Spring 2021
Quarterly Markets Report

By ISO New England's Internal Market Monitor

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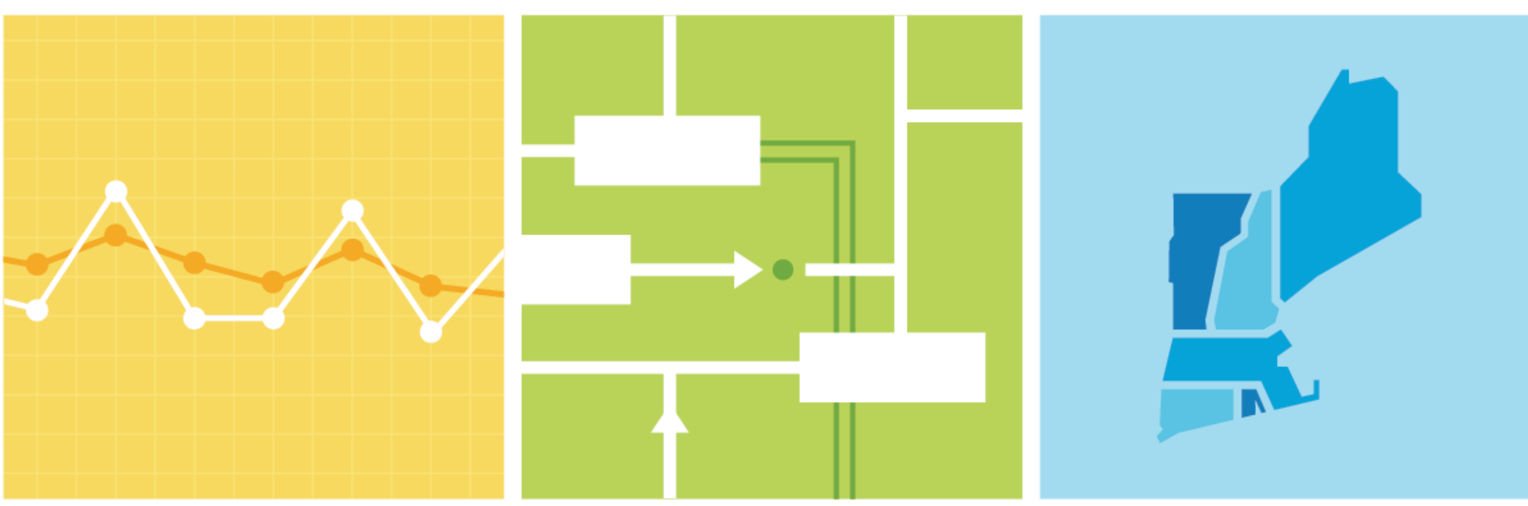

Preface

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

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

All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Spring 2021 (March 1, 2021 through May 31, 2021).[3]

Special Topic: Review of CASPR: The Competitive Auctions with Sponsored Policy Resources (CASPR) initiative has been in effect for the past three Forward Capacity Auctions (FCA). However, during this time we have seen limited entry into the Forward Capacity Market (FCM) through CASPR for new sponsored resources. In this section, we examine the performance of CASPR during the previous three Forward Capacity Auctions and find that the CASPR design is working as intended and that the low volume of sponsored resources obtaining capacity supply obligations (CSO) through CASPR is a function of low primary FCA clearing prices.

We discuss several key rules of CASPR in the context of the capacity volume that ultimately participates in the substitution auction (SA). In particular, “test price” mitigation - designed to prevent policy resource subsidies from suppressing the primary auction price - does not appear to have been a primary factor in low participation from existing resources in the substitution auction. Our opinion is that the primary driver of low participation and clearing in the SA is low primary auction prices that reflect a system that currently has a moderate surplus of capacity.

The fact that few existing resources are participating in the SA under moderate or greater surplus conditions is a good feature of the CASPR design. As more resources retire through conventional, non-CASPR paths we expect the system to be closer to criteria and less long; consequently producing higher primary auction prices. With higher prices, more existing resources will obtain a CSO in the primary auction and participate in the SA where they may retire by trading out of their CSO with new policy resources.

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.49 billion in Spring 2021, up 19% from $1.25 billion in Spring 2020. Higher energy costs drove the increase in wholesale costs. The previous spring (2020) saw historically low loads, natural gas prices, and energy prices, partially due to the economic shutdown associated with COVID-19.

Energy costs totaled $865 million in Spring 2021; up 80% (or $384 million) from Spring 2020 costs. Higher energy costs were a result of increased natural gas prices and loads. Average natural gas prices increased by 74% relative to Spring 2020 prices, while average hourly loads increased by 3% or 320 MW.

Capacity costs totaled $607 million in Spring 2021, down 19% (by $144 million) over the previous Spring. Beginning in Summer 2020, lower capacity clearing prices from the eleventh Forward Capacity Auction (FCA 11) contributed to lower wholesale costs relative to FCA 10. Last year (CCP 10, June 2019 – May 2020), the clearing price for new and existing resources was $7.03/kW-month. In the current capacity commitment period (CCP 11, June 2020 – May

[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).

2021), the clearing price for all new and existing resources was $5.30/kW-month. Lower clearing prices were partially driven by an increase in surplus capacity resulting from no significant resource retirements and a slight decrease in Net ICR.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $28.69 and $27.89 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 58-66% higher than Spring 2020 prices, on average. Spring 2020 saw 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.
- Gas prices averaged $2.80 /MMBtu in Spring 2021, an increase of 74% compared to $1.61/MMBtu during the prior spring.
- Hourly load averaged 11,973 MW, up 3% (≈ 320 MW) on the previous spring. Spring 2021 loads rebounded from record low levels in Spring 2020, when business closures intended to mitigate the spread of COVID-19 led to decreased demand on the system.
- Energy market prices did not differ significantly among the load zones.

Net Commitment Period Compensation: Uplift payments totaled $6.7 million in Spring 2021, an increase of $0.7 million compared to Spring 2020. Uplift payments represented less than 1% of total wholesale energy costs in Spring 2021, a similar share compared to other quarters in the reporting horizon. The majority of uplift (92%) was for first contingency protection (also known as "economic" uplift). Economic payments were evenly split between the day-ahead and real-time markets. Compared to Spring 2020, economic payments increased by $0.8 million (from $4.9 million to $5.7 million). This increase was consistent with higher energy prices in Spring 2021 compared to Spring 2020.

Local second-contingency protection resource (LSCPR) payments totaled $0.3 million, which was similar to Spring 2020 and 2019 payments. Most LSCPR uplift in Spring 2021 was paid in the day-ahead market to support planned transmission outages in Maine and lower south-east Massachusetts.

Real-time Reserves: Real-time reserve payments totaled $1.4 million, a $0.7 million decrease from $2.1 million in Spring 2020. All Spring 2021 reserve payments were for ten-minute spinning reserve (TMSR).

Non-zero TMSR pricing occurred in 325 hours in Spring 2021, down from 490 hours in Spring 2020. The average non-zero hourly spinning reserve price increased from $6.19 in Spring 2020 to $7.85/MWh in Spring 2021. The increase was driven by higher LMPs, which increased re-dispatch costs to provide reserves rather than energy.

***Regulation*:** Total regulation market payments were $4.2 million, up 28% from $3.3 million in Spring 2020. The increase in payments was driven by two factors. First, regulation capacity payments increased, primarily due to manual commitments of expensive regulation generators for several hours in March 2021, and by a small increase in regulation uplift payments. Second, higher natural gas prices resulted in increased regulation service payments.

Energy Market Competitiveness: Spring 2021 saw a slightly higher frequency of pivotal suppliers (14%) compared to the two previous spring seasons (8%). The small increase was likely a result of several factors, including higher loads in Spring 2021 compared to 2020, and fewer net imports compared to any other quarter in the reporting period.

Mitigation occurs very infrequently relative to the initial triggers for potential mitigation (i.e., structural test failures, commitment or dispatch) and the highest frequency of mitigation generally occurs for reliability commitments. This spring, Maine and Southeastern Massachusetts/Rhode Island (SEMA-RI) had the highest frequency of reliability commitment mitigations, 47% of mitigations occurred in Maine and 25% occurred in SEMA-RI in the day-ahead market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past two years, and with the frequency of localized transmission issues within Maine. Overall, reliability mitigations decreased significantly between Spring 2020 (115 asset-hours) and Spring 2021 (33 asset-hours).

Financial Transmission Rights (FTRs): FTRs were fully funded in March, April, and May 2021. Positive target allocations totaled $9.6 million in Spring 2021, up 73% from Spring 2020 ($5.5 million). Day-ahead congestion revenue also increased in Spring 2021, totaling $9.6 million compared to $6.7 million in Spring 2020. Negative target allocations ($1.0 million) were 75% higher than their Spring 2020 level ($0.6 million). Real-time congestion revenue was -$0.2 million in Spring 2021, around 60% lower than both the Winter 2021 and Spring 2020 values. Recently, it has been common to see negative real-time congestion revenue which is likely the result of negative RT congestion combined with negative generation obligation deviations. At the end of May 2021, there was a congestion revenue fund surplus of $1.9 million for 2021. Surpluses carry over until the end of the year, when they are used to pay any unpaid monthly positive target allocations.

Summer 2021 Forward Reserve Market Auction: In April 2021, ISO New England held the forward reserve auction for the Summer 2021 delivery period (i.e., June 1 to September 30, 2021). System-wide supply offers in the Summer 2021 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 was 92, which was below the structurally competitive level, but an improvement over the previous summer auction (Summer 2020 auction). The Summer 2021 RSI was higher than the Summer 2020 value due to a small increase in supply and a small reduction in the requirement.

The net clearing prices for offline 30- and 10-minute system reserves were $600 and $1,150/MW-month, respectively, a decrease from the Summer 2020 prices ($900/MW-month for TMOR and $1,249/MW-month for TMNSR).

Section 2
Special Topic: Review of CASPR

In this section, we review the performance of the Competitive Markets and Sponsored Policy Resources (CASPR) initiative and examine whether it is working as designed. While CASPR has been in effect for the past three Forward Capacity Auctions (FCA), we have seen limited entry into the Forward Capacity Market (FCM) through CASPR for new sponsored resources during this time. To date, only twelve existing resources have entered the auction as eligible to participate in CASPR. Seven of those resources obtained a capacity supply obligation (CSO) in the primary auction, which they could potentially trade to a new sponsored resource in the substitution auction (SA), but only one of those resources (54 MW) successfully retired via CASPR (FCA 13).

We discuss several key rules of CASPR in the context of the capacity volume that ultimately participates in the SA. In particular, "test price" mitigation - designed to prevent policy resource subsidies from suppressing the primary auction price - does not appear to have been a primary factor in low participation from existing resources in the substitution auction. Our opinion is that the primary driver of low participation and clearing in the SA is low primary auction prices that reflect a system that currently has a moderate surplus of capacity.

The fact that few existing resources are participating in the SA under moderate or greater surplus conditions is a good feature of the CASPR design; it is not designed to keep the system long on installed capacity by allowing existing resources to trade out with policy resources on a MW for MW basis. As more resources retire through conventional, non-CASPR paths we expect the system to be closer to criteria and less long; consequently producing higher primary auction prices. With higher prices, more existing resources will obtain a CSO in the primary auction and participate in the SA where they may retire by trading out of their CSO with new policy resources.

In short, it is not correct to judge the CASPR design only on the quantity of sponsored resources cleared through the initiative. We examine the performance of CASPR during the previous three Forward Capacity Auctions and find that the CASPR design is working as intended and that the low volume of sponsored resources clearing in the substitution auction is a function of low primary FCA clearing prices.

2.1 CASPR Overview

CASPR was designed and implemented as the result of a joint ISO New England and stakeholder initiative, Integrating Markets and Public Policy (IMAPP), which sought to accommodate state-sponsored resources into the region's Forward Capacity Market while continuing to provide some protection for capacity market price formation against the injection of public funds.[4] State representatives were concerned that consumers were paying twice for the cost of capacity – once through the FCM, and then a second time through subsidies for state-mandated supply resources. Generation owners, on the other hand, voiced concerns that without mitigation,

[4] CASPR does protect price formation in the primary FCM auction, however once a new subsidized policy resource obtains a capacity supply obligation and becomes an existing capacity resource, there are no protections in place to limit the impact of the subsidy for that resource on price formation in subsequent auctions.

sponsored resources that are subsidized through public funding would depress FCM clearing prices below competitive levels. The solution proposed by ISO New England was CASPR – an augmentation to the existing FCM design that coordinates the entry of new sponsored policy resources with the retirement of existing resources.

Design Criteria

ISO New England developed the CASPR solution based on four foundational objectives which we reprint below[5]:

1. **Competitive capacity pricing.** Maintain competitively-based capacity auction prices by minimizing the price-suppressive effect of out-of-market subsidies on competitive (i.e., unsponsored) resources in the FCA.

2. **Accommodate the entry of sponsored new resources into the FCM over time.** In doing so, the ISO's market rules should help to minimize the potential for New England to develop far more resources on the power system than the ISO requires to reliably operate it.

3. **Avoid cost shifts.** To the extent possible, minimize the potential for one state's consumers to bear the costs of other states' subsidies.

4. **A transparent, market-based approach.** Seek a practical solution approach that extends, rather than upends, the region's existing capacity market framework.

The key challenge for the CASPR design was to find a balance between conflicting design objectives (1) and (2). Subsidies provide sponsored resources with a competitive advantage in that they can offer below their true cost of providing capacity. In this way, these resources force non-subsidized resources to exit the market that would have otherwise obtained a capacity supply obligation. Consequently, the marginal resource that sets the clearing price in the auction will have a lower offer price than would be the case in the absence of subsidies. As a result, the FCA clearing price will be lower than the non-subsidy case.

CASPR Mechanism

CASPR employs a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary FCA. The fundamental component of CASPR is the substitution auction (SA) that takes place immediately following the primary FCA and coordinates the entry of sponsored new resources with the exit of existing capacity resources.

In the substitution auction, existing capacity resources that retained a CSO in the primary FCA and opted into the SA may transfer their obligations to new resources that did not clear in the

[5] These objectives and the initial CASPR design are presented in detail in the ISO discussion paper "Competitive Auctions with Subsidized Policy Resources", April 2017 - https://www.iso-ne.com/static-assets/documents/2017/04/caspr_discussion_paper_april_14_2017.pdf

primary FCA because of the Minimum Offer Price Rule (MOPR)[6]. In the SA, the existing resources form the demand and the new sponsored resources form the supply. This differs from the primary FCA where all resources are offering supply and the demand is set with a system demand curve. The SA clearing price can be positive or negative. When the price is positive, existing resources pay the new sponsored resources for accepting capacity supply obligations and then retain the difference between what they receive as CSO payments in the primary auction and what they pay the sponsored resources to assume the obligations in the SA. If the SA price is negative, then the sponsored resources are willing to pay to take on the obligation for the first year, which would be offset by positive capacity payments in future years when they would be treated as existing capacity. Either way, the existing resources that transfer their obligations in the SA retire from the FCM permanently. We demonstrate the mechanics of the CASPR design through examples that follow below.

Examples of CASPR clearing

To set the stage for this discussion, we revisit an example presented in ISO New England's CASPR white paper from April 2019. While that document presents the example in much more detail, we review the example here as a refresher on the mechanics of the two-stage auction design.

There are three types of resources offering capacity supply in the example[7]:

1. existing resources (E1, E2) that have not opted into the substitution auction,
2. existing resources that have opted into the substitution auction (R1, R2), and
3. sponsored resources that are subject to the MOPR (S1, S2, S3).

The ideal outcome of this stylized FCA is shown in Figure 2-1. All existing resources (E1, E2, R1, R2) have offered low enough to retain a CSO but none of the new sponsored resources (S1, S2, S3) have acquired a CSO. However, two of the existing resources (R1, R2) have opted to enter the substitution auction where they may trade their newly retained CSO with a new sponsored resource.

The existing resources that are seeking to trade out of their CSO become demand in the substitution auction, i.e., they will pay another resource to take on their CSO. The sponsored resources continue to the SA as supply, i.e., they want to sell capacity and take on a CSO. The substitution auction is shown on the right in Figure 2-1 below. Note, the bids and offers for the SA are submitted prior to the FCA and are independent of the FCA offers, i.e., the SA bids/offers do not need to match the FCA offers. The FCA clearing price forms a ceiling price in the SA so bids in excess of this number are adjusted down to this value. Otherwise, if an existing resource were to bid higher than the FCA clearing price in the SA, then it would be willing to pay to get out of the capacity obligation that it just acquired. In this example, resources R1 and R2, trade

[6] In the FCM, new capacity resources are subject to a Minimum Offer Price Rule (MOPR) which sets their floor price based on an IMM-calculated competitive offer benchmark for a given resource's technology type. The MOPR mechanism is intended to prevent public subsidies from depressing prices in the primary FCA.

