Spring 2020 Quarterly Markets Report

By ISO New England's Internal Market Monitor

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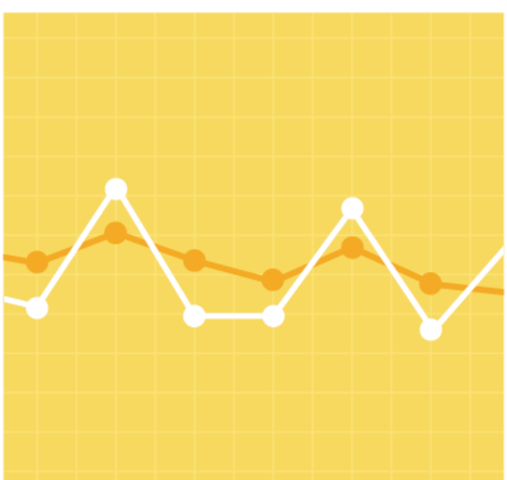
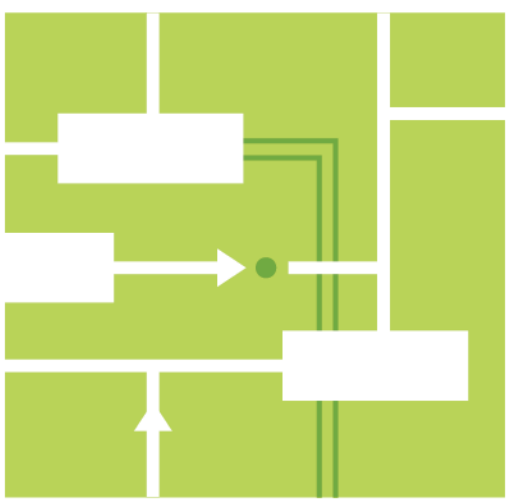


Document Revision History		
Date	**Version**	**Remarks**
7/31/2020	Original	Initial Posting
8/17/2020	Revision 1	1) Correction to the share of transmission costs as a percentage of the total wholesale costs on page 18. Transmission costs comprise more than 20% of total costs as reported in the annual markets report, and not 40% as originally stated. 2) Correction to nuclear generation decrease on page 39. Nuclear production shares fell from 27% (3,300 MW per hour) in Spring 2019, not in Winter 2020 as originally stated.

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.

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[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 Spring 2020 (March 1, 2020 through May 31, 2020).[3]

Review of Notable System Events: On May 27, an unplanned outage of the Phase II interconnection resulted in the unexpected loss of 1,890 MW of energy imports just before 3pm. Phase II returned to service later that evening. On May 29, the ISO first experienced a 1,250 MW loss due to an unexpected nuclear generator outage just after 2pm, and then Phase II tripped at 8:30pm, resulting in a 1,340 MW loss. The losses persisted into May 30. Key observations from these events include:

- Despite the magnitude of the losses (approximately 2-2.5 GW/hour), the system was able to recover quickly and the ISO did not experience a capacity scarcity event.[4]
- To ensure system reliability, the ISO's market software and RAA process committed additional generators in real-time following the supply losses. The magnitude of additional generation committed was appropriate, as it was smaller than the supply losses on average. Additionally, spinning reserve margins remained at low to normal values, indicating that there was no notable excess of online generation.
- The major supply losses resulted in high 5-minute real-time energy prices, peaking at $183.93/MWh around 5pm on May 27 and at $224.46/MWh at 12:30am on May 30.
- Reserve prices peaked at $129.32/MWh on May 27 and at $50/MWh on May 29 and 30. Though redispatch was needed to procure additional non-spinning reserves on May 27, the system did not become deficient in non-spinning reserves, and the reserve constraint penalty factors (RCPFs) for the 10- and 30-minute non-spinning products did not bind.
- Real-time first contingency uplift payments during the hours affected by system events on May 27, 29, and 30 totaled $381,000.

Transmission Cost Allocation Issues for Behind-The-Meter Generation: Regional Network Load (RNL) is used as an allocator of transmission costs among network customers, and per the ISO New England (ISO-NE) tariff is required to be grossed up (or reconstituted) to account for behind-the-meter (BTM) generation. This is because network customers with BTM generation continue to rely on the same firm-like, homogenous and integrated transmission service as customers without BTM generation.

We are concerned that there is potentially widespread under-reporting of RNL due to not reconstituting peak usage for BTM generation. Under-reporting of RNL results in a lower allocation of transmission costs to the under-reporting transmission customer, and consequently over-allocation to others. The financial impact of under-reporting can be significant for individual projects or transmission customers. At the state level, considering

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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] Under the capacity market's pay-for-performance rules, a capacity scarcity event occurs when the system or local area is short on ten- and/or thirty-minute non-spinning reserves, and the reserve constraint penalty factor for one or more of these non-spinning products is setting the real-time reserve price.

current and future projections of BTM photovoltaic generation, the extent of cost shifting due to not reconstituting RNL appears to be relative small.

We conclude our assessment with the following recommendations:

a. As required under the ISO-NE tariff, non-compliant transmission owners and network customers should change their current practices to reconstitute monthly RNL to account for actual or estimated BTM generation production during the monthly peak hour.
b. ISO-NE should review the need for a certification process requiring entities submitting monthly RNL values confirm they have been appropriately reconstituted.
c. The PTOs, in coordination with ISO-NE, should review the tariff to assess if certain clarifications or additional specificity would be helpful. We recommend adding a definition for *Behind-the-Meter Generation* and more specificity on the determination of *Monthly Regional Network Load*, including the determination of the peak load hour. The ISO should review operating procedures to determine whether references to load reducers should be clarified.
d. A wider review may be warranted as part of a PTO-led initiative to assess whether the uniform regional transmission rate structure, based on monthly RNL, is consistent with current transmission planning practices, and/or should be revised to account for the value of BTM generation.

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.25 billion, down 35% from $1.91 billion in Spring 2019.

- Lower energy and capacity market costs drove the decrease in wholesale costs.

Energy costs totaled $481 million; down 46% (or $413 million) from Spring 2019 costs. Lower energy costs were a result of lower natural gas prices and lower loads. Natural gas prices decreased by 47% relative to Spring 2019 prices, while average hourly loads decreased by 6% or 750 MW.

Capacity costs totaled nearly $751 million, down 24% (by $242 million) from last Spring. Beginning in Summer 2019, lower capacity clearing prices from the tenth Forward Capacity Auction (FCA 10) resulted in lower wholesale costs relative to previous quarters.[5] Last year, the capacity payment rate was $9.55/kW-month in all capacity zones except SEMA/Rhode Island.[6] This year, the payment rate for new and existing resources was lower, at $7.03/kW-month. The lower clearing prices caused capacity costs to decrease.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $17.33 and $17.62 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 39-42% lower than Spring 2019 prices, on average, and were the lowest average quarterly prices since the implementation of the current market structure in March 2003.

- Day-ahead and real-time energy prices continued to track with natural gas prices.

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[5] FCA 10 was run in February 2016, approximately 3.5 years prior to the annual delivery period commencing on June 1, 2019.

[6] As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones.

- Gas prices averaged $1.61/MMBtu in Spring 2020, a decrease of 47% compared to $3.04/MMBtu in the prior spring.
- Hourly load averaged 11,608 MW, the lowest average seasonal load since at least 2000, and down by 6% (≈750 MW) on the previous spring. The decrease was driven by the COVID-19 pandemic, along with the continued increase in behind-the-meter solar generation and energy efficiency.
- Energy market prices did not differ significantly among the load zones.

Net Commitment Period Compensation: Uplift payments totaled $5.5 million, a decrease of $1.8 million compared to Spring 2019. Uplift payments represented 1% of total wholesale energy costs in Spring 2020, a similar share compared to other quarters in the reporting horizon. The majority of uplift (89%) was for first contingency protection (also known as "economic" uplift). The ISO paid out most of the first contingency payments in the real-time market. Compared to Spring 2019, economic out-of-merit payments[7] fell by $0.5 million (from $3.6 million to $3.1 million). This decrease offset the increase in posturing payments, which increased by $81 thousand compared to Spring 2019 due to unexpected generator and transmission outages at the end of May 2020.

At $0.2 million, local second-contingency protection (LSCPR) payments accounted for just 4% of total uplift payments. These payments decreased by $0.3 million relative to Spring 2019, and were primarily paid to generators in New Hampshire, southeastern Massachusetts, and Rhode Island to support planned transmission outages.

Real-time Reserves: Real-time reserve payments totaled $2.1 million, a $0.3 million decrease from $2.4 million in Spring 2019. The small decline resulted from lower energy prices and a decrease in the magnitude of non-zero reserve prices. Most (91%) Spring 2020 reserve payments were for ten-minute spinning reserve (TMSR). The majority of non-spinning reserve payments for Spring 2020 occurred on May 27, when the unexpected loss of the Phase II interconnection resulted in tight system conditions.

The average non-zero hourly spinning reserve price decreased relative to Spring 2019, from $10.97 to $6.19/MWh. The frequency of non-zero spinning reserve prices increased from 371 hours to 490 hours.

***Regulation*:** Total regulation market payments were $3.3 million, down 25% from $4.3 million in Spring 2019. The decrease in payments reflects a reduction in real-time energy market LMPs that reduced energy market opportunity costs for regulation generators.

Financial Transmission Rights: The volume of FTR transactions that cleared in the three prompt-month auctions for April, May, and June 2020 ranged from 15,362 MW to 19,783 MW. The cleared volumes and levels of participation were lower compared to other recent prompt-month auctions. These decreases may reflect participants' expectations of reduced congestion in the day-ahead market, possibly as a result of lower load levels stemming from the economic shutdown intended to reduce the spread of COVID-19. The total auction revenue for the prompt-month auctions that were conducted in Spring 2020 was $1.2 million, which was lower than the revenue for the prompt-month auctions held in Winter 2020 and Spring 2019.

[7] Out-of-merit NCPC ensures recovery of as-offered commitment and dispatch production costs that are not recovered through the LMP.

The volume of FTR transactions that cleared in the out-month auctions administered in April, May, and June was relatively low.[8] The number of participants in these out-month auctions 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 Spring 2020 was just $17 thousand.

Summer 2020 Forward Reserve Market Auction: In April 2020, ISO New England held the forward reserve auction for the Summer 2020 delivery period (i.e., June 1 to September 30, 2020). System-wide supply offers in the Summer 2020 auction exceeded the requirements for both ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR).

The Residual Supply Index (RSI) for the system-level TMNSR product declined to 84, which was below the structurally competitive level. The decreased competitiveness resulted from an increased TMNSR requirement and a small net reduction in supply offers.

The net clearing prices for offline 30- and 10-minute system reserves were $900 and $1,249/MW-month, respectively, a decrease from the Summer 2019 price ($1,899/MW-month for both products).

[8] On September 17, 2019, the ISO implemented the Balance of Planning Period (BoPP) project, which increased opportunities for market participants to reconfigure their monthly Financial Transmission Rights (FTR) positions following the two annual auctions. In additional to buying and selling FTRs for a given month during the prior month ("prompt-month"), participants also can buy and sell monthly FTRs positions over the remainder of the year before the "prompt-month" auctions take place. The new auctions are called "out-month" auctions.

Section 2
Special Topic: Review of Notable Events and Market Performance

This section covers market outcomes and performance for three days at the end of May 2020, when substantial unexpected losses of energy supply resulted in tight system conditions and high real-time energy prices.

On May 27, the Phase II interconnection with Hydro Quebec went off-line just before 3pm due to a lightning strike, resulting in the unexpected loss of 1,890 MW of energy imports into New England. Phase II returned to service later that evening. On May 29, the ISO first experienced a loss of 1,250 MW due to an unexpected nuclear generator outage just after 2pm, and then later at 8:30pm the Phase II interconnection unexpectedly failed due to an equipment issue, resulting in a loss of 1,340 MW. The losses persisted into May 30: Phase II partially returned in the afternoon, while the nuclear generator remained out of service until June 1, despite having a day-ahead schedule for May 30.

Although the unexpected losses of energy on both occasions was relatively large (in the 2-2.5 GW/hour range), the ISO's real-time energy market did not experience a capacity scarcity event, and the ISO did not have to implement M/LCC2 or OP4 protocols.[9, 10,11] On both May 27 and May 29, conditions were relatively stable before the supply losses occurred, and the system was able to recover from the losses quickly. The ISO committed additional generators in real-time following the system events, and the commitments were appropriate given the supply losses. On average, the additional real-time generation commitments were smaller in magnitude than the supply losses. Further, spinning reserve margins remained at low to normal values, indicating that there was no notable excess in online generation.

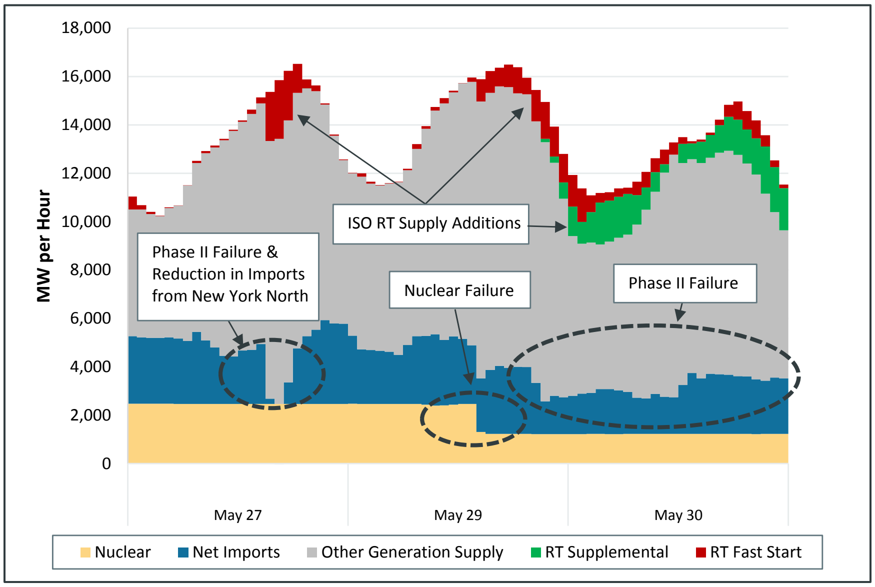
[9] A capacity scarcity event occurs when the system or local area is short on 10- and/or 30-minute non-spinning reserves, and the reserve constraint penalty factor for one or more of these non-spinning products is setting the real-time reserve price.

[10] When notified of an M/LCC 2 Abnormal Conditions Alert, applicable power system personnel and market participants are expected to take precautions so that routine maintenance, construction or test activities do not further jeopardize the reliability of the power system.

[11] Operating Procedure #4 establishes criteria and guidelines for actions during a capacity deficiency, as directed by the ISO and as implemented by ISO and the Local Control Centers (LCCs).

The timing and magnitude of these unexpected supply losses are illustrated in Figure 2-1 below.

Figure 2-1: Real-Time Supply Composition on May 27, 29 and 30[12]



To ensure the reliability of the transmission system during these substantial supply losses, the ISO committed additional generators to provide both energy and reserves. These commitments included both fast-start generators that could come on-line quickly (within 10 or 30 minutes, red shading in figure) and longer-lead-time generators that were supplementally committed on May 29 several hours after the initial recoveries and May 30 the next day (green shading).[13]

The following section describes system conditions when the supply losses occurred and the ISO's response to these losses.

2.1 System Conditions

Load Forecast Error

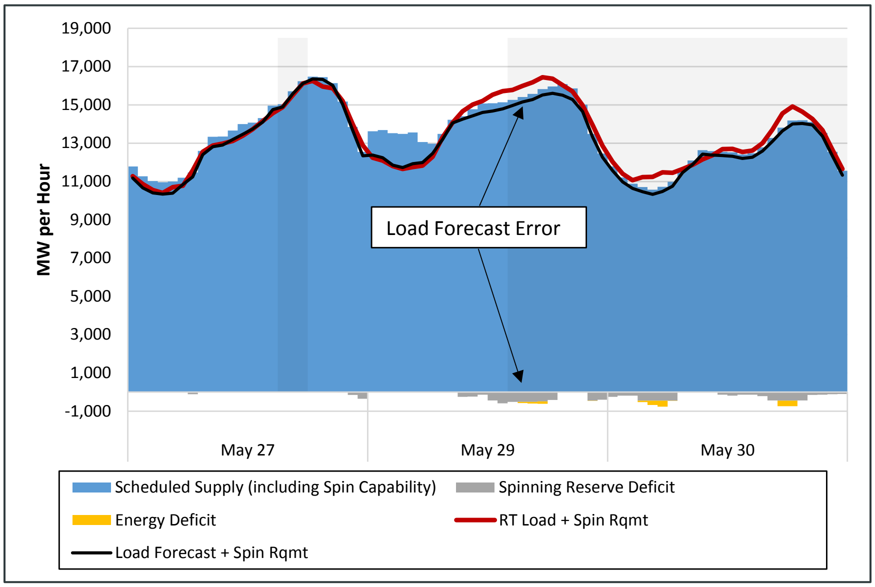
In reviewing system conditions on the days with significant supply reductions, we also reviewed load forecast error to determine whether it contributed to the need to commit additional supply. This measurement of load forecast error utilizes the load forecast and operating plan developed in the Reserve Adequacy Assessment (RAA). The ISO performs the RAA after the day-ahead market (DAM) closes, to ensure that sufficient capacity has been committed to meet the ISO's load forecast for the real-time market and its reserve requirements; it represents the initial operating plan developed by the ISO, and real-time market load that significantly exceeds the ISO's RAA forecast can be expected to result in the commitment of additional supply during the operating day.

[12] Reduction in net imports from New York North is relative to the day-ahead cleared quantity.

[13] Supplementally-committed generators simply refer to longer-lead-time generators committed after the day-ahead market had closed.

The degree of load forecast error in the real-time energy market on the event days is indicated in Figure 2-2 below.

Figure 2-2: Load Forecast Error's Contribution to System Conditions in the Real-Time Energy Market



Because the ISO must commit sufficient on-line capacity to meet both load and the spinning reserve requirement, load forecast error is measured as the difference between actual real-time load plus the spinning reserve requirement (red line) and the RAA load forecast plus the spinning reserve requirement (black line). The blue area of the chart shows the total energy available to satisfy both load and spinning reserves in the RAA. Load forecast error can affect the sufficiency of spinning reserves and also affect the ability to meet consumption. On the graph, the darker gray shaded areas below the blue area indicate the spinning reserve deficit resulting from load forecast error and the yellow shaded areas indicate an energy deficit when on-line capacity is insufficient to satisfy spinning reserves and consumption. The light background shading on the chart indicates the periods when the real-time market experienced the large supply disruptions.

The data suggest that the RAA load forecast was reasonably accurate on May 27: load forecast error was inconsequential, with only four hours of spinning reserve deficits averaging 162 MW per hour. Absent the loss of imports over Phase II and a reduction in expected imports over the New York North interface during the operating day, sufficient supply had been committed in the day-ahead market to meet real-time load and spinning reserve needs.

On May 29 and 30, however, real-time loads exceeded expectations by more significant margins. By the late morning of May 29, the real-time market's load levels had become noticeably higher than the RAA's forecast. From hours ending 10 through 19, load forecast error would have resulted in deficits for committed supply that ranged from 100 to 600 MW per hour, all other factors equal. Load forecast error again arose late in the day on May 29 and carried over to most hours on May 30. The resulting supply deficit during these hours ranged from approximately 100 to 800 MW per hour and averaged approximately 350 MW per hour.

