (~9,100

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175 Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

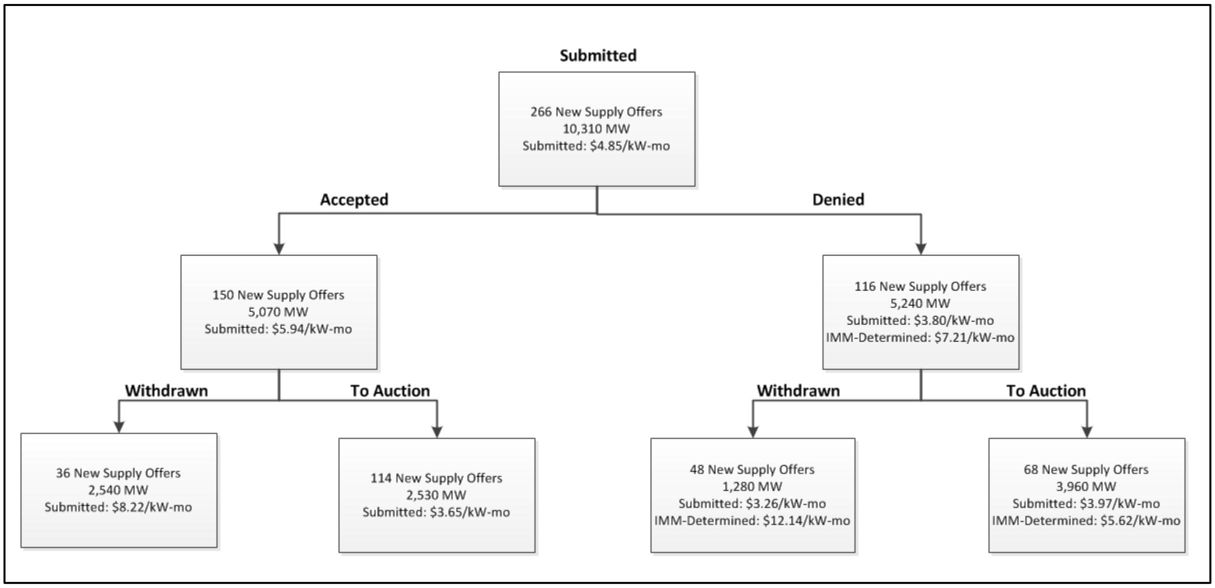
176 Note that this total does not include supply offers from new import capacity resources without transmission investments, which are discussed in the supplier-side market power section.

177 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.

MW). Demand response resources accounted for the remaining 12% (~1,200 MW). No new import capacity resources with transmission investments completed the review process.

Figure 6-17 provides summary statistics from resources requesting to offer below their respective ORTP in FCAs 8 through 11. Note that all offer prices are megawatt-weighted averages.

Figure 6-17: Reviewable Offer Request Summary Statistics, by Key Milestone Action (FCA 8 – 11)



The IMM mitigated approximately 44% of the new supply offers that it reviewed, or approximately 51% of the new supply capacity.[178] These mitigated offers represented approximately 56% and 15% of the capacity associated with these resource groups, respectively.

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 $3.41/kW-month (from a submitted price of $3.80/kW-month to an IMM-determined price of $7.21/kW-month).

[178] Note that the number of mitigated new supply offers also includes 19 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 the ISO New England's forward and real-time markets. The costs of ancillary service products, such as reserves and regulation, and make whole or "uplift" payments associated with these products, declined in 2016 in line with lower fuel costs. Ancillary services represent a relatively small portion (approximately 2%) of the total wholesale costs. The IMM observed that the market for *forward* reserves (reserves purchased from fast-response generators months in advance of the delivery period) has structural market power issues. The IMM continues to monitor the forward reserve market's competitiveness.

- Real-time operating reserves represent excess 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 refers to generators that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand and to maintain frequency in the real-time energy market.
- The Winter Reliability Program provides economic inducements for certain generating resources to maintain adequate fuel supplies during winter months, intended to remedy fuel supply issues that can threaten reliability.

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. ISO New England maintained adequate levels of reserves to maintain system reliability in 2016. To ensure that adequate levels of reserves are available to respond to such contingencies, the ISO procures several different reserve products through the locational Forward Reserve Market (FRM) and real-time market. The following section reviews real-time operating reserve products and analyzes real-time reserve outcomes in 2016.

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).[179]
- **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), South West 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 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 7-1.

Table 7-1: Reserve Constraint Penalty Factors

Requirement	Requirement Sub-Category	RCPF ($/MWh)
System TMSR (10-min spinning)		50
System TMNSR (10-min non-spinning)		1,500
System TMOR (30-min)	Minimum TMOR	1,000
	Replacement Reserve	250
Local TMOR		250

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

- 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.

[179] 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. 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

- 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.[180]
- 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 on-line 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)

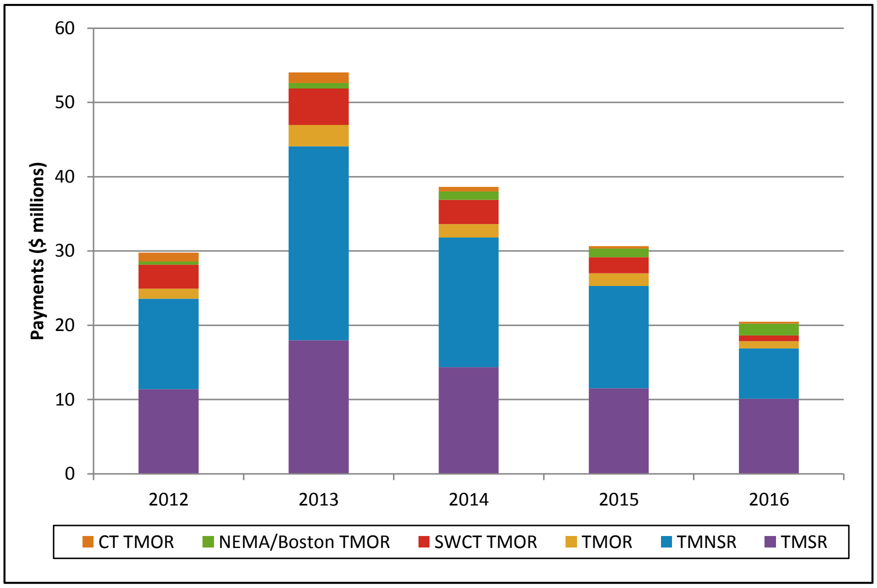
The price of higher-quality reserve products must be at least as high as the price of lower-quality reserve products. For example, if the ISO alters the dispatch to provide TMOR at a cost of $40/MWh, the prices for TMSR and TMNSR both must be equal to or greater than $40/MWh. The ordinal ranking of reserve 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 Outcomes

Total real-time operating reserve payments decreased by 33% from $30.7 million in 2015 to $20.5 million in 2016. The 2016 value of $20.5 million was < 1% of total wholesale market costs in New England. This shows that, although real-time operating reserve payment totals may change significantly on a percentage basis from year to year as a result of changes in operating reserve requirements, fuel prices, and system conditions, total payments are relatively small compared with overall energy market and capacity market payments. Reserve payments for all reserve products are shown in Figure 7-1 below.

[180] 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.

