2006 Assessment of the Electricity Markets in New England

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Table of Contents

Table of Figures

I. Executive Summary

This report assesses the efficiency and competitiveness of New England's wholesale electricity markets during 2006. The current locational wholesale electricity markets began operation on March 1, 2003 and were referred to as Standard Market Design ("SMD"). Since that time, ISO-NE has implemented operating reserves and other markets to satisfy the electricity requirements of the New England region. These markets include:

- Day-ahead and real-time energy markets for the wholesale purchase and sale of electricity;
- A market for Financial Transmission Rights ("FTRs") that allow participants to hedge the congestion costs associated with delivering power to a location that is constrained by the limits of the transmission network.
- Forward and real-time operating reserves markets intended to ensure that sufficient resources are available to produce electricity when a generator outage or other system contingency occurs;
- A regulation market to procure the ability to instruct specially-equipped generators to increase or decrease output on a moment-by-moment basis to keep supply and demand in balance; and
- An installed capacity market that is intended to assure that the long-term market signals result in efficient new investment and the maintenance of existing resources that are needed to meet the reliability needs of the region.

These markets provide substantial benefits to the region by ensuring that the lowest cost supplies are utilized to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term. Although it is difficult to quantify some of these benefits, particularly the long-term benefits, they are considerable because the markets coordinate the decisions and actions of numerous buyers and sellers of electricity. Good coordination is essential due to the physical characteristics of electricity and the transmission network used to deliver the electricity to customers. This coordination affects not only the prices and costs of electricity, but also the reliability with which it is delivered.

The New England energy markets efficiently dispatch generation on the basis of supply offers to satisfy energy demand and operating reserve requirements, while preventing power flows on the network from exceeding transmission constraints. The markets establish locational marginal prices ("LMPs") that reflect the marginal system cost of serving load at each location on the network. When the market is functioning well, these prices provide transparent price signals that facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions.

A. Introduction and Summary of Findings

In addition to providing a summary of market outcomes in 2006, this report includes findings in two primary areas: the competitive performance of the market and the operational efficiency of the markets. The findings in each of these areas are discussed below.

Competitive Performance of the Market

We analyzed the competitive performance of the overall market in New England, as well as a number of constrained areas within the market. Based on the results of these analyses, we find that the markets have performed competitively in 2006. We found little evidence that any suppliers were either economically or physically withholding resources to raise prices in the transmission-constrained areas or in the broader market. Although nominal prices for electricity have been higher in recent years than they were historically, this is almost entirely attributable to the substantial increase in fuel prices. Because fuel costs constitute the vast majority of the marginal costs of producing electricity, increases in fuel costs will translate directly to increases in offer prices and market clearing prices for electricity.

During eight hours on August 1 and 2, real-time energy prices rose to $1000/MWh. The extraordinary prices resulted during record load conditions that caused significant shortages of operating reserves in New England. We examined the conduct during this period particularly closely and did not identify any concerns related to potential economic withholding of generating resources. There was also no indication of physical withholding as forced outages and other deratings were at relatively low levels during this period. However, we did find that inefficient transmission flows between New York and New England contributed to the shortages on these days. This report includes a recommendation for addressing this issue.

We also found that frequent supplemental commitment for local reliability has encouraged some generators in constrained areas to raise offers above competitive levels (i.e., marginal cost).

When local reliability requirements are satisfied outside the normal market process, the suppliers are generally paid their offer price because the clearing price is usually not sufficient for them to recover their full offer price (sometimes referred to as their "as-bid" cost). When suppliers are paid their offer price rather than a clearing price, it changes their incentives to submit offers at their marginal costs (i.e., it will have "pay-as-bid" incentives). Because they receive payments equal to their offer price, generators that are frequently committed for local reliability have "pay-as-bid" incentives. Even under perfect competition, suppliers with pay-as-bid incentives rationally offer above their marginal cost to receive the full market value for their supply. For this reason, it can be difficult to distinguish economic withholding from a competitive outcome when suppliers have pay-as-bid incentives. Generators committed for local reliability requirements often do not face meaningful competition to satisfy these requirements and, therefore, market power can be a significant concern. In these cases, however, the market power mitigation measures are designed to limit their ability to exercise market power.

Operational Efficiency of the Markets

In general, the day-ahead and real-time markets have operated efficiently in 2006 with prices that reflected underlying market fundamentals. Electricity prices in New England have been strongly correlated with changes in underlying fuel prices as one would expect in a well-functioning market. To maintain reliability in the constrained areas, however, ISO-NE has continued to commit substantial quantities of additional resources to supplement the market-based commitments in the day-ahead market. This is an issue that is common to all electricity markets and arises when the market requirements do not fully reflect the reliability needs of the system. Additionally, the limited quantities of fast-start resources in these areas increase the need for these commitments. Therefore, the ISO must commit larger, slower-starting steam and combined-cycle generation to assure reliability and manage voltage in constrained areas.

This additional online supply in constrained areas substantially reduces the congestion into these areas and generates significant supplemental charges to New England loads that are difficult for them to hedge (we refer to these charges as "uplift charges"). Therefore, reducing the need for these supplemental commitments should remain a high priority for ISO-NE. To that end, ISO-NE made a number of changes in its market rules and worked with market participants to address the underlying reasons for the supplemental commitments. For example, in late 2004 and early 2005, the ISO worked with participants to install equipment and make other operational changes to improve its ability to manage voltage in the NEMA/Boston area. These improvements contributed to sharp reductions in supplemental commitments for voltage support in 2005 and 2006. Additionally, a significant decrease in the supplemental commitments in Boston in 2006 occurred as a result of ISO-NE entering a reliability agreement with a large supplier in the area. The agreement stipulated that the supplier's units be offered at marginal costs in the Day-Ahead market. This generally caused them to be committed in the Day-Ahead market. Previously, they had often been supplementally committed by ISO-NE after the Day-Ahead market.

ISO-NE made several major market enhancements in October 2006 under Phase II of the ASM project that should improve market operations. The most significant changes were the addition of locational requirements to the forward reserve market and the introduction of reserve markets with locational requirements that are co-optimized with energy in the real-time market. Additionally, ISO-NE is implementing substantial changes to its installed capacity market, moving to a forward capacity market ("FCM") with locational requirements that would cause capacity to be procured three years forward. This forward procurement is intended to facilitate the entry of new generation, which generally requires at least three years to complete the regulatory and construction processes to enter the market. The transition to this market has begun and the first auction is scheduled to be held in February 2008 to meet the capacity requirements beginning in June 2010.

These changes are expected to lead to at least three significant improvements. First, markets that recognize the need for locational reserves are more consistent with the system's operating requirements. This should reduce the need for manual actions by the operators and, thereby, lower the uplift costs associated with these actions. Second, these changes will address a significant issue regarding the long-run economic signals in the New England markets – the lack of economic signals that fully reflect the local reliability requirements in transmission-constrained areas. The fact that significant reliability requirements are not priced within the New England market framework causes the long-term economic signals in the key constrained areas to be understated. The understated price signal, in turn, limits the entry of new resources that are needed, particularly fast-start units that are well-suited to provide operating reserves. Third, the understated price signals have resulted in a heavy reliance on reliability agreements to ensure that existing generation needed for reliability in the constrained areas remains in operation. Reliability agreements are poor substitutes for efficient, transparent market prices and do little to facilitate efficient investment in new generation and demand response resources over the long-term.

The report contains some recommendation for potential improvements to the New England markets. These recommendations generally involve modifications to certain operating procedures and rules that should increase the efficiency of the New England markets. The recommendations are described in the following sections along with a summary of the report's findings and conclusions in each area.

B. Energy Prices and Congestion

In 2006, electricity prices declined from the relatively high levels that prevailed from July 2005 through January 2006, which were driven by very high natural gas prices. The correlation between natural gas prices and electricity prices is consistent with a well-performing market given that: a) fuel costs constitute the vast majority of most generators' marginal costs, and b) natural gas-fired units are frequently on the margin (setting the market price) in New England.

In the majority of hours, demand was lower in 2006 than in 2005. However, several days of extremely hot weather in early August increased load to a record peak in excess of 28 GW. This led to eight hours of New England-wide reserve shortages on two days. Consistent with the market rules, prices increased to $1000/MWh during the reserve shortage.

Congestion and Financial Transmission Rights

Under SMD, New England has experienced relatively little congestion in historically-constrained areas, including the NEMA/Boston area and Connecticut. In fact, a large portion of the price separation between net exporting regions and net importing regions has been due to transmission losses rather than transmission congestion. For instance, 50 percent of the difference between prices in Maine and NEMA/Boston was due to losses and 50 percent was due to congestion in 2006.

While the overall level of congestion in the New England markets was low, congestion into the Norwalk-Stamford load pocket continued to be significant during 2006. Day-ahead market prices in the Norwalk-Stamford load pocket averaged approximately $22/MWh more than the surrounding areas in Southwest Connecticut. Imports to the Norwalk-Stamford load pocket accounted for approximately 60 percent of the net congestion revenues collected by the ISO from the day-ahead and real-time markets in 2006.

The ISO operates annual and monthly markets for Financial Transmission Rights ("FTR"). These markets generally functioned well during 2006. The FTR prices determined in the annual auction, which took place prior to 2006, modestly over-estimated the value of congestion in the Day-Ahead market. However, the monthly auction prices were lower than the annual auction prices, as market participants adjusted their expectations of congestion. The improvement between the long-term auction and the shorter-term auctions is a positive indicator regarding the liquidity and overall efficiency of the FTR market.

Day-Ahead to Real-Time Price Convergence and Virtual Trading

We evaluate price convergence at the New England Hub, which is broadly representative of prices outside of transmission-constrained areas. Consistent with prior experience under SMD, average prices in the day-ahead market were higher than average prices in the real-time market, but the differential declined from $1.65/MWh in 2005 to $0.83/MWh in 2006. The persistent difference is partly due to the fact that allocations of uplift for NCPC payments are higher when load buys energy in the real-time market versus the day-ahead market. When the uplift allocations are combined with energy prices to estimate a total cost of scheduled load, the difference is reduced to $0.07/MWh in 2005 and $0.16/MWh in 2006. Hence, once we consider the full cost to load serving entities of purchasing power, there is no significant difference between average day-ahead and average real-time prices at the Hub.