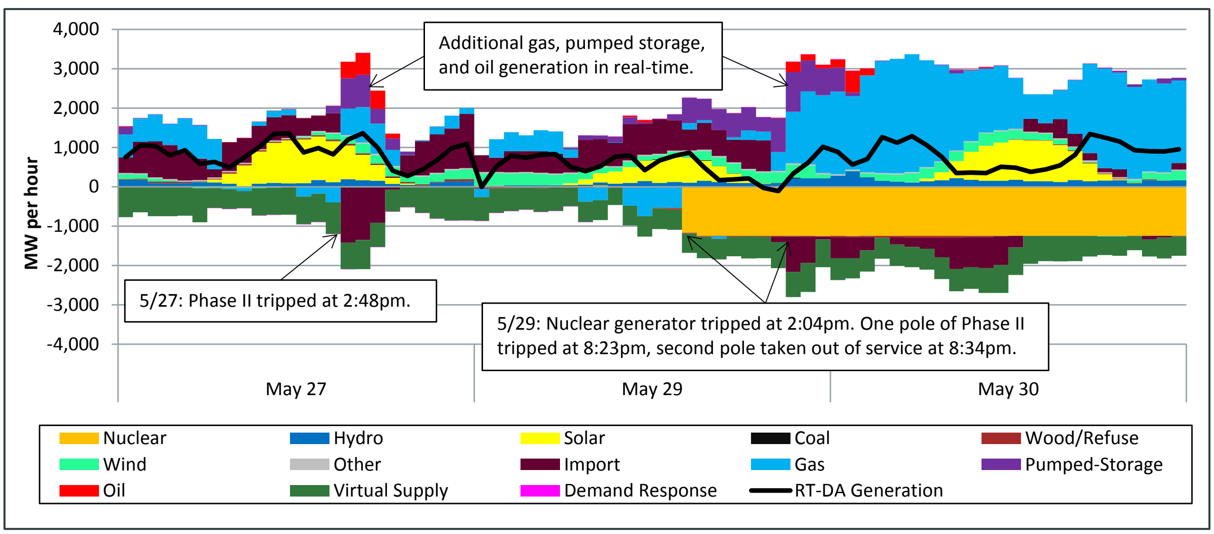
On these days, the load forecast error, however, primarily affected the system's ability to meet spinning reserves needs and not energy needs. The need for additional energy was apparent only in a few hours and was relatively small (never exceeding 304 MW per hour). Hence, the forecast error would lead to the need to commit additional supply to restore unloaded capacity (i.e., spinning reserves) – rather than meeting energy needs.

2.2 ISO and Market Response

Day-Ahead vs. Real-Time Supply Mix

The differences between day-ahead and real-time generation obligations provide insight into the types and amount of day-ahead cleared supply that failed to materialize in real-time and those that exceeded day-ahead obligations in real-time. These differences have important implications for real-time price formation. The breakdown in differences between day-ahead and real-time generation obligations is shown in Figure 2-3 below. The stacked area represents the hourly real-time deviations aggregated by fuel type, and the black line illustrates the net deviation.

Figure 2-3: Average Hourly Differences between Real-Time and Day-Ahead Generation Obligations[14]



In the three hours after the May 27 Phase II loss, imports collectively provided 900-1,400 MW less per hour than their aggregate day-ahead supply obligation in those hours. Additionally, the total real-time generation obligation was greater than the generation that had cleared in the day-ahead market, indicating that more generation was needed to meet real-time load than was anticipated in the day-ahead market. The unplanned loss in imports and the higher real-time generation obligation resulted in additional real-time gas, pumped-storage, and oil generation between 3pm and 6pm. Figure 2-3 also shows additional solar (including settlement-only

[14] The import category on this graph includes imports only, and is therefore different from the net interchange values presented elsewhere in this section, as net interchange accounts for exports.

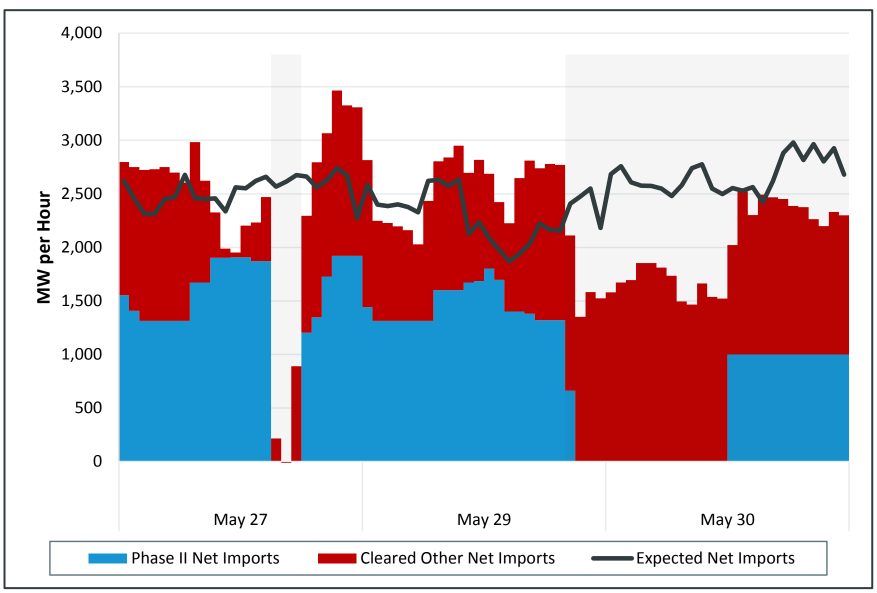
generation) and wind generation on the system in real-time, which is a common occurrence because these types of generators tend to clear less in the day-ahead market.

In the hours preceding the May 29 supply losses, the real-time generation obligation was higher than the day-ahead obligation, but additional supply from imports and renewable generators displaced some of the gas generation that had cleared in the day-ahead market. After the major generator trip at 2pm, there was 1,250 MW less real-time nuclear generation compared to the day-ahead generation obligation; additional pumped-storage and gas generation was needed to compensate for the loss. Then, the Phase II trip around 8:30pm, resulted in additional needs for more real-time generation. During the hours between 10pm on May 29 and 8am on May 30, there was between 2,500 and 3,000 MW of additional gas, pumped-storage, and oil generation on the system in real-time. Since day-ahead schedules for May 30 had already been established prior to the May 29 trips, the supply losses from nuclear generation and imports persisted into May 30. In addition, low pond levels indicated that fuel supplies were extremely limited for 1,500 MW of online capacity during the period, which led to spinning reserve shortages.

Net Imports

Two disruptions to net imports resulted in significant supply reductions over the system event period of May 27, 29 and 30. On each day, these reductions totaled between 1,000 to 2,000 MW per hour, based on both flows during the operating day that preceded the outage and the expected flows used in the ISO's planning for the operating day. The hourly actual net interchange and the total expected net flows are indicated in Figure 2-4 below.[15]

Figure 2-4: Net Imports in the Real-Time Energy Market on May 27, 29 and 30



The most significant supply disruptions occurred with the loss of Phase II on May 27 and then again on May 29 and 30 (loss periods indicated by the light background shading). On May 27, a

[15] The expected net interchange reflects the assumed net interchange used in the RAA.

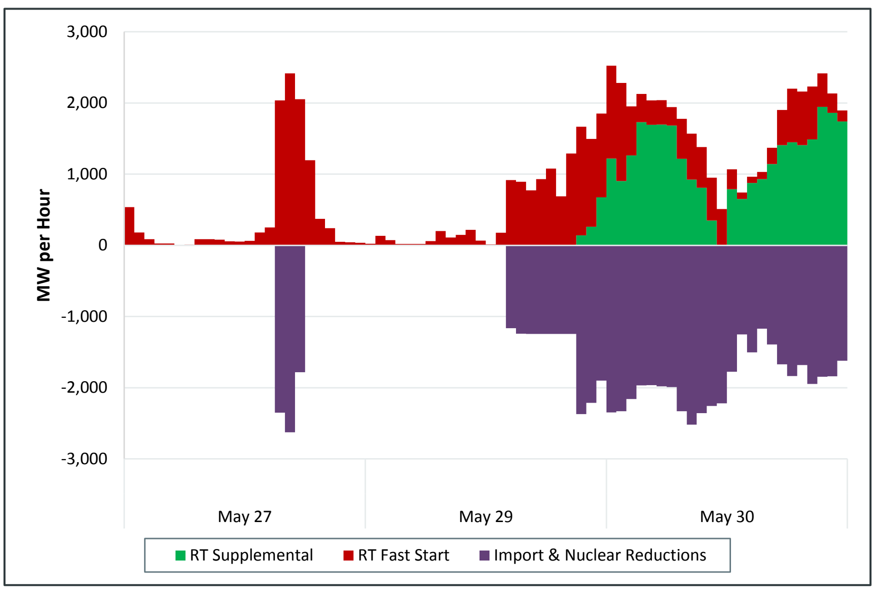
lightning strike disabled flows over Phase II into New England (blue shading), reducing supply by almost 1,900 MW per hour (based on the flows just preceding the outage). In addition, expected net imports over the New York North interface were also reduced (relative to the day-ahead cleared quantity), decreasing net imports into New England to almost 0 MW for two of the three outage hours.

On May 29, an explosion on pole 1 of Phase II and a related forced outage of pole 2 disabled flows into New England, reducing net imports from Phase II by over 1,000 MW per hour during the outage. Other net imports increased over this period to partially offset Phase II losses by up to 500 MW per hour; the additional imports came from the New Brunswick and Northport-Norwalk interfaces. This outage persisted until the early afternoon of May 30, when it returned at a reduced capacity of 1,000 MW as a result of one pole being restored. The other pole was restored on June 3. As a result Phase II was limited to 1,000 MW until June 3.

Energy from Real-Time Supplemental Generator Commitments

During the May 27 period with the Phase II loss and New York North import reduction and the May 29 and 30 period with the nuclear outage and Phase II loss, the ISO committed significant additional generation in the real-time energy market. These corrective actions ensured that real-time load would be met, while maintaining spinning reserve capability. The ISO's corrective commitments, relative to the supply losses, are shown in Figure 2-5 below.

Figure 2-5: Supplemental Generator Commitments on May 27, 29 and 30

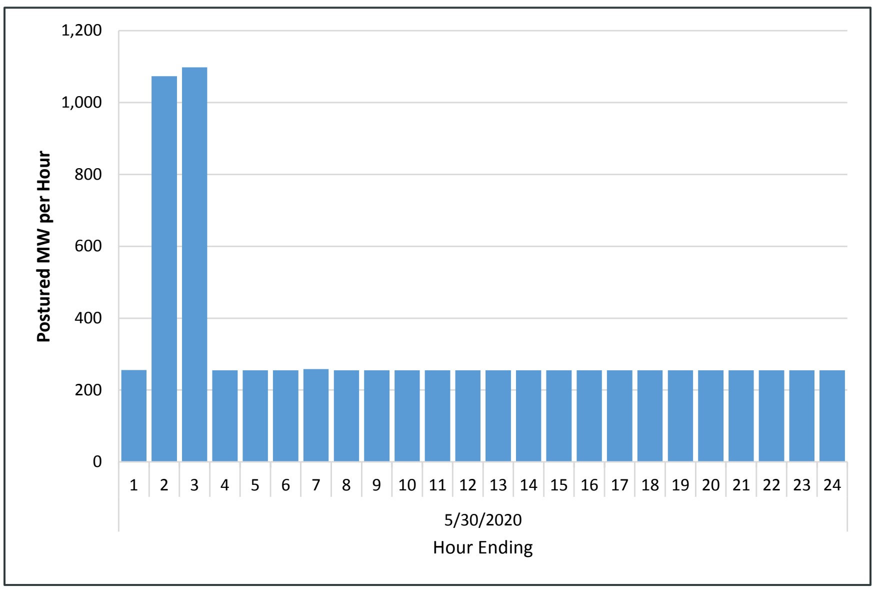


During the periods with the large unexpected supply reductions, the market software and RAA process committed an average of 1,600 MW per hour of additional supply (energy); the supply reductions averaged 1,800 MW per hour. Because of fluctuations in self-scheduled generation and settlement-only generation, the ISO did not need to commit additional supply equal to the full energy reductions in most hours. Both fast-start generators and longer lead-time generators were committed by the ISO. On May 27, the ISO committed only fast-start generators for the relatively short-duration import losses. On May 29 and 30, both longer lead-time and fast-start generators were committed for the longer duration nuclear and Phase II outages, but most of the additional energy provided on May 30 came from the longer lead-time generators (i.e., 1,100 MW per hour on average, versus 500 MW per hour from fast-start generators). The supply committed to offset the energy losses came exclusively from generators, with no significant supply commitment from demand reduction resources.

Posturing

The ISO may "posture" generators to ensure adequate operating reserves or to provide voltage (VAR) support. Posturing refers to instances where a generator is instructed to operate below its economic dispatch point for reliability reasons.[16] The ISO postured generators on just one of the three supply disruption days. On May 30, the ISO instructed several pumped-storage generators to go (or remain) off-line, to ensure the adequacy of 10-minute operating reserves due to limited fuel availability and uncertainty about supply availability for the next operating day. The magnitude and timing of the posturing is depicted in Figure 2-6 below.

Figure 2-6: Generator Posturing



Hours ending 2 and 3 had the highest levels of posturing, at approximately 1,100 MW per hour (with four postured generators). In all other hours, pumped-storage posturing totaled slightly more than 250 MW per hour (with a single postured generator). Non-pumped-storage generators were not postured during the operating day.

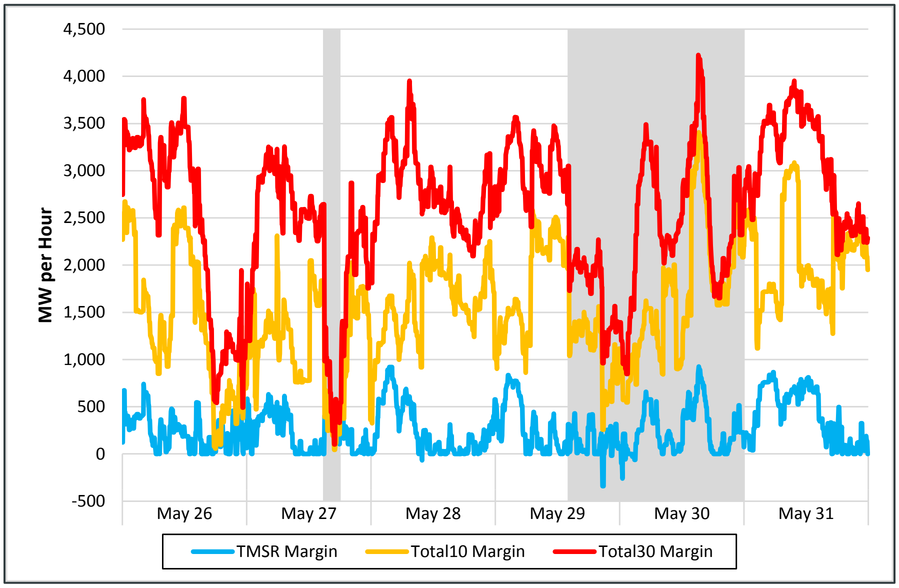
Reserve Margins and Excess Commitment Determination

Observing the availability of reserve products can provide insight into whether or not the ISO committed excess generation in response to the unexpected supply losses. The margins for each reserve product from May 26 to May 31 are shown in Figure 2-7 below. The additional days outside of the system event periods are shown for comparison. The hours that were affected by

[16] Control Room Operating Procedure, CROP.25001 Posturing, outlines the ISO's posturing procedures.

large supply losses are highlighted in gray. For each reserve product, the margin is equal to available reserves minus the reserve requirement.

Figure 2-7: Reserve Margins from the Real-Time Unit Dispatch System[17]



Shortly after the 1,890 MW loss of Phase II on May 27, the Total30 reserve margin dropped quickly, and ranged from just 100 to 240 MW between 4:30pm and 5pm. This was well below the average Total30 margin for January 2019 through May 2020, which was 3,100 MW. The Total30 margin increased after the ISO committed additional generators to compensate for the import losses. However, the margins for each reserve product all fell within low to normal ranges after the event. The reserve margin fluctuations following the Phase II trip were consistent with the loss in net imports and the commitment of generators to compensate for the loss.

On May 29, the Total30 reserve margin decreased by nearly 1,200 MW immediately after the nuclear generator loss, falling to about 1,800 MW. Despite the loss, the Total30 margin remained positive in the early afternoon, and rose above 2,000 MW for several hours before the next supply loss. After the loss of Phase II around 8:30pm, the Total30 margin decreased to 960 MW, and further decreased to 850 MW for 20 minutes during the early hours of May 30. The drop in the Total30 margin was not as drastic on May 29 as it was on May 27 because the supply losses were spread out over several hours, with smaller immediate supply losses on May 29 (1,250 and 1,340 MW on May 29, compared to 1,890 MW on May 27). Additionally, the initial pre-loss margin was higher on May 29.

The ten-minute spinning reserve (TMSR) margin is a better indicator of excess commitments than the offline reserve margins, because the TMSR margin only includes reserves from resources that are synced to the grid (online). Following both system events, the TMSR margins remained relatively low or normal compared to historical values. On May 27, the hourly average TMSR margin ranged from about 60 to 450 MW after the Phase II trip. On May 29, the hourly

[17] The reserve margins presented in this figure are from the dispatch run of the market optimization software. The non-spinning reserve margins from the *pricing* run of the market software went down to 0 for certain intervals on May 27, resulting in non-zero TMNSR and TMOR pricing.

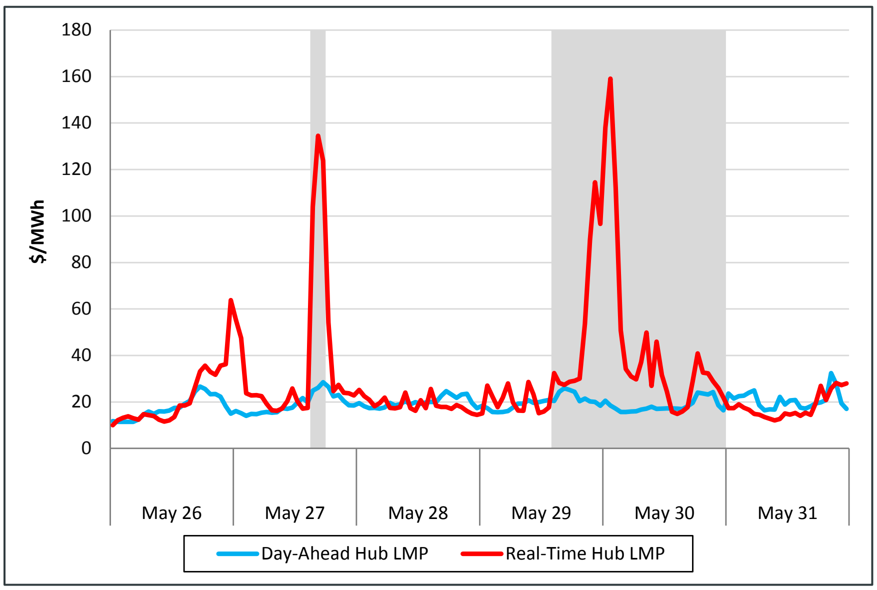
average TMSR margin ranged from 24 to 335 MW between the first generation loss and the end of the day, and remained at low or normal values for most of the following day. The low TMSR margins following the system events and the typical margins hours later indicate that the ISO did not overcommit the system. The volume of real-time supplemental commitments compared to the supply losses described in the previous section also support this.

2.3 Market Impacts and Event Outcomes

Real-Time Energy Prices

Hourly day-ahead and real-time energy prices at the Hub are shown in Figure 2-8 below. The additional days outside of the system event periods as well as the day-ahead prices are shown for comparative purposes. The hours that were affected by large supply losses are highlighted in gray.

Figure 2-8: Houry Hub LMPs, May 26-31



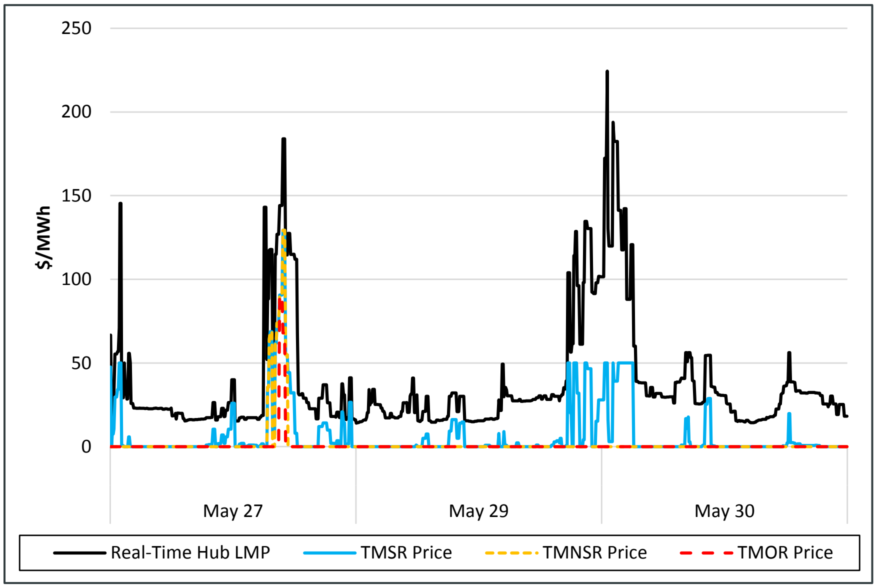
On May 27, real-time prices increased significantly shortly after the Phase II trip. From 3pm-6pm, hourly day-ahead prices ranged from $24.86-$28.46/MWh, while hourly real-time prices ranged from $103.92-$134.48/MWh. The highest five-minute real-time LMP was $183.93/MWh, which occurred for 15 minutes between 4:50pm and 5:05pm.