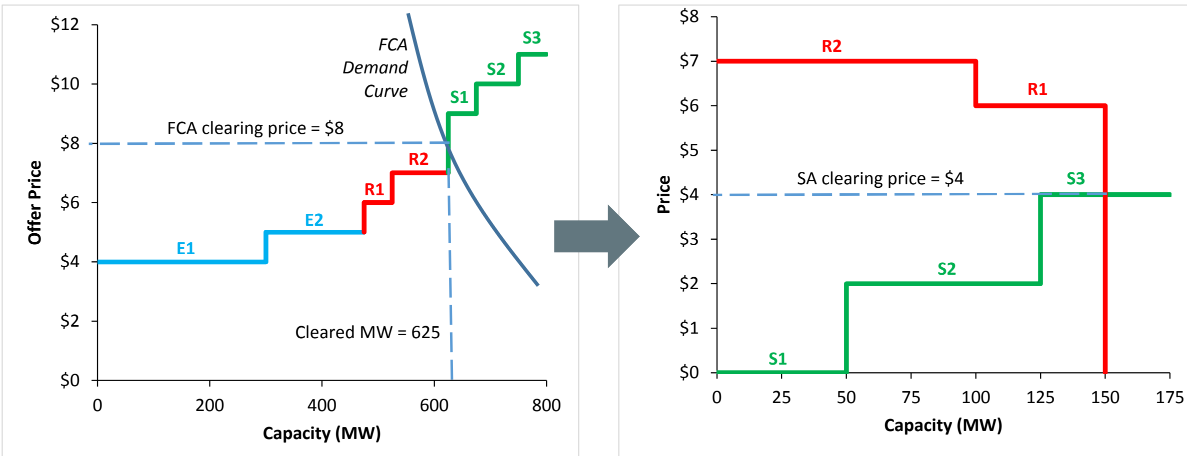
[7] Note, sponsored resources that obtain a CSO are treated as existing resources in the following years and are no longer subject to the MOPR even though they may still be subsidized.

their obligations to S1, S2, and S3 at a clearing price of $4.[8,9] Resources R1 and R2 retire with a net payment of $4 ($8 from the CSO obligation they obtained in the FCA minus $4 that they will pay the sponsored resources to taken on their obligation) and sponsored resources receive $4 for providing capacity and also become existing resources in future auctions.

Figure 2-1: CASPR Clearing Example 1

Primary Auction

Substitution Auction



Now that we have illustrated the SA mechanism, we examine two cases where the SA does not clear any new sponsored resources.

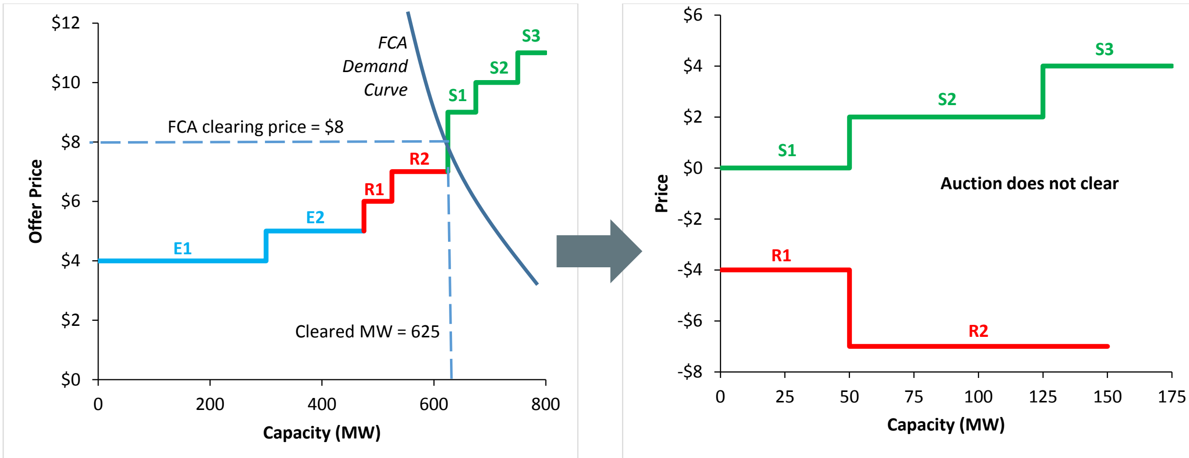
In example 2, shown in Figure 2-2 below, the FCA proceeds as before with the two exsiting resources that have opted into the SA obtaining CSOs and the three sponsored resources not recieving CSOs. While the offers from the sponsored resources have remained the same as the previous example, we now see that the retirement resources (R1, R2) have demand bids that are all below the supply offers. By bidding at -$7 resource R2 is asking to be paid $7 to give up its CSO. In other words, resource R2 wants to receive the $8 from the FCA and be paid an additional $7, for a total of $15 to exit the capacity market. Similarly, resource R1 wants to be paid $12 to exit the capacity market. However, in this case, no sponsored resources are willing to pay to take on a CSO. Note, in practice it may be financially prudent for a new entrant to pay to take on a CSO in the first year because the resource will become exisiting for future auctions and then receive the full FCA payments.

[8] Resource S3 obtains a CSO for only a portion of its capacity. In the SA, supply is rationable but demand is not.

[9] CSO payments are in $/kw-month.

Figure 2-2: CASPR Clearing Example 2

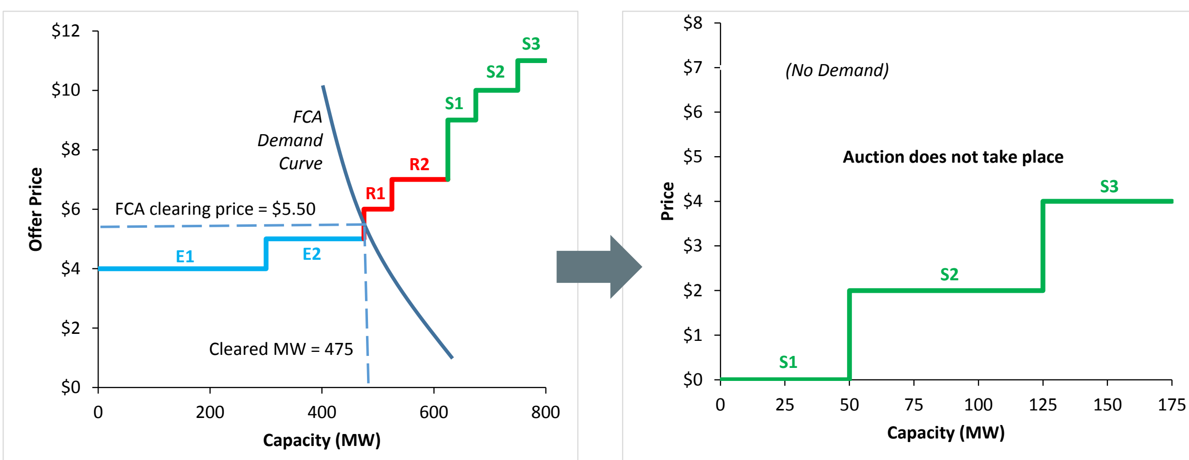
Primary Auction Substitution Auction



Example 3, shown in Figure 2-3 below, shows a case where the subtituion auciton would not take place. This example differs from the previous two in that the FCA demand curve in now lower. In this case, offers from resources R1 and R2 are too high to obtain a CSO in the primary auction. Consequently, they do not have a CSO to trade in the SA and, without demand, the SA cannot take place.

Figure 2-3: CASPR Clearing Example 3

Primary Auction Substitution Auction



2.2 CASPR Test Price Mitigation

The test price mitigation rule was introduced in FCA 14, and applies to resources (above 3 MW) seeking to retire through the substitution auction. The rule is designed to protect the primary FCA from price suppression, by mitigating behavior commonly referred to as "bid shading" in which an existing resource reduces its primary auction offer below a competitive level in the hopes of retaining a CSO that it can trade for a severance payment in the substitution auction.

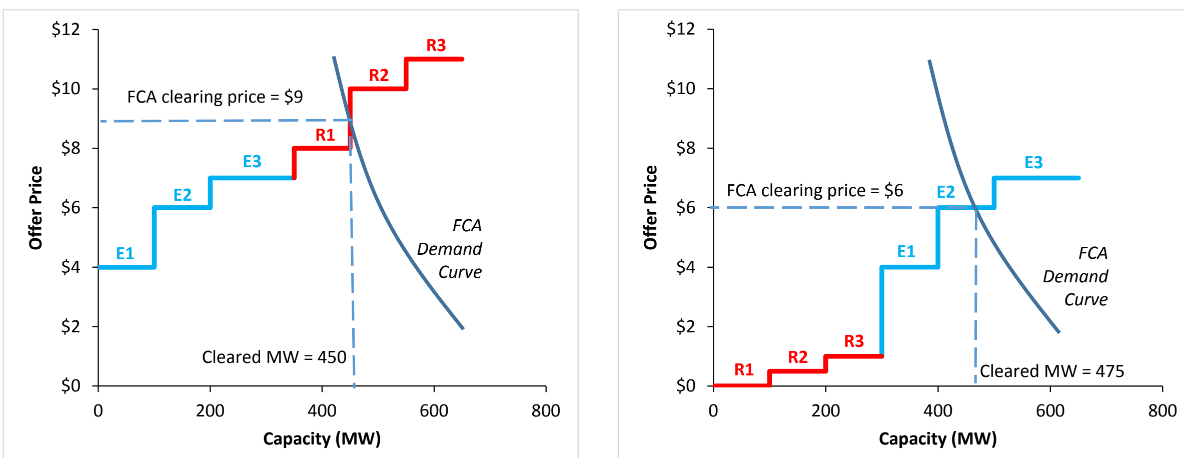
The purpose of bid shading is to increase the likelihood a resource would be able to capture some revenue from sponsored resources in the SA. This, effectively, monetizes expected public funded subsidy from sponsored resources into bids in the primary auction and can have a similar price suppressing effect in the primary auction as though the sponsored resources were offering below competitive levels (i.e., no MOPR is applied). In other words, allowing this practice would undermine the price formation benefits of MOPR.

Bid shading is problematic because the resources most likely to lower their offer below cost are those that are close to, or above, the FCA clearing price. As a result, the supply curve is reshuffled with a lower priced resource now becoming the marginal supplier and setting the FCA clearing price at a lower level than would otherwise have been the case. We illustrate this with the simple example shown in Figure 2-4 below.

Resources R1, R2, and R3 wish to retire through the SA but with test price mitigation only R1 will obtain a CSO and enter the SA. Both R2 and R3 will retire in the primary FCA without a severance payment. Without test price mitigation (shown on the right graph), all three resources offer very low prices to ensure they clear the FCA and they retire through the SA with severance payments. However, resource E2 now becomes the marginal resource and sets the FCA clearing price at $6.

Figure 2-4: Test Price Mitigation

Primary Auction with Test Price Mitigation | Primary Auction without Test Price Mitigation



The test price is an IMM-calculated value, based on a cost submission from the resource owner, which represents the competitive cost of obtaining a CSO (excluding any expected severance payment from the substitution auction). The test price serves as a screen to determine whether a resource's demand bid will be entered into the SA based on the clearing price of the primary auction. If the resource's test price is below the primary auction clearing price, the resource is allowed to enter the SA.[10] If the test price is greater than the primary auction clearing price, the resource is not permitted to enter a demand bid into the SA.

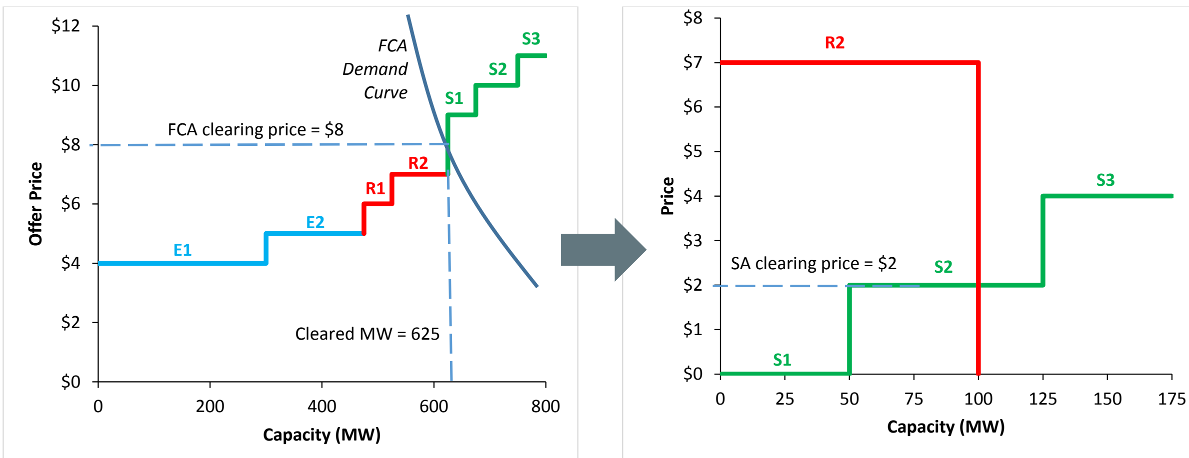
[10] In practice, participation in the SA is conditional on obtaining a CSO in the primary auction at a value that is no less than 90% of their test price. This allows some margin for uncertainty around the estimation of the test price. See Market Rule 1 Section III.13.2.8.3.3.

We demonstrate the impact of test price mitigation in Example 4, Figure 2-5, below in which we include test prices for resources R1 and R2 at $9 and $7 respectively. As in Example 1, both R1 and R2 obtain a CSO in the primary auction. However, while resource R1 has an offer that is low enough to obtain an obligation in the FCA, it has a test price above the FCA clearing price and is ineligible to proceed to the SA. As a result, only R2 proceeds to the SA and the auction clears at a lower price and quanity than shown in the previous example.

Figure 2-5: CASPR Clearing Example 4

Primary Auction

Substitution Auction



2.3 Substitution Auction Outcomes

Participants elect to participate in the substitution auction months in advance of the February FCA. For existing resources, participation in the SA is conditional on obtaining a CSO in the primary FCA at a value that is no less than 90% of their test price. In addition, the initial pool of potential demand in the SA is whittled down when resources retire or delist before or during the primary auction. The reduction in demand from election through to the substitution auction is shown for each FCA in Table 2-1 below.

Table 2-1: Substitution auction demand from election to SA

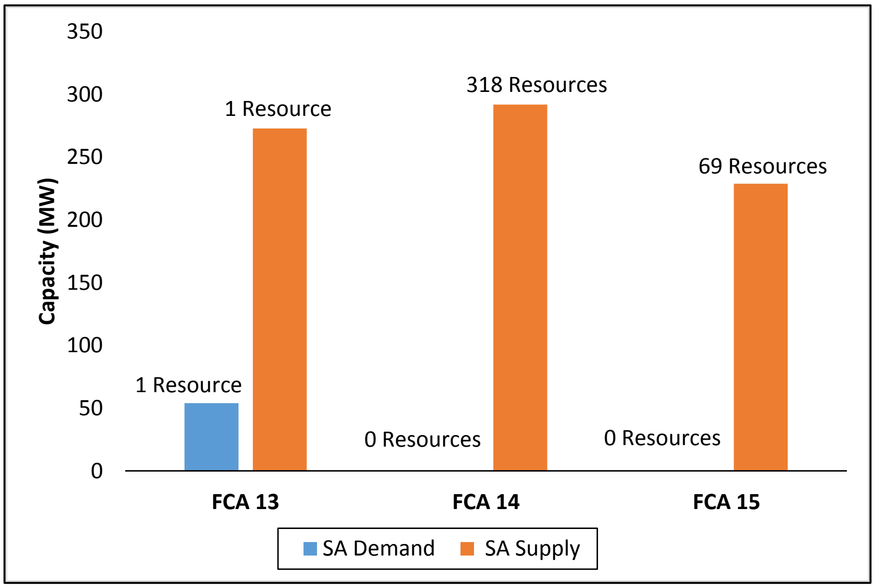
	SA Election		Proceed to FCA		Retained	Active Test	SA Cleared	
Auction	MW	# Resources	MW	# Resources	CSO	Price Mitigation	MW	# Resources
FCA 13	2,160	14	1,580	6	6[11]	n/a	54	1
FCA 14	446	14	188	3	1	1	0	0
FCA 15	196	13	98	3	0	0	0	0

New sponsored resource interest is also reduced between election and the SA for three reasons: 1) resources that elect to participate in the SA do not obtain qualification status before the FCA;

[11] Two resources totaling 1,413 MW were retained for reliability and three other resources bid too low to clear in the SA.

2) resources clear capacity through the primary auction[12]; and 3) resources withdraw before the auction. Below, in Figure 2-6, we summarize substitution auction participation and outcomes for the last three years. Most notable is the fact that while supply has been ample in every auction; demand has only materialized in one auction. Since its inception, the substitution auction has cleared only 54 MW of sponsored capacity in total.