Price convergence was better at the New England Hub than at the four import-constrained locations in Boston and Connecticut. This condition can be attributed to the fact that unforeseen market events can have a greater price impact in isolated areas. When the transmission system is unconstrained, all buyers and sellers participate in a single, regional market. An unconstrained system diminishes the price impact that individual events, such as generator outages, have in their immediate surroundings. However, in the presence of transmission congestion, such events can have a much greater effect in a particular area. Boston provides an example of how a single market event can affect convergence between day-ahead and real-time prices. On May 9th, day-ahead prices cleared below $150/MWh, but real-time prices rose to $900/MWh during the afternoon and evening due to several large unit outages. If we exclude this 10-hour event, Boston would have had a $0.36/MWh *day-ahead* price premium rather than a $0.50/MWh *real-time* price premium.

Price convergence has a tendency to improve over time as market participants learn to form better expectations regarding market events. For instance, Norwalk-Stamford began to experience severe congestion on a frequent basis in 2005. As a result, LMPs in Norwalk-Stamford were more volatile than other regions of New England. Because supplemental commitment frequently occurs after the day-ahead market, the additional supply tends to reduce real-time congestion. This pattern attracted virtual supply, but not in sufficient quantities to bring full convergence. Because of the inherent difficulty of predicting the congestion, average day-ahead prices were significantly higher than average real-time prices. In 2006, congestion into Norwalk-Stamford continued and convergence improved substantially. The difference between average day-ahead and real-time prices decreased from more than $10/MWh 2005 to less than $4/MWh in 2006.

External Transactions and Price Convergence with New York

Our evaluation of the external transactions indicate that the market participants are not effectively arbitraging the price differences between New York and New England by scheduling transactions that modify the power flows between the markets. This is particularly important during shortages or very high-priced periods because modest changes in the physical interchange can substantially affect the market outcomes in both New England and New York.

This was demonstrated during the peak demand events on August 1st and 2nd when prices in New England experienced sustained operating reserve shortages and prices as high as $1000 per MWh in eight hours. New England exported significant amounts of power to New York even though the clearing prices were higher on the New England side of the border by as much as $800/MWh during much of this period. In all eight hours, ISO-NE made emergency purchases from the

New York ISO. Had the interchange between the markets been optimized, it is likely that New England would not have experienced a shortage in at least five of the eight hours.

On the basis of these results, we continue to recommend that the ISO develop provisions to better coordinate the physical interchange between New York and New England. These provisions would facilitate a more seamless market in the Northeast, which would: ensure that power is efficiently transmitted to the highest-value locations, achieve substantial economic savings for customers in the region, and improve reliability. Some have argued that this recommendation would constitute involving the ISOs in the market. This is not the case. The ISOs would be utilizing the bids and offers submitted by participants in each market to establish the optimal interchange between the markets in the same way they do to establish the optimal power flows across each transmission interface inside both markets.

C. Market Operations

This section covers a wide variety of areas related to the operation of the SMD markets, including the market consequences of certain operating procedures and the scheduling actions of participants.

Real-Time Commitment and Pricing of Fast-Start Resources

One key operational area that affects the performance of the market is the commitment of fast-start resources in the real-time market and the effect of these resources on real-time prices. Fast-start units are generally capable of starting from an offline status and ramping to their maximum output within 10 minutes or 30 minutes of receiving an instruction. This enables them to provide reserves while offline. Areas without significant quantities of fast-start generation must maintain more of their reserves on online units, which can be very expensive. Since offline fast-start units can be deployed very quickly, they are able to participate in the real-time energy market (i.e., the real-time software will commit fast-start units). In making the decision to commit a fast-start unit, the real-time market software takes into account both the commitment costs (start-up costs and no-load costs) and the incremental energy costs. However, market clearing prices are always set based only on suppliers' incremental energy offers. Hence, the full cost of a decision to start a fast-start unit may not be included in the real-time prices.

Additionally, fast-start units may not always set energy prices when they are needed to satisfy energy, operating reserves, or local reliability requirements. For both of these reasons, the real-time prices will tend to be understated when fast-start resources are needed to manage congestion into a constrained area or satisfy the New England demand for electricity more broadly. This pricing issue has been identified previously in both New York and the Midwest ISO markets.

The real-time market deployed fast-start units in unconstrained areas in 4.6 percent of the intervals in 2006. In more than 40 percent of these intervals, LMPs were lower than the full costs of economic fast-start units – 35 percent lower on average. Inefficient market incentives may result when real-time prices do not reflect the costs of deploying fast-start units. First, understated real-time prices will reduce the incentives to fully schedule load through the day-ahead market because the day-ahead prices will tend to be higher than the real-time prices if load is fully scheduled day ahead. The consequences of under-scheduling day ahead are that fewer slow-starting units will be committed and the market will rely more heavily on fast-starting resources in real time to meet the incremental load. This pattern reduces the overall market efficiency and increases the uplift costs borne by market participants.

Second, it does not provide a correct signal to participants that may import or export power to or from New England. The understated prices in this case will likely lead to fewer net imports and increase New England's reliance on the fast-start resources. Finally, it diminishes the price signals that govern new investment in the longer term. Hence, we recommend that the ISO evaluate 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.

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Supplemental Commitment and Out-of Merit Dispatch

While there was a modest decline from 2005 to 2006 in the overall quantity of supplemental commitment, the distribution of these commitments shifted from Boston to Lower Southeast

Massachusetts. In Southeast Massachusetts, supplemental commitment increased due to changes in fuel costs and offer patterns that caused units needed for local reliability to no longer be economic. Hence, these units had to be supplementally committed more frequently in 2006 to ensure reliable service to the Cape Cod area. In Boston, supplemental commitment declined for two reasons. First, the ISO completed a series of transmission upgrades in 2005 addressing voltage issues that previously required ISO-NE to make supplemental commitments in the area. Second, ISO-NE entered into a reliability agreement with a large supplier in Boston with requirements that caused the supplier's units to generally be committed in the Day-Ahead market. Previously, the supplier's units had often been supplementally committed by ISO-NE after the Day-Ahead market. The latter reduction will not likely be sustained because the reliability agreement expired at the end of 2006.

Supplemental commitments also frequently result in a significant quantity of out-of-merit dispatch, i.e., energy produced by resources whose energy offer prices are higher than the market energy price. This occurs because once they are committed, online resources must be dispatched at or above their minimum output parameter ("EcoMin"). These units cannot be shut down since their capacity is needed to satisfy the local capacity requirement. Since out-of-merit resources are treated as must-take resources (equivalent to assigning them a zero offer price) and are not eligible to set LMPs when running at their EcoMin, they displace the marginal source of energy. This results in lower prices in constrained areas and in the broader New England market as well. Since most of the out-of-merit energy is produced from resources committed supplementally, the changes in out-of-merit energy generally mirror changes in supplemental commitments. Hence, the report finds that out-of-merit energy decreased slightly overall -- increasing in Lower Southeast Massachusetts and decreasing sharply in Boston.

Supplemental commitments and out-of-merit energy dispatch create four issues in the New England market.

- They can create inefficiencies in the commitment because supplemental commitments are made with the objective of minimizing commitment costs (i.e., start-up, no-load, and energy costs at EcoMin), rather than minimizing the overall production costs.

- They tend to mute market signals to invest in areas that would benefit the most from additional generation and transmission investment. They also diminish incentives to develop demand response capability.
- They can create incentives for generators frequently committed for reliability to avoid market-based commitment when they would be economic at the day-ahead LMP. This can induce the ISO to commit the resource in the Resource Adequacy Assessment ("RAA") process for local reliability where the generator is paid its offer price in the form of NCPC.
- They cause a substantial amount of uplift costs, which are difficult for participants to hedge and can be quite volatile. Some of the uplift is allocated in ways that create inefficient incentives. The report discusses these allocations and recommends a re-evaluation of them by ISO-NE.

ISO-NE implemented a major change in the market in 2006 that should improve its operational performance. Under Phase II of the Ancillary Services Market Project, the ISO began to operate a Real-Time Reserve Market and a Forward Reserve Market with locational requirements and prices in October 2006. Due to the limited quantity of fast-start resources in the constrained areas, a large portion of these reserves must be held by on-line resources. If additional fast-start resources are added in these areas over the longer term, the frequency and quantity of supplemental commitment would be substantially reduced. The reserve markets have improved the economic signals for suppliers to provide reserves in Connecticut and Boston from fast-start units and other low-cost reserve providers, although they have not resolved the supplemental commitment issues in the short-term.

Price Corrections

Price corrections are frequently an indicator of implementation problems or software errors. Since 2003, the year SMD markets were implemented, the rate of price correction has been very low, generally less than 0.3 percent of the five-minute intervals. It is particularly notable that the rate of price corrections remained low during the last three months of 2006 after the implementation of real-time reserve markets. Real-time co-optimization of energy and reserves required significant changes to the market software. Major software deployments often lead to more frequent price corrections. These results support the conclusion that the real-time reserve market development and deployment were well-managed and the SMD markets overall are working well.

Load Forecasting

Day-ahead load forecasting is an important determinant of efficient day-ahead commitment. The accuracy of the ISO's forecasts is important because the forecasts are a key input to the ISO's reliability assessments, forecasted transmission limits, and supplemental commitment decisions. They also provide information to market participants for their day-ahead scheduling and bidding.

The ISO's load forecasting improved in the summer of 2006 compared with the previous summer. The average error in forecasting the daily peak load in New England declined from 2.2 percent in 2005 to 1.8 percent in 2006. In both years, the forecasted load was higher on average than actual load by 0.7 percent.

Day-ahead Transmission Limits

Imports into a given area are generally limited by the capacity of the transmission interfaces into the area. Any load that cannot be served by imports must be served by local resources within the transmission-constrained area. The forecasted transmission limits used in the day-ahead market help determine the commitment of resources in these areas. Significant differences between the day-ahead and real-time limits can reduce the market efficiency and increase costs. Our evaluation in this area indicated that the limits used in the day-ahead market were systematically lower than the real-time limits for the transmission interfaces into several key constrained areas up until the fall of 2006. From September through December of 2006, the limits became more consistent in the two markets, which indicates an operational improvement in the calculation of these limits.