On May 29, real-time prices increased just slightly above day-ahead prices shortly after the major generator loss. Real-time system conditions were stable up to the point of the generator trip, as it was well before the evening peak, and there was additional low-priced supply coming from imports and renewable generators. However, the Phase II trip in the evening put additional strain on the system, and real-time prices went up to $89.75-$159.09/MWh from 9pm on May 29 through 3am the following morning. The highest five-minute real-time LMPs occurred at 12:30am on May 30, reaching $224.46/MWh.

Real-Time Reserve Pricing

During certain times on these three days in May, high reserve prices contributed to high real-time LMPs. The real-time Hub LMP and system level reserve price for each product are shown at the five-minute level in Figure 2-9 below.

Figure 2-9: Five-Minute Real-Time Hub LMPs and Rest-of-System Reserve Prices



On May 27, there was non-zero pricing for all three reserve products. For a total of 105 minutes between 3:20pm and 5:15pm, system redispatch was needed to procure additional non-spinning reserves, and there were non-zero prices for either the TMNSR or TMOR products, or for both during the same interval. The maximum reserve price occurred between 4:50pm and 5pm, reaching $129.32/MWh. At certain times, the prices for different reserve products were the same, because the TMNSR price was added to the TMSR price, and the TMOR price was added to the TMNSR and TMSR price. This cascading of reserve prices is done to ensure that higher quality reserve products are paid at least as much as lower quality reserve products.

Though non-spinning reserve pricing occurred on May 27, there were no deficits for the non-spinning products and the system did not experience a capacity scarcity event. For reference, during the capacity scarcity event that occurred on September 3, 2018, deficits triggered reserve constraint penalty factors (RCPFs) of $1,000/MWh (TMOR requirement) and $1,500/MWh (TMNSR requirement), and reserve prices reached $2,500/MWh.

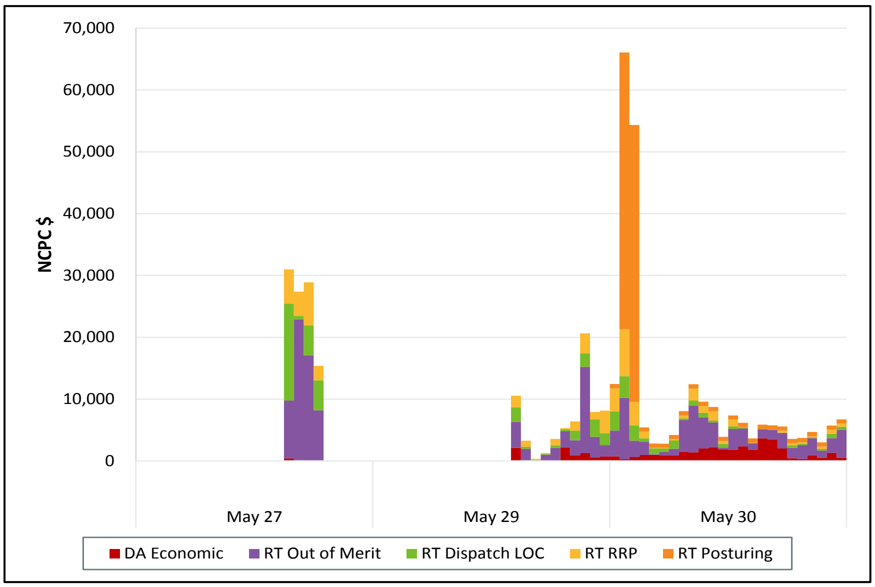
On May 29 and 30, the only reserve product with non-zero pricing was the ten-minute spinning reserve (TMSR) product. The TMSR RCPF of $50 was in effect for 50 minutes on May 29, and for 115 minutes on May 30. Figure 2-9 shows how the highest real-time LMPs occurred when the TMSR RCPF was in effect.

NCPC Payments

The ISO provides uplift payments (net commitment period compensation, NCPC) when generators operate at a loss as result of following the ISO's commitment and dispatch directives. Losses can result from energy market revenues being insufficient to cover a generator's as-bid costs or from a generator being held below economic operating levels when satisfying the ISO's energy or reliability needs. Uplift payments may increase during periods requiring relatively large quantities of supplemental commitments and other actions to ensure system reliability in the real-time energy market.

Economic or first contingency uplift payments are shown in Figure 2-10 below. The figure only includes payments for the hours during which the system events occurred (i.e., hours ending 16-18 on May 27, and hour ending 15 on May 29 through hour ending 24 on May 30).

Figure 2-10: Hourly NCPC Payments During Supply Disruption Hours on May 27, 29 and 30



Day-ahead economic uplift payments during the system event hours were relatively small at \$42,000. Total real-time payments for categories associated with meeting the system's first contingency needs (to maintain energy and operating reserves) totaled \$381,000.

The real-time payments are broken down by uplift payment type. The most notable payments occurred for posturing (orange) during the hours ending 2 and 3 on May 30, when over 1,000 MW of pumped- storage generating capacity was postured off-line by the ISO to ensure 10-minute operating reserves. Uplift payments for posturing during these hours totaled approximately \$90,000 (24% of total real-time uplift payments); total posturing payments during all event hours was \$105,000 (28% of total real-time uplift payments). Posturing may reduce a generator's output level below its economic dispatch point, causing the generator to forego short-run profits. When this occurs, posturing uplift payments restore the foregone profits to ensure the postured generator will follow the ISO's dispatch instructions.

Real-time out-of-merit uplift payments (purple) during the event hours had the highest total at $161,000 or 42% of the overall payments. Out-of-merit uplift is the traditional form of uplift, and is provided when market revenues are insufficient to cover a generator's as-bid commitment and dispatch costs. Two other categories of real-time uplift also were significant: dispatch lost opportunity cost (green) and rapid response pricing opportunity cost (yellow). Dispatch LOC and RRP OC uplift payments (similar to posturing payments) result from the ISO instructing a generator to operate at a level other than its economic dispatch point; both types of payments restore opportunity costs incurred by generators when following the ISO's dispatch instructions. Dispatch LOC payments totaled $56,000, and RRP payments totaled $58,000; each accounts for 15% of the total.

Conclusions

Key observations from the system events on May 27, May 29, and May 30 include:

- On May 27, an unplanned outage of the Phase II interconnection resulted in the unexpected loss of 1,890 MW of energy imports just before 3pm. Phase II returned to service later that evening. On May 29, the ISO first experienced an unexpected nuclear generator outage at 2pm, and then Phase II unexpectedly failed at 8:30pm. The losses persisted into May 30.
- Despite the magnitude of the losses, the system was able to recover quickly and the ISO did not experience a capacity scarcity event.
- To ensure system reliability, the market software and RAA process committed additional real-time generation following the supply losses. These commitments included both fast-start generators and longer-lead-time generators that were supplementally committed on May 29 and May 30. The commitments were appropriate given the supply losses.
- To ensure the availability of 10-minute operating reserves, the ISO instructed several pumped-storage generators to go (or remain) off-line on May 30. No other types of generators were held back to provide reserves during the system events.
- The major supply losses resulted in high real-time energy prices, with 5-minute LMPs peaking at $183.93/MWh and $224.46/MWh on May 27 and May 30, respectively.
- Reserve prices peaked at $129.32/MWh on May 27 and at $50/MWh on May 29 and 30. The amount of available non-spinning reserves did not fall below the requirement, and the reserve constraint penalty factors (RCPFs) for the 10- and 30-minute non-spinning products did not bind. For reference, during the capacity scarcity event that occurred on September 3, 2018, deficits triggered RCPFs and reserve prices reached $2,500/MWh.
- Real-time uplift payments associated with meeting the system's first contingency needs on May 27, 29, and 30 totaled $381,000.

Section 3
Special Topic: Transmission Cost Allocation Issues for Behind-the-Meter Generation

Regional Network Load (RNL) is used as an allocator of transmission costs among network customers, and per the ISO New England (ISO-NE) tariff is required to be grossed up (or reconstituted) to account for behind-the-meter (BTM) generation. This section assesses the possible extent to which RNL is currently not being reconstituted, evaluates the related financial impacts, and provides a number of recommendations to address the issue.

We consider BTM generation to generally include generation located behind the retail meter, connected to the distribution system and intended to serve host load.[18] In New England, photovoltaic (PV) generation currently makes up a large share of overall BTM generation, and is projected to continue to grow substantially over the next decade. We find that there is potentially widespread under-reporting of RNL due to not reconstituting peak usage for BTM generation. Under-reporting of RNL results in a lower allocation of transmission costs to the under-reporting transmission customer, and consequently over-allocation to others. The financial impact of under-reporting can be significant for individual projects or transmission customers. As an example, we estimated the avoided transmission charges due to observed reductions in the July 2019 aggregate peak load of municipal utilities to be $831k, based on an avoided charge rate of $9.33/kW. These avoided charges could be significantly higher than the cost of the load-reducing measures, such as strategically operating a diesel generator, resulting in net savings of employing such a strategy.[19]

At a broader load area or state level, under-reporting can shift costs to other load areas or states. However, our analysis indicates that the impact on transmission costs erroneously shifted due to under-reporting RNL appears relatively small. Based on 2029 BTM PV projections, the estimated annual state-level impact ranges from $3 million in excess charges to $5 million in potential savings.

Regional network service (RNS) is New England's regional transmission service that allows transmission network customers to use pool transmission facilities (PTFs) to move electricity into or within the New England balancing area to serve load in the area. The costs associated with providing this service represent a significant portion of overall wholesale costs, totaling

[18] BTM generation is not defined in the ISO New England tariff. In the individual Schedule 21 Local Service schedules, we note that some PTOs do not reference BTM generation, while others do. See, for example, Schedule 21-CMP and Schedule 21-NHT wherein Central Maine Power and New Hampshire Transmission, respectively reference BTM generation. In our review of various ISO/RTO tariffs (MISO, NYISO, PJM, SPP), there appears to be general consistency in the definitions of BTM generation, although specifics do vary.

[19] Utilities also employ other forms of demand response measures or energy management options that do not entail the dispatch of BTM generation, and some that do not require reconstitution. The future definition of BTM generation should address the reconstitution requirements for battery storage technologies and technologies backing FCM demand response resources.

over $2 billion in 2019 and comprising more than 20% of total wholesale costs.[20, 21] The Open Access Transmission Tariff (OATT) governs the allocation of these costs, which are billed according to a transmission customer's RNL in a month. RNL is based on the customer's share of energy usage during its respective local transmission system's peak load hour in each month. In this way, each network customer pays for its share of the total costs of firm-like, homogenous and integrated access rights to the regional transmission network to serve their load. Based on our review of the relevant ISO-NE tariff provisions and FERC Order 888 (1996), we conclude that RNL is required to be "grossed up" (or reconstituted) to account for energy output from BTM generation during the monthly peak load hour.[22]

We are concerned that there may be potential widespread non-compliance with the ISO-NE tariff and inconsistent implementation with respect to the requirement to reconstitute RNL. This evaluation is based on discussions with, and responses to information requests from, a number of stakeholders, including network customers and transmission owners about their process of reconstituting RNL. The assessment shows that savings in transmission charges from reducing peak demand (and not reconstituting) can be a significant factor in the business case for installing BTM emergency generators and other forms of distributed generation, most notably photovoltaic (PV) generation in New England. Therefore, there can be strong financial incentives to under-report. While BTM generation can have positive impacts in terms of reducing peak load levels and potentially transmission investment, under the current tariff provisions the benefits should not be monetized through under-reporting (or not reconstituting) load. Network customers with BTM generation continue to rely on the same firm-like, homogenous and integrated transmission service (as customers without BTM generation).

We assessed the potential distortionary impacts of not reconstituting RNL at the state level, given different levels of BTM PV generation and varying goals and policies among the states. However, we found that each state's relative share of transmission costs is not significantly impacted by this issue. In 2019, no state avoided or received additional transmission charges in excess of $2 million. By 2029, our estimates show that no state will receive more than $5 million in transmission cost savings or incur additional charges greater than $3 million. Additionally, we also analyzed the behavior of municipal utilities during one monthly peak. In July 2019, municipal utilities potentially avoided $831k of transmission charges. For illustrative purposes, when assuming the load reductions are achieved through the dispatch of high-cost BTM diesel generation, we find that the net benefit can still be significant. The savings that arise due to not reconstituting RNL improperly shift the cost burden to other transmission customers.

We conclude our assessment with a number of recommendations:

a. As required under the ISO-NE tariff, non-compliant transmission owners and network customers should change their current practices to reconstitute monthly RNL to

[20] The costs associated with RNS include the Participating Transmission Owner's capital investment, maintenance and operation costs associated with the PTFs.

[21] See page 5 of the IMM's 2019 Annual Markets Report at https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf

[22] The terms "gross up" or "reconstitute" are used throughout this section and are intended to have the same meaning. That is, the output from behind-the-meter generation is added to wholesale demand for the coincident peak hour.

account for actual or estimated BTM generation production during the monthly peak hour.

b. ISO-NE should review the need for a certification process requiring entities submitting monthly RNL values confirm they have been appropriately reconstituted.
c. The PTOs, in coordination with ISO-NE, should review the tariff to assess if certain clarifications or additional specificity would be helpful. We recommend adding a definition for *Behind-the-Meter Generation* and more specificity on the determination of *Monthly Regional Network Load*, including the determination of the peak load hour. The ISO should review operating procedures to determine whether references to load reducers should be clarified.
d. A wider review may be warranted as part of a PTO-led initiative to assess whether the uniform regional transmission rate structure, based on monthly RNL, is consistent with current transmission planning practices, and/or should be revised to account for the value of BTM generation.

3.1 Overview of Transmission Cost Recovery and Settlements

Network customers who take Regional Network Service (RNS) have access to ISO-controlled transmission facilities, or Pool Transmission Facilities (PTF).[23,24] "In return for this service, they pay a monthly transmission rate based on their share of the local network's aggregate Regional Network Load (RNL), as measured by the network customer's hourly demand during the local network's peak. The local network peak hour may be non-coincident with the system peak load.

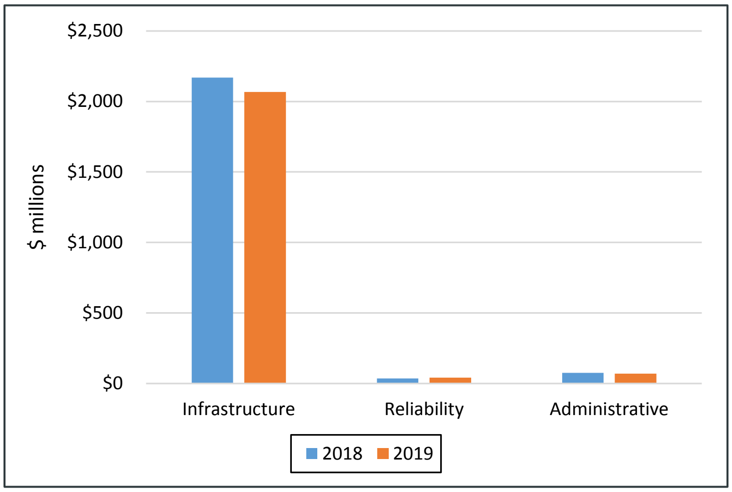
3.1.1 Regional Network Load Costs

RNL costs are divided into three major cost categories, Infrastructure, Reliability and Administrative costs. The breakdown of each RNL cost category for the past two years is shown in Figure 3-1 below.

[23] Section I, General Terms and Conditions, of the ISO-NE Tariff defines a Network Customer as a Transmission Customer receiving RNS or LNS. Various types of entities can be Network Customers, including utilities, municipal utilities and generators. For a list of Network Customers, see ISO-NE's Monthly Regional Network Load Report.

[24] Regional Network Service is the transmission service over the PTF described in Part II.B of the OATT, including such service, which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Figure 3-1: Breakdown of Regional Network Load Costs



This analysis focuses on the allocation and recovery of Infrastructure Costs and the associated charges to customers, since they make up the vast majority of overall RNL Costs.[25] Infrastructure costs primarily include transmission owners' capital investment, maintenance and operating costs.[26] In 2018 and 2019, Infrastructure Costs accounted for 95% of total RNL costs, with reliability and administrative costs comprising a relatively small share of costs.

The ISO-NE tariff outlines the process for Participating Transmission Owners (PTOs) to recover their reasonably-incurred infrastructure costs associated with constructing, operating and maintaining the PTF.[27] The cost recovery mechanism provides PTOs with incentives to operate and maintain a reliable transmission system, while incentivizing future prudent investments. Each year, PTOs calculate their necessary revenue requirements based on formula rates approved by FERC.[28] The Annual Transmission Revenue Requirement (ATRR) is then used to calculate the transmission rate, which is one of two main components (along with the monthly RNL value) of the monthly charge to network customers.[29]

3.1.2 Monthly Settlements

ISO-NE provides a monthly settlement service for RNL costs, but is not responsible for determining inputs to the transmission charges. ISO-NE bills network customers and allocates those receipts to the associated PTOs.[30] A network customer's monthly transmission charge consists of two major components, their monthly Regional Network Load (monthly RNL) and

[25] Administrative costs reflect costs incurred by both the ISO and the PTOs for scheduling, system control, and dispatch service of the transmission system and to bill and collect for NESCOE's operating budget. Reliability costs are intended to recover the costs of certain reliability programs such as resources retained for reliability (RFR) in the Forward Capacity Market (FCM), voltage support, high-voltage control, and system restoration.

[26] Infrastructure Costs are further broken down into two sub-categories, which depend on the date when the transmission lines came into service (pre-1997 and post-1996). Both subcategories of Infrastructure Costs use roughly the same cost recovery methodology, but determine their revenue requirement and rates independently of one another.

[27] Participating Transmission Owners own the PTFs and are a party to the TOA.

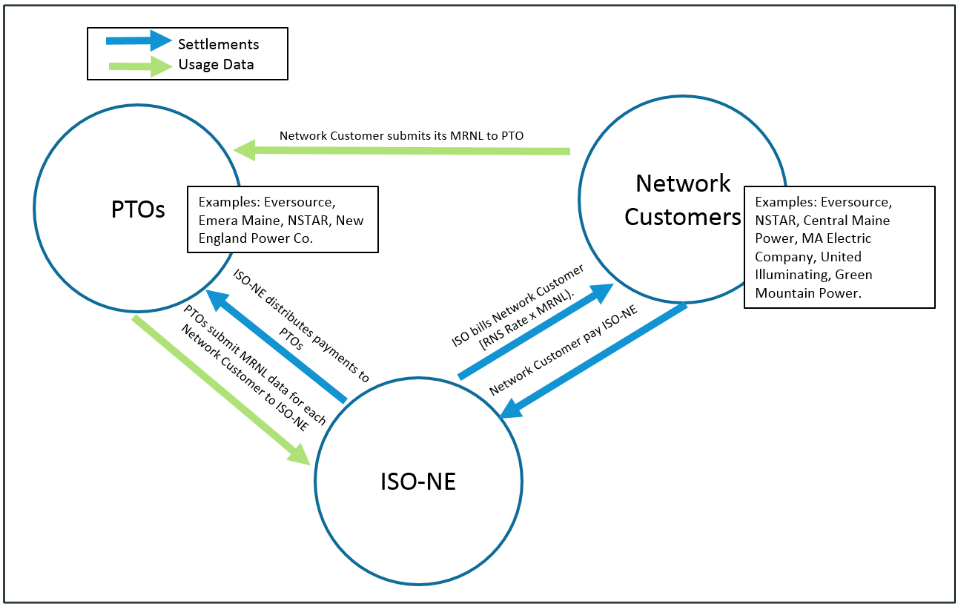
[28] For full details on the calculation of the Annual Transmission Revenue Requirement, see Schedule 9 of the OATT.

