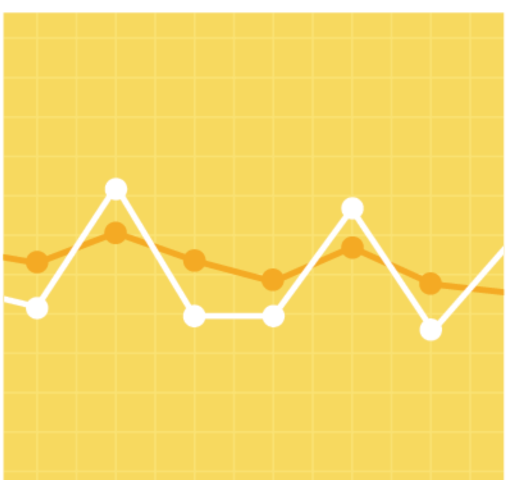
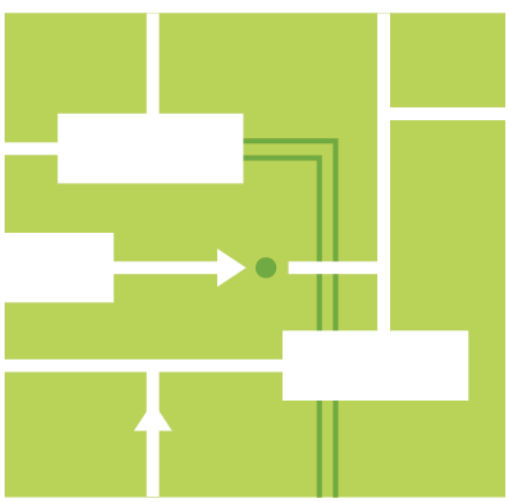
Summer 2020 Quarterly Markets Report

By ISO New England's Internal Market Monitor

NOVEMBER 11, 2020





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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.

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Summer 2020 (June 1, 2020 through September 30, 2020).[3]

DNE Wind Generator Must-Offer Compliance: We update an earlier review on the performance of do-not-exceed (DNE) wind generators. The previous review examined offer behavior after a June 2019 market rule change, which required DNE generators with capacity supply obligations (CSOs) to offer the full hourly amount of expected real-time generation into the day-ahead market.[4]

The updated review finds that the day-ahead market offer behavior of DNE wind generators with CSOs is consistent with the applicable Tariff requirement. The day-ahead market offers typically indicate the expected energy during peak real-time production hours, but tend to overstate available wind energy during non-peak production hours. However, the energy offered in the day-ahead market in excess of real-time production levels is offered at prices that are unlikely to clear in that market. In the real-time market, offer prices are reduced to ensure the clearing of available wind energy.

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.48 billion, down 15% from $1.74 billion in Summer 2019. The decrease was driven by lower energy and capacity costs.

Energy costs totaled $849 million; down 12% (or $120 million) from Summer 2019 costs. Lower energy costs were a result of lower natural gas prices. In Summer 2020, gas prices decreased by 25% compared to Summer 2019 prices.

Capacity costs totaled $603 million, down 19% (by $143 million) from last summer. Beginning in Summer 2020, lower capacity clearing prices from the eleventh Forward Capacity Auction (FCA 11) contributed to lower wholesale costs relative to the previous summer. Last summer, the capacity payment rate for new and existing resources was $7.03/kW-month. This summer, the payment rate was lower, at $5.30/kW-month. The lower clearing prices caused capacity costs to decrease.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $22.50 and $22.52 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 10-13% lower than Summer 2019 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $1.62/MMBtu in Summer 2020, a decrease of 25% compared to $2.17/MMBtu in the prior summer.

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

[4] See the Summer 2019, Quarterly Markets Report, Section 5.2.

- The downward impact of lower gas prices on energy prices was partially offset by higher loads in Summer 2020. Hourly load averaged 15,199 MW, up by 2% (≈ 230 MW) on the previous summer. The increase was driven by warmer weather.
- Energy market prices did not differ significantly among the load zones.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $7.0 million, an increase of $0.3 million compared to Summer 2019. NCPC remained relatively low when expressed as a percentage of total energy payments, at under 1%. The majority of NCPC (81%) was for first contingency protection (also known as "economic" NCPC). Summer 2020 economic payments increased by 46% compared to Summer 2019 payments. Most of these payments occurred in the real-time market.

At $0.9 million, local second-contingency protection reliability (LSCPR) payments accounted for 13% of total NCPC payments. These payments decreased by $1.3 million relative to Summer 2019 payments. The majority (91%) of Summer 2020 LSCPR payments went to generators located in Maine and NEMA/Boston, which were committed to support planned transmission line outages.

Real-time Reserves: Real-time reserve payments totaled $4.4 million, a $1.8 million increase from $2.6 million in Summer 2019. The increase was driven by larger ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) payments, which rose by $847 thousand and $437 thousand, respectively. Non-spinning reserve payments occurred on multiple days when system conditions were tight due to factors such as load forecast error and generator trips.

The average non-zero spinning reserve price decreased relative to Summer 2019, from $9.81 to $6.96/MWh. The frequency of non-zero spinning reserve prices increased to 506 hours from 365 hours. This increase in frequency, which was driven by the aforementioned days with tight system conditions, was the primary reason for the increase in real-time reserve payments in Summer 2020.

Regulation: Regulation market payments totaled $6.4 million, up 11% from $5.8 million in Summer 2019. This increase reflected higher regulation capacity requirements, along with an increase in service offer costs.

Financial Transmission Rights: The volume of FTR transactions that cleared in the three prompt-month auctions for July, August, and September 2020 ranged from 19,760 MW to 21,391 MW. The cleared volumes were moderately higher compared to other recent prompt-month auctions, while the level of participation was slightly lower. The decreased number of bidders may have reflected participants' expectations of reduced congestion in the day-ahead market during the summer months, as there tend to be fewer significant transmission outages during this period. The total auction revenue for the prompt-month auctions that were conducted in Summer 2020 was $0.7 million, which was lower than the revenue for the prompt-month auctions held in Spring 2020 ($1.2 million) and Summer 2019 ($2.5 million).

The volume of FTR transactions that cleared in the out-month auctions for August 2020 through December 2020 was low, ranging from 1,136 MW to 2,040 MW per month. The number of participants in the out-month auctions that occurred in Summer 2020 ranged from 10 to 15, which is about one-third to one-half of the level of participation seen in the prompt-month auctions. The total auction revenue of the out-month auctions conducted in Summer 2020 was just $14 thousand.

Winter 2020/21 Forward Reserve Market Auction: In August 2020, the ISO held the forward reserve auction for the Winter 2020-2021 delivery period (October 1, 2020 to May 31, 2021). System-wide supply offers in the Winter 2020-2021 auction exceeded the requirements for both ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR), and there were no pivotal suppliers.

The net clearing prices for offline system thirty- and ten-minute reserves were $540 and $678 per megawatt-month (MW-month), respectively. This was lower than the Winter 2019-2020 auction clearing prices, which were $799/MW-month for both products.

Section 2
Special Topic: DNE Wind Generator Must-Offer Compliance

In this section, we update an earlier review of the performance of do-not-exceed (DNE) wind generators.[5] That review examined the change in offer behavior of DNE wind generators prior to and after a market rule change implemented in June 2019.[6] With the benefit of a further year's data and experience, and based on questions from participants, we are providing this follow-up analysis.

The market rule change required DNE generators with capacity supply obligations (CSOs) to offer the full hourly amount of expected real-time generation into the day-ahead market (DAM); the change aligned the "must-offer" obligations for DNE generators with CSOs, with the must-offer requirements for other types of dispatchable generators.[7] Because only generators with CSOs were affected by the rule change, this review focuses solely on wind generators with CSOs.

Wind generation comprises a relatively small share of total supply to meet New England's energy and capacity needs, supplying about 3% of total energy and about 1% of capacity in 2019.[8] However, on- and off-shore wind generation represents more than two thirds of new supply in the ISO interconnection queue, totaling nearly 14,300 MW.[9] Therefore, while the impact of wind generation participation on energy market outcomes is somewhat muted by its small relative share of the supply mix, that impact has the potential to become more significant in future years.

Wind Generator Energy Market Offers

Previously, we reviewed three aspects of DNE wind generator offers, given the change in the market requirement to offer expected wind energy in the DAM: (1) total energy offered in the DAM by these generators,(2) DAM energy offers relative to actual energy provided by these generators, and (3) the impact on DAM clearing. The earlier review covered the initial three months after the implementation of the must-offer requirement (i.e., June to August 2019); this update addresses each of these areas through August 2020.

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[5] The DNE dispatch instruction specifies a maximum generation level for the DNE generator, and the ISO expects that the generator's output will not exceed that level. The 2016 DNE changes incorporated intermittent wind and hydro resources into the economic dispatch and pricing software. Rather than manually curtailing wind generators to manage congestion, the changes provided a market solution to this reliability issue and allowed congestion to be reflected in real-time prices. See ISO New England's Tariff change request, RE: ISO New England Inc. and New England Power Pool, Docket No. ER15--000, Do Not Exceed ("DNE") Dispatch Changes (filed with FERC on April 15, 2015).

[6] See the Summer 2019, Quarterly Markets Report, Section 5.2.

[7] The ISO's Tariff at section at III.13.6.1.6.1, Energy Market Offer Requirements, indicates: "Beginning on June 1, 2019, Market Participants with DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource."

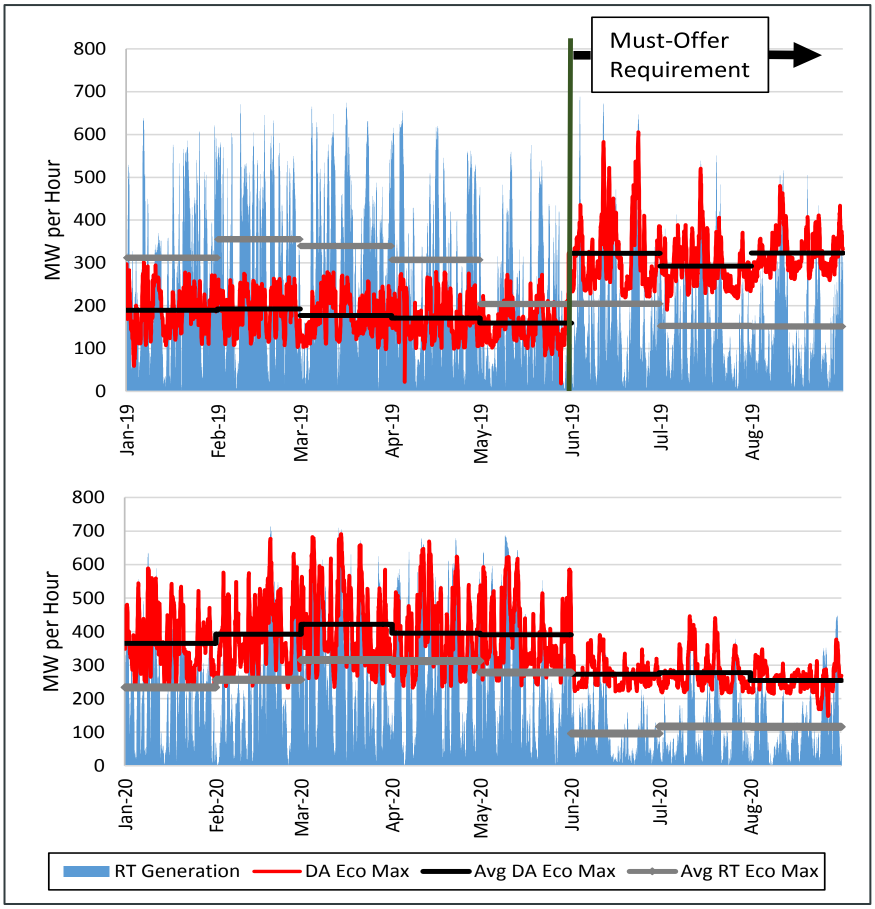
[8] Annual Markets Report 2019 by the Internal Market Monitor.

[9] 2020 Regional Electricity Outlook by ISO New England.

Day-Ahead offered capacity reflects real-time peak energy production

Consistent with our previous review, the DAM energy offers for wind generators with CSOs continue to reflect peak energy production in the real-time energy market.[10] Figure 2-1 shows DAM offers and real-time energy production of DNE wind generators with CSOs.[11]

Figure 2-1: DNE Wind Generator DAM Offers and Actual Production[12]



With the implementation of the revised DAM offer requirements in June 2019, DAM offers increased from an average of approximately 180 MW per hour (January to May 2019) to slightly

[10] Because the revised must-offer requirement only applies to wind generators with CSO, these data exclude any DAM offers from wind generators without CSOs. Over the review period, assets mapped to resources with CSOs have ranged from 33% to 49% of wind DNE assets and have averaged 45% of DNE assets. Wind generators with CSOs accounted for approximately 59% of the total wind energy produced by DNE wind generators during the review period.

[11] The "eco max" values shown in the graph represent the offered economic maximum values for the day-ahead energy market and the ISO's 15-minute forecast values for wind energy for these assets in the real-time energy market.

[12] Data for September to December 2019 are omitted in the graphs to enhance legibility; the values for those months exhibit the same trends as shown for June to August 2019 and January to August 2020, with average DAM-offered generation exceeding 300 MW per hour.

more than 300 MW per hour for the June to August 2019 period.[13] DAM-offered generation increased in the months of January to May 2020, with an average of almost 400 MW per hour. The reduction in DAM-offered wind energy for June to August 2020 (average offered MWs per hour equaling approximately 270) reflects two factors: lower expected real-time production levels and the shedding of CSO by some wind generators during this period that reflects lower expected energy output during the summer months.

The monthly average real-time energy market economic maximum (eco max) data in the chart are the wind forecast data for these generators 15 minutes prior to dispatch.[14] The forecast data represent the potential production levels for these generators, based on weather conditions at a wind generator's location. These data indicate that, prior to the "must-offer" requirement, day-ahead energy offers tended to be much less than the potential energy available to these generators in the real-time market. From January 2019 through May 2019, day-ahead eco max offers averaged approximately 125 MW less than the expected real-time potential production; only in May 2019 were the offered day-ahead eco max values somewhat close to the potential energy production, with the gap narrowing to an average of 45 MW.