Additional Recommendations to Improve Market Operations

In order to further reduce the inefficiencies associated with supplemental commitments, we recommend that the ISO:

- Consider integrating local reliability requirements currently used in the RAA process into the day-ahead market commitment model. Solving the day-ahead market model with these operating requirements would lead to a more efficient commitment and lower costs. In response to this recommendation last year, the ISO has been undertaking an evaluation of this potential change.;
- Re-evaluate the allocation of uplift costs associated with supplemental commitments for local 1st contingencies, voltage support, and market-wide capacity needs. We

recommend that these costs be allocated in a manner that reflects the causes of the costs to the maximum extent possible. In the case of local 1st contingencies and voltage support commitments, for example, this may result in a more targeted allocation to the areas affected by the commitments. Such a change should improve participants' incentives and the efficiency of market outcomes; and

- Consider rule changes to alleviate increased uplift costs and other market effects caused when Participants self-commit generation after the RAA process.

D. Regulation Market

In this section of the report, we evaluate the new market for regulation that was implemented in October 2005. Regulation expenses increased substantially after the new market was deployed. The monthly costs of regulation peaked at $18.4 million for the month of December 2005 before decreasing in 2006 to an average of $6.4 million per month. Some of the increase in late 2005 can be traced to market design elements and changes in the behavior of Regulation suppliers. Other portions of the increase can be attributed to broader factors affecting New England's energy markets.

Regulation Market Design Changes

The new market adopts a model that minimizes consumer payments, rather than minimizing system cost (as had been the objective of the prior market). The new market design also incorporates "mileage" payments for responses to regulator instructions in addition to payments for providing regulation capability and the opportunity cost of not selling energy. Lastly, the lost opportunity cost payment under the new market is not reduced to account for net revenues the supplier received from the regulation market.

To minimize the expected payments for regulation, the regulation selector chooses those regulating units with the lowest "rank price". The rank price for a generator is the sum of five quantities: (1) estimated capacity payment, (2) estimated mileage payment, (3) estimated lost opportunity cost payment, (4) estimated production cost change, and (5) the "look ahead penalty." The look ahead penalty was included in order to avoid selecting units that would earn a large opportunity cost payment if they were to regulate into a range of energy offers priced at extreme levels.

Regulation Market Performance

We attributed the initial increase in costs following the introduction of the new market design in late 2005 to a combination of factors. Because these factors were all occurring at the same time, it is difficult to determine the relative contribution of each factor to the increased regulation costs.

- Natural gas prices increased substantially and contributed to higher regulation cost.
- The mileage payment was added, but there was no corresponding adjustment in the offer prices of regulation suppliers. Adding the mileage payment should have roughly doubled the expected stream of payments associated with the RCP. This change was expected to, but did not initially, lead suppliers to reduce their offer prices.
- There was a bias in the regulation selector that over-weights lost opportunity costs. The effect of this redundant component was that the market would not always select the offers that lead to the lowest estimated payments by consumers (the objective of the new market), which can result in higher RCPs. Additionally, we found the Look Ahead Penalty component for some resources was not a good estimate of the potential payments it is intended to represent.
- There was a substantial reduction in the quantities of regulation offers associated with the withdrawal of one of the large regulation suppliers late in 2005, and an increase in offer prices by the some regulation suppliers. These higher offer prices contributed to the higher RCPs and market costs.

Many of these factors were reversed in 2006. Suppliers lowered their offer prices and increased the quantities offered. The lower offer prices may be due to experience gained with the new market (most notably the additional revenue provided by the mileage payment) and the reduction in natural gas prices that occurred in 2006. The lower offer prices and higher offer quantities led to lower RCPs and regulation expenses in 2006. In addition, energy prices tended to be lower in 2006, leading to lower Lost Opportunity Cost payments on average.

On the basis of our initial review last year of the new regulation market, we recommended the elimination of the Production Cost Component and a substantial change to the Look-Ahead Penalty. The Internal Market Monitor had conducted an independent review of the regulation market and made similar recommendations. In November 2006, the ISO proposed these changes to FERC, and FERC accepted the changes to go into effect in January 2007. These changes should improve the selection of resources to provide regulation, the participants' incentives, and the overall efficiency of the market.

Regulation Market Conclusion

Based on our review of the regulation market, we find that the performance of the regulation market improved substantially in 2006. The changes deployed in January 2007 should further improve its performance. In the long-term, given the complex interaction of the regulation market with the energy market (particularly with respect to commitment decisions made in the day-ahead market), we recommend that the ISO evaluate the benefits of moving to day-ahead and real-time regulation markets that are co-optimized with the energy and ancillary services markets over the long-term.

E. Reserve Markets

ISO-NE made several major market enhancements in October 2006 under ASM Phase II that should improve market operations. Most notably, the ISO added locational requirements to the forward reserve market and introduced real-time reserve markets with locational requirements that are co-optimized with energy in the real-time market. These enhancements should better enable the wholesale market to meet the reliability needs of the system and thereby reduce the need for manual actions by the operators. This section of the report provides an assessment of the first three months of operation of the Phase II ASM markets.

Design of Reserve Markets

Under ASM II, the real-time market software jointly optimizes reserves scheduling with energy scheduling. By *co-optimizing* the scheduling of energy and reserves, the market is able to reflect the re-dispatch costs that are incurred to maintain reserves in the clearing prices of energy, and vice versa. Previously, the energy-only market did not recognize the trade-offs between scheduling a resource for energy or reserves. It is particularly important to consider such trade-offs during tight operating conditions, because efficient scheduling reduces the likelihood of a reserve shortage. When available reserves are not sufficient to meet the required levels, the real-time model will be short of reserves and set the reserve clearing price at the level of the Reserve Constraint Penalty Factor (“RCPF”).

Although ISO-NE is not the first RTO to co-optimize energy and reserves in the real-time market, it is the first to optimize the level of imported reserves to constrained load pockets. Local reserve requirements can be met with reserves on internal resources or import capability that is not used to import energy. This enhancement is important because the New England market meets most of its local area reserve requirements with imported reserves rather internal reserves. For example, during constrained intervals, 71 percent of the Boston area requirement was satisfied with imported reserves and 39 percent of the Connecticut area requirement was satisfied with imported reserves.

The Locational Forward Reserve Market ("LFRM") is a seasonal auction where suppliers sell reserves that they are obligated to provide in real-time. LFRM obligations must be provided from either an online resource with unused capacity or an offline resource capable of starting quickly (i.e. fast-start generators). The auction procures 10-minute non-spinning reserves ("TMNSR") for all of New England and 30-minute operating reserves ("TMOR") for All of New England, Boston, Connecticut, Southwest Connecticut, and Rest of System. The reserve products transacted in the LFRM are consistent with the reserve products required in the real-time market, except the LFRM does not separately procure of 10-minute spinning reserves ("TMSR"). This reflects the intended purpose of the LFRM, which is to capture in a forward market signal the value of reserve capacity that is available in real-time, particularly from fast-start units that are able to provide reserves without incurring commitment costs.

Real-Time Market Results

Reserve clearing prices were relatively low in the real-time market during the first three months of operation under ASM II. Outside the local constrained areas, average clearing prices were 27 cents/MWh for TMSR, 13 cents/MWh for TMNSR, and 1 cent/MWh for TMOR. In the local areas, the most significant costs resulted from the Connecticut area TMOR requirement, which exhibited an average clearing price of $1.04/MWh. In Southwest Connecticut, the clearing price was nearly identical to the rest of Connecticut because the Southwest Connecticut area requirement was infrequently binding.

In this report, we evaluate the relationship between real-time local reserve clearing prices and local Excess Capacity, which we define as the amount of local capacity that is online or capable of starting within 30 minutes relative to the amount of local capacity that is required to meet load and reserve requirements. We find that there is a strong correlation between the local reserve clearing price and the amount of local Excess Capacity. When local Excess Capacity is less than 0 MW (i.e. there is a shortage), the local reserve clearing price rises to the RCPF ($50 per MWh). We find that when Excess Capacity in Connecticut was between 0 MW and 200 MW, the local reserve clearing price averaged about $6.50 per MWh. When Excess Capacity increased between 200 MW and 400 MW, the local reserve clearing price declined to an average of about $2.50 per MWh. Thus, reserve clearing prices in the local area decline rapidly as the amount of Excess Capacity rises. This is expected because the marginal cost of supplying reserves is very low for most units.

The Reliability Adequacy Assessment ("RAA") process is designed to prevent capacity shortages, but this evaluation indicates that committing excess amounts of capacity substantially affects real-time reserve clearing prices, thereby, reinforcing the tendency of the day-ahead market to under-commit in the local area. We recommend that the ISO continue to evaluate ways to improve the efficiency of this process while still meeting its reliability requirements.

Reserve Constraint Penalty Factors

In the real-time market model, the RCPFs put a limit on the costs that may be incurred to meet the reserve requirements. Consequently, if the cost of maintaining the required level of a particular reserve requirement exceeds the applicable RCPF, the real-time market model will incur a reserve shortage. Thus, the particular levels of the RCPFs are important because they determine how the real-time market responds to acute operating conditions. When the reserve requirements cannot be met, the RCPFs prevent the model from incurring extraordinary costs for little or no benefit. However, if the RCPFs are not sufficinently high, the market may not schedule all available resources to meet reliability requirements. In such cases, the operator must intervene to maintain reserves. To determine whether the RCPFs are set at appropriate levels, we performed two analyses that are detailed in this report.

The first analysis compares the local-area RCPF ($50 per MWh) to the marginal re-dispatch costs incurred to meet the Connecticut-area reserve requirement during the first three months under ASM II. We found 160 intervals when the marginal cost of maintaining local reserves exceeded the RCPF. In these intervals, the real-time model either went short of reserves in Connecticut or the operators met the requirement by dispatching additional generation in Connecticut. This indicates that the RCPF was not sufficiently high to maintain reserves under normal operating conditions during shoulder months.

The second analysis compares the local-area RCPF to the uplift costs incurred to satisfy Connecticut-area reserve requirements in the RAA process. While generators are committed in least-cost order, the ISO is required to commit sufficient capacity to meet local 2nd contingency requirements, regardless of the cost. We find that the uplift costs from local 2nd contingency commitments per megawatt-hour of Connecticut-area capacity requirements satisfied exceeded the RCPF on nearly half of the days from October to December 2006.

Our analyses indicate that the costs incurred by the ISO to maintain local reserves frequently exceed the RCPF. It is often necessary to commit generators for local reliability in the RAA process because insufficient capacity is committed in local areas in the day-ahead market. A higher RCPF would more accurately reflect the value of local reserves and increase incentives for more market-based day-ahead commitment in the local areas. Hence, we recommend that the ISO monitor the effects of the current local RCPFs, and after experience is gained during the summer, determine whether the local RCPF levels are appropriate.