[29] The Annual Transmission Revenue Requirement is the total of all PTOs' revenue requirements.

[30] A Network Customer is any Transmission Customer receiving Regional Network Service or Local Network Service.

the RNS rate. Figure 3-2 below depicts, at a high level, the role each entity plays in the billing cycle.

Figure 3-2: Overview of Entities in RNL Billing Cycle



A network customer's monthly RNL is its hourly load occurring at the same time as its local network's peak load. For its network, the PTO determines the peak load hour and calculates the monthly RNL for its network customers receiving RNS from its network. Each individual network customer's monthly RNL is then multiplied by the RNS rate to determine its transmission charge for that month.

The RNS rate is calculated on an annual basis (based on power year beginning on June 1) by taking the sum of all the PTOs' ATRRs divided by the average of the previous year's monthly RNL values.[31] For example, for 2020/21 the approved ATRR for all the PTOs is nearly $2.4 billion. In 2019, the average Monthly Regional Network load was 18,557 MW. This led to a RNS rate of $129.26/kW-yr ($1,077/MW-mo), which took effect beginning June 1, 2020.[32]

3.2 Background Review and Legal Considerations

The genesis of open access to the transmission system and its incorporation into the ISO-NE tariff dates far back to the 1990s. A review of some of the key regulatory orders and proceedings provides useful context to the issues assessed in this report. We then conclude this section with a review and our interpretation of the relevant provisions in the ISO-NE tariff.

[31] This also includes any Forecasted Transmission Revenue Requirements and Annual True-ups. See schedule 9 for full details on the RNS rate calculation.

[32] This is a total of the Pre-1997 ($15.01/kw-yr) and Post-1997 (114.25/kw-yr) rates. The Pre-1997 ATRR and Post 1996 ATRRs were approximately $0.3 billion and $2.1 billion, respectively.

3.2.1 FERC Orders

FERC Order 888 (1996) established and promoted wholesale competition by ensuring fair access to the high-voltage transmission system for power generators and consumers. As part of that Order, the Commission issued a *pro forma* open access transmission tariff (OATT). The *pro forma* OATT and the relevant FERC Orders provide insight into the development of transmission cost allocation and the role BTM generation plays in determining transmission charges. The various FERC Orders and rehearings suggest that load served by BTM generation should be grossed up to determine a network customer's transmission charges.

ISO-NE's OATT uses similar language to the Commission-issued *pro forma* OATT. Under *the pro forma* OATT, a network customer must designate its total load as part of receiving transmission service. However, a network customer may designate "less than its total load as Network Load but may not designate only a part of the load at a discrete Point of Delivery".[33] A network customer that designates less than it total load "is responsible for making separate arrangements under Part II of the tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load."

Network customers' charges for taking transmission service are based on their share of total load, allowing transmission providers to recover their ATRR. Network customers pay a monthly demand charge based on their monthly Network Load, which is equal to "its hourly load coincident with the Transmission Provider's Monthly Transmission System Peak."[34] In Order 888-A (1997), the Commission indicated a preference for monthly peak demand charges because utilities typically plan transmission systems based on monthly peak demand.[35]

In Order 888-A, network customers and transmission owners requested further clarification on the definition of network load and if BTM generation can be used to reduce a customer's share of transmission costs. Several network customers argued that in previous rulings the Commission allowed for netting of any load met by BTM generation.[36] However, some utilities argued that load met by BTM generation must be added back into network load, because utilities must plan the transmission system to meet the full potential demand of network customers. In other words, if a customer's BTM generation is unavailable, the transmission system must be capable of meeting a higher load level.

In Order 888-A, the Commission ruled that the definition of network load in the *pro forma* OATT does not allow for the use of BTM generation to lower a network customer's coincident peak demand. It provided for the exception whereby BTM generation could be excluded:

> *Customers that elect to do so… must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by 'behind the meter' generation that seek to eliminate the load from their network load ratio calculation.*[37]

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[33] See FERC Order 888, Appendix D Pro Forma Open Access Transmission tariff 1.22.

[34] See FERC Order 888, Appendix D Pro Forma Open Access Transmission tariff 34.3.

[35] See Order 888-A (2) Twelve Monthly Coincident Peak v. Annual System Peak" Rehearing Requests. P. 237

[36] The network customers generally citied FMPA v. FPL, 74 FERC 61,006 at 61,012-13 (1997).

[37] See Order 888-A (3) Load and Generation "Behind the Meter" Rehearing Requests. P. 245.

This language is similar to that used in the ISO-NE tariff today, which we will turn to further below. In FERC Order 888-A, the Commission clarified that Order 888 did not allow network customers to avoid network service charges by utilizing BTM generation during the monthly peak. The rationale appears to be that if network customers could exclude load met by BTM generation, they would receive the same transmission service as customers without BTM generation, but use BTM generation during the monthly peak to avoid paying for the full transmission service. This is what the IMM understands to be happening in New England today. A network customer with BTM generation may choose to serve its load with BTM generation, however the network customer must take a different transmission service.[38] The Commission reaffirmed its position on BTM generation in later FERC Orders, including in Orders 890[39], 890-A and 890-B.[40] However, the Commission did state that it would be open to reviewing BTM generation on a "case-by-case basis".[41]

3.2.2 ISO New England Regional Network Load

The ISO-NE tariff contains a similar structure and terminology to the FERC *pro forma* OATT. Like several other ISOs[42] and the *pro forma* OATT, the network customer must designate its RNL to receive Regional Network Service (RNS), and then is billed by the ISO based on its monthly peak load (or monthly RNL).[43] While RNL uses a similar definition to the *pro forma* OATT's Network Load, the tariff definition of RNL explicitly states that the network customer's RNL "shall not be credited or reduced for any behind-the-meter generation."[44] The definition is as follows [with emphasis added]:

> ***Regional Network Load*** *is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and* ***shall not be credited or reduced for any behind-the-meter generation.*** *A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate*

[38] The IMM understands that examples of other types of services might be non-firm (or interruptible) transmission service (in which case the customer would have a higher probability of not being served under certain system conditions) or point-to-point (as opposed to integrated) service.

[39] See FERC Order 890 ¶ 1619, "The Commission is not persuaded to require transmission providers to allow netting of behind-the-meter generation against transmission services charges (…)".

[40] See FERC Order 890-B ¶ 216, "the pro forma OATT permits transmission customers to exclude the entirety of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point service.

[41] Order 890-A and Order 890-B.

[42] For example, see MISO and SPPs Tariff.

[43] See ISO tariff Section II.18 for the designation of RNL and Section II.21.2 for the definition of Monthly RNL.

[44] See Section I.2.2 of the ISO tariff for the full definition of RNL.

arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such nondesignated load.[45]

We understand the underlying premise to be that network customers receives firm-like, homogenous and integrated access to a transmission system through regional network service (RNS), whereby the customer with BTM generation has the same access rights as others (without BTM generation).For this service, the ISO bills network customers based on their monthly RNL as defined as "its hourly load coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month".[46]

While the definition of "Monthly RNL", unlike the definition of "RNL", does not explicitly cover the treatment of BTM generation, the IMM's view is that there is a clear requirement to reconstitute peak demand by BTM generation. To interpret the provision otherwise would be inconsistent with the approach taken by the region following FERC's Orders, and with the tariff-defined concept of RNL. It would also seem to create a disconnect between the benefits of the firm-like and integrated transmission service being received through RNS and the amount being paid in return.

Further, the IMM does not believe that the absence of a tariff definition for behind-the-meter generation is a reasonable argument for not reconstituting load. BTM generation is a well-understood concept in the industry and tends to be used interchangeably with distributed generation. The tariff definition of distribution generation provides good guidance, as follows:[47]

> ***Distributed Generation*** *means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.*

3.2.3 Implications of Excluding BTM Generation

Network customers are avoiding paying their share of the costs of the transmission network if monthly RNL does not include load served by BTM generation (is not reconstituted), despite receiving the same service as customers without BTM generation.

However, it is also important to recognize that reductions in peak demand due to BTM generation can have both short- and long-term system benefits. For example, a higher penetration of BTM generation will have the impact of reducing forecasted demand, which is an input into the transmission planning process. While there are other factors and complex interactions in transmission planning, BTM will generally reduce overall investment needs.

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45 In ISO-NE tariff Section 1, General Terms and Conditions, Point-To-Point Service is defined as "the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service"

46 See ISO-NE tariff, Section II.21.2 for the definition of Monthly Regional Network Load.

47 See ISO-NE tariff, Section I – General Terms and Conditions.

However, those benefits should not be allocated by circumventing the provisions of the ISO-NE tariff.

In addition, unreported BTM generation by network customers leads to a higher RNS rate for all network customers. Since the ISO-NE tariff bases RNS rates on average historical Monthly RNL values, RNS rates are higher if Network Customers do not gross up load met with BTM generation. For example, if Network Customers operated an average of 1,000 MW of BTM generation during the monthly peaks without grossing up their Monthly RNL, the average 2019 Monthly RNL would have decreased from $129.26/kW-yr to $122.65/kW-yr.[48] However, if the absence of reconstitution were systemic across the region (i.e. everyone is understating their share), the dollar impact for network customers could potentially be small.

3.3 Participant Outreach

Beginning in December 2019, for the purposes of this assessment, the IMM reached out to several network customers and transmission owners requesting information about their reporting of monthly RNL. The goal was to gain a better understanding of the RNL reporting process, whether they were reconstituting their monthly RNL to account for BTM generation, and how they do so.

A number of important issues, some common, emerged from the responses and from our discussions with stakeholders. The key points are summarized below.

1) *An interpretation that the tariff does not require reconstituting for BTM generation when reporting monthly RNL*

Some network customers pointed to a disconnect they saw between the tariff definitions of *RNL* and *Monthly RNL*. Whereas RNL states that RNL "shall not be credited or reduced for any behind-the-meter generation"[49], Monthly RNL, as the basis for billing, does not explicitly mention reconstituting for BTM generation.[50]

2) *Behind-the-meter generation is not defined in the ISO-NE tariff*

BTM generation is not a tariff-defined term.[51] While some network customers acknowledged that RNL should be reconstituted to account for BTM generation, they offered different interpretations of what constitutes BTM generation. This included an understanding that BTM generation was settlement-only generation participating in the wholesale market for which revenue quality metering was available. Another interpretation was that under ISO-NE's

[48] See the 2020/2021 OATT Schedule 9 Rate Development Worksheet for more information. The example adds 1,000 MW to the 2019 Network Load value.

[49] Section I.2.2 Definitions of the ISO tariff contains the definition for Regional Network Load.

[50] See Section II.21.2 of the ISO tariff.

[51] The tariff defines Controllable Behind-the-Meter Generation, which must be located at the same facility as a DARD or Demand Response Asset. It also defines "distributed generation" as "generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area."

Operating Procedure 14, generators under 5 MW not participating in the wholesale market were defined as *load reducers* and not as BTM generation.[52]

3) Transmission Owners use varying approaches to collect monthly RNL data

There appears to be different approaches used to facilitate the reconstitution of monthly peak load to account for BTM generation. In one example, the network customer makes an adjustment for BTM generation (that meet's their definition) to the meter data for the peak hour and submits it to the PTO. For another network customer, its PTO only requests the meter reading for the peak hour and does not provide a format that requires the network customer to reconstitute its load.

4) Lack of BTM data and visibility

Network customers and PTOs stated that monthly RNL is calculated using revenue quality metering data and the PTO has no way of estimating BTM generation, or in some cases knowing that it exists.

5) Grossing up RNL for BTM Generation would provide no compensation for transmission benefits

Some network customers advocated the benefits of BTM generation to the transmission system, in terms of deferring or negating the need for future investment and potentially alleviating congestion. In their view, requiring RNL to be reconstituted would not recognize this important value added by BTM generation.

3.4 Example and Assessment of Load Reconstitution Impacts

The feedback received from a limited number of participants indicates that network customers and/or PTOs do not reconstitute their monthly RNL to account for BTM generation, or are inconsistent in their application. Further, public documents issued by various types of stakeholders promote the benefits of reduced transmission costs due to BTM generation.

While there may be benefits, those benefits should not be allocated by under-reporting demand, which is inconsistent with the ISO-NE tariff. The incentive to do so can be substantial and may be having an inappropriate effect on business cases for installing BTM generation, whether it be for emergency diesel, photovoltaic (PV), or other types of generation.

This section illustrates the potential savings and effects of under-reporting monthly RNL. One example compares the load curve of municipal utilities to the overall system load curve. This example shows a distorted load curve during the monthly peak, which may be due to several load-reducing measures including the dispatch of BTM generation. We further elaborate on how this can be a profitable strategy, even assuming a high-cost load reduction measure of diesel

[52] OP-14 outlines registration options for generators below five MW: See OP-14 for complete information on generator registration. Similarly, OP-14 allows "distributed generation" to elect to not register as a generator and to be treated as a "load reducer."

generation. The second example shows the current and estimated impact of peak load reductions due to BTM PV at the state level.

3.4.1 Peak Load Curve of Municipal Utilities

Figure 3-3 below provides an example of how network customers may avoid transmission charges by operating and not reporting BTM generation during the monthly peak. The blue line represents the load curve for the entire system on July 30, 2019, the day with the highest load during the year.[53] The red line (corresponding to the right axis) represents the load curve for all municipal Load-Serving Entities (LSE). The under-reporting of BTM generation is likely not specific to municipal utilities, but municipal load was chosen because of the cleaner mapping between these entities as both LSE's in the wholesale energy market and as network customers, and because of the relatively abnormal load reduction. The dashed red line represents potential load curves in the absence of BTM generation.

Figure 3-3: Load Reduction during July 30, 2019

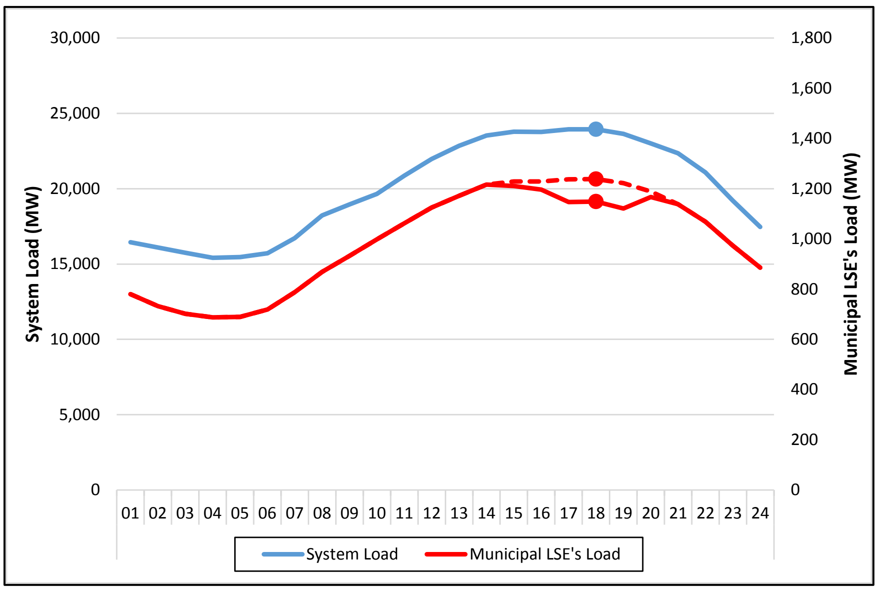


Figure 3-3 shows that the municipal LSEs had clear wholesale load reductions during the monthly peak in July 2019, and a profile that differed from the system's. From HE 14 to HE 18, the load curve for the municipal LSEs decreases, falling from 1,216 MW to 1,149 MW.[54] The rest of the system still observes rising loads, increasing from 23,523 MW to a daily peak load of 23,951 MW over the same period.[55] The different load curves from the municipal LSEs suggest that some BTM generation may have operated over approximately a 6-hour time window.[56] The

[53] This example assumes all local network's monthly peak demand hour occurred during the system's monthly peak.

[54] Decreasing loads may also be partly attributable to other forms of demand reduction programs which do not require reconstitution for transmission charges.

[55] While the figure shows only one month. Lower peak municipal loads are observed in other months as well.

[56] This is from hour ending 14 to hour ending 20, when municipal loads increase after the rest of the system load already began decreasing.

dashed red provides an estimate of how the wholesale load profile might have looked for municipal LSEs, in the absence of the load-reduction measures.

3.4.2 Estimated avoided RNL costs of reducing demand (without reconstitution)

Continuing with the real-world example above, we estimate what the network customer's load would have been if the assumed BTM generators were not dispatched. Assuming the same rate of change as system demand, the customer's estimated wholesale load would have been 1,238 MW, an 8% (89 MW) increase over actual metered wholesale load. For illustrative purposes, we assume that the lower wholesale loads were due to the dispatch of BTM diesel generation operating over a 6-hour period in anticipation that one of those hours would be the coincident peak demand hour.[57] The purpose of this example is to show the estimated financial results of employing this strategy, not to suggest that this strategy was actually used.

Table 3-1 below shows the breakdown of the estimated operating costs and revenues of this hypothetical strategy. Costs are shown both in dollar and $/kW terms, with the assumed kW value of about 89,000 kW based on the estimated peak load reduction. We do not account for the capital, leasing or operating and maintenance cost of the generator, and therefore estimated cost savings based on this technology type are at the high end of scale.

Table 3-1: Estimated Cost Savings

Revenue/(Cost) Item	$ (thousands)	$/kW
Diesel generator operating cost	($61)	(0.68)
Avoided wholesale energy costs (at Hub LMP)	$18	0.20
Avoided transmission charges	$831	9.33
Monthly Net Savings	$788	8.85

With a RNS rate of $9,328/MW-Month, the estimated 89,000 kW reduction led to an estimated savings of $831k ($9.33/kW) in RNL charges (which must be recovered from other network customers) and an overall net savings of $788k ($8.85/kW) for July.

3.4.3 Impact of Behind-the-Meter Photovoltaic Generation at the State Level

Photovoltaic (PV) generation is the most prevalent form of BTM generation in New England.[58] Installed BTM PV capacity is currently estimated at over 2,000 MW.[59] By 2029, ISO-NE estimates that the installed capacity will exceed 4,400 MW. As BTM PV continues to grow in response to state goals and policies, network customers with BTM PV installations would inappropriately realize transmission cost savings if their monthly RNL load is not reconstituted.

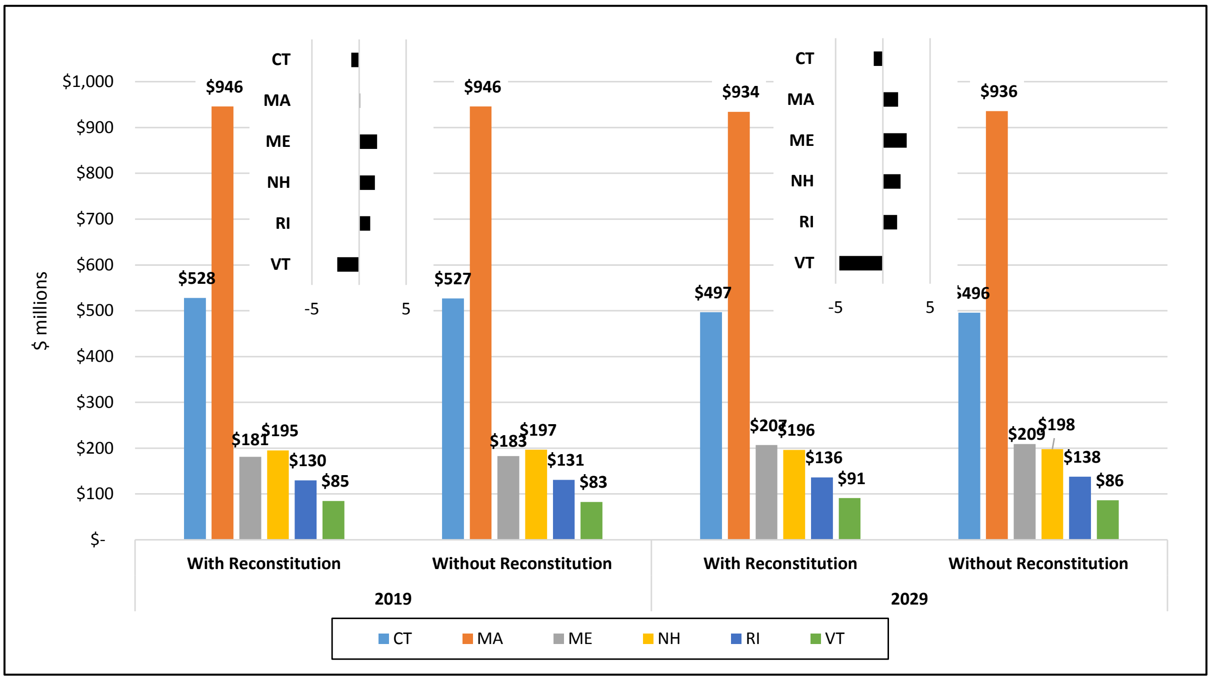
[57] This is a calculation of the marginal cost of generating a diesel generator given a fuel price of $14.61 and an assumed full load average heat rate of 11.7 MMBtu/MWh. This heat was chosen, as it falls within the range of diesel generator heat rates in Consortium for Electric Reliability Technology Solutions' Modeling of Customer Adoption Of Distributed Energy Resources (pg.7).

