ISO New England's Internal Market Monitor

Summer 2016

Quarterly Markets Report

Internal Market Monitor
November 15, 2016

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Preface

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets 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.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

This report covers the spring period from **June 1, 2016 to August 31, 2016** (the "reporting period"). The report contains our analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media

[1] Capitalized terms not defined herein have the meanings ascribed to them in Section I of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff").

[2] *Available at* http://www.theice.com.

Section 1
Executive Summary

This report presents metrics and analysis of the performance of ISO New England wholesale electricity and related markets for the Summer of 2016 (June 2016 through August 2016).[3]

1.1 Summary of Market Outcomes and Performance for Summer 2016

- The total estimated wholesale market costs were $1.56 billion in the reporting period, a 13% increase compared to the same period in 2015 (Summer 2015).
    - Higher natural gas prices were the primary driver for the increase in total energy costs. Natural gas prices averaged $2.68/MMBtu. This is a 17% increase from last quarter and a 31% increase compared to Summer 2015.
- In Summer 2016, the average hourly demand was 15,884 MW, compared to 15,620 MW in the same season of 2015, an increase of 2%. This increase can be explained by hotter weather, particularly in the month of August. The peak real-time load during the reporting period, which occurred on August 12, 2016, was 25,521 MW, 4% higher than the peak load observed in Summer 2015.
- Day-ahead and real-time energy market prices at the Hub averaged $29.83/MWh and $30.35/MWh, respectively. Day-ahead prices were 15% higher and real-time prices were 13% higher than Summer 2015 prices. These outcomes were driven by natural gas prices and higher demand.
- Total real-time reserve payments were $14.2 million, a 40% increase from $10.1 million in Summer 2015. The increase in total payments compared to Summer 2015 was primarily the result of higher prices for all reserve products. The higher prices were driven by the high reserve prices during the Shortage Event on August 11 and during several days following the event.
- Regulation payments totaled $8.9 million, a 70% increase from $5.2 million in Summer 2015. The ISO's manual selection of large regulation resources during periods of high prices contributed to the increase in payments. The manual selection of resources allowed the ISO to address reliability concerns, but also resulted in more capacity being reserved for regulation than was needed in those hours.
- Net Commitment Period Compensation (NCPC) payments in the quarter totaled $13.1 million, a 35% decrease from Summer 2015. The decrease in first and second contingency payments in Summer 2016 compared to Summer 2015 can be explained largely by differences in the NCPC rules between the two periods.[4] First contingency payments in

[3] In Quarterly Markets Reports, outcomes are reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

[4] At the end of Winter 2016, modifications to the NCPC rules were implemented that prevent generators from receiving compensation for real-time commitment costs for hours during which their commitment costs are evaluated for day-

Summer 2016 of $9.0 million were 34% lower than first contingency payments made last summer and similarly, second contingency payments in Summer 2016 of $3.4 million were 43% lower than payments made last summer.

- Summer 2016 coincides with the beginning of the commitment period associated with FCA 7.The NEMA-Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources, and the Rest-of-Pool cleared at the floor price of $3.15/kW-month. In Summer 2016, capacity payments totaled $303 million. This represents an increase in capacity payments compared to Summer 2015 of $17 million, or 6%. The capacity price associated with Summer 2015 was $3.43/kW-month.

1.2 Review of System Events on Thursday, August 11 and Friday, August 12, 2016

The system experienced a two-day period of tight system conditions on Thursday, August 11 and Friday, August 12, 2016. A combination of generator forced outages and high load levels resulted in significantly reduced reserve margins, and high real-time energy prices.

During that two-day period, the ISO implemented M/LCC 2 (Abnormal Conditions Alert) due to a forecasted operating reserve deficiency. The ISO's Operating Procedure #4, Actions 1 and 2, were in effect for several hours on August 11.[5] Action 2, involved the dispatch of all available real-time demand resources in all load zones, with the exception of Maine which was export-constrained.

Notable market and settlement results during this period included the following:

- On August 11, there was an increase in full generator outages of approximately 1,500 MW compared to the prior day. On August 12, significant unplanned outages continued and increased capacity reductions by a further 350 MW. Major reductions in the availability of coal-fired, natural gas-fired, and nuclear generation were offset by oil-fired generation, imports and demand response resources. Oil-fired generators were marginal during 21% of real-time pricing intervals on August 11, and 15% of real-time pricing intervals on August 12.

- Five-minute real-time energy prices reached a peak of $2,691/MWh at the Hub over a ten-minute period from 14:50 to 15:00 on August 11. Over the two-day period, energy prices incorporated frequent and significant reserve pricing as re-dispatch was required to maintain requirements. Thirty-minute reserve pricing occurred during a total of almost 9 hour and ten-minute spinning reserve prices occurred during 5.6 hours over the two-day period.

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ahead NCPC compensation. *See ISO New England Inc. and New England Power Pool*, Market Rule 1 Revisions to the NCPC Credit Rules, Docket No. ER16-250-000 (filed November 3, 3015).

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

- Under the provisions of the Forward Capacity Market rules a Shortage Event occurred from 14:25 through 18:15 on August 11.[6] Penalties resulting from the Shortage Event totaled $7.3 million; representing about 7.2% of the $101 million in FCM payments for August 2016.

- Real-time energy prices also exceeded the Peak Energy Rent (PER) strike price for six hours in all capacity zones on August 11. It is estimated that the total PER adjustment attributable to the event is approximately $101 million, roughly equivalent to the total FCM payments for the month.

- High real-time prices led to significant real-time costs. As a result of large deviations from generator day-ahead schedules and very high real-time prices, real-time costs made up about 40% of the total energy costs. Most charges to recover these costs were to generators that failed to deliver on their day-ahead schedules. NCPC during the system event totaled approximately $4 million, with $3.5 million of those costs incurred on August 11. The majority of NCPC, $3.1 million, was paid to generators that were postured to provide reserves.

[6] At a general level, a shortage event is a period when the New England power system is stressed and is using nearly 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. It is a feature of the Forward Capacity Market during which resource availability is measured and subject to penalties based on a resource's availability score.

Section 2
Summary of Market Outcomes and System Conditions

This section summarizes the region's wholesale electricity market outcomes and measures of market performance.

2.1 Market Outcomes

The following subsections present and discuss the key trends and drivers of market outcomes from Winter 2014 (beginning December 2013) up to the most recent seasonal quarter. It covers trends in the wholesale cost of electricity, key market statistics and describes outcomes in the ISO's real-time and forward markets.

2.1.1 Total Wholesale Electricity Market Value

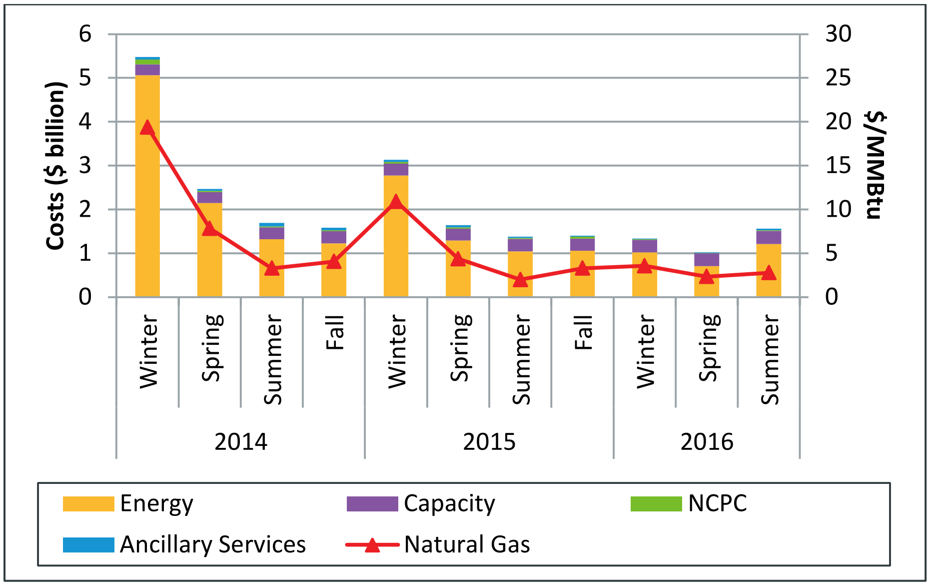
Figure 2-1 below shows the estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu).[7] In Summer 2016, the total estimated market cost increased by about 13% compared to the same quarter last year ($1.56 billion in Summer 2016 compared to $1.38 billion in Summer 2105), and increased by 53% when compared to the last quarter, Spring 2016 ($1.02 billion).[8]

By contrast, Summer 2016 Net Commitment Period Compensation (NCPC) costs of $13 million were 35% lower than Summer 2015 NCPC costs and 31% higher than Spring 2016 NCPC costs. This trend is explained in section 2.2.1 below. Ancillary service costs, which include reserve and regulation payments, totaled $38 million in Summer 2016, an increase of 25% when compared to Summer 2015, and an increase of 119% when compared to Spring 2016.

[7] The natural gas average prices used throughout this report are based on the Next Day Tennessee Gas Pipeline Co. - Zone 6, 200 Line index price as reported by the Intercontinental Exchange.

[8] 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 as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

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



Natural gas prices are a key driver behind changes in energy costs in New England. The increase in natural gas prices between Summer 2015 and Summer 2016 resulted in higher energy costs in this most recent quarter. Additionally, higher natural gas prices in Summer 2016 resulted in increased energy costs compared to Spring 2016.

2.1.2 Key Market Statistics

Table 2-1 shows selected key statistics for load levels, real-time and day-ahead energy market prices, and fuel prices.

Table 2-1: Key Statistics on Load, LMPs, and Natural Gas

	Summer 2016	Spring 2016	Percent Change Summer 2016 to Spring 2016	Summer 2015	Percent Change Summer 2016 to Summer 2015
Real-Time Load (GWh)	35,072	28,262	24%	34,489	2%
Weather Normalized Real-Time Load (GWh)	34,898	28,371	23%	34,509	1%
Peak Real-Time Load (MW)	25,521	19,029	34%	24,437	4%
Average Day-Ahead Hub LMP ($/MWh)	$29.83	$23.36	28%	$25.94	15%
Average Real-Time Hub LMP ($/MWh)	$30.35	$22.10	37%	$26.86	13%
Average Natural Gas Price ($/MMBtu)	$2.68	$2.29	17%	$2.05	31%

The following factors contributed to the differences in Summer 2016 market outcomes compared to Summer 2015:

- Higher natural gas prices in Summer 2016 were the primary driver for higher day-ahead and real-time prices when compared to the same season last year.
    - Natural gas prices during the reporting period increased by 31% compared to gas prices last summer. The cause of this increase is explained in the section below.
- The real-time load in Summer 2016 was also 2% higher than the real-time load in Summer 2015. The peak load for summer 2016 was 4% (1,084 MW) higher than the peak load from last summer.

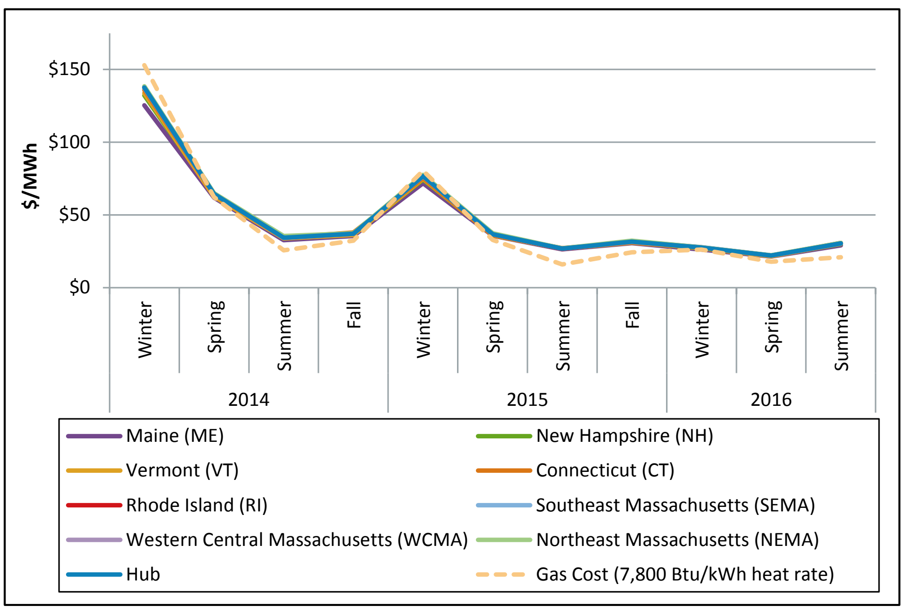
2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average real-time Hub energy price was $30.35/MWh in the reporting period. In contrast to the general trend in previous quarters where real-time prices cleared at a discount to day-ahead prices, system events in the real-time market on August 11 and 12 of this year contributed to a slight premium of $0.52/MWh, or 1.7%, in real-time prices this quarter.

Real-time energy prices in Summer 2016 were higher than Summer 2015 by 13%, but lower than Summer 2014 by 12%. Real-time prices continue to follow the cost of natural gas generation, although as observed in prior summer periods, energy prices exhibited a positive divergence from gas generation costs as higher-cost resources are dispatched during summer peak loads. Energy prices did not differ significantly among the load zones.[9] Figure 2-2 shows the seasonal average real-time energy prices and the estimated cost of gas generation based on a unit heat rate of 7,800 Btu/kWh and the Tennessee Gas Pipeline Zone 6 index price.

Figure 2-2: Simple Average Real-Time Energy Prices and Gas Generation Costs

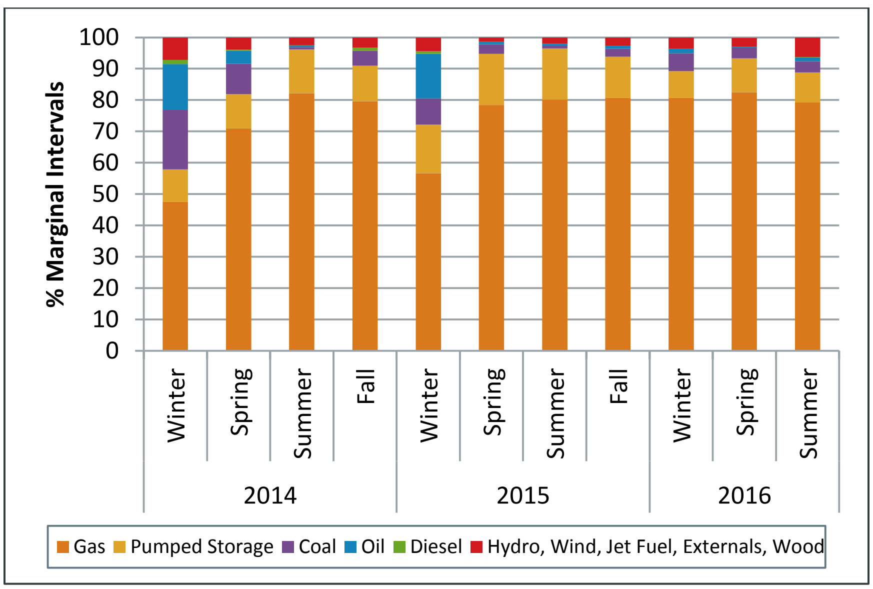


[9] A *load zone* is an aggregation of pricing nodes within a specific area; there are currently eight load zones in the New England region that correspond to the reliability regions.