Forward Market Results

The first Locational Forward Reserve Market ("LFRM") auction was held in August 2006, procuring forward reserves for the eight months from October 2006 to May 2007. In the local areas, TMOR cleared at the cap of $14,000 per MW-month because supply was insufficient to meet the local TMOR requirement. Outside the local areas, TMNSR and TMOR cleared at $4,200 per MW-month.[1]

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1 Forward reserve clearing prices are affected by the market rule that suppliers do not receive capacity payments for their forward reserve sales. During the period from October 2006 to May 2007, the primary source of

While suppliers offer forward reserves on a portfolio basis, it is generally most efficient for them to meet their obligations with fast-start capacity. Accordingly, suppliers satisfied 97 percent of their forward reserve obligations with fast-start generators between October and December 2006. Non-fast-start units face additional costs to provide forward reserves, because they must incur the commitment costs in order to provide reserves. In contrast, fast-start units can provide reserves while offline. Given the low level of participation by non-fast-start generation, it is unclear whether the local TMOR requirements will be met in future LFRM auctions before additional fast-start generation is installed.

To understand why suppliers with non-fast-start generation have not participated more, we estimate the profitability of satisfying forward reserve obligations with non-fast-start generation in the local areas at the cap of $14,000 per MW-month. For fast-start and non-fast-start units, the cost of providing forward reserves includes the lost profits from foregone energy sales when the LMP is less than the Threshold Price. However, non-fast-start units must incur commitment costs when it is not profitable to be online. We find that a hypothetical combined cycle generator would have earned net profits of $500 to $5,000 per MW-month after adjusting for the foregone Transition Payments, while a hypothetical oil-fired or gas-fired steam generator would have broken even or lost money.

These estimates assume one type of unit is used to satisfy the forward reserve obligation, although it would reduce the cost to share the obligation between a combined cycle generator and a steam generator. However, units under reliability agreements and units frequently committed for reliability have disincentives to sell forward reserves. This was the case for most combined cycle capacity in the constrained areas at the time of the first locational forward reserve auction. However, some combined cycle generation in the local areas may be offered in the forward reserve market in the local areas after the expiration of their reliability agreements. The forward reserve market is not likely to reduce supplemental commitment for local reliability or the associated NCPC without more participation from non-fast-start generation.

capacity revenue was from Transition Payments, which were $3,050 per MW-month from December 2006 to May 2007. Thus, a seller of TMOR in the unconstrained area would receive $4,200 per MW-month, but also give up $3,050 per MW-month for six months, which is $2,287.50 per MW-month averaged over eight months.

Conclusion

The implementation of ASM Phase II went smoothly with no disruptions in service and there was no substantial rise in the frequency of price corrections, which is expected after major changes to the market software. The new reserve market design with locational requirements provides a framework for the wholesale market to more completely satisfy the reliability requirements of the system while establishing efficient price signals that reflect these requirements. Based on the initial period under the new market design, we identify two areas for potential improvement within the new framework. First, we recommend the ISO continue to evaluate ways to improve the efficiency of the RAA process in order to minimize the effects of supplemental commitment on price signals in the constrained areas while still meeting the local reliability requirements. Second, we recommend the ISO monitor the effects of the current local RCPFs, and after experience is gained during the summer, determine whether the local RCPF levels are appropriate. This evaluation should also consider whether any other potential design improvements are suggested by the first full year of ASM market results.

F. Competitive Assessment

This section of the report evaluates the market concentration and competitive performance of the markets operated by the ISO–New England in 2006. Under locational marginal pricing, there may be greater potential for certain participants to exercise market power in constrained areas within New England that become separate geographic markets when congestion arises. This assessment identifies the geographic areas and market conditions that are most susceptible to the exercise of market power, and evaluates the conduct of market participants in these areas. We analyze the following areas:

- All of New England;
- Connecticut;
- Norwalk-Stamford, which is in Connecticut;
- Boston; and
- Lower Southeast Massachusetts

The first part of our assessment evaluates each geographic market using a pivotal supplier analysis to determine the demand conditions under which a supplier may have market power.

This analysis identifies conditions when the energy and operating reserve requirements cannot be satisfied without the resources of a given supplier (i.e., the "pivotal supplier").

The preliminary result of this analysis indicates that the largest suppliers in Norwalk-Stamford, Boston, Connecticut, and Lower Southeast Massachusetts are pivotal in a large number of hours. However, these areas contain large amounts of nuclear capacity and capacity covered under reliability agreements that significantly mitigate the incentives to exercise market power. After taking the effects on incentives of nuclear capacity and reliability agreements into account, the areas where market power was the greatest concern in 2006 were: (i) Lower Southeast Massachusetts, where the largest supplier was pivotal in 52 percent of all hours, (ii) Norwalk-Stamford, where the only supplier was pivotal in 23 percent of all hours, and (iii) all of New England, where one supplier was pivotal in 11 percent of all hours. However, our analysis suggests that once the reliability agreements expire, market power will be a more significant concern in Boston and in the portions of Connecticut outside Norwalk-Stamford. Hence, it will be important to continue to monitor these areas closely and ensure that the market power mitigation measures are fully effective.

The second part of this assessment examines market participant behavior to determine whether it was consistent with the profitable exercise of market power. We analyze the market for potential economic withholding (i.e., raising a resources offer prices to reduce its output and raise prices) and physical withholding (i.e., reducing the claimed capability of a resource or falsely taking a resource out of service). Based on our evaluation in this report, as well as the monitoring we performed over the course of the year, we find little evidence of behavior that is consistent with the exercise of market power.

Outside Norwalk-Stamford, congestion was relatively mild due to substantial amounts of supplemental commitment. Additionally, a large quantity of capacity is covered by reliability agreements that mitigate the incentives of suppliers to withhold resources. Competitive concerns are likely to rise in the future as the reliability agreements expire and supplemental commitments decline. Thus, we recommend that ISO-NE continue to closely monitor structural and behavioral market power indicators.

While there is no substantial evidence that suppliers withheld capacity from the market in order to raise clearing prices, suppliers can also exercise market power by inflating the NCPC payments they receive when they are needed for local reliability. To the extent that a supplier may have market power due to a local reliability requirement, the market power mitigation measures are designed to remedy attempts to economically withhold resources to inflate NCPC payments.

Conclusion

Based on the analyses of potential economic and physical withholding in this section, we find little evidence of significant withholding that might indicate market power abuses during 2006. The pivotal supplier analysis suggests that market power concerns exist in a number of areas in New England. However, the abuse of this market power is limited by the ISO-NE's market power mitigation measures and the large amount of capacity under reliability agreements. Nonetheless, ISO-NE should continue to monitor closely for potential economic and physical withholding, particularly in constrained areas.

II. Prices and Market Outcomes

In this section, we review trends in prices that relate to the performance of the New England wholesale market during 2006. This includes analyses of overall price trends, patterns of transmission congestion, and convergence of prices in the day-ahead and real-time markets.

A. Price Trends

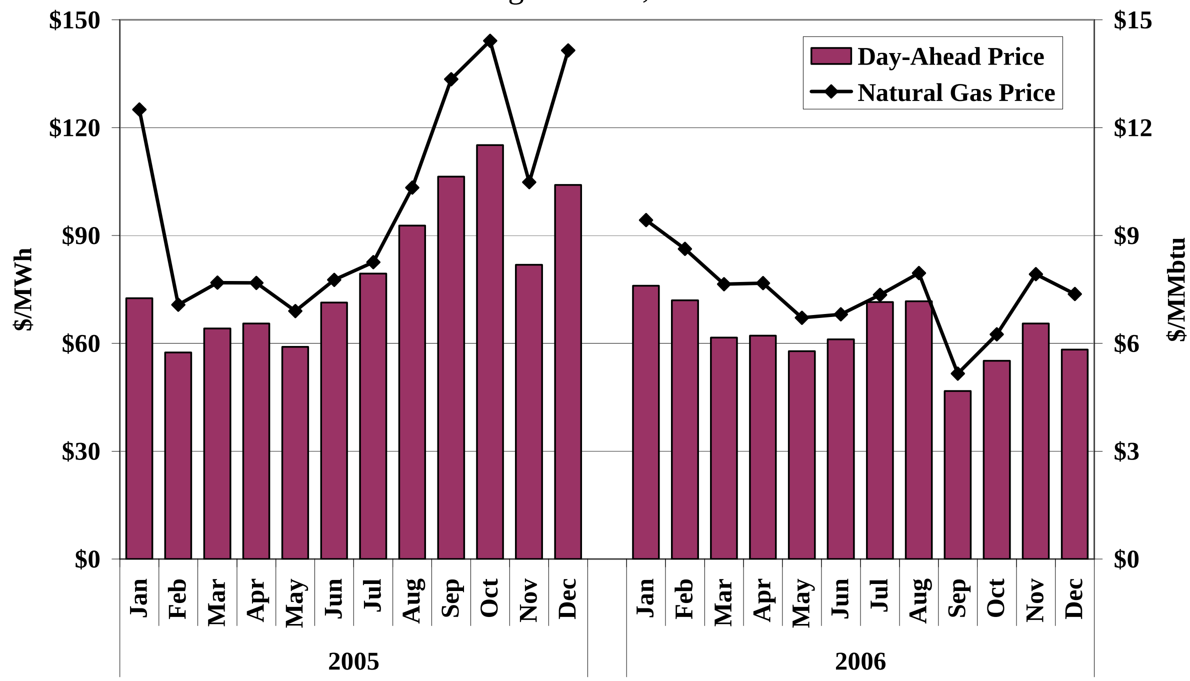
Our first analysis examines day-ahead prices at the New England Hub during 2005 and 2006. The New England Hub is located at the geographic center of New England and is an average of prices at 32 individual pricing nodes. The New England Hub price has been developed and published by the ISO to disseminate price information that will facilitate bilateral contracting.

Figure 1 shows the average[2] price at the New England Hub in the day-ahead market for each month in 2005 and 2006. The figure also shows the average price of natural gas, which should be a key driver of electricity prices when the market is operating competitively. Currently, over 49 percent of the generating capacity in New England is able to run on natural gas.[3] Low-cost baseload resources typically produce at full output, while natural gas-fired resources constitute the majority of capacity that is dispatched at the margin and sets the market clearing price. Therefore, electricity prices are expected to be closely correlated with natural gas prices. This relationship is evident in Figure 1.

[2] This average is weighted by the New England load level in each hour.

[3] ISO New England, "2007-2016 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) Report," Section 1.3. April 2007.