[58] BTM PV consists of estimated installations with no participation in the ISO-NE energy or capacity market.

[59] See the Distributed Generation Forecast Working Group's Final 2020 PV Forecast.

Given the varying levels of current and expected PV generation among the states we estimated the potential degree to which overall RNS costs could be shifted between states if load is not reconstituted. In other words, states with a larger relative levels of BTM PV could potentially push transmission costs to states with lower levels. Our assessment compares BTM PV's peak load reduction in 2019 vs. the estimated peak load reduction in 2029.[60] Figure 3-4 compares actual 2019 (left) and estimated 2029 (right) transmission costs by state, with and without reconstituting peak load to account for BTM PV generation. The bar charts on the left use submitted 2019 monthly RNL values and charges and grosses them up for estimated BTM PV generation during the system peak.[61] The bar charts on the right use forecasted 2029 monthly peak loads (including and excluding peak hour PV reductions) from the ISO-NE CELT Report and PV Forecast. The inset graphs show the differences between reconstituting and not reconstituting peak load. Transmission costs are held constant at $2.06 billion.

Figure 3-4: Transmission Costs by State with and without reconstitution for BTM PV, 2019 and 2029



Our analysis indicates that despite BTM PV's estimated future growth, cost shifting between states is relatively small, both in 2019 and ten years later. Vermont and Connecticut save a combined amount of $5 million on future transmission charges if RNL is not reconstituted, while the other four states would see a corresponding total increase. Vermont would receive the largest transmission cost savings since BTM PV is expected to meet a larger share of their peak load than in the other states.

While individual network customers may see significant benefits depending on their relative levels of BTM PV generation, overall cost-shifting does not appear to increase significantly over the next ten years at the state level. The other reason for the relatively small market impact is

[60] See ISO-NE's 2020 Forecast Data, which are used to produce the CELT Report and the Distributed Generation Forecast Working Group's Final 2020 PV Forecast. 2019 peak load reductions are not included in these sources.

[61] This example also assumes that all local network's peak hour occurred during the same hour as system peak.

the seasonality of peak loads and BTM PV generation. In 2029, ISO-NE estimates just over 1,000 MW of BTM PV generation (compared to 4,400 MW of installed capacity) during monthly peak from May through September. ISO-NE estimates no output from BTM PV during the other seven months of the year, as the peak hour is likely to occur after sunlight hours.

3.5 Key Findings and Recommendations

In this section, we summarize the key issues from the prior sections and provide a number of recommendations to PTOs, stakeholders and ISO-NE to address those issues.

The current practice of not reconstituting load is inconsistent with the ISO-NE tariff and should be brought into compliance

Based on discussions with network customers and various stakeholders, and analyzing peak load meter data, we conclude that there is potentially widespread non-compliance with the ISO-NE tariff and inconsistency in application. Network customers may be operating BTM generation during the monthly peak hour and not adding that output back to metered wholesale load for RNL reporting and billing purposes. Some network customers may be doing this intentionally to reduce their share of transmission costs, and incorporating the savings in their business cases for investing in BTM generation.

Network customers raised the issue of how PTOs collect monthly RNL data. The ISO-NE tariff requires the PTOs to calculate the monthly RNL of all network customers within their specific transmission network.[62] However, some PTOs appear to collect meter data without consulting the network customers. In such a case, the network customer has no opportunity to gross up load served by BTM generation. If the Network Customer is responsible for grossing up RNL load for BTM generation, the PTO must provide them with an opportunity to do so.

Practices should be reviewed and changed to comply with the meaning and intent of the rules. The information flow process should allow for the opportunity to explicitly reconstitute for BTM generation. Further, in its role as settlements administrator, ISO-NE should consider the need for incorporating a certification step into the billing process whereby the RNL data submission includes an attestation that it has been reconstituted consistent with the tariff.

The tariff and operating procedures should be reviewed and changed, as appropriate, to provide helpful clarifications and specificity

Several network customers expressed the view that the ISO-NE tariff does not require the reconstitution of BTM generation for monthly RNL reporting. Some assertions of compliance with the tariff have relied on different interpretations of what constitutes BTM generation and of the definition of *Monthly RNL*.

In our opinion and reading of the ISO-NE tariff, the reconstitution of load for BTM generation is required for monthly RNL reporting and billing. To interpret it otherwise is inconsistent with how the region implemented the various FERC Orders over twenty years ago, and it creates a disconnect between customers receiving the same network service, but essentially allowing for a non-FERC approved discount rate by virtue having BTM generation on site.

[62] See Section II.21.2 of the ISO-NE tariff for the Determination of Network Customer's Monthly Regional Network Load.

However, the different interpretations do point to the potential need to assess if certain clarifications or additional specificity would be helpful. In particular, we recommend that *Behind-the-Meter Generation* be defined and additional specificity be added to the determination of *Monthly Regional Network Load,* including the determination of the peak load hour.[63] It is unclear whether PTOs determine the peak load hour based on the highest gross (reconstituted load) or net load, and this should be clarified and applied consistently across the region.

We recommend that the PTOs engage with ISO-NE and stakeholders on this process.

Review of the Current Rate Structure with transmission planning practice and drivers

The *pro forma* OATT in FERC Order 888 allocates transmission costs based on the network customers' share of monthly peak load.[64] In FERC Order 888-A, the Commission clarified its preference for a twelve month coincident peak demand method, as it generally aligns with how utilities plan their transmission systems.[65] The Commission stated that it would be open to other forms of transmission cost allocation methods, but the proposed method must align with the utility's transmission planning process.

The method in New England was adopted over 20 years ago. Since then, the transmission system has changed significantly and continues to evolve towards a "hybrid grid". The transmission planning process is adapting to those changes and accounts for reductions in wholesale load due to the growth in BTM generation.[66]

In reducing projected peak load, BTM generation may defer or negate the need for some future transmission projects. However, the majority of transmission costs recovered through the uniform RNS rate were incurred some years ago (are sunk), and are recovered over an economic life spanning decades. Exempting BTM generation from transmission charges could raise equity issues of cost shifting and/or stranded costs of investments already made to serve their assumed RNL.

We recommend that PTOs engage with ISO-NE and stakeholders to assess whether the current uniform transmission rate structure is consistent with current transmission planning practices, and/or should be revised to account for the value of BTM generation.

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[63] For Example, MISO defines BTM Generation as "Generation resources used to serve wholesale or retail load located behind a CPNode that are not included in the Transmission Provider's Setpoint Instructions and in some cases can also be deliverable to Load located within the Transmission Provider Region using either Network Integration, Point-To-Point Transmission Service or transmission service pursuant to a Grandfathered Agreement. These resources have an obligation to be made available during emergencies.

[64] See FERC Order 888, Appendix D Pro Forma Open Access Transmission tariff III.34.1

[65] See FERC Order 888-A p.12321.

[66] See 2.3.10.3 of the ISO-NE Transmission Planning Technical Guide. Peak loads are reduced by an assumed output of 26% of BTM PV nameplate capacity during the summer peak. Winter does not account for BTM PV because the peak demand is likely to occur after daylight hours.

Section 4
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 4-1 below.

Table 4-1: High-level Market Statistics

Market Statistics	Spring 2020	Winter 2020	Spring 2020 vs Winter 2020 (% Change)	Spring 2019	Spring 2020 vs Spring 2019 (% Change)
Real-Time Load (GWh)	25,620	30,599	-16%	27,278	-6%
Peak Real-Time Load (MW)	16,558	19,068	-13%	17,876	-7%
Average Day-Ahead Hub LMP ($/MWh)	$17.33	$30.32	-43%	$29.78	-42%
Average Real-Time Hub LMP ($/MWh)	$17.62	$29.97	-41%	$28.89	-39%
Average Natural Gas Price ($/MMBtu)	$1.61	$3.40	-53%	$3.04	-47%
Average Oil Price ($/MMBtu)	$5.71	$13.03	-56%	$12.86	-56%

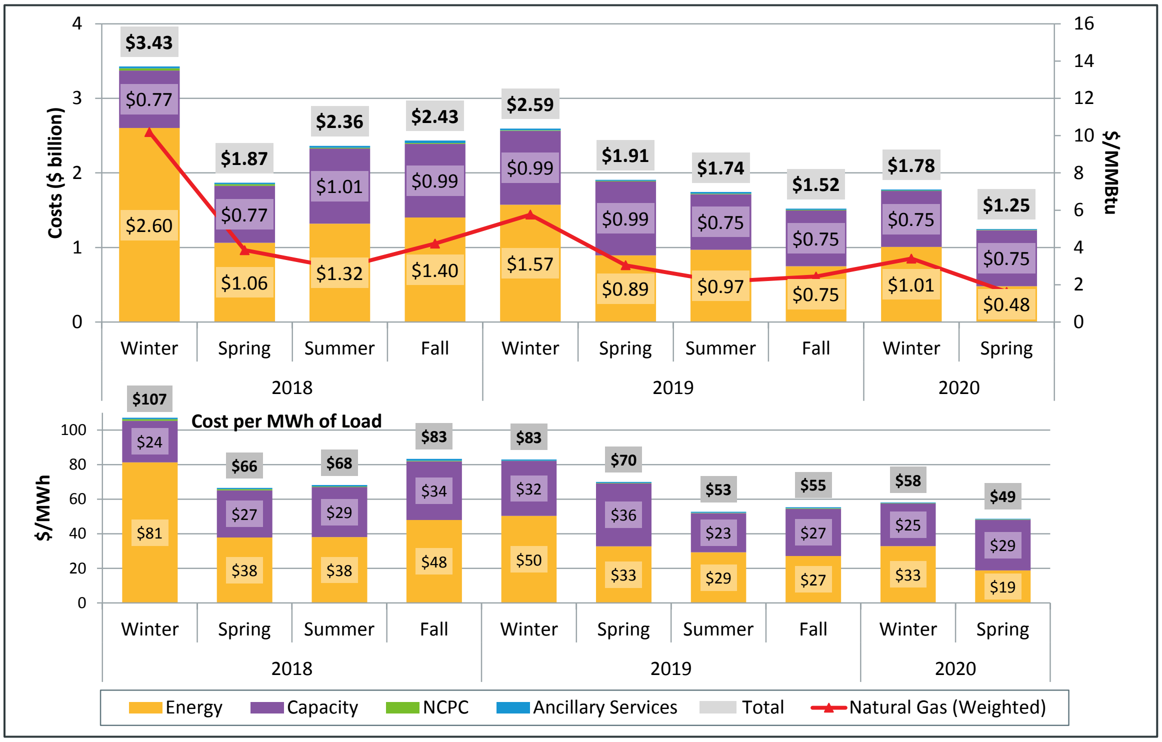
To summarize the table above:

- Average day-ahead LMPs in Spring 2020 were $17.33/MWh, 42% lower than in Spring 2019. Average real-time LMPs were $17.62/MWh, 39% lower than in Spring 2019. Lower gas prices ($1.61/MMBtu) and average real-time load (11,608 MW) in Spring 2020 compared to Spring 2019 gas prices ($3.04/MMBtu) and average real-time load (12,360 MW) put downward pressure on LMPs.
- Total load in Spring 2020 (25,620 GWh) was 6% lower than in Spring 2019 (27,278 GWh). Section 4.2 discusses the impact of the COVID-19 pandemic on demand in detail.
- Average oil prices in Spring 2020 ($5.71/MMBtu) were 56% lower than Spring 2019 ($12.86/MMBtu) prices due to cratering world-wide demand due to the COVID-19 pandemic. Lower oil prices had little impact on ISO-NE markets, since energy offers from oil-fired generators were out of merit for the vast majority of time.

4.1 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 4-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [67,68]

Figure 4-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Spring 2020, the total estimated wholesale cost of electricity was $1.25 billion (or $49/MWh of load), a 35% decrease compared to $1.91 billion in Spring 2019, and a decrease of 30% over the previous quarter (Winter 2020). Natural gas prices continued to be a key driver of energy prices.

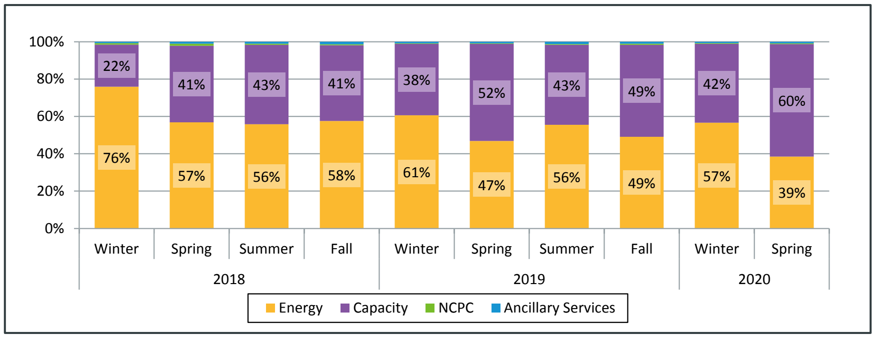
Energy costs were $481 million ($19/MWh) in Spring 2020, 46% lower than Spring 2019 costs, driven by a 47% decrease in average natural gas prices. Energy costs made up 39% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 4-2 below.

[67] 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.

[68] 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 totaled $751 million in Spring 2020, a 24% decrease from Spring 2019 costs. Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 10), and totaled $751 million ($29/MWh), representing 60% of total costs. Beginning in Summer 2019, lower capacity clearing prices from the tenth Forward Capacity Auction (FCA 10) contributed to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate was $9.55/kW-month in all capacity zones except SEMA/Rhode Island.[69] This year, the payment rate for new and existing resources was lower, at $7.03/kW-month. The lower clearing prices caused capacity costs to decrease.

Figure 4-2: Percentage Share of Wholesale Cost



At $5.5 million ($0.21/MWh), Spring 2020 Net Commitment Period Compensation (NCPC) costs represented 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $0.8 million lower than in Spring 2019, driven by a decrease in economic out-of-merit payments.

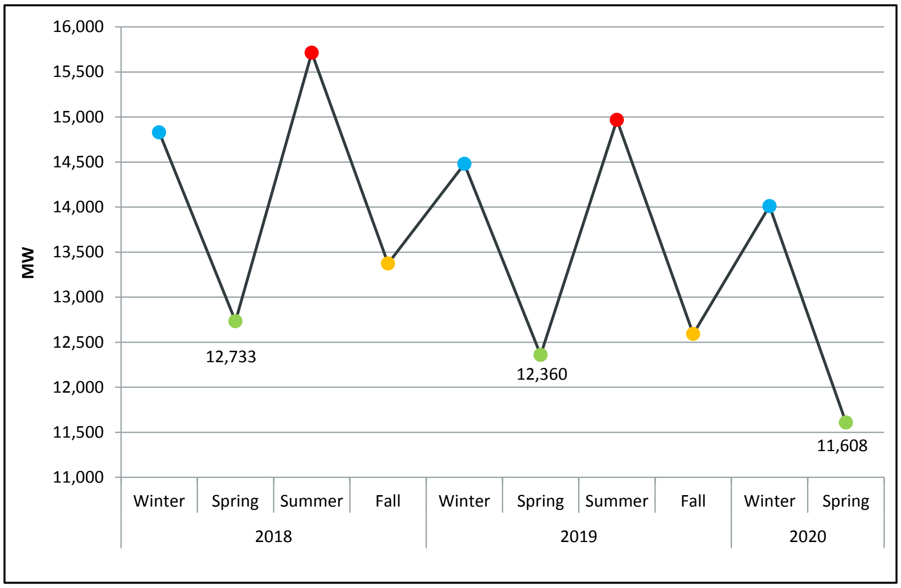
Ancillary services, which include operating reserves and regulation, totaled $10.4 million ($0.41/MWh) in Spring 2020, representing less than 1% of total wholesale costs. Ancillary service costs decreased by 32% compared to Spring 2019, and decreased by 18% compared to Winter 2020.

[69] As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones.

4.2 Load

As discussed above, the COVID-19 pandemic caused lower average wholesale loads in Spring 2020.[70] Increased energy efficiency and behind-the-meter solar generation continue to contribute to the trend of declining wholesale loads. Average hourly load by season is illustrated in Figure 4-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 4-3: Average Hourly Load



Average hourly load in Spring 2020 was 11,608 MW, a 6% and 9% decrease from Spring 2019 and Spring 2018, respectively, and the lowest average seasonal load since at least 2000. Lower loads were largely driven by the COVID-19 pandemic, along with continued increase in behind-the-meter solar generation and energy efficiency. Average temperature in Spring 2020 was 48^{0}F compared to 47^{0}F in Spring 2019 and 2018.

[70] In this section, "load" typically refers to *Net Energy for Load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand, and net interchange (imports minus exports). NEL excludes pumped-storage demand. "Demand" typically refers to metered load. (NEL – Losses = Metered Load).

Load and Temperature

The stacked graphs in Figure 4-4 below show monthly average loads compared to monthly cooling-degree days (CDD) and heating-degree days (HDD).[71]

Figure 4-4: Monthly Average Load and Monthly Heating Degree Days

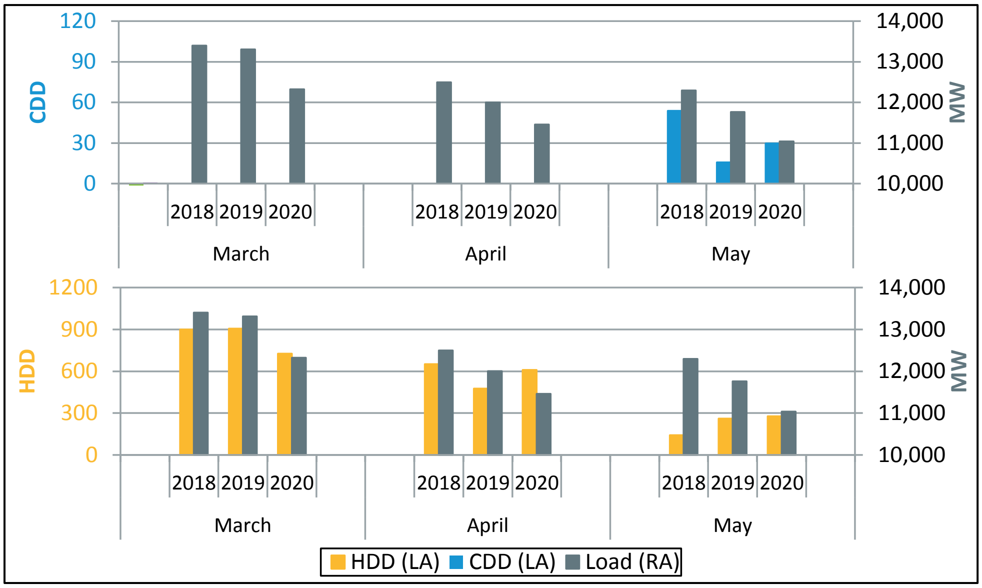


Figure 4-4 shows that loads were lower every month in Spring 2020 when compared to both Spring 2019 and 2018, on average. Typically, temperature fluctuations drive differences in monthly average load. This relationship holds between March 2020 and 2019, when warmer average temperatures (41^{0}F vs 36^{0}F) led to fewer HDDs and contributed to lower average loads (12,320 MW vs. 13,307 MW).[72] However, this temperature-load relationship breaks down in April and May 2020 when the COVID-19 pandemic caused lower wholesale electricity demand despite colder temperatures and increased HDDs and CDDs. In April 2020, the average temperature was 4^{0}F colder than in April 2019 (45^{0}F vs. 49^{0}F), but average loads still decreased year-over-year (11,460 MW vs. 12,001 MW). In May 2020, temperatures averaged 57^{0}F, which was unchanged compared to May 2019. However, despite more HDDs and CDDs than May 2019, loads averaged 11,041 MW, the lowest monthly average loads on record.[73]

[71] 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.

