2014 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS

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Guide to Abbreviations

ASM	Ancillary Services Market
AMP	Automated Mitigation Procedures
CONE	Cost of New Entry
CT DPUC	Connecticut Department of Public Utility Control
EMM	External Market Monitor
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FTR	Financial Transmission Rights
GW	Gigawatt (1 GW = 1,000 MW)
HHI	Herfindahl-Hirschman Index, a measure of market concentration
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LFRM	Locational Forward Reserve Market
LMP	Locational Marginal Price
LOC	Lost Opportunity Cost, a component of the regulation price
LSR	Local Sourcing Requirement
MMbtu	Million British Thermal Units, a measure of energy content
IMM	Internal Market Monitor
MW	Megawatt
MWh	Energy associated with producing 1 MW for one hour
NCPC	Net Commitment Period Compensation
NEMA	North East Massachusetts
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council, Inc.
NYISO	New York ISO
PER	Peak Energy Rent
PPR	Performance Payment Rate
RA	Reconfiguration Auction
RAA	Reserve Adequacy Assessment
RCP	Regulation Clearing Price
RCPF	Reserve Constraint Penalty Factors
RMR	Reliability Must-Run
RTO	Regional Transmission Organization
SEMA	South East Massachusetts
SCR	Special Constraint Resources
SMD	Standard Market Design
TMNSR	Ten-minute non-spinning reserves
TMOR	Thirty-minute operating reserves
TMSR	Ten-minute spinning reserves
UDS	Real-time dispatch software

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 2014 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 2014.

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."

I. 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 ensuring that the lowest-cost supplies are used to satisfy demand in the short-term and by establishing transparent, efficient wholesale price signals that govern investment and retirement decisions in the long-term. The markets achieve the short-term benefits by coordinating the commitment and dispatch of the region's resources, which is essential due to the physical characteristics of electricity and the transmission network used to deliver it to customers. This coordination affects not only the prices and production costs of electricity, but also the level of reliability with which it is delivered.

This report assesses the efficiency and competitiveness of New England's wholesale electricity markets in 2014. Based on our evaluation of the markets (in both constrained areas and the broader market), we find that ISO-NE's energy and ancillary service markets performed competitively in 2014. Although structural analyses indicate that one or more suppliers were pivotal in the real-time market in a large number of hours in 2014, our assessment did not raise significant competitive concerns associated with suppliers' market conduct (see Section II.G for more details). In addition, the ISO's automated market power mitigation process was effective in preventing the exercise of market power under conditions when a supplier may face limited competition. However, the report does recommend some improvements to increase the competitiveness of ISO-NE's forward capacity market.

The remainder of this executive summary provides an overview of market outcomes, a discussion of key market areas, and a list of recommended market enhancements.

A. Key Developments and Market Outcomes in 2014

1. Energy Market Outcomes

The year was characterized by extremely cold weather and tight natural gas market conditions in the first quarter, which was followed by very mild weather and historic low natural gas prices in the rest of the year. Load was particularly mild in the summer months.[2,3] As a result, the market outcomes varied considerably through the year:

- Average natural gas prices increased 73 percent in the first quarter of 2014 from the previous year and fell 26 percent in the rest of the year, resulting in a net increase of 16 percent in 2014;[4] and
- Average energy prices rose 77 percent in the first quarter of 2014 from the previous year and decreased 23 percent in the rest of 2014, resulting in a net increase of 14 percent.[5]

The strong relationship between energy and natural gas prices indicated by these results is expected in a well-functioning, competitive market because natural gas-fired resources were the marginal source of supply in most intervals in 2014. In addition to natural gas price fluctuations, other variations in supply and demand also affected energy prices in 2014:

- On the demand side, average load levels in the winter rose by nearly 4 percent from the prior year as the Polar Vortex produced much colder temperatures than normal.
- Mild weather after the winter led to a decrease of 2 percent in annual average load level and a decrease of 11 percent in summer peak load level from 2013.
- On the supply side, production from non-gas fired generation and net imports rose by an average of 1,650 MW in the winter of 2014, which helped offset the effects of the tight natural gas supplies.

Transmission congestion continued to be relatively limited in New England. In 2014, only $32 million of congestion revenues were collected in the day-ahead market, which were 20 to 30 times less than in other RTO/ISO markets.

A major market design change, Energy Market Offer Flexibility, was implemented on December 3, 2014. This allowed market participants to vary their supply offers by hour and to update their supply offers during the operating day to reflect actual costs. Previously, suppliers submitted one offer on the day prior to the operating day that was applicable to all hours of the day. This change is a significant improvement because supply offers are now more reflective of actual fuel

2 The weather conditions in the first quarter were known as a Polar Vortex that resulted in record cold temperatures throughout the Eastern Interconnect.

3 The low natural gas prices in New England were partly due to higher production in the Marcellus region.

4 This is based on gas price indices reported by Platts for Algonquin City Gates.

5 The real-time price at the New England Hub, which is representative of the New England market, is reported here. The average energy price is weighted by the New England load level in each hour.

costs, especially in the winter months when natural gas prices are more volatile. As a result, real-time price signals should be more efficient.

2. Reserve and Regulation Markets

ISO-NE procures operating reserves in the real-time market to maintain reliability when system contingencies occur. It also procures regulation, which allows it to adjust the output of selected resources every 4 to 6 seconds to keep supply and demand in balance. This subsection summarizes the outcomes in these markets in 2014.

Real-Time Reserves

The average real-time reserve prices fell 16 to 34 percent from 2013 to 2014. The decrease occurred primarily after the first quarter of 2014, reflecting lower natural gas prices, lower load levels, and less frequent peaking conditions (resulting in fewer shortages) than in 2013.

In December 2014, the ISO increased the Reserve Constraint Penalty Factors (RCPF) for the 10-minute total reserves and 30-minute operating reserves from $850 and $500 per MWh to $1,500 and $1,000 per MWh, respectively. To the extent that this better reflects the reliability provided by the operating reserves (i.e., the value of the electricity consumption being protected or "value of lost load"), these changes improve the efficiency of real-time prices by more fully pricing the ISO's true reliability needs and improving generators' performance incentives.

Forward Reserves

Unlike real-time operating reserves, the average clearing prices for forward reserves rose more than 80 percent from 2013.[6] After deducting the forward capacity prices, the effective forward 30-minute reserve clearing prices rose from roughly $2.70/MWh in 2013 to $8.10/MWh in 2014. The large increase in the effective forward 30-minute reserve clearing prices partially reflected the increase in the real-time 30-minute reserve clearing prices. This is expected given that a large component of the cost of providing forward reserves for a fast start generator is the expected forgone revenue from selling real-time reserves.

6 Forward reserve suppliers are paid based on the difference between the forward reserve clearing price and the forward capacity price.

The ISO may wish to consider the long-term viability of the forward reserve market because:

- It has not achieved one of its primary objectives, which was to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The Locational Forward Reserve Market is largely redundant with the locational requirement in the Forward Capacity Market.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. Forward reserve sellers are simply obligated to offer at prices higher than the Forward Reserve Threshold Price, but may still be dispatched for energy.
- 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.

As an alternative to the forward reserve market, we recommend the ISO consider introducing day-ahead reserve markets. Such markets would allow the ISO to procure the reserves it needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond to reserve deployments. This is particularly true for spinning reserve providers, since it is prohibitively costly for them to accept forward reserve obligations for an entire procurement period.

Regulation Service

Average regulation clearing prices rose 63 percent in 2014 and total regulation expenses rose 41 percent to $28.8 million. These increases were driven partly by the market design change in July 2013, which introduced opportunity costs in the capacity clearing prices, and partly by the high natural gas prices in the first quarter of 2014 during the Polar Vortex. On average, more than 600 MW of available supply competed to provide less than 60 MW of regulation service. The significant excess supply generally limits competitive concerns in the regulation market.

ISO-NE recently implemented two-part offers for regulation (i.e., availability and movement) in compliance with Order 755 on March 31, 2015. We will monitor the effects of this change.

3. Forward Capacity Market

Clearing prices for capacity rose sharply in the 8th Forward Capacity Auction (FCA 8), which procures capacity for the 2017/2018 planning year, as retirements reduced the supply considerably and certain external suppliers submitted high-priced offers. The Insufficient Competition ("IC") Rule was invoked for the entire system in FCA 8, which resulted in much lower prices for existing resources than for new resources, and caused ISO-NE to not clear all of the existing resources that would have been necessary to satisfy the capacity requirement. As a result, all new resources and the Boston zone cleared at $15 per kW-month, while existing resources outside Boston received $7.03 per kW-month.

In FCA 9 for the 2018/2019 planning year, the sloped demand curve was used for the first time at the system level, which set the clearing prices at $9.55 per kW-month for all new and existing resources located outside the SEMA-RI Capacity Zone. The SEMA zone was modeled for the first time in FCA 9 and did not have enough resources to meet its local requirements. Hence, the Inadequate Supply Rule was triggered and new resources were paid $17.73/kW-month and existing resources at $11.08/kW-month. Finally, external suppliers were paid less than internal supply because more external capacity was offered than could be accommodated given the interface transfer limits. In this case, the price falls to ration the available transfer capability.

ISO-NE plans to implement local zone sloped demand curves for FCA 11, which we believe will be an efficient means to price capacity in cases where New England has inadequate supply. This change, along with others we recommend to foster more robust competition from new resources, should allow the ISO to discontinue use of the administrative pricing rules. We discuss these issues in more detail and recommend improvements in Section V.

4. Uplift Costs

When ISO-NE makes supplemental commitments of resources that were not economic in the day-ahead market to satisfy the reliability needs of the system, such generators receive NCPC payments to recover their full as-bid costs. When NCPC costs are incurred to address local reliability issues, these costs are allocated to the local customers who benefit directly from the commitments. "Economic" NCPC is allocated throughout New England, most of which is allocated to real-time deviations, up or down, from participants' day-ahead schedules. This allocation to deviations is not consistent with the causes of this NCPC, which is discussed in Section III.A.

Total NCPC uplift charges increased moderately from $150 million in 2013 to $158 million in 2014. The month-to-month variations in each category of NCPC uplift were generally correlated with the level of supplemental commitments and natural gas prices. Both of these were highest during the Polar Vortex, which accounted for almost half of the total NCPC costs in 2014. ISO-NE's uplift costs averaged $1.14 per MWh of load, an amount that is substantially higher than both the NYISO ($0.86) and MISO ($0.36). The higher costs incurred in New England can be attributable to a number of factors:

- The NYISO software allows high-cost peaking resources to set prices that may otherwise require higher uplift payments. MISO recently implemented comparable software. ISO-NE is working on a similar approach, which should reduce its NCPC costs.
- ISO-NE's fuel costs tend to be higher than the other RTO's, leading to higher required make-whole payments.
- Gas pipeline operating issues tend to lead to higher gas availability concerns in New England than in other areas, which can increase the amount of supplemental commitments made by ISO-NE and associated uplift payments.
- NYISO and MISO had hourly generator offers, which was particularly important during the Polar Vortex in early 2014 when natural gas prices were highly volatile. The ability to adjust offers hourly improves resource availability by ensuring that offers reflect actual costs. By more fully reflecting these costs in energy prices, uplift costs decrease. ISO-NE implemented hourly offers in December 2014.
- NYISO and MISO allocate uplift costs more consistently with cost causation, particularly MISO. MISO's allocation promotes full net load scheduling in the day-ahead market (i.e., close to 100 percent) and reduces the need to rely on high-cost peaking units to satisfy the incremental load in real time (generally contributes to market-wide uplift).

As noted above, a number of the market design improvements we have recommended or that are being implemented by ISO-NE promise to improve real-time price formation and, as a result, will lower the NCPC costs in New England.

5. Long Run Price Signals

The economic signals the markets provide that govern participants' long-run decisions (including investment, retirement, and maintenance decisions) can be measured by the net revenues generators receive in excess of their production costs. Net revenues for new and existing generators rose significantly in 2014 because of higher energy revenues (for all units) and higher forward reserve revenues (for fast-start peaking units). Most of the energy net revenues accrued in the first quarter when very cold weather led to higher natural gas prices and larger gas spreads between pipelines. The high gas prices also produced substantially higher net revenues for dual fuel units in 2014. These net revenues provide incentives for generators to maintain dual-fuel capability and oil inventory levels. Additionally, the spread in fuel prices between pipelines serving New England caused net revenues to be higher in Western Connecticut and Western Massachusetts. Not surprisingly, a large majority of the new resources offered in FCA 9 were in these areas.

Our evaluation indicates that the estimated net revenues for a new combined-cycle unit with dual-fuel capability and a new Frame 7 combustion turbine were higher than their respective annual cost of new entry ("CONE"), which is the level that should render such new investments profitable. However, it is important to recognize the some higher net revenues received during 2014 were attributable to the unusual conditions during the first quarter of the year. Net revenues will increase on a sustained basis over the next few years as higher forward capacity market revenues begin to be received by suppliers in New England.

B. Key Market Design Improvements: Energy Markets and Uplift

1. Real-Time Price Setting by Fast-Start Units

Efficient real-time prices are important because they encourage competitive scheduling by suppliers, participation by demand response, and investment in new resources when and where needed. Additionally, efficient price signals during shortages and tight operating conditions can reduce the reliance on revenue from the capacity market to maintain resource adequacy.

Our evaluation finds that fast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2014, 58 percent of the fast-start capacity that were started in the real-time market did not recoup its offer. This leads fast-start resources with flexible characteristics to be substantially under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits. If the average total offers of these units were fully reflected in the energy price, the average real-time LMP would increase approximately $4.20 per MWh in 2014 (market responses by external suppliers and changes in commitment patterns would likely partially offset this increase). If these price increases were reflected in the calculation of NCPC uplift charges, we estimate that NCPC costs would have been $10.2 million lower in 2014.

Based on these substantial benefits, we have been recommending that the ISO develop a pricing model that would allow fast-start peaking units to set real-time prices when they are economic to run. In response, the ISO has evaluated potential changes in the pricing methodology that would allow the deployment costs of fast-start units to be more fully reflected in the real-time market prices and has proposed changes in pricing rules for implementation in 2016.[7] The proposed change is comparable to MISO's "Extended LMP" or "ELMP" model implemented in early 2015, which in turn was patterned after NYISO's gas turbine pricing methodology that it has used for years. These two approaches have functioned well in practice. Hence, we support ISO-NE's proposed improvements in this area and recommend that it continue to place a high priority on it. (see Recommendation 1)

2. Day-Ahead Market Liquidity and NCPC Allocations

When prices in the day-ahead market converge well with the real-time market, it leads to an efficient commitment of resources (and the most economic procurement of fuel). We found that price convergence between the day-ahead and real-time markets was generally not optimal in the past several years despite some improvement in 2014. Average real-time prices at the New England Hub have been persistently higher than average day-ahead prices in most of the months for several years. This is not efficient because small day-ahead premiums generally lead to a more efficient commitment of the system's resources (since the real-time prices tend to be under-stated because peaking resources frequently do not set prices when they are on the margin). The prevailing day-ahead and real-time prices result in roughly only 95 percent of the load being scheduled in the day-ahead market, which makes it impossible for the day-ahead market to efficiently commit the system.

The primary means to achieve an efficient relationship between day-ahead and real-time prices is to foster liquidity in the day-ahead market. Most of the true liquidity in the day-ahead market is

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7 See "Fast Start Pricing: Improving Price Formation When Fast Start Resources Are Committed and Dispatched" by Jonathan Lowell, March 11, 2015, NEPOOL markets committee meeting, for more details of the proposed rule changes.

provided by virtual transactions whose purchases and sales are sensitive to changes in day-ahead prices. Unfortunately, virtual load and supply accounted for only roughly 1.5 percent of actual load in the ISO-NE market, notably lower than in the NYISO and the MISO markets (generally more than 5 percent).

One factor the helps explain the prevailing relationship between day-ahead and real-time prices and the relatively low level of virtual transactions in New England is ISO-NE's current method for allocating economic NCPC charges. NCPC charges are caused by many factors other than real-time deviations, such as when peaking resources are dispatched but do not set LMPs or when supplemental commitments are made for forecasted needs that do not materialize. Although these causes of economic NCPC are unrelated to deviations, the costs are nonetheless allocated to NCPC. This results in charges to virtual transactions that have averaged \$2 to \$4 per scheduled MWh in the past several years, which is significantly higher than the charges that virtual traders face in the NYISO and the MISO markets (e.g., \$0.10 and \$0.71/MWh in 2014, respectively). The high NCPC charges reduce the liquidity of the day-ahead market by reducing virtual trading volumes, and hinder the day-ahead market's natural response to transitory price differences between the day-ahead and real-time markets.

In addition, ISO-NE's allocation does not distinguish between "helping" and "harming" deviations and is, therefore, not consistent with cost causation.[8] We find that the current allocation of NCPC costs to "helping" deviations and over-allocation of costs to "harming" deviations undermines the performance of the day-ahead market.

Therefore, we continue to recommend that the ISO modify the allocation of Economic NCPC charges to participants that cause the NCPC (Recommendation 3). To address this recommendation, the ISO will be evaluating improvements in the allocation of real-time NCPC to virtual transactions and other types of real-time deviations. Stakeholder discussions on these changes should begin in the fourth quarter of 2015.

8 "Helping" deviations, such as over-scheduling load (including virtual load), generally result in higher levels of resource commitments in the day-ahead market and, therefore, usually decrease the ISO's need to make additional commitments to reduce associated NCPC. "Harming" deviations, such as under-scheduling physical load in the day-ahead market, can cause the ISO to have to commit additional units in real-time to satisfy the system's requirements, which are likely to increase NCPC.

3. Efficiency of Interface Scheduling with New York

Efficient scheduling of the interfaces between New England and its neighbors can have a significant effect on the ISO-NE market outcomes. It is particularly important with New York because both regions have real-time spot markets and market participants can schedule market-to-market transactions based on transparent price signals in each region.

Our evaluation of the primary interface between New England and New York finds that, in 2014:

- The price difference between the two markets exceeded $10 per MWh in 38 percent of the unconstrained hours and exceeded $50 per MWh in 7 percent of the unconstrained hours; and
- Approximately 42 percent of real-time transactions were in the inefficient direction (i.e., from the high-priced region to the low-priced region).

These results indicate that the current process does not fully utilize the interface. Uncertainty and long scheduling lead times have prevented participants from fully arbitraging the interface. This has resulted in substantial inefficiencies and higher costs in both areas. It also degrades reliability because the interchange does not adjust predictably to changes in supply or demand changes in New England.

To address this issue, ISO-NE and NYISO are implementing the Coordinated Transaction Scheduling ("CTS") process to improve the efficiency of the interchange between the two control areas. CTS will allow intra-hour changes in the interchange between control areas and is scheduled to be effective in the fourth quarter of 2015. Under CTS, the ISOs will schedule interchange based on short-term forecasts of market conditions and new bidding procedures that allow firms to submit bids that are jointly evaluated by the ISOs. We continue to recommend that the ISO place a high priority on the implementation of CTS (see Recommendation 2).

4. Real-Time NCPC Payments to Units Committed in the Day-Ahead Market

The ISO implemented a package of significant market reforms in December 2014 to increase offer flexibility and modify NCPC payments. The new NCPC rules are designed to ensure that generators always have the incentive to start after being scheduled in the day-ahead market. Effectively, the new rules use real-time prices after-the-fact and make payments to generators that ran but may have been economic to keep offline. These payments have constituted a substantial majority of all real-time NCPC payments since December 2014 and are averaging more than $5 million.

However, we have concluded that the payments are: a) much higher than necessary to provide the incentive effects that are intended, and are b) not necessary for generators to have an incentive to follow the ISO's commitment instruction. The NCPC rules result in payments higher than the potential savings a generator could earn by shutting down because:

- The actual real-time LMPs do not include the effects of shutting down the generators receiving the NCPC. The quantity of these generators frequently exceeded the total headroom (i.e., the system would be in shortage if all the generators receiving payments did not start and prices would be very high). Hence, the LMP used in the calculation is understated, which inflates the NCPC payment.
- The NCPC formula assumes the generator's cost is equal to its real-time offer, but suppliers receiving these payments do not have any incentive to lower their offer in real-time to reflect their true costs, which contributes to the upward bias in NCPC payments.
- The NCPC rule ignores the fact that suppliers will not know what real-time prices will prevail at the time they are starting. In other words, it provides the economic benefit a supplier would receive only if it had perfect foreknowledge of the real-time prices.
- High-cost units committed for reliability in the day-ahead market (and receiving day-ahead NCPC) are likely to not be economic to run at real-time prices. However, there is no equitable basis for making a second real-time NCPC payment to motivate the supplier to start its unit. Efficient incentives would be created by charging such suppliers the NCPC costs of replacing their units if they do not start (or at a minimum, clawing back the day-ahead NCPC payment).

Consequently, the NCPC rules are substantially over-compensating non-fast start generators committed in the day-ahead market on days where the real-time prices turn out in retrospect to be less than the generator's full costs. Additionally, these payments create adverse incentives or inefficiencies because they: a) create inefficient incentives to start uneconomic units on days when the system is substantially over-committed, b) produce adverse incentives for suppliers to modify their offers to significantly inflate these payments; and c) may discourage generators from providing flexibility in their offers. Hence, we recommend that the ISO work as quickly as possible to modify its NCPC rules to eliminate these payments and modify the rules applicable to suppliers that received day-ahead NCPC payments (Recommendation 4).

5. Commitment of Multi-Turbine Units for Local Reliability

Our evaluation finds that multi-turbine combined cycle units accounted for a large share of local reliability commitments in 2014. In many cases, the local reliability need could have been satisfied with a single turbine configuration. We found that the reliability commitments of these multi-turbine units led to nearly $27 million of NCPC uplift in 2014. In many cases, it is likely that the local reliability need could have been satisfied with only one of the units, so committing multiple units led to excess production costs, depressed LMPs, and more NCPC costs. This raises significant concerns because suppliers with units committed for local reliability may increase their profits by registering multiple units as a single generator for bidding purposes, even though each unit is capable of operating separately.

We believe this is analogous to a dual-fueled unit requiring ISO-NE to compensate it for burning oil when it is committed for local reliability when it is capable of burning natural gas at a much lower cost. This conduct is not acceptable, and we find that requiring the ISO to commit units for local reliability in a multi-turbine configuration should also be deemed unacceptable. Hence, we recommend that the ISO modify its tariff to allow it to commit a single unit at a multi-unit generator location when this provides a more efficient means to satisfy the local reliability need (Recommendation 5).

6. Improving the Operating Reserve Markets

As in prior years, we also found that 99 percent of the resources assigned to satisfy forward reserve obligations in 2014 were fast-start resources capable of providing offline reserves. Although it has been effective in generating additional revenue for fast-start resources, we find that the value of the forward reserve market is questionable because:

- It has not achieved one of its primary objectives, which was to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The Locational Forward Reserve Market is largely redundant with the locational requirement in the Forward Capacity Market.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. Forward reserve sellers are simply obligated to offer at prices higher than the Forward Reserve Threshold Price, but may still be dispatched for energy.
- 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. These distortionary effects will have larger price effects in the future if the ISO implements the recommendation to allow peaking units to set the LMP.

Accordingly, we recommend ISO-NE consider eliminating the forward reserve market (see Recommendation 7).

Regardless of whether the forward reserve market is retained, we also recommend the ISO consider introducing day-ahead reserve markets (see Recommendation 6). Such markets would allow the ISO to procure the reserves it needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond to reserve deployments. This is particularly true for spinning reserve providers, since it is prohibitively costly for them to accept forward reserve obligations for an entire procurement period.

C. Key Market Design Improvements: Capacity Market

1. Improving the Competitive Performance of the FCA

Forward Capacity Markets are designed to allow participation by prospective new investors, which increases competition in theory by providing competitive discipline for existing suppliers that might otherwise have an incentive to exercise market power. In each of the last three forward capacity auctions, there has been a need for new resources in at least one capacity zone and the new generators offered have been relatively limited. If participation by new developers is not robust, auction results may not be efficient and competitive.

In particular, this report shows that when new suppliers are pivotal (must clear in order for ISO-NE to satisfy its capacity requirements), that they have strong incentives to raise their offers and increase the capacity prices. This incentive is attributable to the higher revenues they will earn on other existing assets and the seven-year lock-in that extends the revenue benefits of raising capacity prices. Likewise, the report shows that existing suppliers that are pivotal have strong incentives to retire units that would otherwise be economic in order to increase capacity prices. Thus, it is important to evaluate the forward capacity market on an on-going basis and to identify factors that may inhibit participation by new resources or otherwise reduce competition.

The report reviews participation in FCA 9, conducted in February 2015 for the 2018/2019 planning year. This review indicated the following:

- A large amount (557 MW) of new capacity was needed to satisfy the local requirement in Southeast Massachusetts ("SEMA").
- In SEMA, although 880 MW of new generation was proposed to be operational, only 208 MW ultimately qualified and 95 percent was a single project. This developer should have known that it was pivotal in the auction (i.e., that its offer would be accepted at any price below the FCA starting price of $17.73 per kW-month).
- In NEMA, there was a local excess of 265 MW prior to the auction, so additional resources would not have been needed unless existing capacity de-listed in the auction.
  - While 1,048 MW of proposed new generation was in the interconnection queue, it was apparent from information filed by the ISO that 841 MW did not qualify for the auction (leaving just a single 208 MW new generator).
  - Thus, if a non-price retirement request or other supply reduction had occurred, this developer would have known it was pivotal and could set the capacity price at the FCA starting price.

Four observations can be drawn from the results of FCA 9 and earlier capacity auctions:

- Publishing information on qualified capacity (new and existing) ensures that suppliers will recognize when they are pivotal and can benefit by raising capacity prices.
- Information provided through the descending clock auction process likely reduces the competitiveness of the auction results by allowing suppliers to determine when they have likely become pivotal (when other suppliers leave the auction).
- To the extent that the qualification process limits the number of new resources participating in the auction, the competiveness of the auction will be reduced.
- The vertical shape of the demand curve accentuates the price impact that a new resource can have when it is pivotal.

These observations point to several market changes that could enhance competition in the FCA, in addition to implementing sloped demand curves in the local areas by FCA 11:

- Reducing barriers to participation helps provide additional competitive discipline that reduces the incentive for a supplier to raise its offer substantially above its net CONE.
- Reducing the amount of information available before the auction to make it more difficult for a pivotal supplier to determine its profit-maximizing offer and encourage new suppliers to offer competitively at prices closer to their net CONE.

- Transitioning from the descending clock auction process to a sealed-bid auction to eliminate the information provided during the auction that reduces the competitiveness of the auction. This change would also facilitate the joint optimization of the capacity procurements in local areas and system-wide.

Because we have substantial competitive concerns regarding new suppliers' incentives to submit competitive offers, we recommend ISO-NE pursue improvement in each of these areas. With regard to information in particular, this report identifies a number of specific sources of information made available by the ISO that it should consider reducing or eliminating (see Recommendation 10).

In addition, we recommend ISO-NE consider adopting appropriate eligibility rules for resources' use of the Non-Price Retirement Requests (i.e., that it be reserved for cases where the factor driving the decision to retire cannot reasonably be reflected in a de-list offer). This would allow the ISO's supply-side mitigation measures to be appropriately applied to the retirement (see Recommendation 8).

