ISO New England's Internal Market Monitor

Fall 2017

Quarterly Markets Report

Internal Market Monitor
February 21, 2018

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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.***

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 covers key market outcomes and the performance of ISO New England wholesale electricity and related markets for Fall 2017 (September 1, 2017 through November 30, 2017).[3]

1.1 Market Outcomes and Performance for Fall 2017

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.74 billion, an increase of 49% (a $574 million difference) compared to costs of $1.17 billion in Fall 2016. Total costs for Fall 2017 were similar to those of Summer 2017 ($1.75 billion).

- Rising Forward Capacity Market prices were the biggest contributor to the increase in wholesale market costs relative to Fall 2016. Capacity costs totaled $769 million, up 170% ($484 million) compared to last fall. Since the start of the FCM in 2010, the region had excess capacity, resulting in relatively low and stable capacity prices. June 2017 marked the beginning of the FCA 8 capacity commitment period, which had tighter system conditions due to a number of generator retirements. FCM payments increased in Summer and Fall 2017 due to higher FCA clearing prices:
    - Capacity prices to existing resources outside of NEMA/Boston increased 123%, from $3.15/kW-month to $7.03/kW-month.
    - The capacity prices to new and existing resources in NEMA/Boston was $15.00/kW-month.

- Fall 2017 energy costs totaled $925 million, 12% ($99 million) higher than the prior fall. The increase was consistent with higher natural gas prices of 10%. Despite higher natural gas prices compared to the previous season (Summer 2017), Fall 2017 energy costs were down by 6% ($58 million)). This decrease in energy costs was primarily due to lower electricity demand (load):
    - Natural gas prices averaged $2.71, up 11% compared to the previous season, and up 10% compared to Fall 2017.
    - Average hourly load and peak hourly load were both down by around 12% compared to Summer 2017. The decline was primarily due to milder weather. Average hourly and peak hour load were 13,047 MW and 20,946 MW, respectively, compared to 13,239 MW (down 192 MW) and 23,142 MW (down 2,196 MW) in Fall 2016.

Energy Prices: Day-ahead and real-time energy market prices at the Hub averaged $29.11/MWh and $30.45/MWh, respectively. Day-ahead prices were 16% higher ($3.95/MWh) and real-time prices were 23% higher ($5.73/MWh) than Fall 2016 prices.

- Day-ahead and real-time energy prices continue to trend with natural gas prices.
- The month of September saw the greatest divergence between real-time and day-ahead prices for the quarter. Towards the end of the month, significant price spikes occurred over a four-day period due to high loads and low capacity margins.
- Energy market prices did not differ significantly among the load zones. Maine, an export-constrained region, had the highest deviation with consistently lower prices relative to

[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).

the other zones. In the day-ahead market, the Maine average price was $0.51/MWh (2%) lower than the Hub. Price separation in Maine was more notable in the real-time market, with prices $1.74/MWh (6%) lower than Hub prices.

Net Commitment Period Compensation: NCPC payments totaled $14.5 million, down by 57% ($19.1 million) compared to Fall 2016. NCPC payments represented about 2% of the total wholesale energy costs, down from the prior fall, when NCPC comprised over 4% of energy costs. The majority of NCPC (59%) was for first contingency (economic), with local second-contingency protection payments (LSCPR) making up almost 40% of total NCPC. The majority of LSCPR payments went to generators in NEMA/Boston over a 10-day period in November. In Fall 2017, hourly shortfall NCPC credits totaled $0.4 million, a higher amount than in previous quarters. Over half (55%) of total NCPC was paid in the day-ahead market.

Real-Time Reserves: Real-time reserve payments totaled $16.8 million, a large increase relative to the Fall 2016 total of $3.5 million. The frequency of reserve pricing was much higher due to lower operating reserve margins. The average hourly reserve price increased relative to Fall 2016, from $10.21 to $23.36/MWh. The fast-start pricing rules, which were not in effect last fall, contributed to the increase in reserve payments in Fall 2017.

Regulation**:** Total regulation market payments were $7.4 million, up 31% from $5.6 million in Fall 2016. The main driver of this increase was manual regulation commitments that exceed regulation requirements. In Fall 2017, such commitments occurred during 64 hours and resulted in payments of around $2 million.

1.2 Analysis of Multi-Stage Generator Rules

Section 5 of this report covers our analysis of the impacts the ISO's current modeling of multi-stage generators has on market outcomes, specifically NCPC payments and day-ahead energy prices.

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

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

- *When multi-stage generators offer at their highest-output configuration (maximum configuration[4]), excess NCPC costs may occur*

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

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

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

  If the ISO commits multi-stage generators for reliability on their maximum configurations, and if a lower-output configuration would have satisfied the reliability need, then there is excess supply coming from multi-stage generators. In other words, it is producing energy that would otherwise be produced by a lower-cost generator. The generator is typically dispatched at the higher economic minimum associated with the maximum configuration. Generation at economic minimum does not have the ability to set price; it is treated as must-run or price-taking supply. This has a price-suppressing effect, which distorts market signals. For days with such reliability commitments, market simulation results showed that the average day-ahead Hub LMP would have been $1.22/MWh higher ($40.91 vs. $39.69) if multi-stage generators had offered the ISO more options (i.e., all of their configurations), rather than just their maximum configuration.

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

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

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2015 through Fall 2017.

Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 2-1 below.

Table 2-1: High-level Market Statistics

	Fall 2017	Summer 2017	Fall 2017 vs Summer 2017 (% Change)	Fall 2016	Fall 2017 vs Fall 2016 (% Change)
Real-Time Load (GWh)	28,504	32,813	-13%	28,924	-1%
Peak Real-Time Load (MW)	20,946	23,968	-13%	23,142	-9%
Average Day-Ahead Hub LMP ($/MWh)	$29.11	$26.00	12%	$25.16	16%
Average Real-Time Hub LMP ($/MWh)	$30.45	24.78	23%	$24.72	23%
Average Natural Gas Price ($/MMBtu)	$2.69	$2.44	10%	$2.46	9%
Average Oil Price ($/MMBtu)	$9.53	8.38	14%	$7.71	24%

The combination of higher natural gas prices and lower operating margins contributed to higher prices in Fall 2017 compared to Summer 2017 and Fall 2016. In summary:

- Higher natural gas prices in Fall 2017 led to increased day-ahead and real-time LMPs, compared to Summer 2017 and Fall 2016. Natural gas prices increased by 10% compared to Summer 2017 and by 9% compared to the prior fall. The impact of natural gas prices on LMPs is further examined in Section 3.1 below.
- There was a larger increase in LMPs in Fall 2017 compared to the increase in natural gas prices. Outages and reductions averaged over 6,100 MW during Fall 2017, compared to 5,400 MW in Fall 2016. The higher number of outages contributed to a lower average operating capacity surplus and the dispatch of relatively higher-cost generation during Fall 2017 to meet load and reserve requirements.

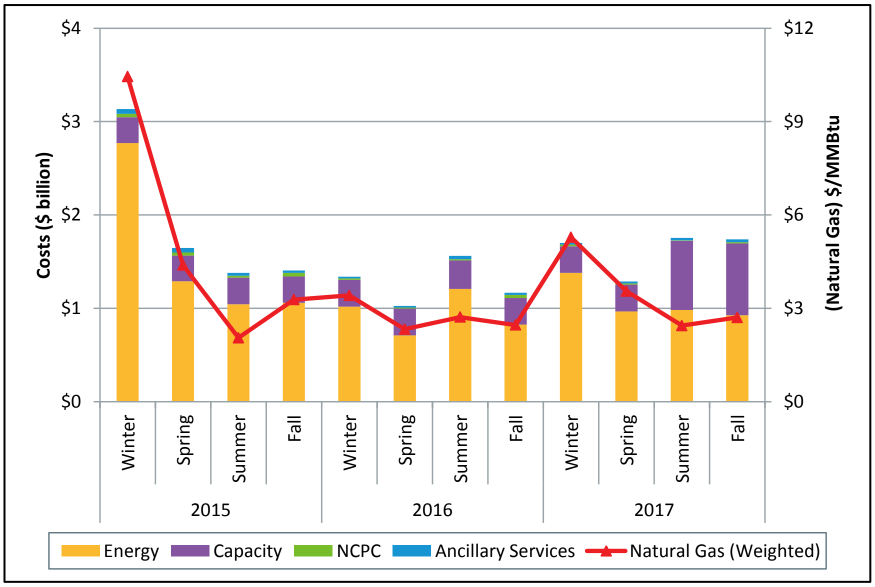
2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below.[5, 6]

[5] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

[6] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland and Tennessee gas pipeline Z6-200L. Next-day implies trading today (D) for delivery during tomorrow's gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 11 on D+2.

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



In Fall 2017, the total estimated wholesale market cost of electricity was $1.74 billion, an increase of 49% compared to $1.17 billion in Fall 2016, and a decrease of 1% over the previous quarter (Summer 2017).

Natural gas prices continued to be the key driver of energy prices. Compared to Fall 2016, energy costs of $925 million in Fall 2017 were 9% higher, consistent with the increase in the average gas price of 10%. Despite higher natural gas prices compared to Summer 2017 (up 10%), overall energy payments decreased by 6% in Fall 2017 ($925 million in Fall 2017 compared to $983 million in Summer 2017). This impact of higher gas prices was offset by lower loads in Fall 2017.

In both Fall and Summer 2017, rising capacity market costs contributed to the higher wholesale costs relative to previous quarters. Up to June 2017, capacity prices were relatively low as the region was long on capacity (i.e. had an excess of supply compared to the region's requirements). Capacity prices from the eighth forward capacity auction (FCA 8), which went into effect beginning in June 2017, reflected a system-wide capacity deficiency of 143 MW due to a number of generator retirements. Due to the capacity shortfall, prices in FCA 8 were set administratively at $7.03/kW-month for existing (non-NEMA/Boston) resources, and at a price of $15.00/kW-month for new and existing resources in NEMA/Boston. This compares to a rest-of-pool clearing price of $3.15/kW-month in the prior auction, FCA 7.

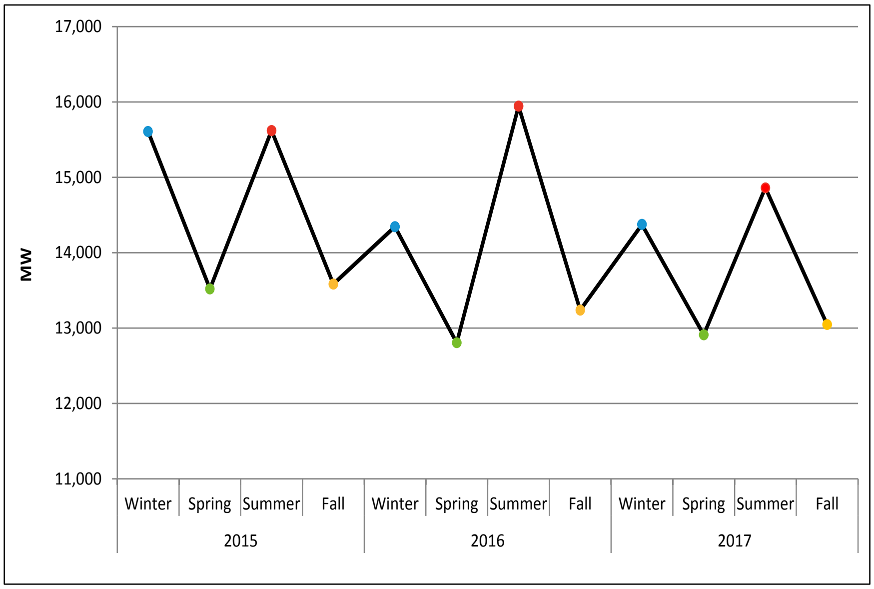
At $14.5 million, Fall 2017 Net Commitment Period Compensation (NCPC) costs represented less than 2% of energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $19 million lower than Fall 2016 NCPC costs, and $9 million higher than Summer 2017 NCPC costs. Section 3.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves and regulation, totaled $30 million in Fall 2017, representing 2% of total wholesale costs. Ancillary services costs increased by 45% compared to Fall 2016, and increased by 18% compared to Summer 2017.

2.2 Load

Average hourly load during Fall 2017 was 13,047 MW, a 1.5% decrease compared to Fall 2016 and a 4% decrease compared to Fall 2015. Average hourly load by season is illustrated in Figure 2-2 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer, and the yellow dots represent fall.