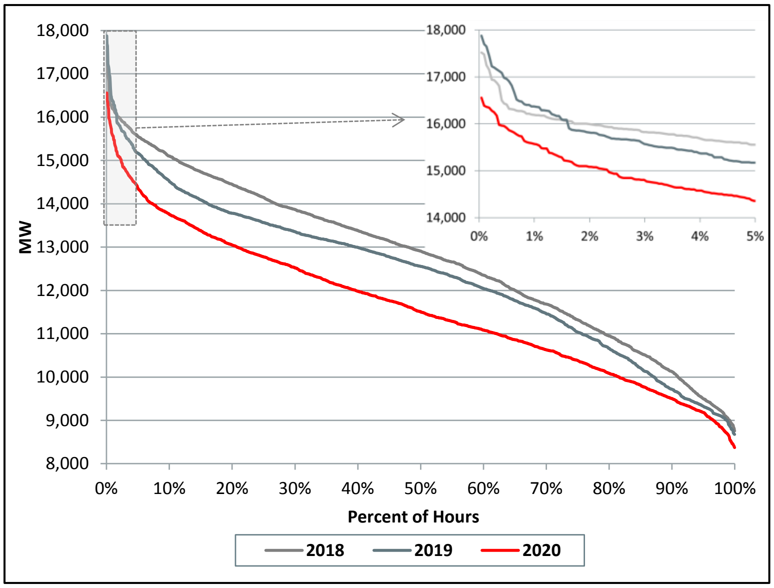
[72] The COVID-19 pandemic also contributed to lower loads in March 2020.

[73] See the Net Energy and Peak Load Report

Peak Load and Load Duration Curves

The system load for New England over the last three spring seasons is shown as load duration curves in Figure 4-5 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 that load levels occur. Spring 2020 is shown in red, Spring 2019 is shown in black and Spring 2018 is shown in gray.

Figure 4-5: Seasonal Load Duration Curves



The red line shows Spring 2020 had lower loads than both Spring 2019 and Spring 2018 in all hours. In Spring 2020, loads were higher than 13,000 MW in about 21% of hours, compared to about 41% and 49% in Spring 2019 and Spring 2018 respectively. The COVID-19 pandemic also affected load during the highest load periods of the season. During peak hours, Spring 2020 load levels were lower than both Spring 2019 and 2018. Loads during the top 5% of hours of Spring 2020 averaged 15,059 MW, 822 MW lower than in Spring 2019 (15,881 MW) and 934 MW lower than in Spring 2018 (15,993 MW).

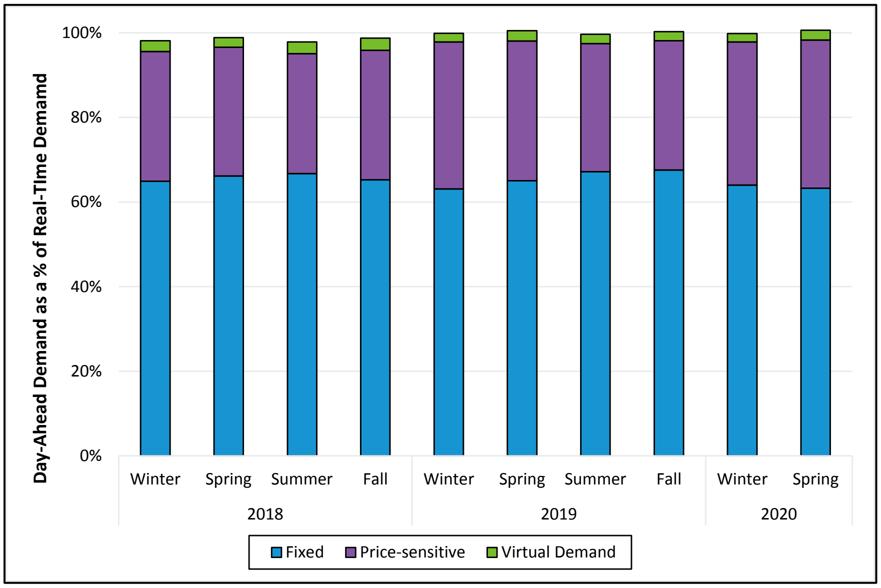
Load Clearing in the Day-Ahead Market

In recent periods, there have been higher percentages of real-time demand clearing in the day-ahead market. 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.[74] For example, when low levels of demand clear in the day-ahead market, supplemental supply commitments or additional dispatch may be needed to meet real-time demand. This can lead to higher real-time prices. The day-ahead cleared demand as a

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

percentage of real-time demand is shown in Figure 4-6 below. Day-ahead demand in broken down by bid type: fixed (blue) price-sensitive (purple) and virtual (green) demand.[75]

Figure 4-6: Day-Ahead Cleared Demand by Bid Type



Day-ahead cleared demand as a percent of real-time demand was higher in Spring 2020 than in any other period over the past two years. On average, 100.6% of real-time demand cleared in the day-ahead market compared to 100.5% and 98.8% during Spring 2019 and 2018, respectively. The year-over-year increase was driven by increased price-sensitive demand, which cleared 35.0% of real-time demand in Spring 2020, an increase from 33.1% and 30.4% in Spring 2019 and 2018, respectively.[76]

4.3 Supply

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

4.3.1 Generation by Fuel Type

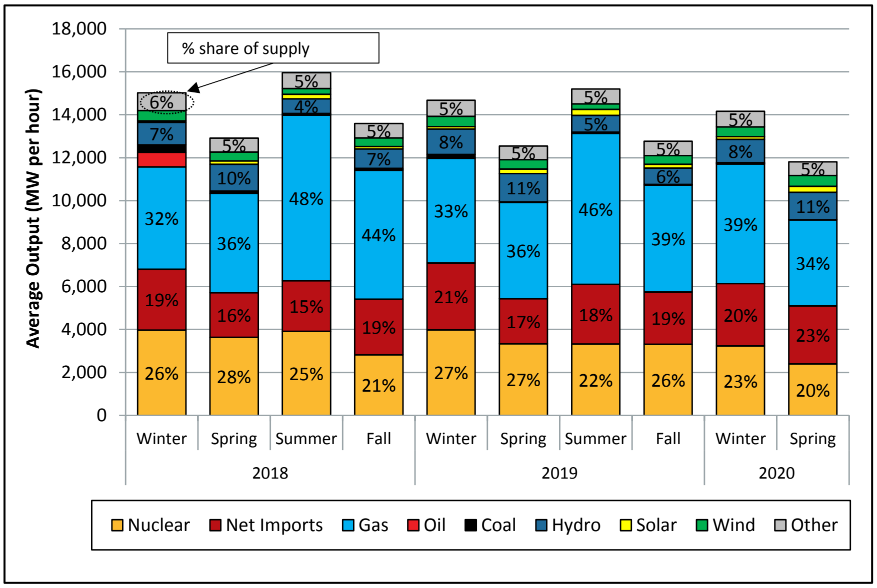
The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2018 through Spring 2020 is illustrated in Figure 4-7 below. Each bar's height represents average

[75] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time demand is equal to native metered load. 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. 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.

[76] While price-sensitive demand only clears if it is above the day-ahead LMP, the term can be misleading since 97.0% of cleared price-sensitive demand bids were priced above the highest day-ahead LMP ($32.87/MWh) of the season.

electricity generation, while the percentages represent the percent share of generation from each fuel type.[77]

Figure 4-7: Share of Electricity Generation by Fuel Type



The majority of New England's energy comes from nuclear generation, gas-fired generation, and net imports (netted for exports). Together, these categories accounted for 77% of total energy production in Spring 2020. Nuclear production shares fell from 27% (3,300 MW per hour) in Spring 2019, to 20% (2,400 MW per hour) in Spring 2020. This was primarily due to the retirement of Pilgrim Nuclear Plant, a 680 MW generator in Southeastern Massachusetts, in June 2019. Additionally, nuclear outages increased from an average of 700 MW in Spring 2019 to 1,000 MW in Spring 2020 primarily due to planned refueling outages.

Compared to Spring 2019, net imports in Spring 2020 increased from 17% to 23%, while natural gas generation decreased from 36% to 34%. In Spring 2018 and 2019, outages across New York North limited tie line capability. In Spring 2020, there were fewer outages, which allowed more imports to flow into New England. This is discussed in more detail in Section 4.3.2. Despite the decline in nuclear generation, natural gas-fired generators produced less in Spring 2020 (4,000 MW) than in Spring 2019 (4,500 MW), on average. The combination of low loads due to the COVID-19 pandemic and an increase in net imports in Spring 2020, particularly across New York North, displaced natural gas generation.

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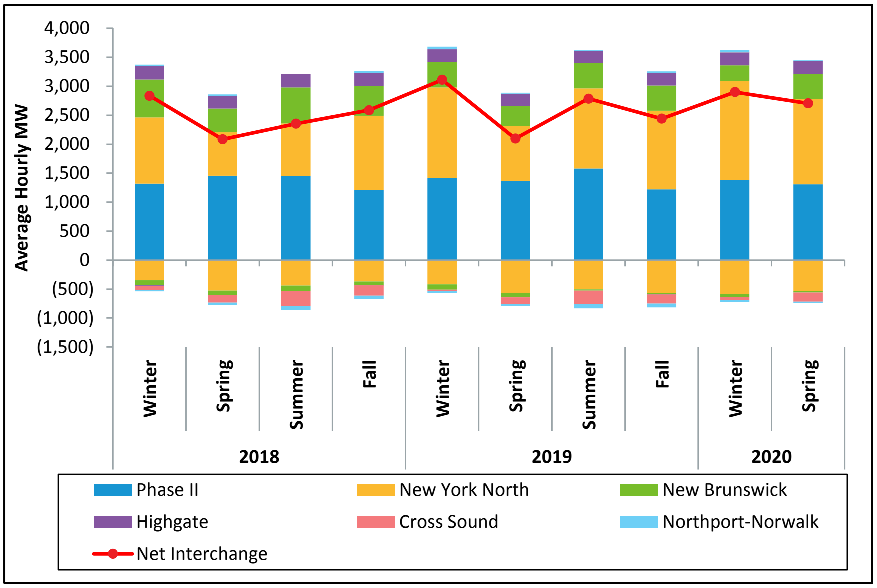
[77] Electricity generation in Section 4.3.1 equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, and wood.

4.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York in Spring 2020.[78] On average, the net flow of energy into New England was 2,705 MW per hour. Figure 4-8 shows the average hourly import, export and net interchange power volumes by external interface for the last ten quarters.

Figure 4-8: Average Hourly Real-Time Imports, Exports, and Net Interchange



In Spring 2020, New England met about 23% of its average load (NEL) from power imported from New York and Canada. This is the highest percentage during the reporting period. This was due to an increase in imports, discussed below, coupled with a decrease in real-time load, discussed above in Section 4.2. The largest share of imports into New England in Spring 2020 (43%) came from the New York North interface, with imports averaging 1,469 MW per hour. This represents a 56% increase from Spring 2019 (945 MW per hour, on average). The Phase II interface contributed an average of 1,309 MW per hour, or 38% of total imports. This represents a 4% decrease from Spring 2019 (1,369 MW per hour).

Figure 4-8 illustrates that net interchange and imports generally fall from winter to spring, when New England energy prices and demand tend to be lower. This pattern persisted between Winter and Spring 2020 but to a much lesser extent than in previous years. The average hourly net interchange value of 2,705 MW was up by 29% from Spring 2019, when average net interchange was 2,097 MW per hour. This increase in net interchange into New England was driven by a reduction in planned transmission outages during the Spring 2020 season, particularly over the New York North interface.

The increase in net interchange discussed above was primarily driven by an increase in imports over the New York North (NYN) interface. In the two prior spring periods transmission line

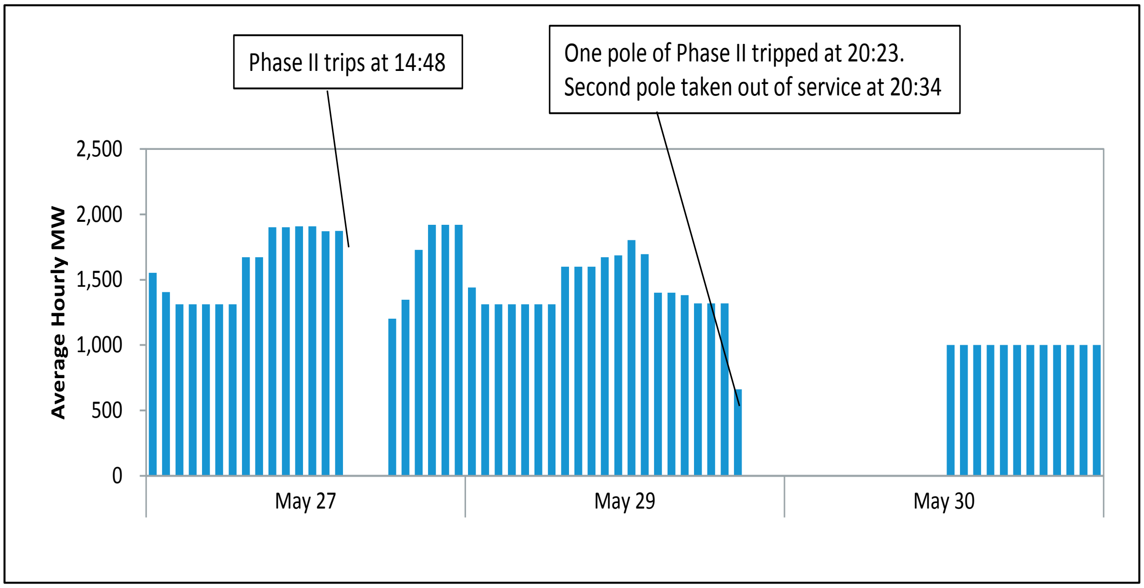
[78] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound cable, and the Northport-Norwalk cable. These last two 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.

outages caused reduced total transfer capability (TTC) over the New York North interface. In Spring 2019, the average real-time import TTC over New York North interface was 710 MW per hour, while in Spring 2018, it was 625 MW per hour. However, there were no extended periods when transmission line outages affected the TTC over the New York North interface in Spring 2020. Consequently, the average real-time import TTC over the New York North interface in Spring 2020 was 1,350 MW per hour.

In May 2020

Over a four-day period in the end of May 2020, the Phase II interconnection tripped offline two separate times. Figure 4-9 shows the average hourly net interchange power volumes by external interface for May 27, 29 and 30.

Figure 4-9:Average Hourly Real-Time Phase II Net Interchange May 27 - May 30



The first trip occurred at 14:48 on May 27 due to a lighting strike in Quebec. The entire interconnection was taken offline but was restored three hours later. Two days later on May 29, one of the Phase II poles tripped offline due to an explosion of a current transformer. The second pole was taken offline as a result of a fire and subsequent restoration efforts. One of the poles was restored 15 hours later, in the afternoon of May 30, allowing 1,000 MW to be imported. Phase II was fully restored in the afternoon of June 3rd.

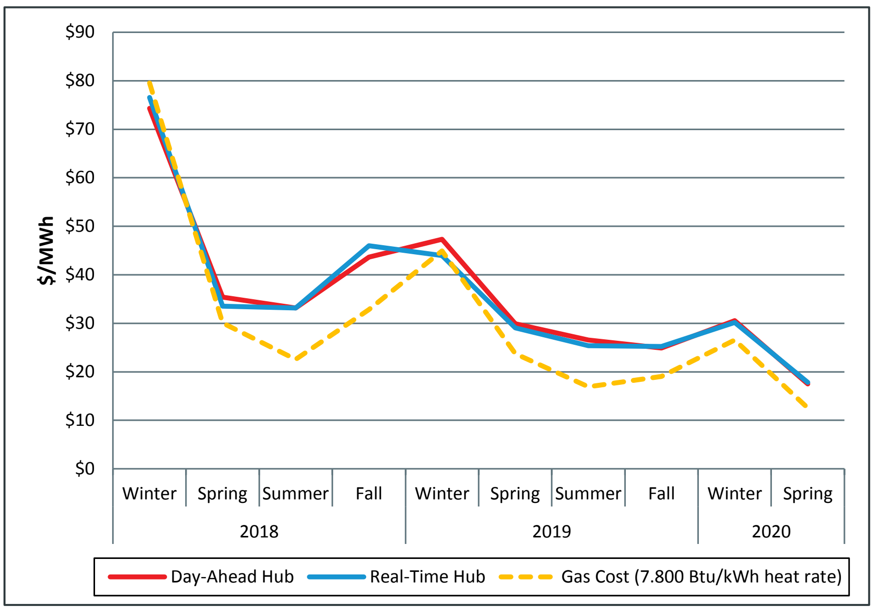
Section 5
Day-Ahead and Real-Time Markets

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.

5.1 Energy Prices

The average real-time Hub price for Spring 2020 was $17.62/MWh, similar to the average day-ahead price of $17.33/MWh, and both representing record lows. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas in New England, are shown in Figure 5-1 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.[79]

Figure 5-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 5-1 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 Spring 2020. Average day-ahead electricity prices were $5/MWh above average estimated gas costs in Spring 2020, slightly lower than the $6/MWh spread in Spring 2019.

In Spring 2020, average day-ahead and real-time prices were substantially lower than Spring 2019 prices, by about $12 and $11/MWh, respectively. This is consistent with the change in natural gas prices, which decreased by 47%. Additionally, average hourly loads in Spring 2020

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

were 750 MW lower than in Spring 2019 due to the COVID-19 pandemic, as well as increases in behind-the-meter solar generation and energy efficiency. The downward impact of lower gas prices and loads on LMPs may have been partially offset by greater baseload generation outages in Spring 2020. This spring, out-of-service nuclear generation capacity averaged about 270 MW higher than in Spring 2019 due to two planned refueling outages, as well as forced outages and reductions caused by mechanical issues.

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 5-2.