Figure 2-6: Substitution Auction Participation



The substitution auction made its debut in the thirteenth Forward Capacity Auction (FCA 13). A single resource traded out of a 54 MW CSO - that it had obtained in the primary auction - at $0/kw-month. The obligation was assumed in its entirety by one resource that was seeking 273 MW.

The fourteenth Forward Capacity Auction (FCA 14) was the second year that the auction included the substitution auction and the first year in which test price mitigation was applied. While there were 292 MW of supply seeking obligations, no demand bids proceeded to the substitution auction and consequently the auction was not held. Three existing demand resources with 188 MW of capacity did participate in the FCA. However, with the primary FCA clearing at $2/kw-month, only one resource received a CSO in the primary auction and that resource was precluded from the SA because its test price was above $2/kw-month. Regardless, even without test price mitigation, the resource would not have cleared the SA because its bid in the substitution auction was too low to clear against any supply, i.e., they wanted to be paid more for their obligation than any new supplier was willing to pay.

The fifteenth Forward Capacity Auction (FCA 15) also completed without a substitution auction taking place. While 229 supply resources sought capacity obligations in the SA, only three demand resources with a total of 98 MW had elected to participate in the SA and none had retained a CSO in the primary auction. Consequently, without demand the substitution did not

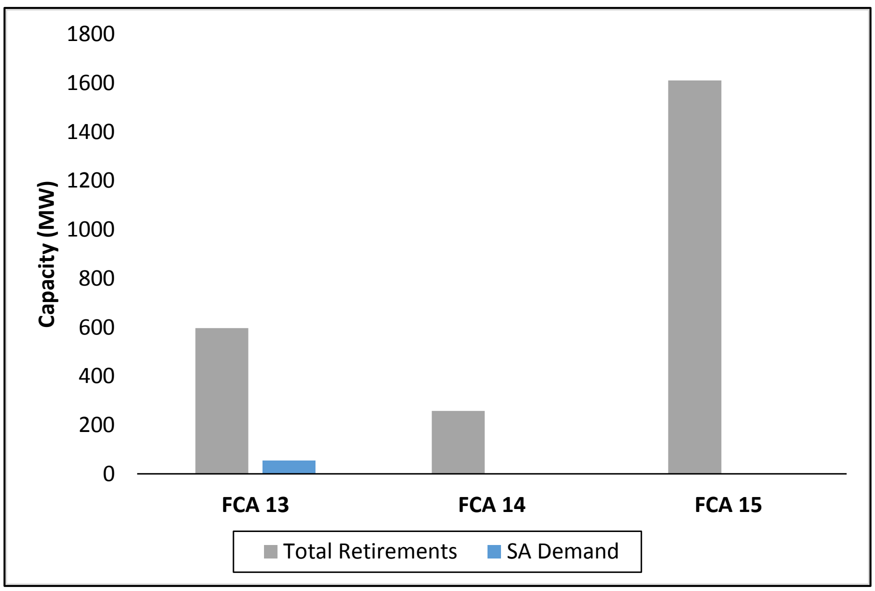
[12] 481 MW of sponsored resources were cleared by the RTR exemption in the in the past three FCAs; 145 MW in FCA 13, 317 MW in FCA 14, and 17 MW in FCA 15.

go ahead. In the next subsection, we explore why we have not seen more demand in the SA to date.

2.4 CASPR Discussion

CASPR has cleared only 54 MW of sponsored capacity over the past three years, but this is not because there is a problem with its design or its implementation. Rather, the low quantity of capacity clearing the SA is a result of a low level of participation from existing resources acting as demand in the SAs. The rate at which sponsored resources enter the capacity market through the SA is dependent on the degree to which existing resources are willing to exit the capacity market for a payoff. This payoff reflects the option value of remaining in the capacity market and, ideally, an existing participant should be indifferent between retiring for this payoff and continuing on in the capacity market. In theory, this makes sense. However, in practice there is likely a large degree of uncertainty around the present value of staying in the capacity market and, consequently, the payoff amount. While sufficient supply from sponsored resources – averaging 265 MW per year – has entered the SA, the quantity of demand participating in the substitution auction has been limited to the 54 MW that cleared in FCA 13. We next examine the reasons for such low demand participation from existing resources.

Figure 2-7: Total Retirements and Substitution Auction Retirements



The Retirement Decision

While CASPR has cleared only one resource retirement of 54 MW, Figure 2-7 above shows that a total of 2,466 MW of capacity retirements have occurred over the same three-year period. However, before we begin to consider the reasons why we don't see more retirements in the SA, we must first examine the nature and timing of the retirement decision.

It is useful for this discussion to categorize existing generators into three groups:

1) **Generators at retirement:** (3 years or less of operating life remaining) These generators have very high costs and must retire or face potentially large financial losses.

2) **Generators that are <u>not</u> close to retirement**: These low-cost generators may continue to operate profitably for many years.
3) **Generators that are approaching retirement:** (Greater than 3 years of operating life remaining) These generators are profitable in the near term but are faced with future costs that will force them from the market, e.g., major repairs, increasing CO_2 permit costs, etc.

Generators at retirement (category 1) require a higher stream of future capacity revenues than the capacity and energy markets might provide. Such generators will likely retire from the capacity market either before or in the early rounds of an FCA. Therefore, these resources are unlikely to obtain a CSO that they may trade out of in the substitution auction. In fact, participation in the SA may be too risky for these generators because retaining a CSO that they are unable to shed in the SA may expose them to financial losses. With the exception of the single retirement through the SA, all other retirements over the past three FCAs fall into this category.

On the other end of the spectrum are generators not close to retirement (category 2). While there would be a severance payment that would make such a generator indifferent between staying in the capacity market and exiting, that payment would likely be far higher than the SA auction could provide.

Finally, we have generators that are approaching retirement (category 3). These generators should remain profitable for at least the next four years but face retirement within the next decade.[13] This is the resource category that CASPR was designed to attract as demand for the substitution auction. The basic idea is that a severance payment with retirement brings that retirement decision forward in time, e.g., a generator could continue to operate for two years and earn $100 or simply exit the market now for a severance payment of $100. The challenge for this type of generator is in estimating its potential revenues and the related severance payment that it would want to exit the capacity market. For example, such a generator may need to consider a number of factors, including:

- future energy and capacity revenue estimates,
- upcoming maintenance costs,
- potential for a new revenue stream, e.g., an energy security program,
- increasing emissions costs, and
- regulatory risks.

Clearly, there is a large degree of uncertainty around the estimation of the present value of a generator's operation. However, this wide range of uncertainty is accommodated in the CASPR design by providing flexibility to generators in the form of two alternative retirement tracks to choose from. A generator that has selected the Track 1 retirement option will retire unconditionally from the capacity market if it does not retain a CSO to trade in the SA. By contrast, in selecting Track 2, a generator may opt into the SA if they retain a CSO in the FCA or otherwise delist from the capacity market for a year. The Track 2 option allows generators to wait and try to retire through CASPR again the following year when conditions may be more favorable, rather than simply retiring unconditionally and without a severance payment. In this

[13] The CSO for the current auction will start in three years and run for one year.

way, with foresight and planning, a participant should have the ability to try for a severance payment a number of times before, ultimately, retiring the resource.

We have seen sufficient interest in retiring through the SA from existing resources in the recent three capacity auctions. However, this potential demand with an initial election of 2,802 MW was reduced to an actual demand number of 54 MW because either: 1) the FCA clearing price was too low for these resources to obtain an obligation in the primary auction; 2) a resource obtained a CSO below its test price but its SA offer was also too low to intersect with any supply in the SA; or 3) a resource was held for reliability.

As stated, a primary driver for demand level participation in the SA is the FCA clearing price. In theory, low FCA prices should move retirement decisions forward in time and increase demand in the SA. However, we have observed that low FCA prices also make it near impossible for resources that are very close to retirement to obtain a CSO in the primary auction that they can trade in the SA. Such resources face the choice of playing a waiting game for FCA clearing prices to rise above their test price or to retire unconditionally. Currently, the system is long on capacity as reflected in relatively low prices when compared with prior years. The record low FCA 14 clearing price of $2 kw-month signaled to the market that the system is so long on capacity that neither the resources close to retirement nor the sponsored resources seeking entry are needed to satisfy forecast system demand.

General Comments

CASPR has a number of shortcomings that are concerning for both the states and generator owners alike. These design aspects (listed below) were discussed at length with stakeholders at Markets Committee meetings during the design phase of CASPR. Nevertheless, they are repeated here as they remain concerning.

1. The CASPR design seeks to maintain competitive capacity pricing (design objective 1) and to accommodate sponsored resources over time (design objective 2). However, these objectives are not equally weighted. CASPR prioritizes maintaining competitive prices in the FCM over accommodating new sponsored entry into that market. The key expression in objective 2 is "over time" because the rate of entry of sponsored resources is dependent on the rate of exit by existing resources through the SA mechanism.

2. The CASPR design does not permit new resources that obtain a CSO in the primary auction to immediately trade that obligation in the SA. Otherwise, there is a potential 'fictitious entry' problem in which capacity projects could be created for the sole purpose of capturing a severance payment in the SA. Consequently, non-sponsored resources have an opportunity to offset any retirements that happen prior to, or during, the FCA. This outcome produces the *double build* problem that CASPR was created to address. Assuming the sponsored resource will be built anyway, the addition of another non-sponsored resource will increase the bill to end-users. The impact level of this issue is a function of the degree to which participants plan for retirement with a CASPR payoff in mind (i.e., participants ensure their resources retire with a payoff rather than unconditionally in the FCA where a new non-sponsored resource would replace it).

3. While the potential slow timing of sponsored entry and the double build problem are concerns for the states, merchant generators worry that sponsored resources entering the capacity auction will suppress FCA clearing prices over time. This is because once a sponsored resource has gained a CSO through the SA it becomes an existing resource in the following year and it is no longer subject to the minimum offer price rule (MOPR). Consequently, for future auctions the resource can continue to offer at artificially low levels (provided it is still receiving sponsorship), and as more sponsored resources gain entry to the capacity market, we start to walk down the supply curve to less expensive offers to find the marginal resource. And, because the marginal resource sets the FCA price, capacity payments decline for everyone.

Conclusion

The low quantity of capacity cleared through the SA is a result of low demand from existing resources in the SA. In turn, this low demand is a result of very low FCA prices that make it difficult for retiring resources to obtain a CSO to trade. Consequently, we would expect to see more demand in the SA as FCA prices increase and participants have more lead time to plan retirements.

At the moment, low FCA clearing prices signal to the market that the region has a surplus of capacity. With such low FCA clearing prices we would expect to see an increase in the number of resources that wish to exit the capacity market particularly as environmental regulations tighten. For example, the Massachusetts Global Warming Solutions Act (GWSA) aims to reduce carbon emissions from electricity generators to one fifth of their 2018 level by 2050. As resources retire and the surplus capacity decreases, FCA prices will rise. However, there are also a number of forces that are expected to exert downward pressure on FCA clearing prices. As mentioned above, as sponsored resources become existing and are no longer subject to the MOPR, the subsidies provided to them will eventually impact primary FCA prices. Additionally, while 242 MW of capacity retired or permanently de-listed in FCA 15, low-priced battery resources quickly absorbed this capacity loss. Low-cost entry from battery resources offsets retirements in the FCA and counteracts increasing FCA clearing prices. Future levels of battery penetration and the degree of price suppression from sponsored resources are unclear. However, it is clear that CASPR does not provide a certain and steady rate of sponsored resource entry in the same way as the Renewable Technology Resource exemption did previously. The rate of entry of sponsored resources is dependent on market forces, as it should be in a well-functioning competitive market.

Section 3
Special Topic: Individual Subsidy Impact on FCA 16 ORTP

To inform the Minimum Offer Price Rule (MOPR) discussion, the Board Markets Committee requested that we provide estimates of the impact of different program subsidies on offer prices in the Forward Capacity Market (FCM) for various technologies. We have provided these estimates in Table 3-1 along with some discussion of the individual program subsidies we evaluated.

As a baseline, we use net cost figures from the Offer Review Trigger Price (ORTP) model with all direct/evaluated subsidies removed. We then add back each direct/evaluated subsidy individually to measure the resulting decrease in net cost. This section does not contain estimated impacts of combinations of subsidy elements, nor does it provide any analysis of the results – these are merely for context to inform the discussion on MOPR.

Table 3-1 shows the estimated baseline net cost, ORTP (for context), and the following for each subsidy type: subsidized net cost, impact of the subsidy in dollar terms, and percentage impact of the subsidy. For context, we have also provided figures for a combustion turbine resource (also the reference resource for Net CONE) and the ORTP for each resource type evaluated.

Table 3-1: Estimated Impact on Net Cost of Subsidy Elements ($/kW-month)

		Combustion Turbine	Wind (off-shore)	Solar	Battery	Co-located Bat. + Solar
Baseline Net Cost		$5.53	$66.84	$36.58	$2.69	$17.80
ORTP		$5.36	$12.40	$1.38	$2.60	$12.40
ITC	**Net cost**		$40.26	$21.34		$13.24
	Impact		-$26.58	-$15.23		-$4.56
	% Impact		-40%	-42%		-26%
REC	**Net cost**		$45.19	$17.06		$14.70
	Impact		-$21.65	-$19.52		-$3.10
	% Impact		-32%	-53%		-17%
30yr Life (BL is 20yr)	**Net cost**	$4.26	$49.96	$25.46	$1.34	$14.49
	Impact	-$1.27	-$16.88	-$11.11	-$1.34	-$3.31
	% Impact	-23%	-25%	-30%	-50%	-19%
WACC 2.5% (BL is 4.3%)	**Net cost**	$4.56	$56.20	$29.61	$1.71	$15.72
	Impact	-$0.97	-$10.64	-$6.97	-$0.98	-$2.08
	% Impact	-18%	-16%	-19%	-36%	-12%
40% Bonus Depreciation	**Net cost**	$5.36	$66.06	$36.07	$2.60	$17.65
	Impact	-$0.17	-$0.78	-$0.51	-$0.09	-$0.15
	% Impact	-3%	-1%	-1%	-3%	-1%

An example of how to interpret the data from the table: For a solar resource, the "subsidy-free" net cost is estimated to be $36.58/kW-month. The Investment Tax Credit (ITC) program provides policy-sourced revenue that reduces the net cost to $21.34/kW-month. The impact of ITC (alone) on the net cost of a new solar resource is -$15.23/kW-month, or a 42% reduction in net cost.

A description of the row elements in the table follow.

Baseline Net Cost: Estimate of all-in cost net of energy and ancillary service revenue and excluding all subsidy elements, amortized over the economic life of the resource. This figure represents a characteristic competitive offer for the resource type absent any direct subsidy.

ORTP: Current Offer Review Trigger Price for the resource category. This figure is provided for context.

ITC: Investment Tax Credit is a dollar-for-dollar tax credit for expenses invested in renewable energy properties, most often wind and solar developments.

30yr Life: The standard for evaluation is a 20 year period. Some policy resources have requested a 30 year life for evaluation purposes. This line item reflects the impact of using a 30 year life instead of 20 years in the financial analysis.

WACC: Weighted Average Cost of Capital baseline is 4.3% - the figure used in calculating the most recent values for the ORTP. Policy resources have often requested lower WACC values, with 2.5% representing the lower end of requested values.

40% Bonus Depreciation: A federal program (Internal Revenue Code §168(k)) that allows "Qualified Property" to depreciate a percentage of an asset in the first year to reduce its tax liability. The 40% bonus is applied for Forward Capacity Auction 16 (FCA 16) as the law allows 100% bonus depreciation for those in service by 2022 and is reduced by 20% per year through 2026.

There are two other relevant policy based subsidies for which we are unable to estimate impacts. First, the Solar Massachusetts Renewable Target (SMART)[14] program designed to replace Solar Renewable Energy Credits (SREC) and incentivize the installation of up to 3,200 MWs of solar interconnected to one of three investor owned utility companies in Massachusetts: Eversource, National Grid, and Unitil. There are currently 1,450 MW approved or in process for approval for this program. And second, the MA Clean Peak Energy Standard (CPES)[15] that was enacted in 2020 to incentivize clean energy production during peak demand. This program is still being implemented with price formation not occurring until 2022. In both cases, the incentive structure was either not clear to us or varied so significantly across resources that we were unable to determine an accurate way to calculate and represent a characteristic impact for this program.