Figure 2-2: Average Hourly Demand



Factors that contributed to lower loads during Fall 2017, compared with the prior two years, were milder temperatures and the growth of energy-efficiency programs. Table 2-2 below compares the weather conditions of the three previous fall quarters. This table compares the average quarterly temperature and the number of hours per quarter when the average Temperature Humidity Index (THI) was greater than 62°F and less than 74°F. Air conditioning use (and the associated electric load) tends to decrease when THI is between this temperature range.

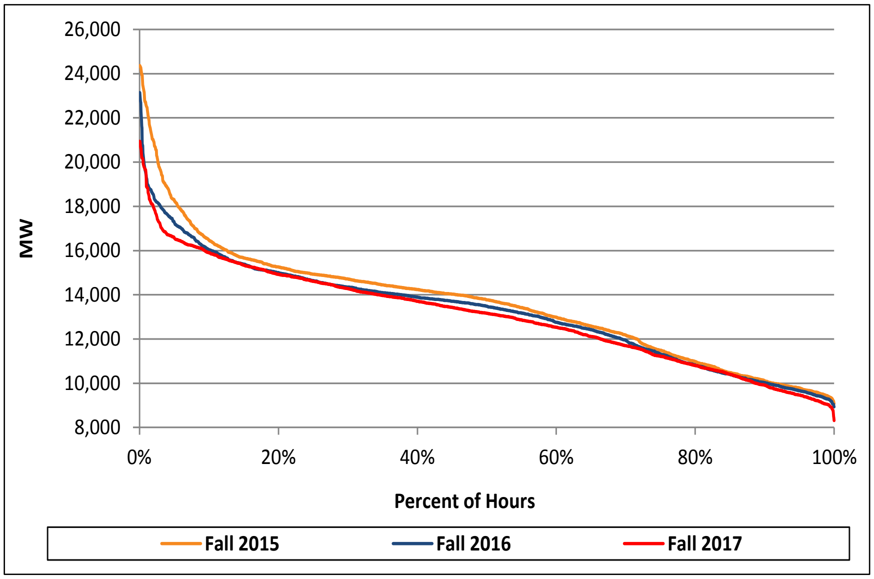
Table 2-2: Quarterly Temperature Humidity Index Statistics for Fall Periods

Fall 2015		Fall 2016		Fall 2017	
Average (in °F)	Number of Hours with 62°F < THI < 74°F	Average (in °F)	Number of Hours with 62°F < THI < 74°F	Average (in °F)	Number of Hours with 62°F < THI < 74°F
56	532	55	527	56	741

There were significantly more hours when the THI levels were between 62°F and 74°F in Fall 2017 (741 hours) compared to Fall 2016 (527 hours) and Fall 2015 (532 hours). Additionally, the load reduction due to energy efficiency in Fall 2017 was 2,382 MW, an increase compared to the Fall 2016 value of 2,111 MW and the Fall 2015 value of 1,845 MW.

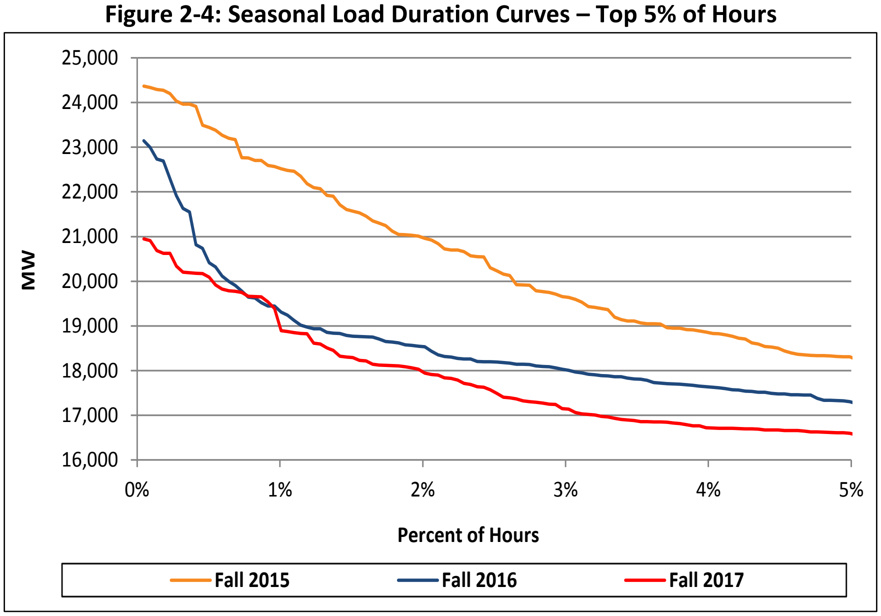
The system load for New England over the last three fall seasons is shown as load duration curves in Figure 2-3 below. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. Plotting several seasonal load duration curves can help illustrate differences between periods.

Figure 2-3: Seasonal Load Duration Curves



The load duration curve for Fall 2017 is comparable to the curves for Fall 2016 and Fall 2015 except at the high-load end of the distribution where the load in Fall 2017 was consistently less than the loads in the prior two years. For this reason, the load duration curves for the top 5% of hourly observations for the last three fall seasons are shown in Figure 2-4. The average of the top 5% of hourly loads in Fall 2017 was less than the same average in Fall 2016 by 724 MW and the same average for Fall 2015 by 2,706 MW.

Figure 2-4: Seasonal Load Duration Curves – Top 5% of Hours



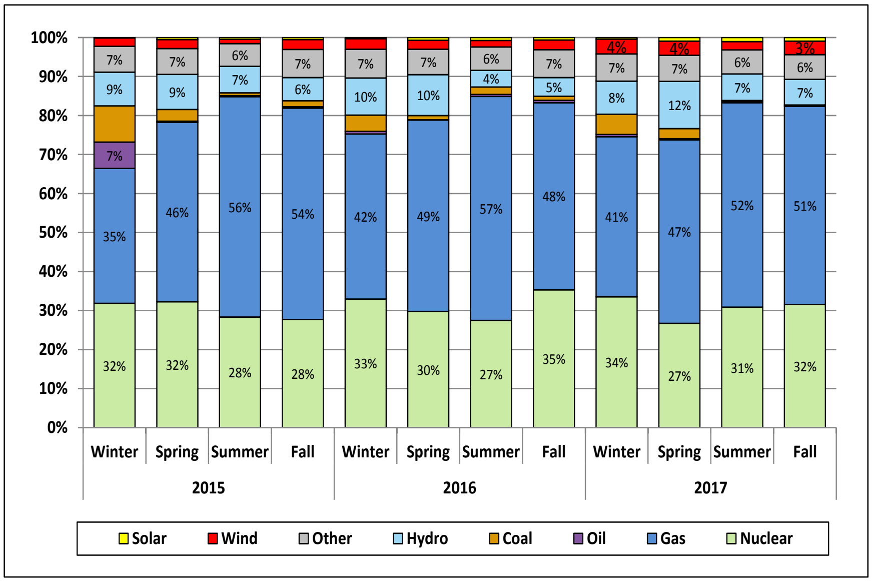
2.3 Supply

This subsection summarizes actual energy production (generation output in megawatt-hours) by fuel type, and flows of power between New England and its neighboring control areas.

2.3.1 Native Generation by Fuel Type

The breakdown of actual energy production by fuel provides useful context for the drivers of market outcomes. Actual energy production by generator fuel type for Winter 2015 through Fall 2017 is illustrated in Figure 2-5 below.

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

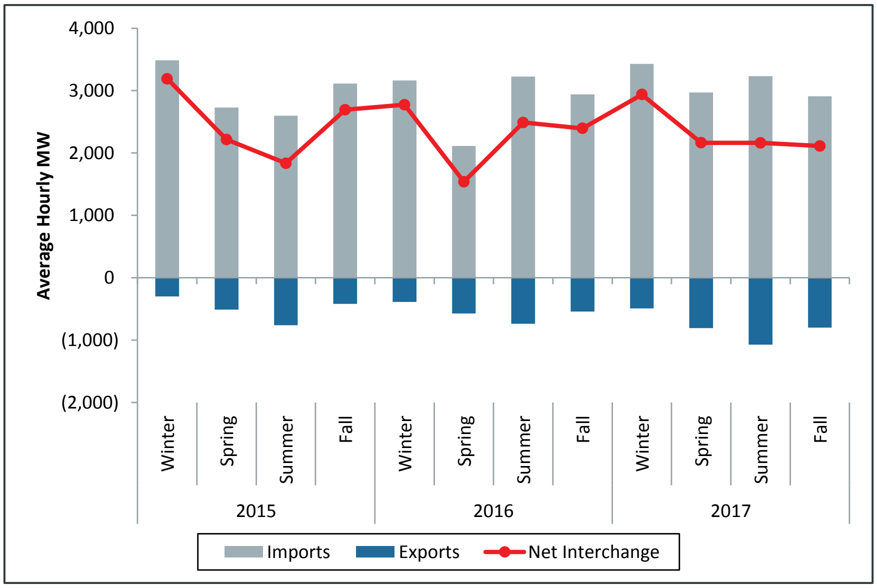


Seasonal fluctuations in fuel mix occur due to market economics and generator availability. The availability of generation is particularly impacted by scheduled outages during the spring and fall seasons. Overall, the fuel mix in Fall 2017 was within a normal range. The majority of New England's generation comes from gas-fired generation, which accounted for 51% of total native energy production in Fall 2017. Coal-fired generation accounted for just 0.1% of native energy production during Fall 2017, 1% less compared to Fall 2016. This reduction was driven by the retirement of the Brayton Point generator. Oil generation accounted for 0.3% of native energy production during Fall 2017, a decrease of 0.35% compared to Fall 2016. Nuclear generation accounted for 32% of total native energy production in Fall 2017, down from 35% in Fall 2016 due to outages. Wind and Solar generation made up 4% of native energy production during Fall 2017, an increase from 3% in Fall 2016.

2.3.2 Imports and Exports

New England was a net importer of about 2,100 MW per hour, on average, during Fall 2017, which was about 300 MW, or 12%, less than the average net interchange of 2,400 MW per hour in Fall 2016. The average hourly gross import and export power volumes and the net interchange amount are shown in Figure 2-6 below.

Figure 2-6: Average Hourly Real-Time Imports, Exports, and Net Interchange



New England is typically a net importer of power from the neighboring control areas in Canada and New York (red line).[7] Figure 2-6 illustrates that net interchange was slightly lower than the net interchange in Fall 2016 and has been consistent in the last three quarters. Compared with Fall 2016, average hourly imports are nearly equal; the difference in interchange was due to a 250 MW increase in hourly exports. A 160 MW average hourly increase in exports over the New York North interface was the primary contributor to the year-over-year decrease in net interchange.

Since Summer 2016, participants have increased price-sensitive export bid volumes at the New York North interface, where Coordinated Transaction Scheduling was implemented in December 2015. The increase in price-sensitive bidding has resulted in a higher volume of exports clearing. Between Fall 2016 and Fall 2017, the average offered exports increased by 300 MW. The increase in volume was accompanied by a decrease in price. The average per-MW export bid price decreased from $75 to -$11, indicating that participants are willing to pay to export out of New England. The change in behavior has led to ISO-NE net exporting over the New York North interface more often when economic (i.e. when New York prices are higher).

In Fall 2017, when New York prices were higher, power flowed from New England to New York 34% of the time. In Fall 2016, power only flowed the correct direction when New York prices were higher about 9% of the time. Despite the improvement in power flow when New York prices are higher, the total percentage of time power flowed the correct direction over the New York North interface only increased from 57% to 59%, fall over fall. New England imported less often when it was economic to do so in Fall 2017. In 2016, the percentage of time New England imported when it was economic to do so was 98%. In Fall 2017, this number dropped to 93% of the time.

[7] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound Cable, and the Northport-Norwalk Cable. These last two run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces, which both connect with the Hydro Québec control area, and the New Brunswick interface.

The remaining 90 MW of additional exports were spread among the New Brunswick, Northport-Norwalk, and Cross Sound Cable tie lines, which each experienced smaller increases in exports (under 40 MW each).