2. Local Capacity Zone Modeling

The sloped demand curve was used for the first time in FCA 9 to clear resources for the system-wide capacity requirement ("NICR"). Sloped demand curves facilitate considerably better market performance because they are much more consistent with the marginal reliability benefits capacity provides relative to vertical demand curves. This is fundamental because the reliability benefit of satisfying the planning requirements is the primary reason the capacity market exists.

Hence, sloped demand curves are essential for capacity markets to perform well and establish efficient clearing prices. Sloped demand curves have been used successfully in the PJM and NYISO capacity markets.

The ISO plans to implement sloped demand curves for local capacity zones in FCA 11, and has been developing proposals on how the curves will be developed and utilized. Although the ISO has withdrawn its latest proposal, this type of approach would lead to increased price volatility and inefficient prices outside of the local capacity zones in the "rest of pool" area ("ROP"). These concerns generally arise because this type of approach models a separate ROP zone with a residual demand curve (system-wide demand curve minus the sum of the individual zonal demand curves) and assumes the demand for capacity in each zone is independent of the supply and demand in other zones.

Given these concerns, we recommend the ISO model a system-wide demand and local zonal demand, rather than modeling a ROP zone that is independent of the local zones. This framework increases the likelihood of satisfying resource adequacy (i.e., 1-day-in-10) criteria at both the local and system levels when there is insufficient supply to satisfy the capacity requirements in the local zone.

Modeling demand curves and clearing the FCA in a manner that recognizes the interdependence of capacity zones will reduce the capacity price volatility and ensure that prices in the ROP zone better reflect the marginal value of reliability. Hence, as the ISO continues to work with its stakeholders to develop a revised zonal demand curve proposal for FCA 11, we recommend the ISO develop curves that efficiently reflect this interdependence. (see Recommendation 9).

D. Table of Recommendations

We make the following recommendations based on our assessment of the ISO-NE's market performance in 2014. 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[9]	Feasible in ST[10]
Energy Markets			
1. Allow the costs of fast-start resources, operator actions, and demand response deployments to be reflected in real-time prices.	✓	✓	
2. Implement provisions to coordinate the physical interchange between New York and New England in real-time.	✓	✓	✓

9 Recommendation will likely produce considerable efficiency benefits.

10 Complexity and required software modifications are likely limited.

Recommendation	Wholesale Mkt Plan	High Benefit[9]	Feasible in ST[10]
NCPC Payment Criteria & Allocation			
3. Modify allocation of "Economic" NCPC charges to make it more consistent with a "cost causation" principle.	✓	✓	✓
4. Eliminate real-time NCPC payments intended to recover commitment costs for non-fast start resources scheduled in the day-ahead market.			✓
Reserve Adequacy Assessment			
5. Utilize the lowest cost configuration for multi-unit generators when committing resources for local reliability.			✓
Reserve Markets			
6. Consider introducing day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
7. Consider eliminating the forward reserve market.			✓
Capacity Markets			
8. Introduce eligibility requirements governing the use of Non-Price Retirement Delist Bids.		✓	✓
9. Determine sloped demand curves for FCA 11 that recognizes the interdependence of the demand for capacity in different zones and system-wide.	✓	✓	
10. Modify interconnection and capacity market rules to foster robust competition from new resources and imports in the FCA.		✓	✓

II. Overview of Market Outcomes and Trends

The ISO-NE operates a multi-settlement wholesale market system consisting of a financially-binding day-ahead market for energy and a real-time market for energy, operating reserves, and regulation. Through these markets, the ISO-NE commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices on a locational basis. In this section, we review wholesale market outcomes in New England during 2014 and highlight market results and performance in the following areas:

- Wholesale energy market;
- Reserves and regulation markets;
- Fuel usage under tight gas supply conditions;
- Market long-run price signals;
- Out-of-market actions and uplift costs;
- Forward capacity market;
- Long run price signals; and
- Competitive performance of the energy market.

A. Energy Market Outcomes

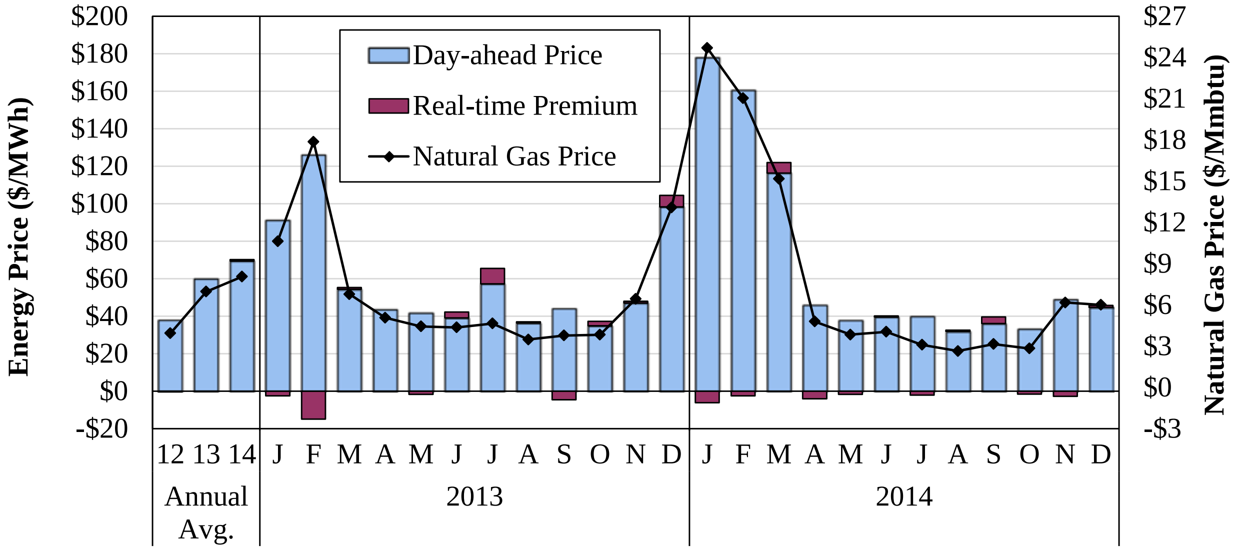
ISO-NE manages flows over the network to avoid overloading transmission constraints by altering the dispatch of its resources and establishing Locational Marginal Prices ("LMPs") to establish efficient, location-specific prices that reflect the marginal value of transmission congestion and losses in order to serve load at that location. Transmission congestion has been relatively limited in New England in the past several years. In 2014, total day-ahead congestion revenues were only $32 million in New England, which is 20 to 30 times less than in other RTO/ISO markets. The low congestion levels in New England are attributable to the extensive transmission investment made over the past few years. Given the limited congestion, we generally focus on the New England Hub in this section as a representative location for our evaluation of price trends and price convergence in the ISO-NE energy market.[11]

[11] The New England Hub is an average of prices at 32 pricing nodes in the center of New England. It is published to facilitate bilateral contracting. Futures contracts are listed on the New York Mercantile Exchange and Intercontinental Exchange that settle against day-ahead and real-time LMPs at the Hub.

1. Energy Prices and Price Convergence

Figure 1 summarizes monthly day-ahead prices and the convergence between day-ahead and real-time prices at the New England Hub over the past two years.[12] The figure also shows the average natural gas price, a key driver of energy prices when the market is operating competitively, which is discussed in more detail in subsection 2.[13]

Figure 1: Monthly Average Energy Prices and Natural Gas Prices
New England Hub, 2013 – 2014



Implied Heat Rate (MMbtu/MWh)	8.7	8.2	8.5	8.0	6.8	7.4	7.7	8.2	7.8	10.5	9.0	10.0	8.0	7.0	7.4	7.7	7.4	7.6	8.5	8.5	8.6	10.7	9.7	9.4	9.9	7.3	6.8
RT Premium (%)	0.8	0.3	-1.1	-2.6	-11.8	1.8	-0.6	-3.8	8.0	14.4	1.8	-10.1	6.5	2.2	6.3	-3.4	-1.6	4.8	-8.6	-4.2	1.5	-5.0	1.7	9.5	-4.4	-5.5	2.2
Avg. Abs. Diff (%)	21	26	27	23	26	21	14	20	30	37	23	24	25	28	29	24	29	27	18	19	24	27	28	36	27	20	48

Summary of Energy Prices in 2014

Overall, the average New England Hub price in the day-ahead market increased 16 percent from 2013 to 2014. Polar Vortex conditions in the first quarter of 2014 contributed to unusually high loads and volatile natural gas prices. The resulting high energy prices during the first quarter of 2014 were the primary cause of annual average price increases from 2013. The increase in the first quarter was partly offset by lower energy prices in the rest of the year as a result of lower natural gas prices and lower load levels (particularly in the summer).

12 These are load-weighted average prices.

13 The figure shows the simple average of gas price indices reported by Platts for Algonquin City Gates.

Implied Marginal Heat Rate

The table in Figure 1 also shows an average implied marginal heat rate.[14] This metric is helpful in identifying changes in energy prices that are not driven by changes in fuel prices (e.g., energy demand, supply availability, etc.). The implied marginal heat rate shows a seasonal variation in energy prices because of factors other than natural gas prices that are not readily apparent in the average monthly prices. For example, the implied marginal heat rates were highest in the peak summer months when high load levels lead to tight market conditions on hot days. July exhibited the highest average implied marginal heat rate and the highest load levels in both 2013 and 2014. The variations in load levels are discussed in more detail in the Section II.A.3.

Correlation of Energy Prices and Fuel Prices

The figure shows that natural gas price fluctuations were a significant driver of variations in monthly average energy prices in 2013 and 2014 as expected. In 2014, nearly 45 percent of the installed generating capacity in New England burned natural gas as its primary fuel and these resources produced 44 percent of all electricity.[15] Nonetheless, natural gas-fired resources were on the margin and set the market clearing price in most hours because low-cost nuclear resources and other baseload resources typically produce at full output and are not marginal.[16] Therefore, energy prices should be strongly correlated with natural gas prices in a well-functioning competitive market. Natural gas prices are typically highest during the winter months when heating demand for natural gas increases due to colder weather. The availability of natural gas to New England generators during cold weather periods is evaluated further in Section II.C.

14 The Implied Marginal Heat Rate equals the day-ahead electricity price minus a generic unit Variable Operations and Maintenance ("VOM") cost (which is assumed to be $3/MWh in this calculation), then divided by the fuel cost that includes the natural gas cost and greenhouse gas emission cost (i.e., RGGI Allowance Cost). For example, if the energy price is $50/MWh, the VOM cost is $3/MWh, the natural gas price is $5/MMbtu, and the RGGI clearing price is $3/CO2 allowance, this would imply that a generator with a 9.1 MMbtu/MWh heat rate is on the margin (i.e., ($50/MWh – $3/MWh) / ($5/MMbtu + $3/ton * 0.06 ton/MMbtu emission rate)).

15 ISO-NE, "2014-2023 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) Report," May 2014.

16 In 2014, 44 percent of net generation was produced from natural gas, while 35 percent was produced from nuclear fuel, 6 percent from hydroelectric, 8 percent from other renewables sources (including refuse burning), 5 percent from coal, and 2 percent from fuel oil.

Day-Ahead and Real-Time Price Convergence

The first measure of convergence reported in Figure 1is the average real-time premium (the average real-time price minus the average day-ahead price). The sum of the average day-ahead price (blue bar) and the average real-time price premium (maroon bar) is equal to the average real-time price. The table below the chart also shows this measure of convergence as a percentage of average day-ahead price. The second measure of convergence, the average absolute difference between day-ahead and real-time prices, is reported in the table as a percentage of the average day-ahead prices as well. This metric indicates the average price difference, regardless of whether the day-ahead price is higher or the real-time price is higher.

The figure shows that the market exhibited a small day-ahead premium in 2014 on an annual basis, in contrast to the small real-time premium as in 2012 and 2013. Half of the months in the past two years exhibited a real-time premium. Although small differences indicate that the day-ahead market is converging well with the real-time market over time, it is important to recognize that New England's day-ahead market will produce the most efficient outcomes when it is priced higher than the real-time market, which will generally lead to a more efficient commitment of the system's resources. This is the case because real-time energy prices frequently do not reflect the full costs of the marginal source of supply, which is shown in Section IV.A. For example, when high-cost peaking resources are committed to satisfy the real-time demand, real-time prices generally do not reflect the full costs of such resources. Because the real-time prices are understated in these cases, day-ahead prices would have to be slightly higher than the actual real-time prices in order to efficiently facilitate a day-ahead commitment of resources to fully satisfy the real-time system needs.

One reason that the New England energy markets do not achieve fully efficient price convergence is its allocation of NCPC charges. If these costs are allocated to those participants that contribute to the need to commit resources after the day-ahead market (e.g., virtual supply, under-scheduled load, etc.) and not to those participants that reduce the need to commit additional resources (e.g., virtual load), the convergence of New England's day-ahead and real-time energy prices would be more efficient. These issues are discussed in detail in Section III.A.

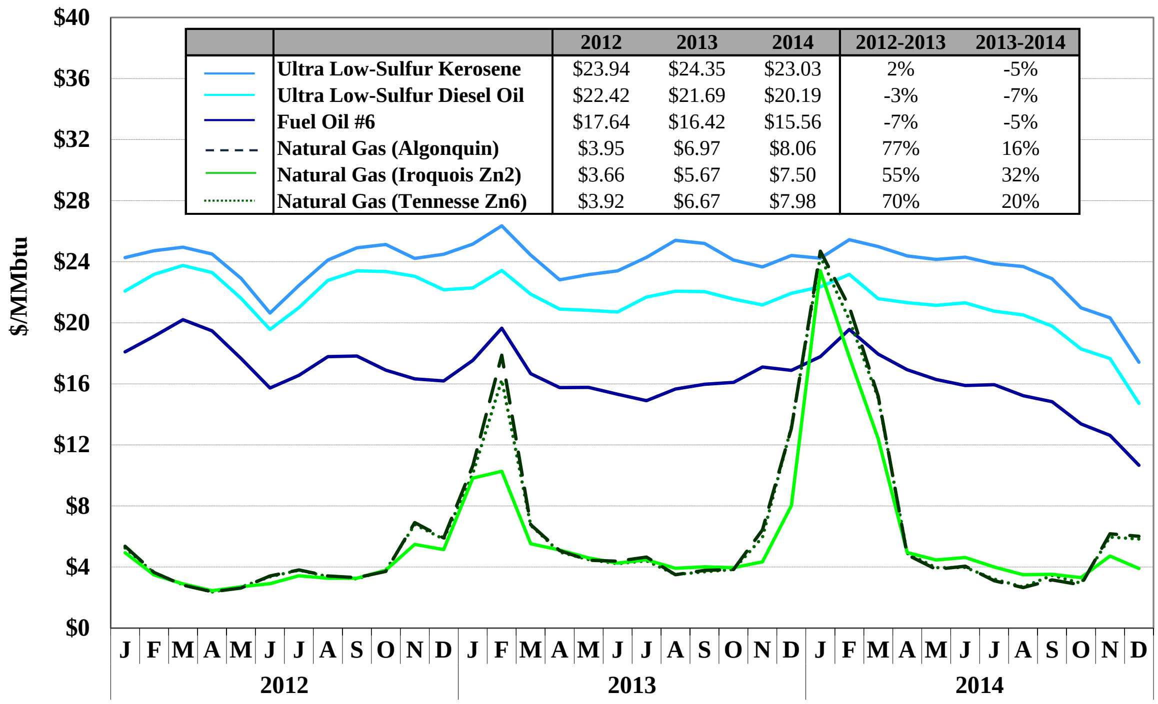
2. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices because most of the marginal costs of thermal generators are fuel costs. Although much of the electricity generated in New England is from hydroelectric, nuclear, and coal-fired generators, natural gas units are usually the marginal source of generation. Hence, natural gas prices more directly affect wholesale energy prices.

Nearly 10 GW of generating capacity in New England is capable of burning oil (including oil-only and dual-fuel capability). On very cold winter days when the supply of natural gas is constrained, the effects of natural gas price spikes on energy prices can be partly mitigated by generators burning fuel oil.

Figure 2 shows natural gas price indices for three pipelines, Algonquin, Iroquois Zone 2, and Tennessee Zone 6, which serve most of generators in Connecticut and Massachusetts, and three oil price indices, ultra low-sulfur kerosene, ultra low-sulfur diesel, and residual oil (#6 oil), which are commonly used fuel oils in New England. The figure shows these average fuel prices by month from 2012 to 2014 and the table shows the annual average fuel prices for three years.

Figure 2: Monthly Average Fuel Prices
2012 – 2014



	2012	2013	2014	2012-2013	2013-2014
Ultra Low-Sulfur Kerosene	$23.94	$24.35	$23.03	2%	-5%
Ultra Low-Sulfur Diesel Oil	$22.42	$21.69	$20.19	-3%	-7%
Fuel Oil #6	$17.64	$16.42	$15.56	-7%	-5%
Natural Gas (Algonquin)	$3.95	$6.97	$8.06	77%	16%
Natural Gas (Iroquois Zn2)	$3.66	$5.67	$7.50	55%	32%
Natural Gas (Tennesse Zn6)	$3.92	$6.67	$7.98	70%	20%

Natural gas prices exhibited a typical seasonal pattern, which tended to rise in the winter when the demand for natural gas was highest and bottlenecks on the natural gas system occurred most frequently. This phenomenon was particularly notable in 2014 because of the Polar Vortex conditions. Natural gas prices rose to an average of $18 to $20/MMBtu in the first quarter of 2014, up significantly from an average of $4/MMBtu during the rest of the year.

Natural gas prices also showed a notable year-over-year variation in 2014. In the first quarter, average natural gas prices rose 73 to 109 percent from 2013 to 2014 because of higher demand associated with the unusually cold weather. However, in the other three quarters, average natural gas prices fell 13 to 26 percent from 2013, partly because of increased natural gas production in the Marcellus region.

Natural gas prices rose above fuel oil prices on many days in the winter of 2014, leading oil-fired generation to be economic more frequently. This helped reduce the severity of natural gas price spikes during tight winter operations. In addition, fuel oil prices started to fall in the middle of 2014, after several years of stability, because of increased global supply. Reported fuel oil prices fell 28 to 33 percent from June 2014 to December 2014 and fell 5 to 7 percent on an annual basis from 2013 to 2014.

These variations in natural gas and fuel oil prices led to comparable variations in generation patterns, import levels, and uplift charges, all of which are discussed throughout the report.

3. Energy Demand

In addition to fuel prices, energy demand is another key driver of wholesale market outcomes in New England. Fluctuations in energy demand normally explain much of the short-term variations in energy prices.

Table 1 summarizes the average load level, the summer peak load level (which is also the annual peak load level in New England), and the winter peak load level for each year from 2012 to 2014. The table also shows the number of hours when the system was in high load conditions separately for the summer and winter seasons.[17] The hours with the highest loads are important because a disproportionately large share of the market costs to consumers and revenues to generators occur in these hours.

Table 1: Summary of Energy Demand
2012-2014

Year	Average Load (GW)	Summer Peak Load (GW)	Winter Peak Load (MW)	Number of Hours: Summer >22GW	Number of Hours: Summer >25GW	Number of Hours: Winter >18GW	Number of Hours: Winter >20GW
2012	14.8	25.9	19.9	149	18	106	0
2013	14.9	27.4	21.5	181	44	239	18
2014	14.7	24.4	21.4	71	0	327	25

In general, energy demand grows slowly over time, tracking population growth and economic activity. However, weather patterns can cause year-to-year fluctuations in load levels, which fell in 2014 from prior years. In 2014, load averaged 14.7 GW and never exceeded 25 GW. Both the annual peak level and the average level were the lowest levels in the past five years. These levels reflected milder weather conditions in most months of 2014, particularly in the summer. Average load was down 7 percent in July and August compared to a year ago and summer peak load was approximately 3 GW (or 11 percent) lower than the summer peak in 2013. Load exceeded 22 GW during only 71 hours in 2014, significantly less than 225 hours in 2013.

Although load levels fell on average in 2014, winter load levels were relatively high because of the Polar Vortex conditions that occurred throughout the Eastern Interconnect. Although the winter peak level (21.4 GW on January 7, 2014) was slightly lower (by roughly 130 MW) than the prior winter peak, average load was up nearly 4 percent in the first quarter of 2014. These load levels contributed to volatile energy prices because constraints on the natural gas system led to unusually high levels of generator outages during these high load conditions. The performance of the system during these conditions is discussed in Section II.C.

17 In this table, the summer season includes the months of June, July, August, and September, and the winter season includes the months of December, January, February, and March.

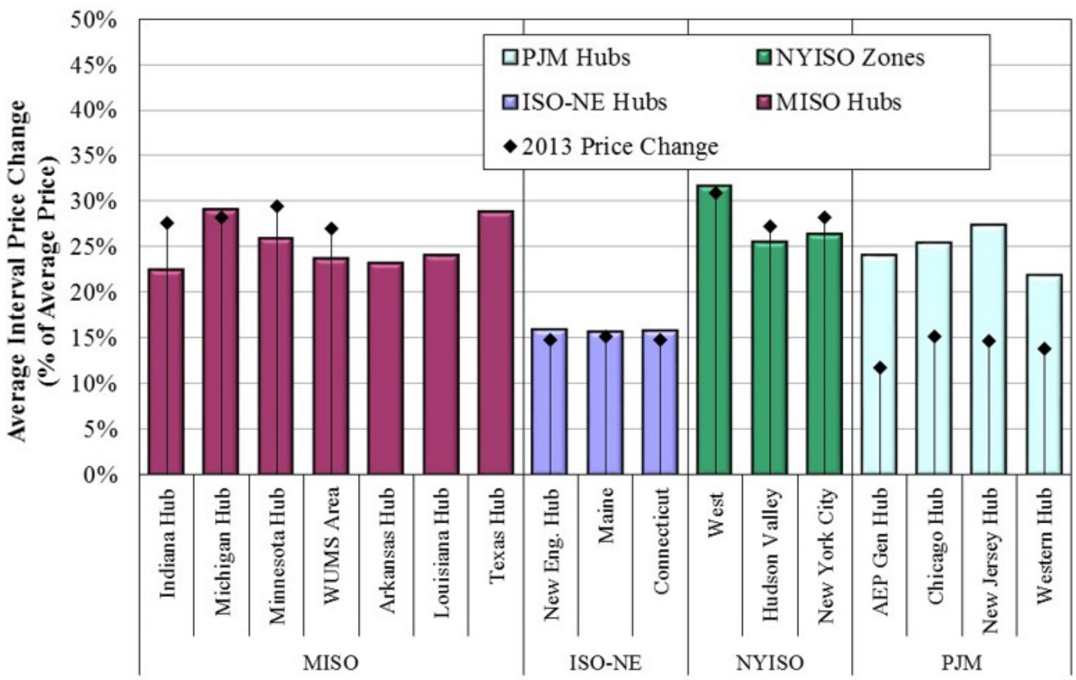
4. Real-Time Price Volatility

Volatility in real-time energy markets is expected because the demand of the system can change rapidly, and supply flexibility is restricted by the physical limitations of resources and the transmission network. In contrast, the day-ahead market operates on a longer time horizon with more commitment options and liquidity provided by virtual transactions.

Real-time markets solve over a limited time horizon – 15 minutes in New England.[18] When conditions change, the real-time market only has access to the dispatch flexibility that its units can provide in this horizon. Since the real-time market software is limited in its ability to "look ahead" and anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some generators are moving as quickly as they can). This limitation can result in transitory price spikes, either upward or downward.

Figure 3 compares fifteen-minute price volatility (the percentage change in prices, up or down, each quarter hour) at representative points in ISO-NE and in three other RTOs in the eastern interconnect.

Figure 3: Fifteen-Minute Real-Time Price Volatility
2014



18 MISO and NYISO dispatch over a 5 minute horizon while PJM is consistent with ISO-NE.

This figure shows that volatility was roughly the same in 2014 as in 2013, although increases in volatility during the first quarter were offset by decreases in the rest of the year. The figure also shows that New England is generally the least volatile market. This is true for a variety of reasons, including:

- ISO New England (and PJM) dispatches their systems every 10 to 15 minutes. Their longer time horizon lowers volatility by reducing ramp constraints.
- ISO New England experiences much smaller fluctuations in imports and exports then some of the RTO's, particularly MISO and PJM.
- Some RTOs have larger amounts of unpredictable supply and demand than ISO-NE, including wind output on the supply side and "non-conforming" load on the demand side.
- Some RTOs have historically priced shortages more aggressively than ISO-NE. This will no longer be the case following recent changes to increase the ISO's RCPFs.

ISO-NE has made and plans to make a number of changes to improve real-time price formation, including defining and pricing replacement reserves that had previously been procured outside of the market (through supplemental commitment), increasing the RCPFs for a number of classes of reserves (which are operating reserve demand curves), and developing enhanced capabilities for inflexible peaking resources and demand response to set real-time energy prices. These improvements tend to increase real-time price volatility, which is good because volatility efficiently compensates flexible resources and improves the incentives for suppliers to be available and perform well.

5. Summary of Imports and Exports

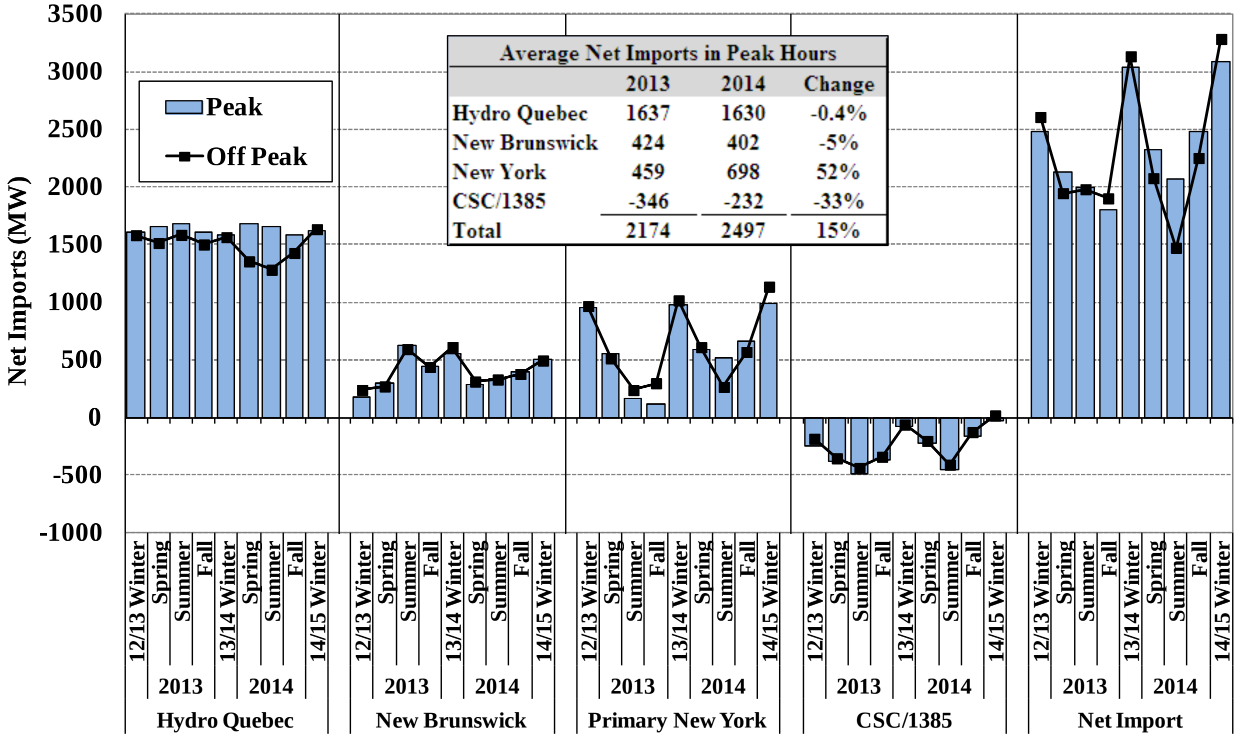
Consumers benefit from the efficient use of external transmission interfaces. The external interfaces allow low-cost external resources to compete to serve demand in New England. The ability to draw on neighboring systems for emergency power, reserves, and capacity also lowers the costs of meeting reliability needs in the interconnected system. Wholesale markets should facilitate the efficient use of both internal resources and transmission interfaces between markets.

