2018 Assessment of the ISO New England Electricity Markets

POTOMAC ECONOMICS

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Preface

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this assessment, we provide our annual evaluation of the ISO's markets for 2018 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor's evaluation of the market outcomes in 2018.

We wish to express our appreciation to the Internal Market Monitor and other staff of the ISO for providing the data and information necessary to produce this report.

1 The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

EXECUTIVE SUMMARY

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights ("FTRs"), and forward capacity to satisfy the electricity needs of New England. These markets provide substantial benefits to the region by coordinating the commitment and dispatch of the region's resources to ensure that the lowest-cost supplies are used to reliably satisfy demand in the short-term. At the same time, the markets establish transparent, efficient price signals that govern long-term investment and retirement decisions.

The ISO Internal Market Monitor ("IMM") produces an annual report that provides an excellent summary and discussion of the market outcomes and trends during the year.[2] The IMM Annual Report shows:

- Energy prices rose 28 to 32 percent from 2017 to 2018 as natural gas prices increased by 33 percent. This correlation is consistent with our findings that the market performed competitively because energy offers in competitive electricity markets should track input costs.
- Load rose 2 percent from 2017, attributable to hot and humid summer weather conditions in 2018. Nonetheless, load levels have been low in recent years because of the increase in energy efficiency programs and the strong growth in behind-the-meter solar generation.
- Capacity prices rose to $9.55 per kW-month in the 2018/2019 Capacity Commitment Period ("CCP"), reaching its peak level in the short-term. Prices will start to fall in FCA 10 (the 2019/2020 CCP) and drop to $3.80 in FCA 13 (the 2022/2023 CCP) as the system returns to a higher surplus capacity with the entry of new resources.
- Pay-for-performance ("PFP") rules became effective in June 2018. The first and only PFP event in 2018 occurred on September 3, driven by unexpected high load and forced generation loss. This event led to $44 million of credits to over-performers and $36 million of charges to under-performers.

The IMM report provides detailed discussion of these trends and other market results and issues that arose in the ISO-NE markets during 2018. This report is intended to complement the IMM report, comparing key market outcomes with other RTO markets and focusing on key market design and competitive issues. Hence, this report includes:

- A cross-market comparison of several key market outcomes and metrics to illuminate how market conditions and market performance vary in ISO-NE from other RTOs;
- A competitive assessment of the energy and ancillary services markets;

[2] See ISO New England's Internal Market Monitor 2017 Annual Markets Report, available at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

- Evaluation of how the ISO's proposed market design reforms should address most of the fuel security challenges facing New England;
- Review of the efficiency of compensation to resources through the PFP framework, including an evaluation of the first-ever PFP event; and
- Analysis of market issues related to out-of-market uplift costs.

Cross-Market Comparison of Key Market Outcomes

We compare several key market outcomes in the ISO-NE markets to comparable outcomes and metrics in other RTO markets in this report and find that:

- ISO-NE has generally exhibited the highest energy prices of the RTO markets. The relatively high energy costs in New England are primarily attributable to the higher natural gas prices in this region.
- ISO-NE experiences far less congestion than any of other RTOs. On a per MWh of load basis, congestion levels in New England are one-tenth to one-fifth of the congestion levels in other RTO markets. This reflects the substantial transmission investments made over the past decade, which has resulted in transmission service cost of nearly $18 per MWh – well more than double the average rates in other RTO markets.
- Net revenues provided by the ISO-NE markets exceeded the entry costs for both new combustion turbines or combined cycle resources in 2018, while none of the other RTO markets produced similar investment incentives. This was largely due to high revenues from the ISO-NE's capacity market, which, however, may not sustain given falling capacity prices in the coming years.
- The CTS process between New England and New York has improved over time because of a) improvements in price forecasts and b) increased CTS bid liquidity that has benefitted from the RTOs' decision not to impose charges on these transactions. These two factors have led to substantial production cost savings. It is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). However, forecast errors are still limit the potential benefits of CTS and the ISO should continue to pursue improvements.

Competitive Assessment

Based on our evaluation of the ISO-NE's wholesale electricity markets contained in this report, we find that the markets performed competitively in 2018. Our pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and in all New England in 2018, driven largely by the new market entry of roughly 1.5 GW of combined cycle generating capacity in the import-constrained areas, portfolio changes in the largest suppliers, and transmission upgrades in Boston. Our analyses of potential economic and physical withholding also indicates that the markets performed competitively with little evidence of significant market power abuses or manipulation in 2018.

In addition, we find that the market power mitigation has generally been effective in preventing the exercise of market power in the New England markets, and was generally implemented consistent with Appendix A of Market Rule 1. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the real-time market software before it can affect the market outcomes.

To ensure competitive offers are not mitigated, it is important for generators to proactively request reference level adjustments when they experience input cost changes due to fuel price volatility and/or fuel quantity limitations. In addition, the ISO implemented a procedure before the 2018/19 winter to allow opportunity costs resulting from fuel limitations in reference levels for oil-fired and dual-fuel generators. This enhancement should lead to more efficient scheduling of energy-limited resources. We will continue monitor its effectiveness particularly under prolonged severe winter weather conditions.

The only area where the mitigation measures may not have been fully effective is in their application to resources frequently committed for local reliability. Although the mitigation thresholds are tight, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we recommend the ISO consider tariff changes as needed to expand its authority to address this concern.

Addressing Winter Fuel Security Concerns

New England has become increasingly reliant on natural gas and vulnerable to disruptions in fuel supplies to the region in recent years. Nearly 5 GW of new fuel-efficient conventional generation has been built and a comparable amount of nuclear, coal-fired, and older steam turbine capacity has retired in the first 13 Forward Capacity Auctions. The New England market has lacked the necessary elements to address reliability needs that are driven by fuel limitations. These concerns were heightened after the ISO entered into an out-of-market contract to prevent the retirement of the Mystic generating station.

The ISO developed the Operational Fuel Security Assessment ("OFSA") model to evaluate the planning reliability needs of New England with explicit consideration of fuel supply limitations. This model is innovative, but we are concerned that it relies on some assumptions that are overly conservative by assuming that the market will not respond with additional fuel supplies under shortage conditions. Consequently, the OFSA model may indicate the need for additional installed capacity to address a fuel security issue that could be fully resolved through market design enhancements that motivate resource owners to procure additional fuel supplies for existing generation.

The market design enhancements being developed by the ISO will compensate resources for holding inventories during tight fuel conditions and provide incentives that help the region conserve fuel supplies. We worked with the ISO to run scenarios of the OFSA model to evaluate how these market design enhancements are likely to affect reliability, since market incentives will improve the operation of the system and decisions by suppliers, including:

- Deploying heavy oil units ahead of light oil units (when light oil units have more limited oil inventories) – Under tight fuel supply conditions, an efficient market design will motivate units with limited inventories to conserve their remaining fuel, leading units with larger inventories to be deployed first—even if the units with limited inventories are more fuel efficient (which is usually the case in New England);
- More frequent refilling of oil inventories – Under tight fuel supply conditions, an efficient market design will motivate dual fuel units to maintain higher inventories and refuel more frequently; and
- Higher utilization of existing LNG-import capacity – If a major fuel source is lost, an efficient market design will induce generators and natural gas shippers to contract with LNG-importers to increase supplies to one of the other two terminals in the region, utilizing up to 50 percent of their remaining surplus capacity.

We evaluated two timeframes, one before the Mystic Units retire and one after the Mystic retention contract expires and the units are assumed to have retired:

- Winter 2022/23 – This is the Capacity Commitment Period ("CCP") corresponding to the Forward Capacity Auction that was held in February 2019 (i.e., FCA 13). We found that the improved deployment and fuel procurement asumptions would effectively address New England's reliability needs—even under severe weather and large supply contingency scenarios. These results highlight the reliability improvements that are possible with better incentives in the day-ahead and real-time markets without any capacity additions.
- Winter 2024/25 – This is the first winter after the Mystic retention contract expires (i.e., FCA 15). The improvements described above would fully address the fuel security concerns after the Mystic units and Distrigas LNG retire. However, the region might still experience reliability issues during severe winter weather in certain extreme supply contingency scenarios.

These results underscore the importance of the market enhancements being developed by the ISO. These enhancements will provide strong incentives for resources to procure fuel necessary to maintain reliability under peak conditions, and increase the utilization of existing equipment for storing oil and importing LNG. This would not only likely eliminate reliability issues during extreme winter conditions, but also enable the ISO to maintain system reliability after the loss of a critical resource, such as the Millstone nuclear plant, a major pipeline, or an LNG import facility. In the longer-term, the ISO's market enhancements will shift investment incentives towards resource entry and retirement decisions that help maintain reliability after the potential retirements of the Mystic units and the Distrigas LNG facility.

Incentives of Pay-for-Performance Rules

The Pay-for-Performance ("PFP") rules were implemented to enhance incentives for suppliers to perform when they are needed the most. This report summarizes market outcomes during the first PFP event since the rules became effective on June 1, 2018. We evaluate the efficiency of compensation received by suppliers during the event compared to the risk of not serving load and the value of lost load. We also identify a misalignment between the compensation of short-duration energy limited resources and their value to the system during reserve shortage events.

The first PFP event in New England occurred for two-and-a-half hours on September 3, during which the ISO ran short of 30-minute reserves by up to 880 MW. The shortage resulted primarily from unexpectedly high load (actual load exceeded the forecast by roughly 2.5 GW) and the sudden loss of generation (roughly 1.4 GW), leading the ISO to cut exports, make emergency purchases, and activate Price-Responsive Demand. The combination of shortage pricing and PFP incentives led to marginal compensation rates of up to $4700 per MWh. Performance of individual resources was generally consistent with expectations as steam turbines accounted for the majority of PFP charges, since most had not been economic to commit in the day-ahead market, while other resource categories generally received more credits than charges with fast-start units and importers doing particularly well.

PPR versus the Marginal Value of Reserves

During reserve shortages, prices should rise gradually with the severity of the shortage, reflecting the marginal reliability value of reserves given the size of the shortage and the risk of potential supply contingencies. The marginal reliability value of reserves is the expected value of lost load ("EVOLL") that will not be served if the available reserves are reduced by 1 MW. Assuming a relatively high value of lost load ("VOLL") of $30,000 per MWh, we estimated the EVOLL based on the probability of contingencies that could result in load shedding during the event on September 3. The EVOLL is important because it reflects efficient shortage compensation for resources that are producing energy and/or reserves.

We estimate that the EVOLL ranged from $700 to $1000 per MWh during the event, far lower than the marginal rate of compensation under the PPR, which ranged from $3000 to $4700 per MWh. However, we find that for reserve shortages of more than 1.2 GW, the EVOLL would quickly rise above $4700 per MWh up to the assumed VOLL of $30,000 per MWh. This illustrates the deficiencies with the current PPR, that the single payment rate is: a) well above a reasonable estimate of the average EVOLL, and b) fixed regardless of the magnitude of the shortage. Hence, we recommend the ISO modify the PPR to rise with the reserve shortage level, and not to implement the remaining planned increase in the payment rate. These changes would enhance price formation during reserve shortage events and encourage more efficient short and long-run decisions by suppliers.

Incentives for Energy Storage Resources

Interest in battery storage and other energy limited resources has grown quickly in recent years as policy-makers look for non-fossil fuel options for integrating intermittent renewables. However, these resources present special challenges for valuing capacity and energy and operating reserves under shortage conditions. We evaluate the reliability value of a 2-hour battery storage resource and find that such units are likely to be over-compensated under the current capacity market rules, including the PFP compensation provisions. This is concerning as policy-makers and developers prepare to invest heavily in this technology in the coming years.

The FCM rules allow battery storage resources to qualify for 100 percent of their maximum capability, but these resources have significant duration limitations that make them less valuable than most conventional resources when the system is near load shedding conditions. Furthermore, the flexibility of these resources make them likely to perform better under the PFP provisions than most resources during mild to moderate reserve shortage conditions. As discussed above, the marginal compensation rate is far higher than the EVOLL during such reserve shortages, leading battery storage resources to be greatly over-compensated.

We performed a Monte Carlo analysis to estimate the reliability value of a 2-hour battery storage resource for avoiding load shedding and the compensation it would receive in the capacity market. This found that a 2-hour battery storage resource would:

- Have 66 percent of the value of an average conventional resource for avoiding load shedding, and
- Receive 117 percent of the total capacity compensation of an average conventional resource.

This over-compensation cannot be fixed by reducing the qualified capacity of these resources to an appropriate level (e.g., 66 percent), since this reduction would be offset by a significant increase in the PFP credit. As stated earlier, a graduated PPR that rises with the magnitude of the reserve shortage would largely correct this over-compensation to these resources. Hence, to correct the over-compensation of energy storage resources, we recommend that the ISO: (a) reduce the qualified capacity of these resources before the FCA, and (b) adopt a graduated PPR that rises with the magnitude of the reserve shortage.

Capacity Market Design Enhancements

The purpose of the capacity market is to provide a market mechanism for ensuring that sufficient resources are procured to satisfy the planning reliability requirements of New England. The forward capacity market coordinates decisions to retire or mothball older resources with decisions to invest in new generation, demand response, and transmission. We evaluate potential market design improvements to facilitate competition in the auction and to enhance incentives for timely delivery of new resources.

Addressing Issues in the Minimum Offer Price Rules

The purpose of the minimum offer price rule ("MOPR") is to prevent uneconomic subsidized resources from artificially depressing market prices. This is important because these price effects will undermine the market's ability to facilitate efficient long-term investment and retirement decisions by market participants. However, MOPR can also potentially interfere with competitive investment or artificially increase prices. Hence, it is important to ensure that MOPR is effective in addressing uneconomic entry while not interfering with economic entry. Based on our evaluation of the MOPR in previous years, we've identified three issues that we recommend the ISO address to improve its MOPR.

Conforming the MOPR to the Pay-for-Performance Framework

Under the PFP rules, most of the value of capacity in the long-run will be embedded in the performance payments. Participants that sell capacity are essentially engaging in a forward sale of the expected performance payments (they receive the capacity payment up front in exchange for not receiving the performance later when they are running during a shortage). However, resources that do not sell capacity can earn comparable revenues by simply running during shortages and receiving the performance payments. In other words, a supplier has two options:

- Sell capacity and commit to producing energy during shortages, relinquishing the performance payments in could have earned; or
- Do not sell capacity and earn the performance payment by producing during the shortages.

In equilibrium, these two options should produce the same expected revenues. MOPR precludes an uneconomic entrant from selling capacity (choosing the first option), which simply means that the mitigated resource would default to option 2. Because option 2 should provide substantial expected revenues, the MOPR will not likely be an effective deterrent under the PFP framework. In addition, an uneconomic entrant will be able to depress capacity prices without selling capacity because it will lower the expected number of shortage hours. Therefore, we recommend the ISO make units that were mitigated under the MOPR ineligible to receive performance payments.

Competitive Entry Exemption

As noted above, the MOPR is intended to address uneconomic subsidized new resources that can artificially increase supply and depress prices. However, the current rules apply to all investment in new resources, including private investment in resources that are receiving no out-of-market subsidies. To the extent that the MOPR affects the offer prices submitted for such resources, it will interfere with competitive market-based investment. Mitigation is not reasonable in these cases because no private entity in New England is likely large enough to benefit from privately funding an uneconomic resource in order to lower prices.

Additionally, there are a number of reasons why a competitive developer may offer less than a default Net CONE level. For example, it may have more optimistic assumptions regarding future fuel prices, electricity prices, capacity prices, or other factors that affect the profitability of the resource. Given risks related to the timing and legal hurdles associated with new investment, it may be efficient for a competitive supplier to incur substantial costs and proceed significantly down the path of developing the unit before offering in the FCA. In this case, it may be competitive to offer at a relatively low level, which would not indicate an attempt to exercise buyer-side market power and would be harmful to mitigate.

Other RTOs have addressed this concern by implementing a "competitive entry exemption" to prevent the MOPR from interfering with private market-based investment.[3] Essentially, such a provision would exempt a new resource from the MOPR if it demonstrates that it is not receiving any direct subsidies or indirect subsidies via contract with a regulated entity. FERC's recent deficiency letter regarding an offer of a new resource in FCA 13 highlights the value of this exemption.[4]

Capping the Minimum Offer Price

The MOPR is intended to prevent prices from reflecting artificial supply surpluses caused by uneconomic entry. There is no economic justification, however, for mitigating new resources when surplus capacity is zero or negative (i.e., when new resources are needed to satisfy the system's planning resource needs). In this case, a competitive and efficient market would facilitate entry at price close to the net CONE, and no price above this level can reasonably be considered depressed. Likewise, it is unreasonable for the MOPR to raise prices substantially above net CONE. Unfortunately, this outcome would occur under ISO-NE's current MOPR protocols.

3 See NYISO's Market Administration and Control Area Services Tariff section 23.4.5.7.9.

4 See Commission's 6 June, 2019 order directing the IMM to make a deficiency filing in the matter of *Results of Thirteenth Forward Capacity Auction*, Docket No. ER19-1166-000.

ISO-NE's version of the MOPR always sets the offer floor at the new resource's actual entry cost, even though it may be much higher than net CONE (currently near $8 per kw-month). This may prevent state-sponsored resources that could satisfy a capacity need from clearing in the FCA and prompt the ISO to clear a conventional resource that is not needed (given the entry of the sponsored resource). This raises additional concerns under the ISO's recently approved Competitive Auctions with Subsidized Policy Resources ("CASPR") provisions because clearing unneeded conventional resources will compel the sponsored resources to pay lower-cost existing resources to retire.

Addressing this issue is straightforward. We recommend that ISO-NE cap the minimum offer price at net CONE. This will prevent artificial suppression of capacity prices below net CONE, but would ameliorate the concerns described above. It would allow sponsored resources to enter at an offer equal to net CONE and displace new conventional resources offered at higher prices. To the extent that some sponsored resources clear in the FCA at or above net CONE, fewer lower-cost existing resources would be prompted to retire and fewer unneeded conventional new resources would enter, both of which would increase efficiency and lower costs for the regions' consumers.

Improving the Competitive Performance of the FCA

In our previous Annual Market Reports, we evaluated the supply and demand in the FCA and concluded that:[5]

- Limited competition can enable a single supplier to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity and the Descending Clock Auction format help suppliers recognize when they can benefit by raising capacity prices.