Section 3
Day-Ahead and Real-Time Markets

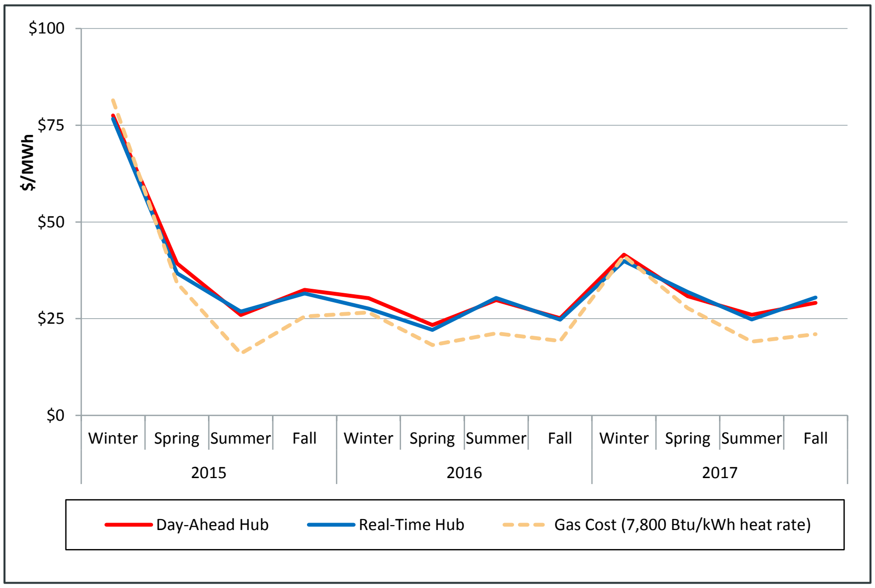
This section covers trends in, and drivers of spot market outcomes, including the energy market, and real-time markets for ancillary services products; operating reserves and regulation.

This section also provides a summary of market and system conditions on October 30, when tropical storm Phillipe left approximately 1.2 million New England customers without power.

3.1 Energy Prices

The average real-time Hub price for Fall 2017 was $30.45/MWh. This was 5%, or $1.35/MWh, higher than the day-ahead price of $29.11/MWh. Day-ahead and real-time prices, along with the cost of generating electricity using natural gas, are shown in Figure 3-1 below. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.

Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



Average prices continue to track closely with the cost of natural gas generation. As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are consistent with changes in natural gas generation costs (dashed line). The spread between natural gas and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels than gas, are required to meet the region's higher demand.

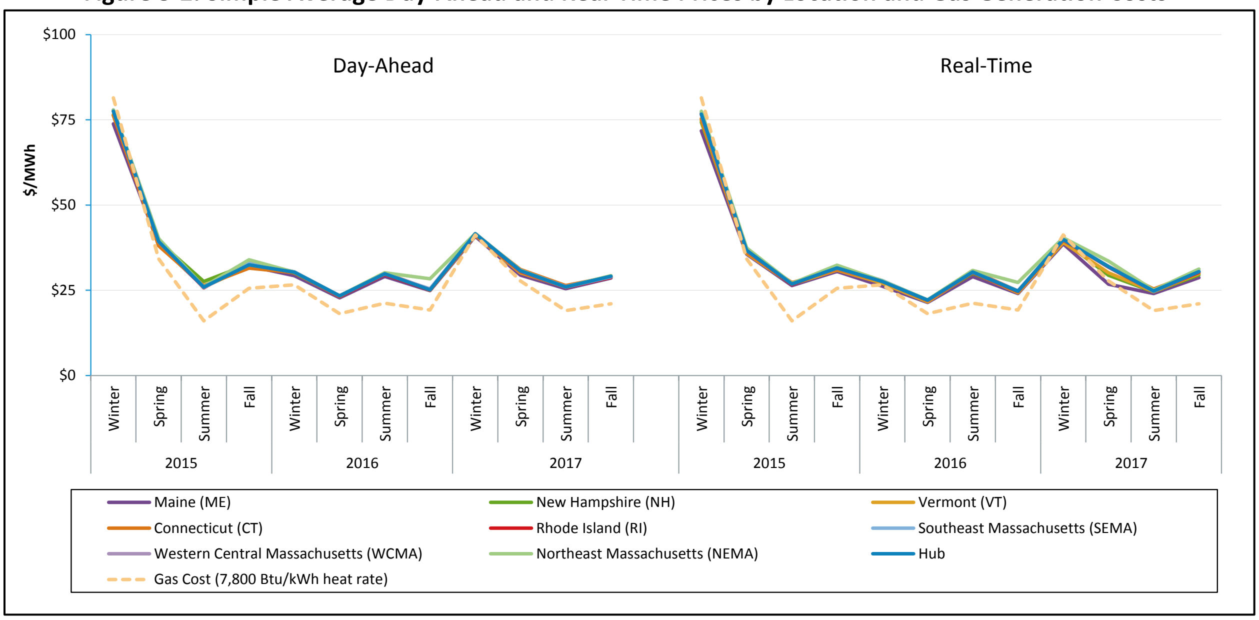
In Fall 2017, the month of September saw the greatest price divergence, with average real-time prices $2.73/MWh greater than average day-ahead prices. Higher average real-time prices in September were primarily driven by significant price spikes that took place over a four-day period. On September 24 to 27, warm temperatures led to high loads, and combined with scheduled generation outages of approximately 5,800 MW, the system experienced low capacity margins. This led to a period of high day-ahead and real-time prices. The higher real-time prices compared to day-ahead prices were further driven by a number of generator forced outages and higher actual loads compared to day-ahead cleared demand.

The Fall 2017 day-ahead price of $29.11/MWh was higher than the Fall 2016 average of $25.16/MWh (up 16%), and less than the average Fall 2015 price of $32.47/MWh (down 10%). In real-time, the average price of $30.45/MWh represented an increase of 23% compared to the prior fall average of $24.72/MWh. The real-time price decreased by 3% compared to the Fall 2015 price of $31.53/MWh.

In Fall 2017, the highest Hub LMPs occurred in November ($33.98 and $33.30/MWh in the day-ahead and real-time markets, respectively). Natural gas prices averaged $3.52/MMBtu in November 2017, an increase of 34% compared to November 2016.

The seasonal average day-ahead energy prices for the Hub and each load zone are shown below in Figure 3-2 along with the estimated cost of gas generation.

Figure 3-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs



Day-ahead prices did not differ significantly among the load zones.[8] The Maine average day-ahead price was $0.51/MWh (2%) lower than the Hub price. Price separation in Maine was more notable in the real-time market, with prices $1.74/MWh (6%) lower than Hub prices.

New Hampshire and Vermont load zone prices were also, on average, lower than the Hub price in real-time, by 3% and 2% respectively. Renewable-type generation resources with lower marginal costs are located in export-constrained areas of northern New England and frequently set real-time prices in these areas. The discount in energy prices in Maine, Vermont, and New Hampshire was more pronounced than in the previous quarter (Summer 2017). This is because there were more instances in which line reductions and outages lowered the transmission capability available to export power to the rest of the system.

Real-time energy prices in the Northeast Massachusetts and Boston (NEMA) zone averaged $31.20/MWh during Fall 2017, which was $0.75/MWh (2%) higher than the Hub. This premium in

[8] 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.

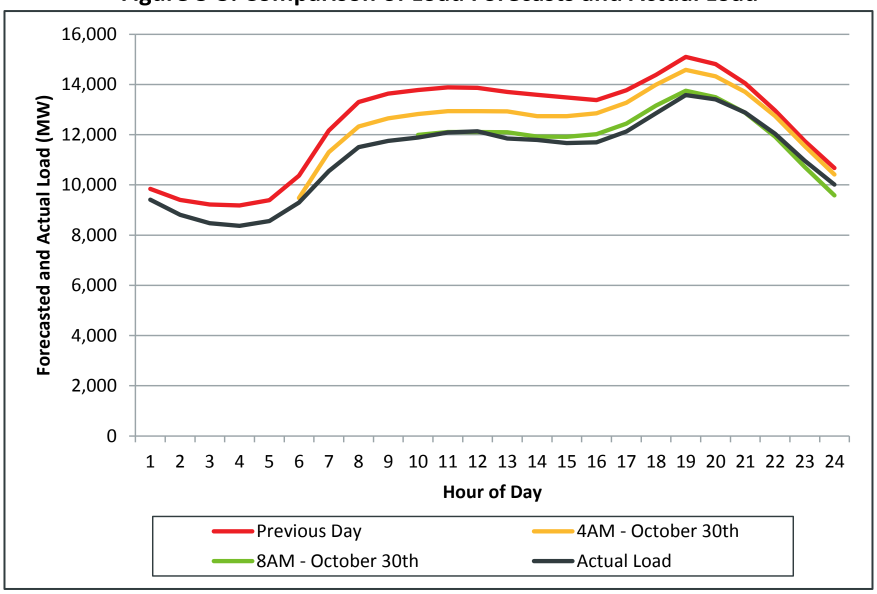
NEMA energy prices for the quarter was almost entirely the result of price separation that occurred between October 23 and November 5 due to a planned line outage.

3.1.1 Market and System Conditions on October 30, 2017

On October 30, 2017, Tropical Storm Phillipe brought strong rain and winds throughout New England. On the morning of the 30th, ISO New England declared a Master/Local Control Center Procedure No. 2 (M/LCC2), signaling abnormal conditions due to severe weather. Equipment outages resulting from the storm left approximately 1.2 million New England customers without power. The unanticipated outages resulted in actual loads being much less than forecasted, which contributed to significant price separation between system locations.

A comparison of the three load forecasts made by the ISO at different times on October 30 and the actual load is shown in Figure 3-3 below. The red line shows the forecast made the previous day, the yellow line shows the forecast made at about 4:00 AM on the 30th, and the green line shows the forecast made at about 8:00 AM on the same day.

Figure 3-3: Comparison of Load Forecasts and Actual Load

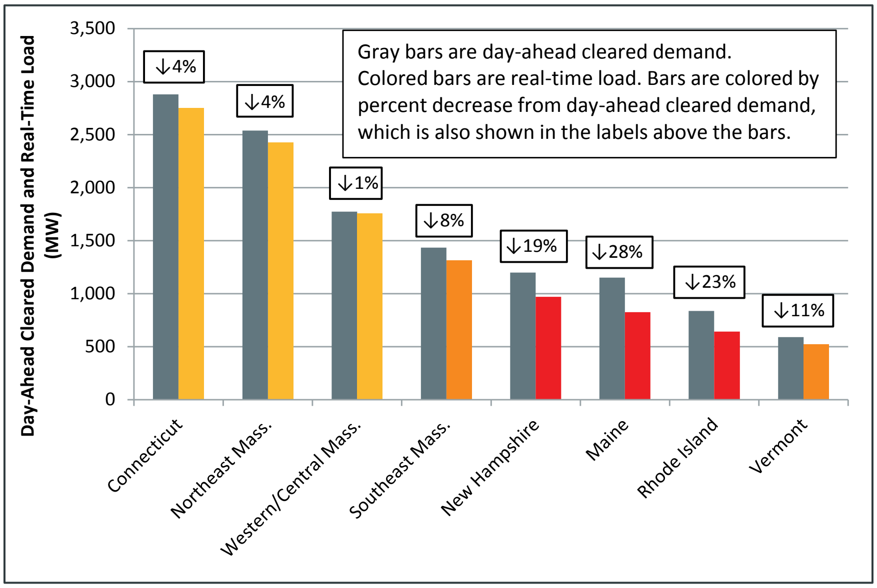


The figure illustrates how the load forecasts were updated as the storm caused power outages across New England. Actual load was significantly less than the forecast made on the 29th (green) all day, and was over 1,500 MW less than the forecast from hour ending seven through hour ending nineteen. The forecast was adjusted on the 30th at about 4 AM, but even that forecast was not reflective of the decrease in load that occurred due to the storm after hour ending (HE) seven. The updated forecast overestimated actual load by an average of about 1,000 MW from HE 9 through HE 20. At 8 AM, a new forecast was generated that more accurately represented load throughout the remainder of the day.