[14] https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program

[15] https://www.mass.gov/info-details/clean-peak-energy-standard-notices-and-updates

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 2021	Winter 2021	Spring 2021 vs Winter 2021 (% Change)	Spring 2020	Spring 2021 vs Spring 2020 (% Change)
Real-Time Load (GWh)	26,424	30,915	-15%	25,715	3%
Peak Real-Time Load (MW)	18,849	21,353	-12%	16,596	14%
Average Day-Ahead Hub LMP ($/MWh)	$28.69	$51.30	-44%	$17.33	66%
Average Real-Time Hub LMP ($/MWh)	$27.89	$51.66	-46%	$17.62	58%
Average Natural Gas Price ($/MMBtu)	$2.80	$5.83	-52%	$1.61	74%
Average No. 6 Oil Price ($/MMBtu)	$12.38	$11.09	12%	$5.71	117%

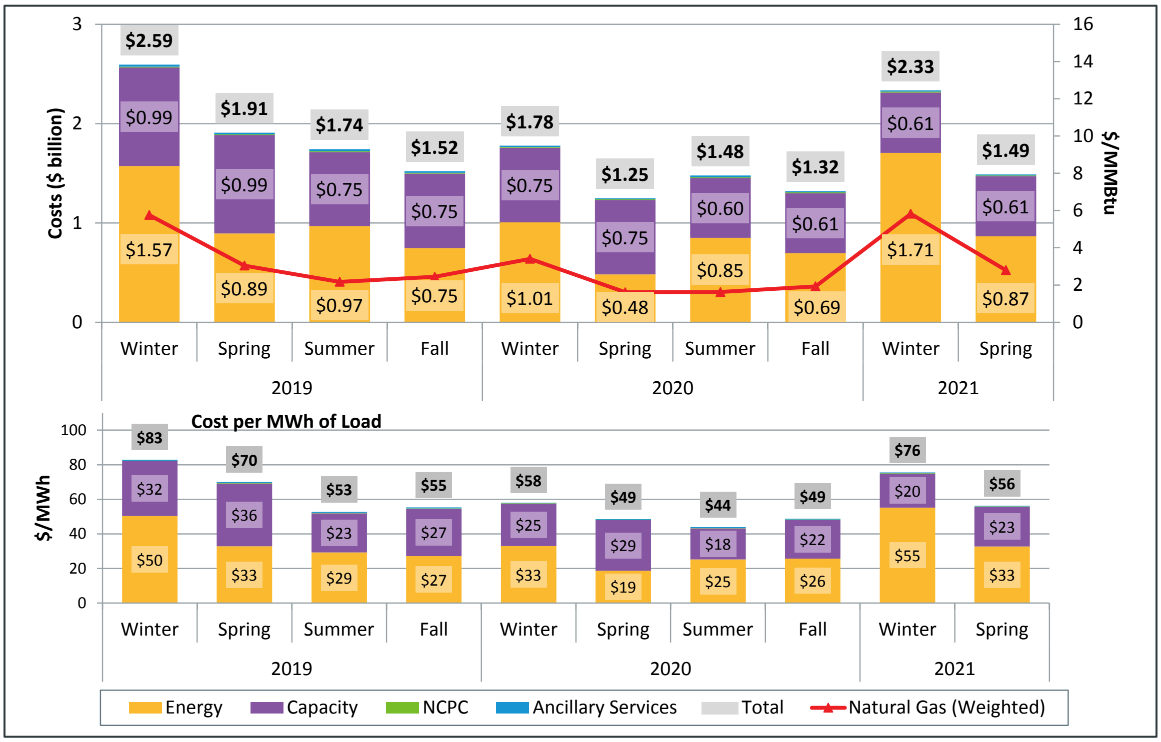
To summarize the table above:

- Average day-ahead LMPs in Spring 2021 were $28.69/MWh, 66% higher than in Spring 2020. Average real-time LMPs were $27.89/MWh, 58% higher than in Spring 2020. The year-over-year increases were driven by higher natural gas prices ($2.80/MMBtu, up 74%) and average real-time load (11,973 MW, up 3%) compared to Spring 2020.
- Average gas prices in Spring 2021 ($2.80/MMBtu) increased significantly from Spring 2020 prices ($1.61/MMBtu). The low prices last spring were the result of lower residential and industrial demand during the COVID-19 pandemic. By comparison, average natural gas prices in Spring 2019 were ($3.04/MMBtu).
- There were fewer nuclear outages in Spring 2021 than in Spring 2020, primarily due to planned refueling outages in Spring 2020. On average, just 8 MW of nuclear generation was on outage every hour in Spring 2021 compared to 955 MW in 2020. This decrease offset some of the increase in day-ahead energy prices (66%) which rose less than gas prices (74%) over the same period.
- Average oil prices in Spring 2021 ($12.38/MMBtu) were 117% higher than in Spring 2020 ($5.71/MMBtu), when oil prices plummeted world-wide due to the COVID-19 pandemic.

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. [16,17]

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



In Spring 2021, the total estimated wholesale cost of electricity was $1.49 billion (or $56/MWh of load), a 19% increase compared to $1.25 billion in Spring 2020, and a decrease of 36% over the previous quarter (Winter 2021). Natural gas prices continued to be a key driver of energy prices. In Spring 2020, gas and energy prices reached historical lows partially due to lower demand caused by the COVID-19 pandemic. Consequently, most wholesale cost categories in Spring 2021 increased compared to the previous spring.

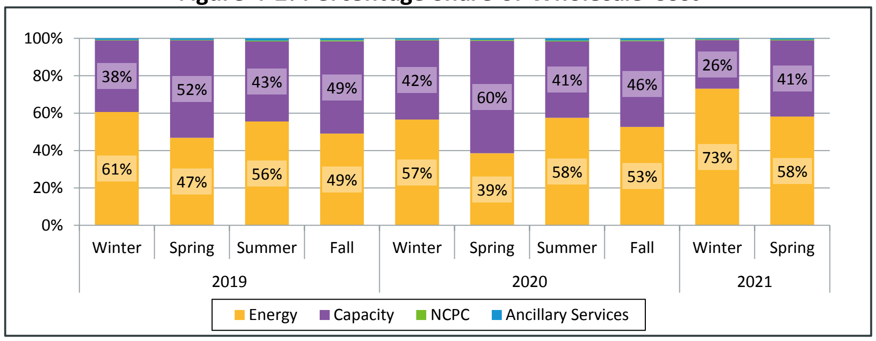
Energy costs were $865 million ($33/MWh) in Spring 2021, 80% higher than Spring 2020 costs, driven by a 74% increase in average natural gas prices. Energy costs made up 58% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 4-2 below.

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

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

Capacity costs are driven by clearing prices in the primary capacity auctions, and totaled $607 million ($23/MWh), representing 41% of total costs. Beginning in Summer 2020, capacity market costs decreased relative to previous quarters. In the prior capacity commitment period (CCP 10, June 2019 – May 2020), the clearing price for new and existing resources was $7.03/kW-month.[18] In the current capacity commitment period (CCP 11, June 2020 – May 2021), the clearing price for all new and existing resources was $5.30/kW-month. Capacity costs decreased with lower clearing prices that were partially driven by an increase in surplus capacity resulting from no significant resource retirements and a slight decrease in Net ICR.

Figure 4-2: Percentage Share of Wholesale Cost



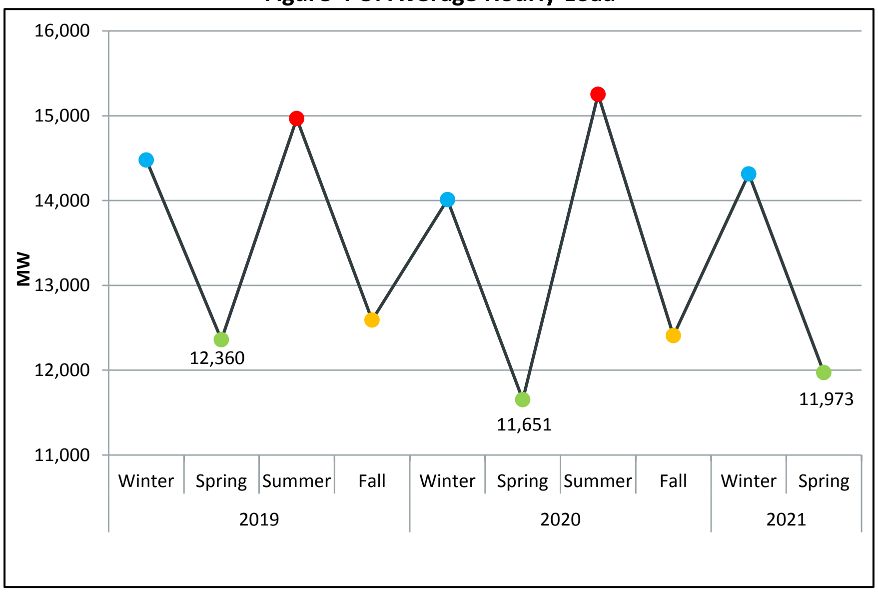
At $6.2 million ($0.23/MWh), Spring 2021 Net Commitment Period Compensation (NCPC) costs represented 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $0.7 million higher than in Spring 2020. The main driver behind the increase was the day-ahead economic commitment of a natural gas-fired generator in the Boston area over three days in April to support a planned transmission outage. Ancillary services, which include operating reserves and regulation, totaled $9.7 million ($0.37/MWh) in Spring 2021, representing less than 1% of total wholesale costs. Ancillary service costs decreased by 7% compared to Spring 2020, and decreased by 21% compared to Winter 2021.

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

4.2 Load

In Spring 2021, average loads increased year over year as economic conditions normalized following the COVID-19 pandemic. 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



In Spring 2021, loads averaged 11,973 MW, a 3% increase from Spring 2020 (11,651 MW) and 3% decrease from Spring 2019 (12,360 MW). Load increased year over year despite warmer average temperatures (49°F vs. 47°F). Typically, warmer spring temperatures, along with the long-term trend of increased energy efficiency and BTM solar generation would lead lower loads. However, loads rebounded in Spring 2021 from Spring 2020 when business closures intended to mitigate the spread of COVID-19, led to record low loads.

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).[19]

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

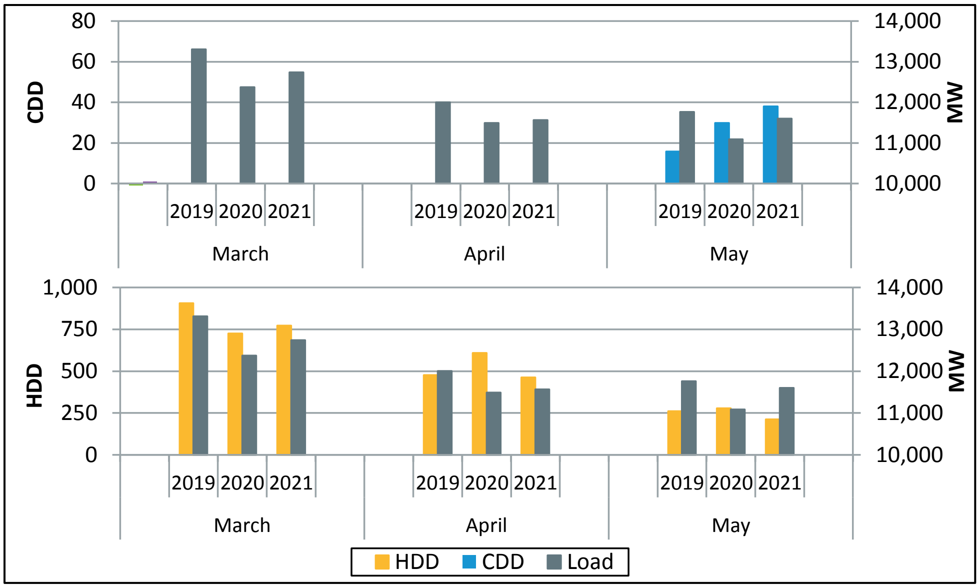


Figure 4-4 shows that loads were higher, on average, every month in Spring 2021 when compared to Spring 2020. Typically, temperature fluctuations are the main driver of differences in monthly average load. However, the COVID-19 pandemic led to lower average loads during the prior year. In Spring 2020, state-mandated closures to mitigate the spread of COVID-19 lowered electricity demand. In Spring 2021, economic conditions normalized and loads increased every month despite generally warmer temperatures.

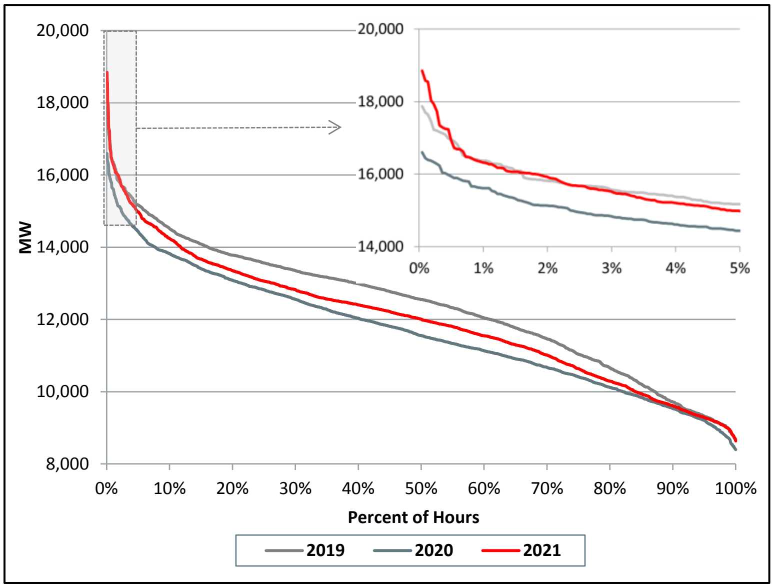
While not the main driver of changes in load, temperature still affected load in New England. In March 2021, temperatures averaged 40°F, a 1°F decrease compared to March 2020 (41°F), contributing to higher loads this year (12,740 MW vs. 12,317 MW). In April and May 2021, the average temperatures were warmer, but the reduced impacts of the pandemic outweighed the impact of temperature, and average loads increased year over year in both months. In April 2021, average temperatures were 5°F warmer than in April 2020 (50°F vs. 45°F), but average loads increased by 75 MW year-over-year (11,566 MW vs. 11,491 MW). In May 2021, temperatures averaged 59°F, a 2°F increase compared to May 2020. However, loads averaged 11,600 MW, a 511 MW increase compared to May 2020 (11,088 MW).

[19] 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.

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 2021 is shown in red, Spring 2020 is shown in black and Spring 2019 is shown in gray.

Figure 4-5: Seasonal Load Duration Curves



The red line shows Spring 2021 had higher loads than Spring 2020 across all hours, and lower loads than Spring 2019 in nearly all hours. In Spring 2021, loads were higher than 13,000 MW in nearly 27% of hours, compared to about 21% and 41% in Spring 2020 and Spring 2019 respectively. During the top 5% of hours, Spring 2021 load levels were higher than Spring 2020 but generally similar to the level in Spring 2019. Loads during the top 5% of hours of Spring 2021 averaged 15,865 MW, 762 MW higher than in Spring 2020 (15,103 MW) and 16 MW lower than in Spring 2019 (15,881 MW).

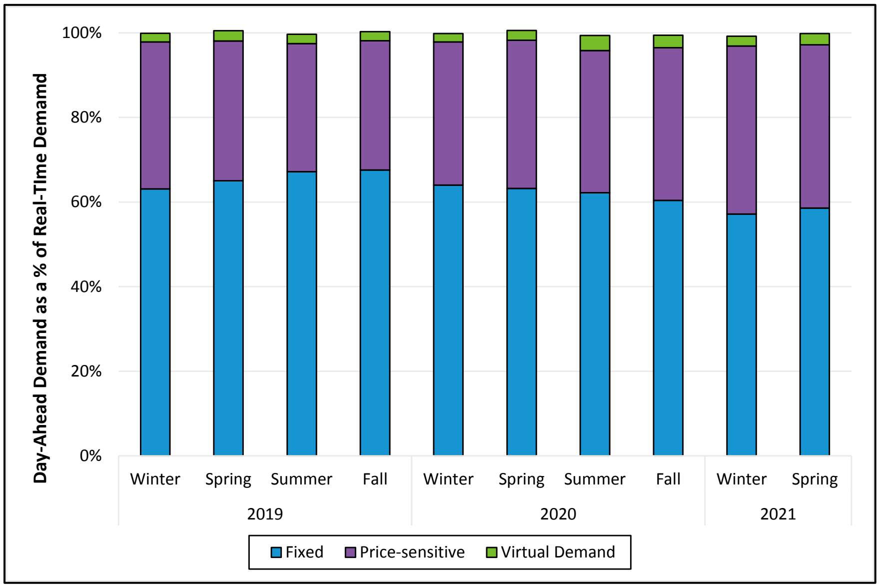
Load Clearing in the Day-Ahead Market

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 Analysis, it influences the generator commitment decision for the operating day.[20] 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

[20] The Reserve Adequacy Analysis (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 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.[21]

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



Day-ahead cleared demand as a percent of real-time demand was lower in Spring 2021 than in both Spring 2020 and Spring 2019. On average, participants cleared 99.8% of real-time demand in the day-ahead market compared to 100.5% in both Spring 2020 and 2019, respectively. Since Fall 2019, participants have cleared less fixed demand, which has mostly been offset by increased cleared price-sensitive demand bids. Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of bids are priced well above the LMP. Such transactions are, in practical terms, fixed demand bids. Therefore, the shift from fixed demand bids to price-sensitive demand bids has not resulted in any significant market impacts.