Figure 2-2 illustrates that average real-time energy prices tend to track closely with the cost of natural gas. This is shown by the movement in the zonal energy price trend lines and the natural gas cost trend line. The 13% increase in Summer 2016 energy prices compared to Summer 2015 occurred as natural gas prices also increased by 31% over the same period. According to the U.S. Energy Information Administration (EIA), a hot summer across the country, increased electric power sector consumption, and production declines contributed to the increase in natural gas prices during Summer 2016.[10]

The LMP at a pricing location is set by the cost of the next megawatt the ISO would dispatch to meet an incremental change in load at that 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 and heat rate. Because of this, examining marginal units by fuel type helps us understand changes in electricity prices. Figure 2-3 below shows the percentage of time resources of different fuel types were marginal by season.

Figure 2-3: Real-Time Marginal Units by Fuel Type



In the reporting period, units burning natural gas were marginal (*i.e.*, setting the price) during 79% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal in 10% of the pricing intervals. Units burning coal, oil, diesel, jet fuel, wood, traditional hydro units, and external transactions were marginal in the remaining pricing intervals.

As seen in the figure above, the composition of marginal units in Summer 2016 was generally similar to previous summers. Wind and coal-fired resources were marginal during more intervals, with a corresponding reduction in the frequency of pumped storage units at the margin. The increase in pricing intervals during which coal was marginal (from 1% to 4% of intervals) corresponds to relatively lower coal prices compared to natural gas, and the resulting increase in the output of coals units during the quarter compared to previous summer quarters. The increase in pricing intervals in which wind units were marginal, from both Summer 2015, and Spring 2016,

[10] US Energy Information Administration. Short Term Energy Outlook September 2016. Washington, DC: US Department of Energy, September 2016. https://www.eia.gov/forecasts/steo/archives/Sep16.pdf. Pages 6 – 8.

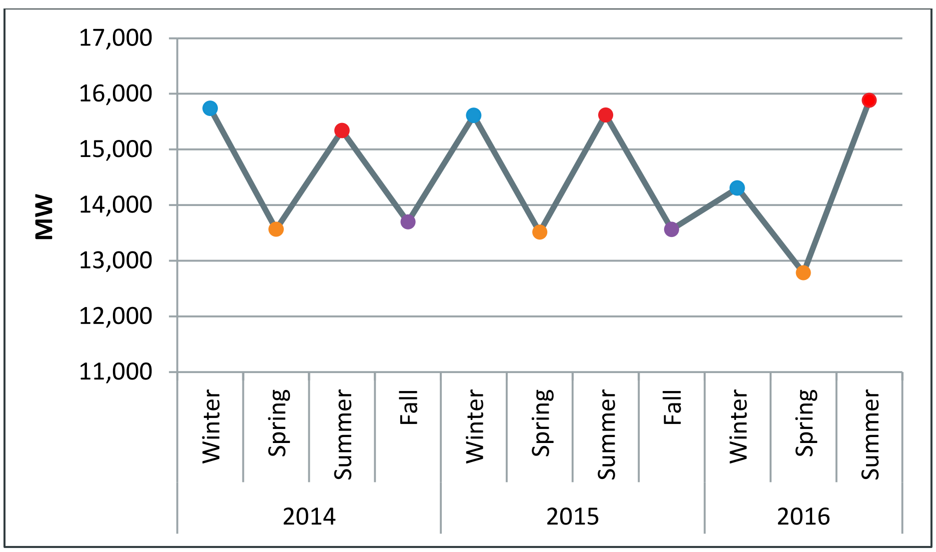
is in part due to the Do Not Exceed (DNE) dispatch rules which went into effect on May 25, 2016.[11] DNE incorporates wind and hydro intermittent units into the unit dispatch, making them eligible to set price. Previously, these units had to self-schedule their output in the real-time market and could not set price.

2.1.3.2 Load Summary

In Summer 2016, the average hourly load was 15,884 MW, a 2% increase compared to the summer 2015 value of 15,620 MW and 4% increase compared to the summer 2014 value of 15,341MW.[12] Warmer weather in summer 2016 helps explain why the average hourly load was slightly higher compared to the past two summer seasons. Of the three months in the quarter (June, July, and August), August 2016 was particularly warmer than August 2014 and August 2015. The maximum temperature humidity index (THI)[13] for August 2016 was 83°F, compared to 79°F and 78°F in August 2015 and 2014, respectively. The monthly average THI for August 2016 was 71°F compared to 70°F and 67°F in August 2015 and 2014, respectively.

Figure 2-4 below illustrates average hourly load by seasonal quarter. The blue dots represent winter, the yellow dots represent spring, the red dots represent summer, and the purple dots represent fall.

Figure 2-4: Average Hourly Demand



[11] *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.

[12] The terms "demand" and "load" are used interchangeably and are intended to have the same meaning in this report.

[13] Temperature Humidity Index (THI) is a combination of Temperature and Dew Point and provides a measure of heat index.

Another way to examine load is to sort all the hourly load values (i.e. 2,208 hourly values in the reporting period) from highest to lowest for any given period. The resulting curve is called a *load duration curve.* By plotting several seasonal load duration curves, one can easily observe differences between periods. Also, since the load duration curves have the same number of observations (hours), the horizontal axis can be expressed as a percentage of the total number of hours in the period of interest as shown in Figure 2-5. The percent axis allows one to quickly view what percentage of hours is above or below a particular load level.

Figure 2-5: Seasonal Load Duration Curves (MW)

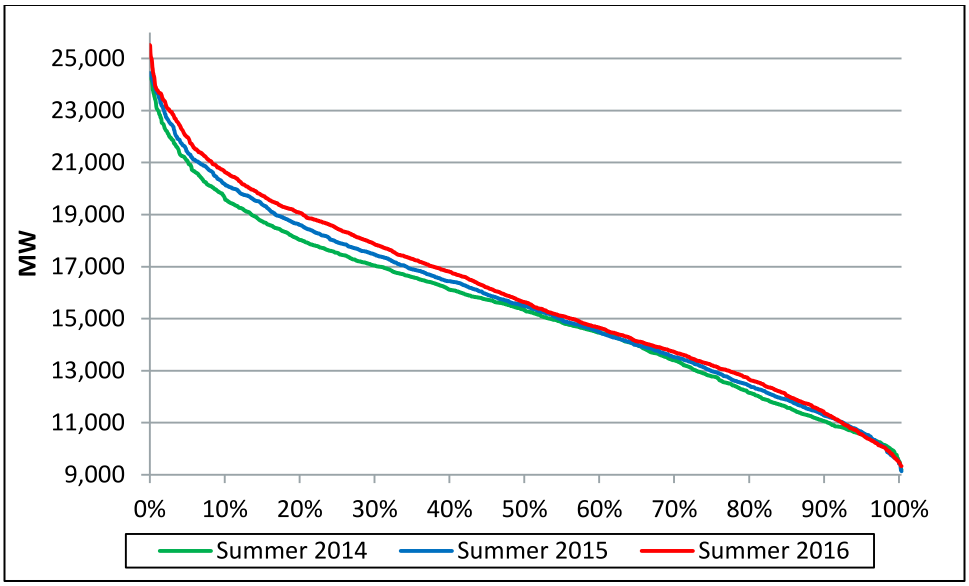


Figure 2-5 illustrates the same trend as Figure 2-4 above; that loads were consistently higher in Summer 2016 when compared to Summer 2014 and Summer 2015.

The peak hourly demand in the reporting period occurred on August 12 at 3:00 PM and was 25,521 MW. This was higher than the summer 2015 peak of 24,437 MW. The peak load of 24,017 MW on Sunday, August 14th, was the highest Sunday load recorded by ISO. The lowest hourly demand in the reporting period was 9,333 MW, similar to the prior two summer periods.

2.1.3.3 Real-Time Operating Reserves

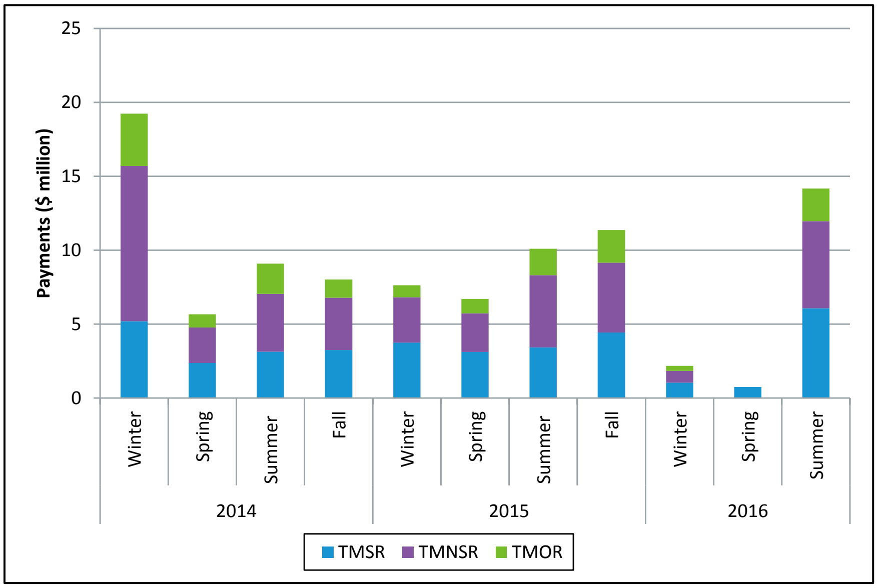
Total real-time reserve payments were $14.2 million in Summer 2016, a 40% increase compared to Summer 2015 payments of $10.1 million.[14] The increase in total payments compared to Summer 2015 is due to higher average prices for all reserve products. The higher average reserve prices were driven by the high reserve prices during tight system conditions; specifically on August 11, when the system experienced a Shortage Event, and during the days following the Shortage Event.[15] About $8.3 million in real-time reserve payments were made on August 11, and $1.6 million were made on August 12. See Section 3 for more details of system conditions and market outcomes during August 11 and 12.

[14] Payment data represent total payments for Real-Time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

[15] *See* footnote 6, *supra*, for the definition of a shortage event.

Figure 2-6 shows the total real-time reserve payments by season from Winter 2014 through Summer 2016.

Figure 2-6: Real-Time Reserve Payments ($ millions)



As shown in Figure 2-6, real-time reserve payments were significantly higher in Summer 2016 compared to the past two years. This was due primarily to the Shortage Event on August 11 and other high reserve pricing during subsequent days.

While reserve prices were higher, the frequency of non-zero reserve prices was generally slightly lower in Summer 2016 compared to the prior summer. The frequency of ten-minute spinning reserve (TMSR) pricing in all reserve zones, except in NEMA-Boston, decreased slightly from 5% to 4.85%.[16] In addition, the frequency of these reserve zones' ten minute non-spinning reserve (TMNSR) pricing and thirty minute operating reserve (TMOR) pricing both decreased from 0.92% and 0.91% to 0.89% and 0.85%, respectively. In contrast, the frequency of reserve pricing in NEMA-Boston increased from Summer 2015 to Summer 2016 in all three categories between Summer 2015 and Summer 2016 due to transmission outages restricting the flow of power into the NEMA-Boston reserve zone on June 29.

In NEMA-Boston, average prices for all three categories of reserve were lower, because the reserve prices were relatively low during the intervals with local reserve pricing. For all reserve zones, except NEMA-Boston, average non-zero TMSR prices increased from $43.44/MWh to $72.66/MWh, average non-zero TMNSR prices increased from $171.88/MWh to $314.28/MWh, and average non-zero TMOR prices increased from $173.16/MWh to $303.90/MWh.

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[16] Because higher quality reserve products can provide reserves for a lower quality product (e.g. ten-minute spinning reserves can provide thirty minute operating reserves), in this analysis reserve products are cascaded. Therefore, thirty minute operating reserve prices apply to both ten-minute spinning and ten-minute non-spinning reserves. Likewise, ten-minute non-spinning reserve prices apply to ten minute spinning reserves. For example, if the thirty minute operating reserve price is $10 and there is no additional reserve pricing, both ten-minute spinning and ten-minute non-spinning reserve prices will be shown as $10.

2.1.3.4 Regulation Market

Total regulation market payments were $8.9 million during the reporting period, up 86% from $4.8 million in Spring 2016, and up 70% from $5.2 million in Summer 2015. A significant portion of the increase in payments can be attributed to the ISO's manual selection of large regulation resources during periods of high prices; the manual selection of resources allowed the ISO to address reliability concerns, but also resulted in significantly more capacity being reserved for regulation than was needed in those hours. During these high-priced hours the opportunity cost component of the regulation capacity price was the most significant driver of high regulation prices and payments. Additionally, average regulation requirements also increased relative to earlier periods. The Summer 2016 regulation requirements were 19% higher than the preceding quarter, and 32% higher than the Summer 2015 requirements. Quarterly regulation payments are shown in Figure 2-7 below.[17]

Figure 2-7: Regulation Payments ($millions)

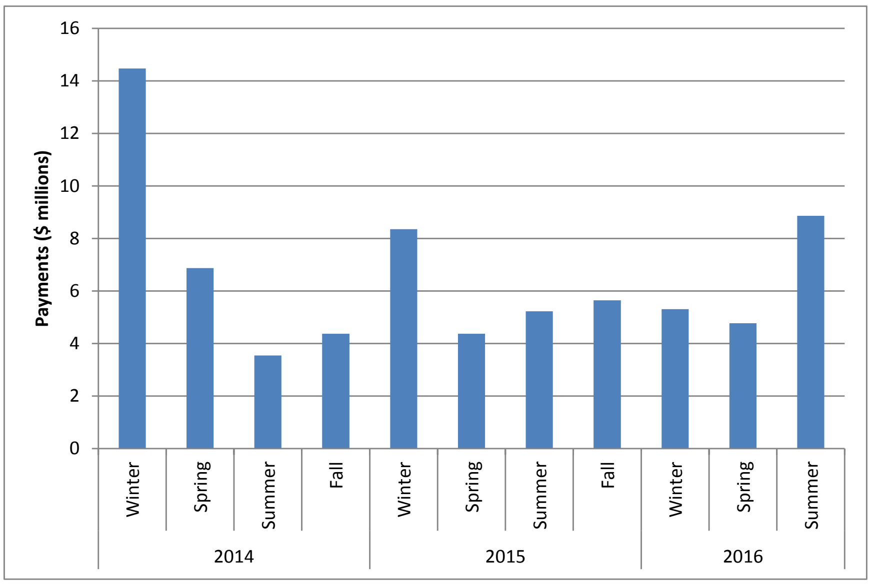


Table 2-2 indicates the portion of regulation payments that occurred during hours when significantly more regulation capability was obtained than required. As noted in the table, the frequency of hours with large excesses of regulation capability increased by a factor of 3, compared to Summer 2015, while average regulation capacity payments were unchanged. The capability obtained by the ISO in these instances exceeded the requirement by approximately 200 MW on average. Payments in these hours accounted for an almost $2 million increase in total regulation payments (compared to Summer 2015).