The difference between the demand that cleared in the day-ahead energy market and actual real-time load varied across locations. Figure 3-4 below compares the day-ahead cleared demand and actual load by load zone. The gray bars represent the average day-ahead cleared demand in the load zone. The colored bars show the average actual real-time load in each load zone. Colors are assigned to the bars based on the percent decrease in load, comparing day-ahead cleared demand with actual load. Yellow bars signify a decrease of less than 5%, orange bars represent a 6% to 15%

decrease, and red bars show very large decreases of over 15%. For reference, the percent decreases are shown in boxes above the bars.[9]

Figure 3-4: Differences between Day-Ahead Cleared Demand and Actual Load by Load Zone

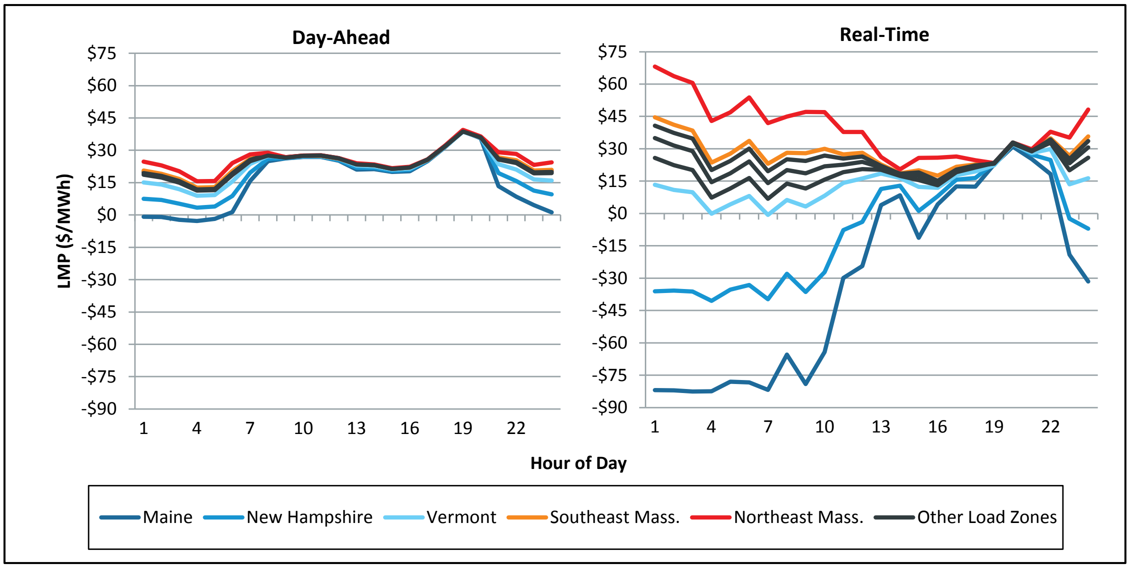


There are a few interesting observations that can be made from Figure 3-4. The three largest load zones by consumption, Connecticut, Northeast Massachusetts, and Western/Central Massachusetts, experienced the smallest percentage decrease in demand. Maine, New Hampshire and Rhode Island experienced the largest decrease measured in both percentage and total demand. The total decrease in system-wide demand was about 10%, or about 1,200 MW per hour on average throughout the day. About 750 MW of that decrease comprised lower demand in Maine, New Hampshire and Rhode Island.

The hourly day-ahead and real-time prices at the load zones are shown in Figure 3-5 below. The day-ahead zonal LMPs are shown side-by-side with the real-time zonal LMPs for comparison. Northeast Massachusetts and Southeast Massachusetts are shown in red and orange, representing the relatively high prices in the load zones compared with the system. Maine, New Hampshire and Vermont are shown in shades of blue, highlighting their relatively low prices.

[9] The numbers presented exclude demand at the external interfaces, and the internal hub.

Figure 3-5: Zonal Price Separation in the Day-Ahead and Real-Time Energy Markets



It is apparent from Figure 3-5 that there was significant zonal price separation in both the day-ahead and real-time markets. There are a few factors that contributed to the price separation. A planned equipment outage reduced the transmission capability of a large interface limiting the southerly flow of lower-cost energy from Vermont, New Hampshire and Maine to the rest of New England. The difference in the relative price of energy on either side of the constraint resulted in price separation. Prices were lower in northern New England, where there is more lower-priced renewable energy, and prices were relatively higher in the rest of the region.

The price separation was more pronounced in the real-time market due to a few factors. First, lower-priced wind generation in Vermont, New Hampshire, and Maine that did not clear in the day-ahead market produced energy in real-time. In total, about 250 MW per hour of additional wind generation in the three states was sold in the real-time market. Approximately 570 MW of virtual supply cleared in the day-ahead market, however the relative price of wind delivered in real-time was much lower (-$83/MWh on average) compared with the average price of cleared virtual supply (-$1/MWh).

The difference in volumes of virtual supply and wind that cleared was offset by the reduction in demand in the states. Maine, New Hampshire and Vermont each experienced large decreases in demand between the day-ahead and real-time market, shown earlier in Figure 3-4. Combined, these three states had a decrease of 620 MW, or a 21% reduction, in their combined hourly demand from day-ahead to real-time. All else equal, this factor alone would have a price depressing effect; combined with the relative difference in the offer prices of virtual supply compared to wind resources, real-time prices in northern New England were much lower.

The other three New England states did not experience the same relative reduction in prices. The average decrease in demand between the day-ahead and real-time markets was 6% lower in the remaining states, about 575 MW per hour on average, as shown in Figure 3-4. In the morning on October 30, a large generator in Connecticut (that had cleared in the day-ahead market) had to reduce its capability in real-time by approximately 300 MW. The reduction effectively offset a majority of the decrease in load of the three southern New England states.

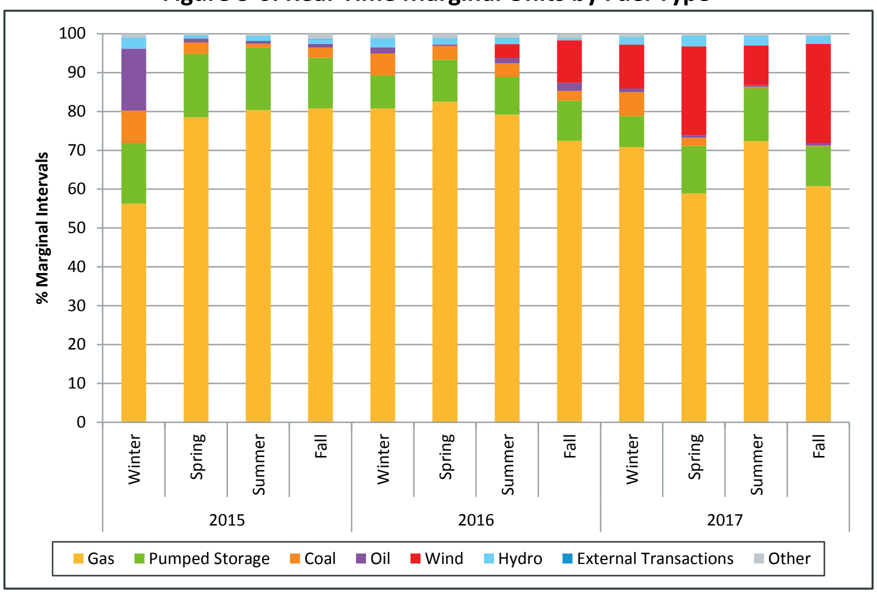
3.2 Marginal Resources and Transactions

The LMP at a pricing location is set by the cost of the next megawatt (MW) the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is "marginal". Analyzing marginal resources by type of transaction can provide additional insight into day-ahead and real-time pricing outcomes.

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

The percentage of time resources of different fuel types were marginal in the real-time market by season is shown in Figure 3-6 below.[10]

Figure 3-6: Real-Time Marginal Units by Fuel Type



In the real-time market, gas units set price about 60% of the time. Gas accounts for approximately half of native generation, and is often the least expensive fossil fuel type generation. The relative price of gas generation compared with other fossil fuel types means that gas generators will be deployed more often, as generators are committed and dispatched in merit order. Most of the time, more expensive fossil fuel generation is not frequently required to meet demand. Because gas generators are often the most expensive units online, they set price frequently.

In addition to their relative cost, many gas generators are eligible to set price due to their operational characteristics. Nuclear generation accounts for about one third of native generation in New England, but does not set price. Nuclear generators in New England are offered at a fixed output, meaning once they are brought online they can only produce at one output level. By definition, if load increased by one megawatt they could not increase their output to deliver it, and are therefore ineligible to set price.

[10] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, and solar.

Wind was the second most frequently marginal fuel type in the reporting period. The characteristics of wind units are very different than those of gas generators. Compared with other fuel types, wind generation has a lower marginal cost. Wind resources are often offered into the real-time market at negative prices and are rarely the most expensive generators online. Wind generation also makes up a small percentage of native generation, only 3%.

The high frequency of marginal wind units reflects the limitation of the transmission system in delivering output from their locations to the rest of New England. Wind units are often in export-constrained areas. They can only deliver the next increment of load in a small number of locations because the transmission that moves energy out of their constrained area is at maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the inexpensive wind energy. Although wind generation is marginal in a high number of intervals, it nearly always sets price in small, export-constrained areas only. In these instances the remainder of the region experiences prices set by other, usually more expensive, resources.

In Fall 2017, wind generators were marginal more frequently than in previous quarters, around one quarter of the time. Equipment outages led to more restrictive transmission limits, resulting in an increase in the frequency of price-setting wind units. Despite the high percentage of time wind units were marginal, wind units only set price for the entire system 0.4% of the time.

The increase in Fall 2017 was part of a longer-term trend. The higher frequency of marginal wind units that began in Summer 2016 is driven by the Do Not Exceed (DNE) dispatch rules, which went into effect on May 25, 2016 (at the end of the Spring 2016 reporting period).[11] DNE improves the modeling of wind and hydro intermittent units in the real-time market. These units are now dispatched by the unit dispatch software and are eligible to set price. Previously, these units were essentially fixed in the pricing process, and therefore unable to set price.

Pump-storage units set price about 10% of the time in the reporting period. Pump-storage units generally offer energy at a price that is close to the margin. They are often called upon when conditions are tight due to their ability to start up quickly and their relatively low commitment costs, compared with fossil fuel units. Because they are online relatively often and priced close to the margin, they can set price frequently. The percentage of time pump-storage units set price in Fall 2017 was consistent with previous seasons.

The percentage of time that each resource or transaction type set price in the day-ahead market since Winter 2015 is illustrated in Figure 3-7 below. Marginal units are shown by category, and generators are outlined in blue and broken up by fuel type further within the generator category.

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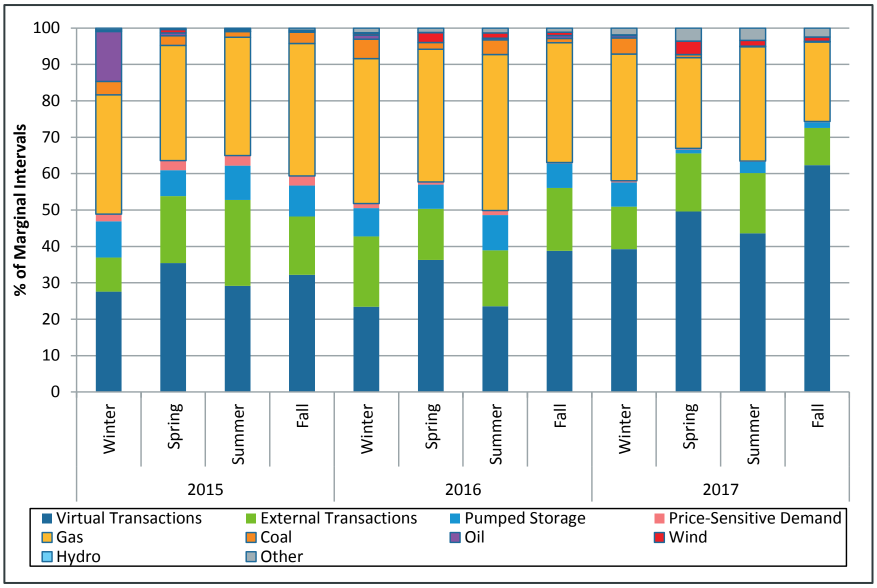
[11] *ISO New England Inc. and New England Power Pool*, Do Not Exceed ("DNE") Dispatch Changes, ER15-1509-000 (filed April 15, 2015); Order Conditionally Accepting, In Part and Rejecting, In Part, Tariff Revisions and Directing Compliance Filing, 152 FERC ¶ 61,065 (2015). In a subsequent filing, the 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.

Figure 3-7: Day-Ahead Marginal Units by Resource and Fuel Type



Virtual transactions set day-ahead prices over 60% of the time in the reporting period. Virtual transactions can be offered at any price, and there are often many priced around the margin. Virtual transactions also have a high propensity to be marginal because they do not have operational constraints, which generally limit the ability to be marginal.[12]

In Fall 2017, virtual transactions were marginal frequently compared with previous seasons. In Fall 2016, the frequency of virtual transactions began increasing, a pattern which has persisted through the most recent quarter. The increase has been driven by virtual traders responding to differences between day-ahead and real-time offer behavior of wind units that can now set price in the real-time market.

Virtual transactions are a day-ahead market product that profit by arbitraging differences between day-ahead and real-time energy prices. When a systematic difference between the day-ahead and real-time markets emerges, virtual transactions are one mechanism through which the day-ahead market can adjust to better reflect real-time conditions. Virtual transactions are discussed in more detail in the next section, Section 3.3.