[21] 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.

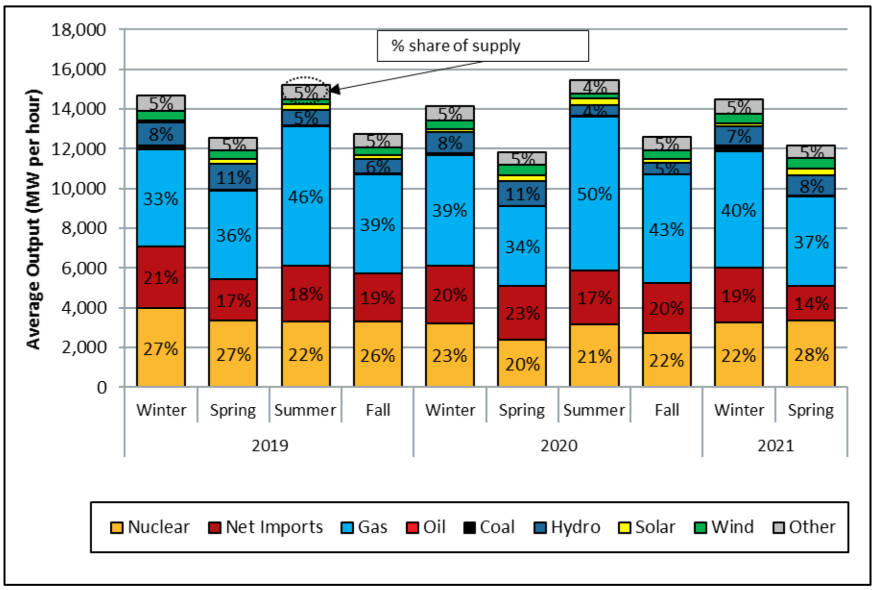
4.3 Supply

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 2021 is illustrated in Figure 4-7 below. Each bar's height represents average electricity generation, while the percentages represent the percent share of generation from each fuel type.[22]

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 79% of total energy production in Spring 2021. Nuclear production shares increased from 20% (2,395 MW per hour on average) in Spring 2020, to 28% (3,351 MW per hour on average) in Spring 2021. There were fewer nuclear outages in Spring 2021 than in Spring 2020, primarily due to planned refueling outages in Spring 2020. On average, 8 MW of nuclear generation was on outage every hour in Spring 2021 compared to 955 MW in 2020. This decrease in outages led to higher capacity factors and shares of total generation. The increase in nuclear generation helped offset the 35% decline of average net imports in Spring 2021 (1,762 MW per hour) from Spring 2020 (2,705 MW per hour). As described in Section 4.3.2, most of the reduction in net imports occurred over the New York North interface.

[22] 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 2021.[23] On average, the net flow of energy into New England was 1,762 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

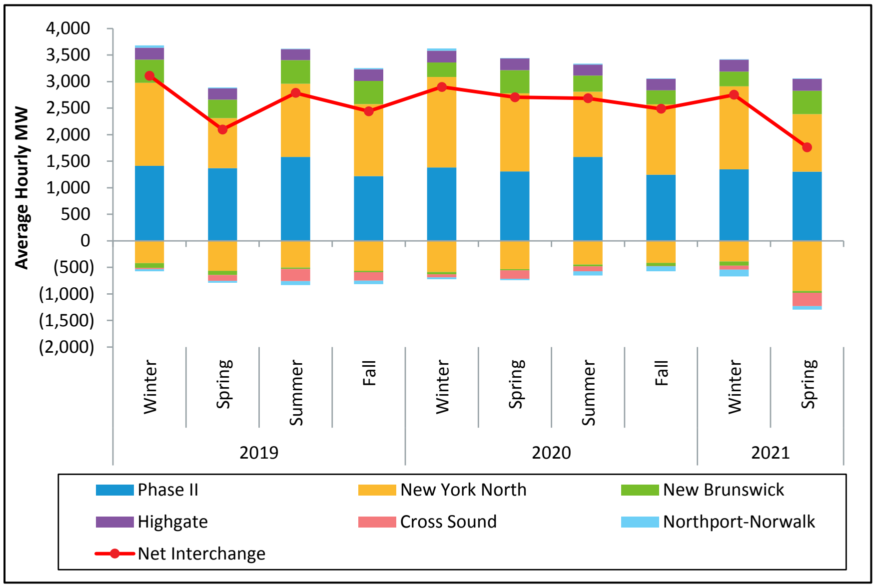


Figure 4-8 illustrates that net interchange and imports generally fall from winter to spring, when New England energy prices and demand tend to be lower. This pattern persisted between Winter and Spring 2021 but to a much greater extent than in 2020. The average hourly net interchange value of 1,762 MW was down 35% from Spring 2020 when average net interchange was 2,705 MW. This decrease in net interchange into New England was driven by a simultaneous increase in exports and decrease in import transactions at the New York North interface. Compared to Spring 2020, real-time exports at the New York North interface increased by 77%, from 534 to 943 MW on average per hour and real-time imports decreased by 26%, from 1,469 to 1,085 MW on average per hour.

In Spring 2021, New England met about 14% of its average load (NEL) from power imported from New York and Canada. This is the lowest percentage during the reporting period. This was primarily due to a reduction in net interchange over the New York North interface, discussed below, coupled with an increase in real-time load, discussed above in Section 4.2. The largest share of imports into New England in Spring 2021 (43%) came from the Phase II interface, with imports averaging 1,302 MW per hour. This represents a 1% decrease from Spring 2020 (1,309 MW per hour, on average). In Spring 2021 the New York North interface contributed an average

[23] 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.

of 1,085 MW per hour, or 35% of total imports. This represents a 26% decrease from Spring 2020 (1,469 MW per hour on average).

The increase in real-time exports at the New York North interface was primarily driven by price differences between New England and New York and an increase in bid and cleared export transaction volumes at low spread prices. Real-time external transactions for all external interfaces are scheduled based on an ISO forecasted price, or in the case of Coordinated Transaction Scheduling (CTS) the forecasted price difference between New England and New York. For an *export* transaction to clear at CTS, the price difference between New York and New England[24] must be greater than the bid price. In Spring 2021 the forecasted price spread[25] was negative (indicating New York is forecasted to have a higher LMP) during 80% of pricing intervals, averaging approximately -$2.00/MWh. By comparison, in Spring 2020 the forecasted spread was negative during 60% of pricing intervals, averaging approximately -$1.50/MWh. A more negative forecasted price spread allows more un-economic export transactions (export flowing to the lower priced area) to clear.

In addition to the forecasted spread being negative on average, which indicated that New York's price was forecasted to be higher than New England's price, more export transactions were submitted in both the day-ahead and real-time markets. In the day-ahead market New York North functions the same as the other external interfaces with bids clearing based on the nodal LMP. In Spring 2021, export transactions at almost all bid price tranches increased. Participants in the real-time market increased export transactions most notably in the price insensitive ranges of -$1,000/MWh to $0/MWh.

[24] The spread price is calculated as $LMP_{NY} - LMP_{NE}$.

[25] In this case, the forecast spread is calculated as $LMP_{NE} - LMP_{NY}$.

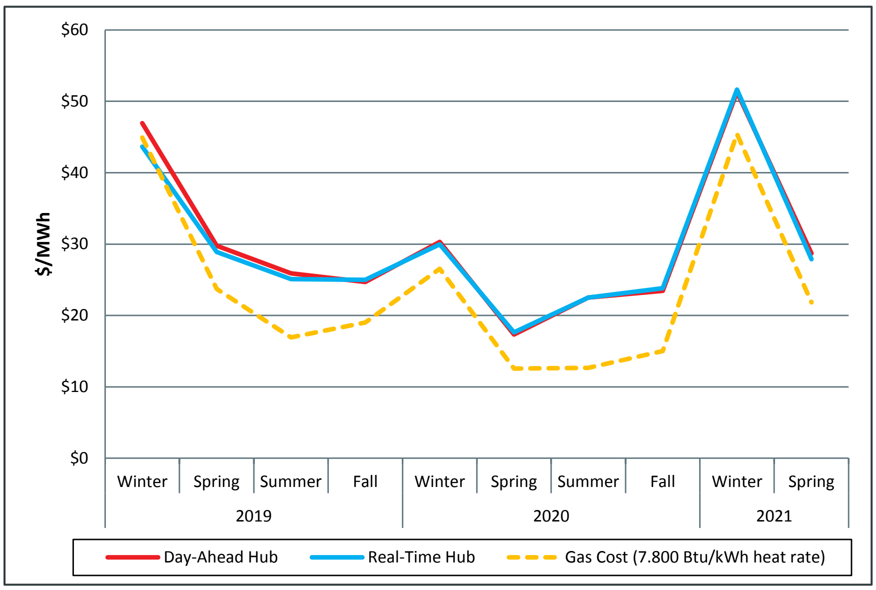
Section 5
Day-Ahead and Real-Time Markets

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 2021 was $27.89/MWh, slightly lower than the average day-ahead price of $28.69/MWh. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas in New England, are shown in Figure 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.[26]

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 $22/MWh in Spring 2021. Average day-ahead electricity prices were $7/MWh above average estimated gas costs in Spring 2021, higher than the $5/MWh spread in Spring 2020, but similar to the three previous quarters.

In Spring 2021, average day-ahead and real-time prices were higher than the record low prices of Spring 2020, by about $11 and $10/MWh, respectively. This is consistent with the change in

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

natural gas prices, which increased by 74%. Additionally, average hourly loads in Spring 2021 were 320 MW higher than in Spring 2020.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones and for the Hub are shown below in Figure 5-2.

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

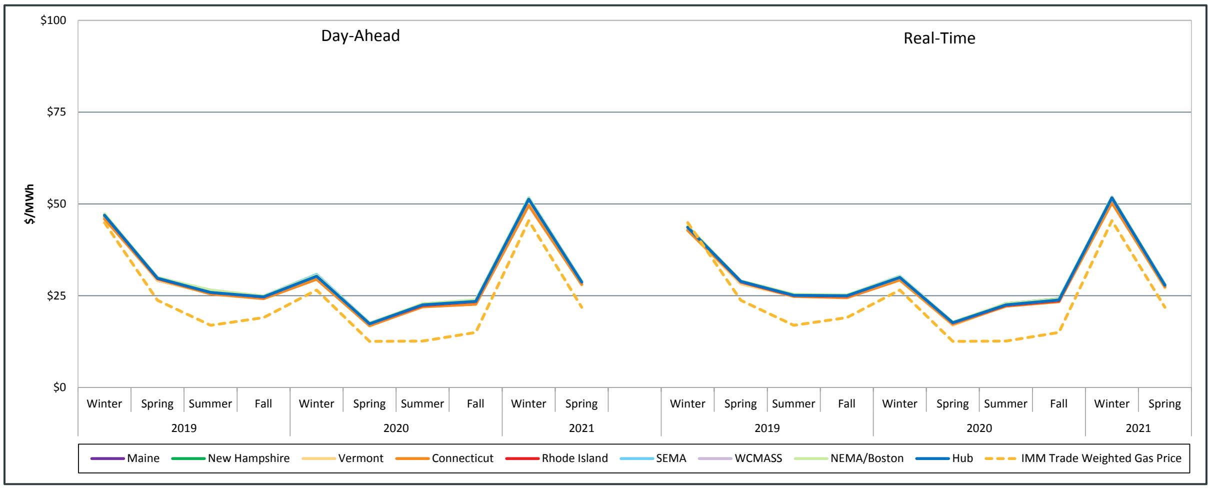


Figure 5-2 illustrates that prices did not differ significantly among the load zones in either market in Spring 2021, indicating that there was relatively little congestion on the system at the zonal level.[27]

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 would provide this next megawatt, and set price, is termed the "marginal" resource. Analyzing marginal resources by transaction type can provide additional insight into day-ahead and real-time pricing outcomes.

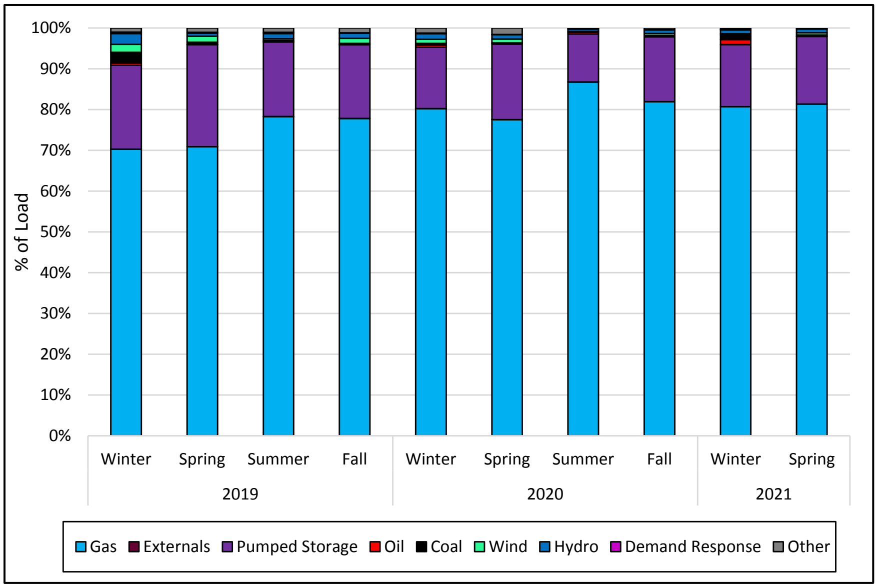
In this section, marginal units by transaction and fuel type are reported on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal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

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

[27] 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.

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.[28]

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

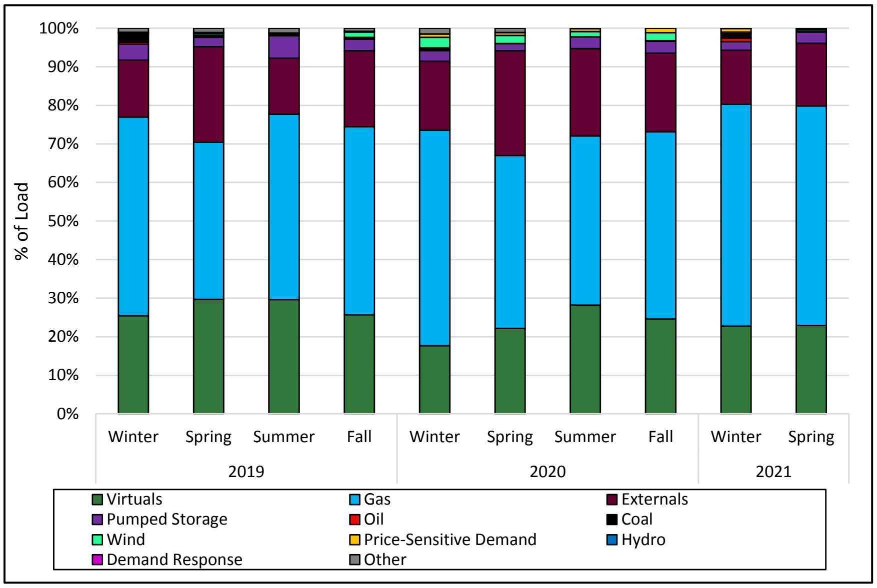


Natural gas-fired generators set price for about 81% of total load in Spring 2021. This is similar to Winter 2021 (81%) and Spring 2020 (78%). Wind was marginal for 1% of total load in Spring 2021; most of which was located in *local export-constrained areas*, where the impact on the average load price 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.

The percentage of load for which each transaction type set price in the *day-ahead market* since Winter 2019 is illustrated in Figure 5-4 below.