Figure 7-1: Real-Time Reserve Payments

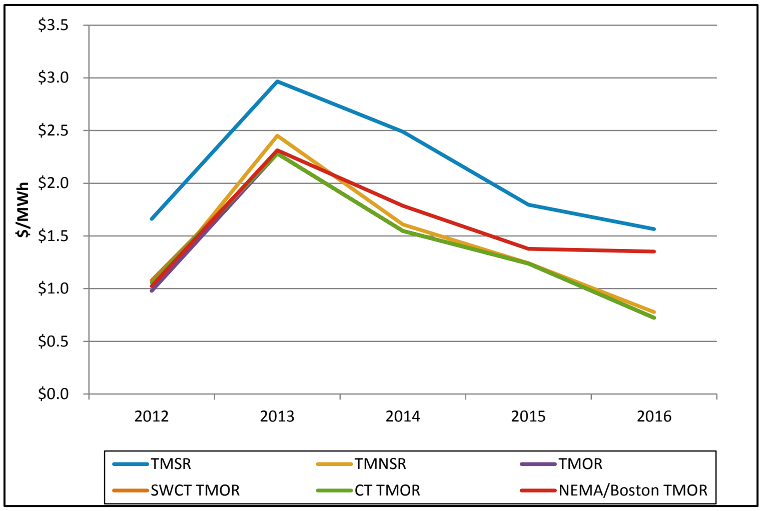


The payments presented above are a measure of the value of real-time reserves. They are based on each resource's real-time reserve designation and the reserve market clearing prices. To ensure participants are not paid twice for the same service there is a settlements mechanism to adjust the real-time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

Overall reserve payments in 2016 decreased for all reserve products compared to 2015 with the exception of NEMA/Boston TMOR, which increased by $397,000 or 34%. The increase in reserve payments in NEMA/Boston was primarily driven by an increase in the frequency of reserve pricing in the zone. The decrease in 2016 payments for all other products was driven by a decrease in the average real-time reserve prices.

Changes in real-time reserve payments are driven by changes in the average real-time reserve prices (both frequency and magnitude of reserve prices) for each reserve product over all pricing intervals. The average real-time price for each reserve product is illustrated in Figure 7-2.

Figure 7-2: Average Real-Time Reserve Prices for all Intervals

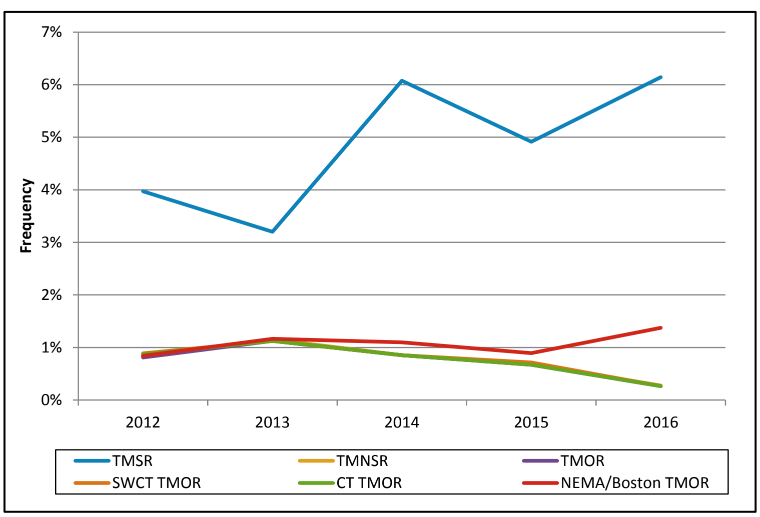


Note: Include all zero and non-zero reserve prices. Average operating reserve prices are based on preliminary prices and do not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

As with total annual payments, the average real-time reserve prices decreased for all products with the exception of NEMA/Boston. The increases or decreases in average real-time reserve prices are determined by two contributing factors: the frequency of reserve pricing and the magnitude of positive reserve pricing. The factors behind the changes in these two outcomes help explain why real-time reserve prices, and subsequently total reserve payments, change over time.

The first of the two contributing 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). An interval without a positive 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. Figure 7-3 illustrates changes in real-time reserve pricing frequency.

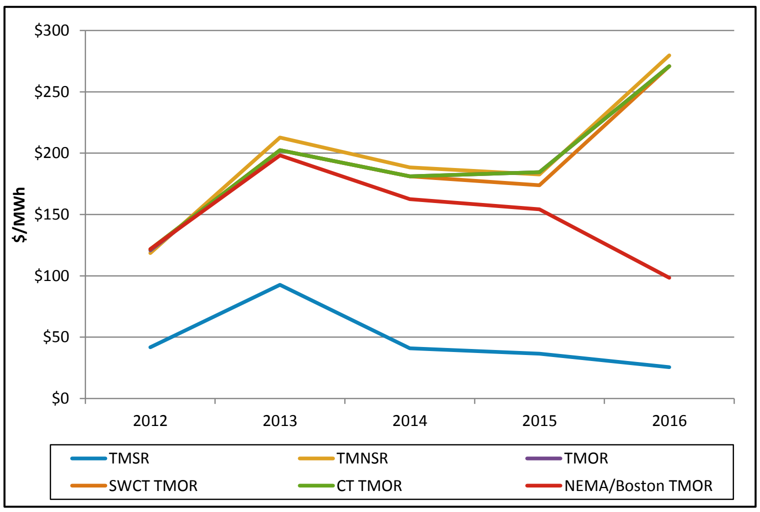
Figure 7-3: Frequency of Intervals with Positive Real-Time Reserve Pricing



As shown in Figure 7-3, the TMSR frequency was higher than the other reserve products in 2016 on average. The frequency of TMSR pricing occurs more often 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 units are scheduled to increase their output. Each unit has a limited amount of ramping capacity (the amount of additional output it can provide over a period of time). As a unit 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 unit's ability to provide 10 minute spinning reserve can be limited.

The other factor is *magnitude*. Magnitude is illustrated by showing the average real-time reserve price for each product in intervals when there was positive reserve pricing. Figure 7-4 below illustrates changes in magnitude over time by reserve product.

Figure 7-4: Average Real-Time Reserve Price for Positive Pricing Intervals



While the TMSR product had a higher frequency of reserve pricing in 2016 than 2015, increasing by 25%, Figure 7-4 shows the average price for positive pricing intervals decreased by 30%. These two outcomes together help explain why the total reserve payment for TMSR decreased by 12% in 2016. In other words, though the system experienced a higher frequency of TMSR pricing, the decrease in the magnitude of the pricing lead to a decrease in total payments.