With the implementation of the must-offer requirement, the trend reversed, with day-ahead eco max offers, on average, significantly exceeding potential production levels; from June 2019 through August 2020, day-ahead eco max offers averaged approximately 120 MW greater than potential real-time production levels. As the hourly offer and generation data in the chart suggest, the change results from day-ahead offers reasonably predicting real-time peak production levels, but significantly over-estimating the amount of potential energy available in the non-peak production hours.

Day-Ahead cleared volumes have increased as a percentage of real-time production

An examination of the energy clearing in the day-ahead market, however, does not indicate that the much higher levels of offered generation in the day-ahead market result in energy clearing in excess of real-time production levels. Figure 2-2 displays DAM-cleared offers and real-time production levels; it also provides an indication of the amount of DAM-cleared energy that occurred, given offer pricing below and above \$0/MWh.[15]

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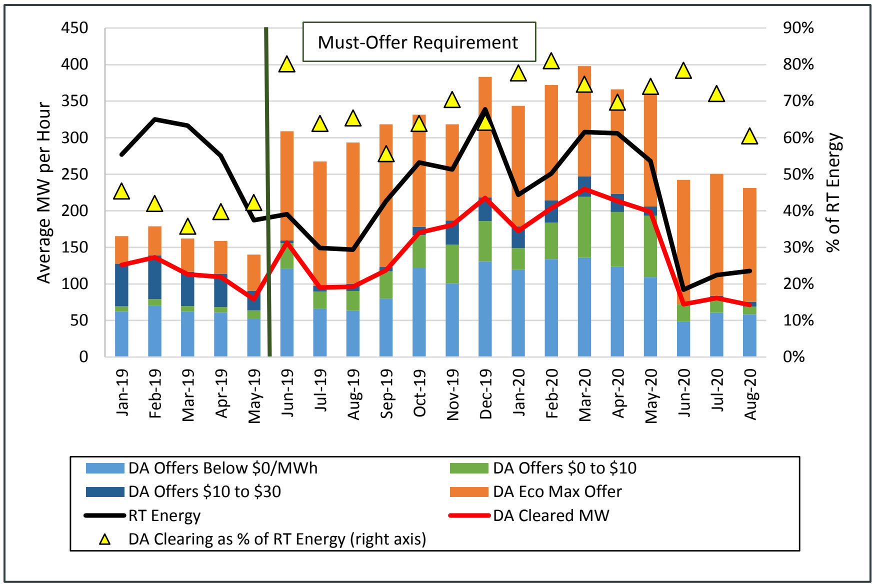
[13] Note that these DAM offer data do not reflect maximum daily energy (MDE) limits. An MDE limits the total available energy offer for a generator in the DAM; the MDE does not specify a limit for a particular hour. As a consequence, any limitation of the offer data in a particular hour to reflect an MDE would distort the hourly offer values. The monthly averages for the hourly values also do not reflect MDE limitations. The MDE reductions in available energy, compared to the offered economic maximum values, equaled approximately 7% over the review period; the highest monthly reduction in offered energy as a result of the MDE constraint equaled 13%.

[14] The 15-minute forecast values represent unconstrained potential wind production: that is, wind production that is not constrained by transmission limits or other factors. These values may also be affected by forecast error. The real-time generation data reflect all operating constraints for these wind generators. As long as the wind forecast data are not significantly biased downward, we would expect the forecast values to be higher on average than the actual delivered energy.

[15] The monthly summary offer values included in this graph have been adjusted to account for MDE values.

Figure 2-2: DAM Offers and Cleared Energy

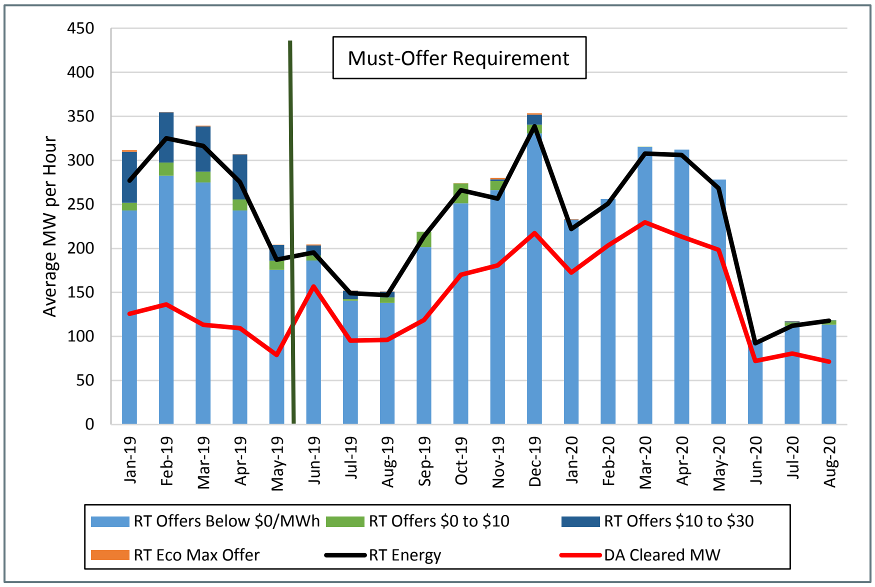


Over the review period, wind generators with CSOs significantly increased DAM offers and cleared energy with the implementation of the must-offer requirement; however, the cleared energy was still significantly below real-time energy market production levels. Over the months of January to May 2019, day-ahead cleared offers (right axis) represented 36% to 45% (average of 41%) of real-time energy production. Since the June 2019 rule change, DAM-cleared offers have represented 56% (September 2019) to 81% (February 2020) of real-time energy production, and have averaged 70%.

While much of the day-ahead cleared generation has occurred at offer levels below $0/MWh, a significant portion of the DAM-cleared offers also have been priced above $0/MWh. From January 2019 to May 2019, cleared energy offers priced above $0/MWh constituted approximately 44% of DAM-cleared offers. Beginning with June 2019, approximately 33% of DAM-cleared offers were priced above $0/MWh (ranging from a monthly low of 18% to a high of 45%). Almost all of the DAM-cleared energy has been priced at less than $30/MWh. Although significantly more wind energy has been offered in the DAM, offers above $30/MWh (which are unlikely to clear given typical day-ahead LMPs) increased by 161 MW on average starting in June 2019, compared to 41 MW in the January to May 2019 period.

In the real-time market, wind generator offers are priced to ensure that most available wind energy will be dispatched. Figure 2-3 indicates the average monthly offer pricing and actual generation (compared to cleared day-ahead generation) for the real-time energy market.

Figure 2-3: Real-time Offers and Cleared Energy



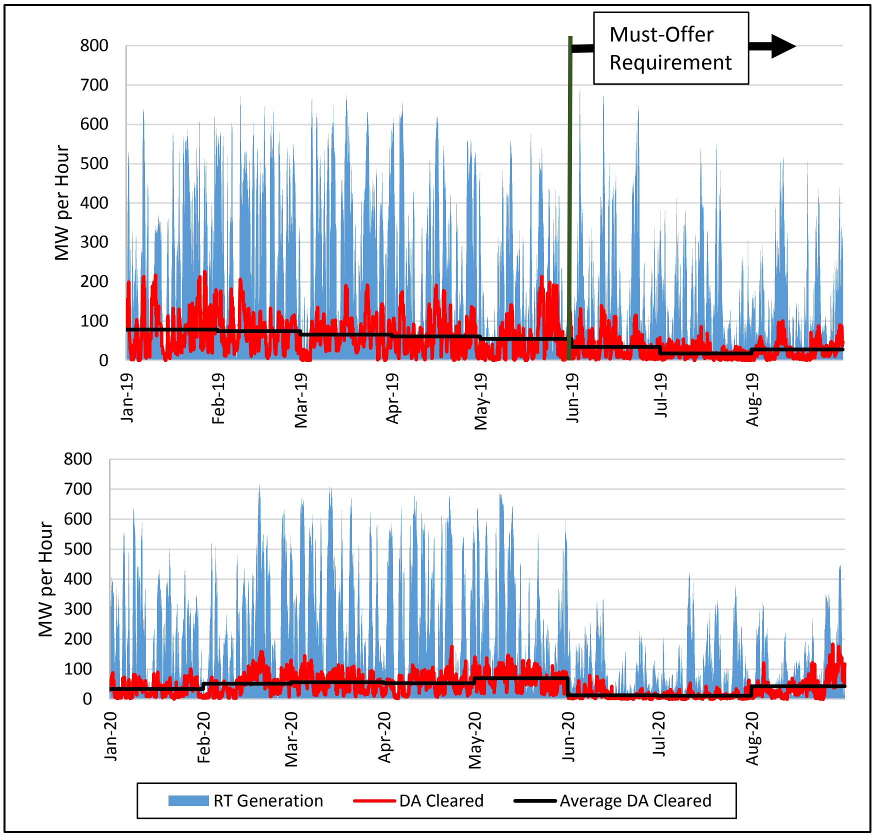
As depicted in the figure, almost all of the wind energy offered in the real-time market occurs at offer prices less than $0/MWh. The percentage of wind generation clearing in the real-time market at less than $0/MWh has ranged from 87% to 100%. While more energy was offered in the real-time market at prices above $0/MWh prior to the must-offer requirement, it is not clear that the must-offer requirement led to this change in offer behavior. The must-offer requirement only affected day-ahead offers; the change in real-time offer behavior is likely reflective of changes in production risks and opportunities in the real-time energy market.

In summary, DNE wind generators with CSOs have continued to offer into the day-ahead energy market consistent with the Tariff requirement: "[to] submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability…." The day-ahead market offers tend to indicate the expected energy during the peak real-time production hours and to overstate available wind energy during the non-peak production hours. However, the energy offered in the day-ahead market in excess of real-time production levels is offered at prices that are unlikely to clear in that market. In the real-time market, offer prices are reduced to ensure the clearing of available wind energy.

The role of virtual supply in filling the day-ahead to real-time energy gap has diminished

We also reviewed virtual bidding behavior at the pricing nodes for these generators. Figure 2-4 shows the hourly level (red) and monthly average (black) of cleared virtual supply at the applicable wind generator pricing nodes relative to the actual production of those wind generators in the real-time (blue).

Figure 2-4: Virtual Supply and Real-Time Wind Generation



The amount of cleared virtual supply at the DNE wind generators with CSOs remains lower than the levels prior to the June 2019 market rule change. From January 2019 to May 2019 participants cleared an average of 67 MW per hour compared to 40 MW per hour since the beginning of June 2019. More tellingly, virtual supply decreased when expressed as a percent of real-time wind generation. In the five months prior to the implementation of DNE offer requirements, virtual supply cleared an average of 24% of real-time wind generation at the same pnodes compared to 18% in the 15 months (June 2019 to August 2020) since the market rule change. The reduction in the clearing of virtual supply is consistent with the increased clearing of physical supply in the day-ahead energy market by these wind generators, after the implementation of the market rule change. The higher levels of virtual clearing prior to the June 2019 rule change helped improve real-time commitment by providing an improved indication of expected wind energy supply in the day-ahead energy market.

Section 3
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 3-1 below.

Table 3-1: High-level Market Statistics

Market Statistics	Summer 2020	Spring 2020	Summer 2020 vs Spring 2020 (% Change)	Summer 2019	Summer 2020 vs Summer 2019 (% Change)
Real-Time Load (GWh)	33,558	25,715	31%	33,049	2%
Peak Real-Time Load (MW)	25,056	16,596	51%	24,361	3%
Average Day-Ahead Hub LMP ($/MWh)	$22.50	$17.33	30%	$25.89	-13%
Average Real-Time Hub LMP ($/MWh)	$22.52	$17.62	28%	$25.09	-10%
Average Natural Gas Price ($/MMBtu)	$1.62	$1.61	1%	$2.17	-25%
Average Oil Price ($/MMBtu)	$7.91	$5.71	38%	$12.08	-35%

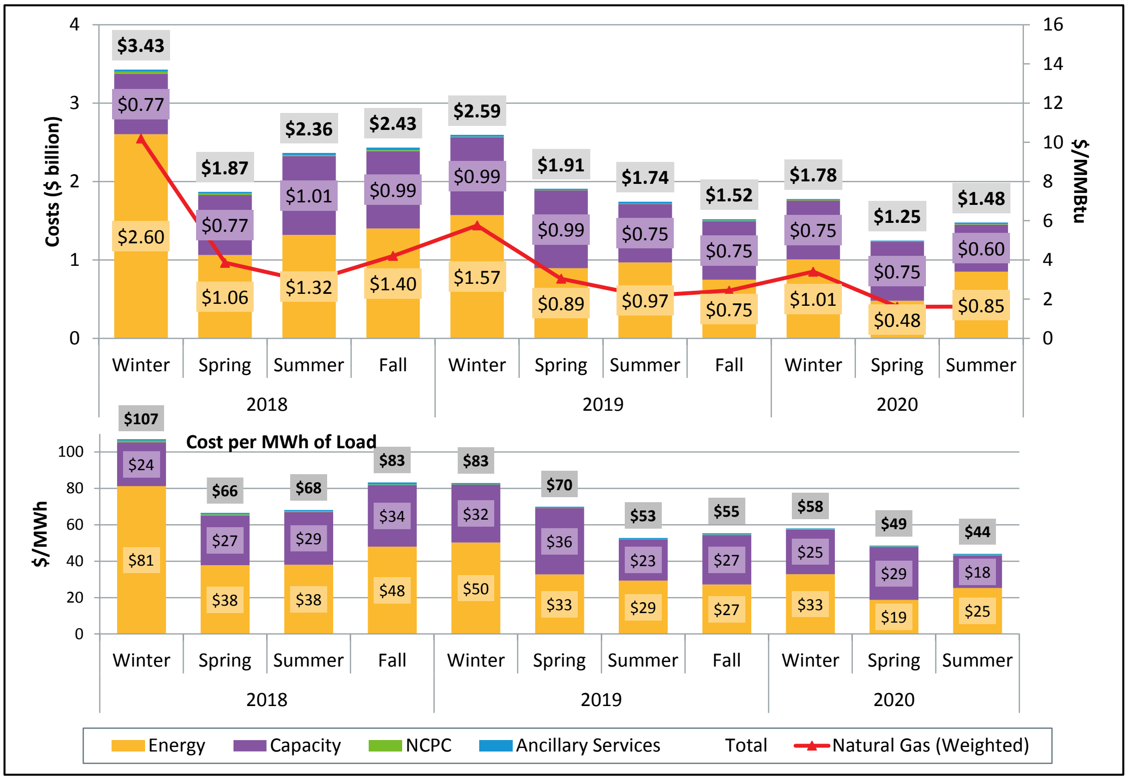
To summarize the table above:

- Average day-ahead LMPs in Summer 2020 were $22.50/MWh, 13% lower than in Summer 2019. Lower gas prices in Summer 2020 ($1.62/MMBtu) compared to Summer 2019 ($2.17/MMBtu) put downward pressure on LMPs.
- Total load in Summer 2020 (33,558 GWh, or an average of 15,199 MW per hour) was 2% higher than in Summer 2019 (33,049 GWh). This was driven by slightly warmer temperatures compared to Summer 2019, which is described in Section 3.1 below.