[17] As noted in the Spring 2016 Quarterly Markets Report, 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. These changes were implemented in April 2016.

Table 2-2: Regulation Payments: Hours When Excess Regulation Capability Is Greater Than 100 MW

Year	Quarter	Frequency (Hours)	Regulation Requirement MW (Average Hourly)	Regulation Provided MW (Average Hourly)	Capacity Clearing Price $/MW (Average Hourly)	Total Regulation Cost ($ Millions)
2015	**Summer**	12	50	256	204	0.87
2016	**Spring**	7	61	281	69	0.22
2016	**Summer**	37	70	266	204	2.68

Table 2-3 summarizes payments during hours when the excess of regulation capability was less than 100 MW. The increase in payments during these hours is primarily explained by the increase in regulation requirement and a slight increase in regulation capacity prices compared to summer 2015.

Table 2-3: Regulation Payments: Hours When Excess Regulation Capability Is Less Than 100 MW

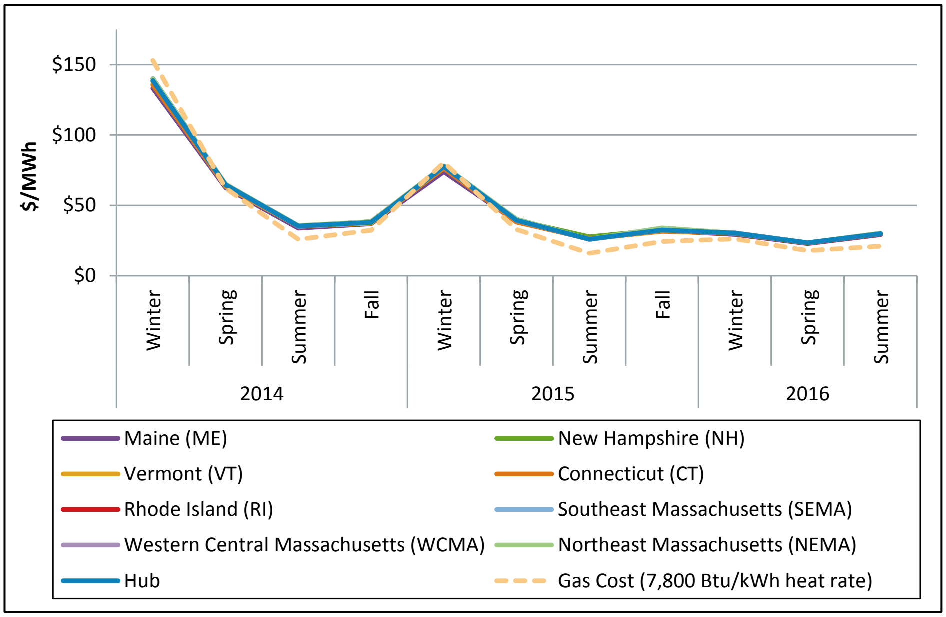
Year	Quarter	Frequency (Hours)	Regulation Requirement MW (Average Hourly)	Regulation Provided MW (Average Hourly)	Capacity Clearing Price $/MW (Average Hourly)	Total Regulation Cost ($ Millions)
2015	Summer	2196	62	66	25	4.35
2016	Spring	2201	69	73	22	4.55
2016	Summer	2171	82	88	27	6.19

2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price for Summer 2016 was $29.83/MWh, an increase of 28% from the Spring 2016 average of $23.36/MWh. Similar to real-time energy prices, day-ahead energy prices remained correlated with natural gas prices. Prices did not differ significantly among the load zones. Figure 2-8 below depicts seasonal quarterly average day-ahead energy prices and estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Tennessee Gas Pipeline Zone 6 index price).

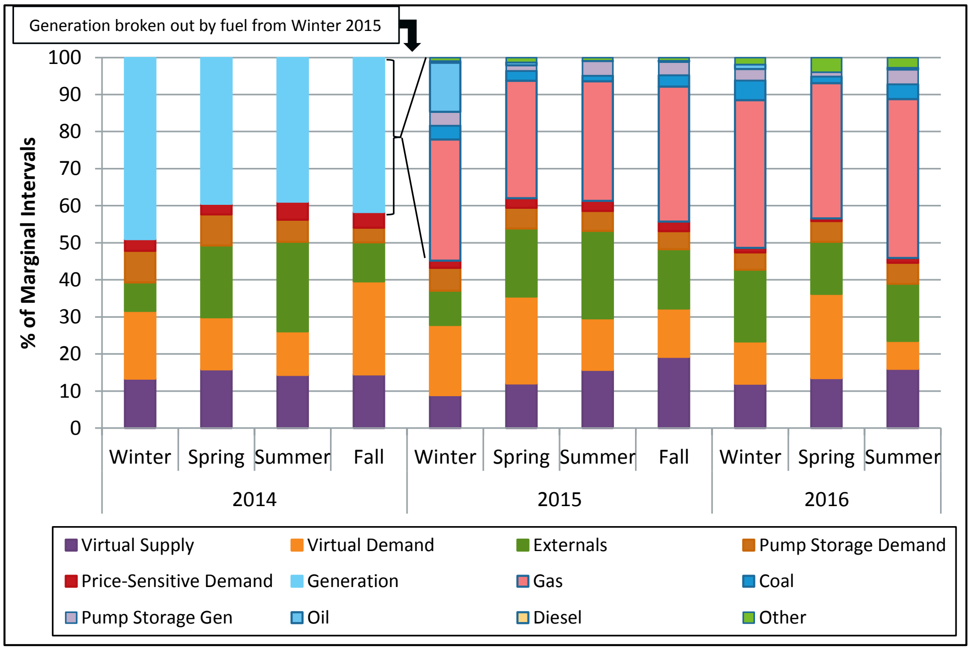
Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs



As shown in Figure 2-8, average day-ahead energy prices at the Hub increased relative to Summer 2015 by 15%, but were lower than Summer 2014 by 15%. The increase in energy prices compared to the prior summer is consistent with the increases in natural gas prices over the same period. The average day-ahead Hub price was roughly 2% lower than the average real-time Hub price of $30.35/MWh– a day-ahead discount of $0.52/MWh relative to real-time prices for the period. As discussed in section 2.1.3.1, this was driven by high real-time energy market prices on August 11 and 12. These real-time events, and resulting prices, were not anticipated in the clearing of the day-ahead energy market. This resulted in large differences between day-ahead and real-time prices on those days.

Figure 2-9 below shows the percentage of time that each resource type set price in the day-ahead market since Winter 2014. In addition to generators, there are other entities that can set price in the day-ahead market, including price-sensitive demand, priced external transactions, and virtual transactions. Beginning in 2015, the graph illustrates a breakdown of the generators category (large blue bar, years 2011-2014) by generator fuel type (bars outlined in blue). With the introduction of Energy Market Offer Flexibility (EMOF) in December 2014, generators submit information regarding fuel 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 starting with Winter 2015.

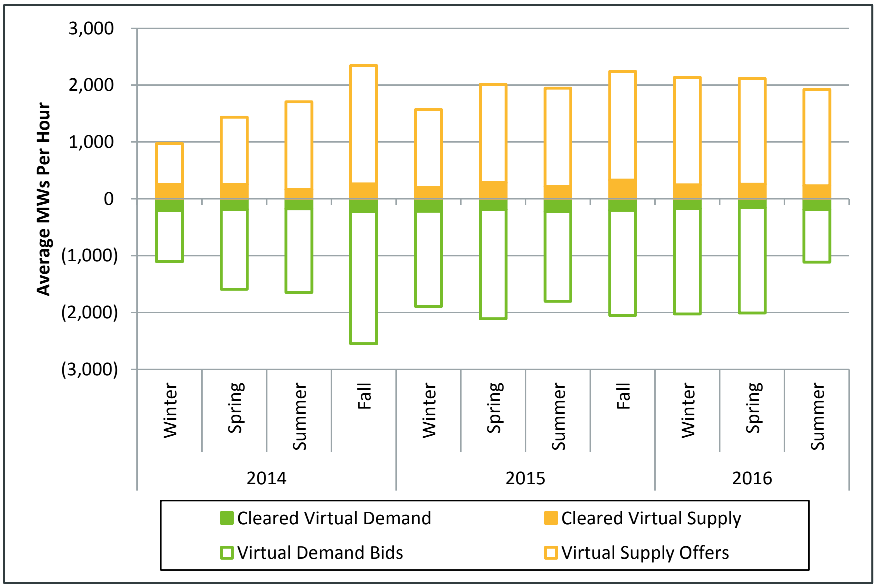
Figure 2-9: Day-Ahead Marginal Units by Resource and Fuel Type



There can be a lot of variation, from one period to the next, in the number of intervals that each resource type sets price in the day-ahead market. This is due to the number of resource types participating on both supply and demand side of the market. By contrast, only physical supply can set price in the real-time market with natural gas generators generally the dominant price-setters. The frequency of marginal units by resource type during the reporting period was within a normal range based on historical observations. Generators set price approximately 54% of the time in the day-ahead market. Virtual transactions (virtual supply and demand) set price approximately 24% of the time, and external transactions set price approximately 15% of the time. Price-sensitive demand (including pump storage demand) was marginal in the remaining 7% of price-setting intervals.

As can be seen from the figure above, virtual transactions perform a significant price-setting role in the day-ahead energy market. Figure 2-10 shows virtual transaction volumes from Winter 2014 through Summer 2016.

Figure 2-10: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



In the reporting period, submitted virtual demand bids and virtual supply offers averaged approximately 3,034 MW per hour, a 26% decrease when compared with Spring 2016, and a 19% decrease from Summer 2015. The decrease in submitted transactions was due to a large decrease in submitted virtual demand bids. Despite the large reduction in submitted virtual transactions, cleared virtual transactions decreased by only 5% compared with Summer 2015 and increased by 2% when compared with Spring 2016. In the reporting period, 16% of the megawatt quantity of virtual bids and offers cleared in the day-ahead market, which is slightly greater than in previous quarters. The percentage of cleared demand bids to submitted bids was much higher than in previous reporting periods. This indicates that the decrease in demand bids was primarily in transactions priced very low that would typically not clear.

2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 95,822 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $1.3 million, approximately the same as the previous reporting period. Thirty bidders in June, twenty-eight bidders in July and thirty-two bidders in August participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.4.3 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[18] The FCM is designed to procure and price capacity before the system will need it. The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

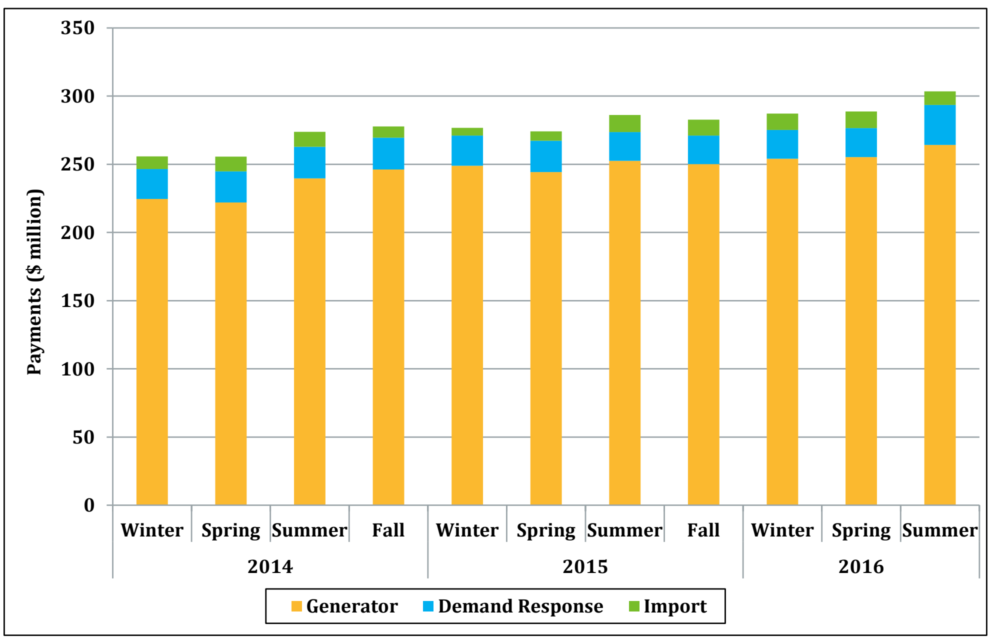
[18] In the capacity market, resource categories include generation, demand response and imports.

During any one three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[19] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual capacity supply obligations (CSOs). Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can take on obligations or shed obligations. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period including total payments and trading of CSOs specific to each commitment period.

Payments. Figure 2-11 shows the total FCM payments by resource type for Spring 2014 through the end of the reporting period.

Figure 2-11: Total Capacity Payments ($ millions)



Summer 2016 coincides with the beginning of the commitment period associated with the seventh Forward Capacity Auction (FCA 7). The NEMA-Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources, and the Rest-of-Pool cleared at the floor price of $3.15/kW-month. In Summer 2016, capacity payments totaled $303 million, which accounts for adjustments to primary auction capacity supply obligations (CSOs). Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

[19] Each capacity commitment period is a twelve-month period starting on June 1 of a year and ending on May 31 of the following year.

Table 2-3 provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Summer 2016, alongside the results of the relevant primary forward capacity auction.

Table 2-3: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

					Capacity Zone/Interface Prices		
FCA # (Commitment Period)	**Auction Type**	**Period**	**System-wide Price ($/kW-mo)****	**Cleared MW**	**NEMA/Bos**	**SEMA/RI**	**HQ Phase I/II**
FCA 7 (2016-17)	Primary	12-month	3.15	36,220	15.00/6.66*		
	Monthly Reconfiguration	Aug-16	1.95	422	6.66		1.70
	Monthly Bilateral	Aug-16	2.08	136			
	Monthly Reconfiguration	Sep-16	1.95	452	6.66		1.75
	Monthly Bilateral	Sep-16	2.10	139			
	Monthly Reconfiguration	Oct-16	1.03	730	15		
	Monthly Bilateral	Oct-16	1.36	150			
FCA 8 (2017-18)	Primary	12-month	15.00/7.03*	33,712	15.00/15.00*		
	Annual Bilateral (2)	12-month	1.32	87			
	Annual Reconfiguration (2)	12-month	7.13	243			
FCA 9 (2018-19)	Primary	12-month	9.55	34,695		17.73/11.08*	
	Annual Reconfiguration (1)	12-month	8.52	238/51***			

**price paid to new resources/price paid to existing resources*
***prices represent volume weighted average prices for bilaterals*
***cleared supply/cleared demand

FCA 7 Commitment Period. In FCA 7 (2016-2017), the ISO modeled import-constrained capacity zones, specifically the NEMA-Boston and Connecticut zones for the first time. The NEMA- Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources. The pricing for existing resources was determined using administrative pricing rules designed to protect the market from the exercise of market power. These administrative pricing provisions were used because there was insufficient competition among new resources to set a competitive price. The clearing price for all other zones was the floor price of $3.15/kW-month.