ISO-NE receives imports from Quebec and New Brunswick in most hours. Between New England and New York, power can flow in either direction depending on market conditions, although ISO-NE imported more power from NYISO than it exported in the past several years. The transfer capability between New England and adjacent control areas is large (relative to the

New England's load), making it particularly important to schedule interfaces efficiently. This subsection summarizes the patterns of ISO-NE's imports and exports.

Figure 4 provides an overview of imports and exports for 2013 and 2014, which shows the average net imports by season across the external interfaces with Quebec, New Brunswick, and New York, in peak and off-peak periods.[19,20] The net imports across the two interfaces linking Quebec to New England (i.e., Phase I/II and Highgate) are combined. The net imports across the two interfaces between Connecticut and Long Island (i.e., Cross Sound Cable and the 1385 Line) are combined as well.

Figure 4: Average Net Imports from Neighboring Areas
By Season, 2013 – 2014



Net imports across the Canadian interfaces averaged approximately 2,030 MW during peak hours in 2014, which were consistent with the level in 2013 and accounted for over 80 percent of total net imports to New England in 2014. The interfaces with Quebec were often fully utilized

19 Peak hours include hours ending 8 to 23, Monday through Friday (not including NERC holidays), and the remaining hours are included in Off-Peak.

20 The figure shows a nine-season period from December 2012 to February 2015.

to import to New England. Average net imports from Quebec were generally higher during peak hours than during off-peak hours by roughly 220 MW in 2014. This reflected the tendency for hydro resources in Quebec to store water during low demand periods in order to make more power available during high demand periods. This pattern is beneficial to New England because it tends to smooth the residual demand on New England internal resources.

In the past, flows from Quebec typically rose in the winter months during periods of high natural gas prices. However, net imports from Quebec fell in the past two winters because of more frequent extreme cold weather conditions that led to limited hydro production and increased winter peaking load in Quebec.

Overall, New England was a net importer from New York in both 2013 and 2014. Net imports averaged 465 MW during peak hours in 2014, up roughly 355 MW from 2013. Most of the increase occurred in the summer and the fall as a result of increased natural gas spreads between New England and eastern New York from the prior year.

The figure also shows that flows across the primary interface with upstate New York and the two controllable interfaces with Long Island exhibited a seasonal pattern. New England tended to import significantly more power across the primary interface from upstate New York (and export less power across the two controllable interfaces to Long Island) in the winter months for several reasons:

- First, New England is more reliant on natural gas generation, which is typically most expensive in the winter months.
- Second, the spread in natural gas prices between New England and eastern New York tends to increase in the winter months when demand for heating rises. The gas spreads between New England and New York averaged roughly $6.30 per MMBtu in the winter but only $1.50 per MMBtu in the remaining three seasons of 2014.[21]

B. Reserves and Regulation Markets

This subsection evaluates the operation of the markets for operating reserves and regulation. These markets only operate in real time and include system-level and locational reserve

[21] The spread is based on the difference between the Algonquin City Gates index, which is representative of natural gas prices in most of New England, and the lower of the Iroquois Zone 2 index and the Transco Zone 6 index, which are representative of natural gas prices in eastern New York.

requirements. The real-time markets co-optimize the scheduling of reserves and energy, which enables real-time prices to reflect economic trade-offs between scheduling resources as reserves or energy. When available reserves are not sufficient to meet the requirement, the market will be short of reserves and the applicable Reserve Constraint Penalty Factor (RCPF) will contribute to setting the price for reserves and energy. ISO-NE also procures regulation to balance generation with load on a moment-to-moment basis. Unlike its reserve markets and other RTOs' regulation markets, ISO-NE's regulation market is not co-optimized with its reserves and energy markets.

The forward reserve market enables suppliers to sell reserves into a forward auction on a seasonal basis. The forward reserve market has both system-level and locational requirements. Suppliers that sell in the forward auction satisfy their forward reserve obligations by providing the specified class of reserves or offering above a designated price threshold.

Figure 5 summarizes market outcomes in the real-time reserves market, the forward reserves market, and the regulation market by quarter and by year in 2013 and 2014.[22] Although there are four geographic areas with reserve requirements: Boston, Southwest Connecticut, Connecticut, and the entire system (i.e., "All of New England"), our evaluation focuses on the system level because the reserve requirements in local areas were rarely binding in the past two years.

The figure shows average clearing prices for 10-minute spinning reserves, 10-minute total or "non-spinning" reserves, and 30-minute operating reserves.[23] Each price is broken into components for each underlying requirement. For example, the system-level 10-minute spinning reserve price is based on the costs of meeting three requirements: the 10-minute spinning reserve requirement; the 10-minute non-spinning reserve requirement; and the total 30-minute reserve requirement.

Unlike resources providing forward reserves and real-time operating reserves, resources providing regulation service receive other market payments in addition to the payment for

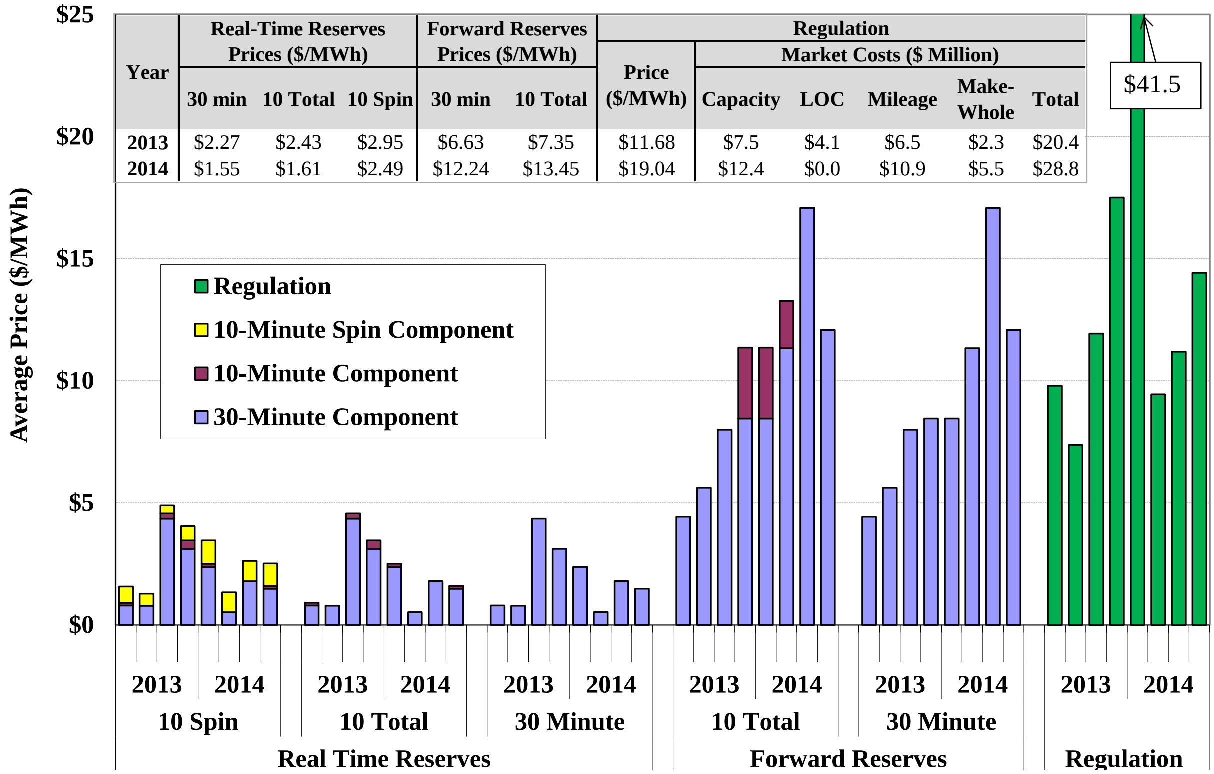
22 ISO-NE holds two forward reserve auctions -- for the summer procurement period (June through September) and the winter procurement period (October through May). The reported quarterly average prices are time-weighted average clearing prices in the relevant procurement-period auctions.

23 ISO-NE does not purchase 10-minute spinning reserves in the forward reserve auctions.

availability (which equals the clearing price times the amount of ancillary service capacity provided by the resource). The inset table reports these payments to resources providing regulation service in the following categories:[24]

- Capacity Payment = the Regulation Clearing Price (RCP) times the amount of regulation capability provided by the resource. The RCP is based on the highest accepted offer price (including energy market opportunity costs since July 1, 2013).
- Mileage Payment = 10 percent of the "mileage" (i.e., the up and down movement in MW) times the RCP. Based on historic regulation deployment, this formula was expected to generate mileage payments and capacity payments of similar magnitude in the long term.
- Lost Opportunity Cost (LOC) Payment = opportunity cost of not providing economic energy when a resource provides regulation service -- eliminated on July 1, 2013.
- Make-Whole Payment = Paid when the revenues from the regulation clearing price are less than the as-offered costs of providing regulation – created on July 1, 2013.

Figure 5: System-Level Reserves Clearing Prices and Regulation Costs
By Quarter, 2013 – 2014



Year	Real-Time Reserves Prices ($/MWh)			Forward Reserves Prices ($/MWh)		Regulation					
						Price ($/MWh)	Market Costs ($ Million)				
	30 min	10 Total	10 Spin	30 min	10 Total		Capacity	LOC	Mileage	Make-Whole	Total
2013	$2.27	$2.43	$2.95	$6.63	$7.35	$11.68	$7.5	$4.1	$6.5	$2.3	$20.4
2014	$1.55	$1.61	$2.49	$12.24	$13.45	$19.04	$12.4	$0.0	$10.9	$5.5	$28.8

24 In Manual M-REG, Capacity Payment is the "Time-on-Regulation Credit," Mileage Payment is the "Regulation Service Credit," and the Lost Opportunity Cost Payment is the "Regulation Opportunity Cost."

To provide context on the ancillary service prices in New England, Table 2 compares the annual average prices for each class of reserves between the ISO-NE, NYISO, and MISO markets. All prices shown as dashes are not applicable because that reserve class does not exist for that RTO.

Table 2: Summary of Reserve Prices by RTO
2013-2014

	ISO-NE		NYISO		MISO	
	2013	**2014**	**2013**	**2014**	**2013**	**2014**
Real-Time Reserves						
10-Minute Spin	$2.95	$2.49	$6.69	$6.47	$3.32	$2.48
10-Minute Total	$2.43	$1.61	$2.66	$1.74	$2.02	$1.50
30-Minute Total	$2.27	$1.55	$0.66	$0.12	-	-
Regulation	$11.68	$19.04	$9.73	$13.77	$10.56	$12.04
Day-Ahead Reserves						
10-Minute Spin	-	-	$8.57	$8.32	$3.25	$2.58
10-Minute Total	-	-	$4.22	$4.14	$1.75	$1.34
30-Minute Total	-	-	$0.48	$0.43	-	-
Regulation	-	-	$10.11	$12.87	$9.10	$11.23
Forward Reserves						
10-Minute Total	$7.35	$13.45	-	-	-	-
30-Minute Total	$6.63	$12.24	-	-	-	-

Real-Time Operating Reserves

Average real-time reserve prices fell 16 to 34 percent from 2013 to 2014. Because the price of higher quality reserve products will always include the price of the lower quality products, nearly all of the decreases shown above were attributable to reductions in 30-minute reserve prices. Although 30-minute reserve prices were substantially higher in the first quarter of 2014 than in the prior year, lower natural gas prices, load levels, and fewer shortages in the final three quarters of the year resulted in the overall reduction in 30-minute reserve prices for the year.

Clearing prices for the 10-minute spinning reserves exhibited the smallest reduction because 10-minute spinning reserve constraints were binding more frequently in 2014. This was because the ISO increased the spinning requirement from roughly 25 percent of 10-minute total reserve requirement to nearly 40 percent since mid-2014.

In general, Table 2 shows that ISO-NE's prices are comparable to the other RTO's shown. The differences can be explained by differences in the requirements in each market, and the differences in the available supply to satisfy the requirements.

In December 2014, the ISO increased the RCPF for the 10-minute total reserves and 30-minute operating reserves from $850 and $500/MWh to $1,500 and $1,000/MWh, respectively. These changes improve the efficiency of real-time prices by allowing the ISO's true reliability needs to be more fully priced, which:

- Improves suppliers' incentives to be available and perform reliably under high load conditions and tight gas market conditions;
- Increases the incentives to invest in new resources with high availability;
- Reduces the revenues required from the FCM to satisfy the ISO's planning requirements;
- Encourages efficient imports from New York and other areas with available capacity; and
- Improves incentives for slow-starting generators to be committed in the day-ahead market and schedule the necessary fuel.

Forward Reserves

Unlike real-time operating reserves, the average clearing prices for forward reserves rose more than 80 percent from 2013 to 2014. Forward reserve suppliers are paid based on the difference between the forward reserve clearing price and the forward capacity price.[25] For example, after deducting the forward capacity prices, the effective forward 30-minute reserve clearing prices rose from roughly $2.70/MWh in 2013 to $8.10/MWh in 2014. Similar to prior years, we also found that 99 percent of the resources assigned to satisfy forward reserve obligations in 2014 were fast-start resources capable of providing offline reserves.

The value of the forward reserve market is questionable because:

- It has not achieved one of its primary objectives, which was to lower NCPC by purchasing forward reserves from high-cost units frequently committed for reliability.
- The Locational Forward Reserve Market is largely redundant with the locational requirement in the Forward Capacity Market.
- The forward procurements do not ensure that sufficient reserves will be available during the operating day. Forward reserve sellers are simply obligated to offer at prices higher than the Forward Reserve Threshold Price, but may still be dispatched for energy.
- 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. These distortionary effects will have larger price effects in the future if the ISO

[25] See Market Rule 1 III.9.8.

implements the recommendation to allow peaking units to set the LMP (see Recommendation 1).

Additionally, increasing forward capacity prices may create issues in future years because they are deducted from the forward reserve settlement. For example, the clearing price in the forward capacity auction for the 2016/17 Capability Year (i.e., FCA 7) is $14.999 per kW-month for the Boston area, which eliminates the incentive for Boston resources to provide forward reserves. Accordingly, we recommend ISO-NE evaluate whether to eliminate the forward reserve market entirely.

Regardless of whether the forward reserve market is retained, we also recommend the ISO consider introducing day-ahead reserve markets. Such markets would allow the ISO to procure the reserves it needs for the following day and to set clearing prices that reflect the costs of satisfying the operating reserve obligations. Such markets would also likely help address the ISO's concerns regarding unit availability. The day-ahead reserve schedules would be established in a timeframe in which suppliers can make arrangements for fuel and staffing to allow them to respond to reserve deployments. This is particularly true for spinning reserve providers, since it is prohibitively costly for them to accept forward reserve obligations for an entire procurement period.

Regulation Service

Overall, the regulation market performed competitively in 2014. On average, more than 600 MW of available supply competed to provide less than 60 MW of regulation service. The significant excess supply generally limits competitive concerns in the regulation market.

However, average regulation clearing prices rose 63 percent from 2013 to 2014 and total regulation expenses rose 41 percent to $28.8 million in 2014. These increases were driven partly by the market design change in July 2013 to include opportunity costs in the capacity clearing prices, and partly by high natural gas prices in the first quarter of 2014 during the Polar Vortex. Natural gas prices can affect regulation market expenses in several ways:

- Generators may consume more fuel when they provide regulation, which would be reflected in participants' regulation offer prices. This directly affects both the Capacity Payments and Mileage Payments.

- Gas-fired combined cycle generators are committed less frequently during periods of high gas prices, which decreases the availability of low-priced regulation supply.
- Higher gas prices normally increase the opportunity costs for units to provide regulation service. This is why regulation opportunity cost expenses in the summer months are generally lower than in the winter months.

ISO-NE's latest proposal for complying with the Order 755 (which allows two-part bidding separately for availability and movement) became effective on March 31, 2015. We will monitor the effects of this change.

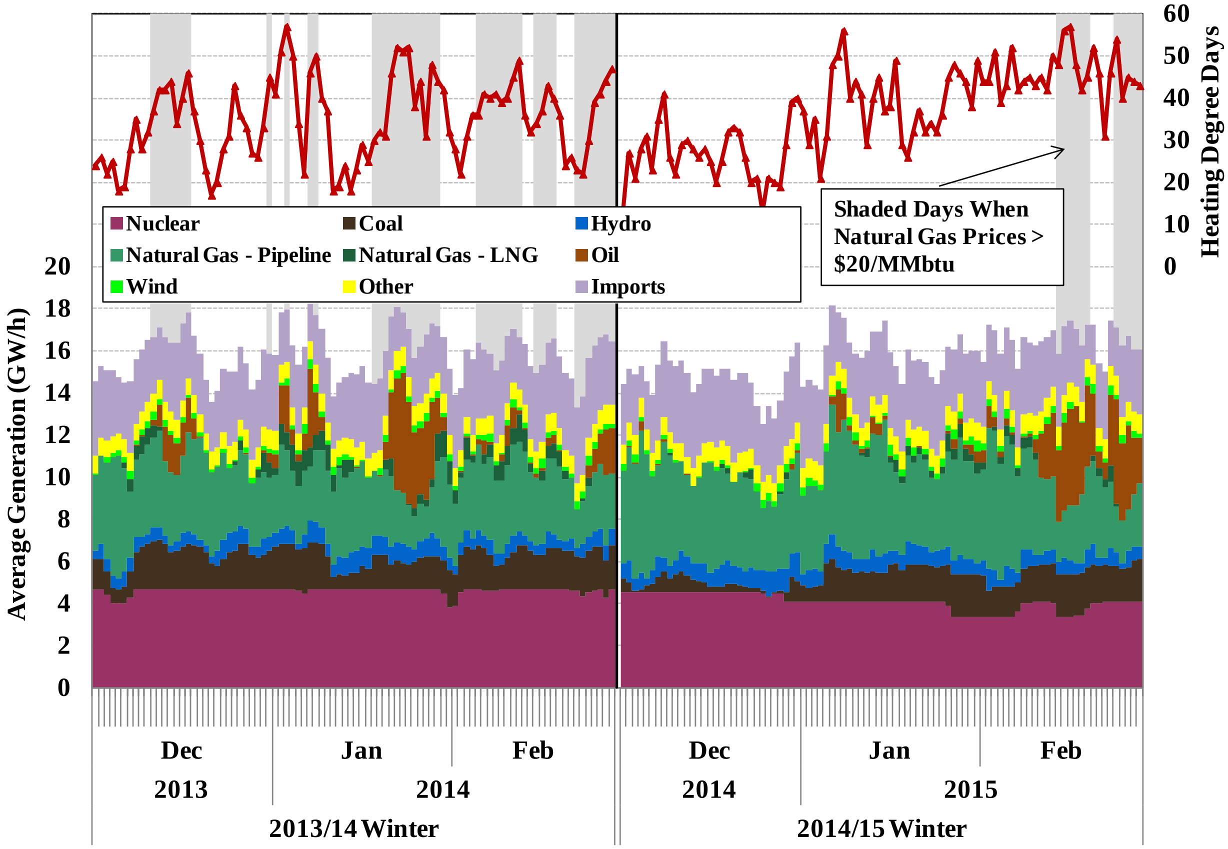
C. Fuel Usage Under Tight Gas Supply Conditions

When bottlenecks on the natural gas pipeline system limit the availability of natural gas (typically in the winter months), the wholesale electricity market has the important role of determining which generators burn the available gas, how much electricity to import, and how to utilize the available fuel inventories of internal oil-fired generation and other non-gas resources. Uncertainty about natural gas prices and the availability of other fuels make it challenging for suppliers to offer their resources efficiently and for the ISO to maintain reliability. The following analysis evaluates the efficiency of fuel usage in New England, especially during periods of tight natural gas supply.

Figure 6 shows the daily fuel usage over the last two winters. The bottom portion of the figure shows average internal generation by fuel type and average net imports to New England. The top portion of the figure shows the Heating Degree Days (HDD) in the upper portion.[26] The figure also highlights the days during which natural gas prices exceeded $20 per MMbtu.

[26] The heating degree days are based on average outside air temperature at Boston and a base temperature of 65 Fahrenheit. For example, if the average air temperature is 15 Fahrenheit, the HDD will be (65-15) = 50.

Figure 6: Fuel Usage Under Tight Gas Supply Conditions
Winter 2013/14 & 2014/15



Cold weather conditions (indicated by high HDD) caused natural gas prices to rise above $20 per MMbtu on 42 days in the winter of 2013/14 and on 11 days in the winter of 2014/15. Oil-fired generation increased sharply on these days, especially during a seven-day period in late January 2014 (i.e., from January 22 to January 28) and a two-week period in February 2015 (i.e., from February 11 to February 28).

During the seven-day period in 2014, natural gas prices averaged $53/MMbtu and oil-fired generation averaged 4,280 MW per hour, which accounted for 41 percent of total generation from oil during the entire winter of 2013/2014. During the two-week period in 2015, natural gas prices averaged $21/MMbtu and oil-fired generation averaged 3,180 MW per hour, which accounted for 82 percent of total oil production during the winter of 2014/15. The large amount of oil used in a single period illustrates the difficulty in predicting (before the winter) how much oil-fired generation will be needed over the winter season.

Although the total amount of oil-fired generation in the winter of 2014/15 was comparable to the winter of 2013/14 (roughly 1.7 million MWh in both winters), the patterns of weather and oil consumption were very different:

- Weather was milder in December 2014 than in December 2013 (average daily HDD was 26 in December 2014, compared to 31 in December 2013). Accordingly, average load was 850 MW lower in December 2014 and the need for oil was limited.
- January 2015 exhibited colder average temperature than January 2014 (which was the coldest month of the winter 2013/14), although the previous year had colder pockets because of Polar Vortex conditions. Nonetheless, oil production was significantly lower in January 2015.
- February 2015 was the coldest month in recent years. Oil consumption was significant in this month, accounting for 88 percent of total oil consumption in the winter of 2014/15.

Despite the general consistency in weather conditions, natural gas prices were substantially lower this winter under even colder weather conditions. For example, the average Algonquin gas price was roughly $7/MMBtu lower in February 2015 than in January 2014, although February 2015 was colder. This was attributable to several factors:

- Higher gas production in the Marcellus region;
- More LNG was delivered to New England this winter because of high natural gas prices in the prior winter.
- Oil prices fell substantially since mid-2014, which limited the increase in natural gas prices during the periods of gas pipeline constraints.

In general, the widespread use of oil on the cold-weather days indicates that the markets have helped manage the available supply of natural gas under tight gas supply conditions. However, although oil-fired generation increased considerably on the days of high gas prices, many oil-fired generators were not fully utilized when they would have been profitable because of low oil inventories. Before each winter, suppliers with oil-fired capacity decide how much oil to hold in inventory after balancing the potential gains from being available when gas prices are very high against the carrying costs of storing oil and the risks of holding unused oil after the winter. Some of factors are difficult to predict, such as the LNG deliveries and oil prices, which are more affected by changing conditions in global fuel markets.

The Winter Reliability Program was instituted to ensure that oil-fired generators would have adequate oil on-site to maintain reliability when natural gas supply was limited during winter peak conditions. However, it is an interim solution that does not provide consistent market incentives to all generators to reduce New England's dependence on the natural gas system. A comprehensive solution is needed to provide efficient incentives for maintaining a fleet of resources that can satisfy the system's summer and winter reliability needs in the years ahead. ISO-NE's performance incentive framework will be an integral component of such a solution.

D. Out-of-Market Actions and Uplift Costs

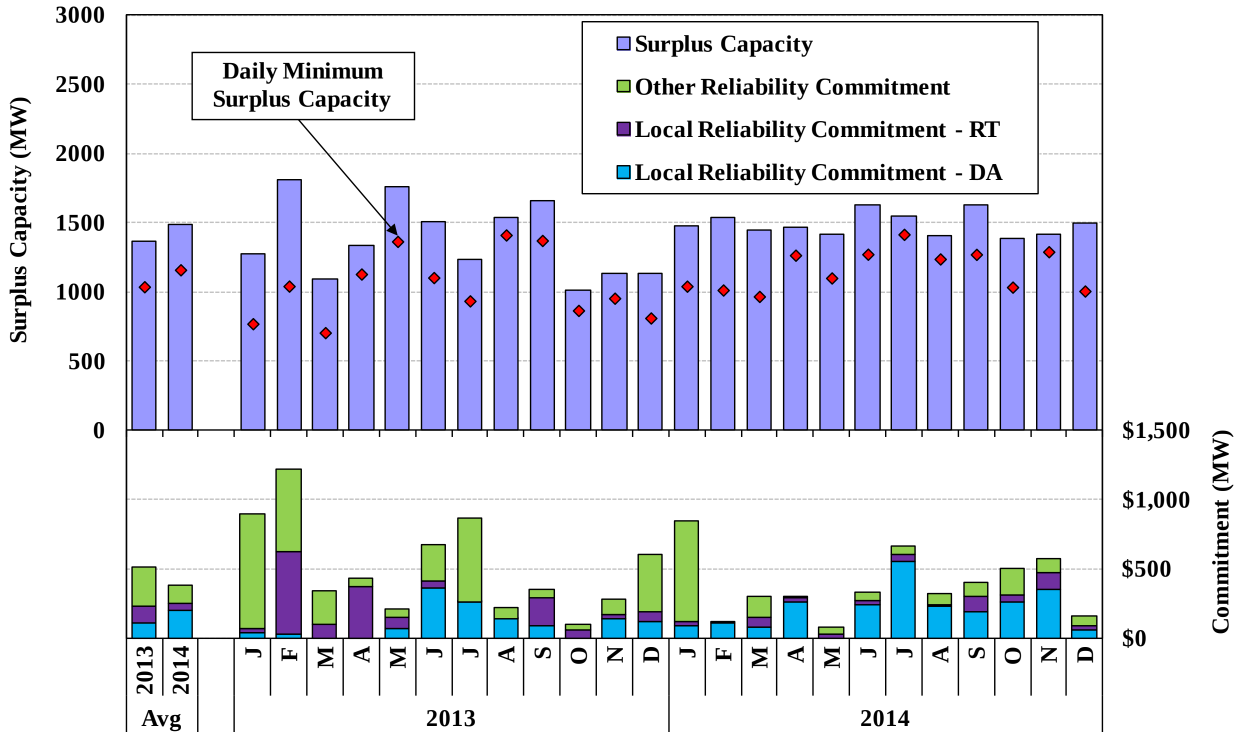
ISO-NE's markets generally procure sufficient resources to satisfy local and system reliability requirements. However, the ISO must sometimes commit additional generators to meet these requirements. Once committed, these generators may lower market prices and generally require NCPC payments to recover their as-bid costs. Hence, it is important to evaluate the supplemental commitments made by the ISO.