3.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in \$/MMBtu) is shown in Figure 3-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served.[16,17]

Figure 3-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Summer 2020, the total estimated wholesale cost of electricity was \$1.48 billion (or \$44/MWh of load), a 15% decrease compared to \$1.74 billion in Summer 2019, and an increase of 18% over the previous quarter (Spring 2020). Natural gas prices continued to be a key driver of energy prices.

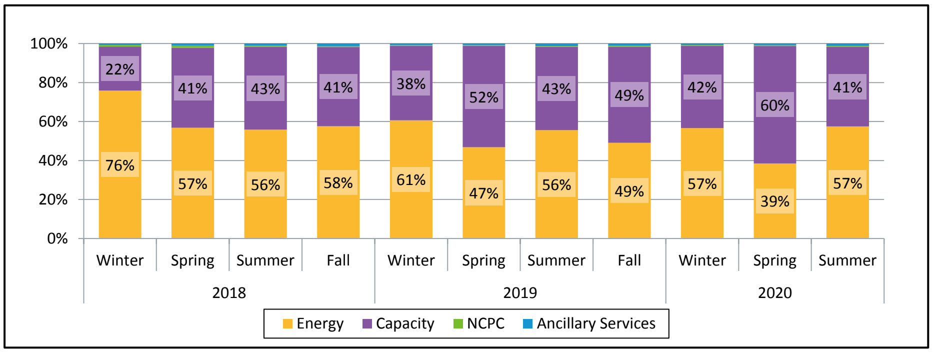
Energy costs were \$849 million (\$25/MWh) in Summer 2020, 12% lower than Summer 2019 costs, driven by a 25% decrease in natural gas prices. Energy costs made up 57% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 3-2 below.

[16] 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.

[17] 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.

Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 11), and totaled $603 million ($18/MWh), representing 41% of total costs. Beginning in Summer 2020, capacity market costs decreased relative to previous quarters. In the prior capacity commitment period (CCP 10, June 2019 – May 2020), the clearing price for new and existing resources was $7.03/kW-month.[18] In the current capacity commitment period (CCP 11, June 2020 – May 2021), the clearing price for all new and existing resources was $5.30/kW-month. The lower clearing prices caused capacity costs to decrease.

Figure 3-2: Percentage Share of Wholesale Cost



At $7.0 million ($0.21/MWh), Summer 2020 Net Commitment Period Compensation (NCPC) costs represented less than 1% of total energy costs, a similar share compared to other quarters in the reporting horizon.

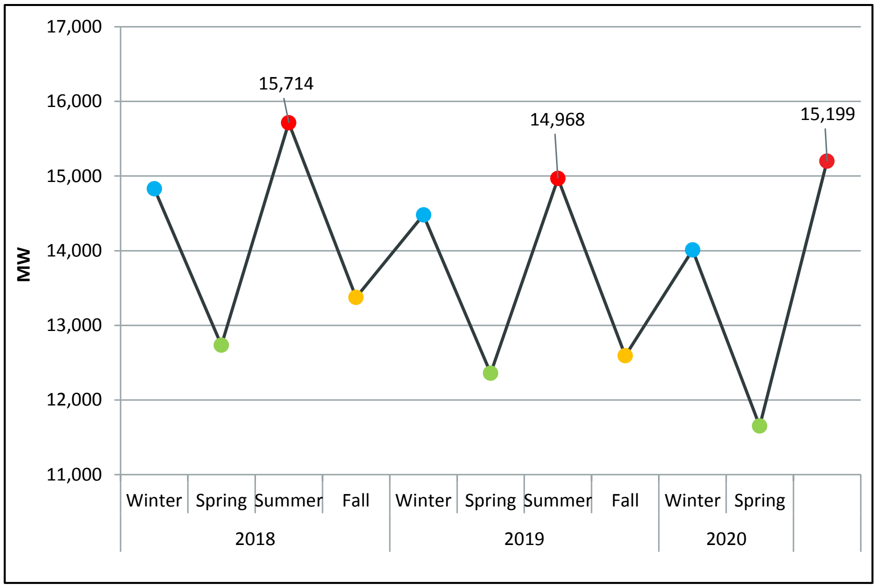
Ancillary service costs, which include payments for operating reserves and regulation, totaled $17.9 million ($0.53/MWh) in Summer 2020, representing 1% of total wholesale costs. Ancillary service costs decreased by 17% compared to Summer 2019, and increased by 72% compared to Spring 2020. The increase was driven by higher reserve payments, which are discussed in Section 4.5.

[18] Imports at the New Brunswick interface cleared slightly lower at $3.38/kW-month.

3.2 Load

In Summer 2020,the impact of warmer weather in New England outweighed increased energy efficiency and behind-the-meter solar generation, leading to a 2% increase in average loads compared to the prior summer.[19] Average hourly load by season is illustrated in Figure 3-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 3-3: Average Hourly Load



Average hourly load in Summer 2020 was 15,199 MW, a 2% increase compared to Summer 2019 and a 3% decrease compared to Summer 2018. Higher loads in Summer 2020 were driven by less humid and milder weather than prior summers.[20] In Summer 2020, the average Temperature-Humidity Index (THI) was 69.5^{0}F compared to 68.8^{0}F in Summer 2019, mostly caused by an increase in average temperature (73^{0}F vs. 72^{0}F).[21] The warmer weather in Summer 2020 led to more Cooling Degree Days (774 CDD vs. 672 CDD) than in Summer 2019.[22]

[19] In this section, the term "load" typically refers to net energy for load (NEL), while "demand" typically refers to end-use demand. NEL is generation needed to meet end-use demand (NEL – Losses = Metered Load). NEL is calculated as Generation + Settlement-only Generation – Asset-Related Demand + Price-Responsive Demand + Net Interchange (Imports – Exports).

[20] Temperature numbers in this report may differ from prior reports due to a change in city weights.

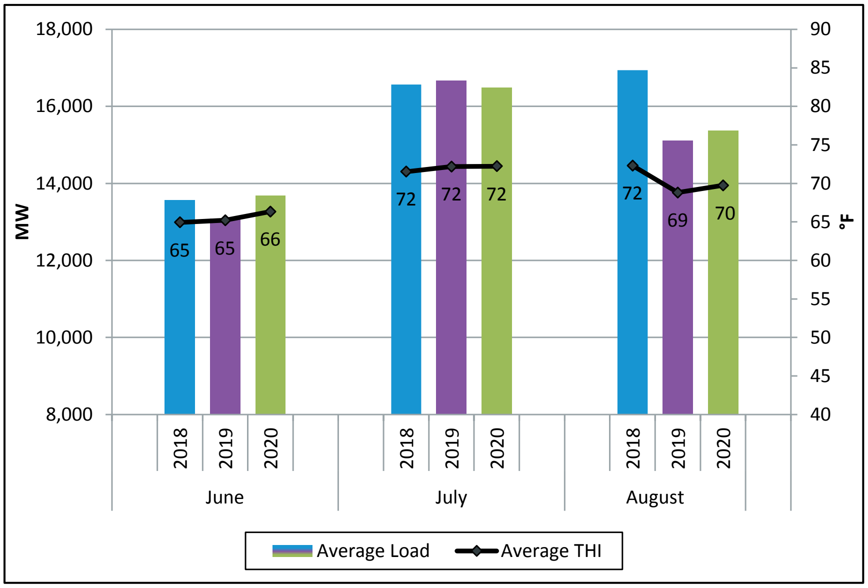
[21] The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (^{0}F)] + 0.3 x [Dew Point (^{0}F)] + 15.

[22] Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F, the HDD for that day is 5. Cooling degree day (HDD) measures how warm an average daily temperature is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is 5.

Load and Temperature

The monthly breakdown of THI and load over the past three summers is shown in Figure 3-4 below. The bars illustrate monthly average load (left axis) and the lines illustrate the monthly average THI (right axis).

Figure 3-4: Monthly Average Load and Temperature Humidity Index



Higher average quarterly loads for Summer 2020 were mainly driven by warmer weather during June 2020 and August 2020 and increased air-conditioning demand due to the COVID-19 Pandemic.[23] The warmer weather led to a higher average THI in June 2020 (66°F vs 65°F) and August 2020 (70°F vs. 69°F). The warmer weather also created more cooling demand, resulting in higher loads. CDDs increased year over year in both June 2020 (163 vs 98) and August 2020 (265 vs 218), leading to increased load. In June 2020, loads averaged 13,683 MW, a 606 MW increase from June 2019 (13,077 MW). In August 2020, loads averaged 15,375 MW, up from 15,104 MW in August 2019.

[23] Throughout the COVID-19 Pandemic, ISO-NE has released weekly reports about the pandemic's impact on electricity demand in New England. For more information on the summer impacts of the COVID-19 Pandemic, see the report: Estimated Impacts of COVID-19 on ISO New England Demand, September 1, 2020.

Peak Load and Load Duration Curves

New England's system load over the past three summers is shown as load duration curves in Figure 3-5 below with the inset graph showing the 5% of hours with the highest loads. A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher. Summer 2020 is shown in red, while Summer 2019 is shown in dark gray and Summer 2018 is shown in light gray.

Figure 3-5: Load Duration Curve

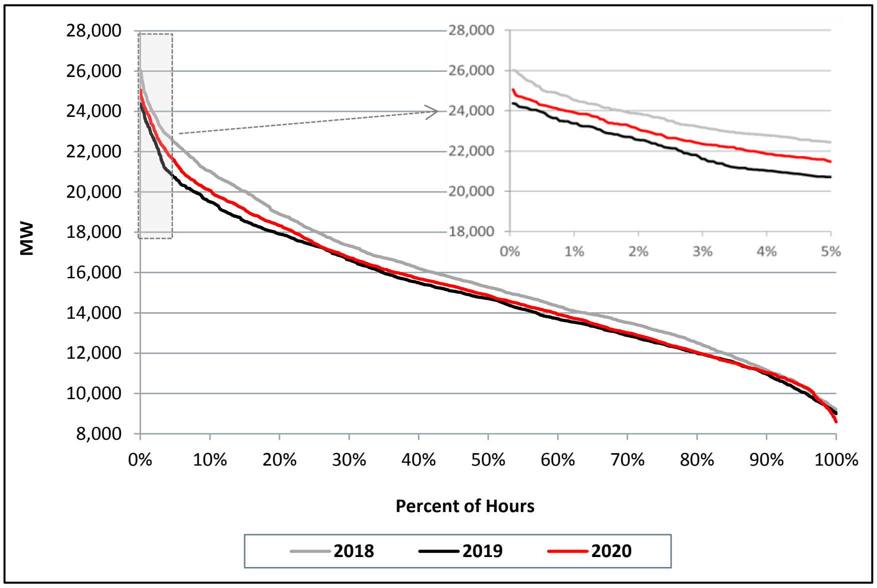


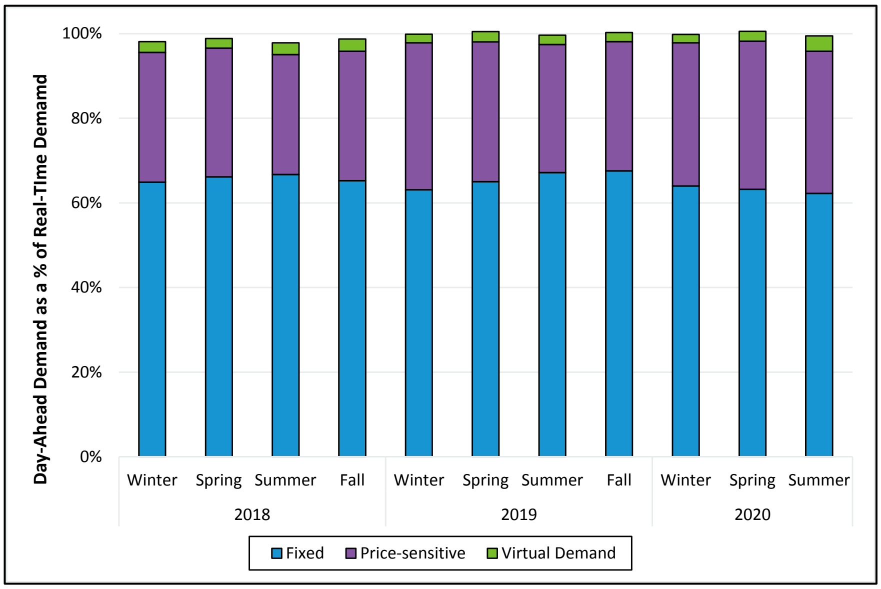
Figure 3-5 highlights that loads in 2020 were higher across more than 94% of all observations when compared to Summer 2019 and lower across 98% of all observations compared to Summer 2018. In Summer 2020, loads were higher than 18,000 MW in 22.0% of all hours compared to 19.3% and 25.4% in Summer 2019 and 2018, respectively. During peak hours, Summer 2020 loads increased from Summer 2019 loads and fell compared to Summer 2018 loads. In Summer 2020, the top 5% of all hours averaged 22,869 MW, which was 664 MW higher than in Summer 2019 and 809 MW lower than in Summer 2018 (23,678 MW). Higher peak loads occurred in Summer 2020 compared to Summer 2019 despite similar THI levels (78.7°F vs. 78.8°F) and the long-term trend of decreasing wholesale loads due to energy efficiency and behind-the-meter solar generation increases. These higher loads are likely due to increased air-conditioning demand created by the COVID-19 Pandemic.[24]

[24] See ISO New England's Estimated Impacts of COVID-19 on ISO New England Demand, September 1, 2020

Load Clearing in the Day-Ahead Market

For the past several years, day-ahead cleared demand as a percentage of actual real-time demand has increased, on average. The amount of demand that clears in the day-ahead market is important because, along with the ISO's Reserve Adequacy Assessment, it influences the generator commitment decision for the operating day.[25] For example, when low levels of demand clear in the day-ahead market, supplemental generation may need to be committed to meet real-time demand. This can lead to higher real-time prices. The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 3-6 below. Day-ahead demand is broken down by bid type: fixed (blue), price-sensitive (purple) and virtual (green) demand.[26]

Figure 3-6: Day-Ahead Cleared Demand as a Percentage of Real-Time Demand



Day-ahead cleared demand as a percentage of real-time demand was slightly lower in Summer 2020 (99.5%) than in Summer 2019 (99.7%) but higher than in Summer 2018 (97.8%), on average. Compared to Summer 2019, increased levels of cleared price-sensitive demand (33.6% vs. 30.3%) and virtual demand (3.6% vs. 2.2%) bids were offset by decreased fixed demand (62.2% vs. 67.2%), on average.