Figure 1: Monthly Average Day-Ahead Prices and Natural Gas Prices
New England Hub, 2005-2006

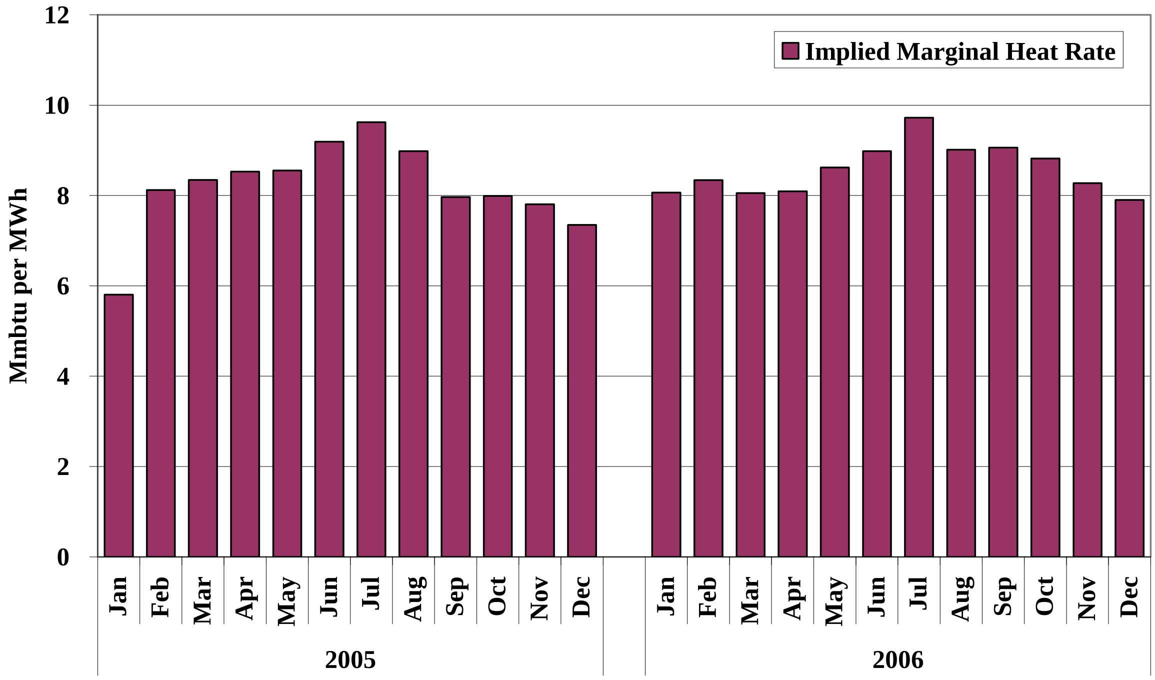


Note: Monthly average prices are load-weighted.

As has been the case in the past, natural gas price fluctuations were a primary driver of the movement in electricity prices in 2005 and 2006. Natural gas price spikes led to elevated electricity prices during the second half of 2005 after the loss of production in the Gulf Coast region due to the hurricanes in late August and September. Electricity prices rose more sharply than natural gas prices during the summer 2005 due to hotter weather conditions than normal. While load set new record peaks in August 2006, lower gas prices and lower demand in most hours of the year led to lower average electricity prices in 2006.

To identify changes in electricity prices that are not related to the fluctuations in natural gas prices, Figure 2 shows the marginal heat rate that would be implied if natural gas resources were always on the margin. The *Implied Marginal Heat Rate* is equal to the electricity price divided by the natural gas price as measured in MMbtu/MWh. Thus, if the electricity price is $63/MWh and the natural gas price is $7/MMbtu, this would imply that a 9.0 MMbtu/MWh generator is on the margin. Figure 2 shows the monthly average implied marginal heat rate for the New England Hub in each month during 2005 and 2006.

Figure 2: Monthly Average Implied Marginal Heat Rate
Based on Day-ahead Prices at New England Hub
2005-2006



Note: Monthly average prices are load-weighted.

By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices. During the summer months, the implied marginal heat rate averaged 9.0 to 9.5 MMbtu/MWh, whereas outside the summer months, the implied marginal heat rate was more frequently in the 8.0 to 8.5 MMbtu/MWh range.

With the exception of January, the implied heat rates were comparable in 2005 and 2006. Implied heat rates dropped significantly during January 2005 when natural gas prices were at extreme levels, because there were a large number of hours when either natural gas-fired units were not on the margin, or they were running but not setting electricity prices.

B. Prices in Transmission Constrained Areas

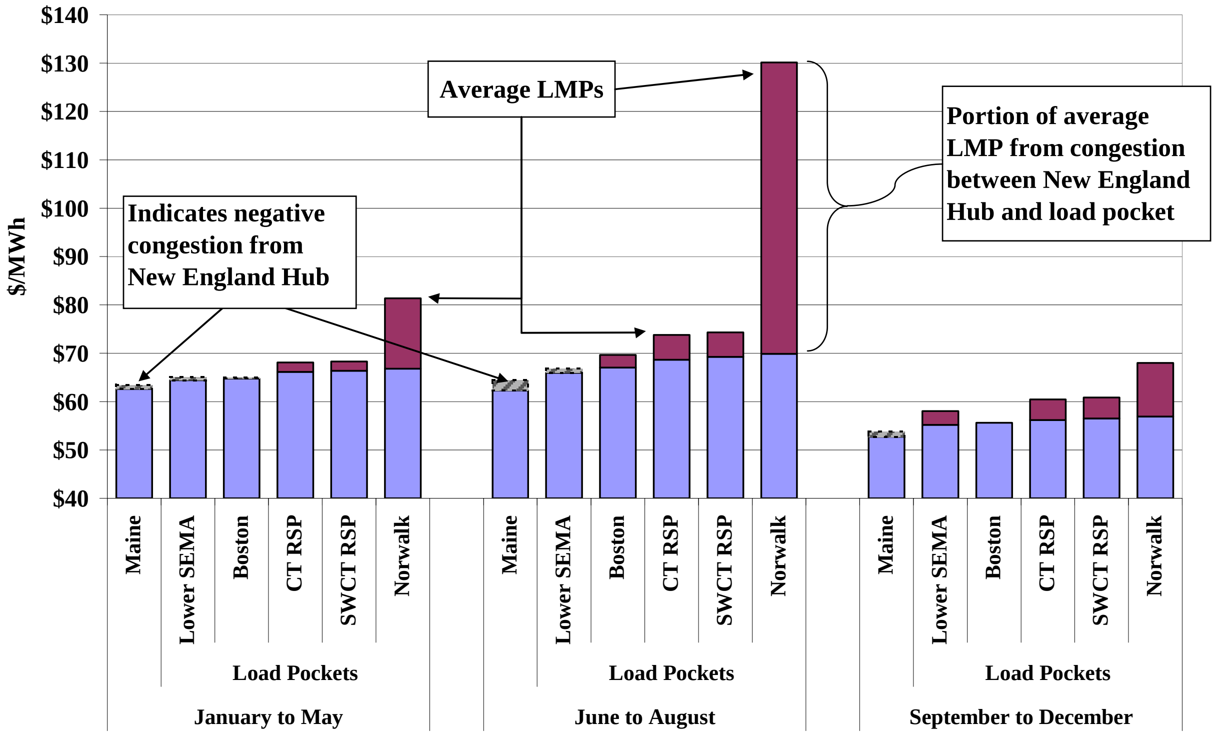
Historically, there have been significant transmission limitations between net-exporting and net-importing regions in New England. For instance, exports from Maine to the south are frequently limited by transmission constraints, while Connecticut and Boston are sometimes unable to import enough to satisfy demand without dispatching expensive local generation. Standard Market Design ("SMD") was implemented in 2003 to help manage these transmission constraints in an efficient manner through energy markets that produce locational marginal prices ("LMPs"). In LMP markets, the variation in prices across the system reflects the marginal value of transmission losses and congestion.

Losses occur whenever power flows across the transmission network. Losses are greater when power is transferred over long distances and at lower voltages. The rate of transmission losses increases as flows increase across a particular transmission facility. Transmission congestion arises in both the day-ahead and real-time markets when transmission capability is not sufficient to allow the lowest-cost resources to be fully dispatched and their output transmitted to the locations where it should be consumed. When congestion arises, LMP markets establish a spot price for energy at each location on the network that reflects the marginal system cost of meeting load at that location. The marginal system cost can vary substantially over the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load while not overloading any transmission facilities. This results in higher spot prices at "constrained locations" than occur in the absence of congestion.

Just as transmission constraints limit the delivery of energy into an area and require higher cost generation to operate in the constrained area, transmission constraints may also require additional operating reserves in certain locations to maintain reliability. In October 2006, the ISO implemented real-time reserve markets under Phase II of the ASM project, providing locational price signals for reserves and better price signals for both energy and reserves when conditions are tight. When generation is redispatched in real-time to provide additional reserves to a local area, the marginal system cost of the redispatch is reflected in the LMPs. The reserves markets are discussed in greater detail in Section VI.

We analyzed the differences in energy prices between several important locations during the study period. Figure 3 shows load-weighted average day-ahead LMPs for (i) the Maine load zone, (ii) Lower SEMA, (iii) NEMA/Boston load zone, (iv) the Connecticut regional system planning ("RSP") sub-area, which excludes South-West Connecticut, (v) Southwest Connecticut RSP, which excludes Norwalk-Stamford, and (vi) Norwalk-Stamford.

Figure 3: Average Day-ahead Prices by Location
2006



For each location, the load-weighted average LMP (including the effects of marginal transmission losses) is indicated by the top of the solid bars. The top bar shows the magnitude of congestion between the New England Hub and each location. The solid maroon bars indicate positive congestion relative to the Hub, while negative congestion is indicated by striped bars. Thus, prices in Maine are lower than the New England Hub due to congestion, while the other areas are load pockets that are typically congested-up relative to the Hub.

During the spring of 2006, the ISO began to maintain sufficient local reserves to meet second contingency requirements in Lower SEMA. However, Lower SEMA was not modeled as a transmission constraint in the market software until October 2006. Therefore, congestion costs into Lower SEMA were not reflected in LMPs until the final three months of the year. The changes in second contingency requirements for the Lower SEMA area are discussed in greater detail in Section IV.