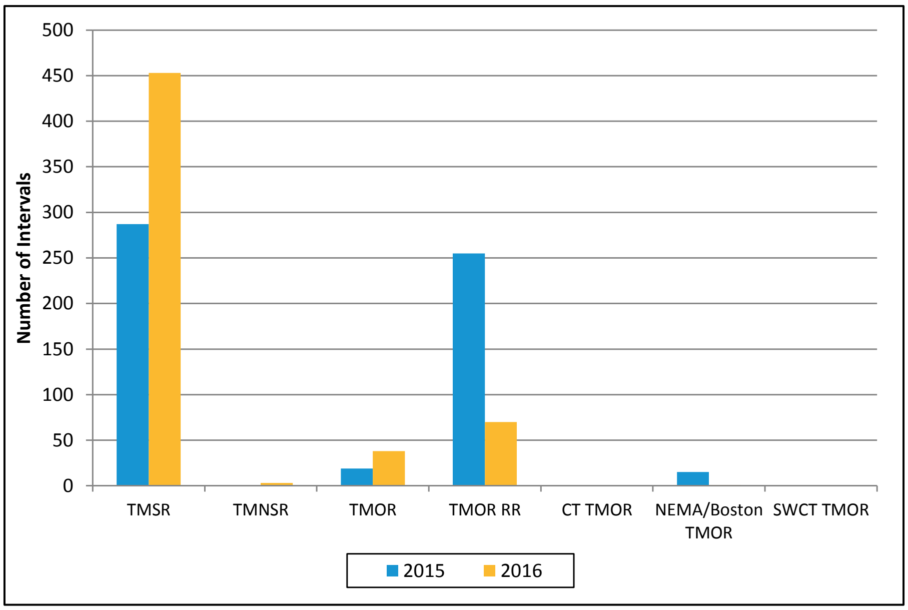
Similarly, even though the average reserve price during positive pricing intervals for TMNSR, system TMOR, SWCT TMOR, and CT TMOR increased between 2015 and 2016, the decrease in frequency of reserve pricing for these products led to a decrease in payments. This means that even though the system experienced high reserve prices for these products when there was positive pricing, the frequency of pricing was so low (approximately 0.27% of intervals) that there was an ultimate decrease in reserve payments for these products in 2016.

The only exception to the decrease in payments was NEMA/Boston. This region had a 36% decrease in the magnitude of reserve pricing but a 54% increase in the frequency of reserve pricing for the local TMOR product. The increase in frequency was primarily driven by the local reserve constraint binding with transmission outages in and around the Boston area affecting the import capability into the load and reserve zone.

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. At 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 Intervals, 2015-2016



The TMSR RCPF had the highest frequency of triggering with 453 five-minute intervals, or about 38 hours over the year. The TMOR replacement reserve RCPF was triggered in 70 intervals, or about 6 hours. The only local TMOR RCPF that was triggered in 2016 was for the NEMA/Boston local reserve zone with one five-minute interval.

The TMSR RCPF had the highest frequency of activations in part due to the higher frequency of TMSR pricing intervals compared with the other reserve products. The TMSR RCPF activation frequency was also higher in 2016 than in 2015 due to an increase in the frequency of TMSR pricing between the two years. The spinning reserve product also has a relatively low RCPF value of $50/MWh. 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 TMOR replacement reserve RCPF had the next highest frequency of activations. This is because the ISO operators will not take manual action (through unit re-dispatch or commitment) to address the depleted replacement reserves once the RCPF has been activated. The operators will not take manual action to restore replacement reserves because, unlike the other reserve requirements, replacement reserves are not a North American Electric Reliability Corporation (NERC) requirement. This is in contrast to the other reserve products, for which manual ISO action is more likely. The number of RCPF intervals for replacement reserves greatly decreased in 2016 compared to 2015. This was in part due to fewer intervals in which the system TMOR product had positive pricing in 2016 compared to 2015.

Many of the RCPF activation intervals in 2016 took place between August 11 and 12 when the system experienced tight system conditions and a shortage event. In fact, all 38 instances of the TMOR RCPF activations and all 3 instances of the TMNSR RCPF activations in 2016 took place during this time period signaling tight reserve conditions on the system.[181] The system conditions leading to these activations were discussed in Section 3.4.6.

When the RCPFs are triggered because of a shortage of available capacity to meet the reserve 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 2016, on average, the impact of reserve pricing on the energy price was small. As shown in Figure 7-2, the average TMSR price in 2015 was $1.56/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 biding). As a result, the average impact of reserve pricing on the real-time Hub LMP in 2016 was less than 6%.

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 auction clearing prices are calculated for each reserve product in each reserve zone. When enough supply is offered under the price cap 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

[181] 8% of TMSR RCPF activations and 43% of replacement reserve RCPF activations in 2016 took place during this time period as well.

marginal supply offer. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the $9,000/MW-month price cap.[182]

Until the 2016 FRM auctions, the FRM payment rate (or price) was reduced by the contemporaneous delivery period's FCA clearing price. This was done to avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity. Starting in 2016, FCA prices are no longer being netted from FRM compensation. This change resulted from the netting process leading to unintended consequences under certain circumstances, including uneconomic resource selection and zero, or nearly zero, FRM compensation for auction participants.[183]

To attract and maintain resources that normally are expected to provide reserves instead of electricity, the FRM requires participants to designate resources as forward-reserve resources. It also requires resources to offer a megawatt quantity of energy equal to the participant's FRM obligation at or above the FRM threshold price. 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%. If the threshold price is set accurately, 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.

Participants are not expected to designate resources that are normally in merit below this level because they would forego the infra-marginal revenue from selling energy. Conversely, designating high-incremental-cost peaking resources creates a lower opportunity cost because such resources are in-merit less frequently. The forward-reserve auction clears megawatt obligations that are not resource specific. Before the end of the re-offer period for the Real-Time Energy Market, participants must submit energy offers equal to or greater than the threshold price for resources they control to satisfy their obligation. Before midnight of the day before the operating day, participants with FRM obligations must assign obligations to physical resources to satisfy their FRM obligations.

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

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

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182 As indicated below, the auction price cap was reduced for the 2016 auctions, when "price netting" (i.e., subtraction of the FCA compensation from the FRM compensation) was terminated.

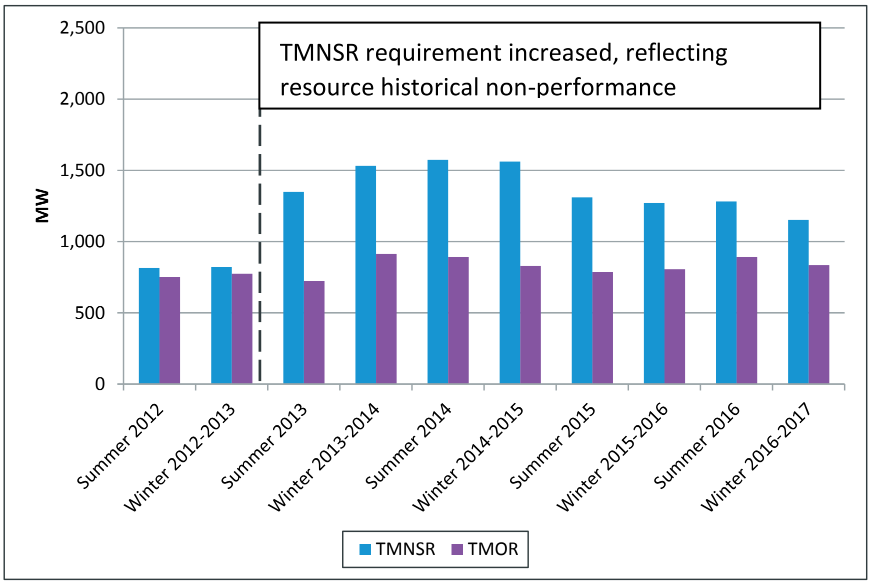
183 ISO New England and New England Power Pool, Docket No. ER16-921-000; *Revisions to Forward Reserve Market Offer Cap and Elimination of Price Netting*. https://www.iso-ne.com/static-assets/documents/2016/02/er16-921-000.pdf See section IV of the ISO's filing for a description of the unintended consequences and undesirable effects of the netting mechanism.

7.2.1 Market Requirements

The FRM auction is intended to ensure adequate reserves to meet ten and thirty minute reserve 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 all of New England, the ISO identifies requirements at a regional level, as well as a system-wide requirement, for each reserve product procured in the auction.

The forward reserve requirements, from Summer 2012 through Winter 2016-17, are shown in Figure 7-6.