Most of the pre-auction information available to auction participants regarding the existing, new and retiring resources either needs to be published for other purposes or is available from sources that are outside the ISO's purview. However, the ISO's DCA process provides key information on other suppliers offers that is not relevant for constructing competitive offers, and instead would allow a resource to raise its offer above competitive levels.

A sealed bid auction would eliminate such information and improve the incentives for suppliers to submit competitive offers. Accordingly, we recommend the ISO transition from the DCA to a sealed-bid auction.

5 See Section V.A of our report on *2014 Assessment of the ISO New England Electricity Markets*, Section IV.A of *2015 Assessment of the ISO New England Electricity Markets*, and Section IV.A of *2017 Assessment of the ISO New England Electricity Markets*.

Causes and Allocation of NCPC Charges

Although the overall size of NCPC payments are small relative to the overall New England wholesale market, they raise a number of important concerns:

- They usually indicate that the markets do not fully reflect the needs of the system. Ultimately, this undermines the price signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term.
- NCPC payments can also distort suppliers' incentives. Thus, we evaluate the causes of NCPC payments to identify market improvements that would limit such distortions.
- NCPC payments tend to shift investment incentives away from flexible resources that will be increasingly valuable with the growth in intermittent renewable generation.

Our evaluation in this report shows that even with the improvements made in recent years, ISO-NE's uplift charges exceed the levels generated by most other RTOs. Given the concerns that NCPC payments raise, we evaluate the causes of NCPC payments in order to identify potential market improvements.

Day-Ahead NCPC Charges

In our assessment of day-ahead NCPC charges, we found that in 2018, 47 percent was attributable to commitments for local second contingency protection, while 30 percent was attributable to commitments for the system-level 10-minute spinning reserve requirement. Although these requirements are reflected in the real-time market, there is no day-ahead market for operating reserves. Thus, the costs of committing generation to satisfy these requirements are not reflected efficiently in day-ahead prices. This process resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, 60 percent of which would not have been needed under a co-optimized energy and reserve market.[6]
- Depressed clearing prices for energy and 10-minute spinning reserves providers. We estimate that additional generation was committed to satisfy the 10-minute spinning reserve requirement in nearly 4,000 hours in 2018, although this was not reflected in energy prices or spinning reserve prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration.

[6] Note, this includes LSCPR units that were committed by a constraint in the day-ahead commitment model, while the majority of LSCPR units in Boston were determined before the day-ahead market.

We make three recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves with energy in the day-ahead market (i.e., determine the lowest cost set of offers that simultaneously satisfies energy demand and operating reserve requirements).
- A day-ahead reserve market would also facilitate our recommendation to eliminate of the Forward Reserve Market, which has resulted in inefficient economic signals and market costs.
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

ISO-NE has started several initiatives to address energy security concerns, including co-optimizing procurement of energy and operating reserve in the day-ahead market. We support this effort and expect it will address the issues we identified and discussed in this report.

Real-Time NCPC Charges and Allocations

In assessing the real-time NCPC charges in 2018, we found that 9 percent were for local reliability and 14 percent were for system level capacity requirements, while the vast majority were associated with inconsistencies between the output of economically scheduled generators and clearing prices in the real-time market.

Similar to our prior findings, we found that real-time deviations contribute to just 14 percent of the real-time NCPC in 2018, but they are allocated 40 percent of the NCPC charges. Hence, we continue to find that ISO-NE over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market. In 2018, the gross volume of cleared virtuals (including both virtual load and virtual supply) averaged roughly 7 percent of load in the ISO-NE market compared to nearly 20 percent in the NYISO and MISO markets.

The ISO is currently considering a market design improvement, a Multi-day Ahead Market, to address energy security concerns. Virtual trading will be playing a very important role in aligning prices in the multi-day ahead market with the prices in the real-time market. Therefore, we recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.

Table of Recommendations

We make the following recommendations based on our assessments of the ISO-NE's market performance. A number of these recommendations have been made previously and are now reflected in the ISO's Wholesale Market Plan.

Recommendation	Wholesale Mkt Plan	High Benefit[7]	Feasible in ST[8]
Reliability Commitments and NCPC Allocation			
1. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.	✓		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.			✓
Reserve Markets			
3. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
4. Eliminate the forward reserve market.			✓
External Transactions			
5. Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		✓	✓
Capacity Market			
6. Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			✓
7. Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.			
8. Consider modifying the capacity compensation of energy limited resources to be consistent with the reliability value.			
9. Improve the MOPR by: a) eliminating performance payment eligibility for units subject to the MOPR, b) capping the Minimum Offer Price at net CONE, and c) exempting competitive private investment from the MOPR.			✓

7 Recommendation will likely produce considerable efficiency benefits.

8 Complexity and required software modifications are likely limited.

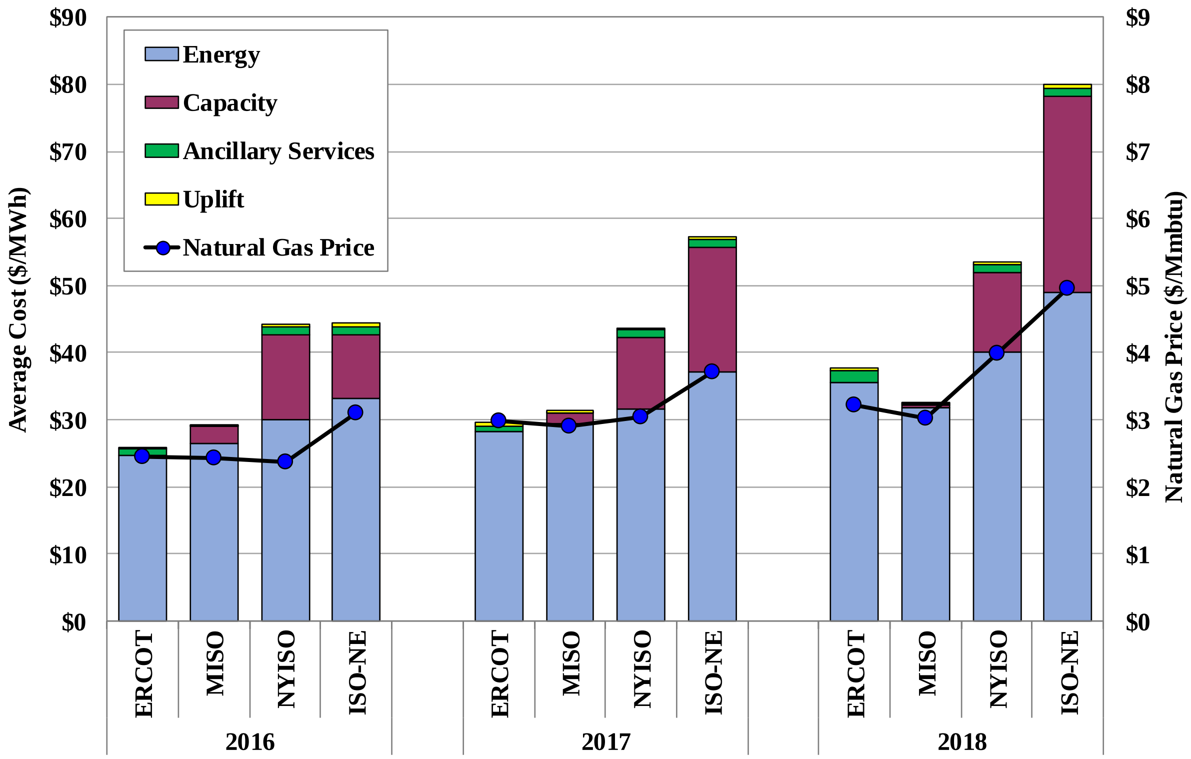
I. Comparing Key ISO-NE Market Metrics to Other RTOs

The 2018 Annual Markets Report by the Internal Market Monitor (IMM) provides a wide array of descriptive statistics and useful summaries of the market outcomes in the ISO-NE markets. The IMM report provides a very good discussion of these market outcomes and the factors that led to changes in the outcomes in 2018. Rather than duplicating this discussion, we attempt to place the key market outcomes into perspective in this section by comparing them to comparable outcomes and metrics in other RTO markets.

A. Market Prices and Costs

While the RTOs in the US have migrated to relatively similar market designs, including Locational Marginal Pricing (LMP) energy markets, operating reserves and regulation markets, and capacity markets, the details related to the market rules can vary substantially. Additionally, the market prices and costs in different RTOs can be significantly affected by the types and vintages of the generation, the input fuel markets and availability, and differences in the capability of the transmission network. To compare the overall prices and costs between RTOs, we produce the "all-in price" of electricity in Figure 1.

Figure 1: All-In Prices in RTO Markets
2016 - 2018



The all-in price metric is a measure of the total cost of serving load. The all-in price is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load. We also show the average natural gas price because it is a principal driver of generators' marginal costs and energy prices in most markets.

This figure shows some clear sustained differences in prices and costs between these markets. ISO-NE has generally exhibited the highest energy prices and uplift costs of these markets. The relatively high energy costs are in New England are primarily attributable to the higher natural gas prices at the pipeline delivery locations serving New England's generators. However, the natural gas price premium is larger than the energy price premium in New England because average system-wide energy prices in all other markets are inflated by transmission congestion. Although we do not show the most congested locations in neighboring markets, such as New York City, these locations exhibit all-in prices substantially higher than prices in New England and contribute to higher system-wide average prices in those markets. Conversely, the unusually low levels of transmission congestion in New England tends to lead to lower system-wide average energy prices. We discuss congestion levels and trends in more detail in the next subsection.

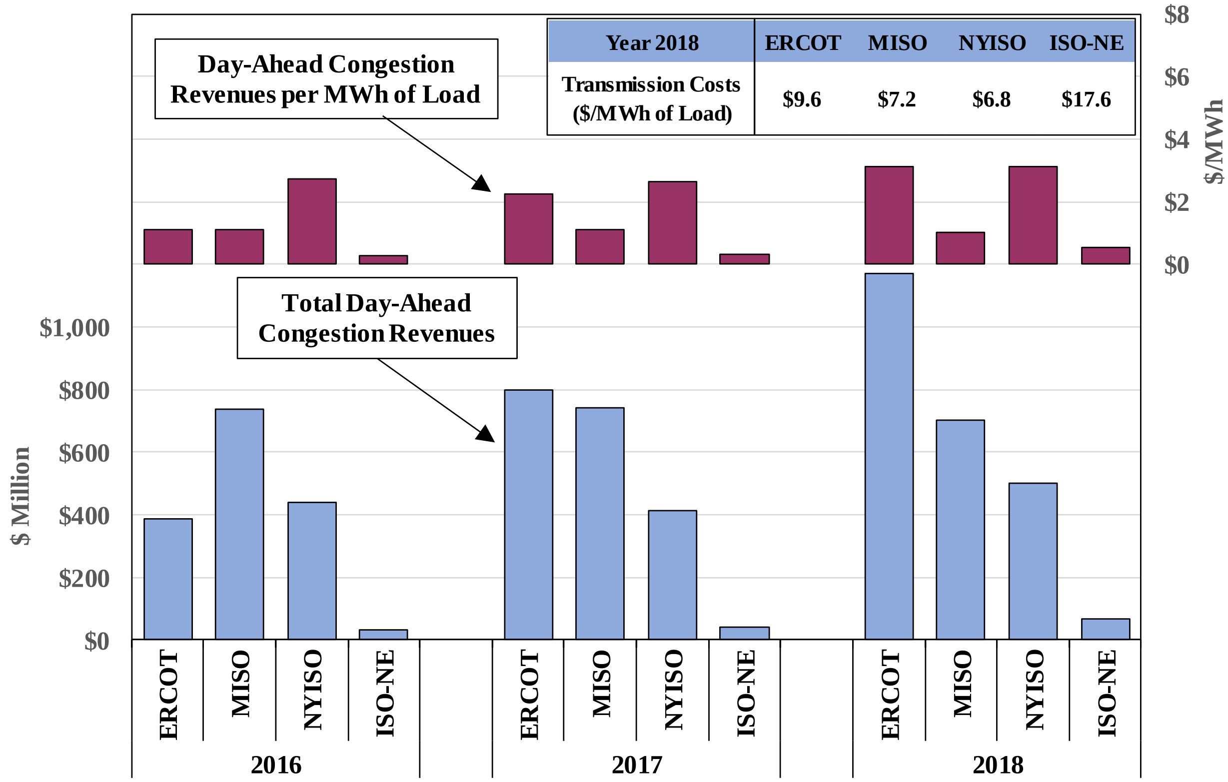
The figure also that the capacity component of the all-in prices is substantially higher than the other RTO's shown. The capacity costs are NYISO are lower primarily because its surplus in the 2018 planning year is higher than the surplus in New England. The low capacity costs in the other two RTOs is attributable to the market design. ERCOT operates an "energy-only" with no capacity market, while MISO operates a capacity auction with a vertical demand curve that is not design to reveal the true value of capacity. Although not optimal, MISO has been content with this market design because additional revenues are provided through retail rates to regulated entities that play a key role in maintaining resource adequacy in MISO.

The other result shown in the figure, although it is difficult to discern, is that the average uplift costs per MWh is higher in ISO-NE than any of the other markets shown. Although this amount appears small, it is important because it is difficult to hedge. Owning or contracting for generation will hedge load-serving entities against volatile costs of procuring energy and ancillary services, but uplift costs are an additional cost that is not typically hedged by supply procurements. The categories of uplift and a discussion of the reasons for the higher uplift levels incurred in New England are discussed in Section III in this report.

B. Transmission Congestion

One of the principal objectives of the day-ahead and real-time markets is to commit and dispatch resources to control flows on the transmission system and efficiently manage transmission congestion. The following figure shows the amount of congestion revenue collected through the Day-Ahead markets in a number of RTO markets in the U.S. To account for the very different sizes of these RTOs, we show the total amount of Day-Ahead congestion revenues divided by actual load in the top panel of the figure.

Figure 2: Day-Ahead Transmission Revenues
2016 - 2018



This figure shows that ISO-NE experiences far less congestion than any of these other RTOs. On a per MWh basis, congestion levels in the other RTOs are five to ten times larger than the congestion levels in New England.

The low level of congestion in New England is not a surprise given the substantial transmission investments that were made over the past decade. These investments have led to transmission rates that are more than double the average rates in the other RTO areas at nearly $18 per MWh. The transmission rates in other RTO areas are much lower than New England, even given the billions in incremental transmission costs that have been incurred in Texas and MISO to support the integration of wind resources. For example, ERCOT has incurred more than $5 billion in transmission expansion costs to mitigate the transmission congestion between the wind resource in west Texas and the load centers in eastern Texas.

Going forward, economic transmission investment should occur when the marginal benefit of reducing congestion is greater than the marginal cost of the transmission investment. Given that average congestion in New England has been less than $0.40 per MWh over the past three years, it is unlikely that additional transmission investment will be economic in the near term.

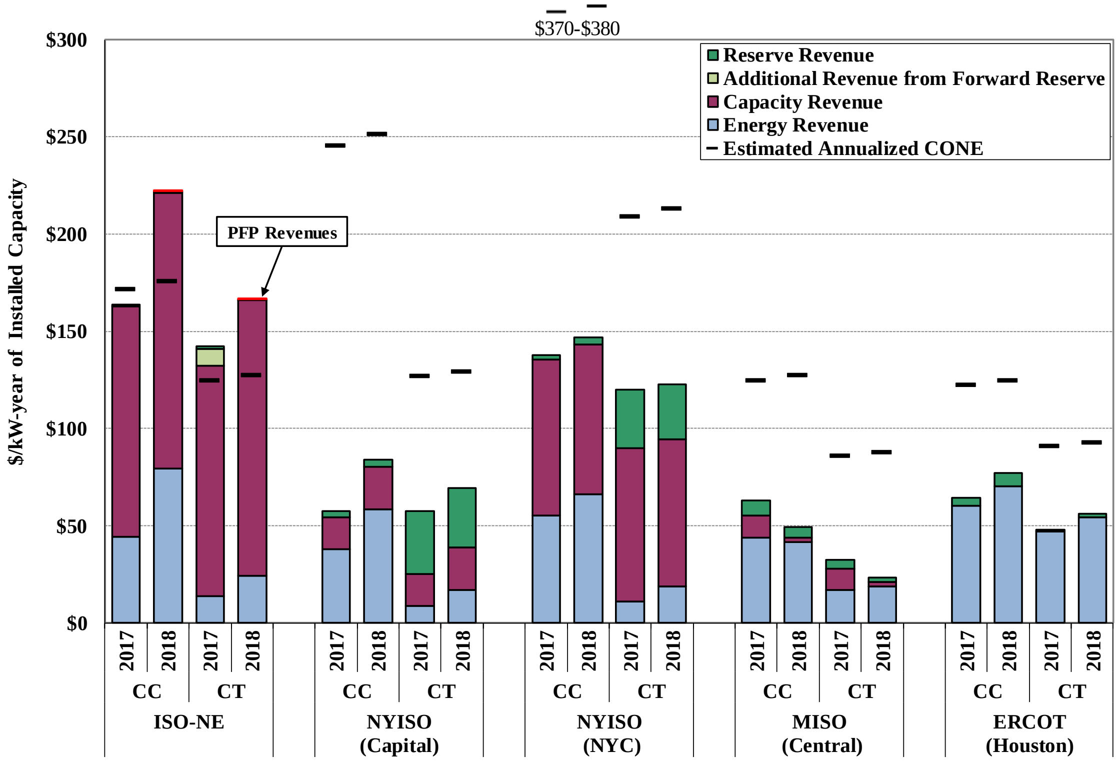
C. Long-Term Economic Signals

While price signals play an essential role in coordinated commitment and dispatch of units in the short term, they also provide long-term economic signals that govern investment and retirement decisions for generators and transmission. This section compares the long-term economic signals in ISO-New England to other markets by measuring the net revenue a new generating unit would have earned over the past two years.

Net revenue is the revenue a new unit would earn above its variable production costs if it ran when it was economic to run. A well-designed market should produce net revenue sufficient to support new investment when existing resources are not adequate to meet the system's needs. Figure 3 show estimated net revenues for a new combustion turbine (CT) and combined-cycle (CC) generator for the prior two years in New England and other RTO markets. For comparison, the figures also show the annual net revenue that would be needed for these new investments to be profitable (i.e., the "Cost of New Entry" or CONE).