All three monthly reconfiguration auctions during the reporting period took place for the FCA 7 commitment period. The cleared megawatts by auction were 422 MW, 452 MW, and 730 MW in August, September, and October 2016, respectively. The cleared capacity for August 2016 was 422 MW, with prices of $1.95/kW-month in Rest-of-Pool, $6.66/kW-month in NEMA-Boston, and $1.70/kW-month at HQ Phase I/II. The cleared capacity for September 2016 was 452 MW, with prices of $1.95/kW-month in Rest-of-Pool, $6.66/kW-month in NEMA-Boston, and $1.75/kW-month at HQ Phase I/II. In August and September the tie-lines price separated because the lines reached the capacity transfer limit.

The final reconfiguration auction in the quarter was for October 2016. The cleared capacity was 730 MW, with prices of $1.03/kW-month in Rest-of-Pool and $15.00/kW-month in NEMA-Boston.

In the October 2016 auction there were no demand bids in the NEMA-Boston zone, therefore a price of $15.00/kW-month was given as a price signal even though no capacity cleared.

In the three bilateral periods there were 136 MW, 139 MW, and 150 MWs of approved capacity traded for the August, September, and October 2016 bilateral periods, respectively. The volume-weighted prices were $2.08/kW-month in August, $2.10/kW-month in September, and $1.36 /kW-month in October. Table 2-3 shows the amount of megawatts transferred and acquired by resource type.

Table 2-4: Bilateral Acquired and Transferred MW for FCA Commitment Period 7

Month	Resource Type	Acquired MW	Transferred MW	Net MW
August 2016	Demand Response	23	73	(50)
	Generator	113	8	105
	Import	0	55	(55)
August 2016 Total		**136**	**136**	**0**
September 2016	Demand Response	23	73	(50)
	Generator	115	10	105
	Import	0	55	(55)
September 2016 Total		**139**	**139**	**0**
October 2016	Demand Response	22	78	(56)
	Generator	128	22	106
	Import	0	50	(50)
October 2016 Total		**150**	**150**	**0**

FCA 8 Commitment Period. The second annual reconfiguration auction for the 2017-2018 commitment period took place in June 2016 and cleared 243 MW of capacity at a system-wide price of $7.13/ kW-month. The initial clearing price for FCA 8 in NEMA-Boston was $15.00/kW-month for existing and new resources. In all other zones, the clearing price was $7.03/kW-month for existing resources and was $15.00/kW-month for new resources.

FCA 9 Commitment Period. The first annual reconfiguration auction for the 2018-2019 commitment period took place in June 2016. This was the first reconfiguration auction to use the sloped demand curve instead of solely using participant demand bids. The sloped demand curve is designed to procure sufficient capacity supply to maintain resource adequacy and reduce price volatility over time. Cleared supply was 238 MW, while cleared demand equaled 51 MW at a clearing price of $8.52/kW-month.

2.2 System Conditions

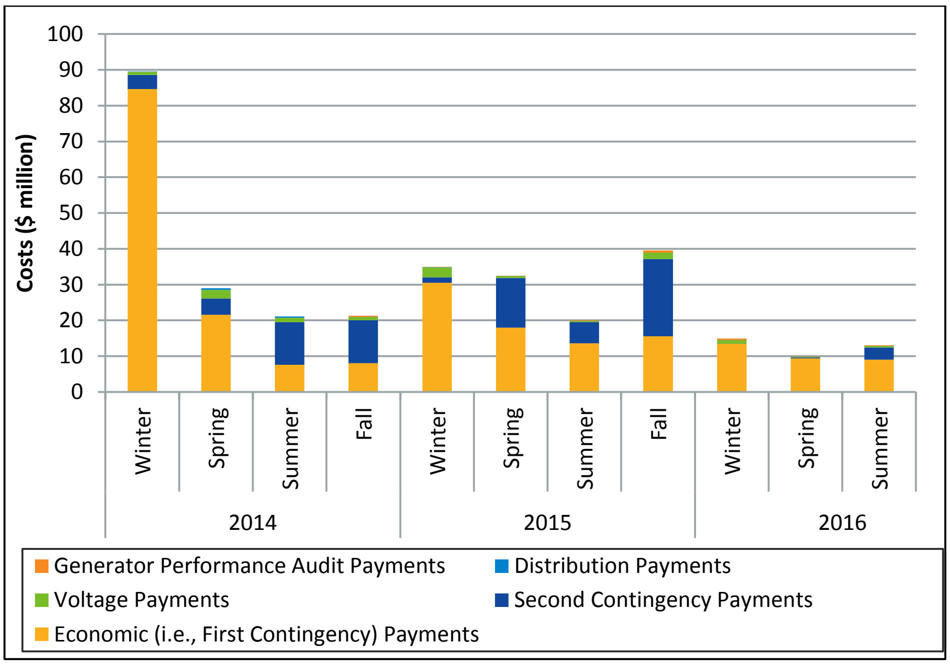
The following two subsections cover recent trends and outcomes in Net Commitment Period Compensation (NCPC), or uplift, payments, and in flows of power between the New England and its neighboring control areas in New York and Canada.

2.2.1 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing a make-whole payment to resources when energy market payments are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require make-whole payments. NCPC is paid to resources for providing first- and second-contingency protection, voltage support and control, and distribution system protection in either the day-ahead or real-time energy markets, and for generator performance auditing.[20]

In Summer 2016, NCPC payments totaled $13.1 million. This is a 35% decrease compared to the same season last year ($20.0 million) and a 31% increase compared to Spring 2016 ($10.0 million). NCPC payments by season and category are shown in **Error! Reference source not found.**

Figure 2-12: NCPC Payments by Category ($ millions)



The majority of NCPC (69%) incurred during the reporting period was for first contingency protection. Approximately $8.7 million of total NCPC was paid in the real-time market, of which $8.2 million was for first contingency.[21] Approximately $4.4 million of total NCPC was in the day-ahead market, of which $0.8 million was for first contingency.

[20] NCPC payments include *economic/first contingency NCPC payments*, *local second-contingency NCPC payments* (reliability costs paid to generating units providing capacity in constrained areas), *voltage reliability NCPC payments* (reliability costs paid to generating units dispatched by the ISO to provide reactive power for voltage control or support), *distribution reliability NCPC payments* (reliability costs paid to generating units that are operating to support local distribution networks), and *generator performance audit NCPC payments*.

[21] *Economic/first contingency NCPC payments* include:

- Reliability costs paid for generation committed and dispatched to provide energy on short notice and create operating reserves that allow the system to recover from the loss of the first contingency within the specified period.

Payments for second contingency protection accounted for 26% of total NCPC. All $3.4 million of second contingency payments were made to units in the NEMA load zone. Transmission outages limiting transfer capability within the NEMA load zone, coupled with periods of high summer power demand, resulted in additional reliability commitments required within the load zone. These committed generators were subsequently paid NCPC and made whole to their offers for periods during which they were committed for reliability and didn't recover their full costs though the LMP.

The decrease in first and second contingency payments in Summer 2016 compared to Summer 2015 of $6.9 million can be largely explained by differences in the NCPC rules between the two periods. First contingency payments in Summer 2016 of $9.0 million were 34% lower than first contingency payments made last summer and similarly, second contingency payments in Summer 2016 of $3.4 million were 43% lower than payments made last summer. As mentioned in previous reports, at the end of Winter 2016, modifications to the NCPC rules were implemented that prevent generators from receiving compensation for real-time commitment costs for hours during which their commitment costs are evaluated for day-ahead NCPC compensation. It is estimated that $9.5 million in real-time first and second contingency NCPC was paid last summer to eligible generators under the prior rules that were in effect in Summer 2015 and changed in Winter 2016.

2.2.2 Net Interchange

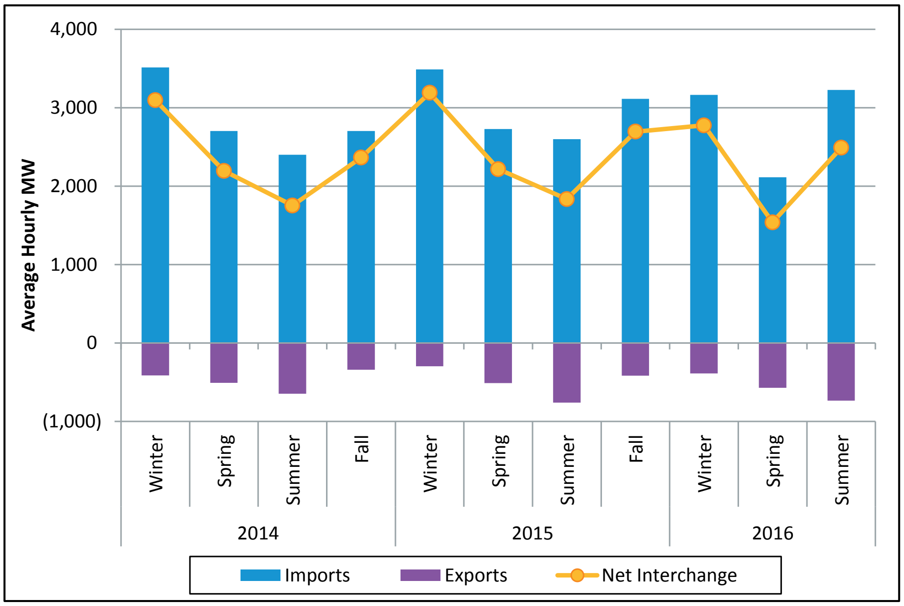
In the reporting period, New England was a net importer of power with most of the imported energy coming from Canada.[22] Net interchange with neighboring areas averaged 2,488 MW per hour for the reporting period, a 62% increase compared with Spring 2016 and a 36% increase when compared to Summer 2015. The increase compared to Spring 2016 was primarily due to the Hydro-Quebec Phase II interface returning from a planned outage that occurred during the Spring 2016 quarter.[23] Figure 2-13 shows imports, exports, and net interchange by season.

- Reliability costs paid for the commitment and dispatch of generation to provide system-wide stability or thermal support or to meet system-wide electric energy needs during the daily peak load hours.
- Reliability costs incurred for generation committed for daily peak load hours but are still on-line after the daily peak load hours to satisfy minimum run-time requirements.

[22] New England has transmission connections with Canada and New York; Quebec (via the HQ Phase II and HQ Highgate interfaces), New Brunswick and New York (via the New York-North, Northport-Norwalk and the Cross Sound Cable interfaces). The Canadian interfaces total approximately 2,600 MW (New England/New Brunswick: 1,000 MW, Highgate HVDC: 200 MW, and Phase II HVDC: 1,400 MW) in import capability. Under normal circumstances, the Canadian interfaces import power into New England. The New York Interfaces are as follows: The New York-North interface has a net import capability of 1,400 MW and a net export capability of approximately 1,200 MW. This interface can import power to, or export power from New England. Northport-Norwalk has a capability of approximately 200 MW and is generally a net exporter of power to New York. The Cross Sound Cable is a DC Converter with a capability of approximately 330 MW and power is generally exported to New York.

[23] A planned outage of the Phase II interconnection occurred from April 1st through May 30th – two of the three months during the Spring 2016 quarter - to replace and test interface protection and control equipment.

Figure 2-13: Average Hourly Imports, Exports, and Net Interchange



The figure shows that net interchange has been seasonal in nature, with more imports typically occurring during the winter months when New England energy prices have been at their highest over the past few years. However, Summer 2016 net imports were higher, on average, than Summer 2015 by 653 MW per hour (36%) and higher than Summer 2014 by 736 MW per hour (42%). These increases have been driven primarily by increases in net imports at the New York North, HQ Phase II, and New Brunswick interfaces. Compared to Summer 2015, net imports at the New York North location were higher by 245 MW per hour (79%), on average. Over Summer 2016, the average New England real-time price at its New York North pricing location was 0.6% higher than New York, compared to 3.5% higher during Summer 2015. Imports over the Phase II interface were higher by 208 MW per hour (15%) and New Brunswick imports increased by 146 MW per hour (38%), on average, compared to Summer 2015.

Section 3
Review of System Event in August 2016

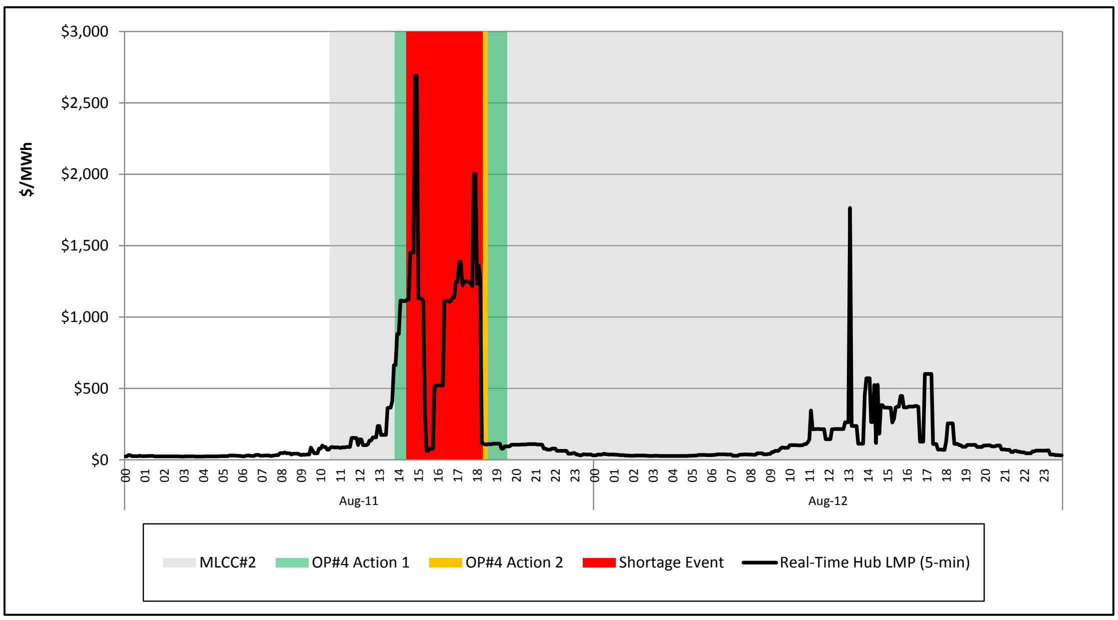
The system experienced a two-day period of tight conditions on Thursday, August 11 and Friday, August 12, 2016. Numerous generator forced outages, together with high load levels, resulted in significantly reduced reserve margins and high real-time prices.