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

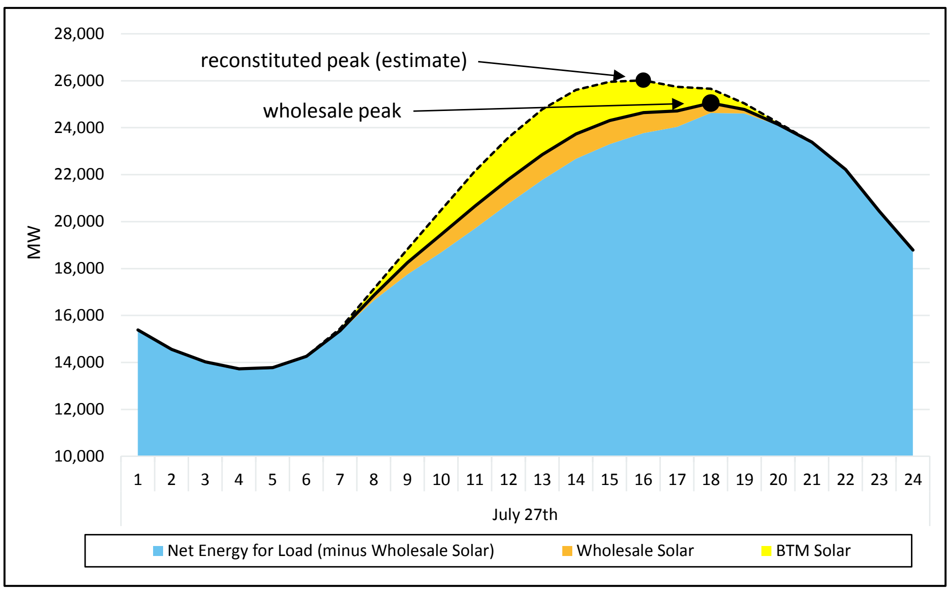
[26] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand, while real-time metered load is calculated as generation + settlement-only generation – asset-related demand + price-responsive demand + net imports – losses. This is different from the ISO Express report, which defines day-ahead cleared demand as fixed demand + price-sensitive demand + virtual demand - virtual supply + asset-related demand. Real-time load is calculated as generation – asset-related demand + price-responsive demand + net imports – losses. The IMM has found that comparing the modified definition of day-ahead cleared demand and real-time metered load can provide better insight into day-ahead and real-time price differences.

Behind-The-Meter Solar Generation

In recent years, New England has seen an influx of behind-the-meter (BTM) solar generation, which contributes to declining wholesale electricity demand.[27] BTM solar is typically small scale (< 5 MW) and is not part of the regional wholesale power system, therefore, it is not controlled by the ISO New England system operators. Increased BTM solar generation affects the wholesale market by reducing demand during day-light hours. It also adds to the challenge of forecasting wholesale load.

In Summer 2020, BTM solar reached an estimated installed capacity of nearly 2,500 MW and an estimated peak hourly generation below 2,173 MWh.[28] Figure 3-7 below shows the load curve for July 27, the peak load day of 2020. The graph includes Net Energy for Load (NEL) without wholesale solar generation (blue), wholesale solar generation (orange) and estimated BTM solar generation (yellow).[29] The graph also includes a solid line to represent NEL and a dashed line to represent gross load, i.e. NEL reconstituted for load met by BTM solar generation.

Figure 3-7: July 27 Load Curve and BTM Solar



In Summer 2020, BTM solar reached an estimated installed capacity of nearly 2,500 MW and an estimated peak hourly generation below 2,173 MWh. Figure 3-7 below shows the load curve for July 27, the peak load day of 2020. The graph includes Net Energy for Load (NEL) without wholesale solar generation (blue), wholesale solar generation (orange) and estimated BTM

[27] While behind-the-meter solar generation is still electricity supply, in the wholesale electricity market behind-the-meter solar is a substitute for wholesale electricity demand, therefore during periods of solar generation, wholesale electricity demand decreases.

[28] BTM solar generation and nameplate capacity data are estimates as BTM does not participate in the wholesale energy market. The estimated data for behind-the-meter solar generation and nameplate capacity includes solar passive demand resources. Like BTM solar generation, passive demand resources are not visible to the ISO and do not participate in the energy market, but they do participate in the Forward Capacity Market.

[29] In this example, wholesale generation includes solar generation that participates in the energy market. This includes solar generation that is real-time telemetered and settlement-only generation (less than 5 MW). Only generators that are greater than 5 MW are visible to the ISO.

solar generation (yellow). The graph also includes a solid line to represent NEL and a dashed line to represent gross load, i.e. NEL reconstituted for load met by BTM solar generation.

Figure 3-7 illustrates that BTM solar generation can serve a significant portion of load during the day, and is notably higher than wholesale solar generation. On July 27, BTM solar output was estimated to be 14,051 MWh (averaging over 585 MW per hour) compared to just 8,873 MWh for wholesale solar (averaging 370 MW per hour). In addition, BTM solar can reduce system load, and shift the daily peak hour. Without BTM solar generation (dashed line) on July 27, loads would have reached an estimated 26,021 MW in HE 16. However, BTM solar generation reduced wholesale load (solid line) to 24,641 MW in HE 16. Since BTM solar generation lowers wholesale load, wholesale load increases as BTM solar generation decreases in the evening. In this way, the wholesale load reached a year-to-date peak of 25,056 MW on July 27 in HE 18.

While BTM solar can help reduce wholesale load, operational load forecasting becomes more challenging due to the difficulty of predicting the next day's cloud cover at a granular level.[30] On average in the summer, BTM solar reduces the slope of the load curve, but quick changes in cloud cover can increase or decrease BTM solar generation causing changes in wholesale load. Variable loads must be met by responsive generators, such as a fast-start natural gas-fired generator. To mitigate the operational issues of BTM solar generation, the ISO has invested in better solar forecasting data to provide more accurate system load forecasts.[31]

[30] For more information on the difficulties of solar forecasting see https://www.bnl.gov/isd/documents/94838.pdf

[31] For more information on how ISO New England is continuously working to improve forecasting methods, see https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

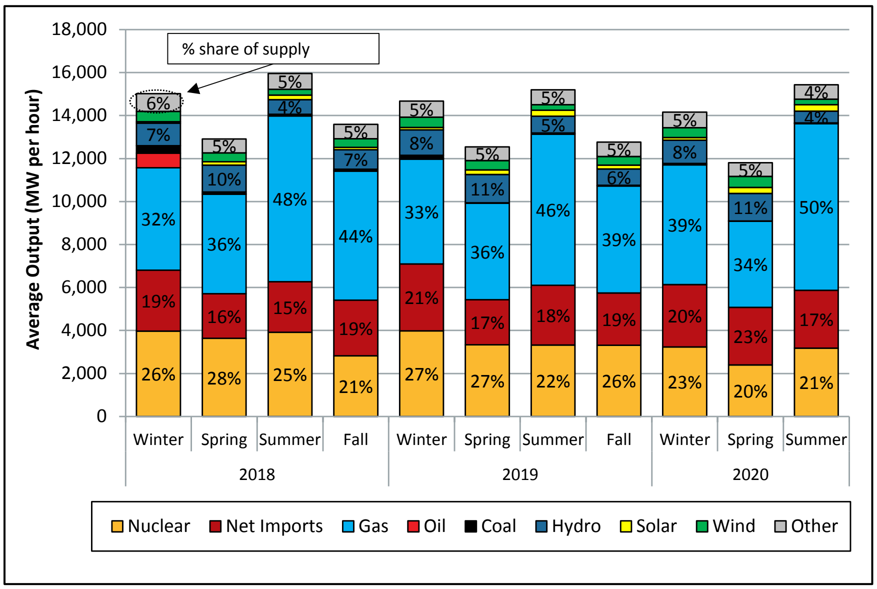
3.3 Supply

This subsection summarizes actual energy production by fuel type, and flows of power between New England and its neighboring control areas.

3.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2018 through Summer 2020 is illustrated in Figure 3-8 below. Each bar's height represents average electricity generation, while the percentages represent the share of generation from each fuel type.[32]

Figure 3-8: Share of Electricity Generation by Fuel Type



The majority of New England's energy comes from nuclear generation, gas-fired generation, and net imports (imports netted for exports). Together, these categories accounted for 88% of total energy production in Summer 2020. Similar to 2018 and 2019, natural gas production increased from Spring to Summer. Since gas-fired generators are more efficient and have lower fuel costs than other fossil-fuel burning generators, they are typically used to meet higher loads in the summer. Additionally, lower gas demand from industrial and residential users typically leads to lower gas prices in the summer.

[32] Electricity generation in Section 3.3.1 equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, and wood.

3.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York in Summer 2020.[33] On average, the net flow of energy into New England was about 2,685 MW per hour. Figure 3-9 shows the average hourly import (positive values), export (negative values) and net interchange power volumes by external interface for the last 11 quarters.

Figure 3-9: Average Hourly Real-Time Imports, Exports, and Net Interchange

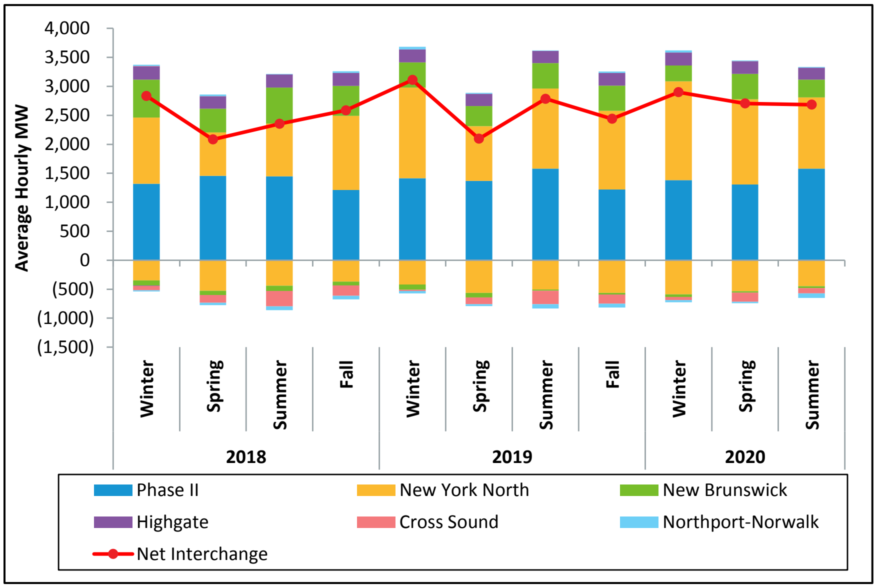


Figure 3-9 illustrates that, historically, net interchange and imports rise from spring to summer when New England energy prices and demand tend to be higher. During Summer 2020, energy demand and prices did rise from Spring 2020, however this did not result in an increase in net interchange. Compared to Summer 2019, average prices in both the day-ahead and real-time markets were lower, which could partially explain lower net interchange.

In Summer 2020, ISO-NE met about 18% of its average load (NEL) with power imported from New York and Canada. This is slightly lower than the average of the prior ten seasons (19%). The average hourly net interchange of 2,685 MW per hour was about 4% lower than Summer 2019, when average hourly net interchange was 2,787 MW per hour. This slight decrease was driven by minor decreases over the New York North (NYN) and New Brunswick interfaces.

The largest share of imports into New England continues to be from the Phase II interface, making up 47%, or an hourly average of 1,578 MW, in Summer 2020. This represents a less than 1% decrease from Summer 2019 (1,582 MW). The NYN interface contributed an average of 1,232 MW or 37% of total imports. This represents an 11% decrease from Summer 2019 (1,379 MW).

[33] 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 slight decrease in imports over the New York North and New Brunswick interfaces seems to be partially driven by changes in bidding behavior. Both interfaces saw a 15-20% decrease in the amount of MWh bid into the day-ahead market and scheduled in real-time. Over the New Brunswick interface participants offered fewer MWhs into the day-ahead market at fixed or low offer prices (below $30/MWh). Most notably, only 75% of offers between $10-$30/MWh cleared in the day-ahead market compared to 96% in Summer 2019. Similarly, over the New York North interface participants offered fewer MWhs as fixed or priced between $10-$30/MWh. There was a slight increase in offers between $0-$10/MWh. Only 60% of offers between $10-$30/MWh cleared in the day-ahead market compared to 75% in Summer 2019. A combination of fewer import offers at lower prices, less of these offers clearing and lower day-ahead prices led to a lower summer net interchange than Summer 2019. This decrease in import offers and cleared quantities does not seem to be driven by a change in spread prices.