The import limits into Connecticut, and particularly Norwalk-Stamford, accounted for most of the congestion in New England during 2006. The average congestion price difference between the New England Hub and Norwalk-Stamford was significant throughout 2006; the congestion into Norwalk-Stamford averaged more than $60/MWh during the summer of 2006. The Norwalk-Stamford transmission interface accounted for nearly 60 percent of net congestion revenue collected by the ISO for all of New England in 2006. Congestion into Norwalk-Stamford is likely to decline in 2007 due to the expiration of PUSH ("Peaking Unit Safe Harbor") offer rules.[4]

C. Convergence of Day-ahead and Real-Time Prices

The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real-time. This is a valuable financial mechanism that allows participants to hedge their portfolios and manage risk. Loads can insure against price volatility in the real-time market by purchasing in the day-ahead market. Suppliers can avoid the risk of starting-up their generator on an unprofitable day, because the day-ahead market will only accept their offer when they will profit from being committed. However, suppliers that sell in the day-ahead market are exposed to some risk, because they are committed to deliver energy in the real-time market. An outage can force them to purchase replacement energy from the spot market during a price spike.

In a well functioning system with day-ahead and real-time markets, we expect that day-ahead and real-time prices will not systematically diverge from one another. If day-ahead prices were predictably higher than real-time prices, buyers would decrease purchases and sellers would increase sales in the day-ahead market. Alternatively, if day-ahead prices were foreseeably lower than real-time prices, buyers would increase purchases day-ahead and sellers would decrease their day-ahead sales.

4 PUSH offer rules allow owners of low capacity-factor generators in Designated Congestion Areas to include levelized fixed costs in energy offers without risk of mitigation.

Historically, average day-ahead prices tend to be relatively consistent with the average real-time prices in New England, although it has been common for day-ahead prices to carry a slight premium over real-time prices. Predictable day-ahead price premiums encourage speculative market participants to schedule *incs* or "virtual supply" (i.e. to sell short at the day-ahead price and buy back at the real-time price). This response puts downward pressure on day-ahead prices and tends to limit the size of the average day-ahead premium. Price convergence is desirable because it promotes the efficient commitment of generating resources and scheduling of external transactions.

In this section, we evaluate the convergence of prices between day-ahead and real-time markets. The first part examines convergence of energy prices at the New England Hub, which is broadly representative of most areas of New England. The second part of this section examines convergence of energy prices in several areas that are sometimes isolated from the rest of New England by transmission constraints.

D. Price Convergence at the New England Hub

Examining price convergence between day-ahead and real-time markets at the New England Hub provides a sense of the overall degree of price convergence in the region. In this section, two measures are used to assess price convergence. The first measure reports the simple difference between the average day-ahead price and the average real-time price. The second measure reports the average absolute difference between day-ahead and real-time prices on an hourly basis. The first measure is an indicator of the systematic bias between day-ahead and real-time prices, while the second measure captures the overall variability between day-ahead and real-time prices over the year.

Table 1 shows load-weighted average day-ahead and real-time energy prices at the New England Hub in 2005 and 2006. The table also shows the average allocation of Net Commitment Period Compensation ("NCPC") charges to participants that purchase energy from the market. NCPC payments are made to generators that are committed and dispatched by the ISO but do not recover their as-bid cost from market revenue.

Table 1: Convergence of Day-Ahead and Real-Time Prices at New England Hub
2005-2006

		2005	2006
Day-Ahead Market:			
Average Price	(1)	**$81.35**	**$63.50**
NCPC Allocation to Load	(2)	**$0.33**	**$0.07**
Price plus NCPC Allocation	= (1) + (2)	**$81.68**	**$63.57**
Real-Time Market:			
Average Price	(3)	**$79.70**	**$62.67**
NCPC Allocation to Load	(4)	**$1.91**	**$0.74**
Price plus NCPC Allocation	= (3) + (4)	**$81.61**	**$63.41**
Average DA minus Average RT:			
Price Only	= (1) - (3)	**$1.65**	**$0.83**
Price plus NCPC Allocation	= (1) + (2) - (3) - (4)	**$0.07**	**$0.16**
Average Absolute Difference	(5)	**$12.99**	**$10.64**
(as a percent of RT Price)	= (5) / (3)	**16%**	**17%**

The table shows that in both years the day-ahead prices were higher than real-time prices, although the average day-ahead premium declined from $1.65/MWh in 2005 to $0.83/MWh in 2006. While real-time prices tend to be lower than day-ahead prices, NCPC allocations tend to be higher in real-time than in the day-ahead market.[5] Therefore, when NCPC payments are included in the assessment of convergence, the average day-ahead premium is reduced to just $0.07/MWh in 2005 and $0.16/MWh in 2006. Hence, once we consider the full cost to load serving entities of purchasing power, there is no significant difference between average day-ahead and average real-time prices.

With the first measure of convergence, a much higher day-ahead price one day can be offset by a much lower day-ahead price the next. The result is a measure which shows which price tends to

[5] Both tendencies are common in integrated power markets with day-ahead and real-time markets, but neither is guaranteed. Energy prices tend to be higher day ahead because load is willing to pay a small premium for the relative stability of day-ahead prices compared to real-time prices. NCPC costs tend to be higher in real-time because the system will have less flexibility in responding to changing resource outputs and load patterns in real time than in the day ahead time frame, often requiring the selection of more costly alternatives. Additionally, commitments made solely for reliability are generally made after the day-ahead market.

be higher on average, but does not indicate how widely prices typically diverge on an hourly basis. This second measure reflects the average size of the difference between day-ahead and real-time prices on an hourly basis, regardless of which price is higher.

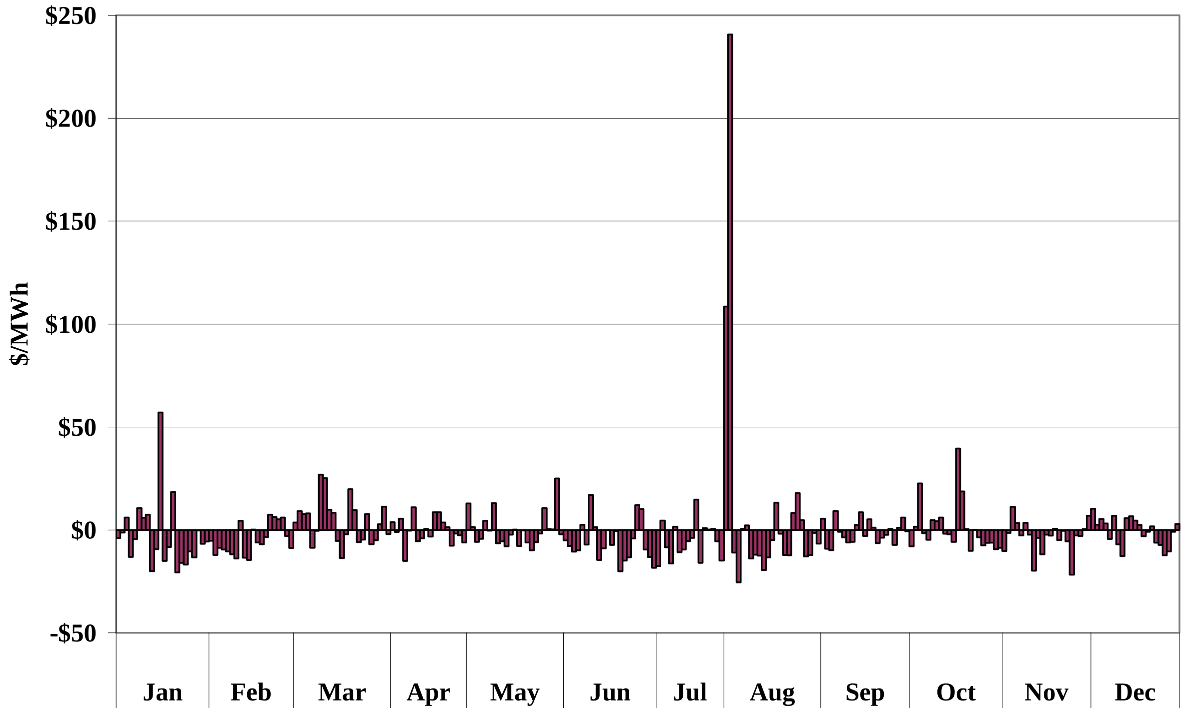
The average absolute difference between day-ahead and real-time prices fell from 2005 to 2006, which is not unexpected given that the average energy price declined significantly in 2006. When considered as a percentage of real-time prices in each year, the average absolute difference did not change substantially from 2005 to 2006.

The factors that affect real-time prices on a particular day are inherently difficult to predict. Changing weather patterns can lead to large differences between forecasted demand and actual demand. Generation outages and transmission outages can arise, leading to sharp reductions in supply. These factors cause day-ahead and real-time prices to differ significantly from one another on individual days even if prices are converging on average. The following analysis examines the pattern of day-ahead and real-time prices on individual days.

Figure 4 shows the average daily real-time premium during peak hours in 2006 (hours from 6 AM to 10 PM, weekdays excluding holidays). The real-time price premium on a particular day is calculated by subtracting the average day-ahead price for the day from the average real time price for the day (i.e., a negative value indicates that the day-ahead price was higher than the real-time price).

The pattern in Figure 4 is typical of wholesale electric markets that have day-ahead and real-time markets. The majority of days (62 percent) exhibit a modest day-ahead price premium, indicated by negative values in the figure. However, to the extent that there are large differences between day-ahead and real-time prices, it is the result of real-time price spikes, which give the figure a lop-sided appearance. On days that exhibited a day-ahead price premium, the largest difference for a particular day was $25/MWh (on August 4th). While on days that exhibited a real-time price premium, the largest difference for a particular day was $241/MWh (on August 2nd).

Figure 4: Real-Time Price Premium at the New England Hub
Weekdays, 6 AM – 10 PM, 2006



Day-ahead prices should include a probability-weighted expectation that a real-time price spike could occur. As the probability of a spike increases in the judgment of market participants, the premium on day-ahead energy also increases. This leads to the pattern that most days exhibit higher day-ahead prices but that differences between day-ahead and real-time prices are larger on days that exhibit higher real-time prices.

E. Price Convergence in Transmission Constrained Areas

When the transmission system is unconstrained, all buyers and sellers participate in a single, regional market. Individual market events that change the supply of generation or demand in one area are responded to by adjustments throughout the system. This diminishes the price impact that individual events, such as generator outages. When transmission constraints are binding, such events can have a much greater effect in a particular area. This section examines price convergence statistics in locations that are most frequently constrained from the rest of New England.