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



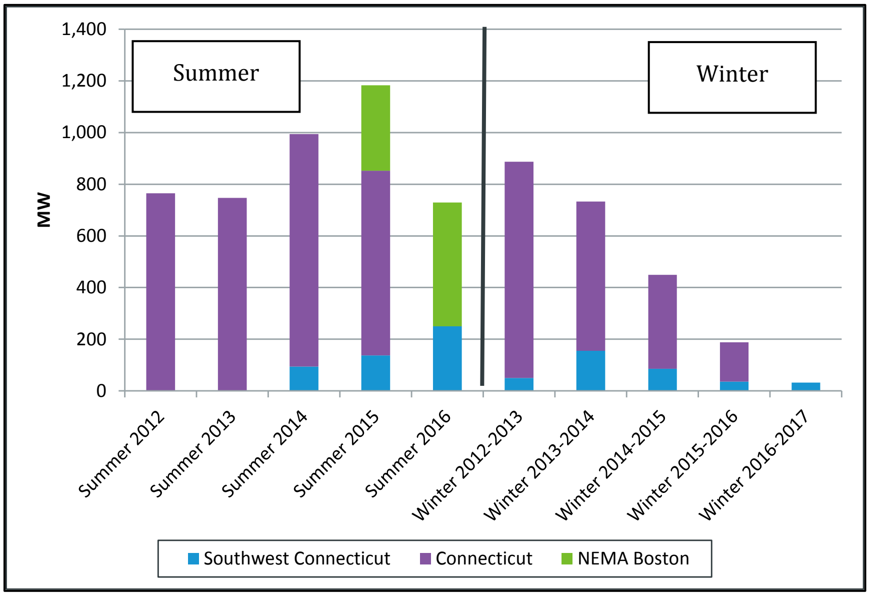
The FRM requirements for the New England control area are based on the forecast of the first and second largest contingency supply losses for the next forward reserve procurement period. Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMNSR purchase amount was increased for the Summer 2013 auction to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency.[184] The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9 or Seabrook.[185]

The net reserve requirement for the past 10 auctions, for the import-constrained reserve zones of Connecticut, NEMA/Boston, and Southwest Connecticut, are shown 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.

184ISO New England Inc. and New England Power Pool, Docket No. ER 13-465-000, *Market Rule Revision Relating to the Procurement of Ten-Minute Non-Spinning Reserve in the Forward Reserve Market,* http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2012/nov/er13_465_000_11_27_2012_proc_ten_min_rule.pdf. This filing also allowed for an additional procurement of reserve to be procured in the Forward Reserve Market to help support the availability of reserves to meet the increased real-time reserve requirements.

185As 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: Net Local Forward Reserve (TMOR) Requirements



The local forward reserve requirements for each applicable reserve zone are based on the 95th percentile value from historical requirements data for the previous two like forward reserve procurement periods for each reserve zone. Local forward reserve requirements (which account for both local second contingency and external reserve support (ERS) megawatts) for the reserve zones reflect the need for a 30-minute contingency response to provide support in import-constrained areas.[186] Resources within a local region as well as operating reserves available in other locations, through external reserve support (ERS) can satisfy second contingency capacity requirements.

The winter procurement period has experienced a significant reduction in net local FRM requirements, as illustrated in Figure 7-7. The amount of ERS has increased considerably due to transmission upgrades to support the Connecticut zone. Connecticut's net requirement also declined to zero in Summer 2016 as a result of a significant increase in the ERS. Southwest Connecticut and NEMA/Boston have both experienced increased net local requirements over recent summer periods, as a result of increased local requirements (SWCT) and decreased ERS (NEMA).

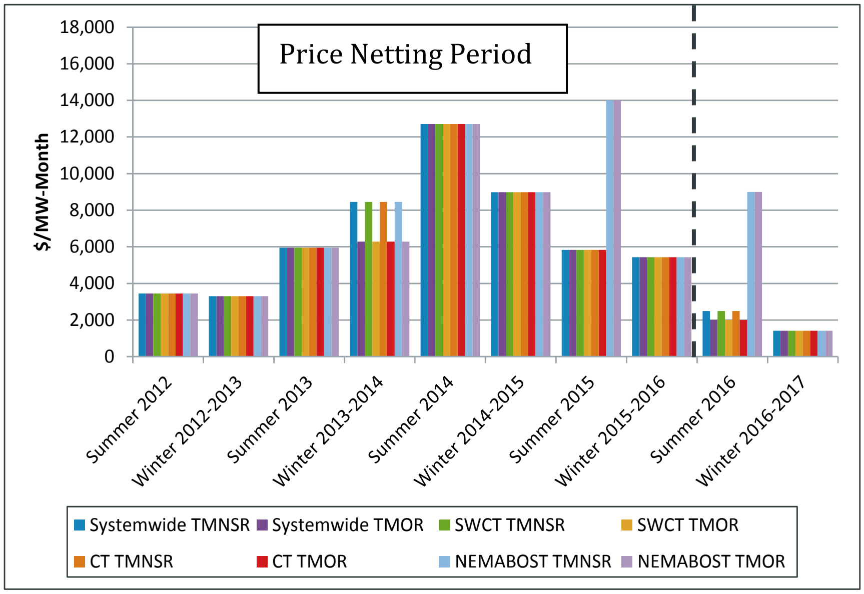
7.2.2 Auction Results

This section covers FRM auction pricing outcomes from Summer 2012 through Winter 2016-17. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-8.[187]

[186] 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.

[187]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

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



FRM prices for the system-wide products decreased in both the summer and the winter auctions in 2015. The summer system-wide TMNSR price decreased 54% relative to summer 2014. Similarly, the 2015-16 winter system-wide TMNSR price decreased by 40%. This is partially the result of a decrease in the TMNSR requirements when compared with 2014.

Prices for the 2016 auctions are not readily comparable to earlier periods, since the 2016 FRM prices no longer are adjusted for FCA prices (i.e., price netting was eliminated for the 2016 auctions). The decline in prices in 2016, relative to earlier periods, is consistent with the elimination of price netting. (Note: a later graph provides a rough indication of comparable pricing in 2016 for system TMNSR and TMOR, relative to earlier periods.)

The relatively uniform prices for systemwide TMOR and TMNSR products suggest that TMOR often had the highest price in the auction; this occurs because TMNSR (a ten-minute, higher-quality reserve product than thirty-minute reserves) cannot have a price that is less than the 30-minute product. If the TMNSR price that results from satisfying the ten-minute reserve requirement in the auction is less than the TMOR price for satisfying the thirty-minute requirement, TMNSR will receive the higher thirty-minute price.[188] In two instances during the review period, TMNSR cleared the auction at higher prices than system-wide TMOR, as shown in the graph.

At the reserve zone level, note also that local resources providing TMNSR receive the systemwide TMNSR price, unless the local TMOR reserve price is greater than the TMNSR price. Because the local TMNSR resources can also provide thirty-minute reserves to satisfy the local requirement, the local TMNSR resources cannot receive prices lower than the local TMOR price.

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.