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

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

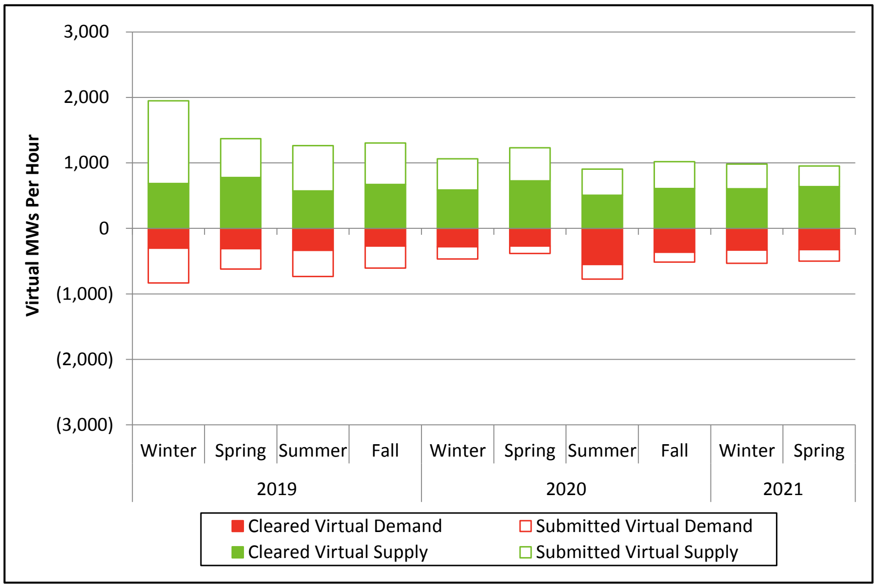


Gas-fired generators were the most frequent marginal resource type in the day-ahead market, setting price for 57% of total day-ahead load in Spring 2021. The percentage of load for which gas-fired generators were marginal increased by 12% between Spring 2020 and Spring 2021. This increase largely displaced marginal external transactions which decreased from 27% to 16% between Spring 2020 and Spring 2021. The decline in marginal external transactions was driven by fewer price setting imports from New York and Canada.

5.3 Virtual Transactions

In the day-ahead energy market, participants can submit virtual demand bids and virtual supply offers to capture differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence. This indicates that the virtual transactions help the day-ahead dispatch model better reflect real-time conditions. Submitted and cleared virtual transaction volumes from Winter 2019 through Spring 2021 are shown in Figure 5-5 below.

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



Over the last 10 quarters, submitted and cleared volumes of virtual transactions have remained relatively consistent.[29] Spring 2021 total submitted virtual transactions averaged approximately 1,456 MW per hour, which was 4% lower than the average amount submitted in Winter 2021 (1,513 MW per hour) and 10% lower than Spring 2020 (1,613 MW per hour). On average, 965 MW per hour of virtual transactions cleared in Spring 2021, which represents a 3% increase compared to Winter 2021 (936 MW per hour) and a 3% decrease compared to Spring 2020 (994 MW per hour). Cleared virtual demand amounted to 326 MW per hour, on average, in Spring 2021, down 2% from Winter 2021 (333 MW per hour) and up 21% from Spring 2020 (269 MW per hour). Meanwhile, cleared virtual supply amounted to 639 MW per hour, on average, in Spring 2021, up 6% from Winter 2021 (603 MW per hour) and down 12% from Spring 2020 (725 MW per hour).

Virtual supply tends to clear at higher volumes than virtual demand. This happens because certain types of generation, especially wind generators, do not always clear their entire real-time output in the day-ahead market. When wind output is higher in the real-time market, areas with large amounts of wind generation may become export-constrained and experience significantly lower real-time prices. Participants often clear virtual supply to fill the gap between lower day-ahead supply and higher real-time output in these areas. For example, 45% (287 MW of 639 MW) of all cleared virtual supply bids cleared were located in Maine, an area that can often become export-constrained when wind output is high.[30] Only 10% (or 32 MW of 326 MW) of all cleared virtual demand bids occurred in Maine.[31]

[29] After Winter 2019, one participant stopped submitting large volumes of virtual supply, leading to the overall decline in submitted virtual supply.

[30] The following is the breakdown of virtual supply by location: Hub - 12%, External Nodes - 1%, Connecticut – 5%, Maine – 45%, Massachusetts – 16%, New Hampshire – 8%, Rhode Island – 4%, Vermont – 8%.

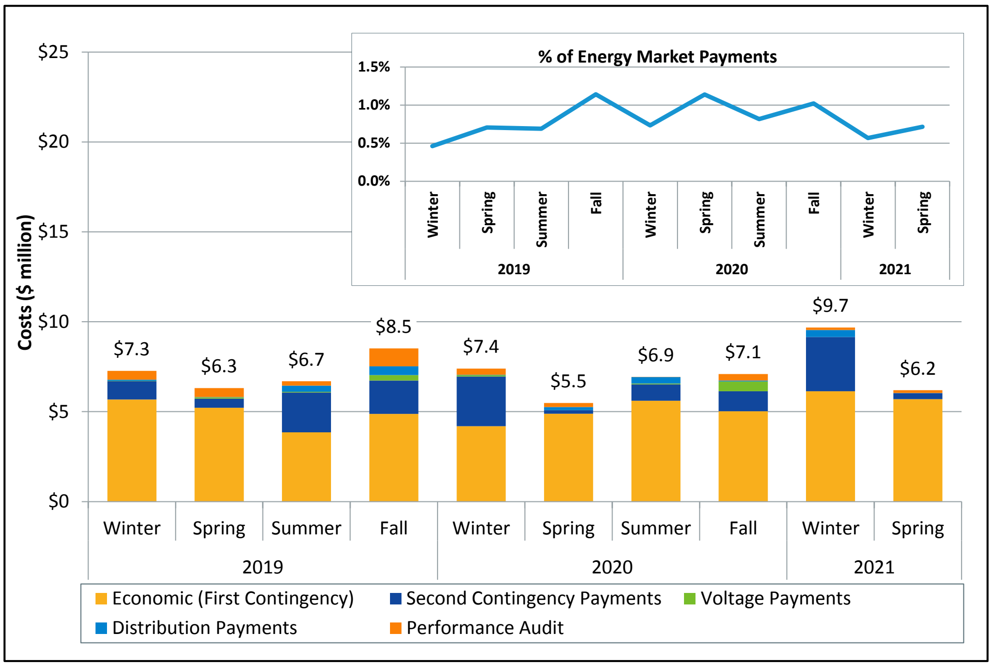
[31] The following is the breakdown of virtual demand by location: Hub - 24%, External Nodes - 0%, Connecticut – 21%, Maine – 10%, Massachusetts – 29%, New Hampshire – 5%, Rhode Island – 8%, Vermont – 2%.

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 2019. The data show that uplift payments have remained constant, averaging $7.2 million from Winter 2019 through Spring 2021. 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.[32]

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 2021 amounted to $6.2 million, an increase of $0.7 million, or 13%, compared to Spring 2020 and consistent with Spring 2019. Day-ahead total payments increased by $1.3 million from Spring 2020, with economic payments making up approximately 90% of the increase. Total real-time payments decreased by $0.6 million. The main driver behind the lower real-time payments was the absence of external uplift payments, discussed further below. Total uplift payments as a percentage of energy payments fell in Spring 2021 to 0.7% from 1.1% in Spring 2020.

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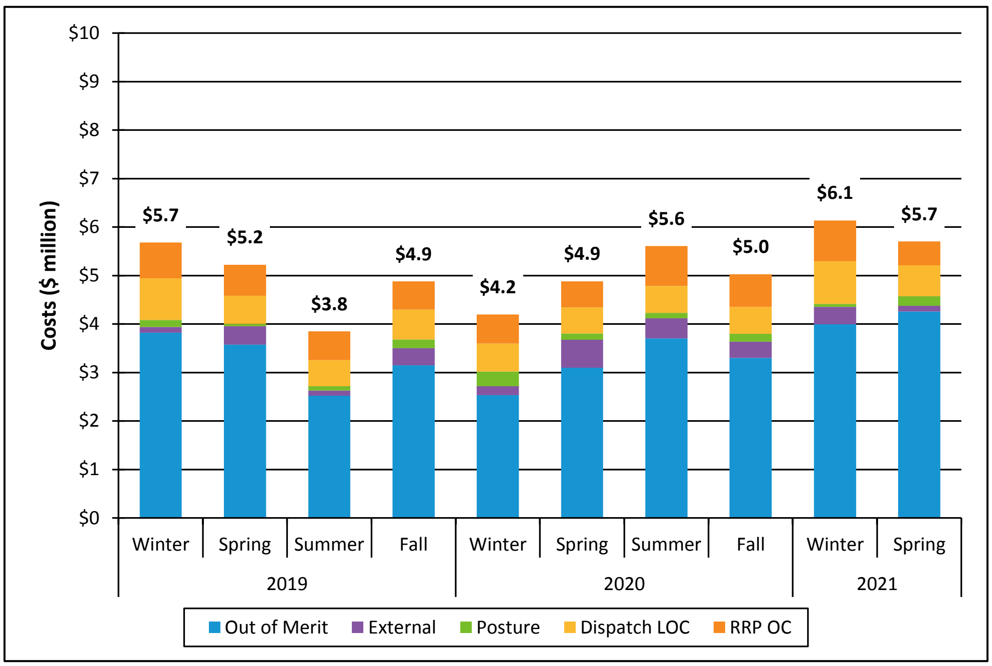
[32] NCPC payments include *economic/first contingency NCPC payments*, *local second-contingency NCPC payments* (reliability costs paid to generators providing capacity in constrained areas), *voltage reliability NCPC payments* (reliability costs paid to generators dispatched by the ISO to provide reactive 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).

Economic payments comprised the majority of uplift (92% or $5.7 million) during Spring 2021. Unlike previous quarters, economic payments were evenly split between the day-ahead and real-time markets. Compared to Spring 2020, total economic uplift increased by $0.8 million or 17%. The main driver behind this increase was a $1.0 million day-ahead economic commitment of a natural gas-fired generator over three days in April. A planned transmission outage in the Boston area necessitated the day-ahead commitment of this generator. This increase was partially offset by decreases in external transaction uplift payments.

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. Out-of-merit payments increased by 37% from $3.10 million to $4.26 million between Spring 2020 and Spring 2021. Posturing payments increased by 54% between Spring 2020 and Spring 2021 but remained relatively low at $0.20 million. All of these payments were paid to pumped-storage facilities over three days. Approximately $0.13 million, or 65%, of these payments were paid in the morning hours of one day in April due to higher loads than forecasted the prior day. Opportunity cost uplift remained consistent, totaling $1.13 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.[33] External transactions payments decreased by almost 80%, from $0.58 million in Spring 2020 to $0.12 million in Spring 2021 indicating that the ISO forecasted price scheduled transactions in merit.

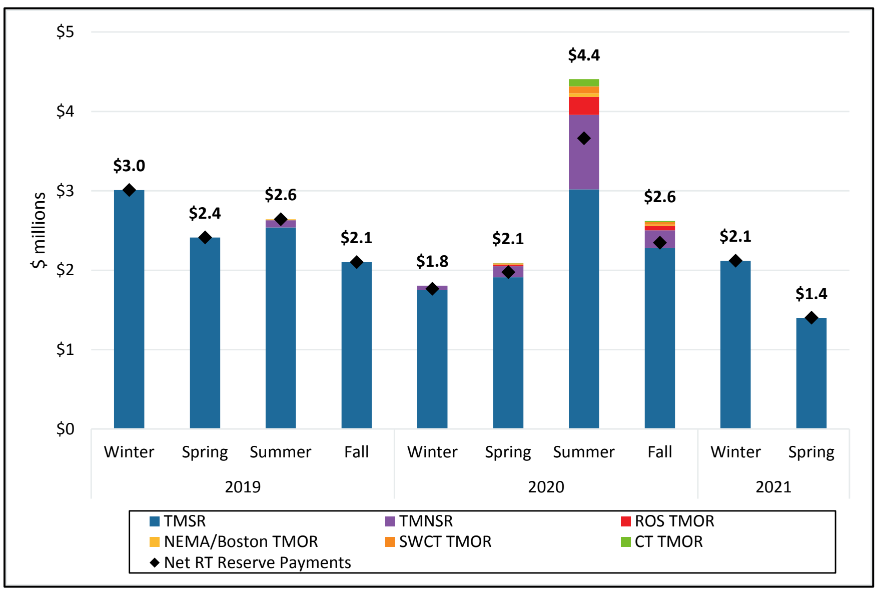
Total second contingency or LSCPR payments of $0.3 million were consistent with Spring 2020 and 2019. Almost all LSCPR uplift in Spring 2021 was paid in the day-ahead market for planned transmission outages primarily in Maine, and lower south-east Massachusetts.

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 $1.4 million in Spring 2021. 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 were the same as gross payments, since there were no ten-minute non-spinning (TMNSR) or thirty minute operating reserve (TMOR) payments for the second quarter in a row.

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



Spring 2021 reserve payments ($1.4 million) were down $0.7 million from Spring 2020 ($2.1 million). In Spring 2021, there were no intervals with TMNSR or TMOR pricing. Additionally,

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

there were fewer intervals with ten-minute spinning reserve (TMSR) pricing in Spring 2021. The absence of large nuclear outages led to increased fixed generation on the system. This increased the amount of energy available from online dispatchable generators to meet the TMSR requirement. That is why the ten-minute spinning reserve margin averaged 413 MW in Spring 2021, compared to 307 MW in Spring 2020.

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.[34]

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

Product	Zone	Spring 2021		Spring 2020		Spring 2019	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$7.85	325.0	$6.19	489.7	$10.97	371.4
TMNSR	**System**	$0.00	.	$59.79	2.3	$0.00	.
TMOR	**System**	$0.00	.	$80.66	0.6	$0.00	.
	NEMA/Boston	$0.00	.	$80.66	0.6	$0.00	.
	CT	$0.00	.	$80.66	0.6	$0.00	.
	SWCT	$0.00	.	$80.66	0.6	$0.00	.

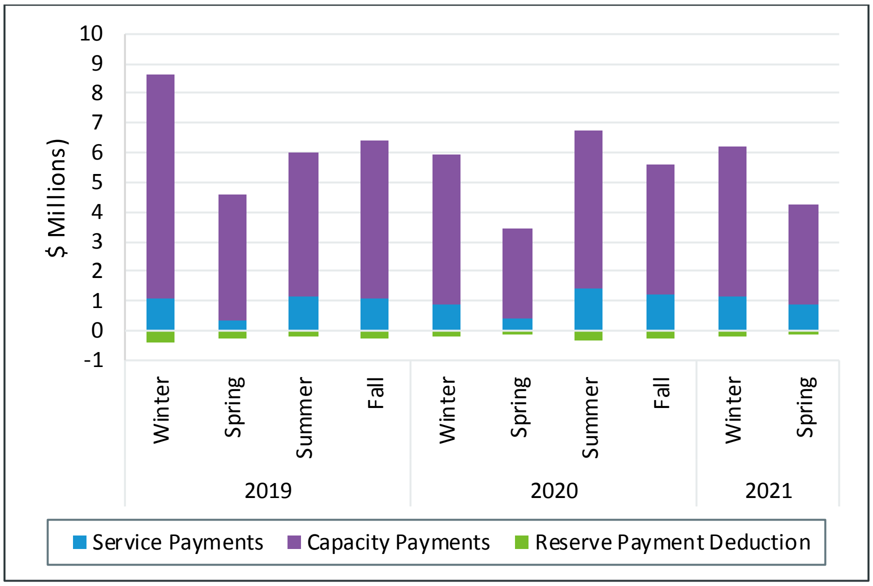
The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 325 hours (15% of total hours) during Spring 2021, lower than the number of hours of non-zero reserve pricing in Spring 2019 and Spring 2020. In the hours when the TMSR price was above zero, the price averaged $7.85/MWh, an increase consistent with high energy prices in Spring 2021 compared to Spring 2020.

[34] 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.

Figure 5-9: Regulation Payments ($ millions)



Total regulation market payments for Spring 2021 were $4.2 million, up approximately 28% from $3.3 million in Spring 2020, and down by 31% from $6.0 million in Winter 2021.[35] The significant increase in payments year-over-year resulted from two factors: capacity payments increased by approximately $0.4 million and service payments increased by approximately $0.5 million. The increase in capacity payments is primarily explained by the manual commitment of expensive regulation generators for several hours in March 2021 ($0.25 million), and by a small increase in regulation uplift payments ($0.1 million). The increase in service payments reflects increased regulation service prices throughout Spring 2021. The increased regulation service prices are consistent with increased gas prices (by 74%) between Spring 2020 and Spring 2021. Service prices and payments include compensation to regulation resources for incurring regulation mileage (the up and down movement of resources when providing regulation service). The decline in regulation payments between Winter 2021 and Spring 2021 is consistent with the 52% reduction in natural gas prices over the two periods, and a significant reduction in both service and capacity prices between the periods.

[35] 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
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. Section 6.1 evaluates energy market competitiveness at the quarterly level by presenting two metrics on structural market power at the system level. Section 6.2 provides statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM's reference level.

6.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in the real-time energy market using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI). Both of these widely-used metrics identify instances when the largest supplier has market power.[36] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand, and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers. This analysis presents the average RSI for all five-minute real-time pricing intervals by quarter.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[37] to the sum of each participant's total supply that is available within 30 minutes.[38] When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each quarter to obtain the percentage of intervals with pivotal suppliers.

The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 6-1 below.

[36] Many resources in New England are owned by companies that are subsidiaries of larger firms. Consequently, tests for market power are conducted at the parent company level.