As discussed above, at the end of the Spring 2016 reporting period Do Not Exceed (DNE) dispatch rules were introduced to allow intermittent wind and hydro resources to set price in the real-time energy market. The change resulted in an increase in price setting wind units in the real-time market – at consistently low prices. A majority of wind units clear much less energy in the day-ahead market compared to real-time. This puts downward pressure on real-time prices, but not day-ahead prices. This difference provides an opportunity for virtual traders to profit by "replacing" the wind energy with low-priced incremental offers, improving the day-ahead market's scheduling in the process.

[12] For example, a committed 100 MW block-loaded resource must clear 100 MW and is generally incapable of setting price. It is fixed and cannot increase its output to deliver another increment of load. A 100 MW virtual transaction can be cleared at any quantity between 0 and 100 MW. If it is cleared at any quantity less than 100 MW it can deliver the next increment of load and is eligible to set price.

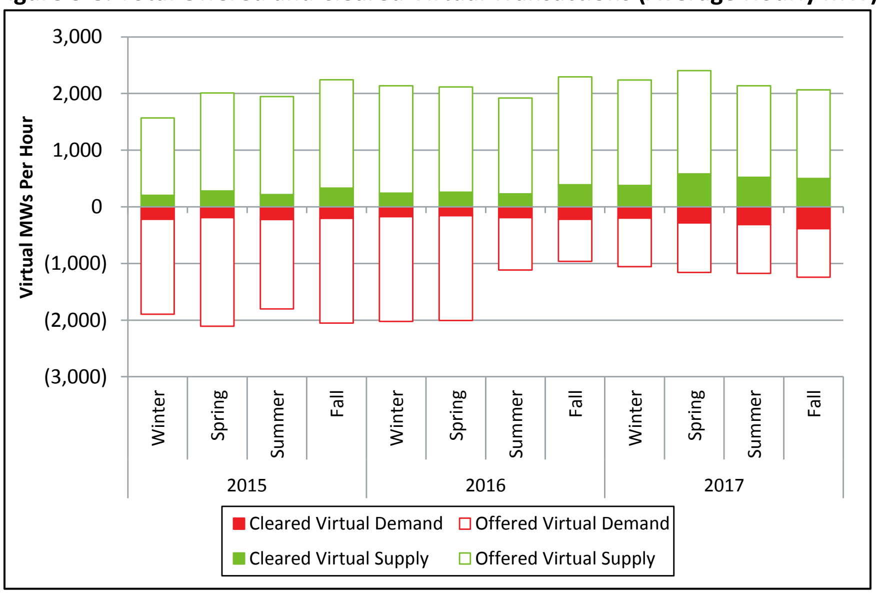
In Fall 2016, day-ahead marginal virtual supply offers began to increase following the real-time increase in marginal wind units. Due to planned transmission outages, both real-time wind generation and day-ahead virtual transactions were high in Fall 2017.

Gas units were the second most frequently marginal resource type in the day-ahead market; they set price in 22% of hours. Just as gas units are the most frequent marginal fuel type in the real-time market, they make up most of the marginal *generation* in the day-ahead market. Generators as a group composed 26% of all marginal entities in the day-ahead market.

3.3 Virtual Transactions

Virtual transaction volumes from Winter 2015 through Fall 2017 are shown in Figure 3-8 below.

Figure 3-8: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



In Fall 2017, submitted virtual demand bids and virtual supply offers averaged approximately 3,300 MW per hour, which was unchanged from Summer 2017, and a 2% increase from Fall 2016. Total volumes of cleared virtual transactions increased by 6% and 38% compared to Summer 2017 and Fall 2016, respectively.

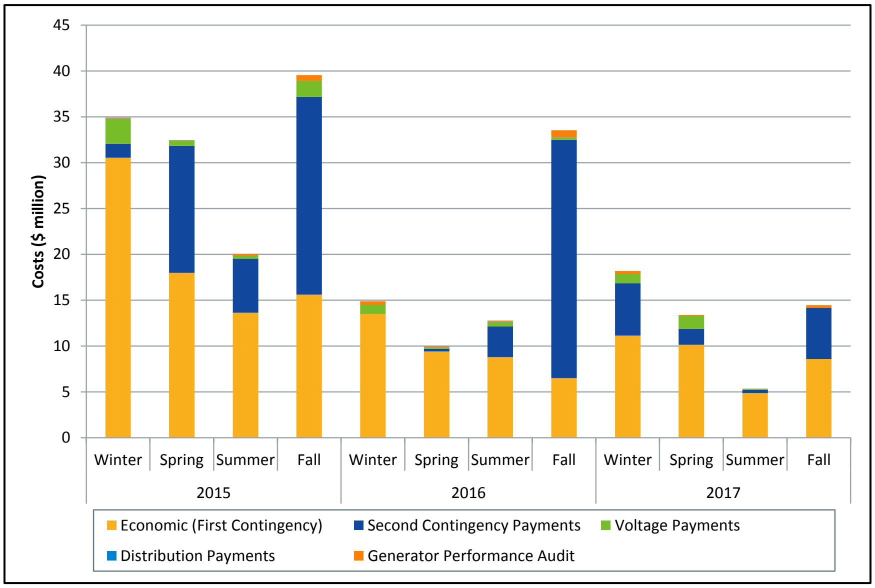
Beginning in Summer 2016, the average offer prices of virtual transactions have converged towards actual LMPs, resulting in higher percentages of virtual transactions clearing. A reduction in transaction costs, in the form of reduced NCPC costs that are charged in part to virtual transactions, may have contributed to this offer behavior. In February 2016, real-time economic NCPC payments made to generators receiving a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid. The fast-start pricing rules implemented in March 2017 also had a downward effect on real-time economic NCPC.[13] In Winter 2016, the average RT NCPC charge was \$2.81/MW. This value has declined substantially as evidenced by the average charge of \$0.81/MW in Fall 2017.

[13] See section 5 of the IMM's Summer 2017 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing make-whole payments to resources when energy prices 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 NCPC payments. NCPC is paid to resources for providing a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and for generator performance auditing.[14] NCPC payments by season and category are illustrated in Figure 3-9.

Figure 3-9: NCPC Payments by Category ($ millions)



In dollar terms, NCPC payments decreased this quarter by 57% (from $33.5 million to $14.5 million) compared to the previous fall However, NCPC payments increased 172% compared to Summer 2017, when an unusually low amount of NCPC payments were made ($5.3 million). NCPC payments this quarter represent about 1.6% of total wholesale energy costs, down markedly from Fall 2016, when NCPC payments represented about 4.1% of total wholesale energy costs.

The majority of NCPC (59%) incurred during the reporting period was for first contingency protection. Total first contingency payments of $8.6 million were 32% higher than payments made last fall and 76% higher than payments made in Summer 2017. Nearly 5% of the first contingency payments ($416 thousand) made in this reporting period were hourly shortfall NCPC payments. The vast majority of this form of NCPC payment occurred on October 18, when two units received hourly shortfall credits totaling $0.4 million for two hours in which they negatively deviated from their day-ahead obligation due to transmission outages.

[14] 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*.

The second largest category of NCPC (39%) incurred during the reporting period was for local second-contingency protection (LSCPR). Total LSCPR payments of $5.6 million were 78% lower than the nearly $26 million paid out last fall. During Fall 2016, nearly $24.2 million of LSCPR payments went to units in NEMA/Boston, while only $4.6 million was paid to units located within this zone in Fall 2017. Fewer reliability commitment were made by the ISO in Fall 2017 compared to Fall 2016, due to an increase in transmission import-capability into NEMA/Boston combined with less self-scheduling of generation. However, LSCPR payments were significantly higher than those made in Summer 2017, when very few resources were committed to provide local second-contingency protection. LSCPR payments totaled $347k in Summer 2017.

Of the total LSCPR payments in the reporting period, $4.2 million (75%) was paid during a 10-day period between November 6 and November 15. Nearly all of the LSCPR payments made over this period were to units in NEMA/Boston. Transmission outages during this 10-day period limited the transfer capability into NEMA/Boston, which required additional generators to be committed for reliability 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.

Generator performance audit NCPC payments totaled $0.26 million in Fall 2017. This reflects a 66% decrease from the total paid last fall ($770,000) and a significant increase from the $10,000 of GPA payments made in Summer 2017. Distribution NCPC payments was very small in Fall 2017, amounting to just over one thousand dollars.

Lastly, voltage payments in the quarter totaled $30,000. This was a modest decrease compared to $280,000 last fall and $90,000 last quarter. The decrease in payments was mainly associated with fewer outages that required specific generator commitments for voltage support.

Over half of the total NCPC paid in Fall 2017 ($7.9 million) was in the day-ahead market, while the other 45% ($6.5 million) originated from the real-time market. Nearly two-thirds of the day-ahead NCPC ($5.3 million) was for local second-contingency protection. The majority of real-time NCPC ($6.0 million) was for first contingency protection (or economic NCPC).[15] As was observed in Summer 2017, fast-start pricing rule changes also had a downward impact on NCPC during Fall 2017. It is estimated that the rule changes reduced real-time economic NCPC by as much as $4.7 million.

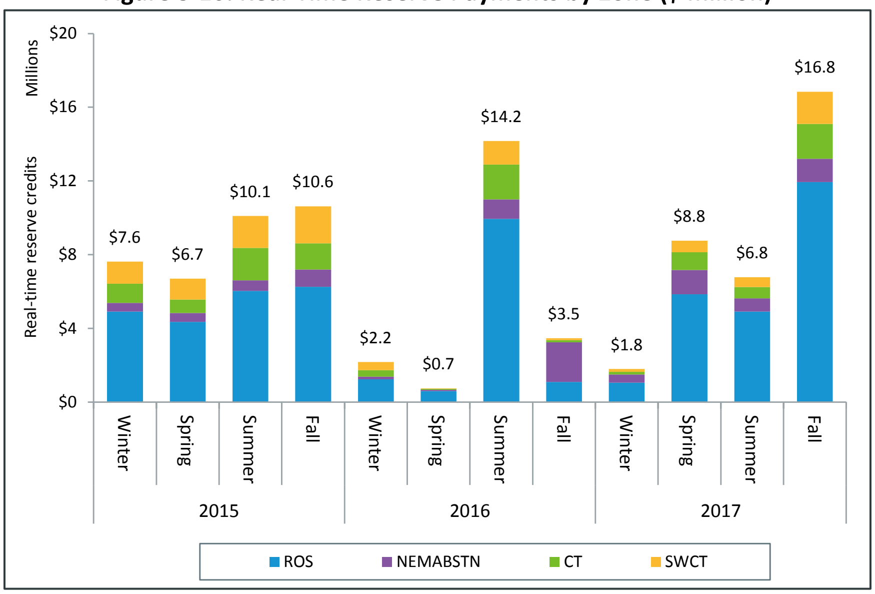
[15] First Contingency payments include real-time dispatch lost opportunity cost NCPC and rapid response pricing NCPC beginning in Spring 2017. Dispatch Lost-Opportunity Cost (DLOC) is an NCPC credit calculated for a resource instructed by the ISO to run at a level different than its economic dispatch point due to the timing of the dispatch and pricing processes. DLOC compensates the resource for the difference between the maximum net profit it could have earned at its economic dispatch point and the actual net profit earned at the dispatch instruction point. Rapid-Response-Pricing Opportunity Cost (RRPOC) is an NCPC credit calculated for a resource that is instructed not to operate at its economic dispatch point when fast-start pricing affects price. RRPOC compensates the resource for the difference between the amount it would have earned for energy and reserves at its economic dispatch point and the amount that it actually earned for energy and reserves in the interval following its dispatch instruction. Both of these credits were implemented on March 1, 2017 with fast-start pricing rule changes. (https://www.iso-ne.com/participate/support/faq/ncpc-rmr).

3.5 Real-Time Operating Reserves

Real-time reserve payments for Fall 2017 totaled $16.8 million, which was a large increase relative to the Fall 2016 total of $3.5 million and the Fall 2015 total of $10.6 million. This increase was due in significant part to the implementation of changes to the fast start pricing rules, and to lower operating reserve margins, discussed in more detail below.

Total real-time reserve payments, by reserve zone, from Winter 2015 through Fall 2017 are plotted in Figure 3-10 below. Note that these figures are intended to show the value of real-time reserves and therefore are the gross real-time credits for providing reserve products at the respective real-time clearing price. The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the chart totals. For reference, the total reductions for forward reserve obligations amounted to $3.1 million during Fall 2017, which resulted in total net real-time payments of $13.7 million.