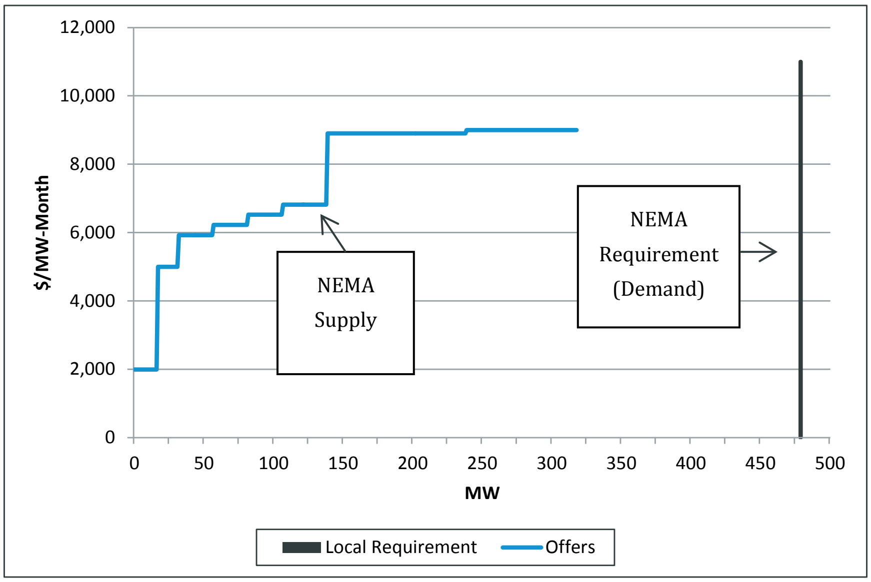
188 See Market Rule 1, Section III.9.4, Forward Reserve Auction Clearing and Forward Reserve Clearing Prices; and, Manual M-36, Forward Reserve and Real-Time Reserve, Section 2.6, Forward Reserve Auction Clearing.

For zonal pricing, there have been two instances of significant price separation during the five-year period, as illustrated in Figure 7-8. In both the summer 2015 and summer 2016 procurement periods, there was price separation between NEMA/Boston and all other zones.

In these instances, supply was inadequate to satisfy the local TMOR requirement, and pricing reached the auction offer cap in each period. The 2015 NEMA/Boston summer period price exceeded the summer 2016 price, because the cap was reduced for 2016 (from $14,000/MW-month to $9,000/MW-month), when FCA price netting was eliminated.[189]

This is illustrated in Figure 7-9 below for the Summer 2016 auction.

Figure 7-9: Supply and Demand for the TMOR Product in NEMA/Boston for the Summer 2016 Auction

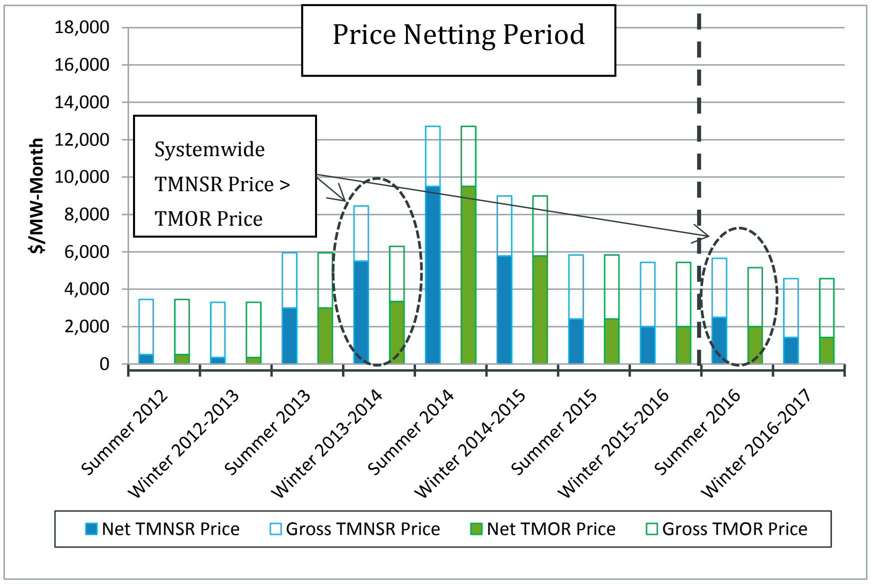


The above figure shows NEMA/Boston's supply and demand curves for the 2016 summer FRM auction. With zonal supply approximately 150 MW less than zonal demand, the zonal clearing price was set to the auction price cap, resulting in a $9,000/MW-month price for local TMNSR and TMOR.

Finally, the gross and net forward reserve prices for TMNSR and TMOR are shown in Figure 7-10 below, to illustrate the price netting concept that applied to periods 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 system-wide 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 2016 auctions.

[189]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 System-Wide TMNSR and TMOR



For comparison, the graph includes the 2016 period and provides an estimated gross price for 2016: the contemporaneous FCA period clearing price has been added to the FRM auction clearing prices for 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. FRM auctions in 2015 and 2016 have resulted in relatively stable net FRM compensation levels for system-wide TMNSR, close to $2,000/MW-month. Higher net prices in earlier periods, in part, are indicative of higher system TMNSR requirements for the FRM (as illustrated in Figure 7-6 above).

7.2.3 Structural Competitiveness

The competitiveness of the FRM is 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 - Figure 7-2 below - shows the offer RSI for TMNSR at a system level and TMOR for zones with a non-zero TMOR requirement. The colors indicate the degree to which structural market power was present, staring with low RSIs shown in red, followed by white and green colors, with the later indicating that there was still ample offered supply without the largest supplier.

Table 7-2: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	TMNSR System-wide	TMOR ROS	TMOR SWCT	TMOR CT	TMOR NEMA
Summer 2012	241	189	N/A	114	N/A
Winter 2012-13	193	132	244	134	N/A
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

A 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. Figure 7-2 shows that there were pivotal suppliers in 3 out of the 10 FRM auctions for TMNSR. There were also pivotal suppliers in 6 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 explained by the significant variation in the reserve requirement. For instance, for the SWCT zone the TMOR RSI value jumped from 76 (structurally uncompetitive levels) in Summer 2016 auction to 302 (structurally competitive level) in Winter 2016-17 period. For the same zone and time period, the TMOR local requirement went down from 250 MW to 32 MW. More suppliers are competing to fill a lower requirement.

For both Summer 2016 and Winter 2016-17 procurement periods, the TMNSR RSI values were significantly greater than 100. These values suggest that the TMNSR offer quantities in both the auctions were consistent with a structurally competitive level. Similarly, the TMOR RSI values for the RoS zone were consistent with a structurally competitive level. The SWCT zone was structurally competitive for the Winter 2016-17 period but for the Summer 2016 the offer RSI value was below a structurally competitive level. For the Summer 2016 period, the RSI value for the NEMA zone was significantly below a competitive level. 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 2016. The regulation market was competitive in 2016.

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.[190] 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).[191] NERC establishes technical standards for evaluating area control error (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.[192]

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.[193] 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. The pricing change was implemented effective March 31, 2015.[194]

The service price represents the direct cost of providing the regulation service. 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: these include (1) the expected value of lost energy market opportunities when providing regulation service, (2) elements of fixed costs such as incremental maintenance to ensure a generator's continuing performance when providing regulation, and (3) fuel market or other risks associated with providing regulation.

In 2016, the average service price was $0.43/mile, a 44% increase over the partial year average of $0.30/mile in 2015 (for the period after implementation of two-part pricing). Because separate service regulation pricing was implemented after Winter 2015, the increase in 2016 is likely overstated. Given relatively high gas prices in Winter 2015, it is likely that regulation service offers and prices would have been higher during that season than during the remainder of 2015, and would have led to a higher average price for 2015. Also, an increase in the procurement of regulation service and capacity in 2016 (see Section 7.3.2) resulted in higher-priced regulation being procured.