1. Supplemental Commitment and Surplus Capacity

Given the effects of supplemental commitment on market signals, it is important to minimize these commitments while still maintaining reliability. Figure 7 shows the average amount of capacity committed to satisfy local and system-level requirements in the daily peak load hour in each month of 2013 and 2014. Local Reliability Commitment shows capacity committed both in the day-ahead market and after the day-ahead market to: (a) ensure that reserves are sufficient in local constrained areas to respond to the two largest contingencies; (b) support voltage in specific locations of the transmission system; and (c) manage constraints on the distribution system that are not modeled in the market software (known as Special Constraint Resources ("SCRs")). Other Reliability Commitment shows capacity committed after the day-ahead market for local first contingency protection and for system-level reserve requirements together.

The figure shows the entire capacity of these units, although their impact on prices depends on the amounts of energy and reserves they provide to the market. In the upper panel of the figure, the blue bars show average surplus capacity in the daily peak load hour and the red diamonds indicate average daily minimum surplus capacity.

Figure 7: Supplemental Commitments and Surplus Capacity
During Daily Peak Load Hours, 2013-2014



Supplemental commitment by the ISO averaged 390 MW during daily peak load hours in 2014, down from 515 MW in 2013. The reduction was largely due to the decrease of non-local reliability commitments from 2013 to 2014.

Local Reliability Commitments

Local reliability commitments accounted for 65 percent of all supplemental commitments, the majority of which were made for the second contingency protection in Boston. The increase in Boston was largely attributable to higher procurement costs of LNG for the two Mystic combined-cycle units (that were often needed for local reliability), which caused them to be committed economically much less frequently in 2014.

In addition, most of local reliability commitment (82 percent) has shifted to the day-ahead market since May 2013 because of enhancements in ISO procedures. Making these commitments in the day-ahead market has reduced over-commitment (because fewer units outside the local area are likely to be committed) and lowered costs.

Other Reliability Commitments

Other reliability commitments accounted for 35 percent of all supplemental commitments and were mostly made for system-wide reserves. These commitments decreased more than 50 percent from an average of 280 MW in 2013 to 135 MW, reflecting lower load levels (average load down 2%, peak load down 11%) and higher net day-ahead load scheduling (94.8 to 96.7%).

Reliability commitment for system-wide needs was high in January of 2014, most of which occurred on days with substantial uncertainty regarding the availability of fuel to both gas-fired and oil-fired generators. Nonetheless, supplemental commitments in the 13/14 winter were lower than in the prior winter, despite more frequent peaking winter conditions. The improvement was attributable to several changes in market operations during 2013, including: a) earlier timelines for the day-ahead market and the RAA process starting in May 2013; b) revisions to the generator audit process in June 2013 to improve the reliability of reserve schedules; and c) enhanced analytical tools to track supply and usage of natural gas on New England generators.[27]

2. NCPC Uplift Costs

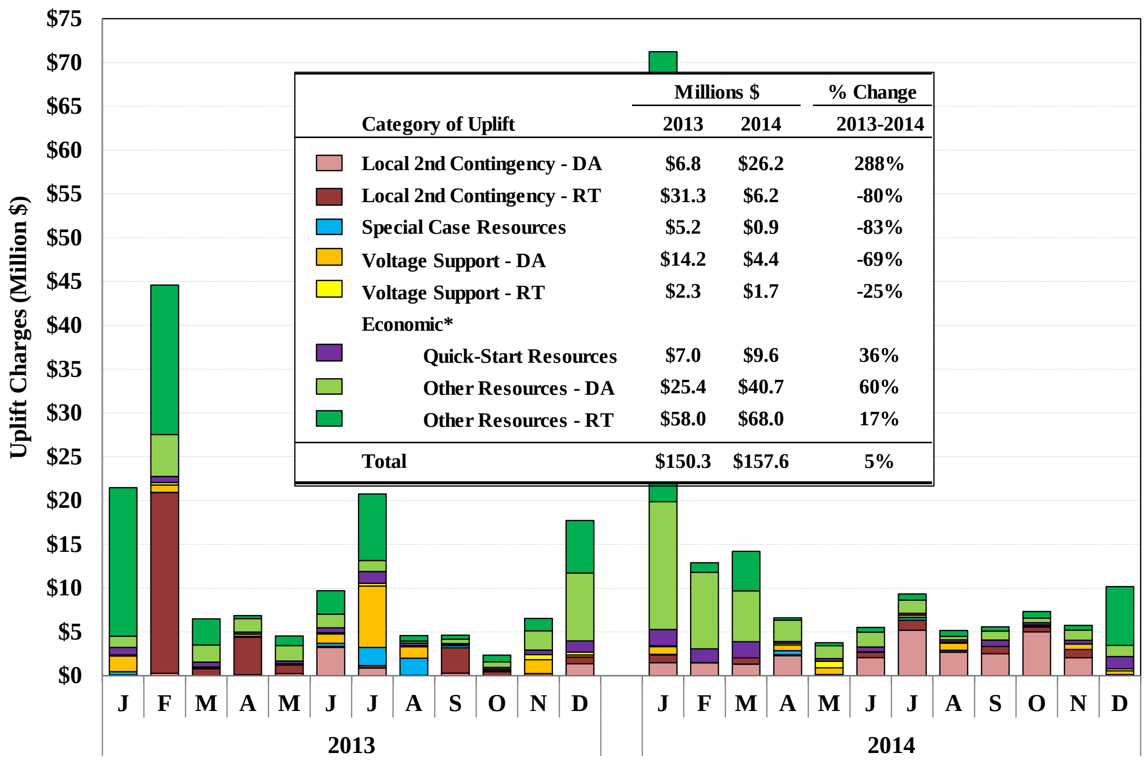
When ISO-NE makes supplemental commitments of resources that were not economic in the day-ahead market to satisfy the reliability needs of the system, such generators receive NCPC payments to recover their full as-bid costs. These costs are recovered from market participants through uplift charges. This subsection describes the main sources of NCPC uplift charges and how they are allocated to market participants. The following figure summarizes the monthly NCPC uplift in 2013 and 2014 incurred to meet local reliability requirements (second contingency protection, SCRs called by transmission owners, and voltage support), and to meet system-wide capacity and congestion management needs (economic and first contingency).

Uplift charges incurred to address local reliability are appropriate to allocate to the local customers who benefit directly from the commitments. For this reason, all local reliability commitments are allocated locally, with the exception of voltage support costs that are allocated system-wide. “Economic” NCPC is allocated throughout New England to real-time deviations

[27] See our 2013 State of Market report Section VIII.C for more discussion of effects of these changes.

(up or down) from participants' day-ahead schedules. This allocation to deviations is not consistent with the causes of this NCPC, which is discussed in Section III.A.

Figure 8: Uplift Costs by Category by Month



Total NCPC uplift charges increased moderately from $150 million in 2013 to $158 million in 2014. The month-to-month variations in each category of NCPC uplift were generally consistent with the level of supplemental commitments and the level of natural gas prices, which affects the commitment costs of gas-fired units. These factors converged during the Polar Vortex, causing 45 percent of total NCPC uplift in 2014 to occur in January.

NCPC uplift charges for second contingency protection in the local area increased during most months of 2014, consistent with the rise in the reliability commitment for local second contingency protection.[28] In addition, most uplift charges in this category have shifted to the day-ahead market because most of the second contingency commitments now occur in the day-ahead market. Units in Boston accounted for the majority of NCPC uplift in this category. We discuss improvements in Sections III.B and III.C that would lower these costs.

28 February 2013 had over $20 million of NCPC uplift in this category because Winter Storm Nemo caused generation and transmission outages, resulting in local reliability commitments in Boston and Rhode Island.

The "Economic" NCPC payments associated with fast-start resources were nearly $10 million. As described in detail in Section IV.A, fast-start resources committed economically by the real-time market can require NCPC payments to cover their as-bid costs because they generally do not set the LMP at the level of their total offer cost. This underscores the importance of efforts to modify the real-time pricing and dispatch software to allow fast start resources to set the clearing price when they are the marginal source of supply (i.e., when their deployment enables the real-time model to avoid scheduling more expensive resources).[29]

Finally, to place these costs in context, Table 3 shows the total day-ahead and real-time uplift costs over the past two years incurred by ISO-NE, NYISO, and 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 3: Summary of Uplift by RTO
2013-2014

		ISO-NE		NYISO		MISO	
		2013	**2014**	**2013**	**2014**	**2013**	**2014**
Real-Time Uplift							
Total	Local Reliability ($M)	$33.60	$7.95	$20.24	$8.54	$0.79	$6.99
	Market-Wide ($M)	$65.02	$77.55	$34.27	$45.31	$80.04	$104.99
Per MWh of Load	Local Reliability ($/MWh)	$0.25	$0.06	$0.12	$0.05	$0.00	$0.01
	Market-Wide ($/MWh)	$0.49	$0.56	$0.21	$0.28	$0.16	$0.15
Day-Ahead Uplift							
Total	Local Reliability ($M)	$20.99	$30.60	$50.47	$64.31	$7.50	$85.35
	Market-Wide ($M)	$25.42	$40.65	$27.97	$12.29	$13.96	$48.07
Per MWh of Load	Local Reliability ($/MWh)	$0.16	$0.22	$0.31	$0.40	$0.01	$0.13
	Market-Wide ($/MWh)	$0.19	$0.30	$0.17	$0.08	$0.03	$0.07
Total Uplift							
Total	Local Reliability ($M)	$54.59	$38.56	$70.72	$72.85	$8.29	$92.34
	Market-Wide ($M)	$90.44	$118.20	$62.25	$57.60	$94.00	$153.05
Per MWh of Load	Local Reliability ($/MWh)	**$0.41**	**$0.28**	**$0.43**	**$0.46**	**$0.02**	**$0.14**
	Market-Wide ($/MWh)	**$0.68**	**$0.86**	**$0.38**	**$0.36**	**$0.19**	**$0.23**
	All Uplift ($/MWh)	**$1.09**	**$1.14**	**$0.81**	**$0.82**	**$0.20**	**$0.36**

29 See Section IV.A for a discussion of this recommendation.

This table shows that on a per MWh basis, ISO-NE incurs more uplift costs than NYISO or MISO. This difference can be attributable to a number of factors:

- The NYISO software includes functionality that allows high-cost peaking resources to set prices that may otherwise require higher uplift payments to cover their as-bid costs. MISO recently implemented comparable software, and ISO-NE is working on a similar approach.
- ISO-NE's fuel costs tend to be higher than the other RTO's, leading to higher required make-whole payments.
- Gas pipeline operating issues tend to lead to higher gas availability concerns in New England than in other areas, which can increase the amount of supplemental commitments made by ISO-NE and associated uplift payments.
- NYISO and MISO had hourly generator offers, which was particularly important during the Polar Vortex in early 2014 when natural gas prices were highly volatile. The ability to adjust offers hourly improves resource availability by covering extraordinary costs incurred to obtain fuel and, to the extent these costs will be more fully reflected in energy prices, will tend to reduce make-whole payments.
- NYISO and MISO allocate uplift costs more consistently with cost causation, particularly MISO. MISO's allocation promotes full net load scheduling in the day-ahead market (i.e., close to 100 percent) and reduces the need to rely on high-cost peaking units to satisfy the incremental load in real time (generally contributes to market-wide uplift).

E. Forward Capacity Market

The Forward Capacity Market (FCM) is designed to attract and maintain sufficient resources to satisfy ISO-NE's long-term resource planning requirements efficiently. FCM provides economic signals that supplement the signals provided by the energy and ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment, retirement decisions, and participation by demand response.

Forward Capacity Auctions are held roughly 3 years before the beginning of each year-long Capacity Procurement Period to provide sufficient lead time for a new generator to be built if its offer is accepted in an FCA. Nine FCAs have been held so far, which have facilitated the procurement of installed capacity for the capacity periods ending May 2019.

This summarizes the outcomes of FCAs 8 and 9, which were held in February 2014 and February 2015 to procure capacity for the two years from June 1, 2017 to May 31, 2019. Table 4 shows the outcomes from these two FCAs for local capacity zones, the internal interfaces, and the overall system.[30] Cleared resources are divided into existing generation, new generation, demand response resources, and imports from external areas. The amounts of cleared resources are measured relative to their limits/requirements at each location.[31] The amounts of un-cleared resources are divided into new unsold generation, de-listing generation, demand response resources, and imports. The table also shows the clearing prices from each FCA, separately for new and existing resources at each location.

Table 4: Summary of FCM Auction Results
FCA 8 – FCA 9

Zone or Interface	FCA	Cleared in the Auction (MW)					De-List Generation (MW)	Unsold in Auction (MW)			Requirements/ Interface Limit (MW)	Price ($/kW-Mo)	
		Existing Gen	New Gen	Demand Response	Imports	Total		New Gen	Demand Response	Imports		Existing Resource	New Resource
System Wide													
ISO-NE	FCA 8	29,397	27	3,041	1,237	33,702	278	3	236	589	33,855	$7.03	$15.00
	FCA 9	29,382	1,060	2,803	1,449	34,694	192	1,032	253	1,362	34,189	$9.55	$9.55
Export Zone													
Maine	FCA 8	3,149	5	399	202	3,755	1	1	20	38	3,960	$7.03	$15.00
	FCA 9												
Import Zone													
NEMA/Boston	FCA 8	3,206	14	600	0	3,820	21	0	37	0	3,428	$15.00	$15.00
	FCA 9	3,301	1	625	0	3,927	0	195	73	0	3,572	$9.55	$9.55
Connecticut	FCA 8	8,441	0	749	0	9,190	0	0	91	0	7,319	$7.03	$15.00
	FCA 9	8,415	837	550	0	9,802	17	495	49	0	7,331	$9.55	$9.55
SEMA-RI	FCA 8												
	FCA 9	6,413	214	614	0	7,241	0	0	0	0	7,479	$11.08	$17.73
Interface													
Quebec	FCA 8				357	357				335	479	$7.03	$15.00
	FCA 9				218	218				0	499	$9.55	$9.55
New Brunswick	FCA 8				202	202				38	208	$7.03	$15.00
	FCA 9				177	177				213	177	$3.94	$3.94
New York	FCA 8				678	678				216	1,173	$7.03	$15.00
	FCA 9				1,054	1,054				1,149	1,054	$7.97	$7.97

FCA 8

Qualified supply resources were reduced considerably by generation retirements that had been announced before the auction, and the Insufficient Competition ("IC") Rule was invoked for the

30 Auction results were not shown for Maine in FCA 9 because it was not modeled in this auction. Likewise, results for SEMA-RI are not shown in FCA 8.

31 These limits and requirements include: a) the Local Sourcing Requirement ("LSR") for NEMA/Boston, Connecticut, SEMA-RI, which are import-constrained areas; b) the Maximum Capacity Limit ("MCL") for Maine, which is an export-constrained area; c) the import limit for each external interface; and d) the Net Installed Capacity Requirement ("NICR") for the overall system.

entire system in FCA 8.[32] The IC rule caused ISO-NE to not clear all of the existing resources that would have been necessary to satisfy the capacity requirement. Hence, 278 MW of existing resources de-listed and the ISO ultimately procured 153 MW less than its system-wide requirement, which should be remedied in subsequent reconfiguration auctions.

In addition, relatively high offer prices were submitted by external suppliers that were pivotal (the offers must be taken at any price (up to the cap) in the auction because ISO-NE would otherwise be short. Normally, one would assume that external suppliers cannot have market power because no external supplier can withhold the import capability (i.e., keep other external suppliers from selling in their place). However, due to the nature of the qualification process, an importer may become aware that it is pivotal at the time the FCA is conducted. This competitive concern arises for new resources as well, who may become aware at the time of the auction that they are pivotal for satisfying a local or market-wide requirement. The ISO implemented a mitigation measure to be applied to external suppliers that are pivotal

As a result of the supply reductions and the high offer prices from some of the suppliers, clearing prices increased sharply from prior auctions. All new resources cleared at a price of $15 per kW-month, while existing resources at all locations except Boston were paid $7.03 per kW-month in accordance with the Insufficient Competition Rule. In Boston, the clearing price for existing resources rose to $15 per kW-month because of the Capacity Carry Forward Rule.

FCA 9

The SEMA-RI Capacity Zone was modeled for the first time in FCA 9. However, there were inadequate resources to meet the zone's LSR. Therefore, the Inadequate Supply Rule was invoked, setting the clearing price for new resources in the SEMA-RI Capacity Zone at $17.728/kW-month and the clearing price for existing resources at $11.08/kW-month.

32 The IC rule is triggered when new resources must clear to meet the capacity requirement and the amount of new resources offered is less than two times the amount needed. Unfortunately, this rule undermines the performance of the market when triggered and it should not be required in a well-functioning market. However, there are a number of factors that reduce competition among new suppliers in New England that we discuss and provide recommendations to addressing in Section V.

The sloped demand curve was used for the first time at the system level in FCA 9, which set the clearing prices at $9.55 per kW-month for all new and existing resources located outside the SEMA-RI Capacity Zone (except New York AC Ties imports and New Brunswick imports). There was no price separation between the NEMA/Boston, Connecticut, and all of New England because excess capacity cleared in both capacity zones.

New York AC Ties imports and New Brunswick imports cleared at a lower price of $7.967/kW-month and $3.94/kW-month respectively. This occurs when more external capacity is offered than can be accommodated given the interface transfer limits. In this case, the price will fall to ration the available transfer capability.

Although these auction results were generally competitive, they highlighted issues regarding efficient capacity market design. For example, administrative pricing rules (i.e., Capacity Carry Forward Rule, Insufficient Competition Rule, and Inadequate Supply Rule) were invoked in the two FCAs. These pricing rules produce less efficient price signals that will, in turn, lead to less efficient decisions by market participants. To the extent that the pricing rules discriminate in favor of new resources and against existing resources, they will tend to accelerate retirements of resources that are not economic to retire and compel more costly new investment that ultimately raises to New England's customers.

ISO-NE plans to implement local zone sloped-demand curves for FCA 11, which we believe will be an efficient means to price capacity in cases where New England has inadequate supply. This change along with others we recommend to foster more robust competition from new resources should allow the ISO to discontinue use of the administrative pricing rules. We discuss these issues in more detail and recommend improvements in Section V.

F. Long-Run Price Signals

The ISO-NE markets play a critical role in governing investment, retirement, and other long-term decisions made by market participants. The expected net revenues from ISO New England's energy, ancillary services, and capacity markets are the primary means by which this occurs. Therefore, it is important to evaluate the net revenues produced by these markets, which are defined as the total revenues (including energy, ancillary services, Winter Reliability

Program and capacity revenues) that a generator would earn in the ISO-NE markets less its variable production costs. These net revenues serve to cover a supplier's fixed costs and the return on its investment.

If there is not sufficient net revenue in the short-run from these markets to justify entry of a new generator, then one or more of the following conditions exist:

- New capacity is not needed because sufficient generation is already available;
- Load conditions are below expectations due to mild weather or reduced demand, leading to lower energy prices than expected; and
- Market rules or conduct are causing revenues to be reduced inefficiently.

Alternatively, if prices provide excessive revenues in the short-run, this would indicate a shortage of capacity, unusually high load conditions, or market rules or conduct resulting in inflated prices. Evaluating the net revenues allows us to assess the design and performance of the market in providing efficient long-run economic signals.

In this section, we estimate the net revenues for three types of new technologies and the types of older technologies in recent years. Estimated net revenues are shown separately by revenue category (i.e., capacity versus energy and ancillary services). The results are also shown separately for dual-fuel and gas-only generators to evaluate the potential returns to dual-fuel capability. The technologies we evaluate are:

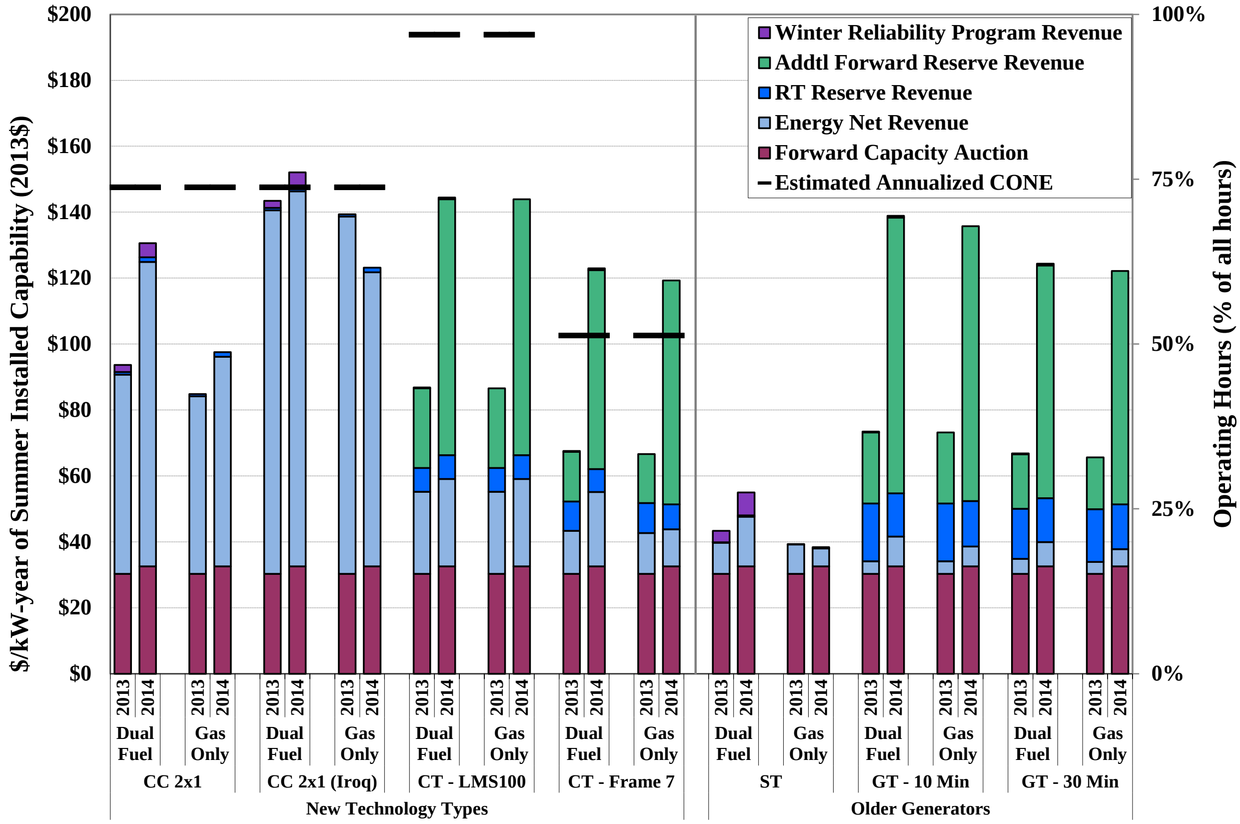
- *Hypothetical new units*: (a) a 2x1 Combined Cycle ("CC") unit, (b) a LMS 100 aeroderivative combustion turbine ("LMS") unit, and (c) a frame-type F-Class simple-cycle combustion turbine ("Frame 7") unit; and
- *Hypothetical existing units*: (a) a Steam Turbine ("ST") unit, (b) a 10-minute Gas Turbine ("GT-10") unit, and (c) a 30-minute Gas Turbine ("GT-30") unit.

We estimate the net revenues that would have been received by the generators at the New England hub.[33] We simulate the two-settlement system by calculating net revenues based on day-ahead prices and schedules, but allow gas turbines to be committed and online units dispatched based on the real-time prices (deviations from day-ahead schedules are settled at real-time prices). A detailed list of assumptions is provided in Appendix A.

33 Fuel costs for all units are based on the Algonquin City Gates gas price index. We also analyzed the profitability of a CC unit ("CC (Iroq)") with access to gas priced at the Iroquois Zone 2 index.

Figure 9 summarizes net revenue estimates of the levelized Cost of New Entry (CONE) for three new technologies. Net revenues are shown from each of the ISO's markets each resource is capable of supplying. The revenues shown for the Forward Reserve market are only those that exceed the revenue that would be earned from selling energy, real-time operating reserves, and capacity. The Winter Reliability Program Revenue is based on the average revenue earned by generators that participated in the program during the prior two winters.

Figure 9: Annual Net Revenue for Generators
New England Hub, 2013 and 2014



Total net revenues increased from 2013 to 2014 for most of the technologies mainly because:

- Reserve revenues for gas turbines rose significantly because of the high forward reserve prices, which they are uniquely capable of supplying.[34] The increase in forward reserve prices and the performance of that market is discussed further in subsection B.

34 CCs and steam turbines never find it profitable to sell forward reserves because they would need to be online in a large number of unprofitable hours.

- Energy prices rose from 2013 to 2014, more than offsetting the effects of higher natural gas prices for most types of units because of more frequent high load conditions during the winter months; and
- The Winter Reliability Program was introduced before the 2013/14 winter, which provided additional revenues for many dual-fuel units.

The net energy revenues during the Polar Vortex in early 2014 were unusually high. Even though New England has experienced some very cold temperatures in early 2015, the net revenues this year were significantly lower than those in early 2014.

In comparing the new resources, net revenues for a new combined cycle unit would normally be much higher than for a gas turbine (Frame 7) because it is much more efficient and would be dispatched more often. However, the forward reserve revenues provided to gas turbines cause their net revenues to be relatively comparable to the combined cycle unit. Since the CONE for a gas turbine is much lower, the analysis indicates gas turbines would have covered their entry costs in 2014 while the combined cycle unit would not.

The analysis also shows that the source of fuel can be very important. A unit with access to gas priced at Iroquois Zone 2 index would earn up to $26 per kW-year more in 2014 than a similar unit that procures gas at the Algonquin City Gates index, which serves most of the units in New England. The larger spreads between Iroquois Zone 2 gas and electricity prices is likely to attract more new investment in areas served by this pipeline, which was the case for over 80% of the new (non-intermittent) generation capacity that qualified for FCA 9.

For older existing units, the estimated net revenues were likely higher than the annualized “going-forward costs” in areas where such units are in operation. This is because retirements would occur if net revenues fell below going-forward costs for a significant period. Among older technologies, the estimated net revenues were highest for the gas turbines primarily because of the increased forward reserve prices. Steam turbines earned the majority of their net revenue from selling capacity, although energy net revenues and winter reliability program revenue were significant for the dual-fueled steam turbine.