Figure 3-10: Real-Time Reserve Payments by Zone ($ million)



As shown in Figure 3-10, total real-time reserve payments were higher in Fall 2017 than in the preceding fall periods. The distribution of payments among the reserve zones reflects that the majority of reserve pricing occurred for system requirements over this quarter.

The frequency of non-zero reserve pricing by zone along with the average price during these intervals over the past three summer periods are shown in Table 3-1 below.[16]

[16] Non-zero reserve pricing means that there was an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

Table 3-1: Hours and Level of Non-Zero Reserve Pricing [17]

Product	Zone	Fall 2015		Fall 2016		Fall 2017	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$61.18	49.2	$10.21	100.8	$23.36	373.9
TMNSR	System	$53.08	0.9	$0.98	0.1	$11.67	4.5
TMOR	System	$52.90	24.8	$0.96	1.4	$10.46	28.7
	NEMA/Boston	$56.52	5.8	$28.48	90.8	$11.13	4.6
	CT	$52.90	0.0	$0.96	0.0	$10.46	0.0
	SWCT	$53.26	3.8	$0.96	0.0	$10.46	0.0

During the Fall 2017 period, the overall ten-minute operating reserve margin (reserves in excess of the requirement) was down compared to the two previous fall periods, which is consistent with the increased frequency of ten-minute reserve pricing. As shown in

Table 3-1, there were 374 hours of system ten-minute spinning reserve pricing during Fall 2017. During these hours, there were 10 hours of reserve deficiency, whereby reserve prices were capped at the corresponding reserve constraint penalty factor (RCPF) of $50/MWh.[18] During Fall 2017 the average price for ten-minute spinning reserve was $23.36/MWh, which was an increase relative to Fall 2016.

The thirty-minute operating reserve margin was also lower in Fall 2017 compared to the two previous fall periods. In Fall 2017, system thirty-minute operating reserve pricing occurred for 29 hours, and the replacement thirty-minute operating reserve RCPF was triggered for 5 hours. A decrease in pricing of thirty-minute operating reserves in NEMA/Boston during Fall 2017 compared to Fall 2016 is due to transmission work that occurred in Fall 2016 that caused local reserve constraints to bind more frequently in that local reserve zone.

While the frequency and magnitude of reserve pricing is a function of many different factors that influence system conditions, the implementation of fast-start pricing in March 2017 has increased reserve pricing. As intended, fast-start pricing more accurately reflects the cost of operating higher cost fast-start generation and, on average, has increased the price of energy.[19] Because the price of energy has increased, so too has the opportunity cost of holding back generators to provide reserves rather than energy, which has resulted in higher and more frequent reserve pricing.

3.6 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their capacity

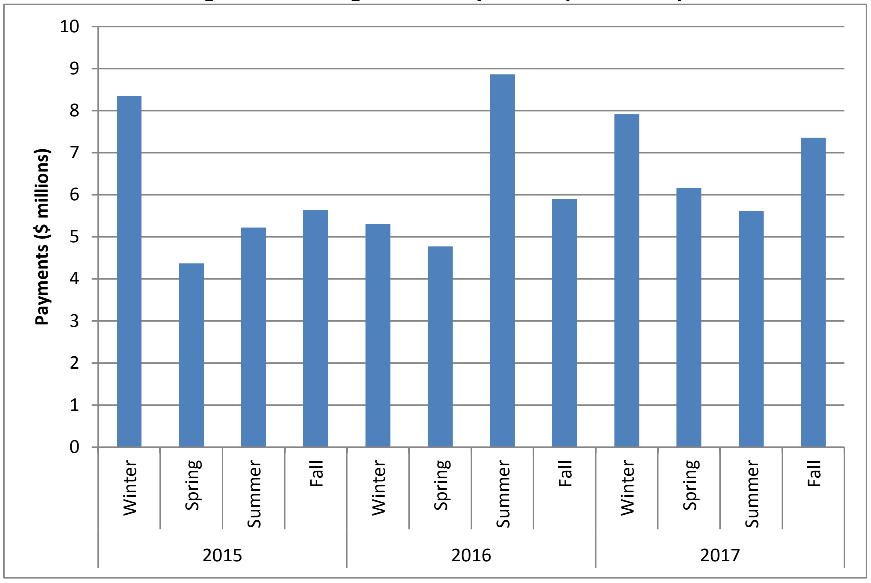
[17] The CT and SWCT load zones have positive average TMOR prices but 0 hours of pricing. This is because the TMOR price for CT and SWCT is equal to the System TMOR price even when reserve zone pricing is not in effect.

[18] The reserve constraint penalty factors are limits on the re-dispatch costs the system will incur to satisfy reserve constraints and will function as the reserve clearing price during a reserve deficiency. The penalty factors for the respective reserve products and their application are defined in Market Rule 1 Section III.2.7.A.

[19] See section 5.5 of the Summer 2017 Quarterly Markets report for detail on fast-start pricing: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

to match supply and demand (and to regulate frequency) over short time intervals. Quarterly regulation payments are shown in Figure 3-11 below. [20]

Figure 3-11: Regulation Payments ($ millions)



Total regulation market payments were $7.4 million during the reporting period, up 31% from $5.6 million in Summer 2017, and up 25% from $5.9 million in Fall 2016. Regulation payments increased relative to the earlier periods predominately as a result of manual regulation commitments that exceeded regulation requirements. In the Fall 2017, such commitments occurred in 64 hours and resulted in payments of approximately $2 million to the manually-committed generators; in the earlier periods, manual commitments occurred in 40 hours with payments of approximately $1 million (Summer 2017) and 27 hours with payments of approximately $500,000 (Fall 2016). Additionally, increased regulation service prices and payments, in part reflecting somewhat higher natural gas prices in Fall 2017 compared to Summer 2017, explain the remainder of the Fall 2017 payment increase.

[20] 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.

Section 4
Forward Markets

This section of the report covers activity in the forward capacity market (FCM) and in financial transmissions rights (FTRs).

4.1 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.[21] 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.

During any 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.[22] 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 buy or sell obligations. Buying an obligation means that the participant will provide capacity during a given period. Participants selling capacity reduce their capacity 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.

The current capacity commitment period (CCP) started on June 1, 2017 and ends on May 31, 2018. In the corresponding forward capacity auction (FCA 8), generator retirements resulted in a system-wide capacity deficiency of 143 MW. 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 all new resources. Existing resources in NEMA/Boston were also paid $15.00/kW-month due to administrative rules.[23]

Total FCM payments as well as the existing clearing price for Winter 2015 through Fall 2017 are shown in Figure 4.1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green

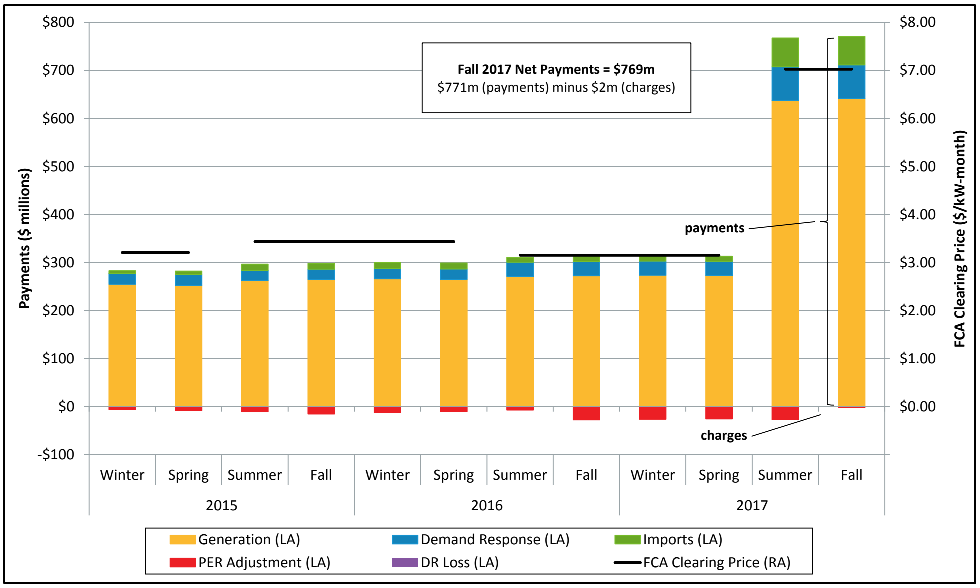
[21] In the capacity market, resource categories include generation, demand response and imports.

[22] 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.

[23] The specific rule is the "capacity carry forward" rule. See pages 11-15 of the FCA 8 filing with FERC: https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/feb/er14_1409_000_fca8_results_filing_2_28_2014.pdf

bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively.

Figure 4-1: Capacity Payments ($ millions)



Total net FCM payments increased significantly from prior quarters. In Fall 2017, capacity payments totaled $769 million, which accounts for adjustments to primary auction CSOs.[24] Payments increased in the second half of 2017, due to higher FCA clearing prices. Net payments increased $29 million compared to last quarter, as PER adjustments (red bar) declined. Peak energy rent adjustments were higher in the previous year because of high real-time energy prices that occurred in August 2016.[25]

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. Table 4-1 below provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity that occurred during Fall 2017, alongside the results of the relevant primary Forward Capacity Auction (FCA).

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[24] 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.

[25] The incremental impacts of peak energy rent in any given month are amortized over the following twelve months as a part of the twelve-month rolling average. To read more about the effect of Peak Energy Rent Adjustments on capacity payments, see the IMM's Summer 2016 Quarterly Markets Report: https://www.iso-ne.com/staticssets/documents/2016/11/qmr_2016_q3_summer_11_15_2016.pdf .

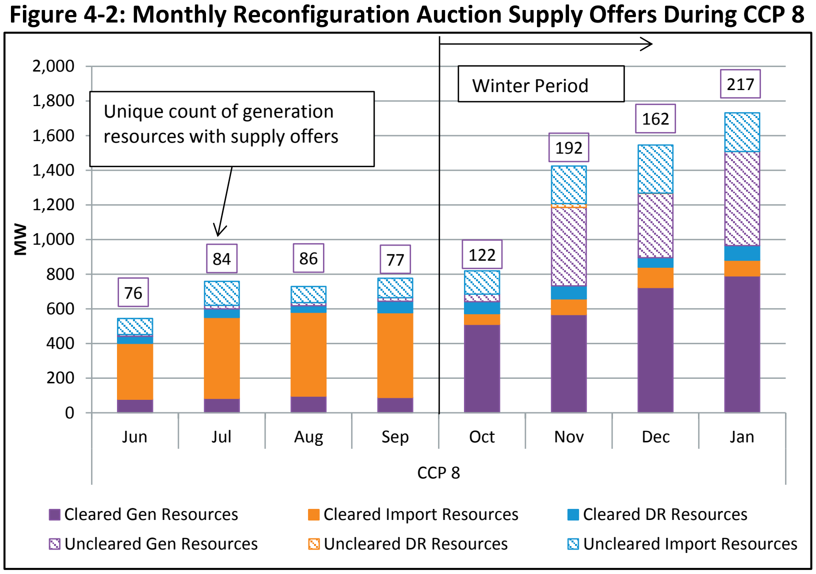
Table 4-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

FCA # (Commitment Period)	Auction Type	Period	System-Wide Price ($/kW-mo)**	Cleared MW	Capacity Zone/Interface Prices			
					NEMA /Bos	SEMA/RI	New Brunswick	New York AC Ties
FCA 8 (2017-18)	Primary	12-mo	15/7.03*	33,712	15/15*			
	Monthly Reconfiguration	Nov-17	1.3	733	3.51			
	Monthly Bilateral	Nov-17	4.17	269				
	Monthly Reconfiguration	Dec-17	1.4	895	3.51			
	Monthly Bilateral	Dec-17	3.12	333				
	Monthly Reconfiguration	Jan-18	0.99	965	1.65			
	Monthly Bilateral	Jan-18	4.20	462				

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

Over the course of Fall 2017, generation resources increased their CSOs through monthly reconfiguration auctions. Generators gain additional capacity due to increased generation capability during the winter period when ambient temperatures are colder.[26,27] This leads to increased participation and lower prices in the monthly auctions. Supply offers, segmented by resource type, for CCP 8 are shown in Figure 4-2. The solid bars represent cleared offers, while the stripped bars represent uncleared offers. Generator, import, and demand response resources are purple, orange, and blue, respectively. The purple text boxes represent the number of unique generator resources that offered supply into the monthly reconfiguration auction.

Figure 4-2: Monthly Reconfiguration Auction Supply Offers During CCP 8



[26] The summer capacity commitment period consists of June through September. This differs from the summer reporting period definition of June through August typically used in this report.