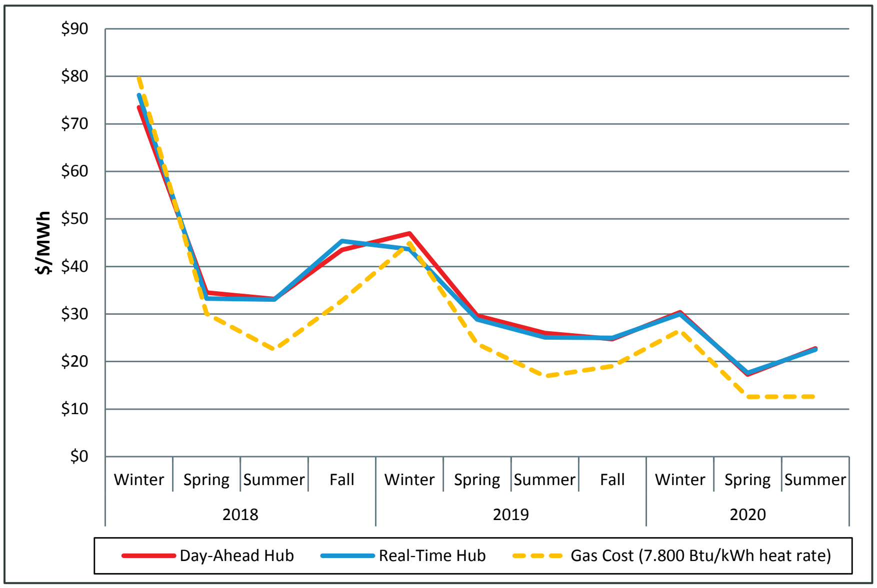
Section 4
Day-Ahead and Real-Time Markets

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

4.1 Energy Prices

The average real-time Hub price for Summer 2020 was $22.52/MWh, similar to the average day-ahead price of $22.50/MWh. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas in New England, are shown in Figure 4-1 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.[34]

Figure 4-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 4-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand. Gas costs averaged $13/MWh in Summer 2020. Average day-ahead electricity prices were $10/MWh above average estimated gas costs in Summer 2020, similar to the $9 and $10/MWh spreads in the previous two summers.

In Summer 2020, average day-ahead and real-time prices were lower than Summer 2019 prices by about $3/MWh. This is consistent with lower natural gas prices in Summer 2020. Gas prices

[34] The average heat rate of combined cycle gas turbines in New England is estimated to be 7,800 Btu/kWh.

decreased by 25% in Summer 2020 compared to Summer 2019. The downward impact of lower gas prices on energy prices was partially offset by higher loads in Summer 2020.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones and for the Hub are shown below in Figure 4-2.

Figure 4-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs

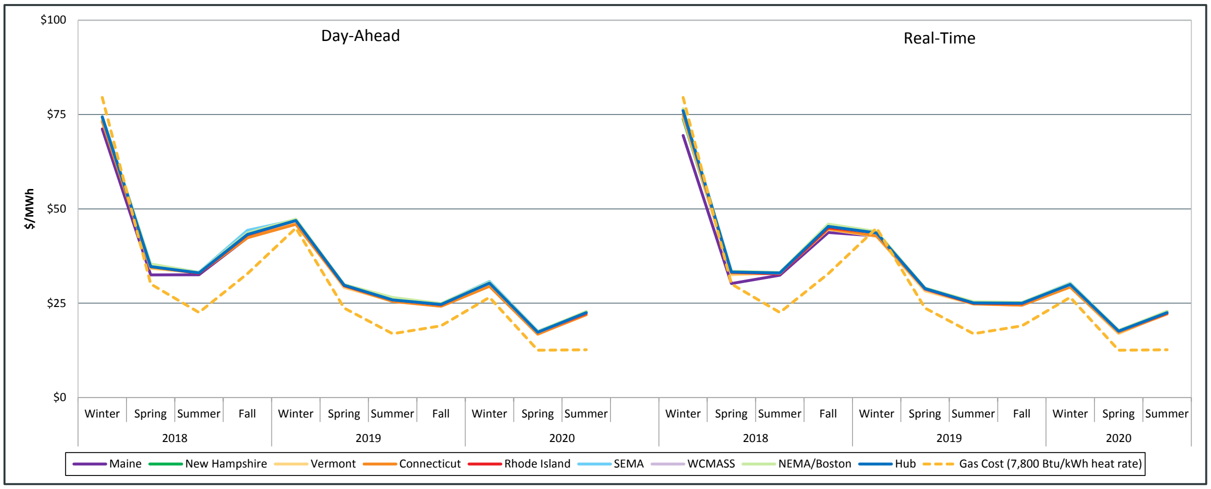


Figure 4-2 illustrates that prices did not differ significantly among the load zones in either market, indicating that there was relatively little congestion on the system at the zonal level.[35]

4.2 Marginal Resources and Transactions

The locational marginal price (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 transaction type can provide additional insight into day-ahead and real-time pricing outcomes.

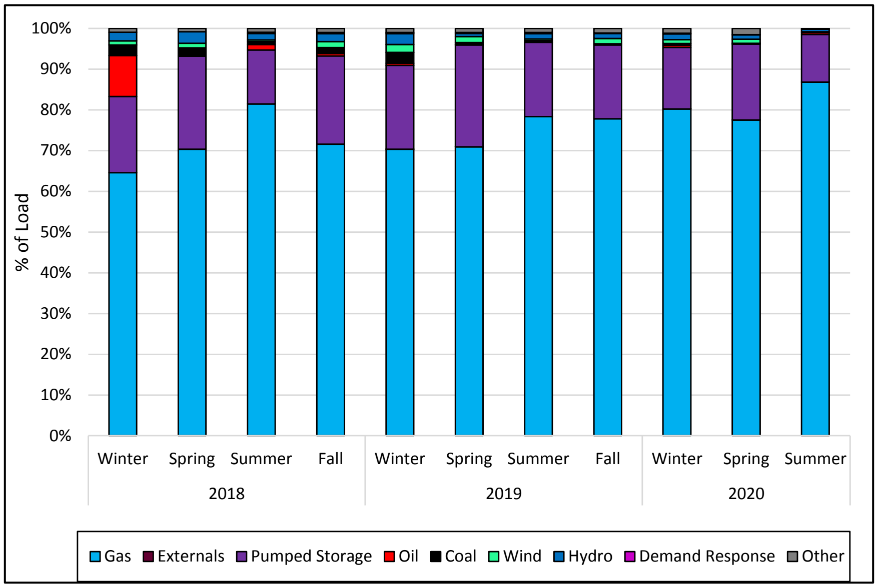
This section reports marginal units by transaction and fuel type on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the system. For example, resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. Consequently, the impact of these resources on the system LMP is muted.

In the day-ahead market, a greater number of transaction types can be marginal; these include 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-fired generators) and pumped-storage demand.

[35] A load zone is an aggregation of pricing nodes within a specific area. There are currently eight load zones in the New England region, which correspond to the reliability regions.

The percentage of load for which each fuel type set price in the real-time market by season is shown in Figure 4-3 below.[36]

Figure 4-3: Real-Time Marginal Units by Fuel Type



Natural gas-fired generators set price for 87% of total load in Summer 2020. Gas-fired generators are often the most expensive units operating, and therefore set price frequently. More expensive coal- and oil-fired generators are not typically required to meet system demand, and therefore set price less frequently.

In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchability. By contrast, nuclear generation accounts for about one fourth of native generation in New England, but does not set price. Nuclear generators in New England offer at a fixed output, meaning that once they come online they can only produce at one output level. If load changes by one megawatt, a nuclear generator cannot increase or decrease its output to meet the demand, and therefore it is not eligible to set price.

Pumped-storage units (generators and demand) set price for about 12% of total load in Summer 2020, which is a decrease from Summer 2019 (18%), and a decrease from Spring 2020 (19%). Pumped-storage generators 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-fired generators. Because they are online relatively often and priced close to the margin, they can set price frequently.

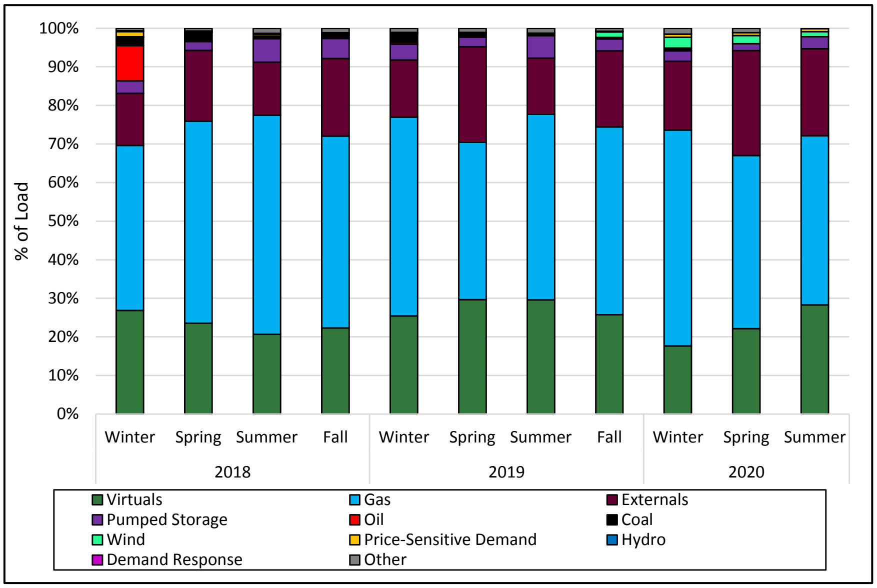
Wind was marginal for less than 1% of total load in Summer 2020; primarily due to wind generators setting price in local export-constrained areas, where the impact on the average load price is limited. Wind generators located in export-constrained areas can only deliver the next increment of load to a small number of locations located within the export-constrained area. This occurs when the transmission network that moves energy out of the constrained area is at

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

maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2018 is illustrated in Figure 4-4 below.

Figure 4-4: Day-Ahead Marginal Units by Transaction and Fuel Type

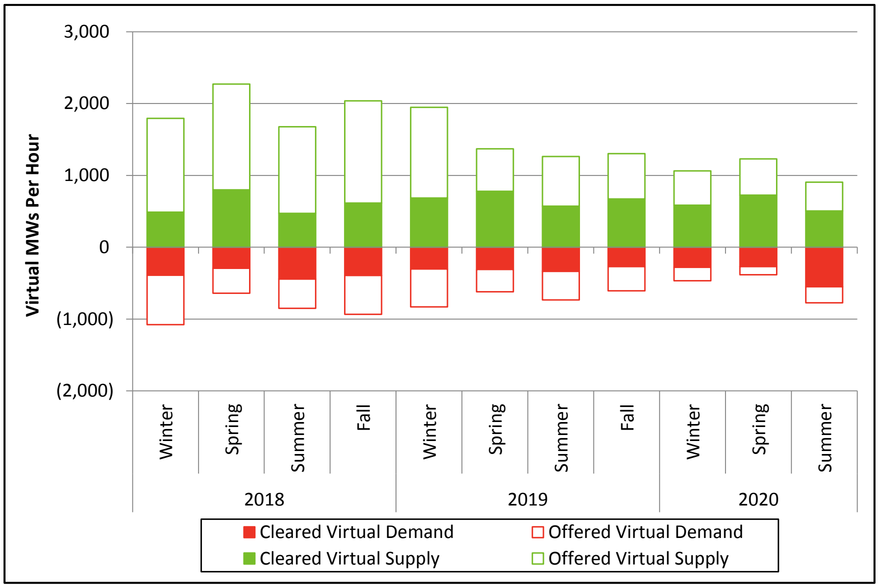


In Summer 2020, external transactions displaced some of the price-setting transactions of gas-fired generators in the day-ahead market compared to Summer 2019. Natural gas-fired generators set price for 44% of load in Summer 2020, a 4% decline from Summer 2019, and a 1% decline from Spring 2020. External transactions set price for more load in Summer 2020 compared to Summer 2019 (23% vs 15%) because the New York North interface was constrained less frequently due to changes in bidding behavior, which is discussed in Section 3.3.2. Fewer constrained intervals across an interface provides the opportunity for external participants to set price for a greater share of load in ISO-NE.

4.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to capture differences between day-ahead and real-time LMPs. The primary function of virtual transactions is to improve the day-ahead dispatch model to better reflect real-time conditions. Virtual transactions that are profitable based on the price difference between the day-ahead and real-time markets generally improve price convergence. Offered and cleared virtual transaction volumes from Winter 2018 through Summer 2020 are shown in Figure 4-5 below.

Figure 4-5: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



In Summer 2020, total offered virtual transactions averaged 1,680 MW per hour, which was 4% higher than the average amount offered in Spring 2020 (1,613 MW per hour) and 16% lower than the average amount offered in Summer 2019 (1,996 MW per hour). Over the period from Winter 2018 to Winter 2019, the average amount of offered virtual transactions was 2,812 MW per hour. Meanwhile, the average amount of offered virtual transactions over the last six quarters (i.e., Spring 2019 to Summer 2020) has been only 1,787 MW per hour. The primary reason for this decrease in offered virtual transactions in recent quarters is that one participant significantly reduced their virtual activity. This participant submitted over 924 MW per hour of virtual transactions, on average, between Winter 2018 and Winter 2019, and submitted less than 7 MW per hour, on average, in the last six quarters (i.e., Spring 2019 through Summer 2020).