The ability to switch fuels away from natural gas can substantially affect a unit’s net revenues. In 2014, the incremental net revenues a supplier earned from having dual fuel capability were substantial for both combined-cycle units (~$35 per kW-year) and steam turbines (~$20 per kW-year).[35] These dual fuel net revenues for combined-cycle and steam turbines constitute 20 to 30 percent of the annual net revenues a new unit would require to break even. However, these estimates assume that units have sufficient fuel on-site to operate when economic. During the winter of 2013/14, some units ran less because of low oil inventories, even with the winter reliability program. Hence, the actual net revenues from dual-fuel capability were likely lower in reality for many dual-fueled units. Nonetheless, this analysis shows the role that efficient real-time energy pricing can play in providing incentives for suppliers to incur costs to increase their availability and performance (such as installing dual fuel capability).

The increase in net revenues was much smaller for gas turbines that have dual fuel capability. This is because they can provide reserves during tight gas supply conditions without having to run on the alternative fuel. While high operating reserve revenues for these units are justified under tight gas conditions if the units can reliably respond if deployed, they are not justified if the units' ability to acquire gas is questionable. Additionally, such units lower prices for other suppliers that have access to fuel. This indicates the importance of programs that audit or otherwise ensure that off-line peaking units that sell operating reserves are capable of responding if deployed. This is particularly important during winter operating conditions when some off-line reserve providers may be less reliable than at other times of year.

Additionally, the energy and reserve markets provide critical incentives for generators to be flexible and available in real-time when clearing prices are likely to be high. This is illustrated by the fact that an older 10-minute gas turbine that can start quickly and provide off-line reserves would earn $30 to $99 more net revenue per kW-year than an older steam turbine (that has slower start times and longer operating times). This differential is large enough to influence decisions about the maintenance and/or retirement of older generation. Likewise, it is sufficient to induce some investors to build new assets with more flexible operating characteristics and dual fuel capability (e.g., a new investor may build a combined cycle that is configured to run as a baseload unit or as a quick start unit). The additional returns to being flexible and available

35 This analysis does not include all of the additional costs necessary to maintain an inventory of fuel oil, and that the use of fuel oil may be limited by low inventories or air permit restrictions.

highlight the benefits of the real-time pricing enhancements that would improve price efficiency during tight conditions, which are discussed in Section IV.A.

In conclusion, although net revenues have increased considerably since 2012, it will be very important for these net revenues to rise efficiently as capacity margins fall in New England to ensure that new investment is sufficient to maintain adequate resources. In this regard, the sloped capacity demand curve filed by ISO New England and the increases in the ISO's shortage pricing levels will play important roles in achieving this objective.

G. Competitive Performance of the Energy Market

This section evaluates the competitive performance of the ISO-NE wholesale markets in 2014. This type of assessment is particularly important for LMP markets. While LMP markets increase overall system efficiency, they can provide incentives for the localized exercise of 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 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.[36] 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.

[36] See, e.g., Section VIII, "2013 Assessment of Electricity Markets in New England", Potomac Economics.

1. 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 cause prices to increase by withholding, not every supplier can profit from doing so. The benefit from withholding is that the supplier will be able to sell into the market at a clearing price above the competitive level. However, the cost of this strategy is that the supplier will lose profits from the withheld output. Thus, a withholding strategy 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.

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

- Forward power sales that reduce a large supplier's incentive to raise prices in the spot market.[37]
- 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.
- The availability of information that would allow a large supplier to predict when the market may be vulnerable to withholding.

2. Structural Market Power Indicators

This subsection of the report examines structural aspects of supply and demand affecting market power. We examine the behavior of market participants in the next subsection.

[37] 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.

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 of 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 if its capacity is needed to meet demand and reserve requirements. A pivotal supplier has the ability to unilaterally raise the spot market prices raising its offer prices or by physically withholding.

The first two structural indicators focus on the supply-side, providing some useful competitive inferences. However, their usefulness is limited by the fact that they ignore the demand-side factors (e.g., the level of load relative to available supply-side resources) that substantially affect the competitiveness of the market.

The Pivotal Supplier Test is a more reliable means to evaluate the competitiveness of spot energy markets. When one or more suppliers are pivotal and have the incentive to take advantage of their position to raise prices, the market may be subject to substantial market power abuse. However, this does not mean that all pivotal suppliers should be deemed to have market power.[38] Suppliers must have both the *ability* and *incentive* to raise prices in order to have market power. For a supplier to have the ability to substantially raise real-time energy prices, it must be able to foresee that it will likely be pivotal. In general, the more frequently a supplier is pivotal, the easier it will be for it to foresee circumstances when it can raise the clearing price.

Figure 10 shows the three structural market power indicators for each of the four regions in 2013 and 2014. First, the figure shows the market shares of the largest three suppliers and the import capability in each region in color-coded stacked bars.[39,40] The remainder of supply to each

38 Even small suppliers can be pivotal for brief periods. For example, all suppliers are pivotal during periods of shortage. But this does not mean they all have market power.

39 The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capability("SCC"), available at: http://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.

region comes from smaller suppliers. The inset table shows the Herfindahl-Hirschman Index (HHI) for each region. In our analysis, we assume imports are highly competitive so we treat the market share of imports as zero in our HHI calculation. Finally, the diamonds in the figure indicate the portion of hours where one or more suppliers were pivotal in each region. In this analysis, we exclude potential withholding from nuclear units because they typically cannot be dispatched down substantially and would be costly to withhold in any case due to their low marginal costs.

Figure 10: Structural Market Power Indicators
2013- 2014

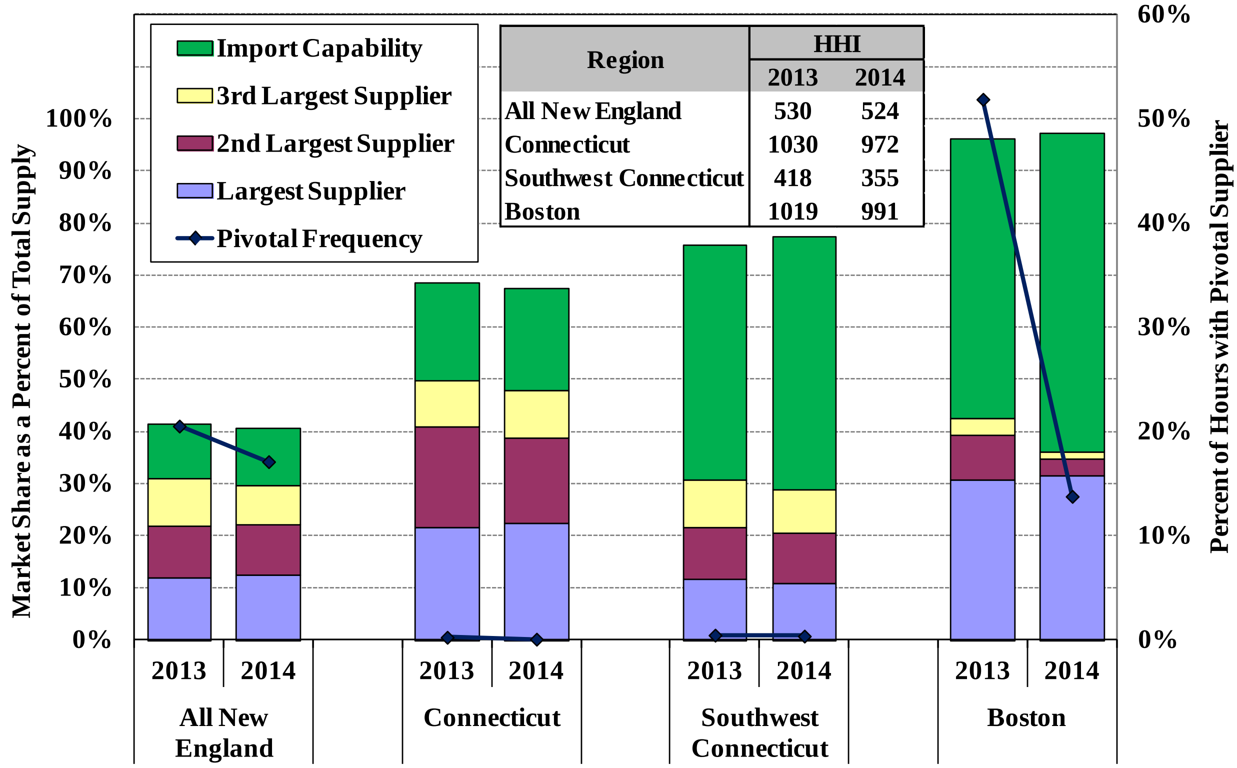


Figure 10 indicates a substantial variation in market concentration across New England. In all New England, the largest supplier had a 12 percent market share in 2014. In the three reserve zones, the largest suppliers had market shares ranging from 11 percent in Southwest Connecticut to 31 percent in Boston in 2014. Likewise, there is variation in the number of suppliers that have

40 The import capability shown for each region is the transmission interface limit used in each year's Regional System Plan, available at: http://iso-ne.com/system-planning/system-plans-studies/rsp. The Base Interface Limit is used for external interfaces, and the N-1-1 Import Limits are used for each reserve zone.

large market shares. For instance, Boston had one supplier with a large market share, while Southwest Connecticut had three internal suppliers with comparable market shares. Because the import capability accounted for a significant share of total supply in each region (ranging from 11 percent in all New England to 61 percent in Boston[41]), the market concentration in all of the areas was relatively low (i.e., less than 1000) in 2014.[42] However, these results do not establish that there are no significant market power concerns. These concerns are most accurately assessed under the pivotal supplier analysis, which indicates that:

- Southwest Connecticut and Connecticut did not raise competitive concerns as there were very few hours (< 0.5 percent) when a supplier was pivotal in these areas in 2013 and 2014.
- In Boston, one supplier owned roughly 80 percent of the internal capacity, but was pivotal in only 14 percent of hours. This underscores the importance of import capability into constrained area in providing competitive discipline; and
- In all of New England, a supplier was pivotal in 17 percent of hours in 2014.[43]

Results from these regions warrant further review of potential withholding behavior from market participants. Nonetheless, the pivotal frequency declined in the two regions from 2013 to 2014:

- Higher net imports (200 MW) and lower average load (250 MW) contributed to the modest reduction in the pivotal supplier frequency in All New England. Most of the load reduction occurred in the summer months when average load fell by almost 1 GW from a year ago.
- The sizable reduction in pivotal supplier frequency in Boston was primarily attributable to:
  - ✓ Transmission upgrades increased the import capability into Boston up to 82 percent of the annual peak load in 2014, up from the 63 percent in 2013.
  - ✓ The combined cycle units of the largest supplier were committed less frequently in 2014 because of increased fuel costs (relative to natural gas prices). This reduced its real-time market share and the frequency it was pivotal.

The following section examines the behavior of pivotal suppliers under various market conditions to assess whether the behavior has been consistent with competitive expectations.

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41 The Boston import capability (i.e., the N-1-1 limit) increased by over 450 MW in 2014 because of transmission upgrades made to address reliability issues associated with the retirement of Salem Harbor.

42 Antitrust agencies and the FERC consider markets with HHI levels above 1800 as highly concentrated for purposes of evaluating the competitive effects of mergers.

43 The pivotal supplier results are conservative for "All New England" because we assume the actual imports are fixed and would not change in response to withholding.

3. Economic and Physical Withholding

Suppliers that have market power can exercise it in electricity markets by withholding resources to increase the market clearing price in the following two ways:

- Economic Withholding – this occurs when a supplier raises its offer prices substantially above competitive levels; and
- Physical Withholding – this occurs when a resource is derated or not offered into the market when it would be economic for the resource to produce energy (i.e., when the market clearing price exceeds the marginal cost of the resource).

We measure potential economic withholding by estimating an output gap for units that fail a conduct test for their start-up, no-load, and incremental energy offer parameters indicating that they are submitting offers in excess of 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.[44] In essence, the output gap shows the quantity of generation that is withheld from the market as a result of having submitted offers above competitive levels. Nonetheless, it is important to recognize that the output gap tends to overstate the amount of potential economic withholding because some of the offers that are included in the output gap reflect legitimate responses by the unit's owner to operating conditions, risks, or uncertainties.

We evaluate potential physical withholding by focusing on short-term deratings and outages because they are more likely to reflect attempts to physically withhold than long-term deratings. In general, it is less costly to withhold a resource for a short period of time. Long-term outages generally result in larger lost profits in hours when the supplier does not have market power.

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.

[44] 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.

Because the pivotal supplier analysis raises competitive concerns in Boston and all of New England, Figure 11 shows the output gap and physical deratings by load level in these two regions. The output gap is calculated separately for:

a) offline quick-start units that would have been economic to commit in the real-time market (considering their commitment costs); and

b) online units that can economically produce additional output.

Our physical withholding analyses focus on:

a) forced outages that last less than one week; and

b) the "Other Derate" 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.

The figure shows the supplier's output gap and physical deratings as a percentage of its portfolio size in each region by load level. In Boston, we compare these statistics for the largest supplier to all other suppliers in the area. In all New England, we compare the top three suppliers, who collectively own one-third of internal resources, to all other suppliers.

Figure 11: Average Output Gap and Deratings by Load Level and Type of Supplier
Boston and All New England, 2014

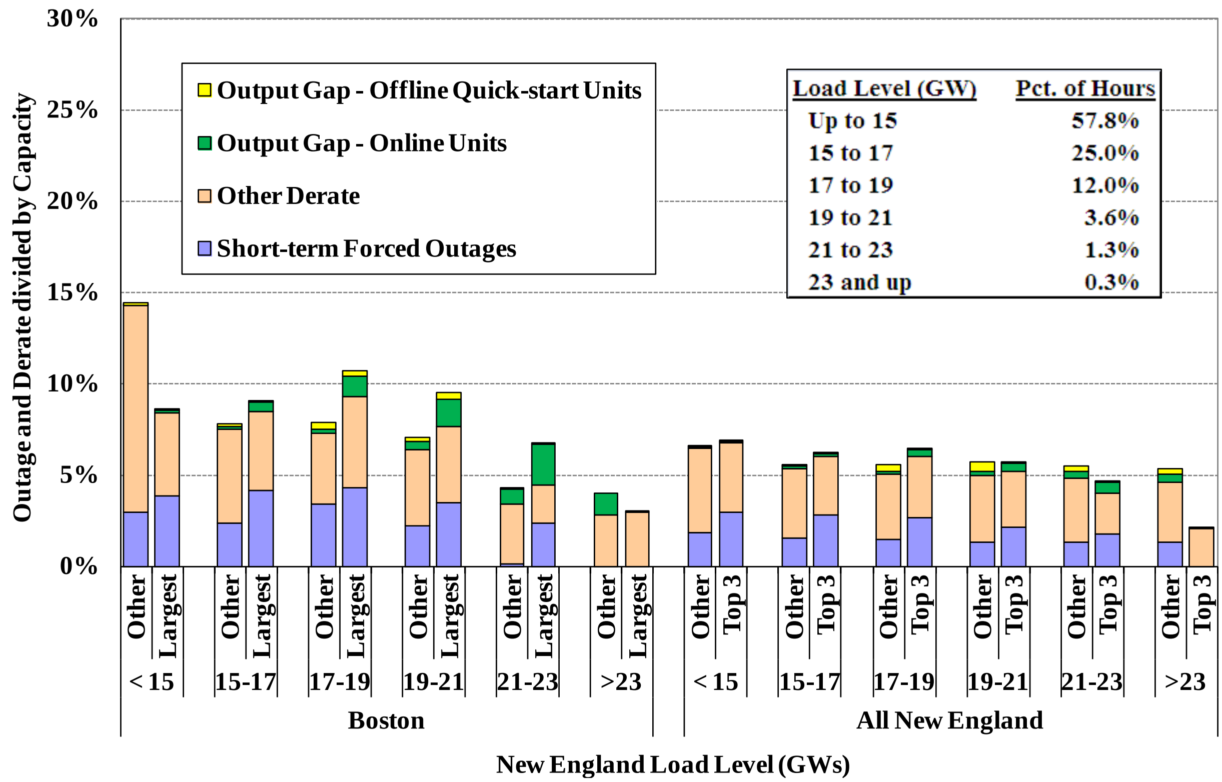


Figure 11 shows that the overall output gap and deratings for the largest suppliers were relatively small as a share of their total capacity in both Boston and all New England, and generally fell as load levels increased to the highest levels (when the capacity needs of the system were generally the highest). Finally, the largest suppliers in each region generally exhibited output gap levels and deratings that were consistent with other smaller suppliers in the region. Overall, this indicates that the market performed competitively and was not subject to substantial withholding.

Nonetheless, the amount of output gap rose modestly in Boston at the higher load levels, which occurred mostly in winter months for two reasons. First, natural gas prices were high and volatile in the winter months, which made the $25 per MWh threshold much tighter as a percentage of LMP levels. Second, our output gap analysis assumes the lower-cost fuel is used by dual-fuel units. However, some units exhibited high output gap levels because they had to burn the high-cost gas when their oil inventories were low. The increase in output gap did not raise significant competitive concerns given our review of the specific conduct in question and the ISO's automated mitigation process.

4. Market Power Mitigation

Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when the market 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:[45,46]

[45] See Market Rule 1 Appendix A Section III.A.5 for details on these tests and thresholds.

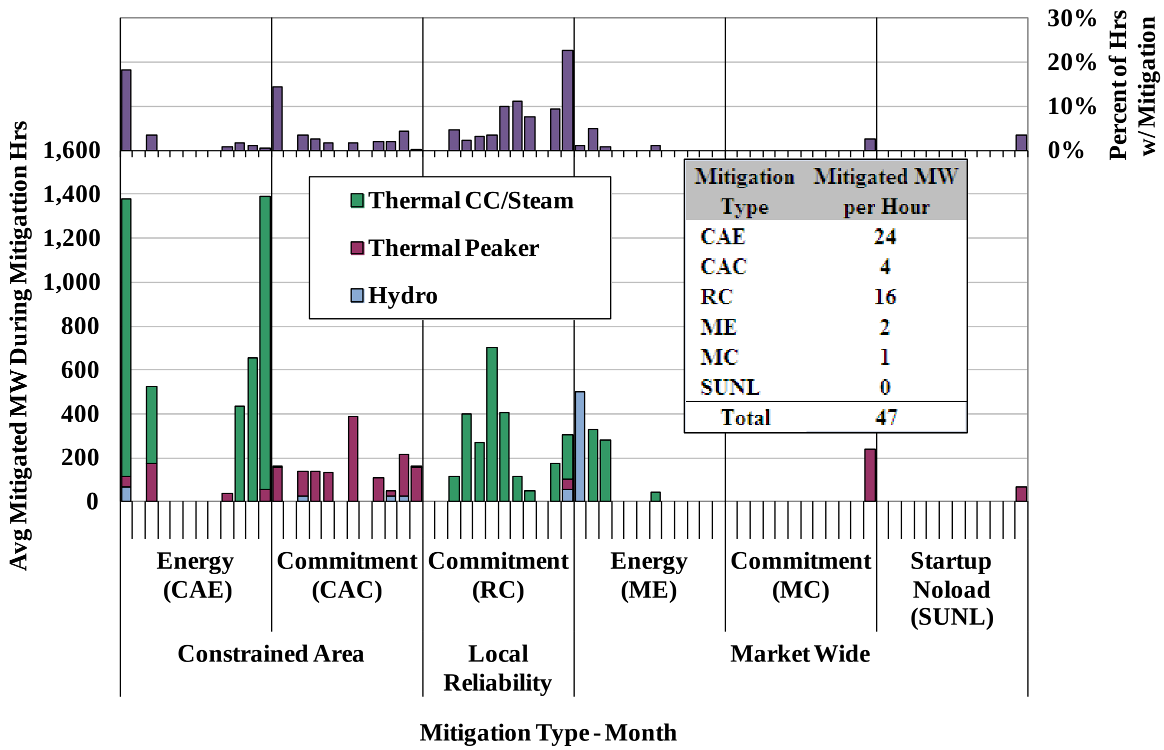
- Market-Wide Energy Mitigation (“ME”) – ME mitigation is applied to any resource that is in the portfolio of a pivotal Market Participant.
- Market-Wide Commitment Mitigation (“MC”) – MC mitigation is applied to any resource whose Market Participant is determined to be a pivotal supplier.
- Constrained 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.

There are no impact tests for the SUNL 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 three categories. This is reasonable because this mitigation is only applied to uplift payments, which will tend to rise substantially as offer prices rise so, in essence, the conduct test is serving as an impact test as well. When a generator is mitigated, all the economic offer parameters are set to their reference levels for the entire mitigated hour.

Figure 12 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. 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 the number of mitigated hours) 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 shows the annual average amount of mitigation for each mitigation type in 2014.

[46] In addition, manual dispatch mitigation is applied to units dispatched OOM above their Mingen level.

Figure 12: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
By Month, 2014



Mitigation in constrained areas and for local reliability commitments together accounted for 95 percent of all mitigation in 2014. This is consistent with the fact that these areas raise the most significant potential market power concerns and are mitigated under the tightest conduct and impact thresholds. Other high-level results shown in the figure include:

- Roughly half of the mitigation only affected uplift payments (commitment mitigation), while half affected the energy market prices and dispatch.
- Almost all mitigation was of thermal units (79 percent non-peaking units and 15 percent peaking units).
- Hydro resources were only mitigated in a material quantity in January and were likely primarily attributable to the difficulty of establishing an accurate reference level for units whose costs are almost entirely opportunity costs (the trade-off of producing more now and less later).

The ISO made changes in December 2014 to address a potential gaming strategy, which resulted in applying local reliability commitment mitigation to units that start earlier or shut down later than their day-ahead schedules. This accounted for some of the local reliability mitigation in December, but the impact of this mitigation on LMPs and NCPC payments was not substantial. Energy mitigation in the constrained area accounted for more than 50 percent of all mitigation in

2014, a large share of which occurred on thermal units in January on days when natural gas prices were highly volatile. These conditions increase the likelihood of mitigation because:

- The $25/MWh threshold in the constrained area is tight under these conditions (relative to low fuel cost periods).
- Volatile natural gas prices 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. Hence, competitive offers may be mitigated when these uncertainties are larger than the applicable conduct thresholds.
  - This is partially addressed by a major enhancement ISO-NE introduced in December 2014 to allow suppliers to update hourly offers and fuel costs in real time. This should improve the accuracy of reference levels and the efficiency of the mitigation process.
- Oil-fired generation becomes economic when the gas prices rise above oil prices. If a unit’s on-site inventory of oil is limited, the supplier may raise its offer prices to conserve the available oil in order to produce during the hours with the highest LMP. This may result in the application of mitigation to offers that are efficient.

To address the last factors, reference level adjustments should be made as necessary to account for the opportunity costs associated with these types of energy limitations, which will reduce the potential for inappropriate mitigation of competitive offers.

5. Competitive Performance Conclusions

The pivotal supplier analysis suggests that market power concerns remain in Boston and in all of New England under high-load conditions. However, based on the analyses of potential economic and physical withholding, we find that the markets performed competitively with little evidence of market power abuses or manipulation in 2014.

In addition, we find that the market power mitigations 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 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. The implementation of the hourly offers in December 2014 better enables generators to submit offers that reflect their marginal costs and for the ISO to set reference levels that properly reflect these costs.

III. Improving the Payment and Allocation of Uplift Costs

This section of the report discusses NCPC costs, which are ISO-NE's primary form of uplift costs. In general, NCPC costs are incurred because the market requirements do not include all of the reliability requirements that ISO-NE must satisfy or, for other reasons, the prices do not fully reflect these requirements. When this occurs, resources are sometimes utilized when the prevailing market prices do not fully cover the resource's as-offered costs, which results in a guarantee payment in the form of NCPC. This section identifies three issues and associated recommendations regarding how NCPC payments are made and how they are allocated back to ISO-NE's customers.

A. Allocation of NCPC Costs

The allocation of NCPC costs plays an important role in facilitating efficient actions by participants and the performance of ISO-NE's day-ahead market. Most economic NCPC costs are currently to deviations from the day-ahead market, including virtual transactions. Unfortunately, virtual transactions and other deviations provide liquidity to the day-ahead market and facilitate its convergence with the real-time market. This is important because the day-ahead market coordinates the overall commitment of resources that are used to satisfy the next day's needs at the lowest cost.

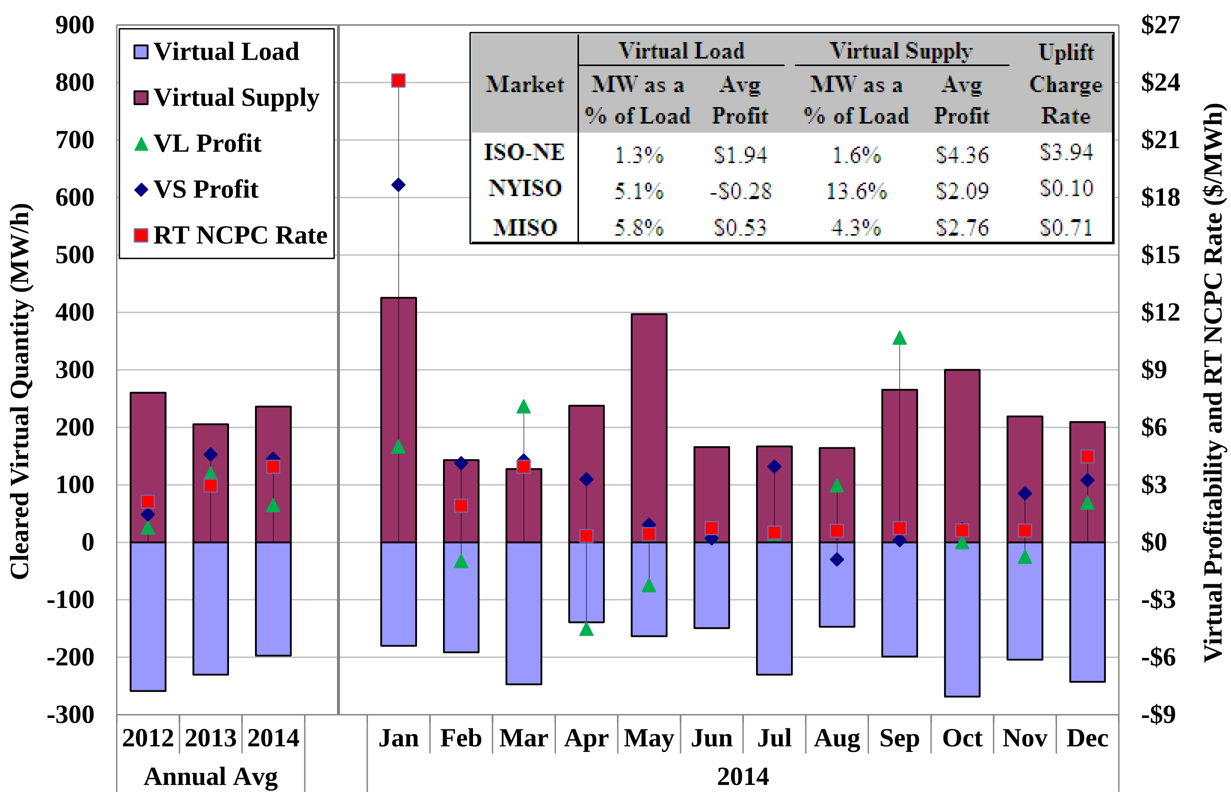
In well-functioning day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge by a substantial amount. However, day-ahead prices tend to be slightly higher than real-time prices in a well-functioning energy market because many buyers are willing to pay a small premium for day-ahead purchases to avoid the more volatile real-time prices. In New England, it is efficient for the day-ahead premium to be larger because the real-time prices are understated, as discussed in Section III.A. An important means for achieving efficient convergence between day-ahead and real-time prices is to allocate the market's NCPC efficiently. We believe that the NCPC allocation has discouraged participation by virtual traders in New England and reduced the liquidity of the day-ahead market overall as shown below.