Figure 3: Net Revenues Produced in ISO-NE and Other RTO Markets

2017 - 2018



This figure shows that Net Revenues provided by the ISO-NE markets increased substantially in 2018. As in most of the other RTO markets, the energy net revenues increased as natural gas prices increased and both types of new resources received higher inframarginal energy revenues. In addition to the energy revenues, the capacity net revenues increased substantially as capacity prices have increased. This increase in capacity revenues contributed to net revenues in New

England in 2018 that exceeded the entry costs for both types of new resources. However, several new resources have entered the market since FCA 10 (i.e. 2019/20) which resulted in a substantial drop in capacity prices. Hence, the total revenues of both types of hypothetical units may be lower than their in respective CONEs for future years.

This outcome in 2018 is unique to New England as none of the other RTO markets produced net revenues that were sufficient to cover the costs of investing in new combustion turbines or combined cycle resources. In New York, this outcome is attributable to the prevailing capacity surpluses. In MISO, this result is due to a poorly designed capacity market that prevents it from delivering efficient revenues, while ERCOT lacks a capacity market and did not experience the shortages in 2017 or 2018 that would be needed to incent new investment. In some areas such as New York and ERCOT, new entry by merchant generators has occurred despite relatively low net revenues. This can occur when a generation site benefits from some special competitive advantage, such as close proximity to a low-priced natural gas pipeline or when investors are particularly optimistic about future market conditions.

Resources in New England also benefit from a number of other revenue streams including PFP, Forward Reserve Markets, and compensation for enhancing reliability during winter months (e.g. Winter Reliability Program and the Interim Compensation for FCA 14 and FCA 15). Although, the total of such revenues was relatively small in 2017 and 2018, they could comprise an increasing share of revenues in future years as the ISO increases the PPR and designs additional products for enhancing energy security during winter months.

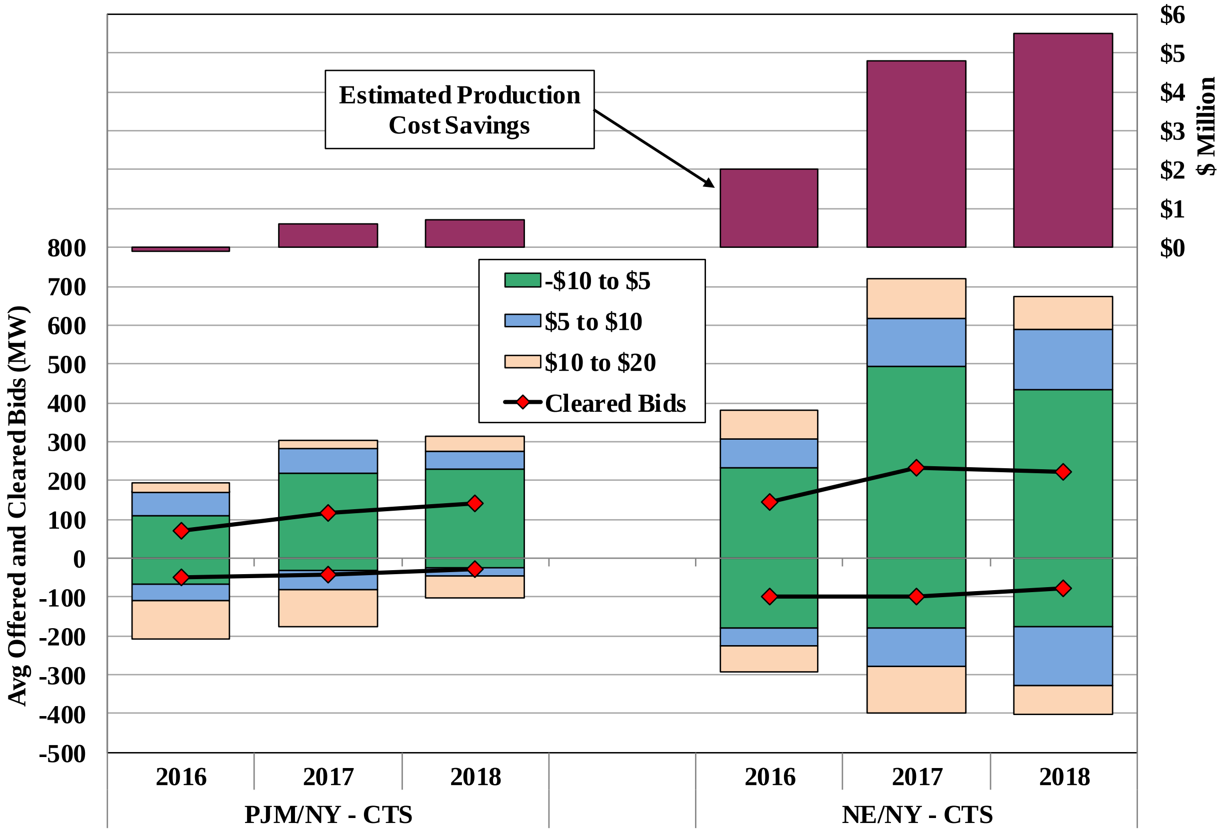
D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling ("CTS") is a market process whereby two neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS is very important because it allows the large interface between markets to be more fully utilized, which lowers costs and improves reliability in both areas. The benefits of CTS are likely to grow in the future as the addition of intermittent generation makes it more difficult for RTOs to balance supply and demand.

Figure 4 evaluates the overall efficiency of the CTS scheduling process between ISO-NE and the NYISO, compared to the CTS process between PJM and the NYISO. The bottom portion of the figure shows annual average quantities of price-sensitivity of CTS bids for three price ranges and schedules during peak hours (i.e., HB 7 to 22) from 2016 to 2018. Positive numbers indicate export bids from New England or PJM to New York and negative numbers represent import offers from New York to New England or PJM. The upper portion of the figure shows the market efficiency gains (and losses) from CTS, which is measured by production cost savings.[9]

The average amount of price-sensitive bids was significantly larger at the NE/NY interface than at the PJM/NY interface. In 2018, the amount of bids offered between $-10 and $10 per MWh averaged over 900 MW (including both import offers and export bids) at the NE/NY interface, more than double the amount at the PJM/NY interface. Likewise, the cleared bids in the same price range at the NE/NY interface nearly doubled the amount cleared at the PJM/NY interface. This has allowed more flow adjustments (in terms of both frequency and magnitude) at the NE/NY interface, contributing to much higher production cost savings.

Figure 4: CTS Scheduling and Efficiency
2016 - 2018



The difference between the two CTS processes is largely attributable to the large fees that are imposed at the PJM/NY interface while there are no substantial transmission charges or uplift

9 Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process. To estimate the adjustment in the interchange schedule attributable to the intra-hour CTS scheduling process, we compare the final CTS schedule to advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour.

charges on transactions at the NE/NY interface. Typically, the NYISO charges physical exports to PJM at a rate ranging from $4 to $8 per MWh, while PJM charges physical imports and exports a transmission rate and uplift allocation that averages less than $3 per MWh. These charges are a significant economic barrier to achieving the potential benefits from the CTS process, since large and uncertain charges deter participants from submitting efficient CTS offers. This is particularly evident from the fact that almost no CTS bids were offered at less than $5 per MWh from NYISO to PJM. This demonstrates that imposing substantial charges on low-margin trading activity has a dramatic effect on the liquility of the CTS process.

The estimated production cost savings from the CTS process between New England and New York increased from $2.0 million in 2016 to $5.5 million in 2018, indicating that the overall performance of this CTS process has improved notably over the past three years. In addition to increased price-sensitive bidding volumes over time, this improvement was also attributable to better price forecasting.

- ISO-NE forecast errors fell from 33 percent in 2016 to 20 percent in 2018, while NYISO forecast errors fell from 29 percent in 2016 to 24 percent in 2018.
- In contrast, price forecasting by PJM was the worst among the three ISOs in 2018, largely responsible for worse CTS performance at the PJM/NY interface.
- ISO-NE's price forecasting is more accurate partly because it forecasts a supply curve (with 7 points representing 7 different interchange levels at the interface), while PJM only forecasts a single price point at one assumed interchange level.

Despite the better performance at the NE/NY interface, the volume of price-sensitive CTS bids was still modest compared to the transfer capability of the interface. This is likely attributable to: (a) interchange ramp limitations, which prevent the interchange from changing by more than 300 MW at each quarter hour and (b) the risk that CTS transactions may be scheduled but be unprofitable because of forecast errors in the scheduling process. Thus, if the ISOs can improve the price forecasts that underlie the CTS prices, it should further improve both the quantity and the price-sensitivity of the CTS bids, and ultimately allow the process to achieve larger savings. Our evaluation of the price forecasting errors at the NE/NY interface indicated that:[10]

- Errors in load forecasting and wind forecasting were the largest contributor (23 percent).
- Differences in timing and ramp profiles between forecasting model and dispatch model were the second largest contributor (22 percent).
- Forced outages and poor dispatch performance by generators were the third largest contributor (15 percent).
- Other factors also made significant contributions collectively, but these had relatively small impacts individually.

10 See Section VI.C in our *2017 Assessment of the ISO New England Electricity Markets*.

Therefore, there is ample opportunity to improve the performance of the CTS process at the NE/NY interface. Nonetheless, it is important to note that the CTS process with NYISO is by far the best performing CTS that has been implemented to date (CTS process have been implemented between PJM and both NYISO and MISO). The primary reason the other CTS processes have performed poorly is that the CTS are allocated substantially costs and transmission charges. We applaud ISO-NE and NYISO for agreeing not to charge such fees to their CTS transactions. We will continue monitor the performance of CTS and evaluate factors that contribute to particularly large forecast errors.

II. Competitive Assessment of the Energy Market

This section evaluates the competitive performance of the ISO-NE energy market in 2018. Although LMP markets increase overall system efficiency, they may provide incentives for exercising market power in areas with limited generation resources or transmission capability. Most market power in wholesale electricity markets is dynamic, existing only in certain areas and under particular conditions. The ISO employs market power mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still important to evaluate the competitive structure and conduct in the ISO-NE markets because participants with market power may still have the incentive to exercise market power at levels that would not warrant mitigation.

Based on the analysis presented in this section, we identify the geographic areas and market conditions that present the greatest potential for market power abuse. We use a methodology for measuring and analyzing potential withholding that was developed in prior assessments of the competitive performance in the ISO-NE markets.[11] We address four main areas in this section:

- Mechanisms by which sellers exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding; and
- Market power mitigation.

A. Market Power and Withholding

Supplier market power can be defined as the ability to profitably raise prices above competitive levels. In electricity markets, this is generally done by economically or physically withholding generating resources. Economic withholding occurs when a resource is offered at prices above competitive levels to reduce its output or otherwise raise the market price. Physical withholding occurs when all or part of the output of a resource is not offered into the market when it is available and economic to operate. Physical withholding can be accomplished by "derating" a generating unit (i.e., reducing the unit's high operating limit).

While many suppliers can increase prices by withholding, not every supplier can profit from doing so. Withholding will be profitable when the benefit of selling its remaining supply at prices above the competitive level is greater than the lost profits on the withheld output. In other words, withholding is only profitable when the price impact exceeds the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it will have the ability and incentive to withhold resources to raise prices.

11 See, e.g., Section VIII, *2013 Assessment of Electricity Markets in New England*, Potomac Economics.

There are several additional factors (other than size) that affect whether a market participant has market power, including:

- The sensitivity of real-time prices to withholding, which can be very high during high-load conditions or high in a local area when the system is congested;
- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market;[12] and
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

When we evaluate the competitiveness of the market or the conduct of the market participants, we consider each of these factors, some of which are included in the analyses in this report.

B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand that affect market power. Market power is of greatest concern in areas where capacity margins are small, particularly in import-constrained areas. Hence, this subsection analyzes the three main import-constrained regions and all New England using the following structural market power indicators:

- Supplier Market Share - The market shares of the largest suppliers determine the possible extent of market power in each region.
- Herfindahl-Hirschman Index ("HHI") - This is a standard measure of market concentration calculated by summing the square of each participant's market share.
- Pivotal Supplier Test - A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices by raising its offer prices or by physically withholding.

The first two structural indicators focus exclusively on the supply side. Although they are widely used in other industries, their usefulness is limited in electricity markets because they ignore that the inelastic demand for electricity substantially affects the competitiveness of the market.

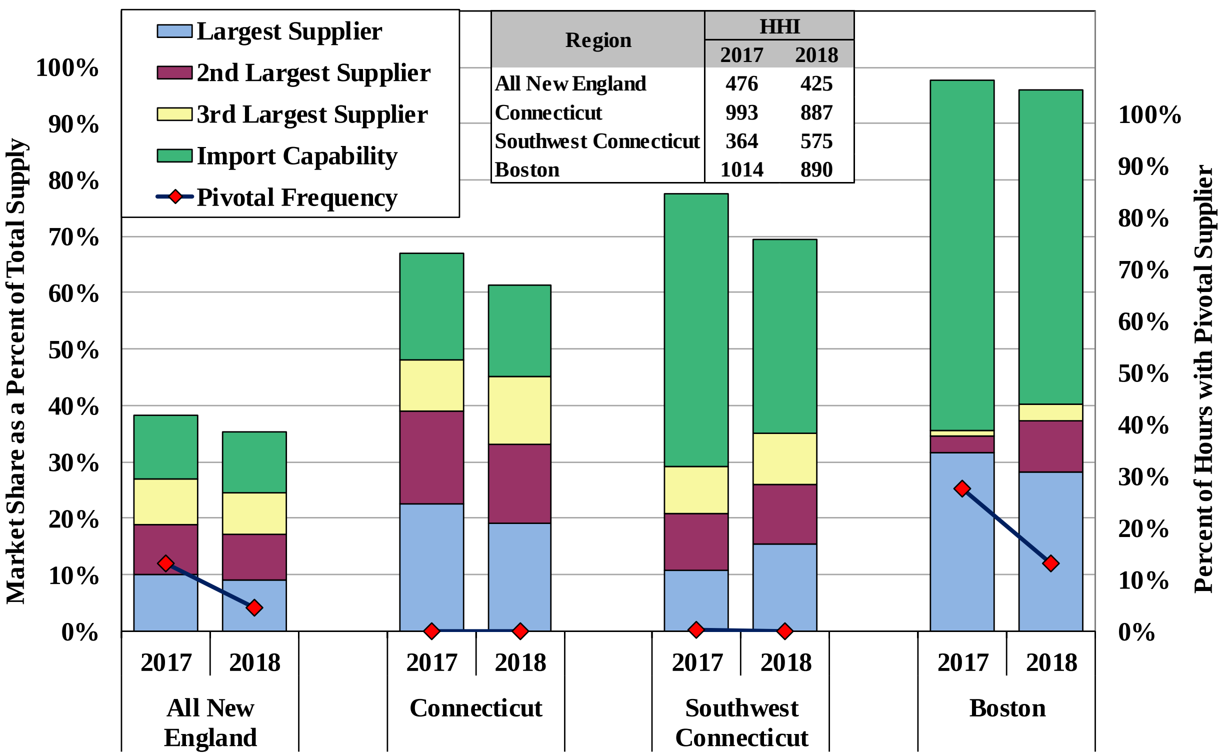
The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of energy markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on the size of the supplier as well as the amount of excess supply (above the demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to substantial market power abuse. This does not mean that all pivotal suppliers should be deemed to have market power. Suppliers must have both the ***ability*** and ***incentive*** to raise prices in order to have market power. A supplier must also be able to foresee when it will

12 When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive still exists because spot prices will eventually affect prices in the forward market.

be pivotal to exercise market power. In general, the more often a supplier is pivotal, the easier for it to foresee circumstances when it can raise clearing prices. For the supplier to have the incentive to raise prices, it must have other supply that would benefit from higher prices.

Figure 5 shows the three structural market power indicators for each of the four regions in 2017 and 2018. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in the stacked bars.[13,14] The remainder of supply to each region comes from smaller suppliers. The inset table shows the HHI for each region. We assume imports are highly competitive so we treat the market share of imports as zero in our HHI calculation. The red diamonds indicate the portion of hours where one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they typically cannot ramp down substantially and would be costly to withhold due to their low marginal costs.

Figure 5: Structural Market Power Indicators
2017 – 2018



Region	HHI	
	2017	2018
All New England	476	425
Connecticut	993	887
Southwest Connecticut	364	575
Boston	1014	890

13 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability("SCC"), available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/seson-claim-cap. In this report, we use the generator summer capability in the July SCC reports from each year.

14 The import capability shown is the transmission limit from the latest Regional System Plan, available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp. The Base Interface Limit (or Capacity Import Capability) is used for external interfaces, and the N-1-1 Import Limits are used for the reserve zone.

Figure 5 indicates that market concentration of internal generation increased in Southwest Connecticut from 2017 to 2018 but fell in other three regions. This was driven primarily by new market entry and ownership changes for the largest suppliers. Two new combined cycle power plants, the CPV Towantic plant and the Footprint plant, came into full service in mid-2018, adding roughly 800 MW of generating capacity in Southwest Connecticut and 700 MW in Boston. Both facilities were managed by the same lead market participant, who became one of the three largest suppliers in 2018. On the other hand, the portfolio sizes of the three largest suppliers in 2017 all decreased (by varying amounts) and two of them were no longer among the top three suppliers in 2018. As a result, the collective market share of the three largest suppliers in all New England fell modestly from roughly 27 percent in 2017 to less than 25 percent in 2018. In Boston, the largest supplier's share also decreased.

The figure also shows variations in the number of suppliers with large market shares across the four areas. In 2018, Boston had one supplier with a large market share of 28 percent, while all New England has three suppliers with market shares of less than 10 percent each. Import capability accounts for a significant share of total supply in each region (ranging from 11 percent in all New England to 56 percent in Boston), so the market concentration (measured by the HHI) was relatively low, well under 1000 in all of the four areas. In general, HHI values above 1800 are considered highly concentrated by the U.S. Antitrust Agencies and the FERC for purposes of evaluating the competitive effects of mergers. However, this does not establish that there are no market power concerns. These concerns are most accurately assessed in our pivotal supplier analysis for 2018, which indicates that:

- In Southwest Connecticut and Connecticut, there were very few hours (< 0.5 percent) when a supplier was pivotal in 2018.
- In Boston, one supplier owned nearly 65 percent of the internal capacity, but was pivotal in just 13 percent of hours in 2018. This underscores the importance of import capability into constrained areas in providing competitive discipline; and
- In all New England, at least one supplier was pivotal in 5 percent of hours in 2018.[15]

The pivotal frequency fell in Boston because of the new entry of the Footprint power plant, which led to less frequent commitments of the Mystic facilities in the portfolio of the largest supplier in Boston. In addition, the Greater Boston Reliability Project made significant progress in the last two years. Planned transmission outages, which were needed for these transmission upgrades, were less frequent in the Boston area during 2018. Completed transmission upgrades

15 The pivotal supplier results are conservative for "All New England" compared to those evaluated by the IMM (see their 2018 SOM report, Section 3.7.3) primarily because of our differences in: (a) treatment of portfolios with nuclear generation; (b) assumptions about supply availability; and (c) frequency of pivotal evaluation. See the memo, "Differences in Pivotal Supplier Test Results in the IMM's and EMM's Annual Market Assessment Reports", NEPOOL Participants Committee Meeting, December 7, 2018.

also helped increase import capability into the area.[16] As a result, the supplier in Boston was pivotal less frequently in spite of higher load levels in 2018.