[37] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -*Demand* - [*Reserve Requirement*]

[38] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

Table 6-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2019	106.3	11%
Spring 2019	107.5	8%
Summer 2019	106.7	18%
Fall 2019	104.8	21%
Winter 2020	108.6	8%
Spring 2020	109.2	8%
Summer 2020	104.8	27%
Fall 2020	105.1	24%
Winter 2021	107.9	8%
Spring 2021	106.6	14%

The RSI was above 100 in every quarter of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. The percentage of intervals with pivotal suppliers was relatively low in recent quarters, ranging from 8% to 27%. The high RSI values and the low frequency of pivotal suppliers indicate that there were limited opportunities for any one supplier to exercise market power over the last ten quarters.

Spring 2021 saw a slightly higher frequency of pivotal suppliers (14%) compared to the two previous spring seasons (8%). The small increase was likely a result of several factors, including higher loads in Spring 2021 compared to 2020, and fewer net imports compared to any other quarter in the reporting period. Winter 2021 saw one of the lowest frequencies of pivotal suppliers in the reporting period, at 8%. There were higher frequencies of pivotal suppliers in Summer 2020, which saw relatively high loads, and in Fall 2020, when several baseload generators had scheduled outages for planned maintenance, inspections, or refueling.

6.2 Energy Market Supply Offer Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[39] Under certain conditions, we will mitigate generator offers. Mitigation results in a participant's financial parameters for a generator supply offer (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values. The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs.

Appendix A of the ISO's Market Rule 1 outlines the circumstances under which the IMM may mitigate energy market supply offers.[40] These circumstances are summarized in Table 6-2 below.

[39] This review of supply offers is automated (along with the offer mitigation process), and occurs within the ISO's energy market software.

[40] See Market Rule 1, Appendix A, Section III.A.5.

Table 6-2: Energy Market Mitigation Types

Mitigation type	Structure test	Conduct test threshold	Impact test
General Threshold Energy (real-time only)	Pivotal Supplier	Minimum of $100/MWh and 300%	Minimum of $100/MWh and 200%
General Threshold Commitment (real-time only)		200%	n/a
Constrained Area Energy	Constrained Area	Minimum of $25/MWh and 50%	Minimum of $25/MWh and 50%
Constrained Area Commitment (real-time only)		25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy		10%	n/a

We administer seven types of ex-ante supply offer mitigation, and apply up to three criteria when determining whether to mitigate a supply offer.[41] The criteria are:

- *Structural test:* Certain market circumstances may confer an advantage to suppliers. This may result from 1) a supplier being "pivotal" (i.e., load cannot be satisfied without that supplier) or 2) a supplier operating within an import-constrained area (with reduced competition).
- *Conduct test:* Represents a determination that the financial parameters of a supply offer appear to be excessively high, relative to a benchmark offer value (a "reference" value).[42] The conduct test applies to all mitigation types.
- *Impact test:* Represents a determination that the original supply offer would have a significant impact on energy market prices (LMPs).[43] This test only applies to general threshold energy and constrained area energy mitigation types.

Energy Market Mitigation Frequency

Energy market supply offers are mitigated only when an offer has failed all applicable tests for a particular mitigation type. This section summarizes three types of mitigation data: structural test failures, generator commitment or dispatch hours, and mitigation occurrences. The structural test represents an initial condition for applying conduct and market impact mitigation tests for generators in constrained areas or associated with pivotal suppliers (general threshold energy mitigation). For other mitigation types, the commitment or dispatch

[41] Ex-ante mitigation refers to mitigation applied prior to the finalization of the day-ahead schedules and real-time commitment/dispatch. There is one additional mitigation type specific to dual-fuel generators not listed in the summary table. Dual-fuel mitigation occurs after-the-fact when the supply offer indicates a generator will operate on a higher-cost fuel than it actually uses (e.g., if offered as using oil, but the generator actually runs using natural gas). This mitigation will affect the amount of NCPC (uplift) payments the generator is eligible to receive in the market settlements.

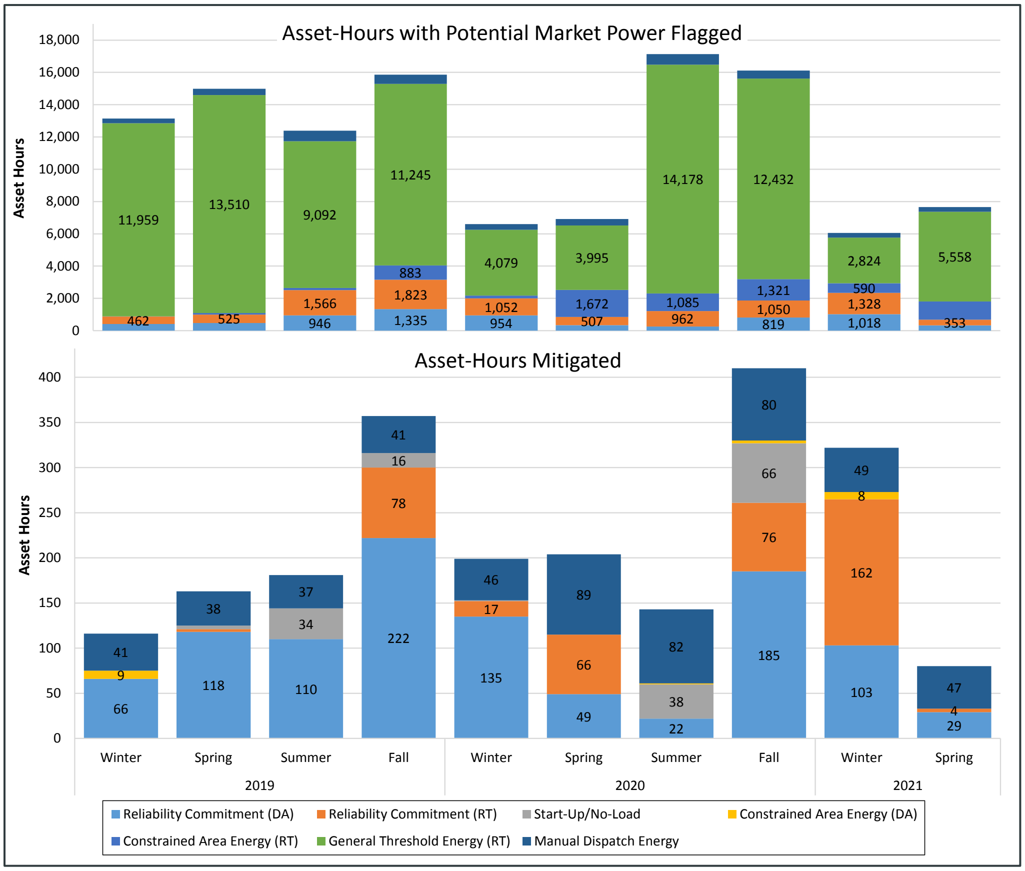
[42] See Market Rule 1, Appendix A, Section III.A.7, regarding the determination of reference values.

[43] For a description of the application of these mitigation criteria (tests), see Appendix A, Section III.A.5.

of a generator triggers the application of the conduct test, when determining whether to mitigate a supply offer.

An indication of mitigation frequency relative to opportunities to mitigate generators by comparing asset-hours of structural test failures, of dispatch or of commitment (depending on mitigation type) against asset-hours of mitigations is illustrated in Figure 6-1 below.[44]

Figure 6-1: Energy Market Mitigation[45]



In general, the data in Figure 6-1 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation (i.e., structural test failures, commitment or dispatch). The highest frequency of mitigation occurred for reliability commitments; this

[44] For example, a generator (asset) committed for reliability for a 12-hour period would represent 12 asset-hours of commitment. If that asset were mitigated upon commitment, then 12 asset-hours of mitigation would occur. For constrained areas, if 10 assets were located in an import-constrained area for two hours, then 20 asset-hours of structural test failures would have occurred. If a pivotal supplier has seven assets and is pivotal for a single hour, then seven hours of structural test failures would have occurred for that supplier; however, more than one supplier may be pivotal during the same period (especially during tighter system conditions), leading to a larger numbers of structural test failures than for other mitigation types. Manual dispatch energy commitment data indicate asset-hours of manual dispatch (i.e., the asset-hours when these generators are subject to commitment). Finally, SUNL commitment hours are not shown because mitigation hours equal commitment hours.

[45] Because the general threshold commitment and constrained area commitment conduct tests did not result in any mitigations during the review period, those mitigation types have been omitted from the figure. The structural test failures associated with each mitigation type are the same as for the respective general threshold energy and constrained area energy structural test failures.

resulted from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM's reference offer value being mitigated. General threshold (pivotal supplier) mitigation and constrained area mitigation types have had the lowest mitigation frequency at close to 0% over the review period. Both of these mitigation types have relatively tolerant conduct test and market impact test thresholds, reducing the likelihood of mitigation given a structural test failure.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[46] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, Maine and Southeastern Massachusetts/Rhode Island (SEMA-RI) had the highest frequency of reliability commitment asset-hours, 43% and 28% respectively in the day-ahead energy market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past two years, and with the frequency of localized transmission issues within Maine. Reliability commitment mitigations also occurred most frequently in Maine and SEMA-RI: 47% of mitigations occurred in Maine and 25% occurred in SEMA-RI in the day-ahead market.[47] Overall, reliability mitigations decreased significantly between Spring 2020 (115 asset-hours) and Spring 2021 (33 asset-hours). Since reliability commitment asset-hours did not decline as significantly as mitigations, this suggests that the generators committed for reliability in Spring 2021 were less likely to offer significantly above reference offer prices than reliability commitments in the earlier period.

Start-up and no-load commitment mitigation: This mitigation type, like reliability commitments, occurs based on a generator's commitment and does not rely on a structural test failure. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters) to guard against the potential commitment of generators that are not covered by other mitigation types and that appear to have grossly over-stated their commitment costs (relative to reference values).[48] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. All generators subject to this mitigation over the review period had natural gas as a primary fuel type, and generators associated with just two participants accounted for 87% of these mitigations. There were no start-up and no-load mitigations in Spring 2021.

Constrained area energy (CAE) mitigation:[49] This mitigation type applies three tests prior to mitigation: structural, conduct and market impact. With relatively tolerant conduct and market impact test thresholds, the frequency of mitigation is low relative to the frequency of structural test failures. The frequency of mitigation given a structural test failure (i.e., generator located in

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[46] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. Market Rule 1, Appendix A, Section III.A.5.5.6.1.

[47] Reliability commitments are typically made in the day-ahead energy market and carry over to the real-time energy market. Hence, day-ahead reliability commitments account for approximately 69% of the reliability commitment asset-hours in the real-time energy market.

[48] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters.

[49] Day-ahead energy market structural test failures are not being reported at this time. This results from questions about some of the source data for these failures. We expect to report on these structural test failures in future reporting.

an import-constrained area) in the real-time energy market over the review period has been 0% (of structural test failure asset-hours) over the review period, as no CAE mitigation has occurred. The frequency of structural test failures follows the incidence of transmission congestion and import-constrained areas within New England. Most of the failures occurred in 2020 (60%); the 2020 failures were spread throughout New England, with 23% in Connecticut, 15% in Western and Central Massachusetts, and 9 to 12% frequency occurring in every other load zone. Transmission work in SEMA-RI and Maine contributed to the higher frequency of transmission congestion in 2020. In Winter 2021, there were very few hours of structural test failures (590), and there were only eight asset-hours of constrained area energy mitigation. There were no structural test failures in Spring 2021.

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type has the lowest frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. General threshold energy mitigation did not occur over the review period. This happened in spite of the highest frequency of structural test failures (i.e., pivotal supplier asset-hours) for any mitigation type. As expected, structural test failures tend to occur for Lead Market Participants with the largest portfolios of generators. Two participants accounted for 59% of structural test failures and four participants accounted for 72% of the structural test failures over the review period. As noted in section 6.1 of this report (Pivotal Supplier and Residual Supply Indices), the frequency of pivotal suppliers increased in Spring 2021.

Manual dispatch energy mitigation: Manual dispatch energy mitigation occurs when a generator is manually dispatched by the ISO. Behind reliability commitment mitigation, this mitigation type has occurred with the second highest frequency of any mitigation type (at 25% on average) over the review period. Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). The dispatch hours for this mitigation type, shown in Figure 6-1, simply refer to asset-hours of manually-dispatched generators in the real-time energy market. As these data indicate, manual dispatch is relatively rare in the real-time energy market, just a few hundred asset-hours occurring each quarter. Combined-cycle generators have had the highest frequency of manual dispatch; this is consistent with manual dispatch frequently occurring in the context of 1) regulation service provided to the real-time energy market and 2) the need for relatively flexible generators to be positioned away from the market software-determined dispatch to address transient issues on the transmission grid. In Spring 2021, there 295 asset-hours of manual dispatch and 47 hours of mitigation. Winter 2021 experienced approximately the same asset-hours of manual dispatch (299) and the same asset-hours of manual dispatch mitigation (49). Compared to Spring 2020, manual dispatch asset-hours declined by 26% in Spring 2021, while mitigation asset-hours declined by 47%.

Section 7
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2021 Forward Reserve Auction.

7.1 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.[50] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[51] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual capacity supply obligations (CSOs). Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can buy or sell obligations. Buying an obligation means that the participant will provide capacity during a given period. Participants selling capacity reduce their 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 capacity commitment period (CCP) associated with Spring 2021 started on June 1, 2020 and ended on May 31, 2021. The conclusion of the corresponding Forward Capacity Auction (FCA 11) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 35,835 megawatts (MW) of capacity, which exceeded the 34,151 MW Installed Capacity Requirement (ICR), at a clearing price $5.30/kW-month. The clearing price of $5.30/kW-month was 25% lower than the previous year's $7.03/kW-month; the price drop was partially driven by an increase in surplus capacity resulting from no significant resource retirements and a slight decrease in Net ICR. This clearing price was applied to all resources within New England as well as imports from Québec. However, the clearing price was slightly lower for New Brunswick imports at

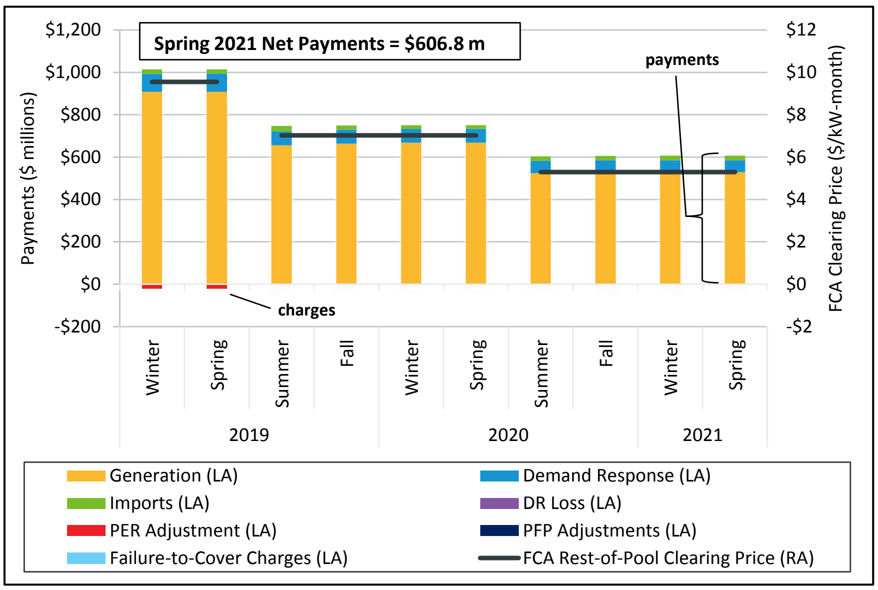
[50] In the capacity market, resource categories include generation, demand response and imports.

[51] 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.

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

Total FCM payments, as well as the clearing prices for Winter 2019 through Spring 2021, are shown in Figure 7-1 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.

Figure 7-1: Capacity Payments ($ millions)



In Spring 2021, capacity payments totaled $606.8 million.[52] Total payments were down 19% from Spring 2020 ($751 million), driven by a 25% decrease in clearing price from FCA 10 ($7.03/kW-month) to FCA 11 ($5.30/kW-month).

Around $0.17 million in Failure-to-Cover (FTC) charges were administered in Spring 2021. 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 2021 alongside the results of the relevant primary FCA are detailed in Table 7-1 below.

[52] Final payments account for adjustments to primary auction CSOs. Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

Table 7-1: 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) Phase I/II	Capacity Zone/Interface Prices ($/kW-mo) New Brunswick
FCA 11 (2020-2021)	Primary	12-month	5.30	35,835		3.38
	Monthly Reconfiguration	May-21	0.35	929		
	Monthly Bilateral	May-21	1.93	193		
FCA 12 (2021-2022)	Primary	12-month	4.63	34,828	3.70	3.16
	Annual Reconfiguration (3)	12-month	1.57	726/309**		
	Monthly Reconfiguration	Jun-21	1.25	437		
	Monthly Bilateral	Jun-21	1.97	18		
	Monthly Reconfiguration	Jul-21	1.40	472		
	Monthly Bilateral	Jul-21	2.02	25		

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

The third Annual Reconfiguration Auction (ARA 3) for CCP 12 took place in March 2021 and cleared 726 MW of supply and 309 MW of demand. The rest-of-pool price was $1.57/kW-month, which is 66% lower than the clearing price for existing resources in FCA 12. An increase in the Net Installed Capacity Requirements (Net ICR) in ARA 3 contributed to higher clearing prices compared to the prior ARAs for the commitment period.[53] Higher Net ICR caused a positive shift in the ISO demand curve, reflecting a greater reliability need from native generation. In response, 417 MWs of additional capacity were brought into the market to meet the updated Net ICR.