On average, 1,056 MW per hour of virtual transactions cleared in Summer 2020, which represents a 6% increase compared to Spring 2020 (994 MW per hour) and a 16% increase compared to Summer 2019 (908 MW per hour). Cleared virtual supply amounted to 506 MW per hour, on average, in Summer 2020, down 30% from Spring 2020 (725 MW per hour) and down 11% from Summer 2019 (571 MW per hour). Meanwhile, cleared virtual demand amounted to 550 MW per hour, the highest level over the reporting period. In Summer 2020, average cleared virtual demand increased 105% from Spring 2020 (269 MW per hour) and increased 63% from Summer 2019 (337 MW per hour). Levels of cleared virtual demand were particularly high during the beginning of Summer 2020 when participants cleared less load in the day-ahead market than was consumed in the real-time market. This contributed to higher real-time prices, leading to increased profits for participants clearing virtual demand. In general, the percent of submitted virtual transactions that have cleared has increased over the 11-quarter period covered in this report, rising from 31% in Winter 2018 to 63% in Summer

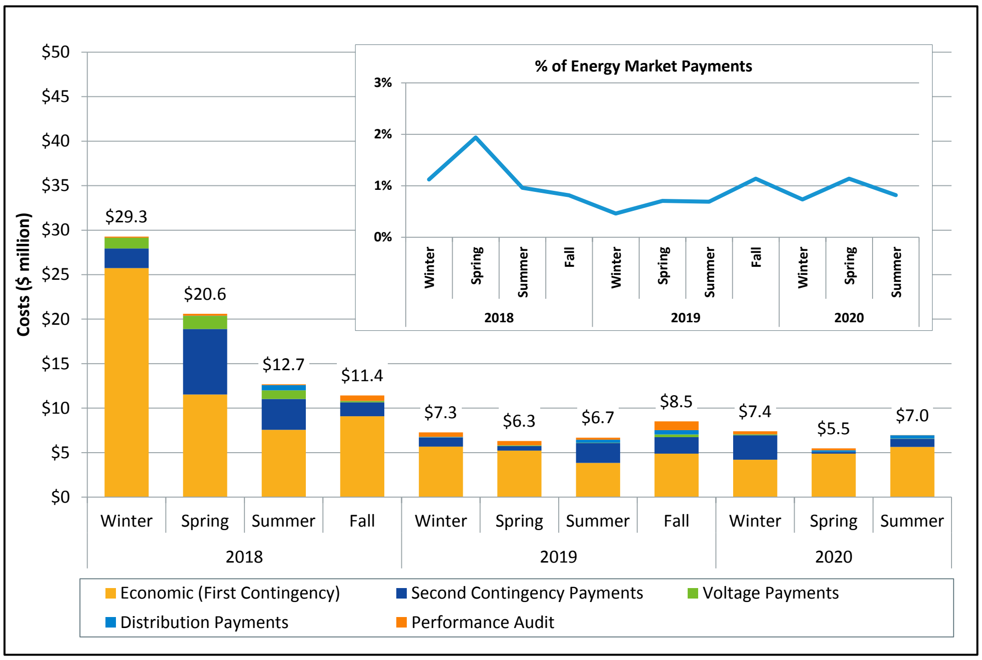
2020. The trend is partly linked to a reduction in transaction costs, in the form of reduced NCPC charges, to virtual transactions.[37]

4.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC), commonly known as uplift, are make-whole payments provided to resources when energy prices are insufficient to cover production costs or to account for any foregone profits the resources lost by following ISO dispatch instructions. Uplift may be required for resources committed and dispatched economically, dispatched out of economic-merit order for reliability purposes, or dispatched away from their economic dispatch point. Uplift is paid to resources that provide a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[38]

Payments by season and by uplift category are illustrated below in Figure 4-6. The inset graph shows uplift payments as a percentage of total energy payments.

Figure 4-6: NCPC Payments by Category ($ millions)



Total NCPC payments in Summer 2020 amounted to $7.0 million, an increase of $0.3 million, or 4%, compared to Summer 2019. Economic payments increased by 46% or $1.8

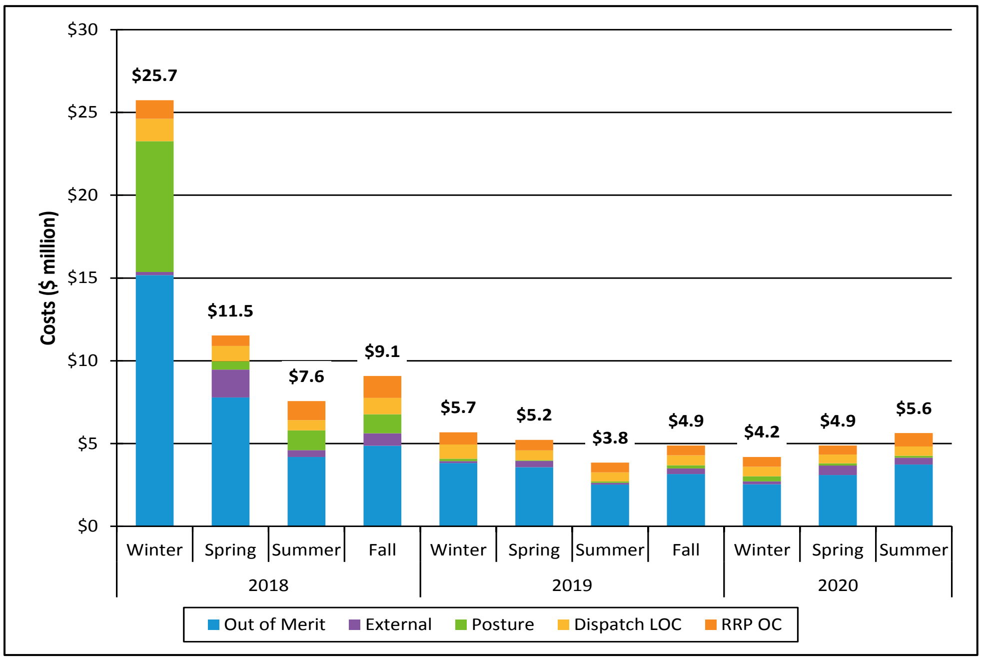
[37] In February 2016, real-time economic NCPC payments made to generators that received a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid. The fast-start pricing rules implemented in March 2017 also had a downward effect on real-time economic NCPC. For more information about fast-start pricing, 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

[38] 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* (costs paid to generating units for ISO-initiated audits).

million from Summer 2019. This increase was offset by a decrease in second contingency reliability payments of $1.3 million or 59%. Economic payments made up the majority of uplift (81% or $5.6 million) during the reporting period, with the majority of total economic payments, 86%, paid in the real-time market. NCPC payments represented 0.8% of total energy payments, which was in line with the historical range.

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that operate at an ISO-instructed dispatch point below their economic dispatch point (EDP). This deviation from their EDP creates an opportunity cost for that resource. Figure 4-7 below shows economic payments by subcategory.

Figure 4-7: Economic Uplift by Season and Subcategory



As illustrated by Figure 4-7, out-of-merit payments continue to make up the majority of economic NCPC. Summer 2020 out-of-merit payments were approximately 48% higher ($1.21 million) than Summer 2019 payments. This increase was driven by real-time commitments made due to generator trips and load forecast error. Most of the payments during these tight system conditions were made to fast-start generators.

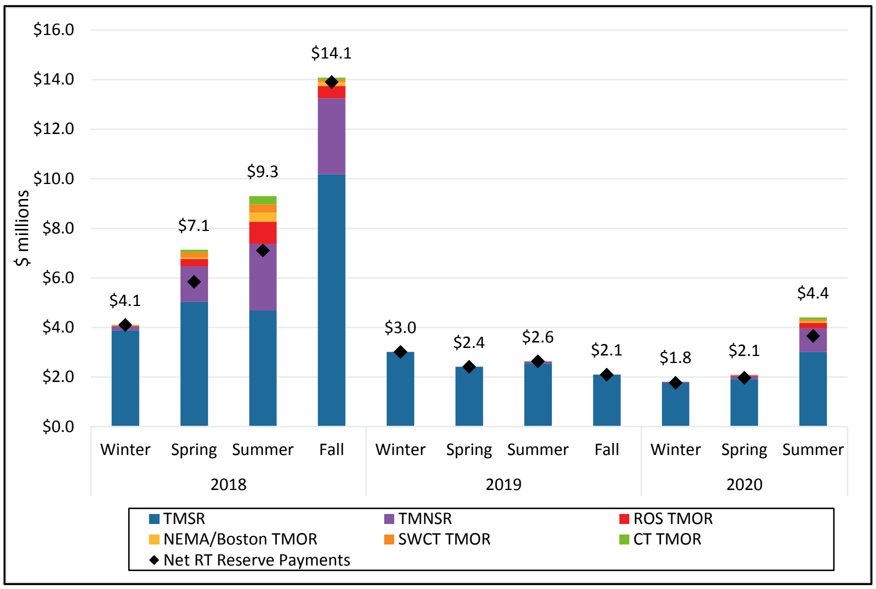
In Summer 2020, total local second contingency protection reliability (LSCPR) payments were 59% lower than Summer 2019 payments. Almost all (91%) of the LSCPR NCPC paid out in Summer 2020 was paid in the day-ahead market in August to generators located in either NEMA/Boston or Maine. During the first two weeks of August, two 345 kV lines that cross the Boston import interface went on a planned outage. This led to four gas-fired generators being committed and receiving 74% or $0.67 million of the total Summer 2020 LSCPR payments. During the last week of August, another 345 kV line went on a planned outage leading to three gas-fired generators being committed and receiving 18% or $0.16 million of the total Summer 2020 LSCPR payments.

4.5 Real-Time Operating Reserves

Bulk power systems must be able to quickly respond to contingencies, such as the unexpected loss of a large generator. To ensure that adequate backup capacity is available, the ISO procures reserve products through the locational Forward Reserve Market (FRM) and the real-time energy market. The ISO's market software determines real-time prices for each reserve product. Non-zero real-time reserve pricing occurs when the software must re-dispatch resources to satisfy the reserve requirement.

Real-time reserve payments by product and by zone are illustrated in Figure 4-8 below. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. Net real-time reserve payments, which were $3.7 million in Summer 2020, are shown as black diamonds in Figure 4-8.

Figure 4-8: Real-Time Reserve Payments by Product and Zone



Real-time reserve payments totaled $4.4 million in Summer 2020, $1.8 million (67%) higher than in Summer 2019. The increase was driven by the need to redispatch the system to maintain adequate off-line reserves during relatively tight system conditions; as a result ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) payments both rose by $847 thousand and $437 thousand, respectively. The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three summer seasons is provided in Table 4-1 below.[39]

[39] Non-zero reserve pricing occurs when there is 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 4-1: Hours and Level of Non-Zero Reserve Pricing[40]

Product	Zone	Summer 2020		Summer 2019		Summer 2018	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$6.96	506.3	$9.81	364.9	$11.46	476.8
TMNSR	System	$57.14	16.3	$109.26	0.6	$149.73	13.1
TMOR	System	$85.04	5.8	$0.00	.	$151.51	12.9
	NEMA/Boston	$85.04	5.8	$31.38	2.4	$151.51	12.9
	CT	$85.04	5.8	$0.00	.	$151.51	12.9
	SWCT	$85.04	5.8	$0.00	.	$151.51	12.9

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 506 hours (23% of total hours) during Summer 2020, higher than the number of hours of non-zero reserve pricing in Summer 2019. In the hours when the system TMSR price was above zero, the price averaged $6.96/MWh, a decrease from the prior spring season and consistent with the decrease in real-time energy prices.

There were 16 hours of TMNSR pricing and six hours of TMOR pricing throughout the quarter, which took place on a few days with tight system conditions. There were several contributing factors to the tight system conditions that led to an increase in non-spinning reserve pricing compared to Summer 2019:

- Generator trips combined with periods of load forecast error heading into the afternoon peak.
- Higher real-time native load compared to cleared day-ahead demand led to real-time commitment of fast start generators. Once online, fast-start generators are providing energy rather than offline reserves.
- Sudden decreases in real-time import schedules due to security concerns, such as disturbance control standards determined by the North American Electric Reliability Corporation.

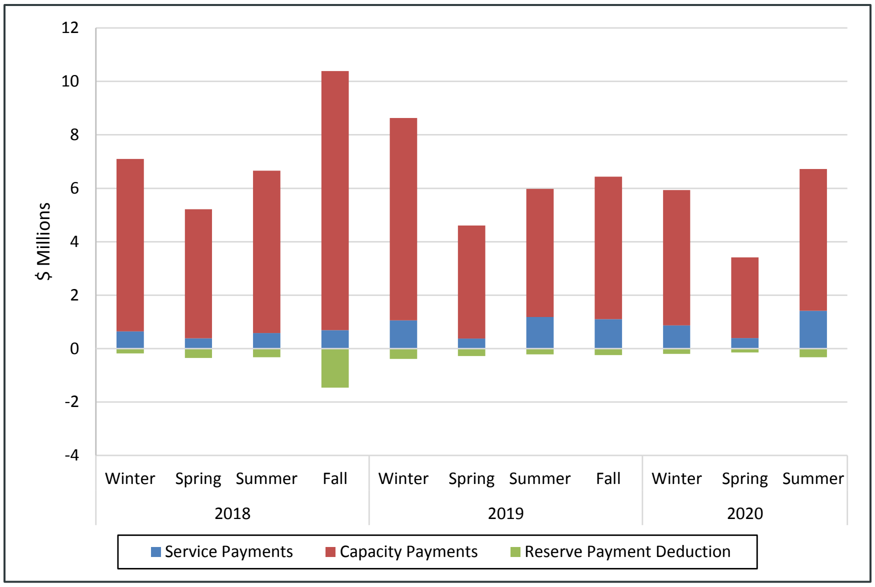
While there were more intervals of TMNSR and TMOR pricing, average TMNSR prices ($57.14/MWh) and TMOR prices ($85.04/MWh) were lower than those of Summer 2018, which had a comparable amount of non-zero pricing intervals. As with TMSR pricing, lower reserve prices are consistent with the decrease in real-time energy prices ($22.50/MWh) compared to Summer 2018 ($33.02/MWh) and Summer 2019 ($25.89/MWh).

[40] The methodology for this metric has changed. In reports prior to Summer 2019, the sum of payments for each reserve product was averaged over the number of intervals for which *any* reserve price was non-zero, which resulted in low calculations for average non-spinning reserve prices. Now, the table shows the average non-zero price for each respective product and zone. For example, the system TMNSR price was non-zero for 35 minutes in Summer 2019. Therefore, the table shows the average system TMNSR price ($109.26) during these 35 minutes.

4.6 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 available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 4-9 below.

Figure 4-9: Regulation Payments ($ millions)



Total regulation market payments were $6.4 million during the reporting period, up approximately 11% from $5.8 million in Summer 2019, and up by 95% from $3.3 million in Spring 2020. The increase in payments comparing Summers 2019 and 2020 reflects a small increase in regulation capacity requirements, along with an increase in service offer costs. The increase in regulation payments for Summer 2020 compared to Spring 2020 reflects an increase in payments for both capacity and service, explained by an increase in the amount of regulation capacity utilized by the ISO during Summer 2020 and increased clearing prices (reflecting higher opportunity costs during the summer period).

Section 5
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Winter 2020/21 Forward Reserve Auction.