This section of the report reviews the system conditions and market results over the two-day period. The section describes the performance of various resource types, including generation, demand response and imports. Finally, a summary of how the events were reflected in the financial settlement of both the capacity and energy market is provided.

3.1 Overview of Event

Figure 3-1 below illustrates the ISO actions and market pricing outcomes during this period.

Figure 3-1: ISO Actions and Market Outcomes during August 11-12, 2016



At 10:30 on August 11, ISO-NE entered M/LCC 2 (Abnormal Conditions Alert) due to numerous generator forced outages and a forecasted operating reserve deficiency.[24] Operating Procedure 4, Action 1, was subsequently implemented by the ISO Control Room at 13:50, informing resources that a capacity shortage existed.[25] At 14:25 ISO-NE proceeded to Action 2 of OP #4 in all load zones,

[24] When notified of an M/LCC 2 Abnormal Condition Alert, applicable power system operations, maintenance, construction and test personnel as well as 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.

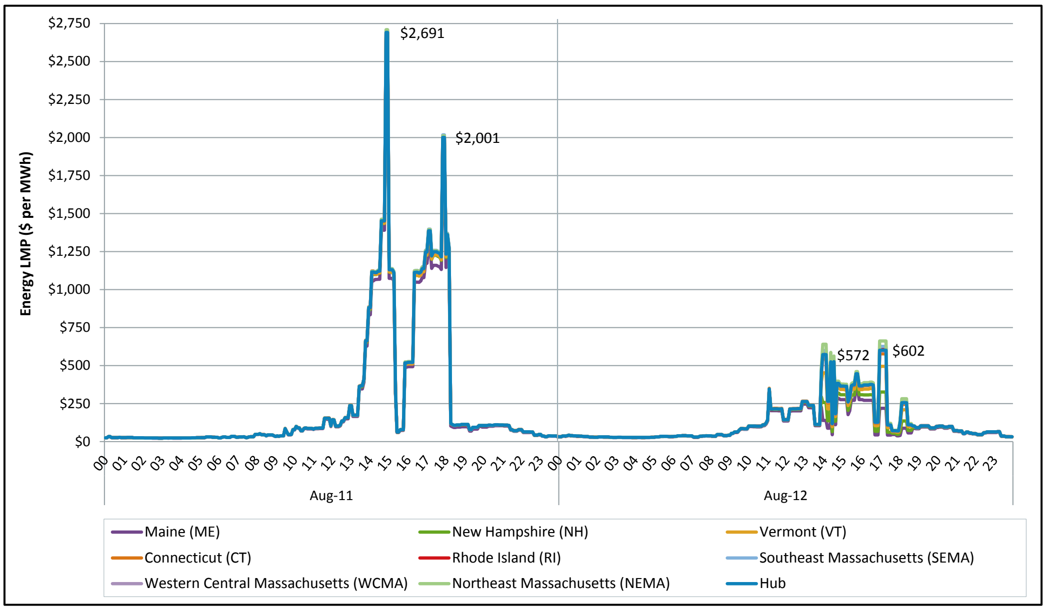
[25] Operating Procedure #4 establishes criteria and guidelines for actions during capacity deficiencies, as directed by the and as implemented by ISO and the Local Control Centers (LCCs). There are eleven actions described in the procedure which the ISO can invoke as system conditions worsen. *See* ISO New England Operating Procedure No. 4 – Action During

with the exception of Maine (which was export constrained), thereby dispatching all available real-time demand resources in those areas. Under the provisions of the Forward Capacity Market rules a Shortage Event occurred from 14:25 through 18:15.[26] During this period, Reserve Constraint Penalty Factors for Thirty Minute Operating Reserve were in place during Operating Procedure No. 4, Action 2. Five-minute real-time Hub LMPs peaked at $2,691/ MWh for ten minutes at 14:50. OP#4 Action 2 was subsequently cancelled at 18:30, Action 1 at 19:30, while M/LCC 2 was cancelled a day later on Saturday August 13 at 23:45.

3.2 Energy and Reserve Prices

Figure 3-2 below charts the five-minute real-time prices for the system hub and eight load zones over the two-day period of August 11 and August 12. There is some price separation among load zones evident in the chart, especially the lower prices in the Maine load zone on August 11 due to transmission export constraints. On August 12 there was more price separation among the load zones also due to transmission constraints.

Figure 3-2: Real-Time Five-Minute Energy Prices for the System Hub and Load Zones



As shown in Figure 3-2 above, prices were significantly higher over the hours of August 11 that corresponded with the Shortage Event than at other times over the two-day period. The energy prices on that day incorporated frequent reserve pricing as re-dispatch was required to maintain requirements. Prices were higher during the Shortage Event period because the system was deficient in Thirty-Minute Operating Reserve and Ten-Minute Non-Spinning Operating Reserve.

A Capacity Deficiency, *available at* https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[26] A Shortage Event is defined in Section III.13.7.1.1.1. of Market Rule 1 as a period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Thirty Minute Operating Reserve during Operating Procedure No. 4, Action 2. It is a feature of the Forward Capacity Market during which resource availability is measured and subject to penalties based on a resource's availability score.

Over the two-day period, five-minute real-time energy prices reached a peak of $2,691/MWh at the Hub over a ten minute period from 14:50 to 15:00 on August 11. During this interval, the system was deficient on the minimum Thirty-Minute Operating Reserve (TMOR) and Ten-Minute Non-Spinning Reserve (TMNSR) requirements, and therefore the respective Reserve Constraint Penalty Factor (RCPF) for each product was incorporated into the real-time LMP and set the reserve product prices. The respective RCPFs are $1,000/MWh for the minimum TMOR requirement and $1,500/MWh for TMNSR.

A subsequent peak in real-time energy prices on August 11 occurred over the period from 17:50 to 18:00 when the Hub price was $2,001/MWh. Again, in this period the system was deficient thirty-minute reserves so the $1,000/MWh RCPF for TMOR was activated and incorporated into energy and reserve pricing. In addition, the security-constrained economic dispatch solution violated the regulation dispatch limits of a unit providing regulation service. The energy dispatch exceeded the unit's regulation limits resulting in a software penalty factor of $1,000 per MWh being applied to the unit's marginal dispatch rate which was incorporated into the LMPs.

On August 12, the real-time hub price reached $572/MWh over the period from 13:55 to 14:10. At this time there was a deficiency in Ten-Minute Spinning Reserve (TMSR) which activated the TMSR constraint penalty factor of $50/MWh and pricing for re-dispatch to maintain replacement TMOR. Then from 16:55 to 17:20 the real-time hub price reached $602/MWh, which was the peak hub price for August 12. Over this period, the system was deficient replacement TMOR and the constraint penalty factor rate of $250/MWh was activated and incorporated into energy and reserve prices.

In Figure 3-3 below, the system total 30-minute operating reserve margin over the two-day period of August 11 and August 12 is graphed for each 5-minute interval with the gray-line series. Here the system operating reserve margin is the surplus (if positive, or deficiency if negative) of available reserves compared to the total of Ten-Minute Spinning, Ten-Minute Non-Spinning, and Thirty-Minute reserve requirements. Also in Figure 3-3 is the incremental cost of meeting each reserve demand in the real-time pricing solution (or "shadow price") which is illustrated with the separate stacked bar series for TMSR (green), TMNSR (orange) and TMOR (blue).

Figure 3-3: System Reserve Pricing and Total 30-minute Operating Reserve Margin

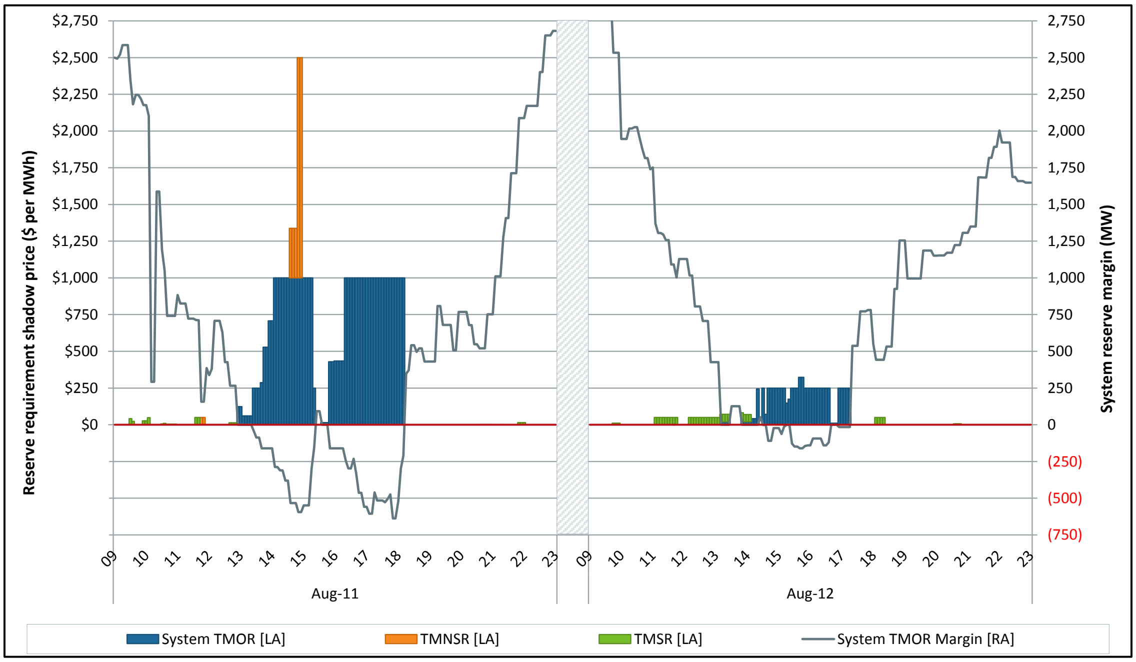


Figure 3-3 above illustrates the frequency and magnitudes of reserve pricing over the course of August 11 and August 12. There was a total of 8.9 hours (107 five-minute pricing intervals) over the two days with system TMOR pricing and, of these, thirty 5-minute intervals had RCPF pricing for the 30-minute replacement requirement and 38 intervals had RCPF pricing for the minimum 30-minute requirement. When the required thirty- or ten-minutes reserves cannot be maintained at a re-dispatch cost less than the applicable penalty factor the reserve price is set at the RCPF value.[27]

Thirty-minute operating reserve pricing occurrences are shown with the blue bar series labeled "System TMOR" in Figure 3-3. There were no local-only 30-minute reserve zone pricing instances over the two-day period. Ten-Minute Non-Spinning Reserve pricing occurred during seven 5-minute intervals over the two days as shown with the orange bar series labeled "TMNSR" in Figure 3-3 and for two of these intervals on August 11th the associated RCPF was active. TMSR pricing occurred for a total of 5.6 hours (67 pricing intervals) over the two days; the majority of instances were on August 12th as is shown by the green bar series labeled "TMSR" in Figure 3-3. During 35 pricing intervals (a total of 2.9 hours) the TMSR price was set by the associated RCPF value.

3.3 Demand and Supply Overview

This section provides an overview of overall demand and supply conditions over the two-day period.

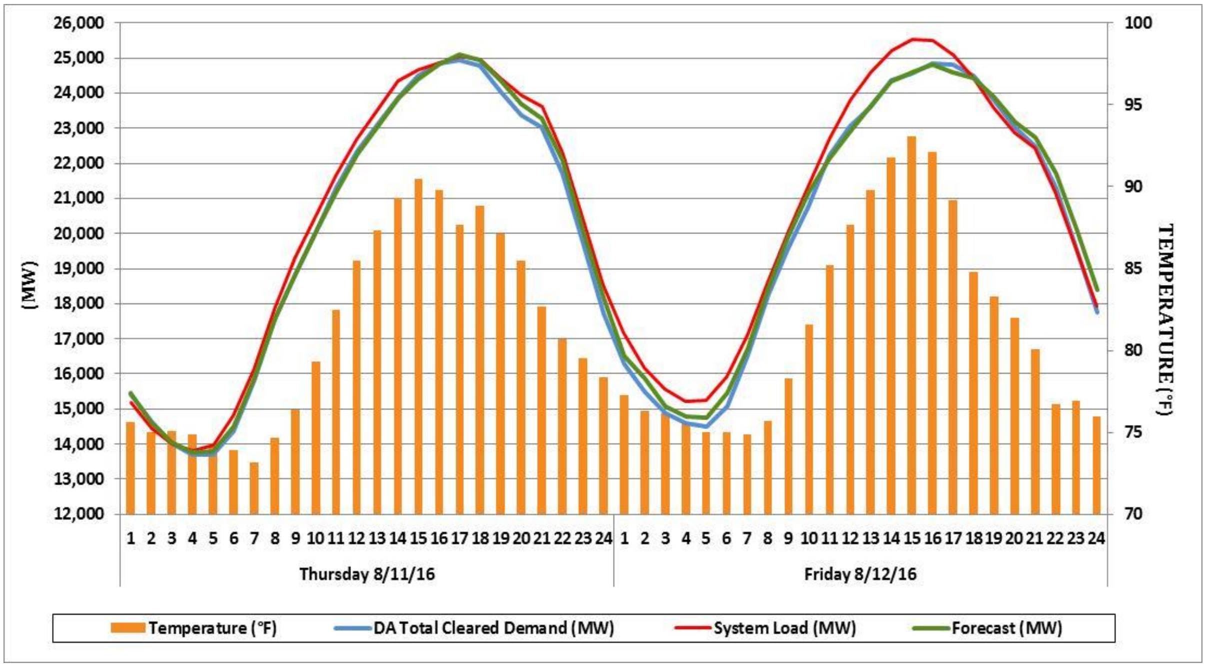
3.3.1 Demand

Figure 3-4 below shows the forecasted and actual demand and hourly temperatures, together with cleared day-ahead demand for August 11 and 12.[28]

[27] The applicable Reserve Constraint Penalty Factor values are presented in Section III.2.7A or Market Rule 1.

[28] Cleared day-ahead demand comprises fixed load, price-sensitive load, exports and virtual demand.

Figure 3-4: Day-Ahead Cleared Demand, Forecast, and Actual System Load MW, August 11-12, 2016



On Thursday, August 11, load forecast error did not contribute to the tight system conditions. Actual temperatures and load throughout the day were close to the forecasted values. Cleared day-ahead demand was also close to actual demand over the course of the day.