The pivotal frequency decreased in all New England as well. This resulted largely from new entry and ownership changes for the largest suppliers mentioned above. Other key contributing factors included:

- The availability of pumped-storage hydro generation increased in 2018 relative to 2017 because of fewer generation outages;
- Net imports from New York rose noticeably; and
- Price-responsive demand resources started to participate in the energy market in June 2018, satisfying a significant portion of reserve requirements.

Taken together, these led the supplier to be pivotal much less frequently in 2018.

In spite of the reduction in pivotal frequency, the results in Boston and all New England still warrant further review to identify potential withholding by suppliers in these regions. This review is provided in the following section, which examines the behavior of pivotal suppliers under various market conditions to assess whether the conduct has been consistent with competitive expectations.

C. Economic and Physical Withholding

Suppliers that have market power can exercise it by economically or physically withholding resources as described above. We measure potential economic and physical withholding by using the following metrics:

- Economic withholding: we estimate an "output gap" for units that produce less output because they have raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit.[17] This may overstate the potential economic withholding because some of the offers included in the output gap may reflect legitimate supplier responses to operating conditions, risks, or uncertainties.
- Physical withholding: we analyze short-term deratings and outages because they are most likely to reflect attempts to physically withhold resources because it is generally less costly to withhold a resource for a short period of time. Long-term outages typically result in larger lost profits in hours when the supplier does not have market power.

16 The N-1-1 import capability into Boston is expected to increase by more than 400 MW upon the completion of the Greater Boston Reliability Project in mid-2019.

17 To identify clearly economic output, the supply's competitive cost must be less than the clearing price by more than a threshold amount - $25 per MWh for energy and 25 percent for start-up and no load costs.

The following analysis shows the output gap results and physical deratings relative to load and participant characteristics. The objective is to determine whether the output gap and/or physical deratings increase when factors prevail that increase suppliers' ability and incentive to exercise market power. This allows us to test whether the output gap and physical deratings vary in a manner consistent with attempts to exercise market power.

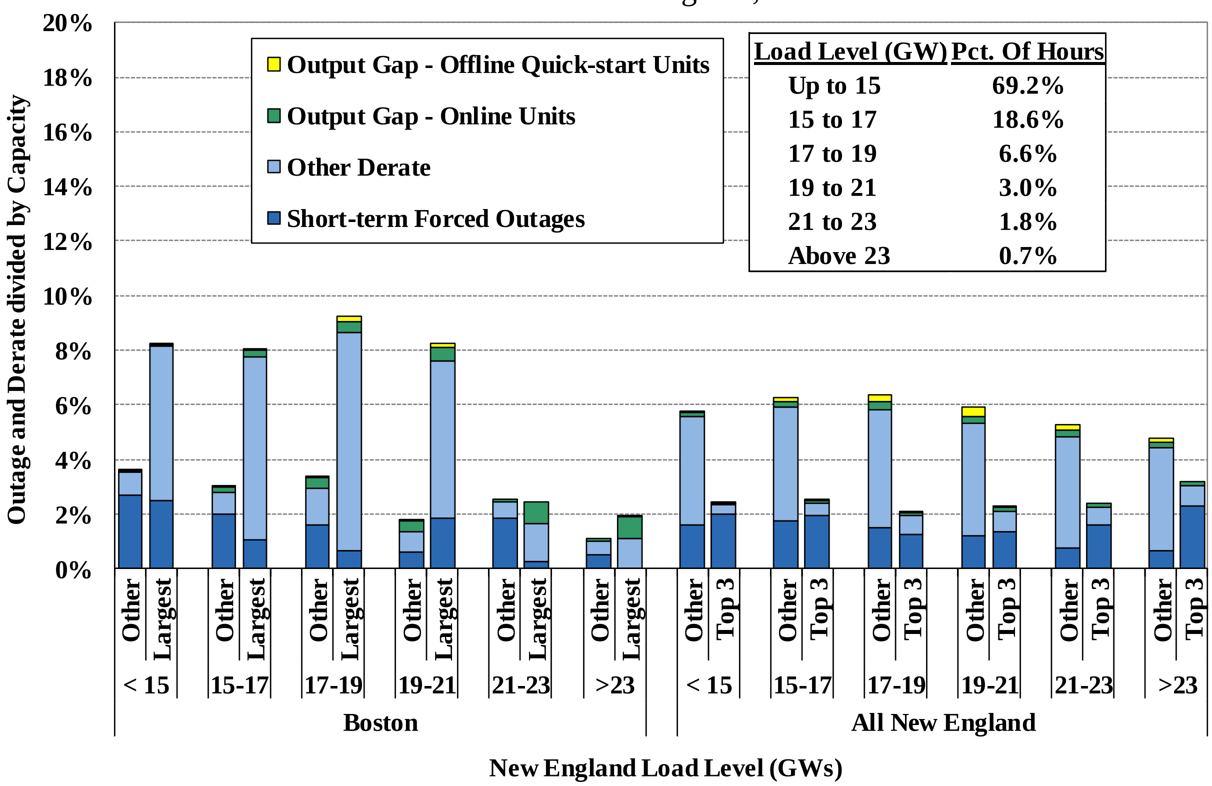
Because the pivotal supplier analysis raises competitive concerns in Boston and all New England, Figure 6 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for:

- Offline quick-start units that would have been economic to commit in the real-time market (considering their commitment costs); and
- Online units that can economically produce additional output.

Our physical withholding analyses focus on:

- Short-term forced outages that typically last less than one week; and
- "Other Derates" that includes reductions in the hourly capability of a unit that is not logged as a forced or planned outage. The "Other Derates" can be the result of ambient temperature changes or other legitimate factors.

Figure 6: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2018



The figure above shows the supplier's output gap and physical deratings as a percentage of its portfolio size in Boston and all New England by load level. In Boston, we compare these statistics for the largest supplier, who owned roughly 65 percent of internal generating capacity in 2018, to all other suppliers in the area. In all New England, we compare the three largest suppliers, who collectively owned roughly 25 percent of internal generating capacity in 2018, to all other suppliers.

In Boston, as was seen in the prior years, the amount of "Other Derate" in the largest supplier's portfolio was notably higher during low load periods. This was because its combined-cycle capacity was frequently offered and operated in reduced configuration during these periods (e.g., overnight hours). This is generally efficient and does not raise significant competitive concerns..

Excluding the contributions of the "Other Derates" in Boston for the reasons described above, Figure 6 shows that the overall output gap and deratings were not significant as a share of the total capacity in both Boston and all New England. The total amount of output gap and deratings generally fell as load levels increased to the highest levels, which is a good indication that suppliers tried to make more capacity available when the capacity needs were the highest. In addition, the largest suppliers and other smaller suppliers in each region exhibited comparable levels of overall output gap and deratings, particularly at higher load levels when prices are most sensitive to potential withholding. The output gap continues to be very low across a wide range of conditions.

Overall, these results indicate that the energy market performed competitively in 2018 and did not raise significant concerns about withholding to raise market clearing prices.

D. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when it is workably competitive. The ISO-NE applies a conduct-impact test that can result in mitigation of a participant's supply offers (i.e., incremental energy offers, start-up and no-load offers). The mitigation measures are only imposed when suppliers' conduct exceeds well-defined conduct thresholds above a unit's reference levels and when the effect of that conduct on market outcomes exceeds well-defined market impact thresholds. This framework prevents mitigation when it is not necessary to address market power, while allowing high prices during legitimate periods of shortage.

The market can be substantially more concentrated in import-constrained areas, so more restrictive conduct and impact thresholds are employed in these areas than market-wide. The ISO has two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules are applied: [18]

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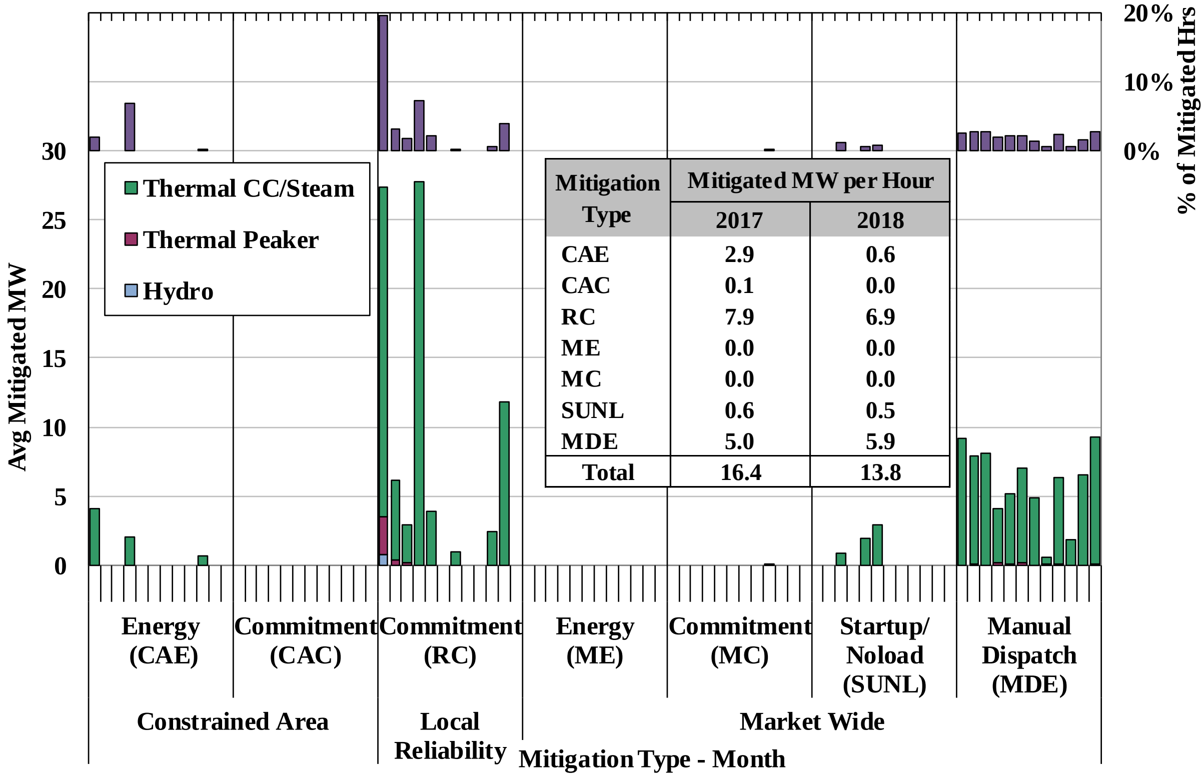
18 See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

- Market-Wide Energy Mitigation (“ME”) – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant.
- Market-Wide Commitment Mitigation (“MC”) – MC mitigation is applied to any resource whose Market Participant is determined to be a pivotal supplier.
- Constrained Area Energy Mitigation (“CAE”) – CAE mitigation is applied to resources in a constrained area.
- Constrained Area Commitment Mitigation (“CAC”) – CAC mitigation is applied to a resource that is committed to manage congestion into a constrained area.
- Local Reliability Commitment Mitigation (“RC”) – RC mitigation is applied to a resource that is committed or kept online for local reliability.
- Start-up and No-load Mitigation (“SUNL”) – SUNL mitigation is applied to any resource that is committed in the market.
- Manual Dispatch Mitigation (“MDE”) – MDE mitigation is applied to resources that are dispatched out of merit above their Economic Minimum Limit levels.

There are no impact tests for the SUNL mitigation, the MDE mitigation, and the three types of commitment mitigation (i.e., MC, CAC, and RC), so suppliers are mitigated if they fail the conduct test in these five categories. This is reasonable because this mitigation is only applied to uplift payments, which usually rise as offer prices rise, so, in essence, the conduct test is serving as an impact test as well for these categories. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour.

Figure 7 examines the frequency and quantity of mitigation in the real-time energy market. Any mitigation changes made after the automated mitigation process were not included in this analysis (because these constitute a very small share of the overall mitigation). The upper portion of the figure shows the portion of hours affected by each type of mitigation. If multiple resources were mitigated during the same hour, only one hour was counted in the figure. The lower portion of the figure shows the average mitigated capacity in each month (i.e., total mitigated MWh divided by total numbers of hours in each month) for each type of mitigation and for three categories of resources: hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the annual average amount of mitigation for each mitigation type between 2017 and 2018.

Figure 7: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2018



Mitigation Type	Mitigated MW per Hour	
	2017	2018
CAE	2.9	0.6
CAC	0.1	0.0
RC	7.9	6.9
ME	0.0	0.0
MC	0.0	0.0
SUNL	0.6	0.5
MDE	5.0	5.9
Total	16.4	13.8

Roughly 92 percent of all mitigation was for either local reliability commitment or manual dispatch energy. Both typically occurred more frequently during the shoulder months because of higher local reliability needs that were often caused by planned transmission outages. The high proportion of mitigation in these categories is expected because local reliability areas raise the most significant potential market power concerns and are mitigated under the tightest thresholds. In general, these two categories of mitigation only affect NCPC payments and have little impact on energy or ancillary service prices.

Although local reliability mitigation has the tightest threshold (10 percent) among all types of mitigation, it is not fully effective because suppliers sometimes have the latitude and incentive to operate in a more costly mode and receive larger NCPC payments as a result. For example, combined-cycle units needed for reliability that can offer in a multi-turbine configuration or in a single-turbine configuration often do not offer in the single-turbine configuration when they are likely to be needed for local reliability. By offering in a multi-turbine configuration, these units receive higher NCPC payments. Likewise, generators are sometimes not required to burn the lowest-cost fuel – e.g., a substantial amount of NCPC was paid in 2018 to a unit that usually burned oil when natural gas was much less expensive. We discuss the two issues in more detail in Section III and continue to recommend that the ISO consider tariff changes that would expand its authority to address these issues.

The amount of non-local-reliability mitigation has been low in recent years because the hourly offer market enhancement that was implemented in December 2014 has allowed suppliers to more accurately reflect their fuel costs (or opportunity costs) on an hourly basis and in a more timely manner. This has improved not only the competitiveness of supply offers but also the accuracy of the mitigation, particularly for:

- Energy limited hydro resources, whose costs are almost entirely opportunity costs (the trade-off of producing more now and less later). These costs are generally difficult to accurately reflect.
- Oil-fired resources, which become economic when gas prices rise above oil prices, but have limited on-site oil inventory. The suppliers may raise their offer prices to conserve the available oil in order to produce during the periods with potentially the highest LMPs.
- Gas-fired resources during periods of tight gas supply. Volatile natural gas prices, particularly in the winter, create uncertainty regarding fuel costs that can be difficult to reflect accurately in offers and reference levels. The uncertainty is increased by the fact that offers and reference levels must be determined by 2 pm on the prior day.

To supplement this improvement in offer flexibility, reference level adjustments should be made as necessary to account for the opportunity costs associated with these types of energy limitations. Appropriately recognizing opportunity costs in resources' reference levels reduces the potential for inappropriate mitigation of competitive offers, helps the region conserve limited fuel supplies, and improves the overall efficiency of scheduling for fuel-limited resources.

We examined market outcomes during the cold spell in the 2017/18 winter to evaluate whether the lack of appropriate opportunity costs in the reference prices had significantly affected efficient market outcomes. We found that:

- There were very few resources that appeared to be limited by the market power mitigation thresholds because of low reference levels. We reviewed offers from the resources with tight oil inventories and found only one resource that appeared to offer just below one of the thresholds (which was also postured by the ISO on several occasions during the cold spell); and
- No resources were mitigated when economically committed or dispatched during the cold spell.

These observations suggest that while the reference levels may have been under-stated, there was a limited impact on market outcomes. Nonetheless, ISO-NE has recognized the issue and developed a model to estimate an opportunity cost for oil-fired and dual-fuel generators with short-term fuel supply limitations to include in their reference prices. The opportunity cost is calculated in a way consistent with profit-maximizing with limited fuel supply over a rolling seven-day period. This has been effective since December 2018, but the 2018/19 winter was relatively mild. Consequently, the use of oil was substantially lower in the 2018/19 winter and there was sufficient oil inventory throughout the winter. Therefore, the effectiveness of the opportunity cost estimator has not yet been challenged by tight market conditions. Nonetheless, this reference calculation enhancement should help address fuel security issues that ISO-NE faces by allowing generators to conserve fuel more effectively with their offers in the future.

E. Competitive Performance Conclusions

The pivotal supplier analysis suggests that structural market power concerns diminished noticeably in Boston and in all New England in 2018, driven largely by the new market entry of roughly 1.5 GW of combined cycle generating capacity, ownership changes for the largest suppliers, and transmission upgrades in Boston. Our analyses of potential economic and physical withholding also find that the markets performed competitively with no significant evidence of market power abuses or manipulation in 2018.

In addition, we find that the market power mitigation rules have generally been effective in preventing the exercise of market power in the New England markets. The automated mitigation process helps ensure the competitiveness of market outcomes by mitigating attempts to exercise market power in the market software before it can affect the market outcomes. To ensure competitive offers are not mitigated, generators can proactively request reference level adjustments when they experience input cost changes due to fuel price volatility. Hourly offers enable generators to modify their offers to reflect changes in their marginal costs and for the ISO to set reference levels that properly reflect these costs.

The ISO has implemented a procedure to calculate an opportunity cost for oil-fired and dual-fuel generators with limited fuel inventories to be incorporated in their reference prices. This enhancement should lead to more efficient scheduling of energy-limited resources. However, its effectiveness was not truly tested because of relatively mild winter conditions. We will continue monitor this and evaluate how the opportunity cost estimator performs particularly under prolonged severe winter weather conditions.

Nonetheless, we find one area where the mitigation measures may not have been fully effective. This relates to resources that are frequently committed for local reliability. Although the mitigation thresholds are tight for these resources, the suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payments as a result. Hence, we recommend the ISO to consider changes that would address this concern.