The following table summarizes convergence between day-ahead and real-time prices at the New England Hub, one frequently export-constrained location (Maine), and four frequently import-constrained locations. As before, we report two measures of convergence: (i) the difference between the average day-ahead and average real-time prices and (ii) the average absolute difference between hourly prices in the day-ahead and real-time markets. The difference in average prices shows whether prices over the entire period were higher in the day-ahead or real-time market. The average absolute difference shows the size of the hourly price differences.

Table 2: Convergence between Day-Ahead and Real-Time Prices by Region
2005-2006

	Real-Time Clearing Price		Day-Ahead - Real-Time Price Difference		Hourly Absolute Price Difference	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**
New England Hub	$79.70	$62.67	$1.65	$0.83	$12.99	$10.64
Maine	$72.86	$58.62	$0.18	$0.70	$11.59	$9.92
NEMA/Boston	$80.58	$63.60	$2.67	($0.50)	$15.66	$12.24
CT RSP (excl. SWCT)	$81.18	$65.01	$1.58	$2.12	$13.76	$12.33
SWCT RSP (excl. Norwalk)	$82.26	$65.29	$0.85	$2.22	$14.20	$12.43
Norwalk-Stamford	$97.31	$86.13	$10.15	$3.96	$25.13	$20.60

Price convergence was generally better at the New England Hub than at the four import-constrained locations shown in Table 2, reflecting that market events tend to have a greater price impact in isolated areas. The first measure of convergence, the difference between the average day-ahead and average real-time price, was generally higher in the import-constrained areas than at the Hub. Likewise, the second measure of convergence, the average absolute difference, was always higher in the import-constrained locations than at the Hub. Price convergence was worse at the Hub than in Maine, the only export-constrained region in the table. This is because binding constraints on exports from Maine reduce the frequency of price spikes in Maine, making real-time prices more predictable.

The $0.50/MWh real-time price premium for Boston in 2006 provides an example of how a single market event can affect convergence between day-ahead and real-time prices. In Boston on May 9th, real-time prices rose to the $900/MWh range during the afternoon and early evening after day-ahead prices had been in the $100/MWh to $140/MWh range. Two large units were out of service due to planned outages, and a third large unit experienced a sudden forced outage. This reduction in supply led to severe real-time congestion into Boston. Excluding this 10-hour event, Boston would have had a $0.36/MWh *day-ahead* price premium and the average absolute difference would have been $11.41/MWh.

Over time, price convergence has a tendency to improve as market participants learn how to predict such events. For instance, Norwalk-Stamford began to experience severe congestion on a frequent basis in 2005. As a result, LMPs in Norwalk-Stamford were more volatile than other regions of New England. Because supplemental commitment frequently occurs after the day-ahead market, the additional supply tends to reduce real-time congestion. This pattern attracted virtual supply, but not in sufficient quantities to bring full convergence. Because of the inherent difficulty of predicting such events, average day-ahead prices were significantly higher than average real-time prices. In 2006, congestion into Norwalk-Stamford continued and convergence improved substantially. The difference between average day-ahead and average real-time prices reduced from $10.15/MWh in 2005 to $3.96/MWh in 2006. Likewise, the average absolute difference declined from 26 percent of the average real-time price in 2005 to 24 percent in 2006.

III. Transmission Congestion and Financial Transmission Rights

A key function of LMP markets is to set efficient energy prices that reflect the economic consequences of binding transmission constraints. These prices guide the short-term dispatch of generation and establish long-term economic signals that govern investment in new generation and transmission assets. Hence, a primary focus of this report is to evaluate locational marginal prices and associated congestion costs.

Net congestion revenue collected by the ISO and net payments to Financial Transmission Rights ("FTRs") holders declined in 2006, primarily due to the milder load conditions and lower fuel prices. Net congestion revenue exceeded net payments to FTR holders for most of the year. Congestion revenue collected in the last four months of the year was less than obligations due to FTR holders, leading to *pro rata* under funding of FTR obligations in those months. We also found that the patterns of prices in the FTR auctions were generally consistent with the patterns of congestion in the day-ahead and real-time markets.

Congestion costs are incurred in the day-ahead market based on the modeled transmission flows resulting from the day-ahead energy schedules. These costs result from the difference in prices between the points where power is generated and consumed on the network. A price difference due to congestion indicates the gains in trade between the two locations if additional transmission capability were available. Hence, the difference in prices between the locations represents the marginal value of transmission. The differences in locational prices caused by congestion are embodied in the congestion component of the LMP at each location.[6]

A participant may hedge congestion charges in the day-ahead market by holding FTRs. An FTR entitles a participant to payments corresponding to the congestion-induced difference in prices between two locations in a defined direction. For example, a participant that holds 150 MW of FTRs from point A to zone B is entitled to 150 times the locational energy price at zone B less

6 The congestion component of the LMP represents the difference between the marginal cost of meeting load at that location versus the marginal cost of meeting load at a reference location, assuming no transmission losses.

the price at point A (a negative value means the participant must pay) assuming no losses. Hence, a participant can hedge the congestion costs associated with a bilateral contract if it owns an FTR between the same receipt and delivery points as the bilateral contract.

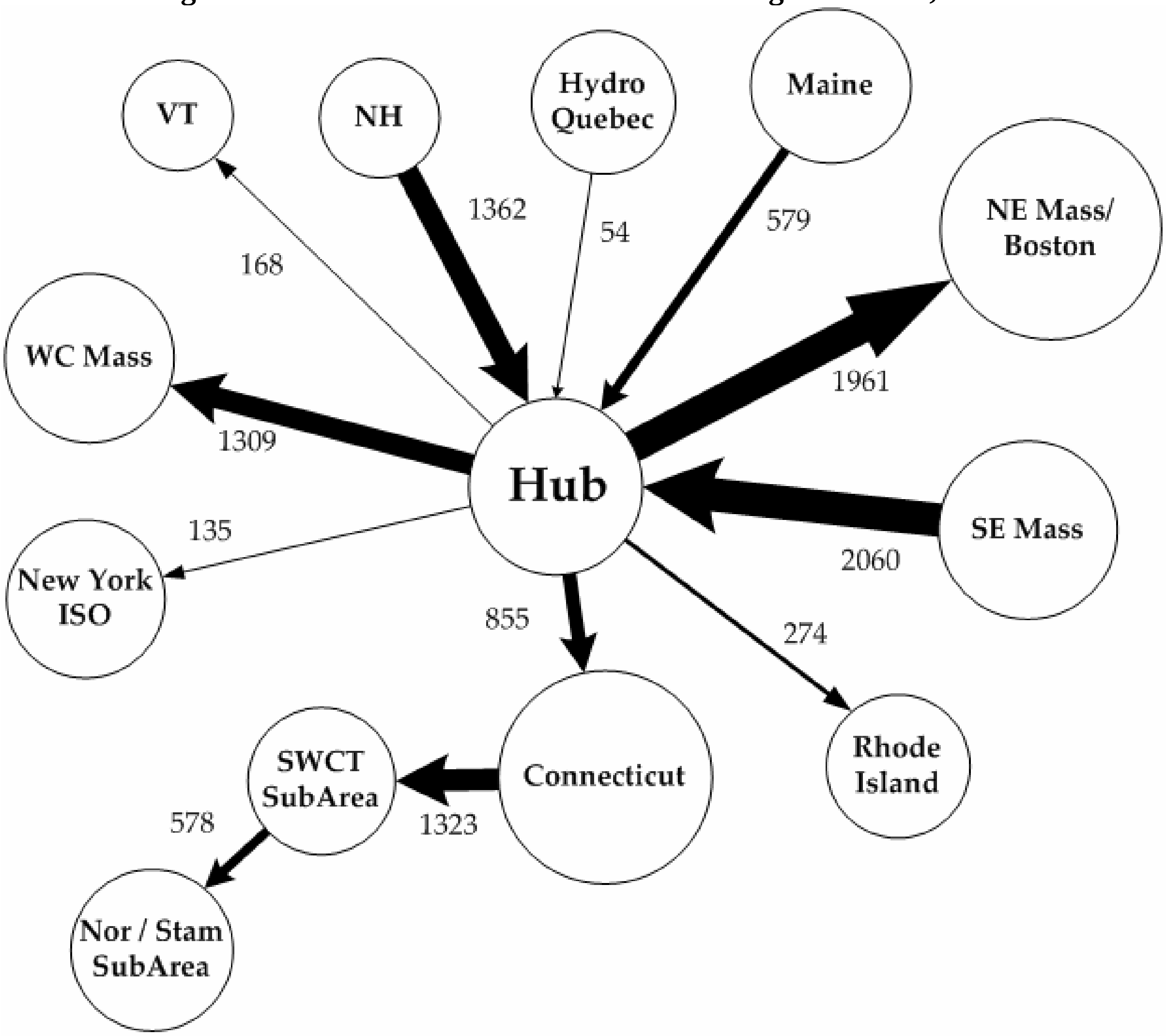
A. FTR Purchases

Our evaluation of transmission congestion in New England begins with an assessment of the pattern of FTR purchases. FTRs can be used to hedge the congestion costs of serving load in congested areas or as speculative investments for purchasers who forecast higher congestion revenues between two points than the cost of the associated FTR. In well-functioning markets, the FTR prices should be highly correlated with the expected levels of congestion on the system. In addition, the pattern of FTR purchases should correspond to the attendant power flows associated with the location of loads and generation.

In 2006, the ISO auctioned FTRs with one-month and one-year terms. The one-year FTRs allow market participants greater certainty by locking-in congestion hedges further in advance. Currently, the ISO releases 50 percent of transmission capability in an annual auction of one-year FTRs, while the remaining 50 percent of capability is made available in the monthly auctions. Figure 5 summarizes net purchases of FTRs into and out of each of the eight New England Zones. It also shows the pattern of FTR purchases between the three primary areas of Connecticut. In the figure, net purchases from the annual auction are combined with the quantities from the monthly auctions.

To simplify Figure 5, we show all of the FTR purchases for each zone relative to the New England Hub, rather than showing the actual sources and sinks. Since FTRs have the properties of geometric vectors, an FTR between any two zones is equivalent to the FTR from the first zone to the hub plus the FTR from the Hub to the second zone. If a zone was a net source for FTRs (more FTRs exit the zone than enter the zone), then the arrow in Figure 5 is directed from the zone to the New England Hub (e.g., Maine). If the zone is a net sink, then the arrow points from the New England Hub to the zone (e.g., Connecticut). Sub-areas nested within larger regions are shown relative to the larger region. Hence, Norwalk-Stamford is shown relative to Southwest Connecticut because it is wholly contained, and likewise Southwest Connecticut is shown relative to Connecticut. Thus, an FTR from Maine to Norwalk-Stamford would be broken into four components in the figure above: from Maine to the Hub, from the Hub to Connecticut, from Connecticut to Southwest Connecticut, and from Southwest Connecticut to Norwalk-Stamford.