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190 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.

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

192 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.

193 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.

194 Market Participants providing regulation service may also qualify for make whole or NCPC payments.

Regulation capacity prices increased by 8% in 2016 compared with 2015, reflecting increased regulation requirements. 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. See Table 7-3.

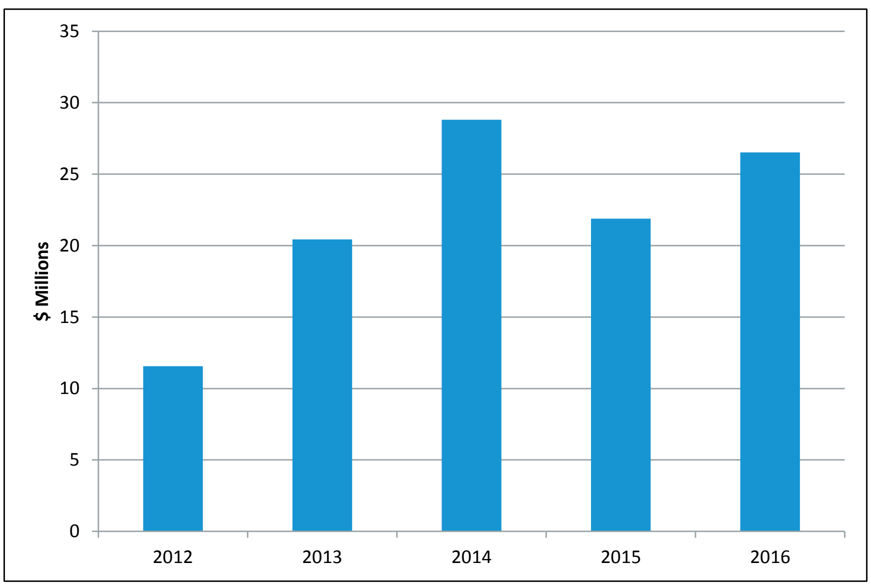
Table 7-3: Regulation Prices, 2012 to 2016

	Regulation Clearing Price ($/MW per Hour)			Regulation Service Clearing Price ($/Mile)			Regulation Capacity Clearing Price ($/MW per Hour)		
Year	Min	Ave	Max	Min	Ave	Max	Min	Ave	Max
2012	0.00	6.75	70.33	n/a	n/a	n/a	n/a	n/a	n/a
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

(a) Pricing rules changed on 3/31/15.

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, and a make-whole payment. Annual regulation payments over the past five years are shown in Figure 7-11.

Figure 7-11: Regulation Payments



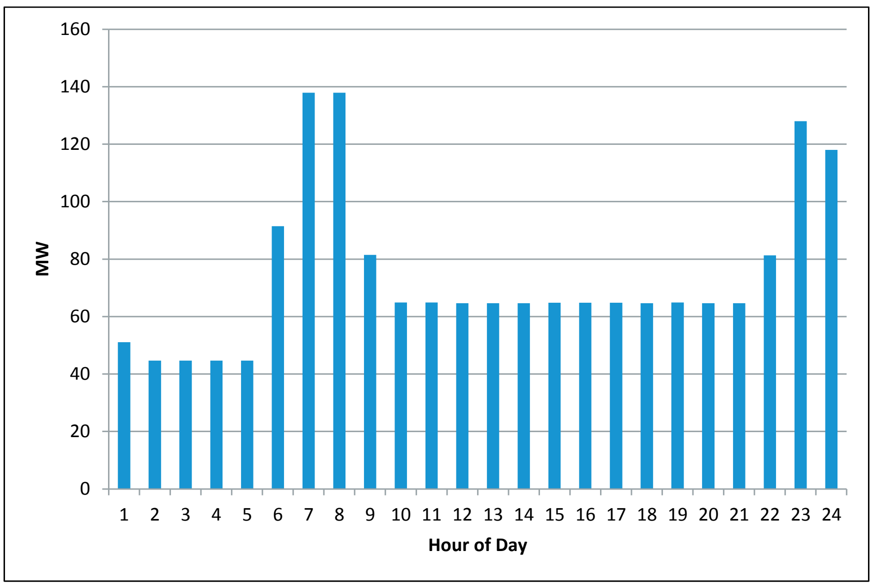
Payments to resources providing regulation service totaled $26.5 million in 2016, a 21% increase from the $21.8 million in 2015. The increase in payments reflects several factors. In April 2016, both regulation capacity and service requirements were increased due to the modification of calculations performed 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. 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.[195] Finally, increased regulation capacity offers (reflecting higher opportunity costs for regulation resources) significantly increased payments in December 2016 relative to December 2015; this increase is consistent with the much higher natural gas prices and energy market LMPs that occurred in December 2016, relative to the prior year. Elevated payments in 2014 reflect elevated regulation costs during winter 2014.[196]

7.3.2 Requirements and Performance

The average hourly regulation requirement of 74.3 MW in 2016 is substantially higher than the 59.6 MW requirement in 2015. As noted above, the revised calculation methodology for determining regulation capacity needs (requirement) has resulted in the 25% increase.

The regulation requirement in New England varies throughout the day and typically is 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, 2016



The ISO seeks to maintain NERC *Control Performance Standard 2* within the range of 90% to 100%. For 2016, the ISO achieved a minimum monthly value of 92.3% and a maximum monthly value of 96.6%. With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO is now using violations of Balancing Authority ACE Limits (BAAL) to measure performance. Violations would result from exceeding ACE limits for more than 30 consecutive minutes; since July 2016, when the ISO began tracking this measure, there have been no violations.

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195 See the Internal Market Monitor's Summer 2015 Quarterly Markets Report, available at https://www.iso-ne.com/static-assets/documents/2015/12/qmr_q3_2015_final.pdf.

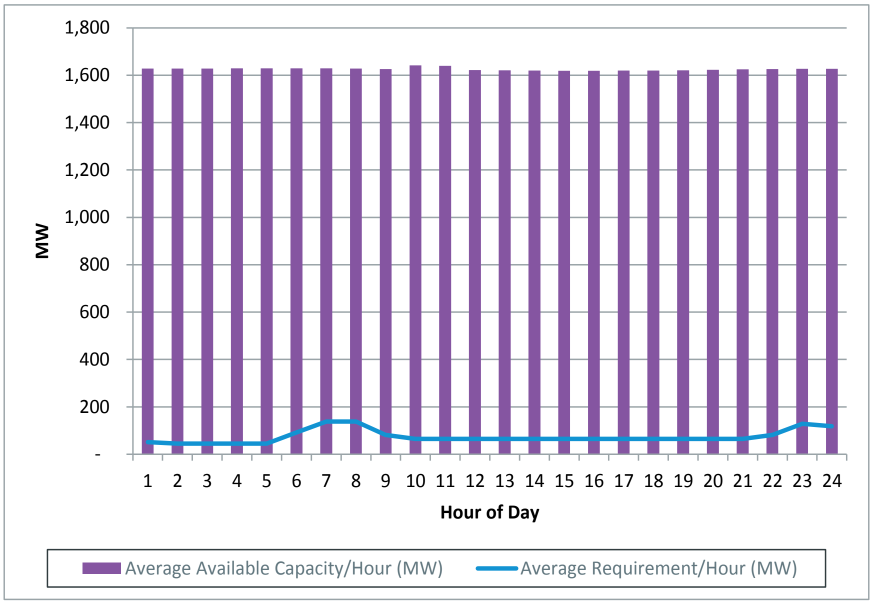
196 See the Spring 2016 Quarterly Markets Report, available at https://www.iso-ne.com/static-assets/documents/2016/08/q2_spring_2016_qmr_final.pdf, for a detailed discussion of regulation payments in 2015 and earlier years. Note that the data presented in Quarterly reports uses a "seasonal" quarter, 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.