1. Virtual Trading and Profitability in New England

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 a relatively small amount of virtual trades in the past several years although the market exhibited a real-time price premium during most of the months. The increased allocation of NCPC charges (per MWh) to virtual load in particular has likely inhibited the natural market response to the sustained real-time price premiums.

Figure 13 shows the average volume of virtual supply and demand that cleared the market in each month of 2014, as well as the monthly average gross profitability of virtual purchases and sales. Gross profitability is the difference between the price at which virtual traders bought and sold energy between the day-ahead and real-time market. The gross profitability does not account for NCPC costs allocated to virtual transactions, which are shown separately in the figure.

Figure 13: Virtual Transaction Volumes and Profitability
2014



The inset table compares the average volume (i.e., average cleared quantity as a percentage of average actual load) and gross profitability of virtual transactions during 2014 in ISO-NE, NYISO, and MISO. The table also lists the average major category of market costs that are charged to virtual traders in each market. The major category of market costs to virtual transactions are the real-time economic NCPC cost allocations in the ISO-NE, the Rate Schedule 1 charge in the NYISO, and the Day-ahead Deviation and Headroom Charge in the MISO. Almost all of these charges are designed to recover similar uplift costs in the various markets.

Virtual transactions have decreased substantially in the past several years. In 2014, scheduled virtual load averaged roughly 200 MW and scheduled virtual supply averaged roughly 235 MW. On average, virtual load and virtual supply each accounted for approximately 1.5 percent of the actual load in the ISO-NE market, notably lower than in the NYISO and the MISO markets (generally more than 5 percent). The low levels of virtual trading are likely the result of the high NCPC charges to scheduled virtual transactions (which we recommend changing) and increased regulatory risk associated with enforcement activities.

Figure 13 shows that virtual trading was generally profitable in 2014 (before including NCPC charges) with an overall net gross profit of $12 million, indicating that virtual trading improved convergence between day-ahead and real-time prices.[47] This is because virtual trades that are profitable generally contribute to better convergence between day-ahead and real-time prices. However, including NCPC charges, virtual transactions netted a loss of $2 million in 2014.

In ISO-NE, real-time economic NCPC charges are allocated across virtual transactions and other Real-Time Deviations. The rate of economic NCPC charges allocated to virtual transactions has been relatively high for several years, averaging roughly $2 to $4 per MWh each year from 2012 to 2014. These charges are significantly higher than the charges that virtual transactions face in the NYISO and the MISO markets, which were only $0.10 and $0.71/MWh in 2014, respectively. High NCPC rates provide a significant disincentive for firms to schedule virtual transactions because virtual profits tend to be small relative to day-ahead and real-time prices.

47 Not including NCPC charges, profits can be tabulated for each category of virtual transactions in the figure by multiplying "Avg MW" and "Avg Profit" by the number of hours in each year.

Hence, high NCPC rates contribute to the low level of virtual trading activity and the inconsistency between day-ahead and real-time prices in New England.

2. Economic NCPC Allocation

ISO-NE currently allocates nearly all real-time "Economic" NCPC charges to deviations between the day-ahead and real-time schedules.[48] In reality, some deviations are "harming" and tend to increase NCPC, while others are "helping" and reduce NCPC. For example, under-scheduling physical load in the day-ahead market can cause the ISO to commit additional units in real-time, which are likely to increase NCPC—this is a "harming" deviation. Conversely, "helping" deviations, such as over-scheduling load (including virtual load), generally result in higher levels of resource commitments in the day-ahead market and, therefore, usually decrease the ISO's need to make additional commitments, thereby avoiding NCPC charges. The current allocation does not distinguish between helping and harming deviations and is, therefore, not consistent with the principle of allocating costs to actions that cause those costs. Hence, this allocation assigns NCPC charges to transactions that actually tend to *reduce* the need for supplemental commitments, including virtual load.

NCPC charges are caused by many factors other than real-time deviations, including: peaking resources not setting real-time prices, operator actions to satisfy system reliability needs, and unforeseen events such as outages. Hence, we find that the current allocation scheme over-allocates costs to deviations relative to the portion of the NCPC they likely cause. This is particularly true of virtual load transactions, which tend to increase day-ahead commitments and, therefore, decrease the need for supplemental commitments. Given that real-time price premiums prevailed for much of 2010 through 2014, allocating substantial NCPC costs to virtual load that does not cause these costs has likely degraded the performance of the day-ahead market.

Hence, we recommend that the ISO modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle, which would generally involve not allocating

48 Real-Time Deviations include Real-Time Load Obligation Deviations, which are positive or negative differences between day-ahead scheduled load and actual real-time load, uninstructed generation deviations from day-ahead schedules, virtual load schedules, and virtual supply schedules.

NCPC costs to virtual load and other real-time deviations that cannot reasonably be argued to cause real-time economic NCPC. The ISO recently proposed to reallocate real-time economic NCPC charges from virtual load and over-scheduled physical load in the day-ahead market to real-time physical load customers.[49] This reallocation would be a significant improvement because virtual load and over-scheduled physical load in the day-ahead market are "helping" deviations, while real-time physical load tends to increase real-time economic NCPC charges because most supplemental commitments are made to maintain reliability for physical load customers.

B. Real-Time NCPC Payments for Day-Ahead Scheduled Units

The ISO implemented a package of significant market reforms in December 2014 under the Energy Market Offer Flexibility Key Project and the Net Commitment-Period Compensation Key Project. The additional offer flexibility allows generators to update their offers in response to changes in market conditions (e.g., gas price variations). The new NCPC rules ensure that generators always have short-term financial incentives to obey the ISO's instructions. Together, these projects were designed to enhance both market efficiency and reliability.

The new NCPC rules are based on the "best alternative" principle that a generator should be "no worse-off" as a result of obeying an instruction from the ISO. For example, if a \$50 generator is instructed to ramp-up when the LMP is \$40, the generator should receive a \$10 NCPC payment in addition to the LMP so that the generator is no worse-off for performing reliably. The "no worse-off" principle is consistent with a key design objective of market-clearing prices in power markets to give suppliers a competitive incentive to reveal their true costs.

Although the best alternative framework is generally sound, we find that the new NCPC rules included a provision that results in unnecessary payments to some generators and that is likely to create incentives for inefficient behavior in some cases. Specifically, the rules assume that the best alternative for a non-fast start generator that is scheduled in the day-ahead market could be for the generator to stay offline in real-time. This subsection discusses why this assumption: (i)

49 See "NCPC Cost Allocation Phase 1" to NEPOOL Markets Committee from Catherine McDonough (ISO-NE) dated April 30, 2014.

results in NCPC payments that are much higher than necessary to make the generator "no worse off" and (ii) is not necessary for generators to have an incentive to follow the ISO's commitment instruction. This subsection also summarizes our conclusions and a recommended change to the NCPC rules.

1. Cause and Effects of the Overstated Payments to Non-Fast Start Units Committed in the Day-Ahead Market

For non-fast start generators that are committed in the day-ahead market, the NCPC rules result in excessive payments when the generator's best alternative is deemed in retrospect to be staying off-line. From December 2014 through March 2015, this category accounted for approximately $22 million (or 67 percent) of the real-time NCPC payments over the period. Although the next subsection explains why we believe these NCPC payments are not necessary for reliability, this subsection identifies three reasons why these NCPC payments exceed the profits that these generators would have earned from not starting-up:

- First, the NCPC formula assumes that the actual real-time LMP would not have been affected if the generator receiving the payment were to be offline, which is unrealistic. Keeping even modest amounts of capacity offline can significantly increase prices and even cause shortages of operating reserves. From December 2014 through March 2015, there were 25 days when the capacity of day-ahead non-fast start units receiving these payments (2.6 GW on average) exceeded the amount of surplus capacity over the peak (1.8 GW). In other words, the ISO would have been in a shortage if they had shut down, which would have eliminated the assumed profitability of staying offline. Hence, the LMP used in the calculation is unreasonably low, which inflates the NCPC payment.
- Second, the NCPC formula assumes the generator's cost is equal to its real-time offer, but this tends to be higher than the costs that a gas-fired day-ahead scheduled generator could avoid by not starting-up. Generators sell significant amounts of gas after the timely nomination window, typically at a discount. However, these suppliers do not face competitive pressure to lower their real-time offered commitment costs to their true marginal cost because this would simply lower their NCPC payment and these offer components are not used to make commitment decisions. Hence, the real-time offer costs likely to contribute to the upward bias in NCPC payments.
- Third, the NCPC rule implicitly assumes that a non-fast start unit can predict with perfect accuracy when it would be profitable to stay offline. However, since such a decision would expose the generator to potentially significant losses, the NCPC payment over-compensates the generator significantly on an expected value basis. In other words, a generator will not know when real-time prices are going to be low and or may forecast that

they will be low with substantial uncertainty.[50] For this reason, an NCPC payment based on actual real-time prices after the fact that were not knowable in advance will be overstated, and higher than necessary to satisfy the "no worse off" principle.

- Lastly, when ISO-NE schedules resources out-of-merit to satisfy reliability requirements through the day-ahead market (e.g., local reliability requirements), it makes a day-ahead NCPC payment to the supplier. In many cases, this unit will not be economic to run in real time (i.e., it was not selected economically in the day-ahead market and if the day-ahead prices converge with real-time prices, it would similarly not be economic in real time). In this case, the NCPC rules would automatically make a real-time NCPC payment for the resource's excess costs notwithstanding that these same costs were already guaranteed through the day-ahead market.

Consequently, the NCPC rules are substantially over-compensating non-fast start generators that were committed in the day-ahead market on those days where the real-time prices turn out in retrospect to be less than the generator's full costs. As discussed above, these costs are averaging more than $5 million per month. In addition to the excess costs to customers, these payments create adverse incentives or inefficiencies because they:

- Create an inefficient incentive to keep start uneconomic units on days when the system is substantially over-committed and production costs could be saved by not starting all of the generators scheduled in the day-ahead market;
- Produce adverse incentives for suppliers to modify their offers to significantly inflate these payments; and
- Favor large generators with long minimum run times and may generally discourage generators from providing flexibility in their offers.

Hence, we recommend that the ISO work as quickly as possible to modify its NCPC rules to eliminate these payments. With regard to out-of-merit units committed for reliability in the day-ahead market, the incentive the ISO desires (for the units to have the incentive to start in real time when needed) would be equitably achieved if it required units to relinquish their day-ahead NCPC if they choose not to start. The following section describes why these NCPC payments are needed to ensure real-time reliability.

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50 For example, if a $30 generator forecasted an equal probability of LMPs ranging from $20 to $40, the generator would expect that staying offline would lead to an expected real-time profit of $0.50. However, the same generator would receive NCPC payments under the current rule of up to $10 per MWh automatically. No competitive generator could ever earn this level of revenue (even assuming LMP used to calculate the NCPC payment is accurate) unless it could forecast real-time prices with perfect accuracy and, therefore, perfectly chooses to keep its resource offline in every case when real-time prices will be less than its cost.

2. Ensuring Reliable Real-Time Operation of DAM-Committed Generators

The ISO can ensure that non-fast start generators start when needed without the new NCPC payments for several reasons:

- First, deciding not to start-up a generator is a much riskier and more costly strategy than assumed for purposes of the NCPC calculation. So, the number of resources that would perceive it advantageous not to start is likely much lower than the resources that received payments in the first four months.
- Second, the new hourly energy offer rules have better enabled generators to protect themselves from market risks after a day-ahead commitment. Prior to December 2014 when hourly offers were implemented, generators scheduled in the day-ahead market would be motivated not to start in real-time if gas prices spike after it is scheduled (because it would likely be running at prices less than its marginal production costs). After December 2014, the new hourly offer rules allow the generator to raise its incremental offer and help ensure that resulting real-time LMPs will reflect the higher gas prices.
- Third, even before the new hourly energy offer rules were in place, it was rare for day-ahead scheduled generators to fail to perform in real-time because of a lack of fuel. These generators are generally in a better position to procure gas because of the additional lead time. During the Winter of 2013/14 (the last winter before the new NCPC rules were implemented), in just four of the 29 instances when the operator log identified a generator as out-of-service for gas supply or gas pressure issues was the generator unavailable in an hour that it had received a day-ahead schedule. Additionally, it is unclear whether the four generators could have avoided the gas issues on these days if they had had the stronger financial incentives from the new NCPC rules.

In addition to these economic reasons, it is also important to consider that capacity suppliers are obliged by the ISO-NE tariff to comply with commitment instructions by the operator. In August 2013, the Commission clarified that:[51]

> …a capacity resource that fails to comply with dispatch instructions when it is physically available but has determined not to procure fuel or transportation due to economic considerations is in violation of the Tariff. (P. 58)
>
> The Commission expects that, going forward, ISO-NE's IMM will refer suspected violations, including any capacity resource's failure to timely notify ISO-NE that the resource is not physically available, to the Commission. (P. 61)

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[51] See FERC August 27, 2013 Order on Complaint, *New England Power Generators Association, Inc. v ISO New England Inc.* http://www.ferc.gov/CalendarFiles/20130827174659-EL13-66-000a.pdf

Hence, failure by a supplier scheduled in the day-ahead market to make a good faith effort to obtain the fuel necessary to start-up as instructed in the real-time market would be a clear violation of the ISO-NE tariff and referable to the Office of Enforcement. This regulatory risk together with the economic incentives described above should more than ensure that resources scheduled day-ahead and needed in the real-time market will be available and start.

3. Conclusions and Recommendation on Real-Time NCPC Payments

It is critically important for generators to obey the ISO's commitment and dispatch instructions, but this objective should be satisfied without the new class of real-time NCPC payments that were implemented in December 2014. Therefore, we recommend ISO-NE modify the NCPC rules to eliminate these payments.

Because it is sometimes efficient for units that are not economic and not needed in real time to not start (i.e., when the system is over-committed), it would be beneficial for the ISO to devise a process for allowing a day-ahead scheduled generator to request that it be released from the obligation to start-up. If the ISO needs the generator for reliability, the generator's request could be rejected. If the ISO does not need the generator for reliability, allowing the generator to remain offline will conserve fuel supplies (increasing the availability of natural gas for other generators or conserving limited oil inventory). Such a process would also help avoid minimum generation emergencies in the electricity market that can result in negative prices.

C. Commitment of Multi-Turbine Units for Local Reliability

The ISO provides generators with significant flexibility in determining how to register multiple units at a particular plant. This is reasonable, since plants often contain individual units with costs that are interdependent. Individual units may share limited fuel supplies, have heat rates that are affected if other units are operating at the site, or have multiple configurations. Under competitive market conditions, generators have an incentive to offer efficiently while taking into account all of these interdependencies. However, this is not the case when a generator does not face competition. This section discusses whether generators that have local market power have registered their assets in a manner that enables them to earn more by being inflexible.

Our primary concern is that generators committed for local reliability may increase their profits by registering multiple units as a single generator for bidding purposes, even though each unit is capable of operating separately. For example, a 2x1 combined cycle generator is normally capable of operating one gas turbine at a time, typically resulting in a modest increase in the heat rate. When a generator is committed for local reliability, it usually receives total compensation from LMP revenues and NCPC payments equal to its operating costs plus some margin under the applicable mitigation thresholds. Hence, doubling the number of units committed for local reliability generally doubles the resulting profits. We believe this is analogous to a dual-fueled unit requiring ISO-NE to compensate it for burning oil when it is committed for local reliability when it is capable of burning natural gas at a much lower cost. This latter conduct is not permissible, but the former currently is permissible.

In 2014, an estimated $38.6 million of day-ahead and real-time NCPC payments were received by non-fast start generators that were needed for local reliability.[52] Of this, $26.5 million (69 percent) went to generators that registered multiple turbines as a single asset for bidding purposes. In many cases, it is likely that the local reliability need could have been satisfied with only one of the units, so committing multiple units led to excess production costs, depressed LMPs, and more NCPC costs. Hence, we recommend that the ISO modify its tariff to allow it to commit a single unit at a multi-unit generator location when this provides a more efficient means to satisfy the local reliability need.

52 This includes units flagged for voltage support or for local second contingency protection.

IV. Real-Time Market Design Improvements

The goal of the electricity market is to coordinate the use of resources to efficiently satisfy the needs of the system. It is critically important to coordinate real-time production and provide efficient real-time price signals. In this section, we discuss and evaluate key market design improvements in the areas of real-time price formation and interchange scheduling with New York. These improvements would foster more efficient market outcomes and price signals.

A. Real-Time Price Formation

Efficient real-time price signals are essential because they encourage reliable performance and increased availability by generators and demand response, and investment in new resources or transmission where it is needed most. The recent efforts to introduce additional Performance Incentives recognize that efficient price signals during shortages motivate resources to be available when needed. Furthermore, to the extent that efficient price signals during shortages or tight operating conditions exceed generators' costs, the revenues needed from the forward capacity auctions to maintain adequate installed capacity margins will fall.[53] Hence, it is beneficial to regularly evaluate whether the market produces efficient real-time price signals.

1. Price Setting by Fast-Start Resources

Fast-start generators are highly beneficial for the operation of the system because they are a low-cost provider of operating reserves that would otherwise have to be held on online resources, which can be very expensive. They tend to be dispatched when the load is highest and are generally the highest-cost resources. During these high-load conditions, it is particularly important that these resources set prices accurately in order to reflect the cost of satisfying demand and reliability requirements. The analyses in this section, however, show that this is frequently not the case because they are inflexible. These analyses assess the efficiency of real-time pricing during periods when fast-start units were deployed in merit order in 2014.

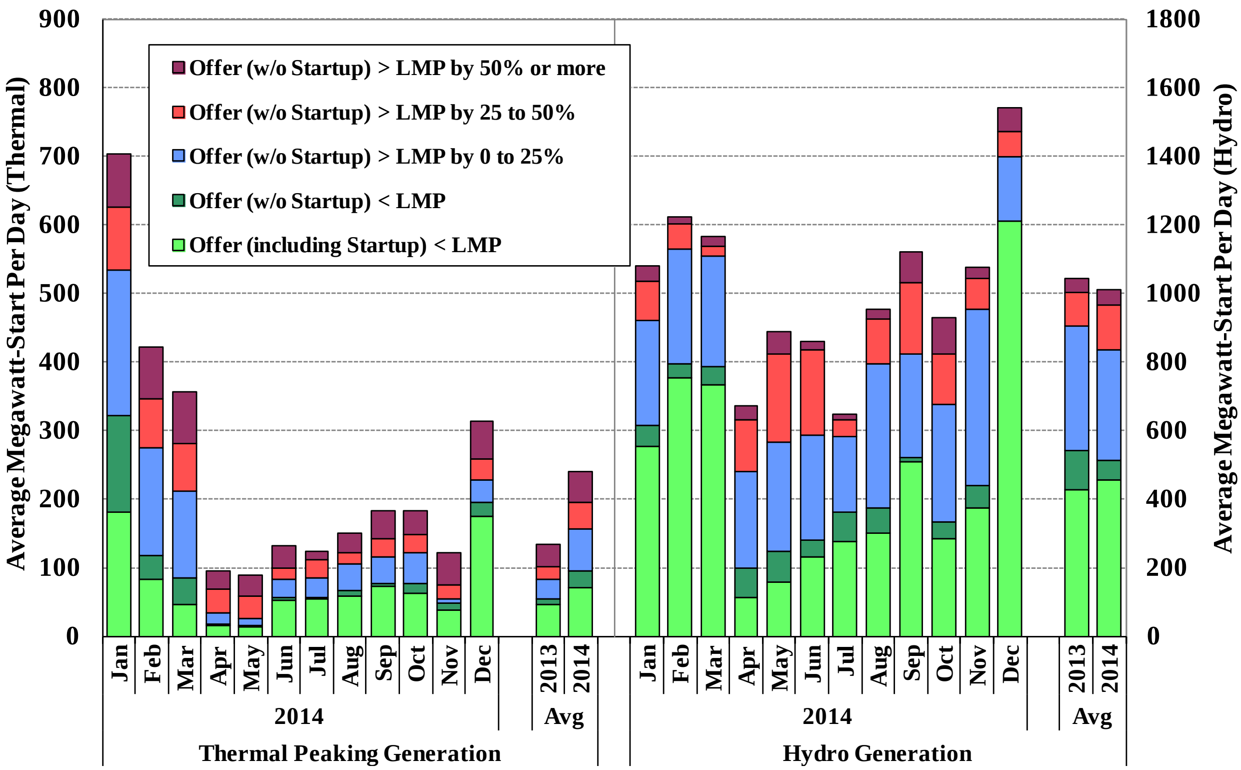
The second analysis evaluates how LMPs would be affected if the average total offers were fully reflected in real-time prices.

53 Section II.F evaluates the amount of net revenue that new and existing generators earn from the capacity and energy markets.

Figure 14 summarizes how consistent the real-time prices are with the offer costs of the fast-start resources economically committed in the real-time market. The average total offer includes no-load and start-up costs amortized over one hour and the comparison is made over the units' the initial commitment period, which is usually one hour. When the average real-time LMP is greater than the average total offer, the market reflects the utilization of the unit. However, when the average real-time LMP is less than the average total offer, LMPs do not fully reflect the cost to the system of deploying the fast-start generator. Figure 14 shows hydroelectric and thermal units separately, and categorizes the occurrences based on the consistency of the prices and costs.

Figure 14: Comparison of Real-Time LMPs to Offers of Fast-Start Generators

First Hour Following Start-Up by UDS, 2014



Flexible hydro generation accounted for over 80 percent of fast-start generation that was started in merit order by UDS in each of 2013 and 2014 because it is generally less costly than the thermal peaking resources. However, the amount of thermal peaking generation that was started in merit order by UDS rose notably from 2013 to 2014, primarily because of the higher winter loads and fuel supply issues in the first quarter of 2014.

With regard to pricing efficiency, the figure shows that in both years the average total offers of the hydro and thermal peaking resources together (including start-up costs) was higher than the real-time LMP in roughly 60 percent of the starts. For the thermal units alone, 60 percent of the thermal peaking generation exhibited offers greater than the real-time LMP even when start-up costs are ignored. Hence, even though these units were dispatched in economic merit order, they often relied on NCPC payments to recoup their full as-bid operating costs. More importantly, these results indicate that real-time prices often do not accurately reflect the marginal cost of serving real-time demand, which affects the economic signals provided by the day-ahead and forward markets in New England.

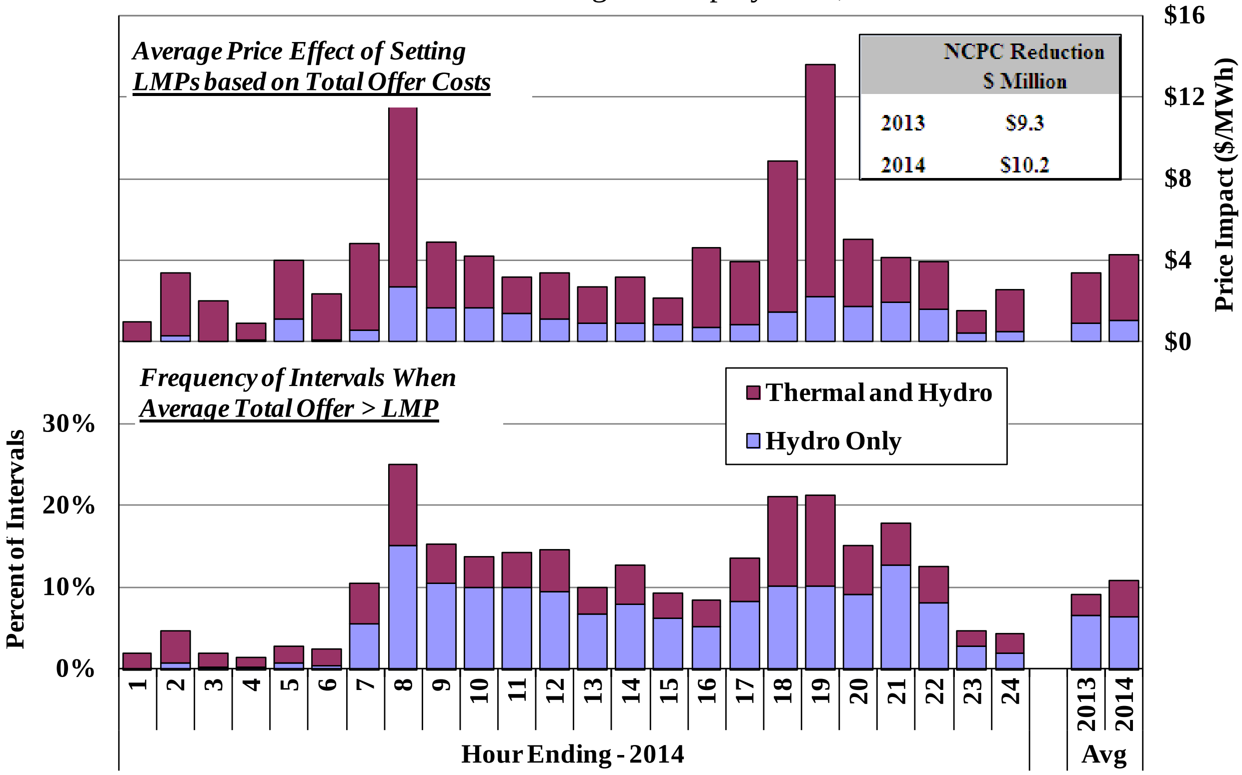
The following figure examines how real-time energy prices would be affected if the average total offers of such units were reflected in real-time LMPs, which is shown in the top panel.[54] The figure excludes fast-start units that were started in import-constrained areas because we are focused on market-wide price effects.[55] These effects are shown by hour of the day and are shown separately for intervals in which at least one thermal fast-start unit is running versus those in which only a flexible hydro unit is running.[56] Since allowing peaking resources to set prices would reduce the NCPC payments they (and others) would require to be made whole, the inset table shows our estimate of the reduction in NCPC costs that would result from this change.

54 If a gas turbine was started with a total offer of $115/MWh when the LMP was $75/MWh, this analysis would assume the unit would increase the LMP by $40 per MWh. Other lower-cost gas turbines or hydro resources started in the same hour would not affect prices because they are inframarginal.

55 The area is treated as import-constrained if the congestion component of the LMP at the fast-start unit's node is greater than the congestion component at New England Hub by $1 per MWh or more.