Figure 5-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs

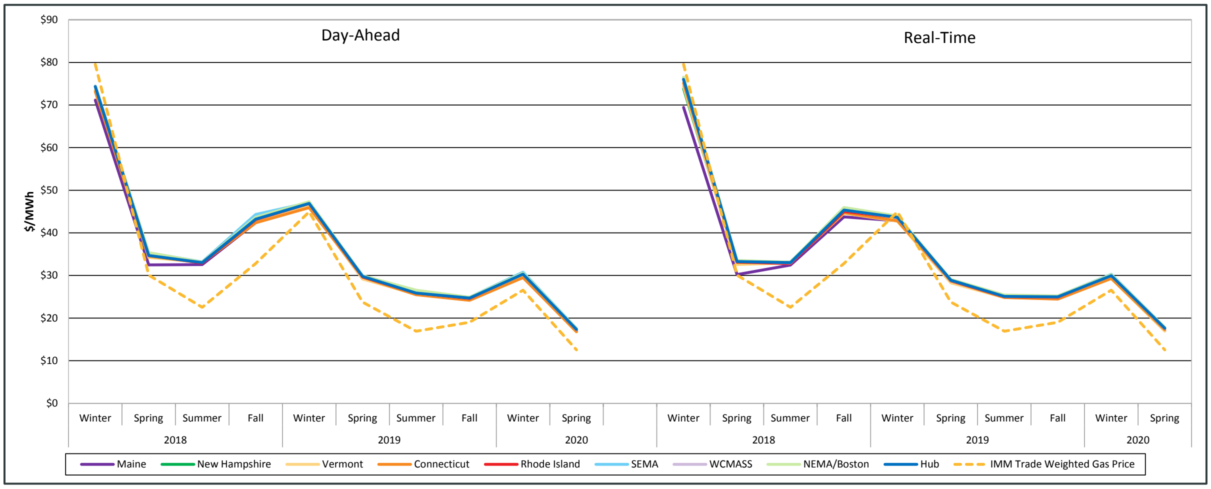


Figure 5-2 illustrates that prices did not differ significantly among the load zones in either market in Spring 2020, indicating that there was relatively little congestion on the system at the zonal level.[80]

5.2 Marginal Resources and Transactions

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

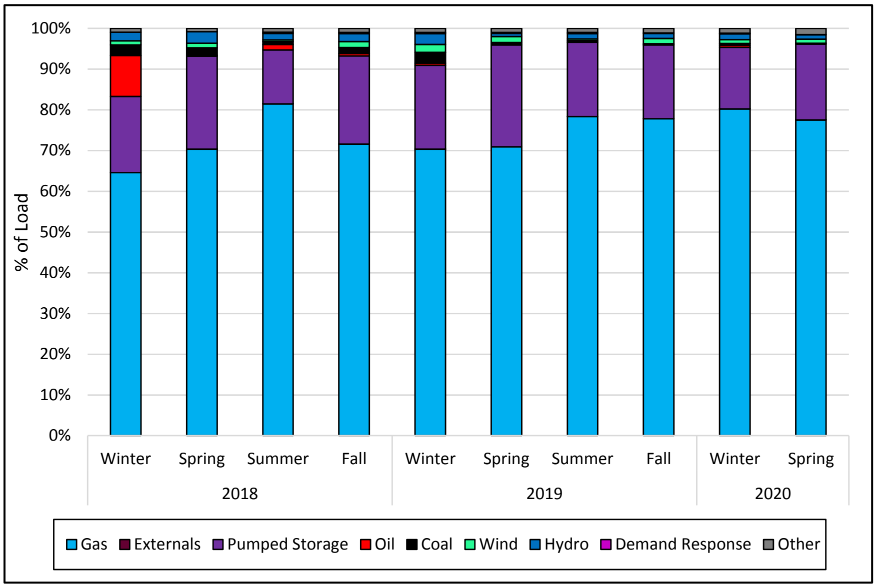
This section reports marginal units by transaction and fuel type on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal resources 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

[80] 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.

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. The percentage of load for which each fuel type set price in the *real-time market* by season is shown in Figure 5-3 below.[81]

Figure 5-3: Real-Time Marginal Units by Fuel Type



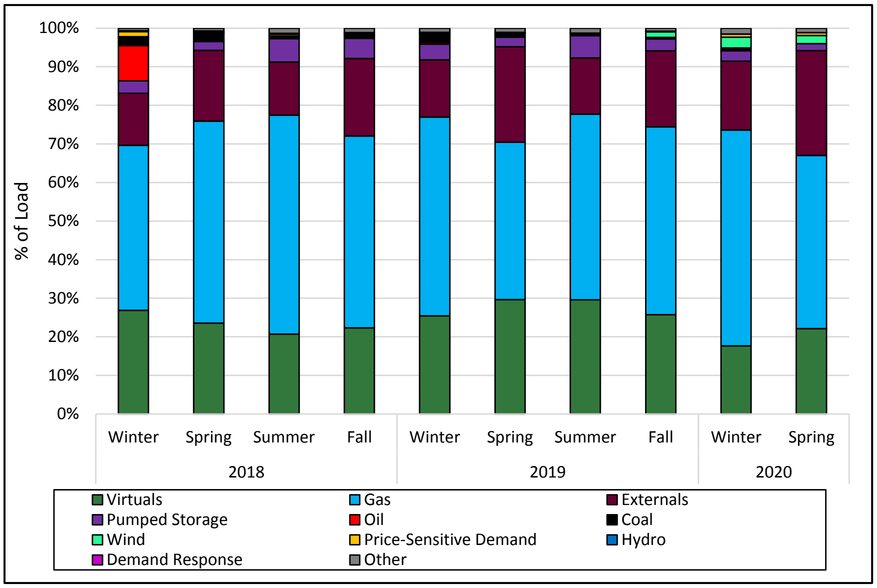
Natural gas-fired generators set price for about 78% of total load in Spring 2020. The increase from Spring 2019 (71%) was due to new efficient combined-cycle generators setting price, and existing gas-fired generators setting price more frequently. As gas-fired generators set price more frequently, pumped-storage units (generators and demand) set price for about 6% less load in Spring 2020 compared to Spring 2019 (19% vs 25%). Increased outages in Spring 2020 compared to Spring 2019 (370 MW vs 130 MW) reduced the amount of opportunities for pumped storage units to set-price.

Wind was marginal for 1% of total load in Spring 2020; most of which was located in *local export-constrained areas*, where the impact on the average load price is limited. Wind generators located in an export-constrained area can only satisfy 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 maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

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

The percentage of load for which each transaction type set price in the *day-ahead market* since Winter 2018 is illustrated in Figure 5-4 below.

Figure 5-4: Day-Ahead Marginal Units by Transaction and Fuel Type

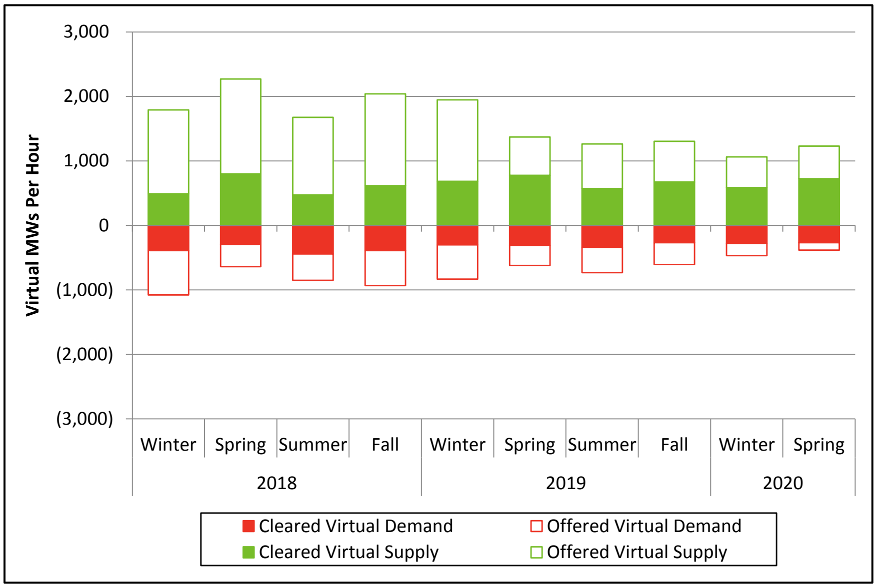


Gas-fired generators were the most frequent marginal resource type in the day-ahead market, setting price for 45% of total day-ahead load in Spring 2020. The increase from Spring 2019 (41%) was due to new efficient combined-cycle generators setting price, and existing gas-fired generators setting price more frequently than prior springs. While virtuals set price for less load in Spring 2020 than in Spring 2019 (22% vs 30%), Spring 2020 outcomes are more in line with historical levels. Externals set price for more load in Spring 2020 compared to Spring 2019 (27% vs 25%) because the New York North interface was constrained less frequently due fewer transmission outages in Spring 2020 compared to prior years. Fewer constrained intervals across an interface provides the opportunity for external participants to set price for a greater share of load in ISO-NE.

5.3 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 these 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 differences between the day-ahead and real-time markets generally improve price convergence. Offered and cleared virtual transaction volumes from Winter 2018 through Spring 2020 are shown in Figure 5-5 below.

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



In Spring 2020, total offered virtual transactions averaged approximately 1,613 MW per hour, which was 5% higher than the average amount offered in Winter 2020 (1,530 MW per hour) but 19% lower than the average amount offered in Spring 2019 (1,992 MW per hour). Over the period from Winter 2018 to Winter 2019, the average amount of offered virtual transactions was 2,811 MW per hour. However, the average amount of offered virtual transactions over the last five quarters (i.e., Spring 2019 to Spring 2020) has been only 1,808 MW per hour. Offered virtual transactions decreased during this period primarily because one participant significantly reduced their virtual transaction activity. Between Winter 2018 and Winter 2019, this participant submitted over 900 MW per hour of virtual transactions, on average. In the last five quarters, this participant's submissions averaged less than five MW per hour.

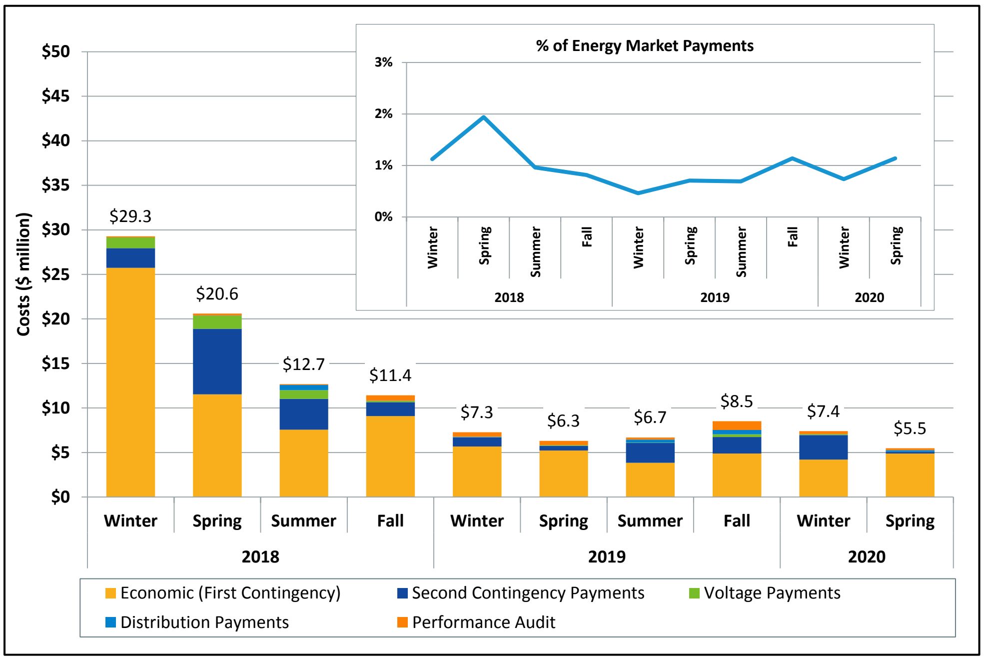
On average, 994 MW per hour of virtual transactions cleared in Spring 2020, which represents an increase of 15% compared to Winter 2020 (866 MW per hour) but a decrease of 8% compared to Spring 2019 (1,086 MW per hour). Cleared virtual supply amounted to 725 MW per hour, on average, in Spring 2020, up 24% from Winter 2020 (586 MW per hour) but down 7% from Spring 2019 (778 MW per hour). Meanwhile, cleared virtual demand amounted to 269 MW per hour, on average, in Spring 2020, down 4% from Winter 2020 (279 MW per hour) and down 13% from Spring 2019 (308 MW per hour). In general, the level of total cleared virtual transactions has stayed within a narrow range over the last 10 quarters – between 866 MW and 1,094 MW – indicating that participants' collective perception of their ability to profit from price differences between the day-ahead and real-time energy markets has remained relatively constant over this period.

5.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC), commonly known as uplift, are make-whole payments provided to resources in two circumstances: 1) when energy prices are insufficient to cover production costs or 2) to account for any foregone profits the resource may have lost by following ISO dispatch instructions. This section reports on quarterly uplift payments and the overall trend in uplift payments since Winter 2018. The data show that uplift payments continue to trend downward with Spring 2020 payments being the lowest of the reporting period. 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.[82]

Payments by season and by uplift category are illustrated below in Figure 5-6. The inset graph shows uplift payments as a percentage of total energy payments.

Figure 5-6: NCPC Payments by Category ($ millions)



Total uplift payments in Spring 2020 amounted to $5.5 million, a decrease of $0.8 million or 13% compared to Spring 2019 and was the lowest over the reporting horizon. With a decrease in total energy payments of about $413 million from Spring 2019, total uplift payments as a percentage of energy payments rose in Spring 2020 to 1.1% from 0.7%.

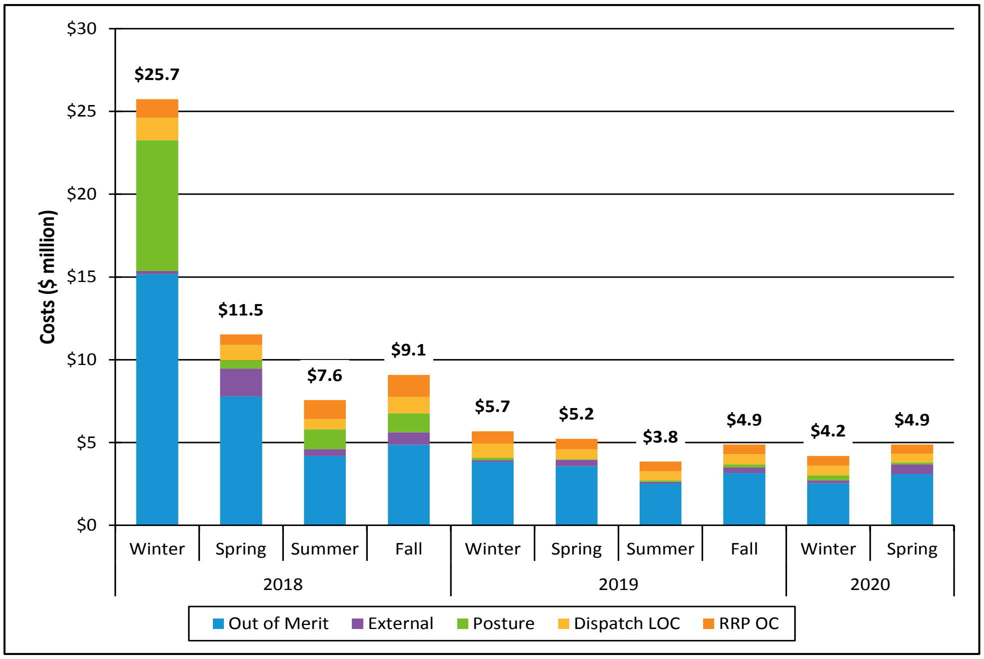
Economic payments comprised the majority of uplift (89% or $4.9 million) during Spring 2020. Like Spring 2019, the majority of economic payments were paid in the real-time market (67%). Compared to Spring 2019, economic uplift fell by $0.3 million. The main

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

drivers behind this decrease were a reduction in economic out-of-merit payments of $0.5 million. This decrease was partially offset by an increases in external transaction and posturing uplift payments, discussed below.

Economic uplift includes payments made to generators providing first-contingency protection as well as generators 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 generator. Figure 5-7 below shows economic payments by category.

Figure 5-7: Economic Uplift by Sub-Category



As illustrated in Figure 5-7, out-of-merit payments continue to make up the majority of economic uplift. Spring 2020 economic payments were slightly higher than Winter 2020 payments, increasing by $0.69 million. Out-of-merit payments fell by 13% from $3.58 million to $3.10 million between Spring 2019 and Spring 2020. Posturing payments more than doubled between Spring 2019 and Spring 2020 due to the system events at the end of May 2020 (see section 2.2) but remained relatively low. Of the $127 thousand paid to pumped-storage generators for posturing 82%, or $105 thousand, was paid on May 30, 2020.

Comparing Spring 2019 to Spring 2020 external transactions payments increased by 52%, from $0.38 million to $0.58 million. Import and export transactions are scheduled in the real-time market based on ISO forecasted prices but the transactions are settled based on actual prices. This uplift credit is intended to make external transactions that end up being out-of-rate (based on actual prices) whole to their bid or offer.[83] In Spring 2020, 71% of real-time external transaction uplift was paid to imports at the New Brunswick interface. This is an increase from Spring 2019, but a decrease from Spring 2018. The majority of

[83] External transactions at the CTS interface (Roseton) are not eligible for this from of NCPC.

Spring external uplift payments consistently are paid out at the New Brunswick interface because of binding system constraints. In Spring 2020 external uplift payments paid out at this interface increased by $170 thousand, but was far lower than the $1.6 million paid out in 2018.

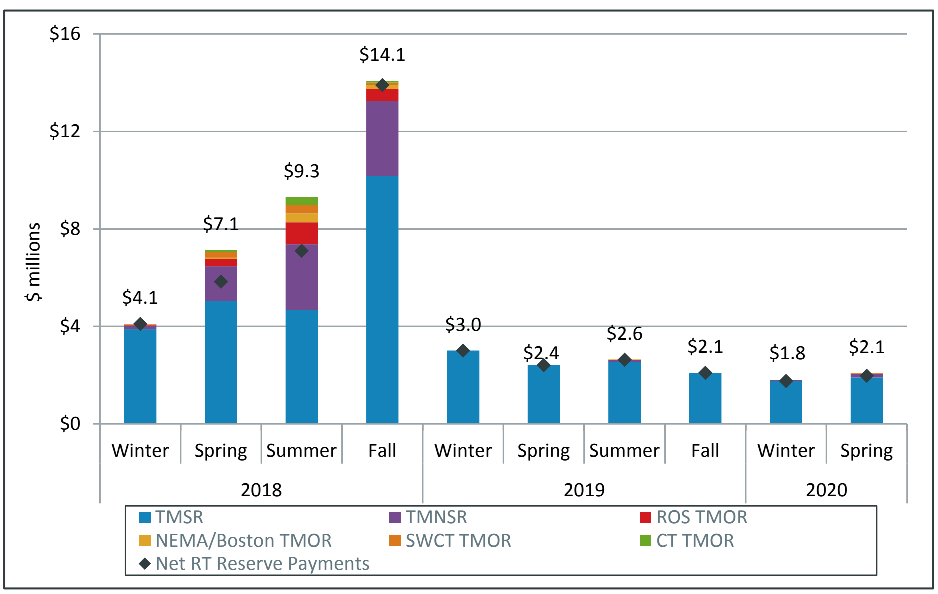
Total second contingency or LSCPR payments of $0.2 million were 93% lower than in Winter 2020 and 60% lower than in Spring 2019. Nearly all LSCPR uplift in Spring 2020 was paid the day-ahead market for planned transmission outages primarily in New Hampshire, lower south-east Massachusetts and Rhode Island.

5.5 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 adequate capacity is available during such contingencies, the ISO procures reserve products through the locational Forward Reserve Market 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 5-8 below. Gross real-time reserve payments totaled $2.1 million in Spring 2020. 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 $2.0 million in Spring 2020, are shown as black diamonds in Figure 5-8 below.

Figure 5-8: Real-Time Reserve Payments by Product and Zone



Spring 2020 reserve payments were down $0.3 million from Spring 2019. The small decline resulted from lower energy prices and a decrease in the magnitude of non-zero reserve prices. Most Spring 2020 reserve payments (91%) were ten-minute spinning reserve (TMSR) payments. The majority of non-spinning reserve payments for Spring 2020 occurred on May 27, when the unexpected loss of the Phase II interconnection resulted in tight system conditions and a subsequent reduction in reserve margins (see Figure 2-7).

The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three spring seasons is provided in Table 5-1 below.[84]

Table 5-1: Hours and Level of Non-Zero Reserve Pricing

Product	Zone	Spring 2018		Spring 2019		Spring 2020	
		Hours of Non-zero Pricing	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*
TMSR	System	457.6	$12.85	371.4	$10.97	489.7	$6.19
TMNSR	System	11.0	$122.18	0.0	$0.00	2.3	$59.79
TMOR	System	9.7	$99.84	0.0	$0.00	0.6	$80.66
	NEMA/Boston	9.7	$99.84	0.0	$0.00	0.6	$80.66
	CT	9.7	$99.84	0.0	$0.00	0.6	$80.66
	SWCT	9.7	$99.84	0.0	$0.00	0.6	$80.66

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 490 hours (22% of total hours) during Spring 2020, higher than the number of hours of non-zero reserve pricing in Spring 2019, but similar to Spring 2018. In the hours when the TMSR price was above zero, the price averaged $6.19/MWh, a decrease from the prior spring season and consistent with the decrease in real-time energy prices.