[27] The gain in capacity is simply the difference between their winter and summer qualified capacity.

The figure highlights increased cleared generation capacity in the winter period. Generator resources take advantage of their increased winter capability discussed in the paragraph above. An average of 173 generator resources participated during the winter period. This is more than double the average of 81 during the summer period. The average volume weighted Rest-of-Pool price in summer months was $4.46/kW-month. The average price declined to $1.68/kW-month during the winter period.

4.2 Financial Transmission Rights

Three monthly Financial Transmission Rights (FTR) auctions were conducted during the Fall 2017 reporting period for a combined total of 86,133 MW of FTR transactions. The total amount distributed to Auction Revenue Rights (ARR) holders was $2.5 million, which was a similar amount to the previous reporting period. Thirty-one bidders in September, thirty-one bidders in October and thirty-two bidders in November participated in the monthly auctions for the quarter. The level of participation was consistent with recent auctions.

Section 5
Participation of Multi-Stage Generators in the Energy Market

Eighteen combined cycle generators in the ISO New England system can operate in multiple configurations. In this section we refer to these generators as multi-stage generators. They consist of two or more gas turbines connected to a shared steam turbine. Fully accounting for the flexibility of multi-stage generators presents unique challenges from both a market and operational perspective. The ISO's market software currently cannot model all of the features of multi-stage generators. This raises concerns about over-committing certain generators (or "lumpy" commitments), excess Net Commitment-Period Compensation (NCPC) payments, and price distortion.

In 2006, the ISO established voluntary rules that allow multi-stage generators to be modeled as multiple *independent* assets in the energy market, according to their number of gas turbines. This approach is known as the Pseudo-Combined Cycle or "PCC" model. While it resolves some issues, such as lumpiness, it does not model the full flexibility of multi-stage generators. Notably, the PCC approach does not account for the time and costs of switching from one generator configuration to another. Moreover, because the PCC model is voluntary, not all multi-stage generators have implemented it.

In this section, we describe alternative multi-stage generator modeling techniques that have been adopted in other markets and that may improve price formation and operational efficiency. We also assess how the current modeling limitations may have impacted outcomes in the energy market. The assessment focuses on multi-stage generators that have not adopted the PCC rules and that were committed to meet local reliability needs; in other words, generators that faced limited competition when committed.[28] The impact assessment is limited to the day-ahead market, since most reliability commitments and NCPC payments to multi-stage generators occur in the day-ahead energy market.

The key findings are as follows:

- *When multi-stage generators offer at their highest-output configuration (maximum configuration[29]), excess NCPC costs may occur*

  Generators committed for local reliability don't typically recover their three-part offer price (start-up, no-load and energy) through the LMP and require NCPC payments to make them whole. Multi-stage generators tend to offer their maximum configuration, or maximum possible output, into the market, even though they could also operate under a configuration that uses only one turbine, or a "minimum configuration". When operators commit multi-stage generators at their maximum configurations, the generators incur higher commitment costs, which results in higher NCPC payments. These payments would decrease if ISO operators could

[28] We do not evaluate the impact on the market of multi-stage generators that have not adopted the PCC rules but offered and cleared in economic merit. Such an analysis would be very complex, requiring operational and commercial data on configuration transitions and modeling software capable of incorporating those inputs.

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

choose which generator configuration to commit, rather than committing the one configuration that the generator offered. We estimate that from 2015 through 2017, there were 37 reliability commitments of multi-stage generators on their maximum configurations, when the minimum configuration would have satisfied the local reliability need. This resulted in an estimated $6.1 million in additional NCPC payments to multi-stage generators.

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

  If the ISO commits multi-stage generators for reliability on their maximum configurations, and if a lower-output configuration would have satisfied the reliability need, then there is excess supply coming from multi-stage generators. In other words, it is producing energy that would otherwise be produced by a lower-cost generator. The generator is typically dispatched at the higher economic minimum associated with the maximum configuration. Generation at economic minimum does not have the ability to set price; it is treated as must-run or price-taking supply. This has a price-suppressing effect, which distorts market signals. For days with such reliability commitments, market simulation results showed that the average day-ahead Hub LMP would have been $1.22/MWh higher ($40.91 vs. $39.69) if multi-stage generators had offered the ISO more options (i.e., all of their configurations), rather than just their maximum configuration.

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

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

In its 2015 and 2016 Market Assessment Reports ISO-NE's external market monitor, Potomac Economics, raised concerns about this issue. It also found that in many cases multi-configurable generators would have satisfied the reliability requirement based on their minimum configurations. Similar to our findings outlined above and in the following sections, Potomac Economics raised issues of inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges. Potomac has recommended that the ISO expand its authority to commit combined-cycle units in a single turbine configuration when that will satisfy the reliability need.[30]

5.1 Multi-Stage Generators in the ISO New England System

Combined cycle generators consist of a gas turbine, plus a heat recovery steam generator (HRSG) that collects exhaust heat from the gas turbine. The HRSG produces steam, which is delivered to a steam turbine and converted into electricity. The addition of the steam turbine allows the generator to run more efficiently than "simple-cycle" plants, which operate with gas turbines only.

[30] See page 36 in Section III of the EMM's *2016 Assessment of the ISO New England Electricity Markets*: https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf

Some combined cycle plants have two or more gas turbines connected to the same steam turbine, which produces electricity with heat recovered from all connected gas turbines.[31] This type of resource is called a multi-stage combined cycle generator, as it has the ability to operate with one or multiple gas turbines turned on. We refer to a multi-stage generator operating with one gas turbine as a 1x1 configuration generator (i.e. one gas turbine plus the steam turbine). This configuration is typically associated with the lowest energy output of the generator (the "minimum configuration"). When a multi-stage generator operates with all gas turbines turned on, we refer to it as a "maximum configuration". The maximum configuration produces the highest energy output of all possible generator configurations. It will have higher economic maximum and economic minimum offer values.

For example, at its minimum configuration (1x1), a multi-stage generator operating with a single turbine might have an operable range of 150 to 300 MW. Operating at its 2x1 configuration, with 2 gas turbines plus the steam turbine producing energy (i.e., its maximum configuration), it can provide a range of 300 to 600 MW.

Quantifying Multi-Stage Generators

There are 48 combined cycle generators in the ISO-NE system. Of these generators, 18 are capable of operating in multiple configurations. When operating at their maximum configurations, the multi-stage generators have a combined Winter seasonal claimed capability (SCC) of 8,456 MW and a combined Summer SCC of 7,379 MW. Multi-stage generators account for a significant portion of total generation capacity on the system (around 25%). This figure will increase in the near future, as several planned combined cycle generators have cleared in recent forward capacity auctions. The combined capability of multi-stage generators by load zone is displayed in Table 5-1 below.

Table 5-1: Capacity of Combined Cycles in New England, by load zone (in MW)

Load Zone	Winter SCC	Summer SCC
Northeast Massachusetts	1,747	1,456
New Hampshire	1,413	1,229
Connecticut	1,256	1,152
Rhode Island	1,246	1,085
Southeastern Massachusetts	1,159	985
Maine	1,109	1,019
Western/Central Massachusetts	527	452
Total	**8,456**	**7,379**

The Northeast Massachusetts (NEMA/Boston) load zone has the highest capacity of multi-stage generation, followed by New Hampshire. The Western/Central Massachusetts load zone has the lowest generation capability from multi-stage generators.

[31] This analysis defines possible configurations of multi-stage generators as combinations of gas turbines working in conjunction with the steam turbine. It does not consider "open cycle" (operating with only gas turbines on and the steam turbine turned off) as a valid configuration. Few generators in New England consistently run in open cycle mode.

5.2 ISO New England's Pseudo-Combined Cycle Rules

To better reflect some of the characteristics of multi-stage generators, ISO-NE implemented Pseudo-Combined Cycle (PCC) rules in 2006. The PCC rules allow participants to *voluntarily* model multi-stage combined-cycle resources as multiple *independent* assets in the energy market. Each asset (pseudo-combined cycle asset) consists of one combustion turbine and a pro-rata portion of the steam turbine. Prior to 2006, multi-stage generators were modeled as a single asset, which ignored their ability to run with one or more gas turbines offline. The PCC rules make it possible for just one PCC asset to clear. The rules were intended to improve commitment flexibility and reduce the cost of reliability commitments when the generator is not needed at its maximum configuration.

A summary of the key characteristics of the PCC rules across three market areas is provided in Table 5-2 below.

Table 5-2: Summary of Pseudo-Combined Cycle Rules

Market Parameters	Settlement and Metering	Auditing
• Each PCC asset is modeled separately • Each asset has start-up, no-load, and energy offers along with corresponding reference prices used for market power mitigation purposes • Each asset has operational parameters and corresponding reference prices • Each gas turbine and corresponding steam turbine portion make up one aggregate p-node, where the market determines a cleared MW value and LMP	• Each PCC asset is metered separately • Markets settle at the PCC asset level[32] • PCC assets are required to have separate revenue quality metering • The steam turbine cannot be over- or under-allocated: power from the steam turbine must be equal to the power from the PCC assets, minus the power from the gas turbines	• Participants can submit ratios that the ISO will use to split the asset into separate PCC assets and calculate p-node factors[33] • The ISO may reject submitted ratios if they are unrealistic • At the time of the next SCC audit, PCC assets that share a steam turbine must establish capability based on simultaneous audits • PCC assets that share a steam turbine must be tested at the same time to avoid double counting the output of the steam turbine during SCC tests

Of the eighteen multi-stage generators in the market, seven have opted to be treated as PCC generators. The seven generators comprise fifteen PCC assets. These generators have a combined Winter SCC of 3,436 MW, and a combined Summer SCC of 3,030 MW. The combined SCC of PCC assets only represents 41% of the capability of all multi-stage generators in the system. Thus, there is a significant amount of multi-stage generation that has not opted to use the PCC rules.

[32] With the exception of the Forward Capacity Market, which is settled at the resource level.

[33] The p-node factors are ratios defined for the physical components (i.e. the gas and steam turbines) of PCC assets. These ratios are used to calculate LMPs for PCC assets.

5.3 Multi-Stage Generator Modeling at Other ISOs/RTOs:

The pseudo-combined cycle approach is not the only model in use in other markets. Table 5-3 provides an overview of various approaches adopted by other ISOs/RTOs to modeling multi-stage generators. Note that there may still be differences in models even if the ISO/RTO is in the same category, but the general approaches are the same:

- Pseudo-combined cycle rules: split up a generator based on its number of GTs and model each as independent assets.
- Multi-configuration combined cycle rules: model specific configurations and sometimes account for dependencies (transitions) between them.

Table 5-3: Multi-Stage Generator Modeling at all U.S. ISOs/RTOs

ISO/RTO	ISO-NE	NYISO	PJM	MISO	CAISO	SPP	ERCOT
Pseudo-Combined Cycle Rules	☑	☑	☒	☒	☒	☑	☒
Multi-Configuration Resource Rules	☒	☒	☒	☒	☑	☑	☑
Voluntary	☑	☑			☒	☑	☑
Max. # of configurations modeled in DAM and RTM					No limit	3	No limit
Supply Offers per configuration					☑	☑	☑
Reference levels per configuration					☑	☑	☑
Transition costs defined					☑	☑	☒
Operational constraints for transitions					☑	☑	Some

ISO-NE and NYISO both use pseudo-combined cycle rules, which do not model specific configurations. MISO does not currently use pseudo-combined cycle or multi-configuration resource rules, but they are in the process of implementing an enhancement that will make their approach similar to that of ERCOT, CAISO, and SPP. PJM is currently considering different modeling options.

The multi-configuration resource approach models attributes of multi-stage generators more precisely than ISO-NE's current method. CAISO, SPP, and ERCOT model each configuration within a multi-stage generator. Costs and operational parameters are defined for transitions between generator configurations at CAISO and SPP. SPP also defines certain parameters (such as minimum run time) at both the plant and configuration level. ERCOT determines whether multi-stage generators can start up or shut down in each configuration, but they do not collect information on additional transition attributes, such as transition times and costs. At CAISO and ERCOT, there is no limit to the number of registered configurations. At SPP, multi-stage units can register up to three configurations.

5.4 Limitations of ISO New England's Current Approach

Pseudo-combined cycle modeling gives operators and participants some additional flexibility in commitment, because they can choose to commit one or all PCC assets. This is an improvement over situations where operators only have the option of committing all turbines of a multi-stage generator. However, the approach has several limitations.