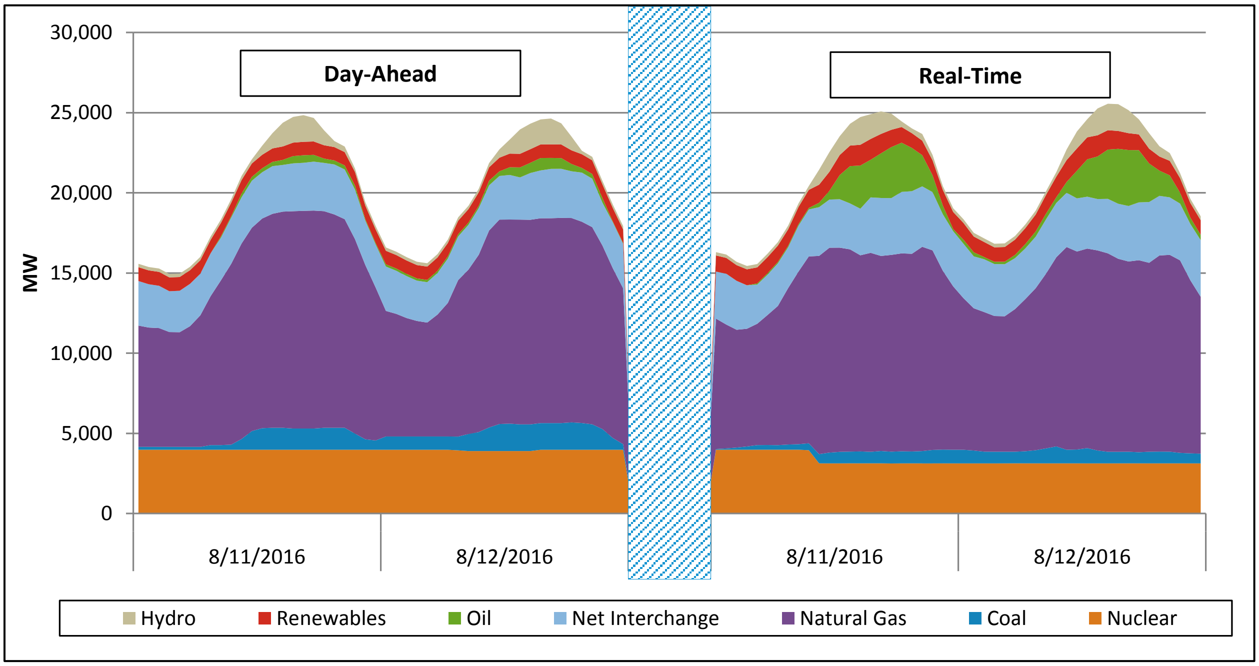
The highest peak load of the year occurred on Friday, August 12. For several hours on August 12 there were significant deviations between actual system load and day-ahead cleared forecasted demand, as high as 1,000 MW during the peak at hour ending 15. The large deviation between actual and forecast system load likely contributed to high real-time prices on August 12.

3.3.2 Supply - Fuel Mix

Generator performance issues were the most significant reason for tight system conditions. Those performance issues related to forced outages and were not reflected in the day-ahead market results for both August 11 and August 12.

Figure 3-5 below shows the supply mix in both the day-ahead and real-time energy markets during the two-day period.

Figure 3-5: Day-Ahead and Real-Time Cleared Generation by Fuel type with Net Interchange



As seen in the figure, most of New England's load in the day-ahead market was satisfied by imports, nuclear generation, and gas-fired generation.[29] Only a small amount of oil cleared in the day-ahead market, ranging from 0 MW during the first 8 hours of August 11, to 773 MW in hour-ending (HE) 16 on Friday, August 12. In the real-time market, numerous forced generator outages as well as generator fuel switching from natural gas to oil resulted in noticeable changes in the fuel mix. These changes were particularly pronounced over the peak hours on both days, including during the Shortage Event on August 11.

The graph illustrates major reductions in coal-fired, natural gas-fired, and nuclear generation compared to what had cleared in the day-ahead market. As seen in the green area, most of the reductions were made up by oil-fired generation. Most of the additional oil-fired generation committed in real-time was the result of unplanned generator outages, but some was due to fuel switching. This means that some dual-fuel generators that had acquired a day-ahead commitment based on a natural-gas offer switched to an oil-based offer in real-time due to constraints on the natural gas pipeline.

On August 11 in HE 18 , the peak load hour and an hour during which the Shortage Event was in place, hydro, natural gas, nuclear, and coal collectively did not provide as much real-time energy as had cleared in the day-ahead market. In real-time coal-fired generation produced 590 MW less in HE 18 than had cleared in the day-ahead market. Similarly, there was 456 MW less of hydro generation, 1,317 MW of gas-fired generation, and 855 MW less of nuclear generation. Most of these deficiencies were made up by oil-fired generation which produced 3,179 MW HE 18, 2,757 MW more than what had cleared in the day-ahead market.

[29] The figure does not include virtual supply and demand. In all hours of the day-ahead market on 8/11 and 8/12, there was a greater volume of decremental bids than incremental offers that cleared in the day-ahead market. The net virtual demand ranged from 17.5 MW in HE 22 on 8/12 to 776.3 MW in HE 17 on 8/11.

Forced unit outages resulted in an increase in the usage of oil-fired resource that set the price more frequently during this period. Oil was the marginal fuel in 21% of real-time pricing intervals on August 11 and 15% of real-time pricing intervals on August 12. Oil-fired resources typically have higher incremental energy costs than coal-fired, gas-fired, or nuclear generation due to input fuel costs and the efficiency of the generating units.

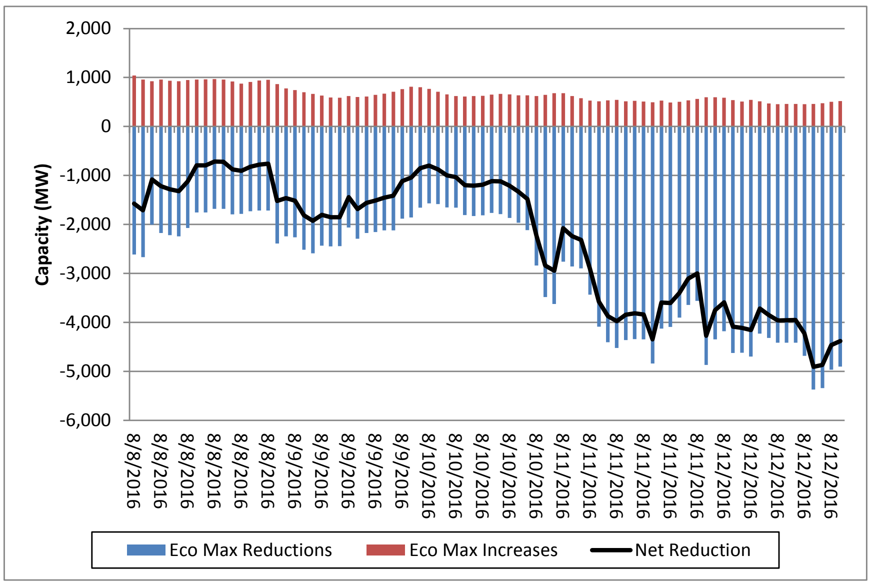
3.4 Resource Performance

This section examines the performance of suppliers across the three categories of generation, interchange and real-time demand response.

3.4.1 Generator Performance

On August 11 and 12, the ISO-NE system experienced significantly reduced generator availability. As indicated in Figure 3-6 below, capacity reductions on those days reached levels approximately double the levels observed in the three immediately-preceding days.

Figure 3-6: Increases and Reductions in Generator Capacity, during Peak Hours (HE 8-23)

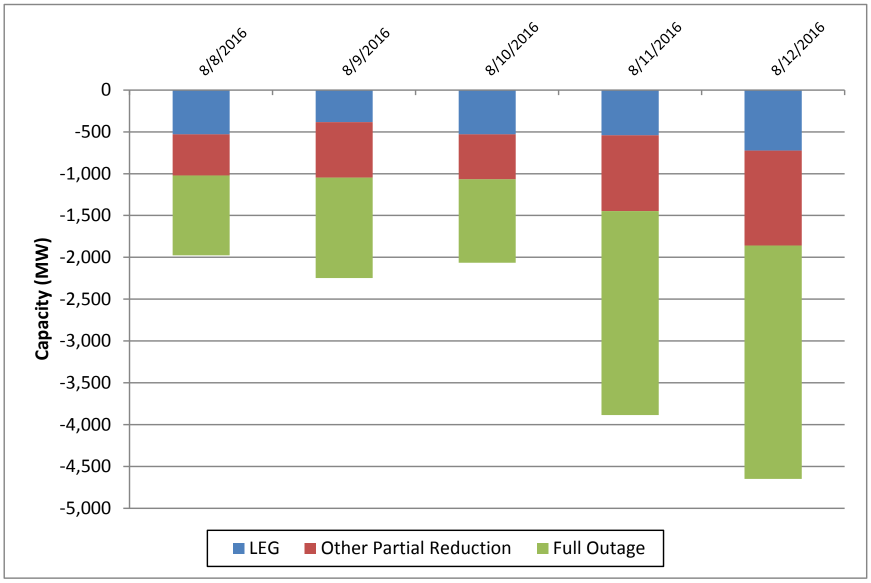


These capacity reductions are measured as the generator economic maximum capacity in the real-time energy market relative to an expected maximum capacity (i.e., the generators' demonstrated maximum capacity values obtained during ISO audits). These reductions can be explained by several factors: limited fuel that reduces generating capability within the hour, maintenance issues that result in partial reductions in capabilities, and full maintenance outages.

Reductions in capacity can be planned and known to the ISO or unplanned ("forced"). Unplanned outages may result in the complete outage of the unit or the outage of just a portion of its capability (referred to as a "partial outage"). As occurred during the two-day period, unplanned outages can cause shocks in the real-time energy market, leading to price spikes and operating reserve deficiencies. In these instances, the ISO may need to call on fast-start generators to recover from unplanned outages. This helps to ensure that electricity supply meets electricity consumption and that adequate operating reserves are maintained. When the real-time contingencies (such as unplanned generator outages) are sufficiently large relative to available system capacity, the ISO may need to institute emergency measures (such as Operating Procedure No. 4) to restore operating reserves or capacity to adequate levels.

Figure 3-7 shows generator capacity reductions by type of reduction.[30] Of particular importance is the large increase in full generator outages. On August 11, full generator outages increased by approximately 1,500 MW compared to the prior day.

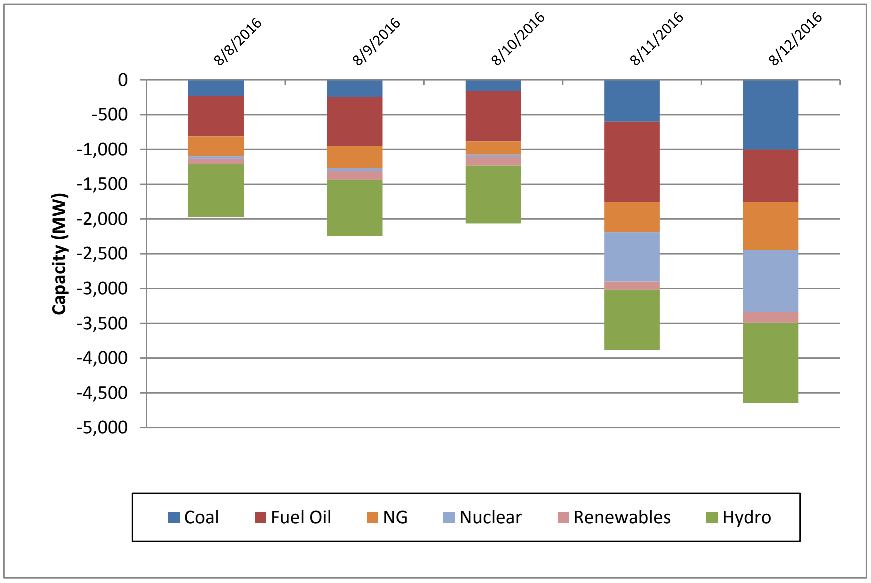
Figure 3-7: Average Capacity Reductions by Type (Peak Hours HE 8-23)



This increase in outages is attributable to unplanned reductions in generator capacity that resulted from three generator failures during the operating day. Two large generators failed and were off-line by approximately noon on August 11, and another large generator failed at approximately 15:00. On August 12, significant unplanned outages continued and increased average peak hour capacity reductions by 350 MW. While some generators that experienced outages on the 11th returned to service on the 12th, other forced outages (including 2 medium-sized combined-cycle generators and a coal generator) resulted in an overall reduction in available capacity from outages. Additionally, the other categories of reduction increased also: energy limitations reduced capacity by 180 MWs and other partial reductions reduced capacity by 230 MW.

[30] LEG stands for Limited Energy Generator, and represents the reduced amount of capacity available from a resource as a result of restricting its energy output below its maximum technical capability. A market participant may "LEG" its resource during the operating day for various reasons, including to preserve limited fuel supplies.

Figure 3-8: Average Capacity Reductions by Generator Type (Peak Hours HE8-23)

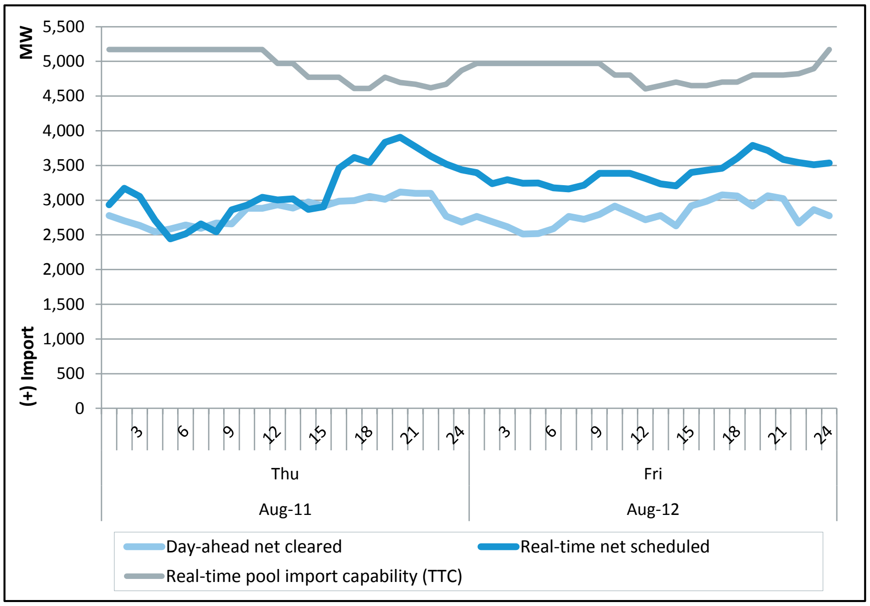


A nuclear generator accounted for a significant portion of the unplanned outages on August 11, while older steam turbine generators accounted for the other significant generator losses. Nuclear generators tend to be highly reliable with low failure rates; the steam turbine generators that failed historically have been less reliable. On August 12, average availability decreased for most fuel types. Notably, average coal availability decreased (400 MW) along with average nuclear (180 MW) and natural gas availability (260 MW); the lower average availability for nuclear generators simply reflects the continuing outage of the nuclear generator forced off-line on the August 11 for the entire peak period on the 12th. Fuel oil generators overall had greater average availability (400 MW).