III. Causes and Allocation of NCPC Charges

When resources are scheduled at clearing prices that produce market revenues that are less than their full as-bid costs, ISO-NE provides an NCPC payment to cover the revenue shortfall. Although the overall size of NCPC payments are small relative to the overall New England wholesale market, NCPC payments are important because they usually occur when the market requirements are not fully aligned with the system's reliability needs or prices are otherwise not fully efficient. Additionally, sustained levels of NCPC can distort the market participants' incentives. Thus, we evaluate the causes of NCPC payments to identify potential inefficiencies.

Like other wholesale electricity markets, the ISO-NE uses a uniform price auction to coordinate the scheduling of resources. The profit-maximizing offer of a competitive supplier in a uniform price auction is its short-run marginal cost, which it can determine without having to make predictions of market clearing prices. In some cases, however, NCPC payments provide incentives for suppliers to raise their offer prices above short-run marginal cost to increase their payments.

Most NCPC payments occur when an operating requirement is not fully reflected in the market's requirements and must therefore be satisfied by scheduling a resource outside of the market. The cost of this action will be reflected in NCPC payments rather than in market-clearing prices. Ultimately, this undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short-term and investment and retirement decisions in the long-term.

Additionally, intermittent renewable generation will likely become more prevalent over the coming decade, which will increase the value of flexible resources. NCPC payments do not provide efficient incentives because they generally reward resources for being high-cost and inflexible. Hence, NCPC payments tend to shift investment incentives away from flexible resources at locations that would bolster transmission security and reliability.

This section evaluates the causes of NCPC charges in 2018 and discusses implications for market efficiency, divided into subsections that address the following topics:

- Comparison of uplift charges and allocations in ISO-NE versus other markets;
- Primary drivers of day-ahead NCPC charges;
- Local second contingency protection requirements that lead to day-ahead NCPC charges;
- System-level operating reserve requirements that lead to day-ahead NCPC charges;
- Discussion of significant drivers of real-time NCPC charges; and
- Summary of conclusions and recommendations.

A. Cross-Market Comparison of Uplift Charges and Cost Allocation

Before discussing the causes and implications of various classes of NCPC costs (generally referred to as "uplift" costs industry-wide), it is useful to place ISO-NE's NCPC charges in context. Table 1 shows its total day-ahead and real-time NCPC charges over the past three years, and the comparable 2018 uplift charges for the NYISO and the MISO. Because the size of the ISOs varies substantially, the table also shows these costs per MWh of load. Recognizing that some RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real-time, the table includes a sum of all day-ahead and real-time uplift at the bottom to facilitate cross-market comparisons.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2016	2017	2018	2018	2018
Real-Time Uplift						
Total	**Local Reliability ($M)**	$1	$1	$4	$23	$3
	Market-Wide ($M)	$27	$23	$40	$19	$78
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.04	$0.14	$0.004
	Market-Wide ($/MWh)	$0.22	$0.19	$0.32	$0.12	$0.11
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$31	$15	$14	$31	$22
	Market-Wide ($M)	$13	$13	$12	$4	$17
Per MWh of Load	**Local Reliability ($/MWh)**	$0.25	$0.12	$0.11	$0.19	$0.03
	Market-Wide ($/MWh)	$0.10	$0.11	$0.10	$0.03	$0.03
Total Uplift						
Total	**Local Reliability ($M)**	$33	$16	$18	$54	$25
	Market-Wide ($M)	$40	$36	$52	$23	$95
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.26**	**$0.13**	**$0.15**	**$0.33**	**$0.04**
	Market-Wide ($/MWh)	**$0.32**	**$0.29**	**$0.42**	**$0.14**	**$0.14**
	All Uplift ($/MWh)	**$0.58**	**$0.42**	**$0.57**	**$0.48**	**$0.17**

The table shows that ISO-NE incurs more uplift costs, adjusted for its size, than the other two markets. Most of these higher uplift costs are associated with ISO-NE's market-wide needs. In 2018, ISO-NE's market-wide NCPC uplift was roughly triple the costs per MWh incurred by NYISO or MISO in 2018. Most of the increase was attributable to the cold spell in the first week of January, which accounted for nearly 25 percent of all NCPC uplift in 2018. Excluding this one-week period, market-wide NCPC uplift would have been comparable to the costs in 2017.

Even excluding the effects of the cold spell in early 2018, however, the market-wide uplift costs are significantly higher than comparable costs in other RTOs. The higher market-wide costs are partly because ISO-NE's fuel costs tend to be higher than the other RTO's, which generally leads to higher required make-whole payments. However, higher fuel costs are only one of the important drivers. We discuss the other drivers of these uplifts in subsections B and E.

Table 1 also shows that local reliability NCPC uplift fell notably in the last two years. This was driven primarily by reduced supplemental commitments in the Boston area because of:

- The transmission upgrades (i.e., the Greater Boston Reliability Project), which have increased the import capability into the Boston load pocket; and
- The new entry of the 700 MW Footprint combined-cycle plant.

These factors have greatly reduced the ISO's reliance on the Mystic generating units which were previously committed frequently to maintain reliability in the Boston area. Uplift for local reliability is smaller than in the NYISO, where generation must be committed for local second contingency protection in New York City. However, local reliability uplift is smaller in the MISO where few areas require commitment for local second contingency protection.

In addition to the differences in the magnitude of the uplift costs, the allocation of the uplift costs also vary substantially among the RTOs. ISO-NE allocated approximately half real-time NCPC charges to real-time deviations, including virtual transactions. This has resulted in higher costs incurred by virtual transactions in New England than in other RTO markets.

In organized wholesale power markets, virtual trading plays a key role in the day-ahead market by providing liquidity and improving price convergence between day-ahead and real-time markets. However, we have observed relatively low levels of virtual trading in ISO-NE compared to other markets we monitor, which we attribute primarily to the allocation of relatively large NCPC charges (per MWh) to virtual transactions, virtual load in particular.

Table 2 shows the average volume of virtual supply and demand that cleared the three eastern RTOs we monitor as a percent of total load, as well as the gross profitability of virtual purchases and sales. Gross profitability is the difference between the day-ahead and real-time energy prices used to settle the energy that was bought or sold by the virtual trader. The gross profitability does not account for uplift costs allocated to virtual transactions, which are shown separately.

Table 2: Scheduled Virtual Transaction Volumes and Profitability

Market	Year	Virtual Load		Virtual Supply		Uplift
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	Charge Rate
ISO-NE	2016	1.3%	$1.70	2.0%	$1.94	$1.25
	2017	2.2%	$1.98	3.6%	$2.71	$0.81
	2018	2.7%	$1.10	4.5%	$2.69	$0.94
NYISO	2018	5.7%	$1.54	12.3%	-$0.35	< $0.1
MISO	2018	9.8%	-$0.31	9.8%	$1.90	$0.64

Table 2 shows that virtual trading generally improved price convergence between the day-ahead and real-time markets in ISO-NE because it was generally profitable. The average volume of cleared virtual transactions has increased gradually in recent years, which was due largely to reduced uplift charges to real-time deviations over the period. In spite of the increase, the virtual trading levels were still substantially lower than the levels observed in both the NYISO and the MISO. In 2018, the gross volume of cleared virtuals (including both virtual load and virtual supply) averaged roughly 7 percent of load in the ISO-NE market, compared to 18 percent in the NYISO market and nearly 20 percent in the MISO market.

Most of the differences shown in the table between ISO-NE and the other RTOs continue to be attributed to ISO-NE's NCPC allocation methodology, which raises significant concerns. In spite of the decrease in recent years, the NCPC charges remain higher and more uncertain than the charges imposed by the other RTOs. This provides a substantial disincentive for firms to engage in virtual trading because virtual profits tend to be small relative to day-ahead and real-time prices. Ultimately, this reduces liquidity in the day-ahead market and explains why the gross profitability of virtual transactions is larger in ISO-NE than the other RTOs (i.e., the day-ahead and real-time prices are not as well arbitraged).

This may become a more substantial concern in the future. The ISO is currently considering a market design improvement, a Multi-Day Ahead Market, to address energy security concerns.[19] Virtual trading will play a essential role in aligning prices in the multi-day ahead market with the prices in the real-time market. Hence, we continue to recommend the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would involve not allocating NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC.

B. Drivers of Day-Ahead NCPC Charges

Day-ahead NCPC charges are incurred when a resource is scheduled in the day-ahead market, but the revenues it receives from selling energy are not sufficient for it to recoup its as-offered start-up, no-load, and incremental costs. In addition to clearing day-ahead bids and offers in the day-ahead market, ISO-NE also commits resources in the day-ahead market to satisfy all of its forecasted reliability needs for the following day. Thus, most NCPC charges for local reliability commitments are incurred in the day-ahead market rather than the real-time market (as is the case for most other RTOs).

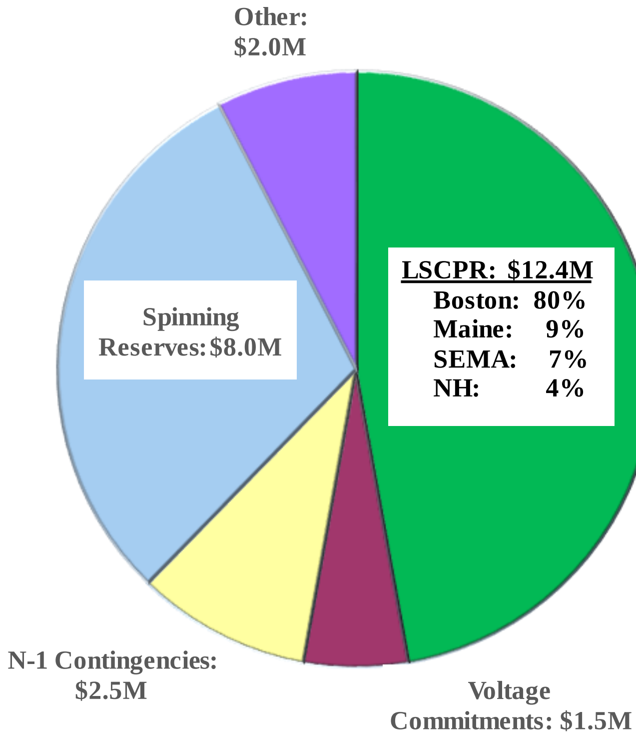
Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after the day-ahead market clears because reliability commitments affect which resources should be committed economically in the day-ahead market. For example, if a 400 MW generator must be committed for reliability in a particular load pocket, the generator also helps satisfy demand

19 See ISO Discussion Paper "Energy Security Improvements", April 2019.

throughout the system so it will likely reduce the amount of resources that are economic to commit outside the load pocket.

To summarize the causes of day-ahead NCPC, Figure 8 shows NCPC charges in 2018 incurred for the following reasons: local second contingency protection, voltage support, local single contingency protection, system-level reserve requirement, and other.[20] The figure also provides regional subtotals for local second contingency protection.

Figure 8: Summary of Day-Ahead NCPC Charges by Category
2018



The largest contributor to NCPC charges in the day-ahead market is commitments to satisfy local second contingency requirements, primarily in Boston. The next largest contributor is commitments to satisfy system-level ten-minute spinning reserve requirements. The market effects of these commitments are analyzed later in this section – local second contingency commitments are evaluated in Subsection C, and commitments for system-level ten-minute spinning reserves are evaluated in Subsection D.

20 *Local second contingency protection resources* are committed to maintain sufficient reserves to protect an area in case the two largest contingencies were to occur in a 30-minute period. *Voltage support resources* are committed to maintain local voltage or resolve a reactive power requirement. *Local first contingency protection resources* are committed to maintain transmission security in case a contingency was to occur unexpectedly. *System-level reserve requirements* are defined for TMSR, TMNSR, and TMOR, and resources may be committed to satisfy those requirements in the day-ahead market.

One notable factor that leads to inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges is that some combined-cycle generators are offered in a multi-turbine configuration even though they are able to operate the turbines individually. In many cases, the reliability requirement could be satisfied with the commitment of a single turbine configuration, so needlessly committing the multi-turbine configuration displaces other more efficient generating capacity. Multi-turbine combined-cycle commitments accounted for:

- More than 50 percent of the capacity committed for local reliability in the day-ahead market in 2018; and
- Roughly 60 percent of day-ahead local second contingency NCPC payments.

We evaluate the market effects of these excess commitments in 2018 in Subsection C.

C. Day-Ahead Commitment for Local Second Contingency Protection

The ISO commits resources for local second contingency protection needs in the day-ahead market. The purpose of these commitments is to ensure that ISO-NE can reposition the system in key areas to be able to respond to the second largest system contingency after the largest contingency has occurred.

While these commitments may be justified from a reliability perspective, they can lead to inefficient prices in the local area for two reasons:

- First, the units receiving NCPC payments systematically receive more revenues than lower-cost resources.
- Second, the costs of these resources will not be reflected in the prices of the operating reserves that are also satisfying the underlying reliability requirement.

These two issues distort economic incentives in favor of high-cost units with less flexible characteristics because, all else equal, they receive higher revenue than lower-cost more flexible units. Hence, when local NCPC is substantial, it is important to identify the underlying causes and consider market reforms as needed to improve the efficiency of prices for energy and operating reserves in local areas.

These concerns are sometimes exacerbated by two other issues that can lead to excess commitment for local second contingency protection.

- First, the day-ahead commitment software does not model the full set of energy and operating reserve requirements, particularly when the commitment of a large unit will alter one of the contingencies for which the software is scheduling. The ISO represents these factors indirectly in the day-ahead commitment logic, but this does not minimize costs because the procurement of operating reserves is not co-optimized with energy.
- Second, some generators that are committed for local second contingency protection offer as a multi-turbine group, requiring the ISO to commit multiple turbines when one turbine would be sufficient.

Of capacity that was committed by the day-ahead market model for local second contingency protection in Boston in 2018, we estimate that roughly 60 percent of the capacity would not have been needed to satisfy the local second contingency requirements modeled in the day-ahead market if energy and operating reserves had been co-optimized with the requirement.[21]

The ISO could avoid excess commitment by: (a) implementing ancillary services markets that are co-optimized with energy in the day-ahead market, and (b) modifying its tariff to require capacity suppliers to offer multiple unit configurations to allow the ISO to commit just one turbine at a multi-turbine group. Not only would these changes result in production cost savings and more efficient prices for energy and reserves as discussed above, but they would also improve market incentives for reliable performance, flexibility, and availability under a wide range of conditions—not just operating reserves shortages. Directing more revenue to generators that have these characteristics would shift investment accordingly and reduce reliance on the capacity market for attracting investment to local areas.

Finally, satisfying these local requirements through a day-ahead operating reserve market should substantially reduce the need to commit resources out-of-market in the local areas that currently receive sizable NCPC payments. These NCPC payments provide adverse fuel procurement incentives. Under the market power mitigation rules, a generator that is committed for reliability can make more money by operating on a more expensive fuel because the relevant offer cap is calculated as a percentage over the generator's estimated cost.[22] For example, one dual-fuel generator in Boston operated on fuel oil for 19 days in 2018 when natural gas was less expensive than fuel oil.[23] Enforcing a requirement that generators committed for reliability burn the most economic fuel will reduce the frequency of commitments that require substantial NCPC payments. Ultimately, this will improve price signals for energy and reserves, and lower costs for the ISO's customers.

D. Day-Ahead Commitment for System Level Operating Reserve Requirements

As discussed in Subsection B, the day-ahead market software commits sufficient resources to satisfy system-level operating reserve requirements in addition to energy schedules. However, these reserve requirements are not enforced in the day-ahead market pricing software because ISO-NE currently does not have day-ahead reserve markets. Consequently, generators are

21 Note, this evaluation considered only local second contingency protection commitments in Boston that were made by the day-ahead market's commitment software, but it does not include commitments that were determined by operations before the day-ahead market. When interpreting these results, it is also important to consider that local second contingency protection units might still have been committed for another constraint even if they were not needed specifically to satisfy the minimum capacity requirement for the local area.

22 See Section III.A.5.5.6.2. of the ISO Tariff.

23 See EPA Air Markets Program Data at https://ampd.epa.gov/ampd/.

frequently committed in the day-ahead market to satisfy operating reserve requirements, but the clearing prices of energy (and reserves) are understated because they do not reflect the costs of satisfying the reserve requirements. We estimate that:

- Additional generating capacity was committed to satisfy the system-level 10-minute spinning reserve requirement in approximately 3,900 hours in 2018.[24]
- Pricing these operating reserve requirements in the day-ahead market would provide efficient compensation for resources providing ten-minute spinning reserves.

Setting more efficient prices for energy and spinning reserves would provide better incentives for reliable performance, flexibility, and availability. This will become increasingly important as the penetration of intermittent renewable generation increases over the coming decade. Under-compensating generators that have flexible characteristics shifts investment incentives towards other types of resources and increases dependence on the capacity market for attracting the investment necessary to maintain reliability.

E. Drivers of Real-Time NCPC Charges

Real-time NCPC charges are incurred when a resource is scheduled in the real-time market, but the revenues it receives are not sufficient for it to recover its as-offered commitment and dispatch costs.[25] Table 3 summarizes real-time NCPC charges in 2018 for the following categories based on their allocations:

- Local Reliability – Units that receive NCPC credits in this category are committed or dispatched to primarily satisfy the second contingency protection or the voltage requirements in the local area. This NCPC uplift is allocated to local loads.
- External Transactions – Transactions are scheduled based on their offer prices, but they receive NCPC credits if real-time prices are below their offer. This NCPC uplift is allocated to real-time deviations at the proxy bus (excluding CTS transactions).
- Market-Wide Charged to Real-Time Load Obligation (“RTLO”) – These are the economic NCPC uplifts that are charged to market-wide load based on their real-time load obligations, including:
  - Generator Performance Audit – Paid to generator for audits initiated by the ISO.
  - Dispatch Lost Opportunity Cost – Paid to a resource instructed by the ISO to run at a level less than its economic dispatch point.
  - Rapid-Response-Pricing Opportunity Cost – Paid to a resource that is postured down when a rapid-response resource is setting price, which compensates the resource for

24 We found very few hours in 2018 when additional capacity was committed to satisfy the total 10-minute reserve and 30-minute reserve requirements. This is likely because New England has sufficient offline fast start capacity to satisfy these requirements in the vast majority of hours.

25 This includes opportunity costs if a generator would have earned more by not following the ISO’s instructions.

the difference between the amount it would have earned for energy and reserves absent being postured down.