5.1 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.[41] 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.[42] Between the initial auction and the commitment period, there are further opportunities to adjust annual Capacity Supply Obligations (CSOs) through annual and monthly reconfiguration auctions. Formerly, three of the annual auctions were bilateral auctions, where obligations were traded between resources at an agreed upon price and approved by the ISO. The other three were reconfiguration auctions run by the ISO, where participants submitted supply offers to take on obligations, or submitted demand bids to shed obligations. After June 1, 2019, the annual bilateral auctions were replaced with the incorporation of Annual Reconfiguration Transactions (ARTs) into the remaining three annual reconfiguration auctions.

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 reconfiguration auctions, participants can pick up or shed obligations. Picking up an obligation means that the participant will provide capacity during a given period, while shedding capacity will reduce their CSO. 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 CSOs traded in each commitment period.

The current capacity commitment period (CCP) started on June 1, 2020 and ends on May 31, 2021. The conclusion of the corresponding Forward Capacity Auction (FCA 11) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 35,835 megawatts (MW) of capacity which exceeded the 34,075 MW Net Installed Capacity Requirement (Net ICR), at a clearing price $5.30/kW-month. The clearing price of $5.30/kW-month was 25% lower than the previous capacity period's $7.03/kW-month. This clearing price applied to all resources within New England as well as the imports from Québec and New York. However, the clearing price was

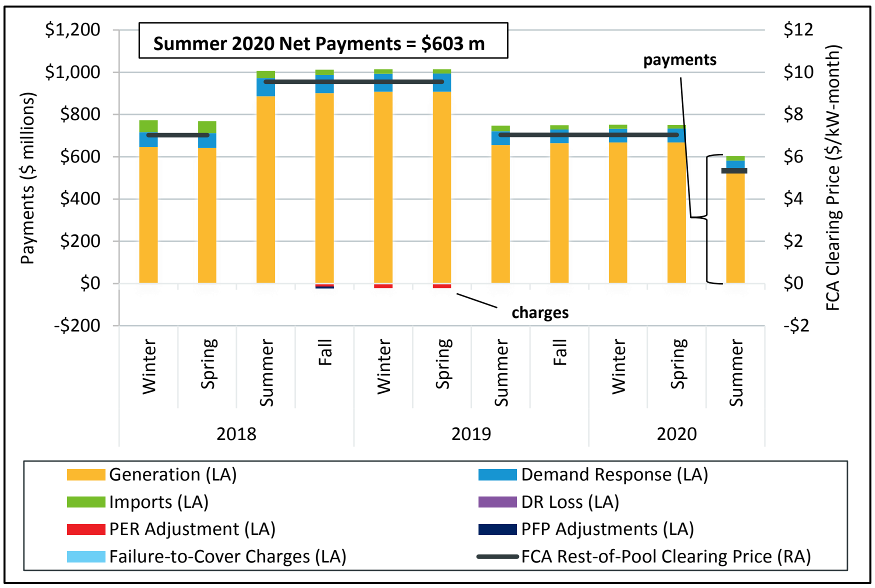
[41] In the capacity market, resource categories include generation, demand response and imports.

[42] 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.

slightly lower for New Brunswick imports at $3.38/kW-month. The results of FCA 11 led to an estimated total annual cost of $2.38 billion in capacity payments, $0.61 billion lower than capacity payments associated with FCA 10.

Total FCM payments, as well as the clearing prices for Winter 2018 through Summer 2020, are shown in Figure 5-1 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 bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The red bar represents reductions in payments due to Peak Energy Rent (PER) adjustment. The dark blue bar represents Pay-for-Performance adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Payments ($ millions)



Total net FCM payments decreased significantly from Summer 2019. In Summer 2020, capacity payments totaled $603 million, which accounts for adjustments to primary auction CSOs.[43] The $5.30/kW-month clearing price (Summer 2020) in FCA 11 was a 25% decrease from the previous FCA clearing price of $7.03/kW-month (Summer 2019).

In Summer 2020, there were approximately $0.1 million in Failure-to-Cover (FTC) charges. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to cover their CSO. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of the resources compared to their CSOs.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Summer 2020, alongside the results of the relevant primary FCA, are detailed in Table 5-1 below.

[43] 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.

Table 5-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW	Capacity Zone/Interface Prices ($/kW-mo) NNE	New Brunswick	Highgate	Phase II
FCA 11 (2020-2021)	Primary	12-month	5.30	35,835		3.38		
	Monthly Reconfiguration	Aug-20	1.76	711				
	Monthly Bilateral	Aug-20	2.39	177				
	Monthly Reconfiguration	Sep-20	3.11	744	1.85	1.85		1.85
	Monthly Bilateral	Sep-20	2.58	132				
	Monthly Reconfiguration	Oct-20	0.35	719	0.30	0.30	0.30	
	Monthly Bilateral	Oct-20	2.19	52				
FCA 12 (2021-2022)	Primary	12-month	4.63	35,835		3.16		3.70
	Annual Reconfiguration (2)	12-month	0.30	174/904**				
FCA 13 (2022-2023)	Primary	12-month	3.80	34,839		2.68		
	Annual Reconfiguration (1)	12-month	1.11	336/978**				

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Two annual reconfiguration auctions (ARAs) occurred during Summer 2020: ARA 2 for capacity commitment period (CCP) 12 (June 2021 – May 2022) in August and ARA 1 for CCP 13 (June 2022 – May 2023) in June. ARA 2 for CCP 12 cleared 174 MW of resource supply and 904 MW of resource demand. The system-wide price for the auction was $0.30/kW-month, which is 94% lower than the clearing price in FCA 12 of $4.63/kW-month. ARA 1 for CCP 13 cleared 336 MW of resource supply and 978 MW of resource demand. The system-wide clearing price was $1.11/kW-month, which is 71% lower than the clearing price in FCA 13 of $3.80/kW-month.

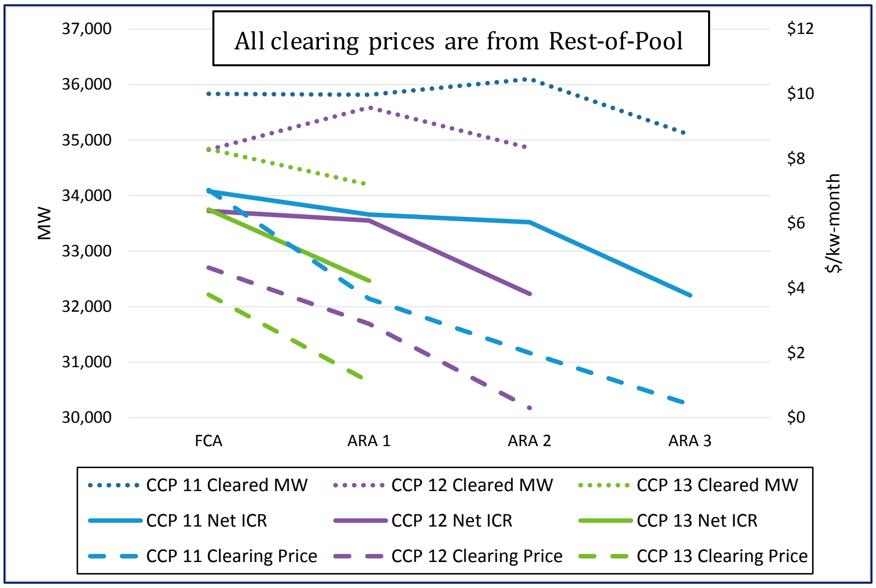
Three monthly reconfiguration auctions took place in Summer 2020: the August 2020 auction in June, the September 2020 auction in July, and the October 2020 auction in August. The system-wide clearing prices for the two summer month auctions (August and September) were higher than the clearing prices in the winter month (October). The three auctions consistently traded around 700 MW.

Decreasing ARA prices under increasing surplus supply conditions

Prior to collecting resource demand bids (bids to shed capacity) in ARAs, the ISO constructs a system-wide demand curve to represent the marginal value of capacity when meeting reliability standards. One result from the marginal reliability calculations is the Net Installed Capacity Requirement, or Net ICR, which is originally forecasted for the FCA. After the FCA, the ISO will recalculate the Net ICR for every ARA to reflect updated expectations of the system's future capacity needs. Adjustments to available capacity (e.g., increased import capability, improved transmission networks) and decreases to load forecasts (e.g., improved energy efficiency, increased behind-the-meter (BTM) solar) have historically caused downward shifts in Net

ICR.[44] Figure 5-2 below displays the cleared capacity MW (dotted lines), Net ICR (solid lines), and clearing prices (dashed lines) for the FCAs and ARAs for CCP 11 (June 2020 – May 2021), CCP 12 (June 2021 – May 2022), and CCP 13 (June 2022 – May 2023).

Figure 5-2: FCA and ARA Cleared MW, Net ICR, and Clearing Rates



For all three CCPs shown, the Net ICR (left-axis) generally decreased as the CCP start date approached. The cleared capacity MW (left-axis) did not decrease at the same rate of Net ICR, leading surplus capacity (cleared capacity above the Net ICR) to gradually increase over time. As capacity surplus increased, the system was expected to be more reliable, diminishing the value of extra capacity above the Net ICR; this diminished value of capacity led to lower clearing prices (right-axis) as the CCP approached.

With reductions in Net ICR, the ARA demand curve shifts inward to represent the decrease in system-wide demand for capacity. Such negative shifts in system demand allowed existing resources to clear demand (shed CSO) without the presence of new supply, as their capacity could be removed from the auction with little impact on system reliability. This outcome of cleared demand not matched with cleared supply created the imbalance of cleared MW volumes shown for two of the ARAs in Table 5-1 above. For ARA 2 of CCP 12, only 174 MW of resource supply cleared while 904 MW of resource demand cleared. Again, in ARA 1 of CCP 13, only 336 MW of resource supply cleared while 978 MW of resource demand cleared.

The resource demand bids cleared through existing supply are cleared in merit order, highest priced to lowest priced. So, an excess of higher-priced demand bids cleared leaves the remaining supply offers and demand bids to clear at much lower prices. The clearing prices of the last three reconfiguration auctions (ARA 3 for CCP 11, ARA 2 for CCP 12, ARA 1 for CCP 13)

[44] In 2018, the ISO published an investigation on common issues affecting Net ICR forecasts from FCA through ARAs in CCP 1-10. The presentation can be found at

https://www.iso-ne.com/static-assets/documents/2018/05/a6_pspc_rev_icr_bias_invtgn_05292018.pdf are the lowest seen for each auction ($0.40/kW-month, $0.30/kW-month, $1.10/kW-month, respectively).

5.2 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that entitle the holders to receive compensation for congestion costs that occur in the day-ahead energy market. FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the relevant period. FTRs awarded in either of the two annual auctions have a term of one year, while FTRs awarded in a monthly auction have a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[45]

1) the holders of FTRs with negative target allocations;
2) the revenue associated with transmission congestion in the day-ahead market;
3) the revenue associated with transmission congestion in the real-time market.

If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected to pay the holders of FTRs with positive target allocations in a month. In this case, the payments to holders of FTRs with positive target allocations are prorated. Any excess revenue collected during the year is allocated to these unpaid monthly positive target allocations at the end of the year, to the extent possible.

On September 17, 2019, ISO-NE implemented the Balance of Planning Period (BoPP) project for FTRs. This project increased the number of opportunities that market participants have to reconfigure their monthly FTR positions following the two annual auctions. Prior to the implementation of this project, market participants could only purchase or sell FTRs for a specific month in the auction that occurred during the month prior to that effective month. For example, if a market participant wanted to buy FTRs that would be effective for December 2020, it had to wait until the monthly auction that took place in November 2020. Under the BoPP design, ISO-NE now administers monthly FTR auctions for not just the next month (now called the prompt-month auction), but also for all the other months remaining in the calendar year (called the out-month auctions). This means that a participant that wants to buy December 2020 FTRs no longer has to wait until November 2020; it can purchase these FTRs in any of the out-month auctions that take place earlier in the year. However, the out-month auctions don't make more additional network capacity available than was made available in the second annual

[45] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location is greater than the congestion component of the source location. Negative target allocations (charges) occur in the opposite situation.

auction (in contrast to the prompt-month auctions, which do make additional capacity available).[46]

The implementation of BoPP was coordinated with the October 2019 prompt-month auction, whose bidding window was open from September 17-19, 2019. During this bidding window, participants could also submit FTR purchases and sales for the November 2019 and December 2019 out-month auctions. FTRs purchased in these out-month auctions are sometimes referred to as the October 2019 *vintage* of the November 2019 or December 2019 FTR contracts.

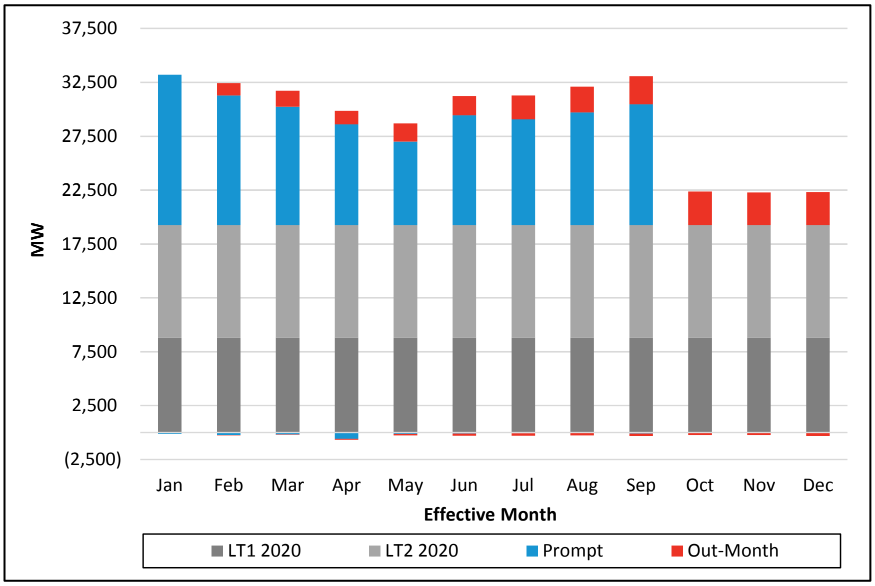
Auction Activity

The MW amount of cleared, on-peak FTRs for each month in 2020 is broken down by the FTR auction in which the transaction occurred in Figure 5-3 below.[47] Cleared FTR purchases are shown as positive values, while cleared FTR sales are shown as negative values. The gray bars indicate FTR transactions that cleared in either the first or second annual auctions (LT1 and LT2), the blue bars indicate FTR transactions that cleared in a prompt-month auction, and the red bars indicate FTR transactions that cleared in an out-month auction. The totals displayed in this figure reflect cleared FTR transactions from all 2020 auctions that have taken place through the end of August 2020 (i.e., up to and including the September 2020 prompt-month auction and all the out-month auctions that occurred coincidentally to it). The out-month totals for a specific month represent the sum of all the cleared transactions for that month that have occurred in out-month auctions up until this point. For example, the out-month purchase total for December 2020 represents the sum of the January 2020 through September 2020 vintage purchases of the December 2020 FTR contract.