3.4.2 Net Interchange

Overall, energy imports from the neighboring control areas increased during real-time, relative to the day-ahead market cleared schedules, as system conditions tightened on August 11. New England is typically a net importer of power in both day-ahead and real-time. As shown in Figure 3-9 below, real-time net imports rose above the day-ahead levels beginning in HE 15 on August 11. Net import levels then continued to remain above day-ahead schedules by an average of 600 MW per hour for the remainder of August 11 and 12.

Figure 3-9: Pool Total Net Interchange in Day-Ahead and Real-Time



As shown in Figure 3-9 there was an overall increase in net energy imports during real-time over the two-day period. The light-blue line series labeled "Day-ahead net cleared" shows the hourly net interchange aggregated across all interties with neighboring control areas. Over the period, day-ahead cleared interchange averaged around 2,800 MW per hour. The darker blue line series labeled "Real-time net scheduled" is the real-time hourly scheduled pool net interchange. The market response to tightening New England conditions is evident beginning in HE 15 on August 11 when real-time net imports rose above day-ahead levels by amounts ranging from 384 MW to 873 MW each hour. Over these two days, the real-time scheduled interchange averaged roughly 3,270 MW per hour. Based on transmission ratings, New England could have received additional real-time energy imports, up to about 5,000 MW hourly, as illustrated by the gray line series labeled "Real-time pool import capability (TTC)" which is the total import transfer capability available to deliver energy across all the interties.

The additional real-time import schedules were delivered from both the Canadian and New York control areas. Figure 3-10 below shows that the overall net increase in real-time energy imports relative to day-ahead on August 11 was the result of additional imports from the New York control area beginning in HE 15. During the morning and early afternoon, real-time imports from New York were lower than in the day-ahead, but then market-to-market trades shifted to produce a net increase in supply for New England.

Figure 3-10: Real-Time Market Adjustments to Day-Ahead Interchange Schedules

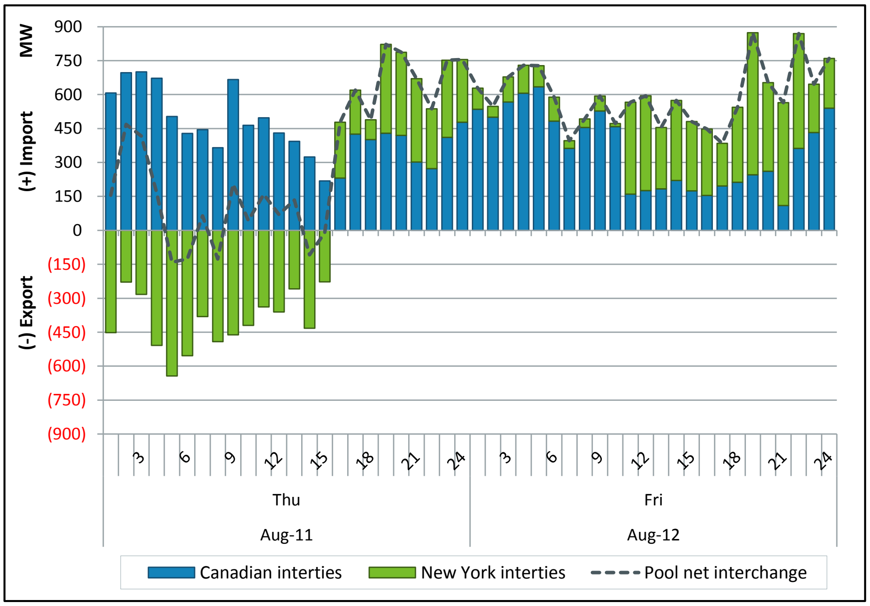


Figure 3-10 above, shows the net adjustment (or deviation) in real-time inter-area power flow that occurred each hour relative to the day-ahead cleared interchange. Note that a positive value shows a net supply increase (i.e., more imports or fewer exports) and a negative value is a net decrease in supply (vice versa). In Figure 3-10, the six New England interties were grouped by those interconnected with New York (the green bar series labeled "New York interties") and those interconnected with the Canadian provinces (the blue bar series labeled "Canadian interties"). The gray dotted-line series labeled "Pool net interchange" is the aggregate adjustment to real-time interchange across all external interfaces each hour. As discussed above, the real-time increase in imported power between HE15 and HE 16 on August 11 occurred when New York tie schedules shifted to bring additional power to New England. The increases from New York came from transactions scheduled at the Northport-Norwalk interface and at the Northern AC (or "Roseton") interface where the enhanced Coordinated Transaction Scheduling (CTS) protocols have been implemented. In general, over the two-day period the scheduling outcomes at the CTS interface appear to be consistent with efficient use of the interface to schedule power flow toward the higher-cost market and utilize the transfer capability between the regions.[31]

3.4.3 Demand Response Performance

On August 11, real-time demand response (RTDR) resources were dispatched effective 15:00 until 18:35, as part of OP#4 Action 2, in all zones except Maine which was not dispatched due to transmission constraints. The RTDR dispatch totaled 192 MW.

[31] As New England prices rose relative to New York prices during August 11, the New York North tie schedule shifted to deliver additional power to New England. From HE 15 to HE16, when New England had a deficiency of ten-minute operating reserves, the hourly integrated import volume rose by 500 MW. The CTS scheduling data show that over three 15-minute scheduling intervals beginning 14:45 to 15:15 on August 11, the clearing solution ramped up imports by 600 MW (200 MW each interval due to the interface ramp limit) to a total of 1,400 MW where the import transfer capability was reached. The completion of that interface ramp aligned with the conclusion of the first shortage event period at 15:20 on August 11. Over the remainder of August 11 and 12, the adjustments in net tie flow were mostly consistent with the market prices differences.

The ISO obtained nearly 81% (156 MW) of the requested load reduction, which helped to mitigate the capacity deficiency on the system.

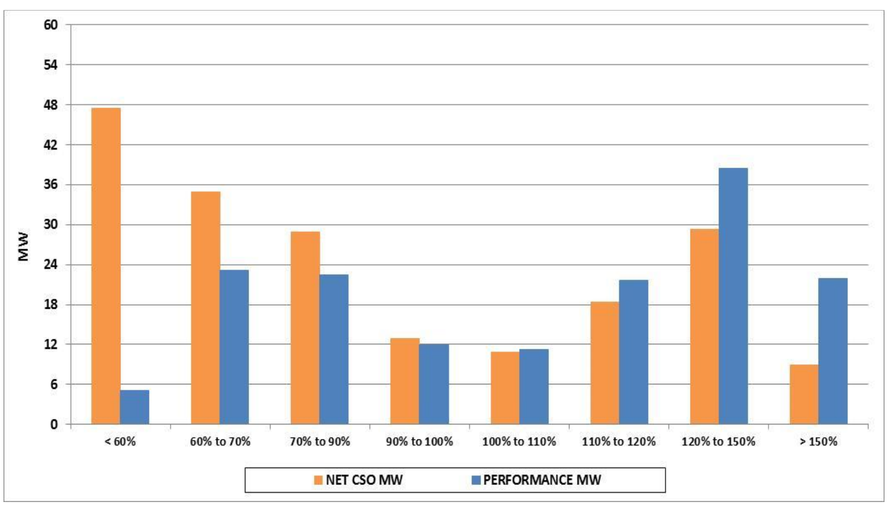
The performance results were comparable with demand response performance on December 14, 2013 and on December 19, 2011 but were poor compared to other four demand response dispatches during capacity deficiencies; see Table 3-1 below.[32]

Table 3-1: Historical performance of Real Time Demand Response dispatch during OP#4 Action 2

Real Time Event Dispatch Date	Dispatch MW (Net CSO)	Performance During 100% Dispatch Period (MW)	Percent Avg. Performance vs. Total Net CSO (Dispatched MW)
06/24/10	669	600	90%
07/22/11	644	645	100%
12/19/2011	504	390	77%
1/28/2013	374	372	99%
7/19/2013	193	188	97%
12/14/2013	248	198	80%
8/11/2016	192	156	81%

There was considerable variation in performance across RTDR resources as shown in Figure 3-3 below. Compared to net CSO the Figure 3-11 shows the MW amount of RTDR performance by various performance tranches. [33]

Figure 3-11: Real Time Demand Response Resource Performance during August 11, 2016 dispatch



The proportion of the number of over- to under-performing RTDR resources was roughly 50%. Under-performing resources fell short by about 62 MW compared to their net CSO, while over-performers reduced their output by about 26 MW more than their obligation.[34] The market rule

[32] Initial Performance of Demand Response Resources might change during the final data submission correction.

[33] NET Capacity Supply Obligation (NET CSO) is capacity supply obligation of the Resource minus transmission and distribution losses.

[34] Net Capacity Supply Obligation (Net CSO) is capacity supply obligation of the Resource minus transmission and distribution losses.

allows over-performing resources to receive an allocation of the penalties paid by underperforming resources.

3.5 Market Settlement Observations

This section provides a summary of how the system conditions and market outcomes discussed up to this point were ultimately reflected in the financial settlement of both the forward capacity market and the day-ahead and real-time energy markets.[35]

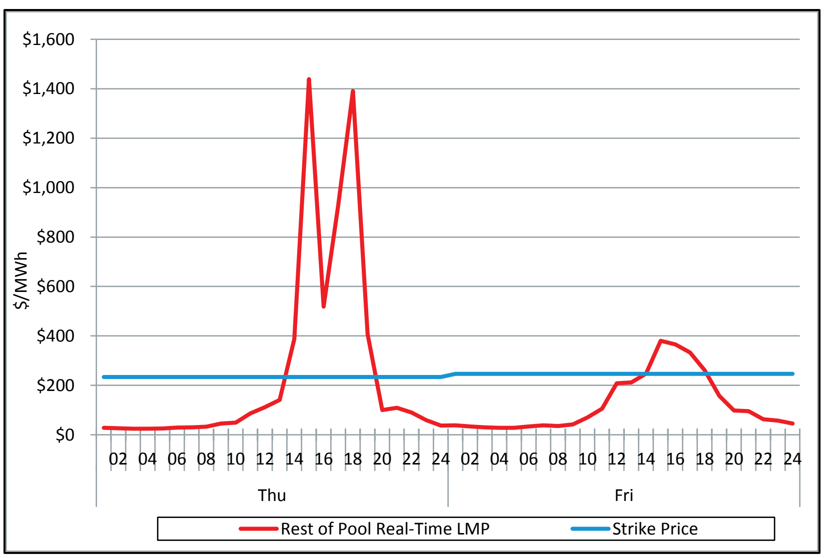
3.5.1 Forward Capacity Market

3.5.1.1 Peak Energy Rent

The Peak Energy Rent (PER) is an adjustment to capacity market revenues when real-time energy prices exceed a strike price as set by a proxy generator with a 22,000Btu/kWh heat rate. The PER concept recognizes that load has paid in advance for sufficient capacity to maintain reliability through the Forward Capacity Market (FCM). The adjustment is primarily intended as a protection for load against high energy prices and limits energy market gains for generator and import capacity resources, even those not producing energy. 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 real-time hub LMP and PER strike price during August 11 and August 12 are shown in Figure 3-12.[36]

Figure 3-12: Real-Time LMP and Strike Price during August 11-12, 2016



The Rest-of-Pool real-time LMP exceeded the strike price for six hours in all capacity zones on August 11 and between one and five hours, depending on the capacity zone, on August 12.[37, 38]

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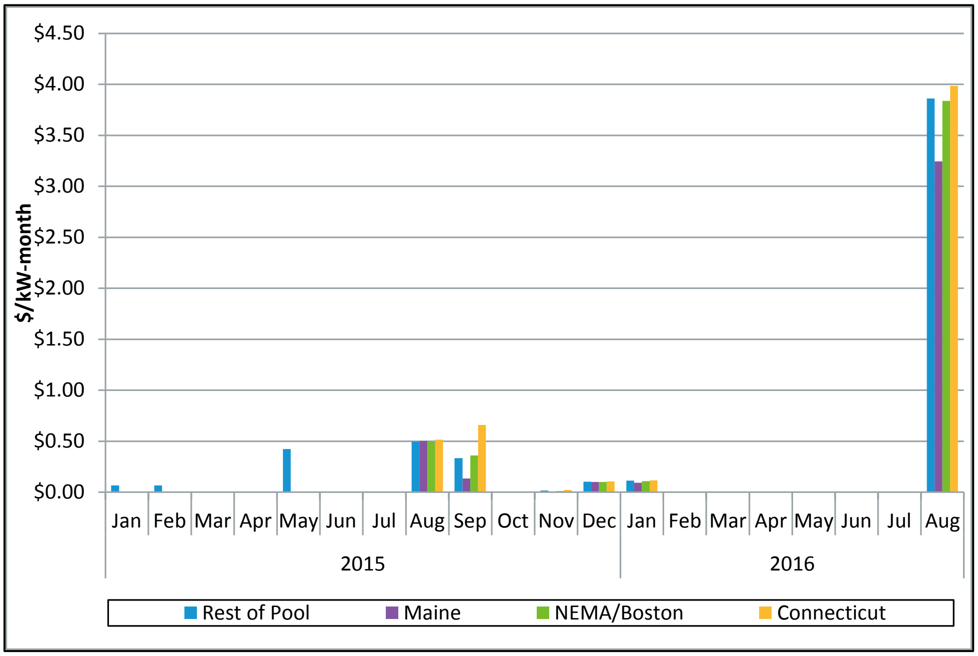
[35] Please note that the settlement analysis in this report is not intended to produce "settlement quality" data and results, but rather is intended to illustrate the magnitude and trends of key settlement outcomes.

[36] The Rest of Pool LMP is shown in the figure. For the purposes of calculating the PER adjustment, the LMPs are calculated based on capacity zones for FCA 7. The capacity zones were NEMA-Boston, Rest-of-Pool, Maine, and Connecticut.

The hourly PER values are aggregated each month by capacity zone to create a monthly PER. The hourly PER values on August 11 account for 82% to 92% of each capacity zones monthly PER. The monthly PER value is part of a twelve-month rolling average used to calculate the PER adjustment. Monthly PER values by capacity zone are shown in Figure 3-13.

Figure 3-13: Monthly PER values, January 2015-August 2016



The highest monthly PER value before August 2016 was $2.07/kW-month in August, 2010. The monthly PER values for August, 2016 ranged between $3.25/kW-month and $3.98/kW-month. The incremental impacts of peak energy rent in any given month will be amortized over the following twelve months as a part of the twelve-month rolling average. This means that the September 2016 to August 2017 PER adjustments will reflect August PER values. The total PER adjustment attributed to August 2016 is approximately $101 million, or $8.4 million dollars a month, roughly equivalent to the total FCM payments for the month.[39]

[37] On August 12, the real-time LMP exceeded the strike price for five hours in NEMA-Boston and Rest-of-Pool, four hours in Connecticut, and one hour in Maine.