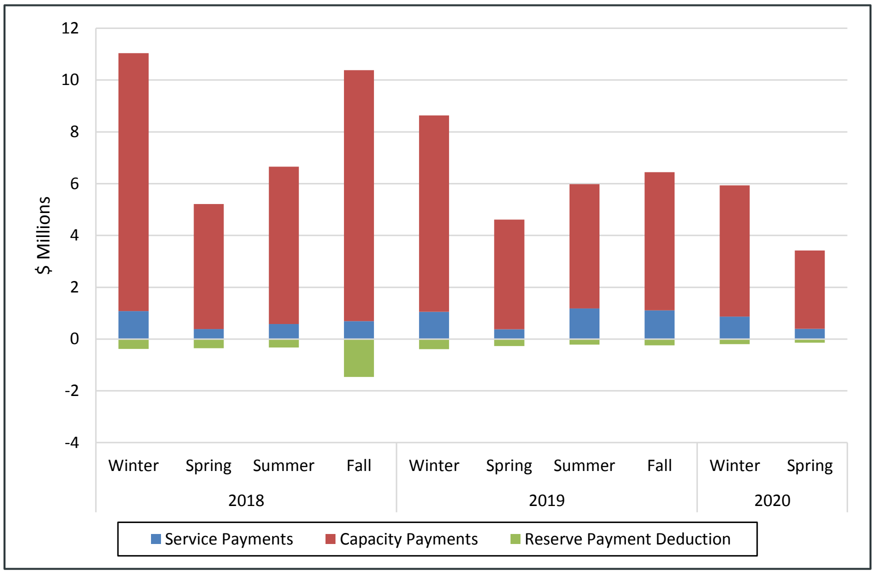
There were approximately two hours of non-zero ten-minute non-spinning reserve (TMNSR) and 35 minutes of thirty-minute operating reserve (TMOR) pricing in Spring 2020, most of which occurred due to the system event on May 27. As Table 5-1 shows, the frequency and magnitude of TMNSR and TMOR pricing were also small in previous spring seasons. Average total 30-minute reserve margins in Spring 2020 were similar to those of Spring 2019 (2,870 MW vs. 2,915 MW).

[84] 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.

5.6 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 5-9 below.[85]

Figure 5-9: Regulation Payments ($ millions)



Total regulation market payments for Spring 2020 were $3.3, down approximately 25% from $4.3 million in Spring 2019, and down by 43% from $5.7 million in Winter 2020.[86] The significant decline in payments primarily reflects large declines in energy market LMPs and natural gas prices for Spring 2020 relative to the earlier periods. Energy market LMPs declined by approximately 40% compared to the earlier periods, reducing the energy market opportunity costs (reflected in capacity payments) for generators providing regulation. Substantially lower natural gas prices helped to significantly reduce regulation service and capacity offer prices. These reduced offer prices are also reflected in the payments for capacity, relative to the earlier periods; service payments in Spring 2020 were approximately the same as for Spring 2019 (at the very low level of $0.4 million), but declined significantly from the Winter 2020 period (when service payments were $0.9 million)

[85] As noted in the Spring 2016 Quarterly Markets Report, both regulation capacity and service requirements were increased due to the modification of calculations performed in accordance with NERC standard BAL-003, Frequency Response and Frequency Bias Setting. These changes were implemented in April 2016.

[86] Starting in March 2017 with the sub-hourly settlement of several market activities (including real-time operating reserves), a deduction was added to regulation payments. This deduction represents the over-compensation of regulation resources for providing operating reserves. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since operating reserves are not actually provided within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. This adjustment is shown in the figure above; since it is small over recent periods, it is not discussed separately in the report.

Section 6
Forward Markets

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

6.1 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.[87] 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.

The ISO introduced Pay-for-Performance (PFP) rules beginning on June 1, 2018 to incent reliable operation during scarcity conditions.[88] Prior to June 1, 2018, resource owners faced de minimis financial penalties when unable to perform during periods of scarcity. The PFP rules improve the underlying market incentives by replicating performance incentives that exist in a fully functioning and uncapped energy market. Pay-for-performance rules provide a two-settlement construct that links payments to performance during scarcity conditions. Without this linkage, participants lack the incentive to make investments that ensure their resources perform when needed most. Also, absent these incentives, participants that have not made investments to ensure their resources' reliability are more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which, over time, erodes system reliability. Paying for actual performance during scarcity conditions incents resource owners to make investments and perform routine maintenance to ensure resource readiness to provide energy or operating reserves during scarcity conditions.

Pay-for-performance works as follows: a resource owner is compensated for that resource's Capacity Supply Obligation (CSO) held in a given month, but is subject to adjustments based on its performance during scarcity conditions. The PFP design replaced the shortage event rules in place through May 31, 2018. PFP is based on a two-settlement market built around the delivery of energy and operating reserves when they are needed most. If a resource fails to perform relative to expectations, it must buy the difference back at a performance payment rate. Under-performers compensate over-performers, with few exceptions.[89] Additionally, energy market only assets (known as PFP-only resources) are compensated for their contribution to load and reserve requirements. Since they hold no CSO, PFP-only resources cannot under-perform and can only receive compensation for over-performance during scarcity conditions.

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

[88] A scarcity condition occurs for the system or for certain capacity zones in five-minute increments. For more information, see Section III.13.7.2.1 of the tariff.

[89] Energy efficiency resources are provided an exemption during off-peak periods. See III.13.7.2.2 of the tariff for actual capacity provided calculations.

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.[90] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual CSOs. Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

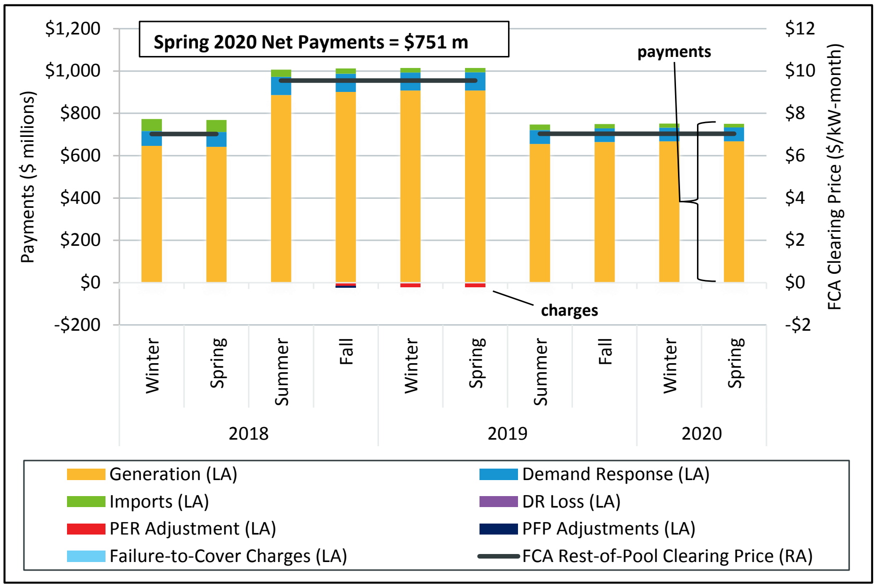
Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can buy or sell obligations. Buying an obligation means that the participant will provide capacity during a given period. Participants selling capacity reduce their 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, 2019 and ends on May 31, 2020. The conclusion of the corresponding Forward Capacity Auction (FCA 10) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 35,567 megawatts (MW) of capacity, which exceeded the 34,151 MW Installed Capacity Requirement (ICR), at a clearing price $7.03/kW-month. The clearing price of $7.03/kW-month was 26% lower than the previous year's $9.55/kW-month. This clearing price was applied to all resources within New England as well as the imports from Québec. However, the clearing price was $6.26/kW-month for New York imports and $4.00/kW-month for New Brunswick imports. The results of FCA 10 led to an estimated total annual cost of $2.99 billion in capacity payments.

Total FCM payments, as well as the clearing prices for Winter 2018 through Spring 2020, are shown in Figure 6-1 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 (PFP) adjustments, while the light blue bar represents Failure-to-Cover charges.

[90] 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.

Figure 6-1: Capacity Payments ($ millions)



Total net FCM payments decreased significantly from Spring 2019. In Spring 2020 capacity payments totaled $751 million, which accounts for adjustments to primary auction CSOs.[91] The $7.03/kW-month clearing price in FCA 10 was a 26% decrease from the previous FCA clearing price of $9.55/kW-month.

In Spring 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 its CSO. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of 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 reconfiguration auction and bilateral trading activity during Spring 2020, alongside the results of the relevant primary FCA are detailed in Table 6-1 below.

[91] 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 6-1: 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	New York AC Ties	Phase II
FCA 10 (2019-20)	Primary	12-month	7.03	35,567		4.00		6.26	
	Monthly Reconfiguration	May-20	0.60	933					
	Monthly Bilateral	May-20	1.77	252					
FCA 11 (2020-2021)	Primary	12-month	5.30	35,835		3.38			
	Annual Reconfiguration (3)	12-month	0.40	116/1126**	0.35	0.35	0.35		
	Monthly Reconfiguration	Jun-20	1.50	722	0.60	0.60	0.60		0.65
	Monthly Bilateral	Jun-20	2.33	117					
	Monthly Reconfiguration	Jul-20	2.00	796					
	Monthly Bilateral	Jul-20	2.42	168					

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

The third Annual Reconfiguration Auction (ARA) for CCP 11 took place in March 2020 and cleared 116 MW of supply and 1,126 MW of demand. The rest-of-pool price was $0.40 /kW-month, which is 92% lower than the clearing price for existing resources in FCA 11. The reduction of Net Installed Capacity Requirements (Net ICR) in ARA 3 contributed to lower clearing prices.[92] Lower Net ICR caused a shift in the ISO demand curve that represents reduced willingness to pay for additional capacity in the final reconfiguration auction. In response 1,010 MWs of capacity was removed from the market to balance the amount of cleared supply and demand heading into the commitment period.

Three monthly reconfiguration auctions took place in Spring 2020. There were lower trade volumes and higher prices in the two summer periods (June and July) compared to the winter period (May). This is consistent with prior summer auctions due to lower generation qualified capacity during the summer months.

6.2 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 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.

[92] For more information about the Net ICR methodology for ARA 3 in CCP 11, see https://www.iso-ne.com/static-assets/documents/2019/11/2020_icr_ara.pdf.

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[93]

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 additional network capacity available than was made available in the second annual auction (in contrast to the prompt-month auctions, which do make additional capacity available).[94]

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.

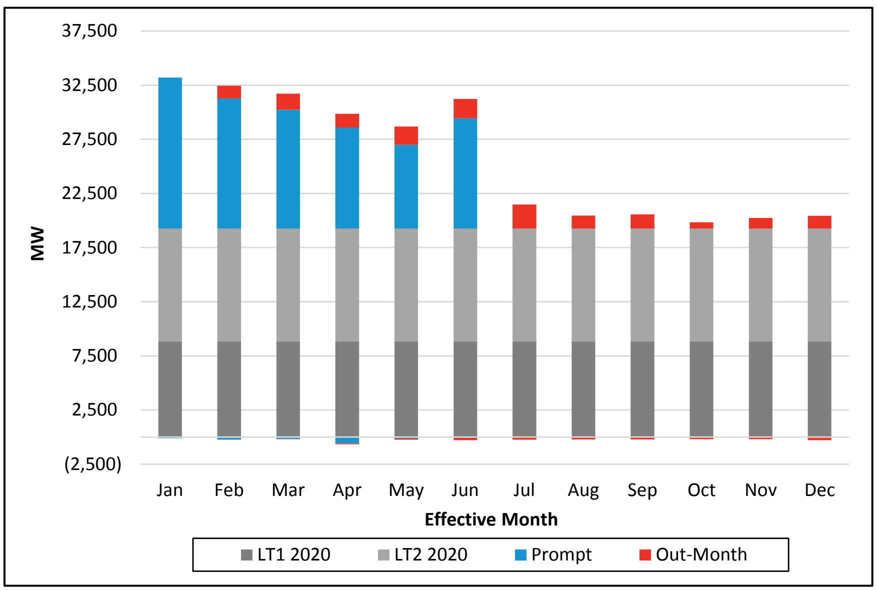
[93] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location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

[94] 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 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 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.

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 6-2 below.[95] 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 May 2020 (i.e., up to and including the June 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 June 2020 vintage purchases of the December 2020 FTR contract.

Figure 6-2: Monthly On-peak FTR MW by Auction



The prompt-month auctions for April, May, and June 2020 were all conducted in Spring 2020. The volume of FTR transactions that cleared in these three prompt-month auctions – 19,377 MW, 15,362 MW, and 19,783 MW, respectively – was lower than other recent prompt-month auctions.[96] The prompt-month on-peak auctions for April 2020, May 2020, and June 2020 had 32, 30, and 32 bidders, respectively. The prompt-month off-peak auction participation was lower: April 2020 had 28 bidders, May 2020 had 26 bidders, and June 2020, had 32 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

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

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

congestion in the day-ahead market, possibly as a result of lower load levels stemming from the economic shutdown intended to reduce the spread of COVID-19.

At the same time as the April 2020 prompt-month auctions, the ISO administered out-month auctions for May 2020 through December 2020. The volume of FTR transactions that cleared in these out-months auctions was quite low – between 500 MW and 1,637 MW, depending on the specific month. The transaction volumes clearing in the out-month auctions that took place concurrently with the May 2020 prompt-month auctions was even lower – between 205 MW and 1,291 MW, depending on the month. The transaction volumes clearing in the out-month auctions that took place concurrently with the June 2020 prompt-month auctions was also low – between 150 MW to 1,386 MW, depending on the month. Between 10 and 15 participants participated in the out-month auctions that occurred in Spring 2020, which is about one-third to one-half the participation level seen in the prompt-month auctions.

The Spring 2020 prompt-month FTR auctions (i.e., the prompt-month auctions for April 2020, May 2020, and June 2020) raised $1.2 million, which represents a 62% decrease compared to the prompt-month auctions that were conducted in Winter 2020 ($3.3 million), and a 54% decrease compared to the prompt-month auctions that took place in Spring 2019 ($2.7 million). The total auction revenue of the out-month auctions that were conducted in Spring 2020 was only $17 thousand.

FTR Funding

FTRs in March 2020 and April 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 May 2020 were not fully funded. In May 2020, FTR holders with positive target allocations received only 95.7% of the revenue to which they were entitled. However, there is a congestion revenue fund surplus for 2020 ($1.7 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.

6.3 Forward Reserve Market

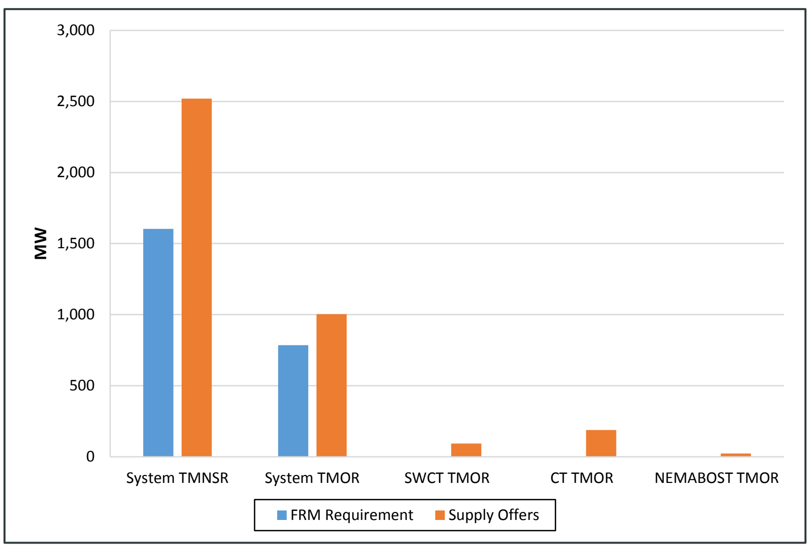
Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During April 2020, the ISO held the forward reserve auction for the Summer 2020 delivery period (i.e., June 1, 2020 to September 30, 2020).[97]

6.3.1 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 (unexpected events such as the loss of a large generator or transmission line).

The requirements for the Summer 2020 auction are illustrated in Figure 6-3 below. These requirements were specified for the ISO New England system and three local reserve zones.[98] The figure also illustrates the total quantity of supply offers available in the auction to satisfy the reserve needs.[99]

Figure 6-3: Forward Reserve Requirements and Supply Offer Quantities



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

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

[99] 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 TMOR 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 shown in the CT TMOR total.

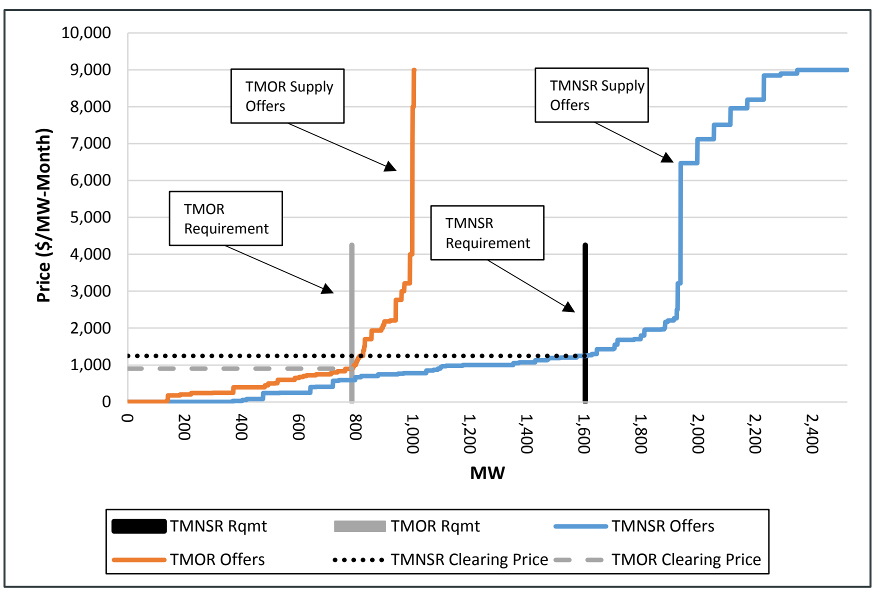
For the system, requirements were set for two reserve products: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). The ISO bases the requirements for each product on possible system contingencies. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,604 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 785 MW TMOR need. 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). 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. For the auction, each local reserve zone was estimated to have substantial, available external reserve support, ranging from 2,800 to 4,700 MW.

6.3.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Summer 2020 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 6-4 below provides the requirements, system-wide supply curves, and clearing prices for both TMNSR and TMOR.

Figure 6-4: Requirements and Supply Curves, System-Wide TMOR & TMNSR



With system-wide requirements of 785 MW for TMOR and 1,604 MW for TMNSR, system-wide supply offers for the two products resulted in clearing prices of $900/MW-month for TMOR and $1,249/MW-month for TMNSR (gray and black dashed/dotted lines in the figure).

6.3.3 Price Summary

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

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

In the Summer 2020 auction, TMNSR and TMOR cleared at significantly lower prices than in the earlier summer auctions. Compared to the Summer 2019 auction, TMNSR and TMOR were lower by $650/MW-month and $999/MW-month respectively; this is explained primarily by significantly lower offer prices for TMNSR and TMOR in the Summer 2020 auction for the section of the supply curves near the historical requirement levels for each product. The clearing prices increased in the Summer 2020 auction compared to the Winter 2019-2020 auction as a result of a lower requirement for TMNSR in the Winter auction, reduced offer prices for TMNSR in the Winter auction, and the substitution of lower-priced TMNSR for TMOR in the Winter auction (which reduced the Winter TMOR price).

6.3.4 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 – Figure 6-6 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.

Figure 6-6: 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)
Winter 2017-18	127	209	N/A	N/A	24
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

An RSI 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. Generally, the RSI values can fluctuate significantly from auction to auction. These fluctuations can be partly explained by variation in the reserve requirement. For instance, the TMOR RSI value for the SWCT zone increased from 183 in Summer 2017 auction (not shown in the table) to 438 in Summer 2018 period. This resulted from the local TMOR requirement decreasing from 52 MW to 21 MW, with a small quantity of local supply available to meet a requirement that decreased by 60%.

With two exceptions, from the Winter 2017-2018 through Summer 2020 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. However, two Summer auctions have RSI values 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 rest-of-system (ROS) zone were consistent with a structurally competitive level throughout the review period.[100] 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.

[100] The ROS zone excludes the local reserve zones.