Three monthly reconfiguration auctions (MRAs) took place in Spring 2021: the May 2021 auction in March, the June 2021 auction in April, and the July 2021 auction in May. Clearing prices rose consistently over the three auctions, jumping from $0.35/kW-month in the May MRA to $1.25 and $1.40/kW-month in the June and July MRAs, respectively. As clearing prices rose, cleared volumes decreased; total cleared MWs fell from 929 MW to 437 MW from the May to June MRAs. The lower cleared volumes accompanied by higher clearing prices can be driven by a decrease in qualified capacity (supply) entering the auction. June marks the beginning of the summer capacity period, decreasing the qualified capacity MWs for many fuel-burning generators due to higher ambient temperatures.

[53] For more information about the Net ICR methodology for ARA 3 in CCP 12, see https://www.iso-ne.com/static-assets/documents/2020/11/er21-___-000_11-25-20_icr_for_2021_ara.pdf.

7.2 Financial Transmission Rights

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

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[54]

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.

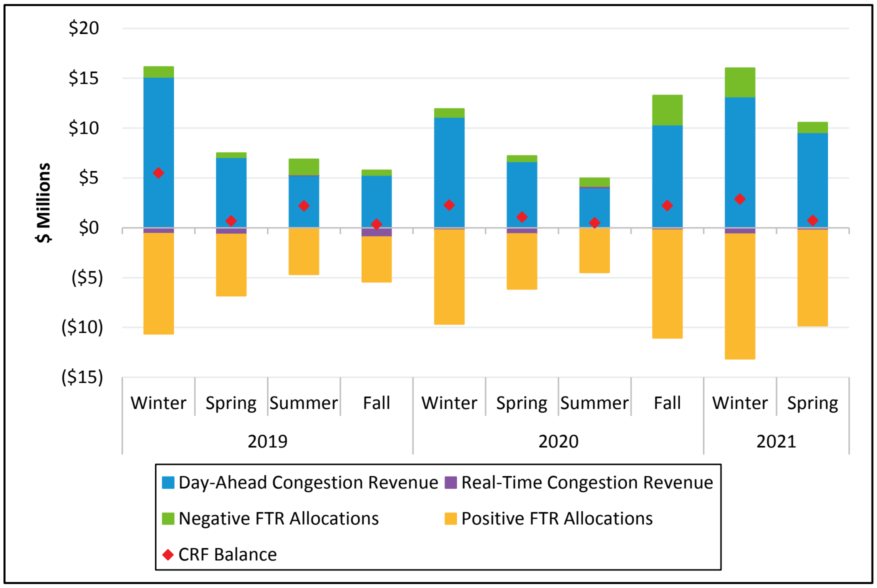
If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected from these three sources 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.

In general, sufficient revenue is collected from the energy market and from FTR holders with negative target allocations to pay FTR holders with positive target allocations all the revenue to which they are entitled (i.e., FTRs are usually *fully funded*). This can be seen in Figure 7-2 below, which shows, by quarter, the amount of congestion revenue from the day-ahead and real-time markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[55] This figure depicts positive target allocations as negative values, as these allocations represent outflows from the CRF. Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

[54] 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.

[55] The CRF balances depicted in Figure 7-2 are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + Negative\ Target\ Allocations + Positive\ Target\ Allocations)$ and do not include any adjustments (e.g., surplus interest, FTR capping). While a positive CRF balance for a quarter indicates that the revenue collected from the three funding sources exceeded the total positive target allocations for the *quarter*, it does not guarantee that this was the case for each month within the quarter. As mentioned in the text above, it is important to note that FTRs settle on a monthly basis.

Figure 7-2: Congestion Revenue and Target Allocations by Quarter



FTRs in March 2021, April 2021, and May 2021 were fully funded. Positive target allocations amounted to $9.6 million in Spring 2021. This represents a decrease of 23% relative to Winter 2021 ($12.5 million) and an increase of 73% relative to Spring 2020 ($5.5 million). Day-ahead congestion revenue in Spring 2021 ($9.6 million) followed a similar pattern, decreasing by 27% relative to Winter 2021 ($13.2 million) and increasing by 44% from Spring 2020 ($6.7 million). Negative target allocations in Spring 2021 ($1.0 million) decreased significantly from their value in Winter 2021 ($2.9 million), largely as a result of reduced congestion associated with the New England West-East interface constraint. However, negative target allocations were 75% higher than their Spring 2020 level ($0.6 million). Real-time congestion revenue was -$0.2 million in Spring 2021, which is around 60% lower than both the Winter 2021 and Spring 2020 values (both totaled around -$0.6 million). Recently, it has been common to see negative real-time congestion revenue; Figure 7-2 shows that in eight of the last ten quarters real-time congestion revenue was negative. It is likely that this is a result of negative RT congestion combined with negative generation obligation deviations. Significant negative real-time congestion revenue can make it difficult to fully fund FTRs.

At the end of May 2021, there was a congestion revenue fund surplus of $1.9 million for 2021. 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.

7.3 Forward Reserve Market

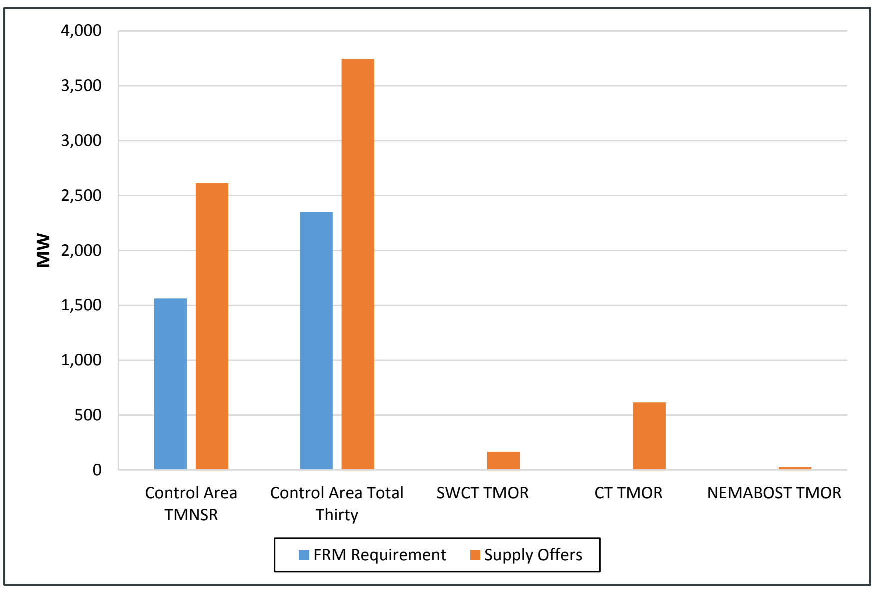
Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During April 2021, the ISO held the forward reserve auction for the Summer 2021 delivery period (i.e., June 1, 2021 to September 30, 2021).[56]

7.3.1 Auction Reserve Requirements

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

The requirements for the Summer 2021 auction are illustrated in Figure 7-3. These requirements were specified for the ISO New England system and three local reserve zones.[57] The figure also illustrates the total quantity of supply offers available in the auction to satisfy the reserve needs.[58]

Figure 7-3: Forward Reserve Requirements and Supply Offer Quantities



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

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

[58] Because thirty-minute operating reserve (TMOR) supply offers within local reserve zones also provide TMOR to the system, the system-wide TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the system-wide TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are also included in the CT TMOR total. The system-level *total* thirty reserve data show all FRM supply offers in the auction, relative to the combined ten-minute non spinning

For the system, requirements were set for two reserve products: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR).[59] 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 1,562 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 a 786 MW TMOR need; the total thirty-minute requirement (depicted in the figure) is the sum of the TMNSR and incremental TMOR requirements (i.e., 1,562 + 786).[60] 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).[61] 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.

reserve (TMNSR) and TMOR system requirements. Finally, because TMNSR supply can contribute to TMOR supply, all TMOR totals in the graph show TMNSR to TMOR supply.

[59] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Summer 2021 Forward Reserve Auction), published March 18, 2021, indicates the system-wide and local reserve zone requirements. For the system-wide requirements, the final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement.

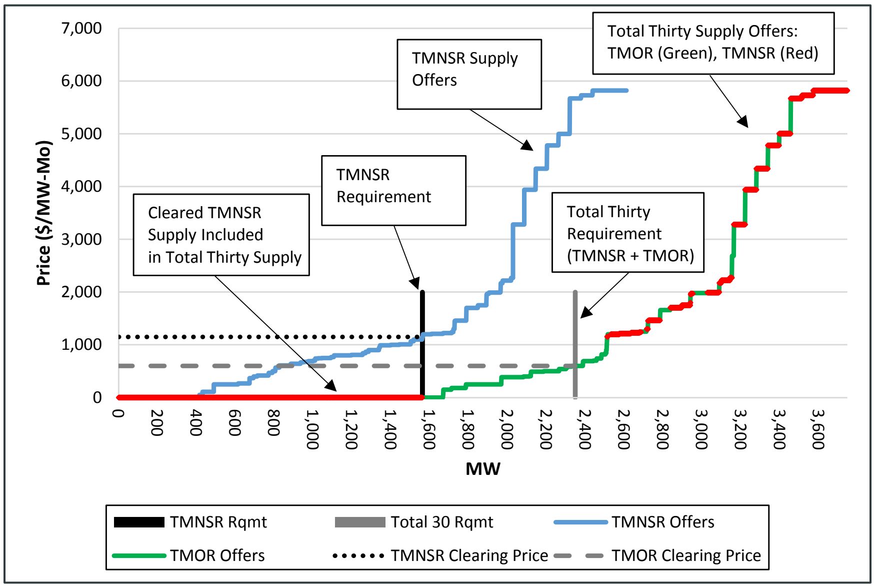
[60] The system TMOR requirement indicated in the ISO's auction assumptions represents an incremental requirement, in excess of the TMNSR requirement. The *total* thirty minute requirement for the auction is the sum of the TMNSR requirement and the system (incremental) TMOR requirement.

[61] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5).

7.3.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Summer 2021 auction exceeded the requirements for both TMNSR and TMOR. Adequate supply ensures that the ISO can successfully obtain forward obligations to meet expected reserve needs in the auction. Figure 7-4 below provides the requirements, system-wide supply curves, and clearing prices for both TMNSR and system-wide total thirty minute reserves.

Figure 7-4: Requirements and Supply Curves, System-wide TMOR & TMNSR



With system-wide requirements of 1,562 MW for TMNSR and 2,348 MW for total thirty, system-wide supply offers for the two products resulted in clearing prices of $1,150/MW-month for TMNSR and $600/MW-month for total thirty (black and gray dotted/dashed lines in the figure). TMNSR supply in the figure is depicted by the blue line; the total thirty-minute supply curve is depicted with both red and green shading, since both TMNSR supply offers (red shading) and TMOR supply offers (green shading) can be used to meet the total thirty-minute requirement.

While TMNSR supply can be used to meet thirty-minute reserve needs, thirty-minute supply offers – as a lower-quality product – cannot be used to meet TMNSR needs. Given that, TMNSR supply is shown relative to the TMNSR requirement; all TMNSR and TMOR supply then can be used to meet the total thirty-minute requirement. The TMNSR supply needed to meet the TMNSR requirement helps to satisfy the total thirty-minute reserve requirement and is shown at $0/MW-month in the TMOR supply curve (as depicted in the figure). The remaining uncleared TMNSR supply and TMOR supply determine the pricing for meeting the total thirty-minute requirement.[62]

[62] The TMNSR supply that clears to meet the TMNSR requirement effectively reduces the total thirty requirement to the incremental TMOR requirement (i.e., 786 MW). TMOR supply, plus TMNSR not cleared to meet the TMNSR requirement, can be used to meet the incremental TMOR requirement. The clearing for the incremental TMOR requirement results in the system-wide TMOR/Total Thirty auction price.

7.3.3 Price Summary

Forward reserve clearing prices for the system-wide TMNSR and TMOR products for the previous six auctions are shown in Figure 7-5 below.

Figure 7-5: FRM Clearing Prices for System-Wide TMNSR and TMOR

In the Summer 2021 auction, TMNSR cleared at a higher price than TMOR; the TMNSR price was $1,150/MW-month and the TMOR price was $600/MW-month. The Summer clearing prices for both TMNSR and TMOR were higher than the preceding Winter 2020-2021 auction prices, which were $678/MW-month for TMNSR and $540/MW-month for TMOR. The increase in the TMNSR price reflects both an increase in the TMNSR requirement for Summer 2021 and an increase in offer prices for the Summer auction; a relatively small increase in offer prices for TMOR supply for the Summer auction explains the increase in the TMOR price. TMNSR and TMOR auction offer prices have tended to be higher in the Summer auctions; this may reflect an expectation of higher energy market opportunity costs (i.e., the forward reserve strike price resulting in reduced dispatch) for fast-start generators during the summer months.

Compared to Summer 2020, the clearing prices in Summer 2021 declined for both TMNSR and TMOR (TMNSR: $1,249/MW-month; TMOR: $900/MW-month). The TMNSR requirement for the Summer 2021 auction declined by a small amount (by 42 MW to 1,562 MW) relative to the Summer 2020 auction; this explains about one half of the reduction in TMNSR prices. The remaining price change for TMNSR and all of the price change for TMOR resulted, primarily, from a decrease in supply offer prices for the 2021 auction.

7.3.4 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; this supply (minus the largest supplier) is compared to the TMNSR requirement. If the requirement can be met without the largest supplier, the RSI will be equal to or greater than 100; if the requirement cannot be met without the largest supplier, the RSI will be less than 100.

The RSI calculation for system-wide total thirty (TMOR) follows the same formulation, considering offered total thirty supply, the largest total thirty supplier, and the total thirty requirement.[63]

The heat map table – Table 7-2 below – shows the offer RSI for system-wide TMNSR, system-wide total thirty, and local zone TMOR (for zones with a non-zero TMOR requirement). The colors indicate the degree to which structural market power was present, starting with low RSIs shown in red, followed by white and green colors, with the latter indicating that there was still ample offered supply without the largest supplier.

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

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI Total Thirty (System-wide)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Winter 2018-19	127	127	N/A	N/A	21
Summer 2019	90	97	N/A	N/A	N/A
Winter 2019-20	120	118	N/A	N/A	N/A
Summer 2020	84	97	N/A	N/A	N/A
Winter 2020-21	102	115	N/A	N/A	N/A
Summer 2021	92	108	N/A	N/A	N/A

An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices.

[63] Starting with this report, the reported total thirty (TMOR) RSI values are being revised based on an updated methodology. Previously, the total thirty/TMOR RSI system-wide calculation included both TMNSR and TMOR supply, and compared that supply to the incremental TMOR requirement (e.g., 786 MW in Summer 2021), rather than comparing that supply to the total thirty-minute requirement (2,348 in Summer 2021). The previous formulation of the RSI calculation overstated the potential competitiveness of TMOR supply offers, by understating the actual thirty-minute requirement. The revised system-wide total thirty RSI is now calculated by comparing all supply offers in the auction (TMNSR and TMOR) to the total thirty-minute requirement.

For the Winter periods, the TMNSR RSI values were greater than 100, indicating that these auctions were structurally competitive. The three Summer auctions, however, had RSI values slightly below the structurally competitive level. In Summer 2019, the decline in RSI resulted from a slightly increased TMNSR requirement 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 Summer 2021 RSI improved somewhat compared to the Summer 2020 RSI, with a small increase in supply and a small reduction in requirement.

The system-wide total thirty RSI values were consistent with a structurally competitive level, except for the Summer 2019 and 2020 auctions. In those two auctions, the RSI estimates were only slightly below the competitive level, reflecting slightly reduced supply and slightly increased reserve requirements in those auctions (relative to the other system-wide total thirty auctions).

Considering the TMOR RSI at the zonal level, only the NEMA/Boston zone had a reserve requirement during the review period. In the Winter 2018-19 auction, every participant that offered forward reserve supply in NEMA/Boston was needed to meet the local requirement, and those supply offers were insufficient to meet that requirement. The auction was not structurally competitive, with every TMOR supplier for that zone potentially having market power.[64]

[64] When there is insufficient supply to satisfy the FRM requirement, the clearing price is set to the offer price cap ($9,000/MW-month). The offer price cap, to some degree, limits the ability of suppliers to exercise market power.