[38] The impact of real-time LMPs exceeding the strike price on Hourly PER is shown in the equation below:

$$HourlyPER_z = \frac{(LMP_z - StrikePrice) * ScalingFactor * AvailabilityFactor}{1000}$$

Where z represents the capacity zone, the scaling factor is weighted based on load, and the availability factor is set in the tariff at 95%.

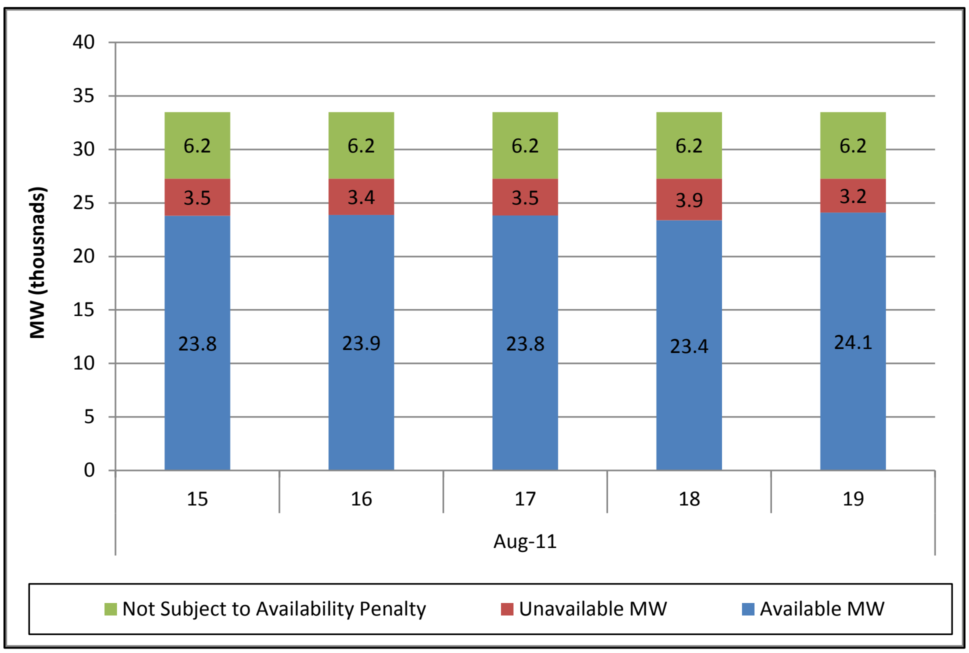
[39] This is an IMM estimate, and does not account for PER Caps. Section III.13.7.2.7.1.1. of the tariff details the calculation of PER adjustments. For simplicity, this calculation assumes that there will be no activity in monthly and annual reconfigurations that have yet to occur and could impact the final PER adjustments.

3.5.1.2 Shortage Event Penalties

The FCM rules provide financial incentives for resources to be available and to not economically withhold during a Shortage Event. The penalty rate depends on the duration of the Shortage Event, and on August 11, was based on 5% of annualized capacity market revenues, which roughly equates to a maximum penalty of $57 million. Penalties resulting from the Shortage Event totaled $7.3 million; representing about 7.2% of the $101 million in FCM payments for August 2016.

During a Shortage Event, off-line generators and import resources with CSOs are evaluated based on available capacity. The penalty paid by under-performing generators and import resources is determined by a Shortage Event availability score, which utilizes information on available MWs.[40] Within the set of generating resources, intermittent power resources are not penalized for performance due to the fact that their qualified MWs are adjusted based on historical availability during "reliability" hours. The available MWs compared to total CSO during the Shortage Event are shown in Figure 3-14.

Figure 3-14: Available MW Compared to Effective CSO during Shortage Event



The total CSO during the month of August was 33,492 MW, or 33.5 gigawatts (GW). The unavailable CSO during the Shortage Event ranged from 3.2 GW to 3.9 GW. Capacity totaling 6.2 GW was not subject to availability penalties, which includes intermittent power resources and demand response resources.

The availability of off-line units with start-up times of 12 hours or less is determined by the IMM based on the competitiveness of supply offers for the day-ahead and real-time markets during a

[40] The available MWs discussed here are not adjusted for supplemental availability bilaterals or exempt planned outages. More information on the calculations for calculating hourly available megawatts can be found in sectionIII.13.7.1. of the tariff. The impact from supplemental availability bilaterals and exempt planned outages is minor compared to total available megawatts.

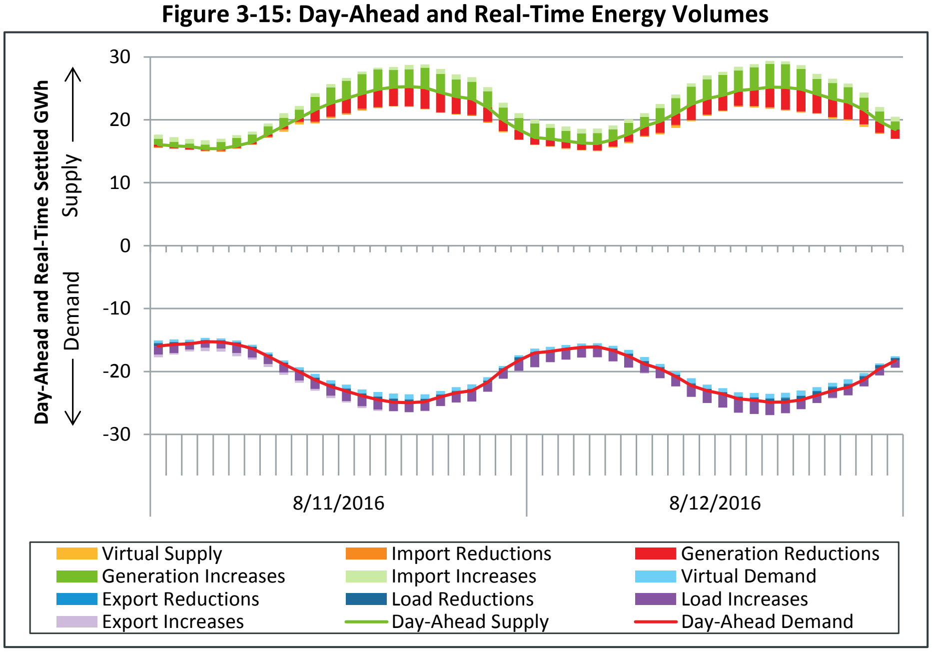
shortage event in accordance with Section III.A.8 of the tariff. Based on the criterion in this provision, if a resource with a CSO is deemed to have not offered competitively, then the resource is considered unavailable. If the resource offered competitively, then the available MWs are based on the minimum of their economic maximum or what is deemed competitive by the IMM. The IMM evaluated the competitiveness of 43 such resources, totaling a combined CSO of 5,224 MW. Of this total, 3,168 MW, or 61%, was determined to be competitive.

3.5.2 Energy Market

In the New England energy markets, over the past five years an average of at least 95% of energy payments have been made in the day-ahead energy market, with less than 5% in the real-time market. However, there can be significant variation around the average as system conditions change, as was seen during the system event when day-ahead payments made up 59% of the total energy payments. In the real-time energy market, only real-time deviations from the day-ahead schedule are paid or charged the real-time energy price. Deviations that receive the real-time price include increases in generation or imports, reductions in load or exports, and virtual demand. Deviations that pay the real-time price include increases in load or exports, decreases in generation or imports, and virtual supply.

Figure 3-15 below shows day-ahead cleared supply and demand along with real-time deviations by type during the two day system event. Bars that sit on top of the day-ahead cleared supply and demand lines represent deviations that received the real-time price, and bars that sit below the lines represent deviations that paid the real-time price.

Figure 3-15: Day-Ahead and Real-Time Energy Volumes

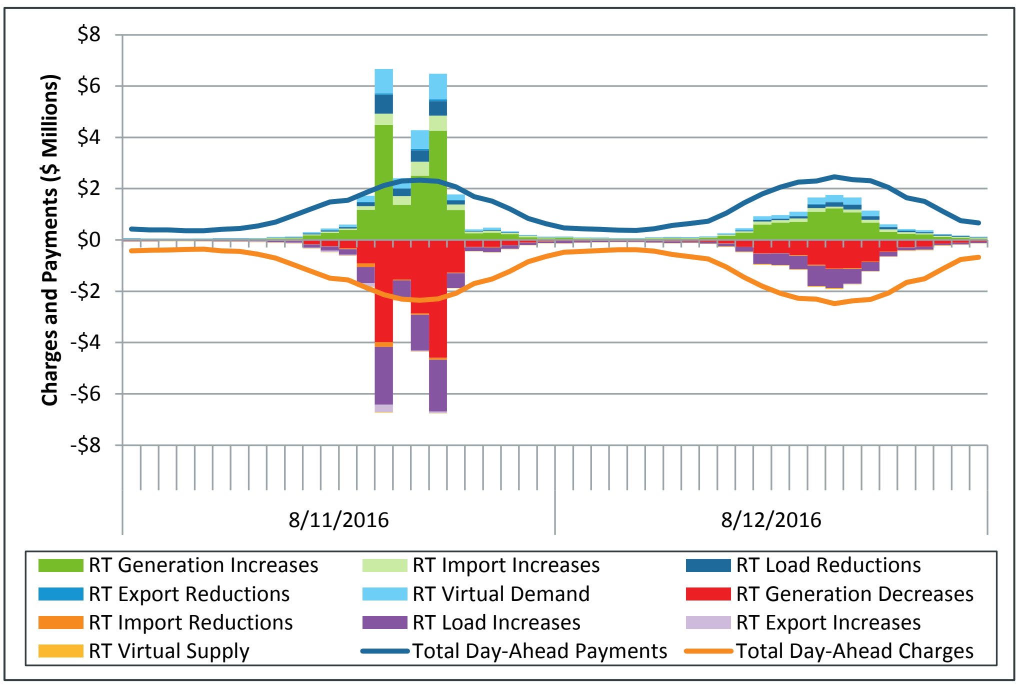


During the two-day system event, most of the positive and negative deviations were due to changes in generation. In Figure 3-15 the red bars below the day-ahead supply line represent generators that failed to deliver on their day-ahead schedules and subsequently had to pay the real-time price to replace the energy that they were obligated to deliver in real-time. The darker green bars represent generators that produced more energy in real-time than they had cleared in the day-ahead market. Consequently, these generators received the real-time price for the additional energy they provided to the system.

As discussed above, the large negative generation deviations were largely due to unplanned outages, which had to be replaced with other generation and imports. To a lesser degree, real-time load was greater than what cleared in the day-ahead market, resulting in some load participants paying the real-time price for the additional energy. Although deviations were relatively high during the system event, they were much smaller in magnitude than the amount of energy cleared in the day-ahead market.

Figure 3-16 below shows the financial settlements for the deviations shown above. The lines show the day-ahead charges and payments, while the bars represent the real-time charges and payments by the type of entity that was paid or charged.

Figure 3-16: Day-Ahead and Real-Time Energy Charges and Payments



During the two-day event, high real-time prices led to significant real-time payments. As a result of large deviations from the day-ahead schedule and very high real-time prices, day-ahead payments made up 59% of the total energy payments. Additionally, in four hours on August 11, HE 15, 16, 17, and 18, corresponding with the four highest real-time priced hours, real-time payments exceeded day-ahead payments. As shown in the graph, most of the charges were to generators that failed to deliver on their day-ahead schedules. In the two hours with the most significant real-time payments, generation paid about twice as much as load market-wide.

During the system event, participants with large positive deviations during high-priced hours received significant revenue, while participants with large negative deviations had high costs. The largest dollar-amount deviations on August 11, by type of transaction, are shown in Figure 3-17 below.

Figure 3-17: Energy Market Deviations, August 11, 2016

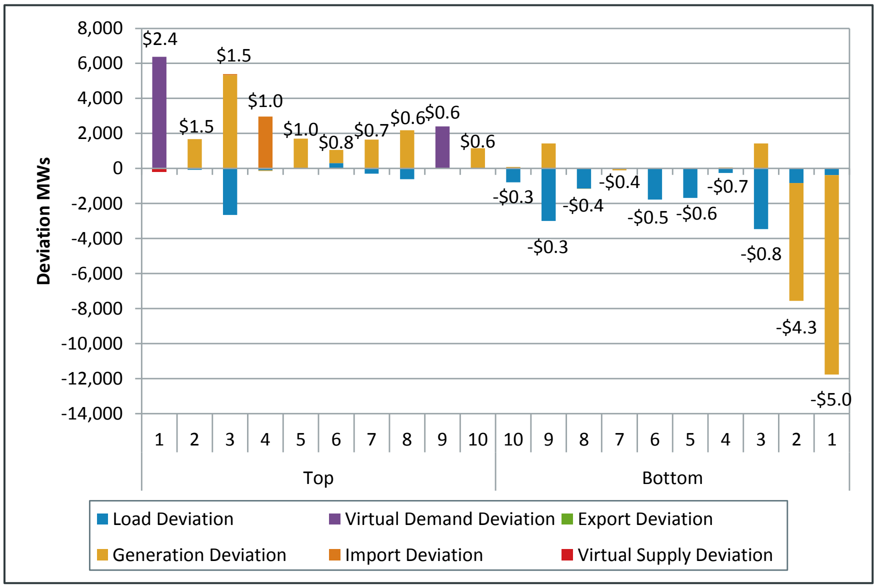


Figure 3-17 shows the profit from real-time deviations for the top ten and bottom ten market participants on August 11. Profit includes costs from negative deviations and revenue from positive deviations. The participant that had the most profitable deviations made about $2.4 million, while the participant with the largest loss was charged approximately $5 million. The participant whose deviations were the most profitable cleared over 6,000 MWh of virtual demand throughout the day. Other participants in the top ten produced generation or imports in excess of their day-ahead positions. The two participants with the highest losses (of $4.3 and $5 million) both had generation deviations; these participants failed to deliver on their day-ahead awards and, therefore, where charged the real-time energy price for those deviations. The remaining participants in the bottom ten were load-serving entities that had to buy load that exceeded their day-ahead positions in the real-time market.

NCPC during the system event totaled approximately $4 million, with $3.5 million of those costs incurred on August 11. Economic NCPC (first contingency NCPC) represented the majority of total costs, making up $3.5 million of the total $4 million over the two-day period. Economic NCPC charges to deviations were negligible. The pool of real-time economic NCPC that gets charged to deviations only included approximately $0.2 million on the August 11 and $0.1 million on the August 12. Real-time economic NCPC payments for posturing generators amounted to $3.1 million, and are allocated to real-time load obligations, as opposed to day-ahead/real-time deviations.