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 2016.

Figure 7-13 below simply plots the regulation requirement relative to available supply.

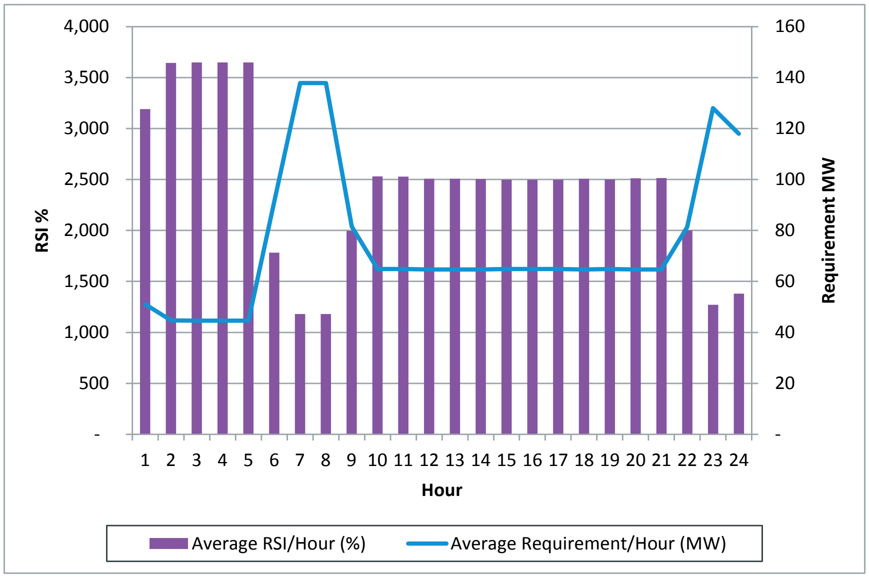
Figure 7-13: Regulation Market Average Requirement and Available Capacity, 2016



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 Supplier Index



In 2016, 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 2016-17 Winter Reliability program. It includes a summary of procured volumes, level of participation, types of participation, pricing, and payments.

The 2016-17 winter season marks the fourth year in which the ISO implemented a winter reliability program.[197] 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. The program will be in place until the winter prior to 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.[198] In the 2016-2017 program, 84 units with a total of 4.4 million barrels (bbls) of oil inventory participated in the program. Around three million barrels of the total inventory were

197 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.

198 Ibid.

eligible for compensation per the winter program rules at the base set rate of $10.21/bbl[199]. Given the initial inventory and payment rate, the maximum oil program cost exposure was $31.16 million.

Participants in the oil program are paid based on their final oil inventory at the end of the winter. Little of the contracted oil was burned due to low gas prices, and some of the burned inventory was replenished, resulting in a high remaining inventory. At the end of the program, 3.035 million bbls of oil remained. The remaining amount was equal to 99% 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. Participants include natural gas-fired generators and dual fuel generators. In the 2016-2017 program, 2 units representing 171 thousand MMBtu of LNG participated in the program at a rate of $1.70/MMBtu. With this quantity and rate, the maximum LNG program cost exposure was $291 thousand. As with the oil program, participants are paid based on the remaining inventory at the end of the winter. Due to the availability of natural gas, no LNG was used during the winter program months.

Demand Response (DR) Service Program:

In the 2016-2017 program, six demand response assets participated in the program with an aggregate interrupting capability of 23 MW of demand. The total cost associated with the demand response service in the 2016-17 program was $126,480.[200]

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 generator assets that have not demonstrated the ability to operate on oil on or after December 1, 2011.[201] No additional dual fuel units were commissioned for the 2016-2017 program. Between the 2014-15 and 2015-16 winter seasons, six units submitted an intent to commission dual fuel capability; four units submitted an intent in the 2014-15 season, totaling 1,039 MW of capability, and two additional units 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 31, 2015 five of the six units 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 7-4.[202]

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199 *See* 2016/2017 Winter Program Rate Memo, http://www.iso-ne.com/markets-operations/markets/winterprogram-payment-rate

200 Winter 2016-2017 numbers are preliminary and subject to change.

201 *See* Market Rule 1, Appendix K, http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-k.pdf.

202 Winter 2016-2017 numbers are preliminary and subject to change.

Table 7-4: Winter Reliability Program Cost Summary

	2013-14	2014-15	2015-16	2016-17
Contracted Volume				
Oil (bbl)	3,057,554	3,817,754	2,953,967	3,050,824
LNG (MMBtu)	n/a	500,000	1,277,976	171,121
Fuel Rate				
Oil ($/bbl)	n/a	18.00	12.90	10.21
LNG ($/MMBtu)	n/a	3.00	2.15	1.70
Remaining Inventory				
Oil (bbl) [203]	2,579,320	2,544,668	2,881,550	3,034,668
LNG (MMBtu)	n/a	500,000	1,277,976	171,121
Additional Costs				
Dual Fuel Service (includes commissioning and auditing costs)	n/a	1,081,114	539,343	782,671
Demand Response Service	198,489	160,857	210,316	126,480
Maximum Cost Exposure ($ millions)	**75.0**	**70.2**	**40.4**	**32.2**
Total Program Costs ($ millions)	**66.0**	**45.1**	**38.5**	**30.6**

As the table above shows, the 2016-17 season had high remaining inventory levels for oil and LNG relative to the contracted volume. The actual total program costs were the lowest of the past four winters. This is primarily the result of lower program payment rates for oil and LNG. In Winter 2016-2017, the cost of the program as a percentage of total energy costs was 2.2%, a decrease from the previous winter when program costs comprised 3.8% of total energy costs.

7.4.2 Summary of FERC Filing Regarding 2013-2014 Winter Reliability Program

In 2016, the Federal Energy Regulatory Commission (FERC) issued an Order on Remand directing the Internal Market Monitor (IMM) to evaluate the competitiveness of the 2013-2014 Winter Reliability Program and whether participants exercised market power.[204] The report was filed with FERC on January 23, 2017.[205] The results of the report found that the program's "pay-as-bid" compensation structure may have incentivized participants to place bids that exceeded their costs. To determine whether the auction was structurally competitive, the IMM conducted tests and estimated the cost of uncompetitive bids relative to total program costs.

Structural Competiveness Test

First, a market concentration test was performed to determine whether there was enough competition among participants to result in prices without excessive margins. A lower supply concentration denotes a greater degree of competition between participants. However, the results showed a high concentration ratio among the four largest participants: Nearly 70% of

203 In the first year of the program, units were paid up front for contracted fuel so the remaining inventory does not contribute to the total costs.

204 *ISO New England Inc.,* 156 FERC 61,097 (2016).

205 *ISO New England Inc.*, Compliance Filing Re: Reasonableness of 2013-14 Winter Reliability Program Bid Results, Docket No. ER13-2266-004 (filed January 23, 2017).

supply bid into the auction came from the four largest participants. Since only a few participants controlled such a large portion of the supply, they may have been able to raise prices above competitive levels.