- Resource Posturing – Paid opportunity costs to resources that are held in reserve for reliability even when it would be more profitable to generate.

- Market-Wide Charged to Real-Time Deviation – These are the economic NCPC uplifts charged to market-wide real-time deviations, which include deviations from generation, load, external transaction, and virtual transactions.
  - Fast Start Resources – These are fast start resources that are committed primarily by the look-ahead model, but do not set price because they are uneconomic in the dispatch model.
  - Supplemental Commitment after DAM – These are non-fast-start units that are committed after the day-ahead market for reliability.
  - Other – These include NCPC credits that resulted from actions by the ISO (e.g., cancel the start of a resource, instruct a resource for regulation) and ramping limitations of resources when following dispatch.

Table 3: Summary of Real-Time NCPC Charges by Category
2018

Real-Time NCPC Category	Charges (Million $)	Share of RT NCPC
Local Reliability		
Local Second Contingency	$0.6	1%
Voltage Support	$0.4	1%
SCR	$0.6	1%
Multi-Turbine Portion	$2.7	6%
External Transactions	$2.7	6%
Market-Wide *Charged to RTLO*		
Generator Performance Audit	$1.4	3%
Dispatch LOC	$3.7	8%
Rapid Response OC	$4.0	9%
Resource Posturing	$10.1	23%
Market-Wide *Charged to RT Deviation*		
Fast Start Resources	$6.9	16%
Supplemental Commitment after DAM	$6.3	14%
Other	$4.4	10%
Total	$43.9	

Local Reliability Real-Time NCPC

Local reliability requirements and other supplemental commitments after the day-ahead market accounted for a relatively small share (collectively 23 percent) of real-time NCPC in 2018. This was down from prior years because of reduced need to commit generation for local Boston-area reliability following transmission upgrades and the market entry of the Footprint combined-cycle plant.

Real-Time NCPC for Posturing and Fast-Start Resources

Resouce posturing accounted for the largest share of real-time NCPC in 2018, although nearly 70 percent of this occurred in early January 2018 during the cold snap because of fuel limitations. Posturing NCPC can provide perverse incentives by allowing resources to earn more profit by running short of fuel and receiving NCPC than they could from procuring fuel and consuming it to produce electricity. This is because they receive NCPC equal to the difference between the LMP and their offer for the duration of the posturing. Thus, if a generator has only three hours of fuel left and it is postured by the ISO for 12 hours, it will be paid for 12 hours of opportunity costs (i.e., estimated lost profits). This is far more than the profit it would make from generating for three hours.

NCPC for resource posturing was very limited in winter 2018/19 because of milder weather conditions and lower gas prices. Furthermore, the ISO implemented a market enhancement in December 2018 that allows opportunity costs associated with short-term fuel supply limitations for oil-fired and dual-fuel units to be included in their reference levels. This should help resources more accurately reflect opportunity costs in their offers and enable better commitment and dispatch through the market (rather than out-of-market actions such as posturing).

Fast start resources accounted for the second largest share of real-time NCPC in 2018. These resources were committed primarily by the look-ahead market model (i.e., the Generation Control Application) based on forecast system needs. However, forecast errors frequently led these resources to be uneconomic under actual real-time prices, resulting in NCPC charges.

Allocation of Real-Time NCPC

It is important to allocate NCPC charges in an efficient manner. However, most of the NCPC charges that are allocated to real-time deviations are not caused by real-time deviations. Specifically, supplemental commitment for market-wide reliability after the day-ahead market is the only category that is driven partly by real-time deviations and this accounted for just 36 percent of real-time NCPC charges in 2018 that were allocated to real-time deviations. This is similar to our finding in prior years. These commitments are sometimes caused by under-scheduling of energy in the day-ahead market or the loss of a significant supply resource after the day-ahead market. So, real-time deviations that reduce scheduling of physical resources in the day-ahead contribute to this category of NCPC charges, which includes virtual supply, under-scheduled load, or a generator that experiences a forced outage after the day-ahead market.

This misallocation of NCPC charges distorts market incentives to engage in scheduling that can lead to real-time deviations. Unfortunately, this distortion is compounded by the fact that NCPC charges are allocated to real-time deviations that actually help reduce NCPC charges such as virtual load and over-scheduling of load in the day-ahead market. Over-allocating NCPC charges to real-time deviations has provided strong disincentives for participation by virtual traders in the ISO-NE market as discussed in Subsection A. Hence, costs should only be allocated to real-time deviations to the extent that they cause the costs and the balance should be allocated to load.

F. Conclusions and Recommendations

In our assessment of day-ahead NCPC charges, we found that in 2018, 47 percent was attributable to commitments for local second contingency protection, while 30 percent was attributable commitments for the system-level 10-minute spinning reserve requirement. Both of these requirements are satisfied by scheduling operating reserves, but operating reserves are not procured in the day-ahead market and the cost of scheduling operating reserves is not reflected efficiently in energy prices. The absence of a co-optimized day-ahead operating reserve market resulted in:

- Excess commitments by the day-ahead market model for local second contingency protection in Boston, 60 percent of which would not have been needed under a co-optimized energy and reserve market.
- Depressed clearing prices for energy and 10-minute spinning reserves providers (by approximately $1.00 to $1.50 per MWh on an annual average basis). We estimate there were 3,900 hours when additional generation was committed to satisfy the system level 10-minute spinning reserve requirement, which was not reflected in prices.

In addition, we continue to find that NCPC costs are inflated when the ISO is compelled to start combined-cycle resources in a multi-turbine configuration when its reliability needs could have been satisfied by starting them in a single-turbine configuration.

We make two recommendations to improve the pricing of energy and operating reserves.

- We recommend that the ISO co-optimize the scheduling and pricing of operating reserves in the day-ahead market.
- We recommend the ISO expand its authority to commit combined-cycle units in a single-turbine configuration when that will satisfy its reliability need.

ISO-NE has started several initiatives to address energy security concerns, including co-optimizing procurement of energy and operating reserve in the day-ahead market. We support this effort and expect it will address a number of the issues we identified and discussed in this section.

One advantage to co-optimizing the scheduling of energy and operating reserves in the day-ahead market is that it would facilitate the elimination of the forward reserve market. As in prior years, nearly all of the resources assigned to satisfy forward reserve obligations in 2018 were fast-start resources capable of providing offline reserves. The value of the forward reserve market is questionable because:

- It has not achieved its objective to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day.

The obligation of forward reserve suppliers to offer at prices higher than the Forward Reserve Threshold Price can distort the economic dispatch of the system and inefficiently raise costs.

In assessing the real-time NCPC charges, we found that just 14 percent of the real-time NCPC can be attributed to real-time deviations, although 40 percent of all real-time NCPC are allocated to these deviations. Hence, we find that ISO-NE currently over-allocates real-time NCPC charges to virtual transactions and other real-time deviations. This has substantially reduced virtual trading activity and the overall liquidity of the day-ahead market compared to other RTO markets. We recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it.

IV. Fuel Security in New England

The New England region has become increasingly reliant on natural gas as nearly 5 GW of new fuel-efficient conventional generation have been built and 5 GW of nuclear, coal-fired, and older steam turbine capacity have retired in the first 13 Forward Capacity Auctions. The share of installed capacity that is primarily natural gas-fired has risen from 47 percent to 67 percent over this timeframe. ISO-NE has frequently raised concerns about the increasing reliance on gas-fired generation in recent years, and the ISO has studied the region's vulnerability to fuel security reliability issues as part of its Operational Fuel Security Analysis ("OFSA").

After the announcement of the proposal to retire Mystic units 8 and 9 and the Distrigas LNG-import terminal, the ISO used the OFSA model to evaluate the fuel security reliability of New England if the Mystic units and the Distrigas facility were retired ("Mystic Retirement Study").[26] The study found tight fuel supply margins during periods of extended cold weather that would result in load shedding in winters of 2022/23 and 2023/24. Likewise, we performed an analysis which found that even with very high utilization of oil inventory capacity and LNG import capability, New England would experience load shedding in a pipeline contingency or in a scenario with major reductions in availability of LNG or oil inventories.[27]

In light of these reliability concerns, ISO-NE: (a) entered into out-of-market contracts to retain Mystic units 8 and 9 (which require the continued operation of the Distrigas terminal) for two years, (b) filed a proposal to create a short-term compensation mechanism for units that maintain firm fuel inventories for the Capacity Commitment Periods for FCA 14 and FCA 15, and (c) is currently working with its stakeholders to design long-term market-based solutions for addressing the fuel security issues. Ultimately, the goal of this effort is to replace the temporary mechanism and the need for out-of-market contracts with a market that channels investment in the most efficient mix of resources for satisfying the reliability needs of the system.

This section builds on previous studies by analyzing how the aforementioned market design enhancements are expected to affect:

- Fuel security reliability during extreme weather and potential supply contingencies, and
- Whether out-of-market contracts for fuel security might be necessary again in the future.

Subsection A discusses these issues in the Capacity Commitment Period for FCA 13, while Subsection B evaluates fuel security in 2024/25 after the contract for the Mystic units expires.

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[26] See ISO's May 1, 2018 *Petition of ISO New England Inc. for Waiver of Tariff Provisions* in Docket No. ER18-1509-000.

[27] See *2017 Assessment of the ISO New England Electricity Markets* by Potomac Economics.

A. Fuel Security Outlook for Winter 2022/23

The ISO is designing rules to provide market incentives for suppliers to acquire the fuel necessary to maintain reliability during periods of natural gas scarcity.[28] In the long-term (i.e., years for which FCAs have not yet been held), these changes should provide incentives for investment in new resources and maintenance of existing resources that are fuel secure. In the short-term, these changes should improve incentives to procure fuel and fully utilize the existing generation to maintain reliability. This section discusses our analysis, which used the ISO's OFSA model to evaluate how the new market rules are expected to affect fuel security reliability during the Winter 2022/23—the last period for which an FCA has been conducted.

The ISO's default assumptions in the OFSA model are very conservative about oil tank replenishment rates and dispatch order, which are based on its past experience. However, the ISO's market design enhancements will provide incentives for generators to act differently in the future. These rules will encourage replenishment and lead to a dispatch order that will help conserve limited fuel inventories. If expected behavior is not modeled accurately, it could overstate the severity of fuel security issues and lead to additional out-of-the market contracts. Accordingly, we requested the ISO run the OFSA model with modifications to the following two default assumptions. The ISO incorporated these two methodological and resource mix changes and provided us the model results for the winter of 2022/23.[29]

- *Light oil units (i.e., combined cycles) are always dispatched before heavy oil units (i.e., older steam turbines).* Although this is expected under normal operating conditions, the ISO's fuel security review is designed to determine whether load shedding would occur under very stressed conditions that have not occurred in the past. Under stressed conditions, light oil units tend to be more limited than heavy oil units by tank capacity, potential refueling rates, and emissions permit limitations. Efficient incentives would encourage units with limited inventories to conserve fuel, which would lead units with larger inventories to produce more. Thus, we requested the ISO reverse the dispatch order in this analysis to simulate efficient incentives to conserve fuel inventories.
- *Oil-fired and dual-fuel generators will not fill their oil tanks to capacity before each winter or fully utilize refueling capacity during the winter.* For light oil units (i.e., combined cycles), this may not understate the units' availability given other limitations that are not explicitly modeled in the review (e.g., 30-day air permit restrictions). However, this assumption would greatly under-estimate the potential production levels of heavy oil units (i.e., older steam turbines),. Hence, we requested the ISO run the OFSA model assuming the market design changes induce more refills of oil tanks.

28 See ISO's May 7, 2019 presentation to Markets Committee *Energy Security Improvements: Market-based Approaches.*

29 See FCA-13 new entry and retirements in *Forward Capacity Auction Obligations*, available at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fca-results. The total capacity we assumed to be retired in our analysis is roughly 50MW less than the capacity that retired or delisted in FCA-13.

Table 4 shows the assumptions and model results for five scenarios that are based off of an original ISO Reference case that used the resource mix from FCA 12. The table also shows the results for several large contingency scenarios that have been identified in the ISO's fuel security studies.[30]

Table 4:Fuel Security Analysis with Modified Assumptions[31]
Winter 2022/23

Scenario Description	No.	Assumptions				Results (Hrs)		
		New Entry and Retirements	Dispatch Order	Oil Tank Refills	LNG (bcf/d)	30 Min Res Depletion	10 Min Res Depletion (< 700MW)	Load Shedding
ISO Ref + Updated Resource Mix	[1]	FCA-13 New Entry/ Retirements	ISO default	1.25	0.8	138	12	2
[1] + Modified Dispatch	[2]	FCA-13 New Entry/ Retirements	CCs after ST units	1.25	0.8	24	0	0
[2] + Modified Refills (*EMM Reference*)	[3]	FCA-13 New Entry/ Retirements	CCs after ST units	Heavy - Unlimited Light - 2	0.8	0	0	0
[3] with Batteries Replacing a ST	[4]	FCA-13 New Entry/ Retirements + 600MW of batteries in place of ST	CCs after ST units	Heavy - Unlimited Light - 2	0.8	2	0	0
Contingencies								
EMM Ref [3] - Millstone outage	[5]	FCA-13 New Entry/ Retirements - Millstone out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	36	0	0
EMM Ref [3] - Pipeline outage	[6]	FCA-13 New Entry/ Retirements - 1.2 bcf/d gas unavailable for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	57	1	0
EMM Ref [3] - Canaport outage	[7]	FCA-13 New Entry/ Retirements - Canaport out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.4	14	0	0

In Scenario 1 simply updates the ISO Reference case to reflect recent resource mix changes. In this scenario, the OFSA model finds significant reliability issues, including two hours of load shedding, twelve hours of 10-minute reserve depletion to 700 MW, and 138 hours of 30-minute reserve depletion. The other scenarios shown in Table 4 indicate that the market design changes being developed by the ISO will substantially affect reliability:

- Scenario 2 (modifying the dispatch so that heavy oil units are scheduled before the more fuel-constrained light oil units) eliminates load shedding and 10-minute reserve

[30] See ISO's January 17, 2018 *Operational Fuel-Security Analysis*. Also see ISO's May 1, 2018 *Petition of ISO New England Inc. for Waiver of Tariff Provisions* in Docket No. ER18-1509-000

[31] We assume imports from external control areas to be at 2800 MW for all the scenarios in Table 4.

depletion, and reduces the frequency of 30-minute reserve depletion by 83 percent. Scenario 3 shows that incentives for frequent refills would eliminate even 30-minute reserve depletion.

- The system would be far more reliable even under contingency scenarios with significant reductions in supply. For example, Scenario 5 reveals that replacing 560 MW of heavy oil units with short duration batteries would result in just two hours of 30-minute reserve depletion.
- None of the extraordinary contingencies considered would result in load shedding hours in the *EMM Reference* scenario. These contingencies result in only one hour where 10-minute reserves are depleted to a level below 700 MW and no hours of load shedding.

As the resource mix in New England changes, it is important to consider how battery storage resources are likely to affect fuel security reliability. Battery storage resources have the potential to provide considerable flexibility to the system, particularly under high renewable penetration conditions. As we discuss in Section V, battery storage resources are well-positioned to earn high levels of capacity revenue as a result of the Pay-For-Performance rules. The interconnection queue currently includes over 2.5 GW of battery storage resources, driven in part by state public policy goals. However, batteries are energy limited resources that have very little fuel security value. Hence, the market design enhancements to promote fuel security will become increasingly important as battery storage resources enter the market.

Although the analysis in this section suggests that market design changes will be sufficient to ensure fuel security reliability even under extreme contingency scenarios, the next section examines the outlook if the Mystic and Distrigas facilities retire.

B. Fuel Security Outlook for Winter 2024/25

ISO-NE entered into an out-of-the-market contract with the owner of Mystic units 8 and 9 (and the Distrigas LNG-import terminal) after finding that their retirement would lead to significant fuel security reliability risks. The contract with Mystic 8 and 9 is for two years and ends after CCP 2023/24. As discussed in the previous subsection, the ISO is developing market design enhancements that will be critical for bolstering reliability during severe winter conditions. In this subsection, we incorporate several changes into the fuel security reliability assessment of 2024/25 winter to simulate the effects of the market design enhancements that are currently under development. These include:

- Deploying heavy oil units ahead of light oil units (when light oil units have more limited oil inventories) – Under tight fuel supply conditions, an efficient market design will motivate units with limited inventories to conserve their remaining fuel, leading units with larger inventories to be deployed first;

- More frequent refilling of oil inventories – Under tight fuel supply conditions, an efficient market design will motivate dual fuel units to maintain higher inventories and refuel more frequently; and
- Higher utilization of existing LNG-import capacity – If a major fuel source is lost, an efficient market design will induce generators and natural gas shippers to contract with LNG-importers to increase supplies to the region.

Table 5 shows the assumptions and results for several winter 2024/25 scenarios that are based on varying assumptions about the state of Mystic units and LNG injection rates:

- Scenario 2 shows an injection rate of 0.4 Bcf/day based on the assumption that the loss of Distrigas would not lead to any incremental increase in LNG imports to the other two import-terminals in the region;
- The higher injection rates shown in Scenarios #3 to #6 are based on the assumption that the loss of Distrigas would likely encourage increased imports to the other terminals.

Table 5: Fuel Security Analysis with Retirement of the Mystic and Distrigas Facilities[32]

Winter 2024/25

Scenario Description	No.	Assumptions			Results (Hrs)		
		New Entry and Retirements	**Oil Tank Refills**	**LNG (bcf/d)**	**30 Min Res Depletion**	**10 Min Res Depletion (< 700MW)**	**Load Shedding**
EMM Reference 2024/25	[1]	FCA-13 New Entry/ Retirements	Heavy - Unlimited Light - 2	0.8	0	0	0
Sensitivities on LNG Injection for Mystic 8 and 9 and Distrigas LNG Retirement Scenario							
LNG Sensitivity #1 (Low Injection)	[2]	FCA-13 New Entry/ Retirements - Mystic 8 and 9 + Distrigas LNG retired	Heavy - Unlimited Light - 2	0.4	216	2	0
LNG Sensitivity #2	[3]			0.5	146	2	0
LNG Sensitivity #3	[4]			0.6	95	0	0
LNG Sensitivity #4	[5]			0.7	52	0	0
LNG Sensitivity #5 (High Injection)	[6]			0.8	23	0	0

32 We assume imports from external control areas to be at 2800 MW for all the scenarios in Table 5.

As was the case with EMM Reference scenario in 2022/23, we continue to find no significant fuel security issues in 2024/25 if the dispatch order and replenishment assumptions reflect the proposed market design changes (EMM Reference 2024/25). However, Scenario #2 in Table 5 indicates that the retirement of the Mystic and Distrigas facilities would lead to two hours of 10-minute reserve depletion to 700 MW and frequent 30-minute reserve depletion (if there was no market response to the shortages from LNG importers).