56 Since thermal fast-start units typically have higher offer costs, lower-cost hydro fast-start units started in the same hour would generally not affect prices because they are inframarginal.

Figure 15: Difference Between Real-Time LMPs and Offers of Fast-Start Generators
First Hour Following Start-Up by UDS, 2014



The bottom panel in Figure 15 shows that fast-start units were frequently deployed economically by UDS when their average total offer was greater than the real-time LMP. This occurred in 11 percent of all intervals in 2014, but most often in the peak hours hours-ending 7 to 22, particularly around the morning peak (hours-ending 7 to 9) and the evening peak (hours-ending 18 to 21). Ramping needs are highest on the system during these periods, which sometimes require fast-start units.

If the average total offers of these units were always fully reflected in the energy price in these intervals, the average real-time LMP would increase approximately $3.30/MWh in 2013 and $4.20/MWh in 2014. More than 70 percent of these increases would be attributable to allowing thermal peaking generators to set prices, even though these units would be started much less frequently than the hydroelectric units. This is because thermal units are generally more costly and, therefore, their price effects are larger. Our analysis shows that the price effects are largest in hours when thermal peaking resources are most frequently running at costs above the LMP, e.g., $13.60 per MWh in hour-ending 19. The ISO recently performed a simulation study for most of 2014 and found that real-time prices would rise by $3.18 per MWh. This is consistent with our estimates, although slightly lower.[57]

We note that these differences likely overstate the impact from more efficient real-time pricing during fast-start resource deployments because they do not consider the likely market responses to the higher real-time prices:

- Incentives to purchase more in the day-ahead market would increase, which would increase the amount of lower-cost generation committed in the day-ahead market.
- Net imports would increase from neighboring control areas, particularly from New York during the morning and evening peak hours.

However, these responses would substantially improve efficiency because higher-cost peaking generation would be displaced by lower-cost intermediate generation and net imports. Allowing peaking resources to set prices when marginal would also improve:

- Incentives for reliable performance during the relatively tight operating conditions, since fast start units are dispatched primarily when operating reserve margins are smallest during the morning and evening peaks; and
- Incentives governing longer-term investment and retirement decisions by participants, since it would provide increased net revenues to generators that are available during tight operating conditions.[58] This would, in turn, reduce the required net revenues from the capacity market.

Finally, if the estimated price increases were reflected in the calculation of NCPC uplift charges, we estimate that they would be reduced by $9.3 million in 2013 and $10.2 million in 2014. Shifting these costs from uplift, which is difficult for customers to hedge, to energy prices is efficient and consistent with FERC's price formation objectives.

Based on these substantial benefits, we have been recommending that the ISO develop a pricing model that would allow fast-start peaking units to set real-time prices when they are economic to run. In response, the ISO has evaluated potential changes in the pricing methodology that would allow the deployment costs of fast-start units to be more fully reflected in the real-time market

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57 See "Fast Start Pricing – Impact Analysis: Price Formation When Fast Start Resources Are Committed and Dispatched" by Ben Ewing & Jon Lowell, April 16, 2015, NEPOOL MC meeting, for more details.

58 Suppose that allowing fast start resources to set the LMP when economic would raise the average LMP by 50 percent of the potential $4.20/MWh shown in Figure 15. This would increase the net revenue of a generator with high availability by up to $18/kW-year. Net revenue is evaluated further in Section II.F.

prices and has proposed changes in pricing rules for implementation in 2016.[59] The proposed change is comparable to MISO's "Extended LMP" or "ELMP" model implemented in early 2015, which in turn was patterned after NYISO's gas turbine pricing methodology that it has used for years. These two approaches have functioned well in practice. Hence, we support ISO-NE's proposals in this area and recommend that it continue to make it a high priority.

2. Price Setting by Demand Response Resources

Price-responsive demand has the potential to enhance wholesale market efficiency. Modest reductions in consumption by end-users in high-price periods can significantly reduce the costs of committing and dispatching generation. Furthermore, price-responsive demand reduces the need for new investment in generating capacity. Indeed, a significant share of new capacity procured in the Forward Capacity Auctions has been composed of demand response capability. As interest increases in demand response programs and time-of-day pricing for end-users, demand will play a progressively larger role in wholesale market outcomes.

The rise in demand response participation over the past several years is beneficial in many ways, but it also presents significant challenges for efficient real-time pricing. Active demand resources procured in the forward capacity market (i.e., Real-Time Demand Response and Real-Time Emergency Generation) are currently not dispatchable within the real-time dispatch software and cannot, therefore, set real-time energy prices. Instead, they are dispatched as part of the OP-4 procedures under Actions 2 and 6.[60]

The activation of demand response in real time can inefficiently depress real-time prices substantially below the marginal cost of the foregone consumption by the demand response resources, particularly during shortages or near-shortage conditions. Although there is little information available on the marginal cost of foregone consumption for demand response resources, the marginal costs of most demand response resources are likely to be much higher

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59 See "Fast Start Pricing: Improving Price Formation When Fast Start Resources Are Committed and Dispatched" by Jonathan Lowell, March 11, 2015, NEPOOL MC meeting, for more details of the proposal.

60 "Dispatchable" refers to resources that are able to modify their consumption or generation in response to dispatch instructions from the ISO. Loads that are dispatchable in the real-time market are able to participate in the Asset Related Demand (ARD) programs. ARDs are paid according to day-ahead and real-time LMPs. ARDs are not paid for capacity, but are also not charged for capacity obligations.

than the marginal costs of most generators. Hence, real-time prices should be very high when demand response resources are activated.

In 2014, there were no occasions when emergency demand response resources were activated. Therefore, the pricing efficiency during activation of demand response resources for 2014 is not evaluated in this report. However, our evaluation of the three demand response activations in 2013 identified two market issues.[61] First, there was a significant amount of available import capability from neighboring areas that could have been used to import power into New England during the hours with operating reserve shortages (which may prevent the system from shortages). However, the current rules require that real-time external transactions be scheduled in advance of each hour. Implementation of CTS between New York and New England will allow for much more timely responses from imports to unforeseen changes in conditions that lead to reserve shortages in New England.[62]

Second, a demand response activation can depress real-time prices when the activation eliminates the shortage of operating reserves (i.e., when the response is larger than the magnitude of the shortage). There would have been a reserve shortage without the real-time demand response activation, so the demand response resources were effectively the marginal resources. It would be efficient for real-time prices to reflect the value of foregone consumption of the demand response resources in such cases, which is not currently possible because demand response resources do not submit bids and are not activated based on economic criteria. The actual real-time prices in these cases were inefficient because the foregone value of consumption for most demand response resources was likely much higher than the LMPs in these hours.

If the foregone value of consumption for demand response resources was better reflected in real-time LMPs, it would provide more efficient scheduling incentives in the day-ahead market. Raising the real-time price in these cases would provide incentives to purchase more energy in the day-ahead market. Increased purchases would, in turn, lead additional lower cost units to be scheduled and reduce the likelihood of the reserve shortages and demand response activations.

61 See our “2013 Assessment of The ISO New England Electricity Markets” for more details.

62 CTS is scheduled to be effective by the end of 2015 and it is discussed in Section IV.B.

Hence, it is important to consider ways to appropriately reflect the value of foregone consumption in real-time prices. To this end, ISO-NE is moving forward with a proposal to enable demand response resources to participate fully in the day-ahead and real-time markets by June 2017.[63] This would allow active demand response resources to submit multi-part offers into the day-ahead and real-time markets and for the ISO to schedule demand response resources in merit order as it would for a generating resource.[64] Since the new demand response programs will allow resources to offer based on their marginal willingness to consume and be scheduled in economic merit order (rather than be activated based on an operating procedure), it should have a better basis for allowing demand response resources to set prices. However, most demand response resources will still be relatively inflexible on a five-minute basis, so market developments that allow fast-start resources to set prices should be applicable to demand response resources as well.

B. Interchange Scheduling with New York

The performance of ISO-NE's wholesale energy markets depends not only on the efficient use of internal resources, but also the efficient use of transmission interfaces with adjacent areas. This subsection examines the scheduling of imports and exports between New England and New York. Since both regions have real-time spot markets, market participants can schedule market-to-market transactions based on transparent price signals in each region. In this subsection, we evaluate the extent to which the interface is scheduled efficiently.

When an interface is used efficiently, prices in adjacent areas should be consistent unless the interface is constrained. For example, when prices are higher in New England than in New York, imports from New York should continue until prices have converged or until the interface is fully scheduled. A lack of price convergence indicates that resources are being used inefficiently. In other words, higher-cost resources are operating in the high-priced region that could have been supplanted by increased output from lower-cost resources in the low-priced region. It is especially important to schedule flows efficiently between control areas during peak

63 See the 2015 ISO-NE Wholesale Markets Project Plan, page 5.

64 See presentation *Full Integration of Demand Response Resources into the Energy and Reserves Markets* by Henry Yoshimura (ISO-NE) to NEPOOL Markets Committee, May 6-7, 2014.

demand conditions or shortages when flows between regions have the largest economic and reliability consequences.

However, one cannot expect that trading by market participants alone will optimize the use of the interfaces. Several factors prevent real-time price differences between New England and New York from being fully arbitraged.

- Market participants do not operate with perfect foresight of future market conditions (e.g., may not be able to predict which side of the interface will have a higher real-time price) at the time when transaction bids and offers must be submitted.
- Differences in the procedures and timing of scheduling in each market serve as barriers to full arbitrage.
- There are transaction costs associated with scheduling imports and exports that diminish the returns from arbitrage. Participants will not schedule additional power between regions unless they expect a price difference greater than these costs.
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when the expected price difference is small.

Given these considerations, one cannot reasonably expect that trading by market participants alone will fully optimize the use of the interface. Nevertheless, we expect trading to improve the efficiency of power flows between regions.

1. Price Convergence Between New England and New York

The following figure evaluates scheduling between New England and New York across the primary interface and the Northport Norwalk Scheduled Line (i.e., the 1385 Line). The Cross-Sound Cable is omitted because it is scheduled under separate rules.[65] Figure 16 shows the distribution of real-time price differences across the primary interface between New England and New York and the 1385 Line in hours when the interfaces were not constrained.[66]

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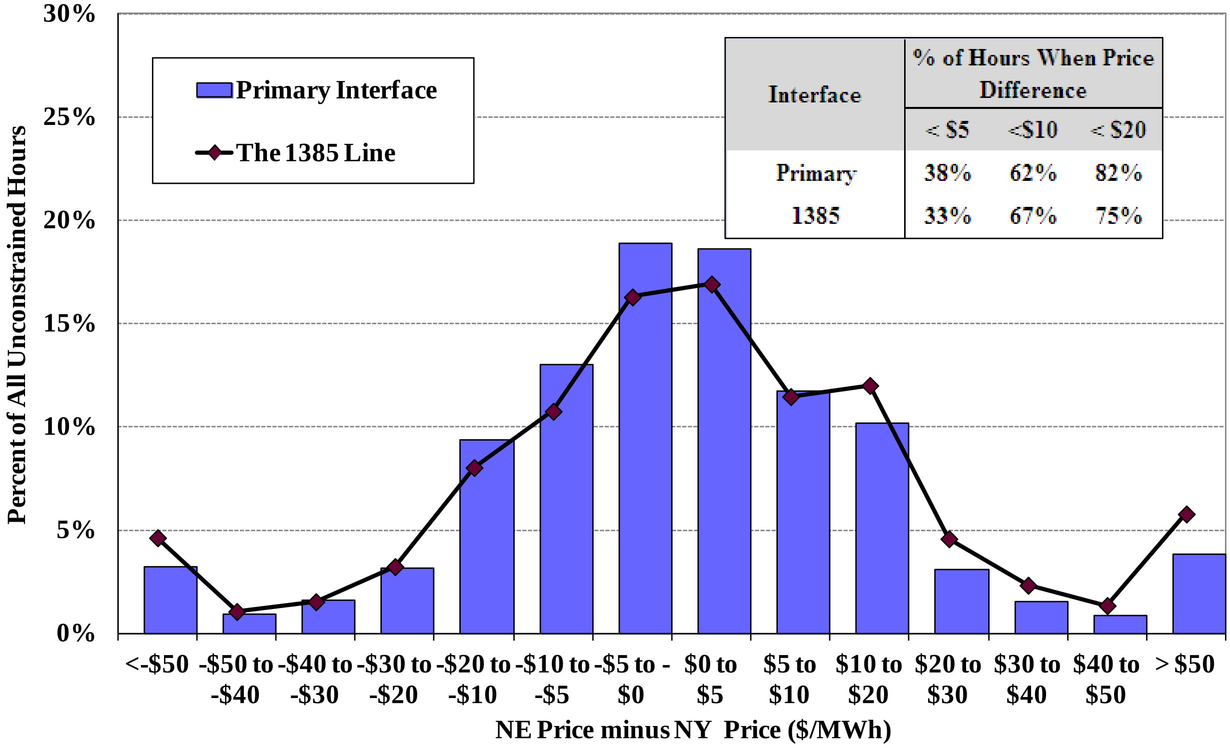
65 Service over the Cross-Sound Cable is provided under the Merchant Transmission Facilities provisions in Schedule 18 of ISO-NE's Tariff, which is separate from the transmission service provisions governing use of the Pool Transmission Facilities. Access to the MTF requires Advance Reservations on the CSC, recommended to be acquired in advance of submitting transactions to the day-ahead market, and energy transactions accepted in ISO-NE and NYISO market systems. Scheduling limits restrict the ability to use the CSC interface for short-run arbitrage transactions between Connecticut and Long Island.

66 The prices used in this analysis are at the New England proxy bus in the New York market (i.e., New York price) and the prices at the New York proxy bus in the New England market (i.e., New England price).

Figure 16: Real-Time Price Difference Between New England and New York
Unconstrained Hours, 2014



While the factors described above prevent complete arbitrage of price differences between regions, trading should help keep prices in the neighboring regions from diverging excessively. Nonetheless, Figure 16 shows that although the price differences were relatively evenly distributed around $0 per MWh, a substantial number of hours had price differences more than $10 per MWh for each interface. In 2014, the price difference between New England and New York exceeded $10 per MWh in 38 percent and 33 percent of the unconstrained hours for the primary interface and the 1385 Line, respectively. Additionally, the price difference was greater than $50 per MWh in 7 percent of the unconstrained hours for the primary interface and in 10 percent of the unconstrained hours for the 1385 Line. These results indicate that the current process does not fully utilize the interface.

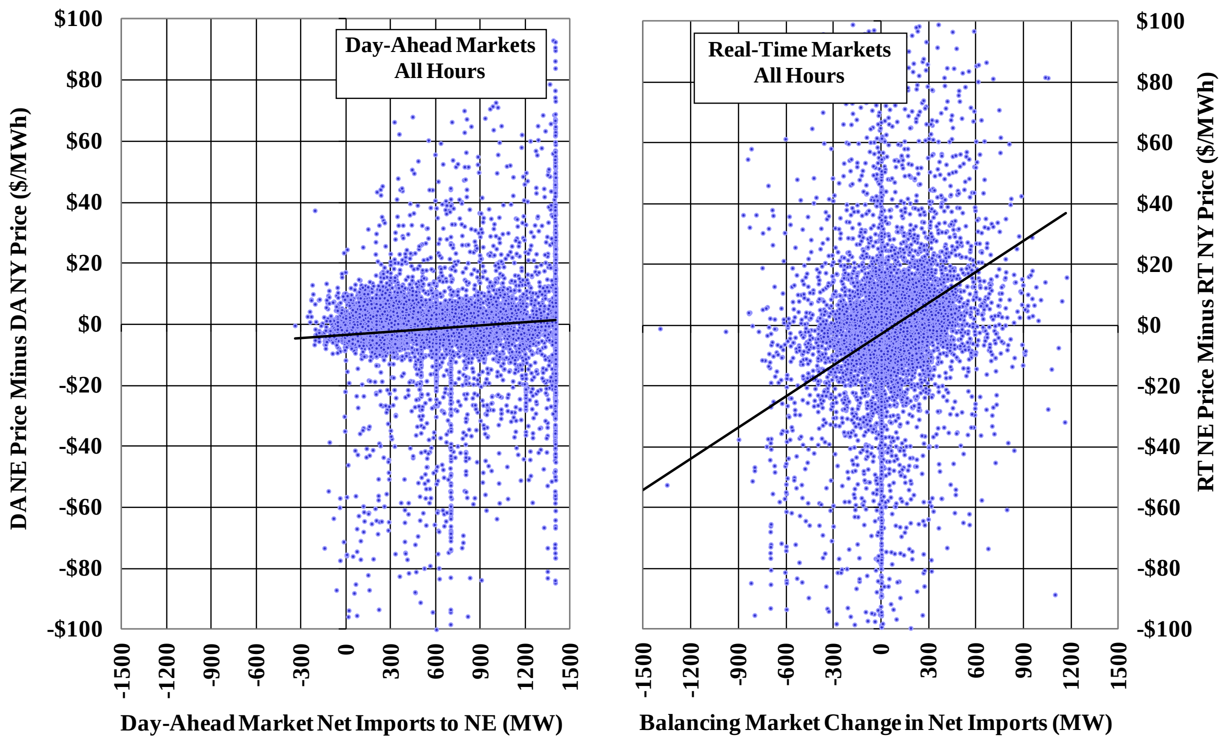
These results also indicate that sizable savings may be achieved by adjusting interchange. Given the pattern of price differences shown, there are many hours when increasing flows from the lower priced region to the higher priced region would have significantly improved the efficiency of clearing prices and production in both regions. This failure to fully arbitrage the interfaces leads to market inefficiencies that could be remedied if the ISOs were to coordinate interchange.

2. Efficiency of Scheduling Between New England and New York

Although market participants have not fully arbitraged the interface between New York and New England, the following analyses evaluate whether the direction of participants' transaction schedules have been consistent with the relative prices in the two regions and have, therefore, improved price convergence and efficiency.

The following analysis focuses on whether the incremental changes in participants' schedules (i.e., real-time adjustments from day-ahead schedules) have been consistent with the relative prices in the two regions. Figure 17 shows a scatter plot of net scheduled flows across the primary interface versus the difference in prices between New England and upstate New York for each hour in 2014. The left side of the figure shows price differences in the day-ahead market on the vertical axis versus net imports scheduled in the day-ahead market on the horizontal axis. The right side of the figure shows hourly price differences in the real-time market on the vertical axis versus the *change* in the net scheduled imports after the day-ahead market on the horizontal axis.

Figure 17: Efficiency of Scheduling in the Day-Ahead and Real-Time
Primary Interface Between New England and New York, 2014



The trend lines in the left and right panels show statistically significant positive correlations between the price difference and the direction of scheduled flows in the day-ahead and real-time markets. However, the correlation in the day-ahead market is relatively weak, which indicates the difficulty participants have in scheduling transactions efficiently. The correlation is stronger in the real-time market, which is consistent with market participants generally responding to price differences by increasing net flows scheduled into the higher-priced region. Additionally, total net revenues from cross-border scheduling in 2014 were $16 million in the day-ahead and real-time markets (not accounting for transaction costs).[67] The fact that significant profits were earned from the external transactions indicates that market participants generally help improve market efficiency overall by facilitating the convergence of prices between regions.

However, the figure also shows that the response of market participants to inter-area price differences is incomplete and unpredictable. In 42 percent of the intervals, the real-time response to the price difference is ultimately in the wrong direction (*from* the high-priced areas *to* the low-priced area). Sometimes this occurs because the response is too large and it causes the prices to prices to reverse. This highlights both the difficulty of predicting changes in market conditions in real-time, as well as the effects of uncoordinated scheduling where each participant is submitting transactions independently. Although market participant scheduling has helped converge prices between adjacent markets, Figure 17 highlights that the external transmission interfaces remain poorly utilized. This can only be addressed by improved coordination of interchange by ISO-NE and NYISO, which is discussed in the next section.

3. Coordination of Interchange by the ISOs

Incomplete price convergence between New England and New York suggests that more efficient scheduling of flows between markets would lead to production cost savings and substantial benefits to consumers. Although past efforts to reduce barriers to market participant scheduling between regions have improved the efficiency of flows and additional such efforts would lead to further improvements, uncertainty and risk are inherent in the market participant scheduling

67 This likely underestimates the actual profits from scheduling because it assumes that day-ahead exports from one market are matched with day-ahead imports in the other market. However, market participants have other options such as matching a day-ahead export in one market with a real-time import in the other market. This flexibility actually allows participants to earn greater profits from more efficient trading strategies than those represented in the figure.

process. Hence, even with improvements, one cannot reasonably expect the current process to fully utilize the interface. As is the case for efficient scheduling of the transmission capability within ISO regions, optimal use of transmission capability between ISO regions requires explicit coordination of the interchanges by the ISOs.

Our simulation of potential benefits from fully optimizing the interchange estimated a benefit of roughly $17 million per year in production cost savings and $200 million per year in consumer savings. The Coordinated Transaction Scheduling ("CTS") proposal that ISO-NE and NYISO agreed to implement would capture a large share of these potential benefits (60 to 70 percent).[68] The CTS is currently under development and is scheduled to be effective by the end of 2015.[69] Under CTS, the ISOs will schedule interchange based on short-term forecasts of market conditions and new bidding procedures that will allow market participants to offer intra-hour transactions that are jointly evaluated by the ISOs. The estimated benefits of this initiative are high, so we continue to recommend that ISO-NE and the NYISO place a high priority on implementing CTS.

68 For a detailed description of simulation models and results, see our 2010 Assessment of Electricity Markets in New England, Section IV.C.

69 See the 2015 ISO-NE Wholesale Markets Project Plan, page 3.

V. Capacity Market Design Improvements

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. In this section, we evaluate potential market design improvements to facilitate competition in the auction and to set sloped demand curves that result in efficient prices across the system. These improvements would enhance competition and improve the efficiency of price signals.

A. Competition in the Forward Capacity Market

Forward Capacity Markets are designed to allow participation by prospective new investors which, in theory, increases competition by providing competitive discipline for existing suppliers that might otherwise have an incentive to exercise market power. In each of the last three forward capacity auctions, there has been a need for new resources in at least one capacity zone.[70] However, the amount of participation by new generation has been relatively limited, causing some new generators to be pivotal in a particular capacity zone.[71]

If participation by new developers is not robust, auction results may not be efficient and competitive. Thus, it is important to evaluate the forward capacity market on an on-going basis and to identify factors that may inhibit participation by new resources or otherwise reduce competition. This section evaluates new suppliers' incentives to offer competitively and existing suppliers' incentives to withhold resources. This section is organized as follows:

- Subsection 1 discusses the incentives of new potential entrants to raise their offers in order to set a higher clearing price when there is limited competition in the auction.
- Subsection 2 discusses the incentives for existing suppliers to retire units to raise prices.
- Subsection 3 evaluates participation in FCA 9.
- Subsection 4 discusses the factors that tend to reduce competition in the FCA.
- Subsection 5 discusses our recommendations related to competition in the FCM.

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70 In FCA 7, new resources were needed to satisfy the NEMA/Boston LSR. In FCA 8, new units were needed to satisfy the system-wide NICR. In FCA 9, new resources were needed to satisfy the SEMA/RI LSR.

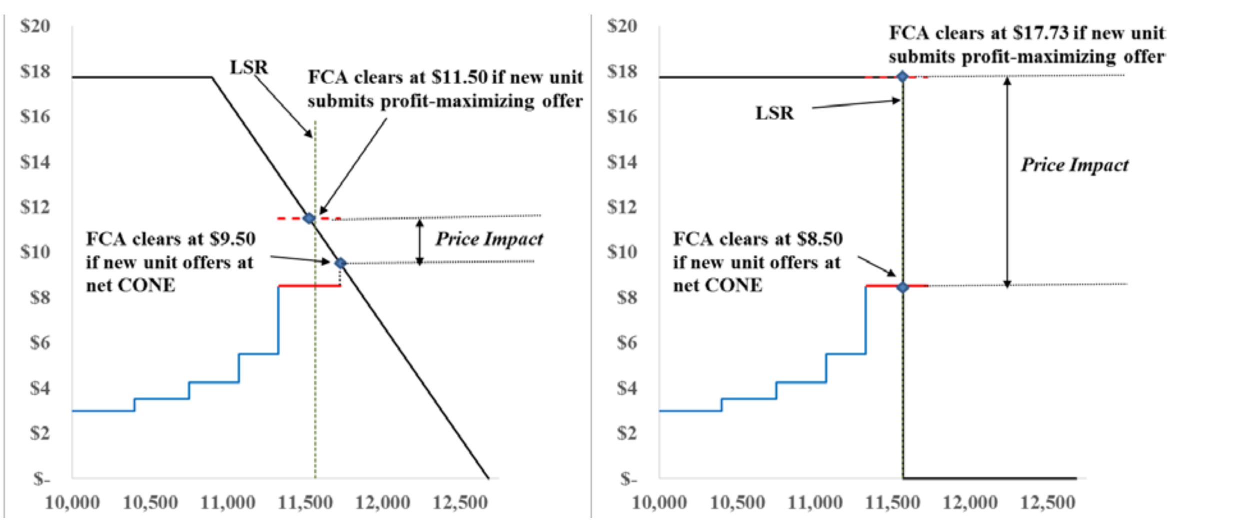
71 A Market Participant is pivotal if some of its capacity is required to satisfy the Local Sourcing Requirement or System-Wide NICR.

1. Incentives for New Generators

The Forward Capacity Market was designed to allow competition by potential new entrants before they move forward with construction. However, the cost of participation and the steps necessary to qualify for the auction limits participation by potential new resources, effectively creating market power for those new suppliers that do participate under some circumstances. If a new resource faces little or no competition, it will have strong incentives to raise its offer price above its net cost of new entry ("CONE") to increase its revenues. This part of the section discusses the incentives for a new resource to raise its offer above its net CONE.[72]

For a new resource that is economic, the developer must develop an offer that balances: (a) the potential gain from setting a higher clearing price and (b) the potential loss from not being selected if its offer price is too high. Factors that increase the benefits a developer achieves from raising prices include the size of its existing portfolio (which increases its total capacity revenues) and the 7-year lock-in provision (which multiplies the gains of raising prices). The incentives of a 400 MW new generator with no other capacity are illustrated in Figure 18 for a capacity zone the size of Southeast New England under both sloped and vertical demand curves. The figure assumes a net CONE of $8.50/kW-month and a zonal shortage of 240 MW.

Figure 18: Illustration of New Generator Incentives to Raise Offer Price



72 In this section, the net cost of new entry (i.e., the FCA price necessary to cover its total investment cost, including capital costs) is referred to as "net CONE," while the net cost of new entry of the generator modeled for purposes of setting the sloped demand curve is referred to as "Net CONE."

This figure shows that if the generator offers at its net CONE, the competitive offer for a new supplier facing robust competition, the clearing price would be $9.50/kW-month and the generator would earn $34 million in excess of its net CONE over the 7-year lock-in period. However, the generator would maximize its profits by offering at $11.50/kW-month, which would result in a profit of $101 million in excess its net CONE over the 7-year lock-in period. Under the vertical demand curve, the generator can raise prices even higher – to $17.73/kW-month – earning a profit of $310 million in excess its net CONE over the 7-year lock-in period.