[46] The first round of the annual auction makes available 25% of the transmission system capability. The second round of the annual auction makes available an additional 25%, meaning that a total of 50% of the network capability is available to be sold in the two annual auctions. The prompt-month auctions make available an additional 45% of the network capability, meaning that 95% of the network capability is available to be sold by the time the effective month arrives. The out-month auctions do not make available any additional network capability beyond that which was made available in the second round of the annual auction. However, FTRs can still be purchased in the out-month auctions on paths that weren't completely subscribed in the second annual auction, as the result of counterflow FTR purchases, or as the result of FTR sales.

[47] The exhibit for 2020 off-peak FTRs looks very similar to the on-peak one and so it is not included in this report.

Figure 5-3: Monthly On-peak FTR MW by Auction



The prompt-month auctions for July, August, and September 2020 were all conducted in Summer 2020. The volume of FTR transactions that cleared in these three prompt-month auctions – 19,760 MW, 20,912 MW, and 21,391 MW, respectively – was a moderate increase compared to other recent prompt-month auctions.[48] The prompt-month on-peak auctions for July 2020, August 2020, and September 2020 had 29, 29, and 28 bidders, respectively. The prompt-month off-peak auction participation was similar: July 2020 had 28 bidders, August 2020 had 29 bidders, and September 2020, had 27 bidders. In general, these participation levels were slightly lower than levels observed in the other prompt-month auctions in 2020. These decreases could reflect participants' expectations of reduced congestion in the day-ahead market during the summer months as there tend to be fewer significant transmission outages during this period in order to ensure that the power system can reliably meet the heightened summer loads.

At the same time as the July 2020 prompt-month auctions, the ISO administered out-month auctions for August 2020 through December 2020. The volume of FTR transactions that cleared in these out-months auctions was quite low – between 1,136 MW and 2,040 MW, depending on the specific month. The transaction volumes clearing in the out-month auctions that took place concurrently with the August 2020 prompt-month auctions was even lower – between 896 MW and 1,108 MW, depending on the month. The transaction volumes clearing in the out-month auctions that took place concurrently with the September 2020 prompt-month auctions was higher – between 1,027 MW to 1,719 MW, depending on the month. Between 10 and 15 participants participated in the out-month auctions that occurred in Summer 2020, which is about one-third to one-half the participation level seen in the prompt-month auctions.

The Summer 2020 prompt-month FTR auctions (i.e., the prompt-month auctions for July 2020, August 2020, and September 2020) raised $0.7 million, which represents a 45% decrease compared to the Spring 2020 prompt-month auctions ($1.2 million), and a 73% decrease

[48] These totals reflect the sum of the FTR purchases and sales made in both the on-peak and off-peak prompt-month FTR auctions.

compared to the prompt-month auctions that took place in Summer 2019 ($2.5 million). In general, prompt-month auction values have been lower in 2020 than in prior years, partly as the result of lower load levels stemming from the economic shutdown intended to reduce the spread of COVID-19. The total auction revenue of the out-month auctions that were conducted in Summer 2020 was only $14 thousand.

FTR Funding

FTRs in June 2020 and July 2020 were fully funded, meaning that enough congestion revenue and revenue from negative target allocations was collected to pay the positive target allocations in those months. However, FTRs in August 2020 were not fully funded. In August 2020, FTR holders with positive target allocations received only 98.3% of the revenue to which they were entitled. However, there is a congestion revenue fund surplus for 2020 ($2.3 million). As mentioned above, surpluses like this carry over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to those entities that paid the congestion costs.

5.3 Forward Reserve Market

Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During August 2020, the ISO held the forward reserve auction for the Winter 2020-2021 delivery period (i.e., October 1, 2020 to May 31, 2021).[49]

5.3.1 Auction Reserve Requirements

Prior to each auction, the ISO establishes the amount of forward reserves, or requirements, for which it will enter into forward obligations. These requirements are set at levels intended to ensure adequate reserve availability in real-time, based on possible system and local reserve zone contingencies (i.e., unexpected events, such as the forced outage of a large generator or loss of a large transmission line).

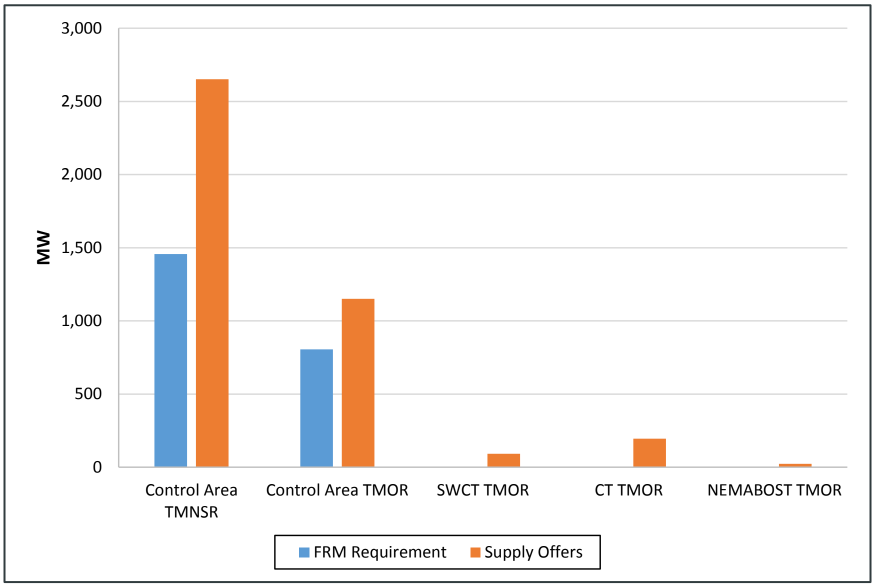
The requirements for the Winter 2020-2021 auction are illustrated in Figure 5-4 below. These requirements were specified for the ISO New England system and three local reserve zones.[50] The figure also illustrates the total quantity of supply offers available in the auction to satisfy the reserve needs.[51]

[49] The Forward Reserve Market has two delivery (“procurement”) periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

[50] The local reserve zones are Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABOST).

[51] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the system-wide TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the system-wide TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are also included in the CT TMOR total. Note that, while the excess TMNSR supply (i.e., supply in excess of the TMNSR requirement) also can be used to satisfy the TMOR requirement, the TMOR supply for the system and local areas has not been adjusted to reflect the availability of excess TMNSR supply.

Figure 5-4: Forward Reserve Requirements and Supply Offer Quantities



For the system, requirements were set for two reserve products: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). The ISO bases the requirements for each product on possible system contingencies. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,456 MW TMNSR reserve need. The system-wide TMOR requirement was based on the expected single contingency of the Seabrook nuclear generator, and was estimated as an 806 MW TMOR need.[52] Supplies were adequate to satisfy requirements for both system-level products.

For the local reserve zones, only a TMOR requirement is specified. The ISO bases the local requirements on local second contingencies, adjusted for the availability of transmission capacity (which can also effectively supply reserves to the local area).[53] After adjustments, all local reserve zones – Connecticut, Southwest Connecticut and NEMA/Boston – were found to need no local reserve requirement, as "external reserve support" (i.e., available transmission capacity) exceeded the local second contingency requirements.

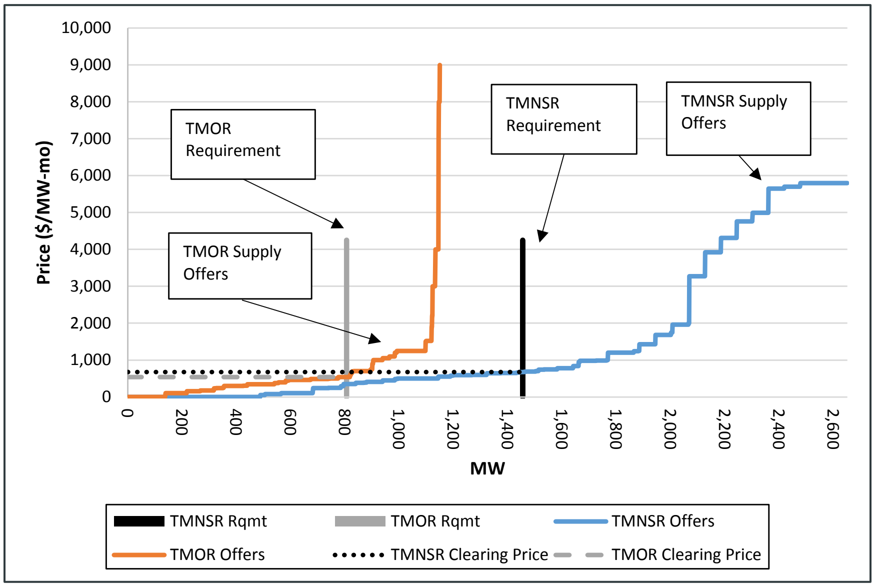
[52] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Winter 2020-2021 Forward Reserve Auction), published July 21, 2020, indicates the system-wide and local reserve zone requirements. For the system-wide requirements, the final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement.

[53] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5). The transmission capacity used to adjust the local requirement is referred to as "external reserve support."

5.3.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Winter 2020-2021 auction exceeded the requirements for both TMNSR and TMOR. Adequate supply ensures that the ISO can successfully obtain forward obligations to meet expected reserve needs in the auction. Figure 5-5 below provides the requirements, system-wide supply curves, and clearing prices for both TMNSR and TMOR.

Figure 5-5: Supply Curves, Requirements and Clearing Prices, System-Wide TMOR & TMNSR



With system-wide requirements of 806 MW for TMOR and 1,456 MW for TMNSR, system-wide supply offers for the two products resulted in clearing prices of $540/MW-month for TMOR and $678/MW-month for TMNSR (gray and black dashed/dotted lines in the figure).

5.3.3 Price Summary

Forward reserve clearing prices for the system-wide TMNSR and TMOR products for the previous six auctions are shown in Figure 5-6 below.

Figure 5-6: FRM Clearing Prices for System-Wide TMNSR and TMOR

In the Winter 2020-2021 auction, TMNSR cleared at a higher price than TMOR (TMNSR: $678/MW-month; TMOR: $540/MW-month). Compared to the Winter 2019-2020 auction, TMNSR and TMOR both cleared at lower prices (Winter 2019-2020: TMNSR and TMOR prices equaled $799/MW-month). This decline in prices resulted from reduced TMNSR and TMOR offer prices in the 2020-2021 auction; the TMOR requirement for both winter auctions was the same, while the TMNSR requirement for the 2020-2021 period increased by approximately five percent.

The clearing prices also declined in the Winter 2020-2021 auction compared to the Summer 2020 auction (TMNSR: $1249/MW-month; TMOR: $900/MW-month). The reduction in the Winter auction prices compared to Summer 2020 again resulted primarily from a decrease in offer prices. The TMOR requirement for the Winter auction increased slightly (3%) and would not explain the reduction in the Winter period TMOR clearing price. The decline in the TMNSR clearing price in the Winter auction was aided by a reduction in the TMNSR requirement (9%); however, the reduction in the TMNSR requirement for the Winter period would only explain about $100/MW-month of the $570/MW-month reduction in the TMNSR clearing price.

5.3.4 Structural Competitiveness

The structural competitiveness of the Forward Reserve Market can be measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest FRM portfolio offer. If the requirement cannot be met without the largest supplier, then that supplier is pivotal. The RSI is calculated based on the FRM offer quantities.

The RSI for TMNSR is computed at a system level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant. The RSI for TMOR is computed similarly for each reserve zone with a non-zero TMOR local reserve requirement. Given that TMNSR can also satisfy the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

The heat map table –Table 5-2 below – shows the offer RSI for system TMNSR and TMOR for zones with a non-zero TMOR requirement. The colors indicate the degree to which structural market power was present, starting with low RSIs shown in red, followed by white and green colors, with the latter indicating that there was still ample offered supply without the largest supplier.

Table 5-2: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2018	112	214	438	N/A	34
Winter 2018-19	127	244	N/A	N/A	21
Summer 2019	90	204	N/A	N/A	N/A
Winter 2019-20	120	254	N/A	N/A	N/A
Summer 2020	84	234	N/A	N/A	N/A
Winter 2020-21	102	253	N/A	N/A	N/A

An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices. With two exceptions, from the Summer 2018 through Winter 2020-21 procurement periods, the TMNSR RSI values were greater than 100. These values suggest that the TMNSR offer quantities in these auctions frequently were consistent with a structurally competitive level. In two Summer auctions, RSI values were slightly below the structurally competitive level. In Summer 2019, the decline in RSI resulted from a slightly increased TMNSR requirement (by approximately 7% compared to Summer 2018) and a medium-sized supplier not participating in the Summer 2019 auction. The Summer 2020 results likewise had an increased requirement (up an additional 4% compared to Summer 2019), coupled with a small net reduction in supply offers (approximately 2% compared to the prior Summer).

The TMOR RSI values for the ROS zone were consistent with a structurally competitive level throughout the review period.[54] Likewise, the SWCT zone was structurally competitive, when it had a reserve requirement. NEMA/Boston, however, has been structurally uncompetitive for all recent auctions for which it had a requirement. In these auctions, every participant that offered forward reserves in NEMA/Boston was needed to meet the local requirement.

[54] The "Rest-of-System" zone is simply the portion of the system that excludes the local reserve zones (CT, SWCT, and NEMABOST).