Ultimately, the impact of retiring the Mystic and Distrigas facilities would depend on the response from other sources of supply, so we evaluated the reliability impact of increasing supply in response to the retirements. Scenarios #3 to #6 in Table 5 show that if the volume of LNG imports through the other two import terminal rose from 0.4 to 0.8 Bcf/day, reserve shortages would become much less frequent. Scenario #6 shows that increasing LNG imports to 0.8 Bcf/day, replacing slightly more than half of the gas supply lost from retiring Mystic and Distrigas, reduces the frequency of 30-minute reserve depletion to 23 hours and eliminates 10-minute reserve depletion to 700 MW.

Although load shedding does not occur under any of the scenarios listed in Table 5, these scenarios do not consider the effects of a large supply contingency (besides Mystic and Distrigas), such as a pipeline contingency. Hence, it is unclear how much additional supply could be lost before New England would experience serious reliability issues. In the coming years, new resources with low fuel security value (e.g., battery storage) may replace generation with high fuel security value (e.g., oil-fired steam turbines), which would increase fuel security reliability risks. Hence, developing a market mechanism to reward fuel security would provide valuable incentives to support the development and maintenance of fuel secure resources, which can reduce or eliminate entirely the reliability impact of the retirement of Mystic and Distrigas.

C. Conclusions and Recommendations

The ISO's Operational Fuel Security Assessment ("OFSA") model was developed to evaluate the planning reliability needs of New England with explicit consideration of fuel supply limitations of individual generators. This innovative model is the first of its kind, but we are concerned that it relies on some assumptions that are overly conservative by assuming that the market will not respond with additional fuel supplies under shortage conditions. Consequently, the OFSA model may indicate the need for additional installed capacity to address a fuel security issue that could be fully resolved through market design enhancements that motivate resource owners to procure additional fuel supplies.

The market design enhancements being developed by the ISO will compensate resources for holding inventories during tight fuel conditions and provide incentives that help the region conserve fuel supplies. Our analysis in this Section indicates that these enhancements will substantially improve reliability under conditions that raise fuel security concerns. These reliability improvements are due to enhanced incentives that will lead to improvements in the operation of the system and decisions by suppliers, including:

- Deploying heavy oil units ahead of light oil units;
- More frequent refilling of oil inventories; and
- Higher utilization of existing LNG-import capacity.

We evaluated two timeframes, one before the Mystic Units retire and one after the Mystic retention contract expires and the units are assumed to have retired:

- Winter 2022/23 – This is the Capacity Commitment Period ("CCP") corresponding to the Forward Capacity Auction that was held in February 2019 (i.e., FCA 13). In this timeframe, we found that the improved fuel procurements by suppliers and operation of the system that should be motivated by the market enhancements are likely to effectively address New England's fuel security concerns. These results highlight the reliability improvements that are possible without any capacity additions.
- Winter 2024/25 – This is the first winter after the Mystic retention contract expires (i.e., FCA 15). The improvements described above would eliminate 10-minute reserves depletion and load shedding after the Mystic units retire. However, these scenarios did not consider the effects of additional supply contingencies (such as a pipeline contingency), so it is still unclear how much additional supply could be lost before New England would experience serious reliability issues.

These results underscore the importance of the market enhancements being developed by the ISO. These market design enhancements will provide strong incentives for resources to procure fuel necessary to maintain reliability under peak conditions, and increase the utilization of existing equipment for storing oil and importing LNG. This would not only likely eliminate reliability issues during extreme winter conditions, but also enable the ISO to maintain system reliability after the loss of a critical resource, such as the Millstone nuclear plant, a major pipeline, or an LNG import facility. In the longer-term, the ISO's market enhancements will facilitate longer-term improvements that will help address potential fuel security issues after the potential retirements of the Mystic units and the Distrigas LNG facility.

V. Evaluation of the Pay-for-Performance Framework

The PFP rules were put in place to enhance incentives for suppliers to perform when they are needed the most. As part of the PFP rules, resources that provide more energy and/or operating reserves than the average capacity provider during a reserve shortage event are paid a Performance Payment Rate ("PPR"), while capacity suppliers that produce less than average are penalized according to the PPR. The Pay-for-Performance ("PFP") rules became effective on June 1, 2018.

In subsection A, we describe the conditions and settlements during the first PFP event that occurred since the rules became effective. In subsection B, we compare the compensation suppliers received during this event to the expected value of load that was at risk of not being served. In subsection C, we evaluate the incentives for energy storage resources under the current PFP and FCM rules, and identify a misalignment between their compensation and their value to the system.

A. First Pay-for-Performance Event

The first PFP event in New England occurred from 15:40 to 18:15 on September 3, 2018. Figure 9 depicts the event by showing the quantities of operating reserve shortages in the lower panel and the prevailing energy prices in the upper panel.

During the event, the shortage of 30-minute reserves ranged from 200 MW to 880 MW. The shortage resulted from a combination of factors that included unexpectedly high load (actual load exceeded forecast by ~2.5 GW), the sudden loss of the Mystic CCs due to a gas pressure issue (~1.4 GW), and other forced outages and deratings. As a result, the ISO cut Cross-Sound Cable exports to NYISO and made emergency purchases from NYISO and New Brunswick. In addition, up to 284 MW of Price-Responsive Demand was also activated.

During the event, the LMP at the Hub approached nearly $2,700/MWh (see Figure 9) in some five-minute intervals due to the shortage of 10-minute and 30-minute reserves.[33] In addition, resources that supplied energy or operating reserves were compensated (or charged) based on the PPR of $2,000/MWh. Therefore, a resource that produced energy or operating reserves during this event would have been compensated at a marginal rate of over $4700/MWh in some

[33] The Reserve Constraint Penalty Factor ("RCPF") is the value that the real-time market model places on satisfying a particular reserve requirement. The RCPF for the 30-minute reserve requirement is $1,000/MWh, and the RCPF for the 10-minute reserve requirement is $1,500/MWh, so a shortage of both types of reserves results in clearing prices of $1,000/MWh for 30-minute reserves and $2,500/MWh for 10-minute reserves, since 1 MW of 10-minute reserves contributes to meeting both requirements. LMP rose above $2,500/MWh, reflecting that one additional MW of energy would allow the model to back down an expensive generator to provide one additional MW of 10-minute reserves.

intervals. These compensation levels are much higher than the expected marginal value of lost load during the event, which we estimate in subsection B.

Figure 9: Energy Prices and 30-Minute Reserve Shortages during PFP Event
September 3, 2018

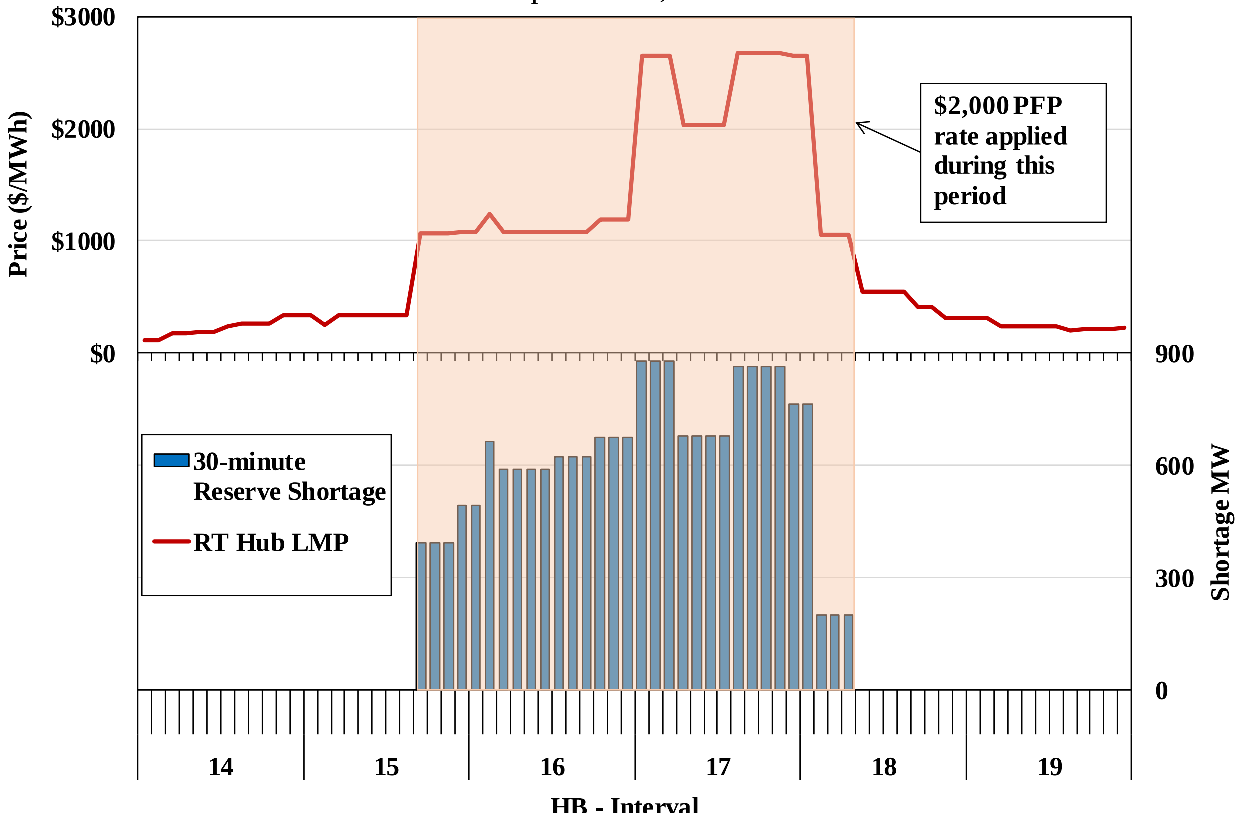
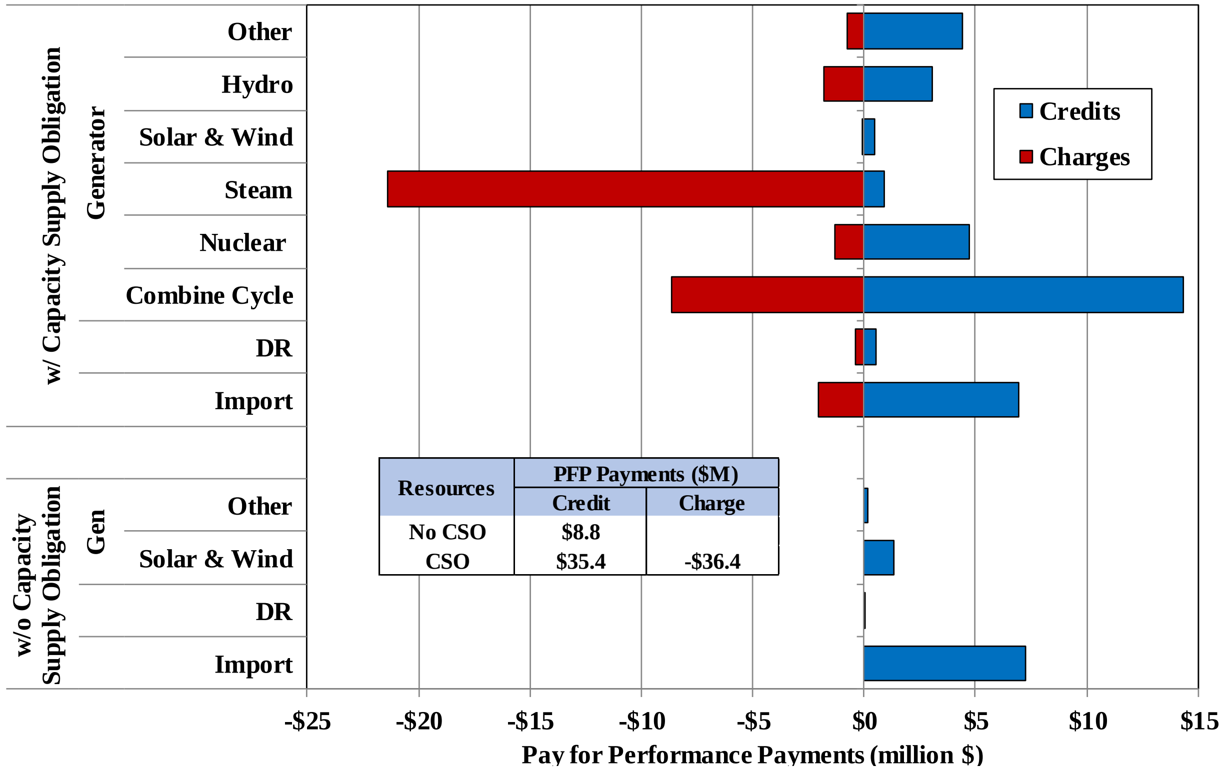


Figure 10 summarizes the settlement effects of the PFP event by type of unit. The total charges are shown in red while the payments are shown in blue. Charges are assessed to suppliers that are producing energy at levels that are less than their obligation, including those that are offline. Payments are made to suppliers producing more energy than their obligation, including those that have no obligation because they did not sell capacity. Payments to suppliers or importers that do not have a capacity obligation are shown separately in the figure.

Steam turbine units incurred the majority of the PFP penalties with total penalties of $22 million. Many of these units were not economic in the day-ahead market and could not respond to the event in real-time because of the units' long start-up times. Consequently, they generally performed below average and were subject to considerable PFP charges. On the other hand, every other category of resource performed above the fleet-wide average. Combined-cycle units with a CSO received more than $14 million in performance payments and paid almost $9 million in penalties on an aggregate basis. In addition, imports received performance payments of nearly $15 million, roughly half of which was paid to importers with no capacity obligations.

Figure 10: Settlements during the PFP Event

September 3, 2018



B. Evaluation of Pay-for-Performance Pricing

Efficient prices during reserve shortages play a key role in establishing economic signals to guide investment and retirement decisions in the long-run and facilitate efficient commitments and reliable performance in the short-run. In this subsection, we evaluate the efficiency of: (a) the shortage prices during the September 3, 2018 PFP event, and (b) the prices that would have occurred if the reserve shortages had been deeper during the event.

During shortages, efficient prices should be set consistent with several criteria. Specifically, prices should:

- Reflect the marginal reliability value of reserves given the shortage level;
- Depend on the risk of potential supply contingencies, including multiple simultaneous contingencies; and
- Rise gradually as the reserve shortage increases and have no artificial discontinuities that can lead to excessively volatile outcomes.

The marginal reliability value of reserves is equal to the expected value of the load that will not be served if the available reserves are reduced by 1 MW. The expected value of lost load ("EVOLL") during a reserve shortage event can be estimated as the product of: (a) value of lost load ("VOLL"), and (b) the probability of losing load. We estimated (a) and (b) during the September 3, 2018 PFP event in the following manner:

- We assume a VOLL of $30k per MWh, which is on the high end of VOLL values that have been estimated;[34] and
- Given the resource mix and the reserve and energy output for each interval, we estimated the probability of losing load using a Monte Carlo simulation. This simulation incorporates the risk of concurrent generator forced outages during the PFP event to estimate the probability of 10-minute reserves falling to a level below 700 MW.[35]

Our simulation results indicate that the highest probability of losing load during the PFP event was only 3.3 percent per hour (Figure 11), which translates into approximately $1,000 per MWh of operating reserves. In contrast, resources that produced energy or reserves during this interval were compensated at a rate of over $4,700 per MWh. When the PPR reaches its maximum level in 2024/25, compensation for resources performing during a PFP event could exceed $7950 per MWh. Hence, the compensation to resources during shortages would substantially exceed the EVOLL in the vast majority of cases and would result in exaggerated shortage pricing that could motivate participants to take inefficient actions.

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34 Estimates of the VOLL vary widely based on a range of demand-side factors that include the customer class being served, duration of the load shedding event, season/ timing of the event and geographical location of customers. A meta-analysis of reliability studies by LBNL and DOE estimated that in a one-hour power interruption, a small C&I customer (who may not have installed power back-up systems) could incur a cost per unserved kWh that is nearly 90 times the cost incurred by a residential customer. (See 2015 report on study tiltled *Estimated Value of Service Reliability for Electric Utility Customers in the United States*.) This study also estimated the cost of interruption for residential customers on a summer morning/ night could be nearly 4 times the cost of interruption on a non-summer evening. VOLL is also known to rise as the length of the outage increases, so a 16-hour long outage can cost an average large C&I customer nearly 22 times what a momentary outage would cost. Hence, VOLL is not a single value and varies considerably.