The illustration above assumes the new supplier does face competition from other new resources. Factors that tend to reduce the incentive for new suppliers to raise prices include:

- The existence of other new suppliers offering at prices levels less than the supplier's profit maximizing offer (e.g., 11.50 per kW-month in the first scenario); and
- Uncertainty about the quantity and price of new resources being offered by other suppliers. Although the mere existence of other new suppliers will discipline a supplier offering a new resources, this discipline is substantially less if it knows the price and/or quantity being offered by the competing supplier because it will know the maximum amount it is able to raise the clearing prices.

Because these two factors will generally increase the competitiveness of the forward capacity market, it is important to facilitate maximum participation by competing firms in the FCA and to minimize the information available about competing suppliers. Subsection 4 of this section discusses possible means to accomplish these objectives.

2. Incentives to Retire Existing Resources

Mothballing or retiring existing generators can result in large price changes given the slope of the demand curves and sizes of the zones. These price changes are efficient if the resource being retired is uneconomic (i.e., is more costly to remain in operation than the revenues it can earn through the ISO-NE markets). However, generators currently may retire a resource by submitting a non-price retirement request even though it has the option of submitting a delist bid that would cover the costs of remaining in operation. In fact, suppliers may retire units that are profitable to continue operating at any time. In other words, although most other forms of withholding from the FCM are effectively mitigated, ISO-NE currently has no authority to mitigate suppliers that physically withhold capacity by retiring economic units. Therefore, it is important to understand when a supplier may have the incentive to do so.

We illustrate these incentives by using the example developed in the prior subsection. In this case, we assume a 600MW generator with an annual going-forward cost ("GFC") of $6.50/kW-month. Additionally, we assume that offers are "non-rationable" (ISO cannot clear part of the offer), and that the capacity zone would be short of capacity by approximately 90 MW without the generator. Finally, we assume the supplier owns an additional 1,000 MW of capacity in the same zone.

In this case, the competitive offer for the existing unit would be $6.50 per kW-month and it would set the price for the zone. However, a non-price retirement request for this resource would produce the following results under the sloped demand curve:

- The price would rise 84 percent to $11.98 per kW-month.[73]
- The generator would receive $66 million more in revenue than if it were to offer competitively and keep the unit in operation.

As we discussed for the new supplier above, the incentives for a supplier to profitably withhold capacity will also depend on the availability of information about other supply participating in the auction. For instance, if the example above were modified to assume that a new 400 MW generator is offered with a net CONE value of $9/kW-month, the price would be set by the new entrant at this level and the net profits from submitting the non-price retirement request would fall to $30 million. However, this result depends on the new entrant facing robust competition from other new entrants and, as a result, offering their resources at prices close to their net CONE. The prior subsection describes why this is likely not to be true.

Other RTOs have recognized these incentives and implemented physical withholding mitigation measures that effectively address the form of anticompetitive conduct. This includes PJM, NYISO, and MISO. In general, these rules involve evaluating whether the retiring unit would clearly be economic to keep in operation. Such rules should never prevent a unit from retiring when that is the efficient and economic choice for the supplier. However, the rules should be effective in preventing or deterring retirements when the retirement is not economically rational for the supplier, absent the benefits the supplier receives through the balance of its portfolio. Absent the introduction of similar rules in New England, we find that ISO-NE's market power

73 This example assumes price separation between the import constrained and ROP zones.

mitigation rules will not be adequate to ensure that capacity market outcomes are workably competitive. We provide a recommendation to address this issue at the end of this section.

3. Participation by New Generation in FCA 9

The FCM qualification process requires a developer to commit significant resources before participating in an FCA, so a limited number of new resources actually compete in each FCA. Consequently, participation by new resources may not provide the desired competitive discipline for new and existing resources in the auction. This subsection summarizes participation by new generation in FCA 9, which is shown in the following table, and identifies factors that may have reduced competition in the FCA.

Table 5: Potential Participation by New Generating Capacity in FCA 9

		Connecticut	SEMA/ RI	NEMA/ Boston	Total
New Generation Capacity in Interconnection Queue (non-intermittent)	[1]	1265	880	1048	3193
Large Units without SIS Study and/ or a Siting Permit Application	[2]		340		340
Capacity from Suspended MPs	[3]		332		332
Rejected New Capacity	[4]			841	841
FCA-9 Qualified Capacity from New Generation (non-intermittent)	[5] = [1]-[2]-[3]-[4]	1265	208	208	1680
Qualified Generation Excluding the Largest New Entrant	[6]	29	11		40
Excess Existing Capacity Relative to LSR	[7]	1790	-557	265	1498

Notes:

[1] Summer capacity (as per publicly available data) of all new non-intermittent generation with a valid Interconnection Request. Excludes resources that will not be operational by the Capacity Commitment Period

[3] ISO-NE issued a public notice suspending Advanced Power on 10/31/2014

[4] Units rejected due to overlapping interconnection impacts analysis were identified in a FERC filing on 11/04/2014

[5] This data differs from the actual qualified capacity to the extent the resource MW data reported in the Interconnection Queue (or other public data) are different from the actual summer capacity. Total actual FCA-9 qualified capacity from non-intermittent new generation (excluding ROP capacity) was 1693 MW

[6] Excludes qualified capacity from intermittent generation and demand resources

[7] Existing capacity and LSR data can be found in ISO-NE's informational FERC filing

The first row in the table shows the amount of non-intermittent generating capacity in the Interconnection Queue at sites located in one of the three import-constrained capacity zones before FCA 9. This represents the potential set of resources that could have submitted a Show of

Interest and participated in the auction. Rows 2, 3, and 4 show the amounts of capacity that did not qualify for reasons that would have been evident to other auction participants from public information. The amounts of qualified generation (Row 5) and qualified generation excluding the largest new entrant (Row 6) are compared to the existing capacity surplus over the local capacity requirement (Row 7), where a negative value indicates a capacity shortfall.

Southeast Massachusetts

A relatively large amount (557 MW) of new capacity was needed to satisfy the local requirement in FCA 9. Although 880 MW of new generation was proposed to be operational by the Capacity Commitment Period in this area, it was apparent from public information on siting permit applications that 340 MW was not likely to participate. Several months before FCA 9, it became apparent that another 332 MW of capacity was not going to participate when ISO-NE published a Notice of Market Participant Suspension for the developer. Other auction participants might have speculated the project would not participate before this, but the notice made this a certainty.

Of the remaining 208 MW that did qualify, 95 percent was a single project, so the developer of the project should have known that its capacity would be pivotal in the auction. In this case, the developer would know that its offer would be accepted at any price below the FCA starting price of $17.73 per kW-month.

Connecticut

There was a relatively large amount of participation by several market participants on top of a substantial excess of existing capacity, so competition to satisfy the local Connecticut requirement was robust.

NEMA/Boston

There was a local excess of 265 MW prior to the auction, so additional resources would not have been needed unless existing capacity de-listed during the auction. While 1,048 MW of proposed new generation was in the interconnection queue, it was apparent from information filed by the ISO that 841 MW did not qualify for the auction (leaving just a single 208 MW new generator).

Thus, if a non-price retirement request or other supply reduction had occurred, this developer would have perceived it was pivotal and could set the capacity price at the FCA starting price.

Four observations can be drawn from the results of FCA 9:

- Limited competition can cause single supplier to be able to unilaterally raise the capacity clearing price by a substantial amount.
- Publishing information on qualified capacity (new and existing) ensures that suppliers will recognize when they are pivotal and can benefit by raising capacity prices.
- To the extent that the qualification process limits the number of new resources participating in the auction, the competiveness of the auction will be reduced.
- The vertical shape of the demand curve accentuates the price impact that a new resource can have when it is pivotal.

These observations point to several market changes that could enhance competition in the FCA in addition to implementing sloped demand curves in the local areas by FCA 11:

- Reducing barriers to participation helps provide additional competitive discipline that reduces the incentive for a supplier to raise its offer substantially above its net CONE.
- Reducing the amount of information available before the auction to make it more difficult for a pivotal supplier to determine its profit-maximizing offer and encourage new suppliers to offer competitively at prices closer to their net CONE.
- Transitioning from the descending clock auction process to a sealed-bid auction to eliminate the information provided during the auction that reduces the competitiveness of the auction. This change would also facilitate the joint optimization of the capacity procurements in local areas and system-wide.

The next subsection provides a discussion these potential changes greater detail. All proposed new generators with active Interconnection Requests are listed in the public Interconnection Queue, which provides: the resource type, date of request, location, size, and progress towards interconnection. Thus, the Interconnection Queue provides a list of potential new competitors before the auction. This part of the section discusses additional information that FCA participants can use to narrow down the list of potential new competitors in the FCA and to estimate the impact of their conduct on clearing prices.

<u>Information from State Proceedings Related to Permit Applications</u>

New generators and changes to existing generators require permits from various state and local agencies *before* the start of construction. The amount of lead time required can be substantial depending on the nature of the permit, type of facility, and location. In Connecticut and Massachusetts, it generally takes at least a year to obtain such permits. Although the FCM rules do not require a developer to obtain permits before the FCA, most new projects will not sell in the FCA before reaching an advanced stage in the permitting process so that the developer can be reasonably certain of being able to satisfy its obligations by the time the commitment period begins.

Permit applications in all New England states require the developer to disclose project information (including the project schedule) and engage the public very early in the process. Therefore, the open nature of the permitting process provides all FCA participants with important data that would allow them to evaluate the progress and feasibility of a new project participating in a given FCA.

Information Published by ISO New England

New and existing FCA participants can refine their offer strategies based on information the ISO publishes about new and existing resources at various stages of the FCA qualification process. In general, publishing such information tends to reduce competitive pressure on auction participants by helping them determine when withholding or raising the offers above net CONE would be profitable. The following four categories of information allow FCA participants to determine how much competition to expect from new resources.

- Rejected Projects – The ISO files with the Commission a description of new resources whose FCM qualification packages were rejected because of the overlapping interconnection impact analysis. These projects are unable to participate because they would require transmission upgrades that might not be feasible before the commitment period. 841 MW in NEMA/Boston was rejected for this reason (see Row 4 of Table 5).
- Conditionally-Qualified Projects – The ISO notifies the Primary (higher-queued) resource and Conditional (lower-queued) resource developers of how their resources will be treated in the FCA. Capacity from a Conditional resource cannot clear unless the Primary resource drops out of the FCA. Hence, providing this information to the Primary resource owner indicates that it cannot be under-cut by the Conditional resource.
- Status of System Impact Study – The Interconnection Queue shows the status of projects' System Impact Studies ("SIS") and approval under section I.3.9. The full scope of the SIS is broader than the scope of the initial interconnection analysis needed for the FCM qualification process and may identify substantial additional costs that must be incurred to interconnect. Therefore, large resources are likely to proceed only after completing a full

SIS. Hence, publishing information about this process may indicate a new unit's likelihood of participating in the FCA.

- Suspension Notice – When a market participant stops meeting the requirements for participation in the market, it may lose its status as an ISO-NE market participant. When this occurs, the ISO must make a public filing notifying the Commission. In some cases, such as in Southeast Massachusetts in FCA 9, this involves a proposed project in an import-constrained zone (see Row 3 of Table 5).

In addition to this information on new resources, the following is three sources of information on the amount of supply from existing resources.

1. Existing Resource Qualified Capacity – The ISO makes a filing to the Commission before the auction with a list of qualified existing generation, demand response, and import resources. Since this list includes the precise number of megawatts for each resource and its location, this information allows auction participants to calculate the exact amount of excess (or shortfall) capacity before the auction, excluding new resources.
2. Non-Price Retirement Requests – The deadline for existing resources to submit a Non-Price Retirement Request is four months before the FCA, so the ISO can review the request for reliability impacts. This deadline is not well-aligned with the new resource qualification process, since it is after the deadline for new resources to submit a Show of Interest. Consequently, new resource developers must wait an extra year before they can respond to the retirement of an existing resource. If the ISO continues to allow resources to submit non-price retirement requests, it would be beneficial to require this request to occur before the Show of Interest deadline.
3. Descending Clock Auction – The descending clock auction format is sometimes touted over sealed bid formats because it provides auction participants with information about the value of a good.[74] However, in the FCA, sellers do not receive any information that may be useful in establishing a competitive offer. Instead, the information learned through the auction process is primarily useful in determining when to leave the auction in order to set the highest price and receive the highest capacity revenue possible. In particular, the ISO-NE clock auction provides the amount of excess system-wide supply at the end of each auction round. Hence, suppliers will know when they are pivotal market wide and, if the new resources are concentrated in a particular zone, this information will allow suppliers to infer how supply conditions may be changing in its zone.

Above is a list of seven categories of information that are published by the ISO that reduce the competitiveness of the auction. We recommend the ISO review this list in light of the limited participation in recent auctions and identify reasonable changes in its information policies.

[74] In most cases, is employed on the demand side with buyers determining when to stop the clock and set the price. It is generally referred to as a Dutch Auction because it is famously used in the Dutch flower market.

4. Conclusions and Recommendations

The forward capacity auction was designed to enhance market efficiency by allowing new proposed resources to compete against existing resources. However, our evaluation of FCM participation in recent FCAs shows that competition from new resources has been limited. Both new proposed resources and imports may find themselves in an auction where they face little competition and have the ability to raise the clearing price significantly. ISO-NE has taken steps to address imports that are pivotal in the FCA. However, competitive concerns remain regarding the offers from pivotal new resources and retirements by pivotal existing suppliers. To address these concerns, we recommend that the ISO:

- Implement sloped demand curves in local capacity zones by FCA 11 as described below in Section B.
- Consider adopting appropriate eligibility rules for resources' use of the Non-Price Retirement Requests (i.e., that it be reserved for cases where the factor driving the decision to retire cannot reasonably be reflected in a de-list offer). This would allow the ISO's supply-side mitigation measures to be appropriately applied to the retirement.
- Evaluate whether it could enhance competition by changing the availability or timing of information about other supply before and during the auction. In particular, we identify three categories of information for the ISO to evaluate:
  - Proposed new resources that are rejected, conditionally-qualified, suspended, or have not undergone System Impact Studies; and
  - Existing resources' qualified capacity and non-price retirement requests.
- Replace the descending clock auction format with a sealed bid auction format.
- Modify its queue rules to allow the FCA to select between projects that are interdependent, rather than providing a preference for one project by designating it Primary and designating the other project as conditionally-qualified. This will allow the FCA to clear the most economic unit and set more efficient prices.

B. Design of Sloped Demand Curves in the Capacity Market

The sloped demand curve was used for the first time in FCA 9 to clear resources for the system-wide capacity requirement ("NICR"). Sloped demand curves facilitate considerably better market performance because they are much more consistent with the marginal reliability benefits capacity provides than vertical demand curves. This is fundamental because the reliability benefit of satisfying the planning requirements is the primary reason the capacity market exists.

Hence, sloped demand curves are essential for capacity markets to perform well and establish efficient clearing prices. Sloped demand curves have been used successfully in the PJM and NYISO capacity markets. In addition to establishing more efficient capacity prices, sloped demand curves also: a) reduce capacity price volatility, which reduces investment risk and lowers the cost of entry; and b) improves market competitiveness by reducing the price effects of withholding capacity.

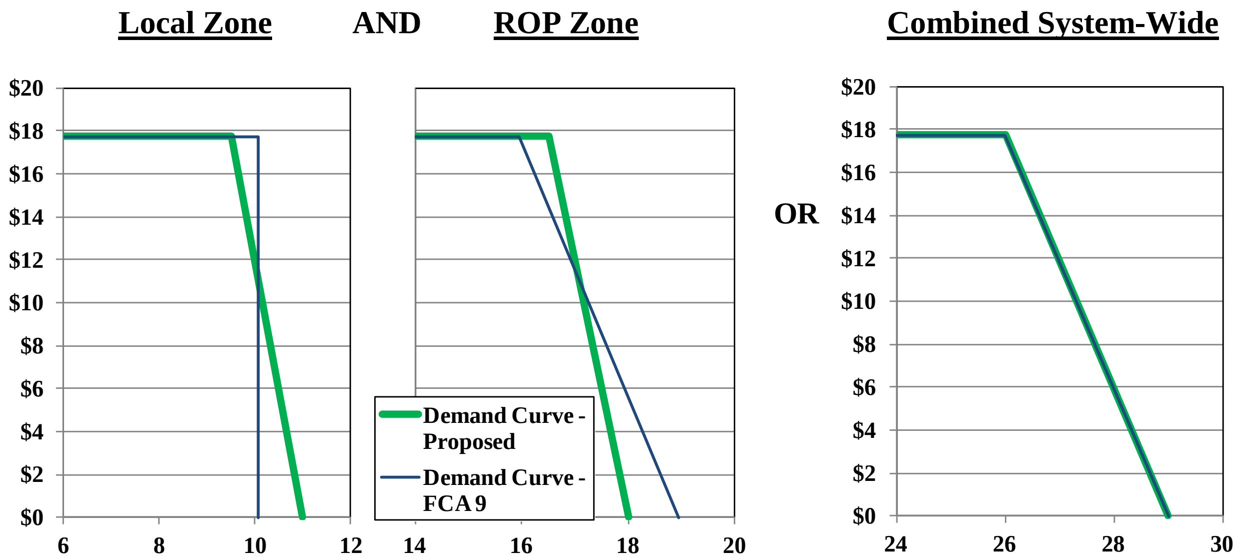
The ISO plans to implement sloped demand curves for local capacity zones in FCA 11, and has been developing proposals on how the curves will be developed and utilized. Stakeholders raised concerns that the ISO's latest proposal would lead to increased price volatility in the Rest of Pool ("ROP") capacity zone and would fail to satisfy the 1-day-in-10-year reliability standard. ISO-NE has withdrawn the proposal and will be working to develop a new demand curve proposal. This section discusses our concerns with approaches similar to the ISO's withdrawn proposal and recommends principles that should guide the development of a new proposal that would ameliorate these concerns.

1. Discussion Prior Proposed Local Capacity Demand Curves

Under prior proposals, the system-wide capacity demand curve would be achieved by employing demand curves for: (a) import-constrained zones, (b) export-constrained zones, and (c) a rest of pool ("ROP") zone. Figure 19 depicts the proposed demand curves for these zones and the system-wide curve, along with the demand curve used for FCA 9.

For simplicity, the example assumes a hypothetical two-zone configuration with no changes in Net CONE, forecast load, or capacity requirements from FCA 9 to FCA 11. The left plot for the import-constrained zone shows the transition from the vertical demand curve to the sloped demand curve. The right plot for the combined system shows that the ISO proposal would not change the system-wide demand curve when there is no price separation between areas. However, the plot in the middle shows that this type of proposal would make the sloped demand curve much steeper in the ROP zone.

Figure 19: Illustration of Proposed Changes in Capacity Demand Curves



The capacity demand curve for the ROP zone would become steeper under the ISO's proposal because the slopes of individual zones are "added" together to generate the demand curve for the combined system. In other words, retaining the same combined system demand curve while giving slope to the import-constrained zone demand curve necessarily requires making the ROP zone demand curve steeper.

One claimed virtue of having demand curves that can be "added" together is that it allows the FCA to be solved as a single welfare maximization problem.[75] However, for the solution to truly be welfare maximizing, it must be the case that the marginal value of capacity in each zone is unrelated to the capacity levels in other zones (i.e., the demand curves are independent). Unfortunately, this is not true, so it is not clear that the FCA with independent zonal demand curves is well-suited to be solved as a single welfare maximization problem. Although it is possible to model the capacity market in this manner, it will exhibit some unappealing attributes that we illustrate below through a hypothetical example. The scenarios in the example are based on the most recent set of zonal demand curves proposed by the ISO.[76]

75 This formulation assumes Welfare = $D_A(x) + D_B(y) - C_A(x) - C_B(y)$, where D is the zonal demand and x and y is the supply in the two zones. $C_A(x)$ and $C_B(y)$ are the costs of supply in Zones A and B.

76 See FCM Sloped Demand Curve: Capacity Zone *Demand Curves* by Matthew Brewster, April 15, 2015 Markets Committee meeting materials.

To illustrate how the proposed demand curves would perform, suppose the auction cleared with supply equal to the requirement in Southeast New England ("SENE"), with 200 MW of excess above the requirement in Connecticut ("CT"), with 350 MW of excess above the requirement in the Northern Zone, and 0 MW of excess in Rest-of-Pool ("ROP"). In this case, the auction would produce the following clearing prices:[77]

- In SENE: $11.08 as the lack of excess in the import-constrained region would lead it to clear at a higher price than other zones.
- In North: $4.39 as the 4.1 percent excess in the export-constrained region would lead it to clear at a lower price than other zones.
- In CT and ROP: $8.09 as the 1.4 percent excess in CT would lead it to clear with ROP.

If just 30 MW were added to the ROP zone, the results in SENE and CT would be virtually unchanged, but the ROP would fall from $8.09 to clear with the Northern Zone at $3.94. These results for the ROP area are more volatile than even the current demand curves (i.e., vertical local demand curves with a sloped system-wide demand curve). The results under the current curves for this example would be:

- SENE: the price would likely be unchanged, set by the marginal supply offer before and after the 30 MW addition.
- CT and ROP: the price would clear at $10.17 before the addition and $10.03 after the addition, a decrease of only 1 percent compared to the 51 percent decrease under the proposed demand curves.

Additionally, we note that the very small excess capacity in the combined CT/ROP area (2.6 percent of the CT requirement) causes the price to clear $2.99 below Net CONE, while the same margin leads the clearing price to fall just $0.91 below Net CONE under the current design. This is important because the market should produce prices that contribute efficiently to the return on new investment (and maintenance of existing supply) as capacity margins fall close to the requirement.

[77] This scenario assumes that areas with sloped demand curves clear at the price level associated with the quantity of capacity purchased in the area. However, it is possible for the clearing price to be set by a non-rationable offer at a higher price level. All capacity prices are shown in $ per kW-month.

Finally, the fact that prices in the ROP could be highly sensitive to small changes in supply increase the incentive for suppliers to withhold capacity or otherwise bid strategically in order to affect the clearing price.[78]

2. Recommended Improvements to Evaluate

Given these concerns, we recommend ISO-NE consider adopting a zonal market framework that better recognizes the interdependence of the supply and demand in different zones. In particular, we recommend the ISO model a system-wide demand and local zonal demand, rather than modeling a ROP zone that is independent of the local zones. This framework increases the likelihood of satisfying resource adequacy (i.e., 1-day-in-10) criteria at both the local and system levels when there is insufficient supply to satisfy the capacity requirements in the local zone.

For example, suppose the available capacity is equal to the requirement in a local capacity zone and in the ROP zone (such that the system just satisfies the resource adequacy criteria). Then assume that a large unit retires in the local zone. Not only will the local zone be short of its planning requirement, but ISO-NE will be short system-wide. However, since the ISO would be modeling the ROP zone as independent of the local import-constrained zone, the price in the ROP could remain very low and not reflective of the system-wide capacity shortage facing the ISO. Conversely, if the local capacity zones have a substantial capacity surplus such that larger procurements are made in these areas, prices and procurements in the ROP area should fall. This will only happen if the capacity market design recognizes the interdependence of the supply and demand in different areas.

Modeling demand curves and clearing the FCA in a manner that recognizes the interdependence of capacity zones will reduce the capacity price volatility and ensure that prices in the ROP zone better reflect the marginal value of reliability. Hence, as the ISO continues to work with its stakeholders to develop a revised zonal demand curve proposal for FCA 11, we recommend the ISO develop curves that efficiently reflect this interdependence.

78 Section V.A discusses the incentives for new and existing firms to affect the clearing price.

Appendix A: Net Revenue Assumptions

The method we use to estimate net revenues uses the following assumptions:

- Fuel costs for all units are based on the Algonquin City Gates gas price index. We also analyzed the profitability of a CC unit ("CC (Iroq)") with access to gas priced at the Iroquois Zone 2 index.
- All units are scheduled before each day based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- CC and ST units may sell energy, 10-minute spinning reserves, and 30-minute reserves; while combustion turbines may sell energy and 10-minute or 30-minute non-spinning reserves. Each gas-only and dual-fueled unit is assumed to offer reserves, limited only by its ramp rate and commitment status.
- Combustion turbines (including older gas turbines) are committed in real-time based on hourly real-time prices. Combustion turbines settle with the ISO according to real-time market prices and the deviation from their day-ahead schedule.
- Online units are dispatched in real-time consistent with the hourly integrated real-time LBMP and settle with the ISO on the deviation from their day-ahead schedule. However, to account for the effect of the slower ramp rate of the ST unit in this hourly analysis, the unit is assumed to operate within a certain margin of the day-ahead energy schedule. The margin is assumed to be 25 percent of the maximum capability.
- All technology types are evaluated under gas-only and dual-fuel scenarios to assess the incremental profitability of dual-fuel capability. ST units are assumed to use low sulfur residual oil. All other units are assumed to use ultra-low sulfur diesel oil.
- Combustion turbines (including older gas turbines) are also evaluated for their profitability based on the generator's decision to participate in the Forward Reserve Auctions for each of the capability periods. It is assumed that generators anticipate when selling forward reserves will be more profitable than selling real-time reserves before each capability period.
- All the dual-fuel units are assumed to offer into the Winter Reliability Program (WRP). The revenues from WRP were estimated based on the weighted average of accepted bids from each type of unit in the most recent auction.
- Fuel costs assume transportation and other charges of 27 cents/MMbtu for gas and $2/MMbtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons.
- The minimum generation level is 440 MW for CCs and 90 MW for ST units. The heat rate is 7,639 btu/kWh at the minimum output level for CCs, and 13,000 btu/kWh for ST units. The heat rate and capacity for a unit on a given day are assumed to vary linearly between

the summer values on August 1 and the winter values on February 1. The summer and winter values are shown in the following two tables.

- Regional Greenhouse Gas Initiative (RGGI) compliance costs are included.
- We also use the modified operating and cost assumptions listed in the following tables:

Table 6: New Unit Parameters for Net Revenue Estimates [79]

Characteristics	CC	LMS 100	Frame 7
Summer Capacity (MW)	715	188	417
Winter Capacity (MW)	754	202	450
Summer Heat Rate (Btu/kWh)	7469	9260	10806
Winter Heat Rate (Btu/kWh)	7405	9041	10383
Min Run Time (hrs)	4	1	1
Variable O&M ($/MWh)	2.4	5.4	3.7
Startup Cost ($)	18402	0	18328
Startup Cost (MMBTU)	3376	430	900
EFORd	2.5%	2.0%	2.0%

Table 7: Existing Unit Parameters for Net Revenue Estimates

Characteristics	ST	GT-10	GT-30
Summer Capacity (MW)	360	32	16
Winter Capacity (MW)	360	40	20
Heat Rate (Btu/kWh)	10000	15000	17000
Min Run Time (hrs)	16	1	1
Variable O&M ($/MWh)	8.0	4.0	4.5
Startup Cost ($)	6000	1200	519
Startup Cost (MMBTU)	2000	50	60
EFORd	5%	10%	20%

79 These parameters are based on technologies studied as part of the ISO's sloped demand curve filing.