First, pseudo-combined cycle modeling is voluntary; generators do not have to implement it. Multi-stage generators that have not split into PCC assets still only offer one set of operational parameters into the market. The ISO can only commit these generators at their offered configuration (typically the maximum configuration). This may not be the optimal configuration from a market perspective, particularly when the generator is committed for local reliability reasons. In this circumstance, the commitment can result in the following problems:

- Additional online capacity and output at the higher economic maximum and minimum levels associated with the maximum configuration
- Additional production costs
- Suppressed consumer costs (lower LMPs) since the additional output at economic minimum cannot set price

There are also market power concerns with multi-stage generators needed for reliability in import-constrained areas. These units may offer at their maximum configurations because they have an incentive to increase their productions costs and margin before mitigation is applied. For reliability commitments, offers that are 10% above cost are mitigated. For example, if a generator's commitment cost is $100,000 for a 1x1 configuration, they can offer up to $110,000 without facing mitigation. If the generator offers its maximum configuration, and says its costs are $200,000, it can offer up to $220,000 before mitigation is applied. Thus, offering the maximum configuration allows the generator to increase the mark-up on the offer from $10,000 to $20,000.

Even when generators do follow the pseudo-combined cycle rules, the approach ignores important attributes of multi-stage generators. It does not consider the time and cost of transitioning from one configuration to another. Since the approach does not model relationships between PCC assets, generators may have to manage operational constraints through self-commitment and interactions with the control room. Otherwise, the PCC assets may be scheduled by the market software in a way that is operationally infeasible in practice. These are imperfect and manual solutions that could be improved with market software enhancements.

Additionally, dividing a multi-stage generator into PCC assets does not have all the benefits of modeling each configuration. Multi-configuration resource models such as those used by CAISO, SPP, and ERCOT are more precise. They allow the market to select specific combinations of turbines to run in each multi-stage generator. This adds increased flexibility in economic and reliability commitment decisions. Implementing a similar model at ISO-NE would require significant enhancements to the current market software.

5.5 The Additional Costs of Multi-Stage Generator Commitment

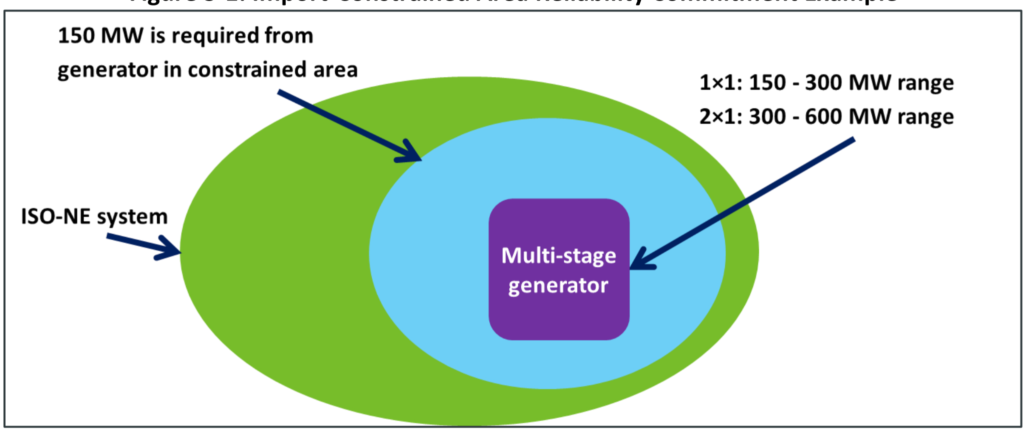
To determine how multi-stage generators affect market outcomes, we measured the additional NCPC costs that arise when participants receive reliability payments for assets committed at their maximum configurations, when a minimum configuration would have satisfied the associated reliability need. In these cases, operators committed generators at their maximum configurations because that was the only configuration the generator offered into the market.

In most cases, reliability commitments arise when the system needs generation to meet minimum capacity requirements.[34] The market software activates minimum capacity requirements to help ensure reliability in import-constrained areas by meeting local contingency requirements. This requirement specifies the number of megawatts that must come from online generators within a particular constrained area.[35] When determining whether a maximum configuration was necessary for reliability, this analysis considered minimum capacity requirement values and the capacity of on-line generators in the constrained area.

Example

To illustrate how additional NCPC costs occur, Figure 5-1 provides a simplified example of a multi-stage generator commitment in an import-constrained area.

Figure 5-1: Import-Constrained Area Reliability Commitment Example



Here, all other generators in economic merit within the constrained area have been committed and dispatched. For reliability reasons, the system needs another 150 MW from an out-of-merit multi-stage generator in the area.

At its minimum configuration (1x1), the multi-stage generator can provide a range of 150 to 300 MW. It can also operate in a 2x1 configuration, with 2 gas turbines plus the steam turbine producing energy. This is the generator's maximum configuration, where it can provide a range of 300 to 600 MW. Ideally, the multi-stage generator would be committed at its minimum (1x1) configuration. Its maximum output would total 300 MW, thereby meeting the minimum capacity requirement with a surplus of online capacity of 150 MW.

The problem is that if the multi-stage generator only offers its maximum (2x1) configuration, there is no choice but to commit it. In this case, the output from the generator must be at least 300 MW (its economic minimum as a 2x1), which is higher than it would have been at its minimum

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[34] The costs associated with other reliability commitments such as voltage support to multi-stage generators were relatively small over the study period and therefore were not included in our analysis.

[35] The minimum capacity requirement is met by the economic maximum values of online generators within the import-constrained area.

configuration. Therefore there is an excess of on-line generation in the area, since only 150 MW is required from the multi-stage generator. It is providing 600 MW of on-line capacity, 450 MW in excess of the required 150 MW.

Table 5-4 below illustrates how this commitment leads to additional NCPC payments.

Table 5-4: Additional NCPC Costs Example[36]

Configuration	MW at Ecomin	Commitment Cost	LMP Revenue	NCPC Credit
Highest-output	300	$230,000	$180,000	$50,000
Lowest-output	150	$115,000	$90,000	$25,000

At its maximum configuration, the multi-stage generator has commitment costs of $230k over its minimum run time. At the minimum configuration, its commitment costs are half that, at $115k. Assuming an LMP of $50/MWh, the multi-stage generator requires NCPC payments to recover its commitment costs. When the generator is committed at its maximum configuration, it receives $50k in NCPC payments, compared to only $25k at its minimum configuration. Thus, the generator receives an additional $25,000 in NCPC payments as a result of being committed at its maximum configuration.

Methodology

The simplified example illustrates how this analysis calculates excess NCPC payments to multi-stage generators. First, we consider instances where multi-stage generators were committed for reliability at their maximum configurations during a three-year period, from 2015 through 2017. We then establish whether it was necessary to commit the generator at its maximum configuration, given the minimum capacity requirement and the capability of other on-line generators in the relevant import-constrained area. If the minimum capacity requirement would have been satisfied by the minimum configuration of a multi-stage generator plus the combined capability of other on-line generators in the area, then committing the maximum configuration was not necessary.

For instances where the maximum configuration commitment was not necessary, commitment costs for a counterfactual scenario are calculated. In this alternate scenario, multi-stage generators are committed at their lowest-output configurations. The total NCPC payments that result in the counterfactual scenario are compared to actual NCPC payments.[37] The difference between the payments is the additional cost associated with committing multi-stage generators at their maximum configurations. The cost savings are totaled for every instance in the study period.

The analysis is intended to show the general effect that maximum configuration multi-stage generator commitments can have on NCPC payments. We do not re-optimize the market or calculate new LMPs for the counterfactual scenario presented here. The simulation discussed in Section 5.6 shows the impact of multi-stage generator commitments on LMPs.

[36] The example relies on number high-level assumptions: a gas price of $5/MMBtu, LMP of $50/MWh, Minimum Run Time of 12 hrs, and heat rates and variable costs reflective of a "typical" 2x1 combined cycle gas turbine.

[37] LMP revenue under both scenarios is based on actual LMP. In other words, the alternate does not recalculate the LMP based on reduced output associated with the minimum configuration. As described in section 5.6, if the impact on the LMP was considered, then the LMP would be higher and NCPC would be lower in the alternate scenario.

Results

Actual NCPC payments to multi-stage generators and alternate scenario payments are shown in Table 5-5 below.

Table 5-5: Additional NCPC Payments from Multi-Stage Generator Commitments ($ millions)

	Actual	Alternate Scenario	Difference
Commitment Costs	$64.1	$52.1	**$12.0**
LMP Revenue	$34.6	$28.7	**$5.9**
NCPC Credits Paid	**$29.5**	**$23.4**	**$6.1**

From January 2015 through December 2017, multi-stage generators received a total of $29.5 million in reliability NCPC payments in the day-ahead market. On 37 days over the study period, NCPC was paid to generators that were operating at their maximum configurations, even though a lower-output configuration would have been sufficient to resolve the reliability problem. In the alternate scenario in which multi-stage generators ran at lower-output configurations when sufficient, commitment costs were lower. This resulted in lower NCPC payments of $23.4 million. Thus, if operators had the option of committing multi-stage generators at lower-output configurations, NCPC payments would decrease by an estimated $6.1 million.

We estimate that the excess generation capacity as a result of inflexible multi-stage generator offers totaled 220.8 GW.[38] Therefore, these units received additional NCPC payments equivalent to $27.63 per MW of capacity that was not needed to satisfy the reliability need.

5.6 How Multi-Stage Generators Affect LMPs: Market Simulation Results

To determine how multi-stage generators impact prices, the day-ahead market clearing was simulated[39] for two different scenarios:

- Scenario 1 is the base case, which produces results similar to what actually occurred in the day-ahead market.[40]
- Scenario 2 is a counterfactual scenario that splits multi-stage generators into separate units, depending on their number of gas turbines. Its purpose is to show how the day-ahead market would clear if operators could choose which configurations to commit, rather than having the maximum configuration as the only available option.

Simulations were run for both scenarios for days when the market software committed multi-stage generators at their maximum configurations, even though a lower-output configuration would have

[38] This is measured as the economic maximum of the maximum configuration minus the economic maximum of the minimum configuration over the duration of the commitment.

[39] 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_ISO.html.

[40] The simulations used for both the base case and counterfactual scenario are subject to modeling differences when compared to the market model the ISO runs for the day-ahead market. We compare the counterfactual results to a base case simulation (which uses actual supply offers) rather than the actual market results to account for these modeling differences.

satisfied the reliability need. The differences between the market results of the two scenarios illustrate how multi-stage generator commitments potentially distort prices.

Table 5-6: Market Simulation Results

	Base Case Simulation	Alternate Scenario Simulation	Difference
Avg. Hub LMP	$39.69	$40.91	$1.22
Avg. import-constrained Load Zone LMP	$40.50	$44.05	$3.55

In the base case simulation, the average Hub LMP over the 37 days was $39.69/MWh. In the alternate scenario, the average Hub LMP was $40.91/MWh, an increase of $1.22/MWh, or just 3%. The price-suppressing effect was more notable in load zones where multi-stage generators were committed at their maximum configuration unnecessarily. In load zones where this occurred, day-ahead prices averaged $3.55/MWh, or 9% higher ($44.05 compared to $40.50/MWh) in the alternate scenario where the minimum configuration would have satisfied the reliability need.

The results suggest that the reliability commitments of multi-stage generators that are not modeled as PCC assets can depress energy prices.

As a result of higher LMPs, payments to all supply increased by 3.1% ($15.5 million) in the alternate scenario. This increase would be partially offset by a $7.4 million[41] decrease in NCPC payments.

5.7 Conclusions and Recommendations

Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are:

- *Expanding the current pseudo-combined cycle rules*

Participants currently have the option to register multi-stage generators as pseudo-combined cycle assets. The ISO should evaluate making this a mandatory requirement. Though this approach fails to account for the relationship between operating configurations, it will give ISO operators the option of committing generators at minimum configurations when necessary, which will result in more efficient market outcomes.

- *Adopt multi-configuration resource rules*

The IMM recommends that the ISO consider enhancements to multi-stage generator modeling and market rules. This approach accounts for more of the complexities of multi-stage generators compared to the current pseudo-combined cycles rules. It models each configuration and the relationships between generator configurations. Several other ISOs/RTOs have either implemented this model or are considering making the enhancement. Though adopting a multi-configuration

[41] The simulation results showed a $7.4 million decrease in NCPC payments to multi-stage generators in the alternate scenario. This is slightly higher than the $6.1 million decrease calculated in the previous section, without the simulation. This is to be expected since the $6.1 million estimate did not account for the higher LMP as a result of committing the multi-stage generators at the minimum configuration.

resource model would help address the market concerns outlined in this report, the costs in terms of software enhancements and additional market rules and operational complexity would need to be considered.