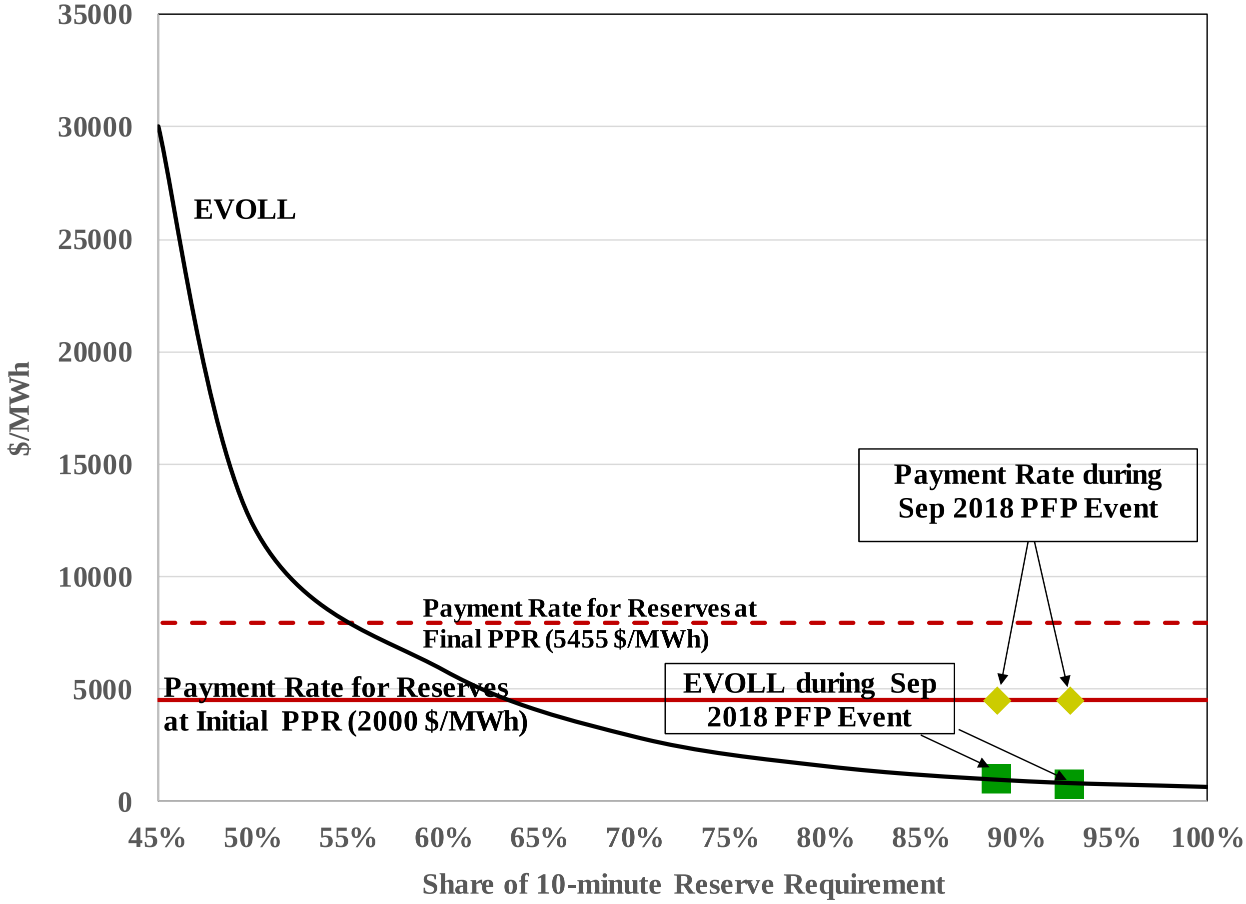
On the other hand, the VOLL that is implied by capacity market payments (estimated to be over $200,000 per MWh in several studies) is significantly higher than the VOLL across almost the studies (and across all key parameters discussed above). This is because capacity markets set capacity demand curves based on the estimated revenue necessary to satisfy certain reliability standards (rather than an evaluation of demand-side factors).

The ISO's planned PPR of $5455 per MWh is derived based on the following two principles: (a) a new entrant's expected FCM revenue should cover its Net CONE and any risk premium it requires to accept a CSO, and (b) a new or existing capacity supplier's FCM revenue should be zero if it expects to not perform during scarcity conditions. See ISO's September 4, 2013 memo to NEPOOL Markets Committee on *FCM Performance Incentives – Performance Payment Rate*. Hence, the ISO's PPR values are not necessarily related to the VOLL during reserve shortages.

35 We assumed that the time between generator forced outages is a random variable that follows a Poisson process. We assumed that the mean of the probability distribution is the corresponding class-average Mean Service Time to Unplanned Outage ("MSTUOs") derived from NERC GADS data. We used the MSTUO for each generator in our simulations to derive the probability that the generator would be on an outage during a two hour look-ahead window. See Section VI for assumptions underlying our analysis.

As the magnitude of the operating reserve shortage increases, the EVOLL increases because the probability of losing load increases. It is efficient for the prices to increase in accordance with the EVOLL because this will provide appropriate incentives for both suppliers and demand to take actions that are consistent with the reliability value of the actions. Therefore, we estimated how the implied EVOLL curves would change at various reserve shortage levels (using the Monte Carlo simulation results) and compared it to the compensation that suppliers would receive at that shortage level.

Figure 11: Comparison of Reserve Prices to EVOLL during PFP Events



The EVOLL curve (Figure 11) has a convex shape to it which indicates that the probability of losing load increases significantly during deeper reserve shortages than during shallow reserve shortages. However, the PPR and the RCPFs are flat and do not reflect this shape. Our results indicate that the combined rate of compensation would be far higher than efficient price levels during shallow shortages and much lower during deep shortages. This could result in over-compensating flexible resources that are capable of helping resolve transient and shallow shortages, and under-compensating resources that contribute to resolving deeper and more serious shortage events.

Therefore, modulating the PPR based on the reserve shortage level would enhance price formation during reserve shortage events and result in more efficient short and long-run decisions from suppliers. In the following subsection, we illustrate one of the negative effects of not providing efficient incentives.

C. Incentives for Energy Storage Resources under Pay-for-Performance

The FCM rules allow battery storage resources to qualify to sell 100 percent of their maximum capability. Owners of energy storage units are exposed to significant performance risk under the PFP framework, however, the current PFP rules do not provide sufficient discipline to energy storage resources in qualifying their capacity for the FCM. Battery storage resources are generally over-compensated for their contribution to system reliability. In this subsection, we discuss this issue further and illustrate the misalignment using simulation results.

Although a storage resource is limited in the duration over which it can provide energy, it can provide reserves for extended periods of time. Unless required to discharge and produce energy during load shedding events, its reserve capability will not be diminished during reserve shortages. Our simulations of a system with just enough capacity to satisfy a 1-day-in-ten-year standard indicate that load shedding is expected to occur in only two percent of reserve shortage hours.[36] Accordingly, the risk of PFP penalties may not be significant for storage resources relative to the potential upside in the form of higher capacity revenue.

Although the owners of storage resources may find it profitable to sell 100 percent of their capacity in the FCM, the reliability value they provide is not likely to be consistent with their compensation. This is illustrated in Figure 12, which shows a hypothetical series of five days with reserve shortages, three of which also show load shedding. Hours with load shedding or reserve shortages are identified with the letter "L" or "R". Hours are shown as green if the resource would receive credit under the PFP rules and red if the resource would be deemed unavailable. The example is shown for a two-hour resource.

36 The actual simulations were based on the representation of the NYISO system in GE-MARS for 2017/18. While the duration of reserve shortage events and load shedding events are likely to vary from market to market, this analysis captures the essential fact that some load shedding events are longer in duration than the capacity of battery storage resources.

Figure 12: PFP Revenues and Penalties for a 2-Hour Battery During a Reserve Shortage

Hour ➡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Day 1											R	R	R	R	R	R	R	R						
Day 2											R	R	R	R	L	R	R	R						
Day 3											R	R	R	R	L	L	L	R						
Day 4											R	R	R	L	L	L	L	R						
Day 5											R	R	R	R	R	R	R	R						

Reserve Shortage Hours

R = Reserve Shortage
L = Load Shedding

PFP Penalty
PFP Revenue

The example shows eight load shedding hours and 32 hours with just reserve shortages. On Day 1, Day 2, and Day 5, the energy storage resource is not used for its full duration of two hours, so it has sufficient charge to provide 100 percent of its capacity as energy or reserves in each hour. On Day 3, the unit runs out of charge after hour 16, making it unavailable in hours 17 and 18. On Day 4, the unit runs out of charge after hour 15, making it unavailable in hours 16 to 18.

In this example, the battery storage resource:

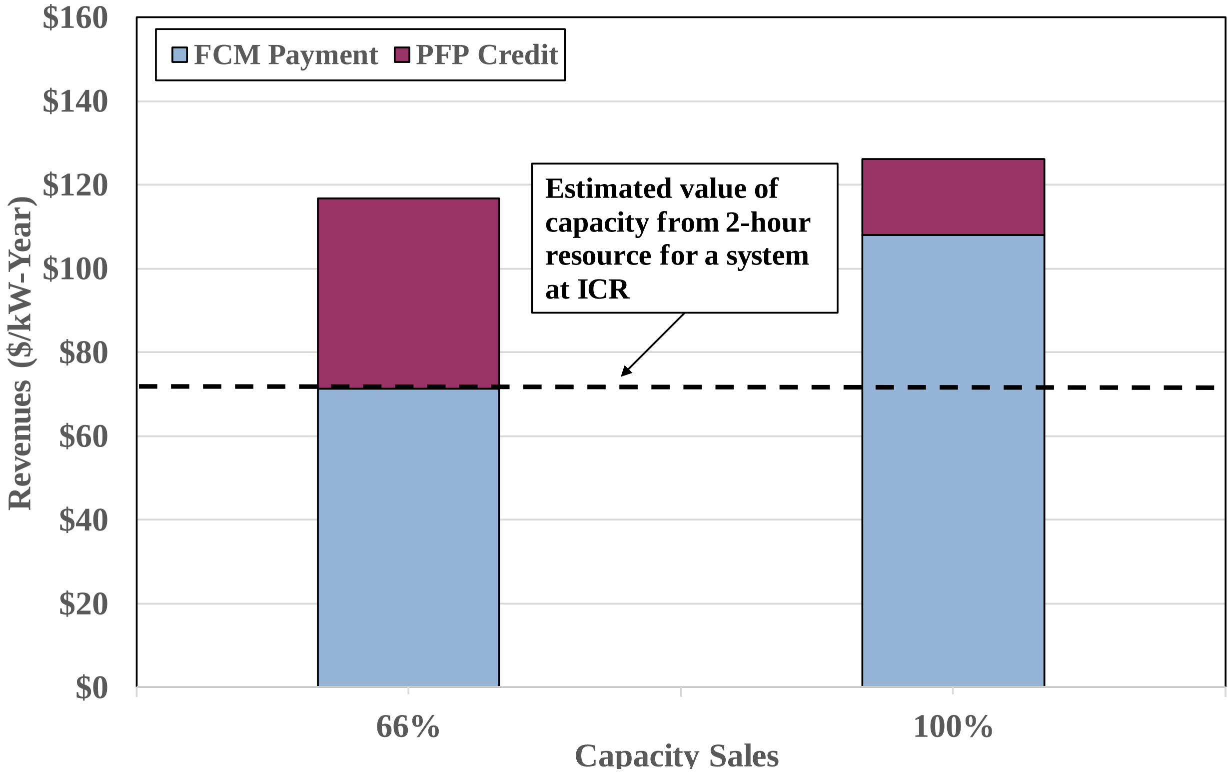
- Has a capacity value of 62.5 percent (compared to perfect availability) because it is helping reduce the magnitude of load shedding in five of eight load shedding hours.
- Will receive a PFP availability rating of 87.5 percent (of perfect availability) because it is providing energy or reserves in 35 of 40 hours with reserve shortages (including load shedding hours).

To evaluate whether there are inconsistencies between the value of battery storage resources for maintaining reliability and the compensation they receive in the capacity market, we performed Monte Carlo simulations of GE-MARS to quantify the value of battery storage resources and the compensation they would receive.[37]

Studies have found that the value of capacity from storage resources is heavily dependent on the penetration level of energy storage resources systemwide. We found that the capacity value of a 2-hour battery storage resource was 63 to 68 percent when the overall penetration of storage resources is 500 MW. In contrast, several 2-hour resources were qualified to sell 100 percent of their maximum capability in FCA-13. We also quantified the number of reserve shortage hours and the combined compensation from capacity revenues and PFP credits for a 2-hour resource would be expected to earn. This is shown for a CSO of 66 percent and 100 percent of its capacity. Figure 13 shows the breakdown of a 2-hour energy storage resource's revenues under these scenarios.

[37] See *Alternative ELR Capacity Value Study: Methodology and Updated Results*, NYISO Installed Capacity Working Group on February 25, 2019 at https://www.nyiso.com/icapwg?meetingDate=2019-02-25.

Figure 13: Breakdown of Revenues for a 2-Hour Battery Resource
Assuming 66/100 Percent Capacity Sales



As shown in Figure 13, storage resources would find it most profitable to sell 100 percent of their capacity in the FCA. In addition, the battery storage resources would also receive more PFP credit than the average capacity supplier. Overall, this resource would receive 117 percent of the compensation of a capacity supplier with average performance.

Even if the storage resources were limited to selling 66 percent of their capacity in the FCA, the battery storage resources would receive a large PFP credit. Overall, this resource would receive 108 percent of the compensation of a capacity supplier with average performance. Although this would reduce the over-compensation to the battery storage resource, it would leave the compensation far above the estimated efficient level of 66 percent.

Hence, the 2-hour battery storage resources appear to be over-valued significantly in the capacity market for two reasons:

- Storage resources are able to sell 100 percent of their maximum capability even though resource adequacy modeling indicates 2-hour storage resources are far less valuable for preventing load shedding than the average conventional resource.
- Storage resources are likely to have high rates of availability during operating reserve shortages and comparatively lower availability during load shedding events.

A key reason why the PFP construct would over-compensate storage resources is that the PPR is the same for all reserve shortages, regardless of the probability that additional reserves would help avoid load shedding. A graduated PPR that rises with the magnitude of the reserve shortage would largely correct the over-compensation to these resources.

D. Conclusions and Recommendations

The Pay-for-Performance ("PFP") rules were put in place to enhance incentives for suppliers to perform when they are needed the most. In this section, we summarize market conditions and settlements during the first PFP event that occurred since the rules became effective on June 1, 2018. We evaluate the efficiency of compensation received by suppliers during the event compared to the risk of not serving load and the value of lost load. We also identify a misalignment between the compensation of short-duration energy limited resources and their value to the system during reserve shortage events.

The first PFP event in New England occurred for two-and-a-half hours on September 3 during which a shortage of 30-minute reserves ranged up to 880 MW. The shortage resulted primarily from unexpectedly high load (actual load exceeded forecast by ~2.5 GW) and the sudden loss of generation (~1.4 GW). In response, the ISO cut exports, made emergency purchases, and activated Price-Responsive Demand. The combination of shortage pricing and PFP incentives led to marginal compensation rates of up to $4700/MWh. Performance of individual resources was generally consistent with expectations as steam turbines accounted for the majority of PFP charges because they had not been economic to commit in the day-ahead market. Every other category of resources received more credits than charges and fast-start units and importers did particularly well.

During reserve shortages, prices should rise gradually with the severity of the shortage, reflecting the marginal reliability value of reserves given the size of the shortage level and potential supply contingencies. The marginal reliability value of reserves is equal to the expected value of the load ("EVOLL") that will not be served if the available reserves are reduced by 1 MW. Assuming a $30,000/MWh value of lost load ("VOLL"), we estimated the probability of contingencies that could result in load shedding during the event on September 3. Furthermore, we extrapolated from these data how quickly the EVOLL would have risen after the occurrence of one or more contingencies.

We estimate that the EVOLL ranged from $700 to $1,000 per MWh of operating reserve during the event, far lower than the marginal rate of compensation which ranged from $3000 to $4700 per MWh. However, we find that for shortages of more than 540 MW, the EVOLL would quickly rise above $4700 per MWh up to the assumed VOLL of $30,000 per MWh. This illustrates the deficiencies with the current PPR, which is set at a single value regardless of the magnitude of the shortage. Modulating the PPR based on the reserve shortage level would enhance price formation during reserve shortage events and result in more efficient short and long-run decisions from suppliers.

Interest in battery storage and other energy limited resources has grown quickly in recent years as policy-makers look for non-fossil fuel options for integrating intermittent renewables. However, these resources present special challenges for valuing capacity and energy and operating reserves under shortage conditions. We evaluate the reliability value of a 2-hour battery storage resource and find that such units are likely to be greatly over-compensated for their value under the current capacity market rules, including the PFP compensation provisions. This is troubling as policy-makers and developers prepare to invest heavily in this technology in the coming years.

The FCM rules allow battery storage resources to qualify for 100 percent of their maximum capability, but these resources have significant duration limitations that make them less valuable than most conventional resources when the system is near load shedding conditions. Furthermore, the flexibility of these resources make them likely to perform better under the PFP provisions than most resources during mild to moderate reserve shortage conditions. As discussed above, the marginal compensation rate is far higher than the EVOLL during such reserve shortages, leading battery storage resources to be greatly over-compensated.

We performed a Monte Carlo analysis to estimate the reliability value of a 2-hour battery storage resource for avoiding load shedding and the compensation it would receive in the capacity market. This found that a 2-hour battery storage resource would:

- Have 66 percent of the value of an average conventional resource for avoiding load shedding, and
- Maximize profits by selling 100 percent of their capacity in the FCA and earn 18 percent more in PFP credits.

Furthermore, this significant over-compensation cannot be fixed by reducing the qualified capacity to these resources to an appropriate level (e.g., 66 percent) because this would increase the size of the PFP credit for a combined total of 108 percent of the average conventional resource. A key reason why the PFP construct would over-compensate storage resources is that the PPR is the same for all reserve shortages, regardless of the probability that additional reserves would help avoid load shedding. A graduated PPR that rises with the magnitude of the reserve shortage would largely correct the over-compensation to these resources.

VI. Appendix

In Section V.B we evaluated the efficiency of prices during reserve shortage events. We compared the actual/ likely prices against the EVOLL at several levels of depleted ten-minute reserves. Our estimated EVOLL reflects an assumed VOLL, and a probability of losing load that we estimated using a Monte Carlo simulation. The simulation incorporates the risk of concurrent generator forced outages to estimate the risk of losing load at each reserve level. The key assumptions and methodology for our simulation are as following:

- We assumed the mix of energy and reserve supply in our simulated system to be similar to the actual mix observed during the September 3, 2018 PFP event. We calculated the average contribution of energy and reserves from each resource duing the PFP event to develop a representative resource mix for our simulation. We scaled down the reserves supplied by each unit uniformly to determine the resource mix at each reserve level.

- For each given reserve level, we performed 10,000 simulations and determined the number of iterations during which load shedding would occur due to generator outages. We assumed that load shedding would occur when the ten-minute reserve levels drop below 700MW. We calculated the probability of losing load for the given reserve level as the fraction of iterations with load shedding.

- For each iteration, we estimated the aggregate generator forced outage as follows. Each generator was assigned a random number between zero and one. If the assigned random number was less than $1\text{-}e^{(-ORP\ /\ MSTUO)}$, the generator was simulated to be forced out of service. For this analysis, we assumed a two-hour outage recovery period (ORP), which is the time needed to fully respond to supply-side contingencies. For each generator, we utilized the NERC GADS database to estimate a class-average Mean Service Time to Unplanned Outage (MSTUO). The class-average MSTUO data we assumed is shown in the table below.

Table 6: Mean Service Time to Unplanned Outage by Generator Type

Technology	MSTUO (Hours)
Coal Steam	613
Gas Steam	342
Nuclear	4194
Combustion Turbine	61
Combined Cycle	304
Hydro	459
Others	342