Second, a residual supply index test evaluated the extent to which supply from program participants was needed to meet auction demand. If there was not enough residual supply to meet demand without the supply from a particular participant, then that participant was deemed pivotal in satisfying demand. Bids from pivotal participants may have cleared in the auction even if they exceeded competitive prices. Therefore, pivotal participants may have exercised market power. The results of the test showed that supply to meet the target procurement was insufficient, and each participant was pivotal. Moreover, the ISO held two iterations of the 2013-2014 auction (because the first iteration did not attract adequate supply) and the first auction's inability to attract adequate supply was publicized. Therefore, every participant had market power and was likely aware of it. The results of the market concentration and residual supply index tests indicate that the auction was not structurally competitive.

Uncompetitive Offer Test

The report also investigated whether bids that exceeded participants' costs were the result of market power. Given the pay-as-bid format of the auction, participants may have had an incentive to bid above cost. To conduct this analysis, participants' marginal costs and the value of the highest accepted auction price were estimated. The expected bid price estimate was increased by 25% to account for participants' lack of information given the program's novelty. Next, the actual bids were compared to the estimated values: About 25% of bid prices were high and potentially uncompetitive, while the remaining 75% of bids appeared reasonable. The results showed that potentially uncompetitive costs totaled $6.6 million, which was approximately 9% of total program costs.

Additionally, the report identified obstacles to quantifying the extent to which higher-priced bidding reflected the exercise of market power, as other factors may have been responsible for high bid prices. First, because the program was new, participants likely faced uncertainty in valuing price and penalty risks. Therefore, participants may have used conservative methods in valuing their inventory, leading to higher bid prices. Second, cost estimates may not have fully captured all aspects of risk valuation by participants. Finally, participants may have misinterpreted the program and priced bids for a 3-month period rather than on a per-month basis.

Conclusion

Though the report concluded that the auction was not structurally competitive, the IMM could not conclude with certainty that market power had been exercised, and to the extent it was exercised it may have only been responsible for a small proportion of the program's total cost. The majority of participants offered supply at prices that were deemed reasonable. Thus, the findings suggested that, to the extent market power was exercised, it was not drastic enough to warrant modification of program payments.

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

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.[206] 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.

Sub-Hourly Settlement (implemented March 1, 2017)[207]

Under the revised settlement rules, all assets and transactions in the real-time energy and reserve market 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

[206] *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).

[207] *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).

the real-time energy market and to enhance the accuracy of real-time energy and reserve compensation.

Do-Not-Exceed Dispatch (Implemented on May 25, 2016)

On April 15, 2015, rule changes were filed to improve the dispatch of certain wind and hydro resources that are classified as intermittent power resources in order to achieve more efficient economic outcomes and improve system reliability.[208] The increase in the amount of intermittent power, particularly in wind generation, in remote areas of the transmission system has led to more frequent localized congestion. Before the DNE changes, congestion was managed through manual curtailment instructions, and was not reflected in real-time energy prices. The DNE changes incorporate "DNE dispatchable generators or DDGs" into the economic dispatch and price-setting process. The desired dispatch point is set to the lesser of the economic output based on the DDG's supply offer and a transmission reliability limit. If the dispatch point is less than the forecast of the resource's unconstrained output, the resource is being constrained or "held down" and can potentially set price. The IMM's has observed a significant increase in the number of intervals that intermittent resources, in particular wind generators, set price since the implementation of DNE changes; see Section 3.4.9. The ISO has also reported the elimination of manual curtailments of DDGs since the implementation of the market rules.[209]

Market Enhancements for Asset-Related Demand (implemented on March 1, 2017)

On February 17, 2016, rule changes were filed to improve the way that pump storage hydro-generating resources are modeled and dispatched.[210] The changes establish new modeling practices and bidding parameters that allow participants with pump 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 pump storage hydro-generating resources and other resources with similar characteristics.

Uneconomic Retirements Changes Proposed for FCA 11

The IMM and External Market Monitor (EMM) recommended market rule changes to address the potential for a capacity supplier to uneconomically retire a resource and raise FCM capacity prices above competitive levels. In December 2015, the ISO filed Retirement Reforms market rule changes, which the Commission substantially approved in April 2016. The Retirement

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208 *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. *See also* Letter Order Accepting Updated Effective Date for DNE Dispatch Changes, ER16-870-000 (issued March 25, 2016) (accepting updated effective date of May 25, 2016).

209 See https://www.iso-ne.com/static-assets/documents/2017/01/a4_presentation_dne_dispatch_implementation.pptm

210 *ISO New England Inc. and New England Power Pool,* DARD Pump Parameter Changes,ER16-954-000, (filed February 17, 2016).

Reforms market rules addressed several weaknesses in the way that the Forward Capacity Market structure handled the potential retirement of existing resources.

First, the under the previous market rules the primary means of fully retiring a resource was using a Non-Price Retirement Request, which means that a supplier that had a resource nearing retirement but that also may continue to be economic at a particular price did not have an effective way to submit the resource's retirement price. The Retirement Reforms addressed this issue by providing for the use of priced retirement bids in place of Non-Price Retirement Requests.

Second, the previous FCM rules did not address the potential for a capacity supplier to exercise market power by retiring a resource prematurely in order to decrease supply, artificially increase prices and benefit the remainder of the supplier's portfolio. The Retirement Reforms addressed this issue by providing for review of priced retirement bids by the IMM and the Commission and, if appropriate, the use of the Commission-approved prices (called Proxy De-List Bids) to mitigate the impact of an uneconomic retirement.

Third, the previous FCM auction schedule did a poor job of signaling potential new entrants that additional capacity may be needed due to the retirement of existing resources. The Retirement Reforms addressed this issue by changing the FCM auction timeline to provide for the submission of retirement bids prior to the "show of interest" deadline for new resources.

FCM Zonal Demand Curves (implemented on February 6, 2017 for FCA 11)

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.[211] 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

Integrating Markets and Public Policy (IMAPP)

Integrating Markets and Public Policy is a NEPOOL stakeholder process designed to identify potential changes in the wholesale power market rules that could advance state public policy objectives. Stakeholders have discussed a number of options, including carbon pricing in the energy markets, forward clean energy markets, and 'two-tiered' pricing reforms to the FCM. As a result of stakeholder discussions, ISO New England is currently developing a conceptual approach to maintain transparent and competitive markets that can incorporate the state-subsidized policy resources in the near term. This effort is expected to continue through

[211] *Demand Curve Design Improvements* (ER16-1434-000), April 15, 2016, http://www.iso-ne.com/static-assets/documents/2016/04/er16-1434-000.pdf.

Quarter 2, 2018. Any potential implementation efforts will depend on the scope of a final proposal. Additionally, the ISO will continue to work with stakeholders on achieving state policies through markets as long term solution.

Energy Market Offer Caps (Order 831)

In November 2016, the Commission issued Order 831 revising its regulation addressing incremental energy offer caps. Order 831 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 Commission requires that each RTO and ISO modify its market rules to: (1) 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 (2) cap verified cost-based incremental energy offers at $2,000/MWh when calculating LMPs. The market rule changes to implement Order 831 will apply to all supply resources, including demand response, that offer incremental energy in the energy markets.

Further, the Commission clarified that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs. The ISO must allow resources to be eligible for make-whole payments in the event that (1) a resource has a verified cost-based offer above the $2,000/MWh hard cap or (2) a resource has incremental energy costs above $1,000/MWh which cannot be verified by the IMM prior to market clearing, but which are verified by the IMM after-the-fact.

The ISO plans to make a compliance filing with proposed rule changes in May 2017.

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