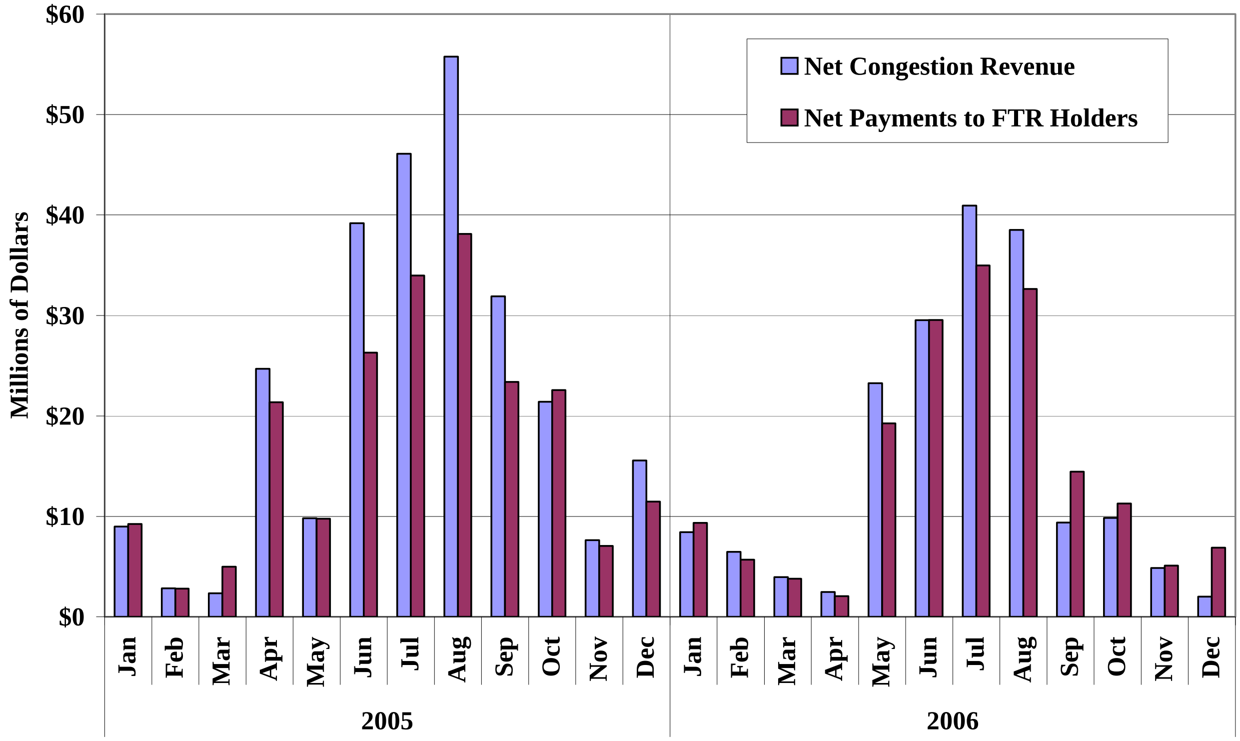
Figure 5: Net FTR Purchases between New England Zones, 2006



The patterns shown in Figure 5 are generally consistent with expectations. Maine and South East Massachusetts, and New Hampshire zones have been net sources for FTRs, consistent with the fact that these zones tend to exhibit net exports of power. NEMA/Boston and Connecticut have been net sinks for the FTRs. This is also generally consistent with historic power flows into these areas.

The next analysis compares the net obligations to FTR holders and the congestion revenue collected by the ISO to satisfy those obligations. As discussed above, the entitlement of an FTR from point A to point B in a particular hour is equal to the size of the FTR in megawatts times the difference in congestion prices between the two points. Congestion revenue, which is generated in the day-ahead market whenever there is a binding transmission constraint, is equal to the megawatts flowing across the interface times the shadow price (i.e., the marginal economic value) of the interface. If the ISO does not collect enough congestion revenue to pay FTR holders the entire entitlement over the year, all FTRs are discounted *pro rata*. Figure 6 shows net congestion revenue collected by the ISO, net payments to FTR holders, and the sum of the discounted (i.e. unfunded) portions of FTRs in each month during 2005 and 2006.

Figure 6: Summary of Congestion Revenue and Payments to FTR Holders
2005 - 2006



The first conclusion that can be drawn from the analysis is that both net congestion revenue and net payments to FTR holders were substantially lower in 2006 than in 2005. Net congestion revenue dropped from $266 million in 2005 to $180 million in 2006. Likewise, net payments to

FTR holders fell from $207 million in 2005 to $163 million in 2006. There have not been significant changes to the capability of the transmission system. Hence, the decrease in congestion is primarily attributable to the milder load conditions and lower fuel prices during 2006. The patterns of congestion in 2006 are evaluated in greater detail in the following subsection.

In 2006, congestion revenues were generally higher than FTR payments, particularly during the summer. In general, congestion revenues exceed FTR payments when the capability of the transmission system is greater than the capability defined by the total portfolio of FTRs held by participants. For example, if the transmissions system could accommodate 800 MW of flows between two points and a net amount of only 600 MW of FTRs were sold from one to the other, we would expect net congestion revenues to exceed payments to FTR holders by approximately 200 MW times the difference in congestion components between the two points. In this case, a substantial portion of this excess can be attributed to the FTR quantities sold into the Norwalk-Stamford area. As shown above, 578 MW of FTRs were sold into this area while the average limit on the interface into this area in the day-ahead market was 795 MW. Because this was the most congested interface in 2006, it resulted in significant excess day-ahead congestion revenue.

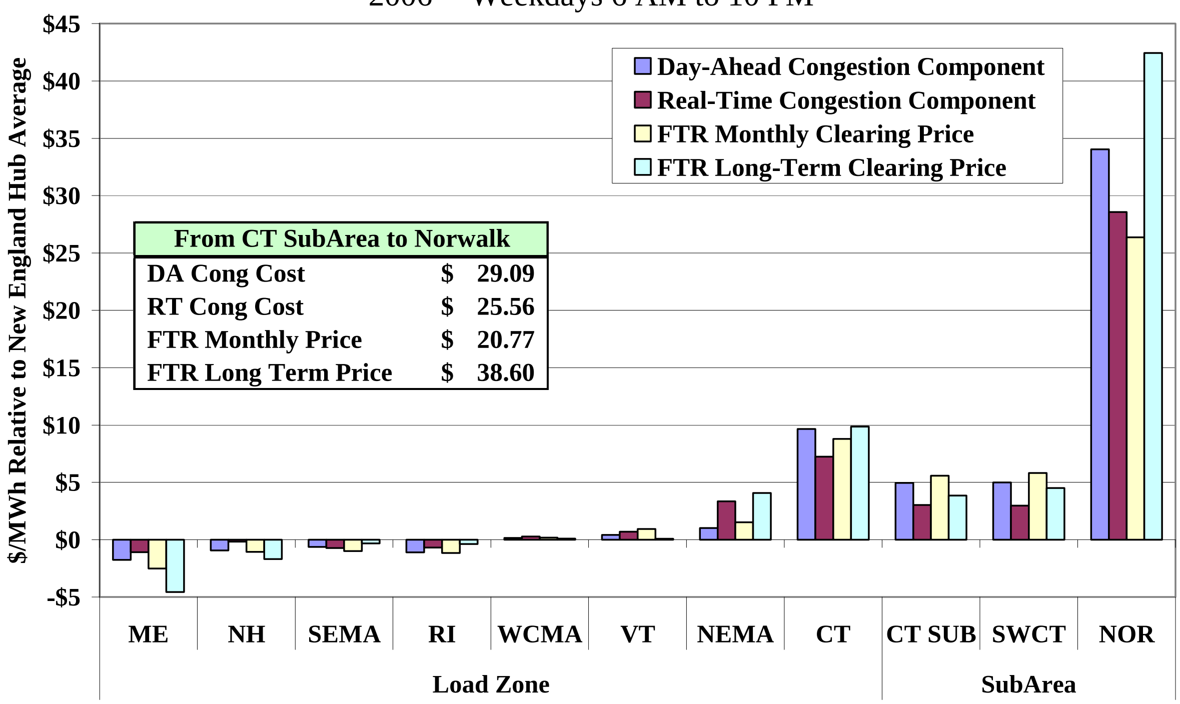
However, there were several months at the end of 2006 when net congestion revenues were less than the net entitlements to FTR holders. When this happens, payments to FTR holders are reduced such that the payments equal the net congestion revenues. However, surpluses from other months are collected over the course of the year and used to satisfy these entitlements. Typically, the monthly shortfalls result from transitory reductions in the transfer capability of key interfaces relative to the net amount of FTRs that cross the interface. For instance, on December 26, 2006, the capability of the Connecticut import interface was reduced to approximately 250 MW in the day-ahead market. There was a net quantity of approximately 1000 MW of FTRs held across the interface. During periods when the interface was congested, the total entitlement of these FTRs was far greater than the amount of congestion revenue collected by the ISO.

B. Congestion Patterns and FTR Prices

This subsection evaluates the efficiency of the FTR auctions by comparing the levels of congestion and the FTR prices into each zone in New England. This evaluation is based on a comparison of the day-ahead and real-time congestion costs to FTR prices in the various zones. In a well-functioning system, these values should be highly correlated.

Figure 7 shows day-ahead and real-time congestion costs compared to FTR prices during 2006 for each of the eight New England load zones and three Connecticut sub-areas. The congestion costs shown are the average for on-peak hours and are calculated relative to the New England hub. Hence, if the congestion component in the figure indicates $4 per MWh, this is interpreted to mean the congestion cost to transfer a MW of power from the New England Hub is $4. The congestion cost between any two points shown in the figure is the congestion price at the sink location less the congestion price at the source location. The analysis is limited to the on-peak hours since the load and the power flows on the system are greatest in these hours.

Figure 7: FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
Locational Averages Shown Relative to New England Hub Price
2006 -- Weekdays 6 AM to 10 PM



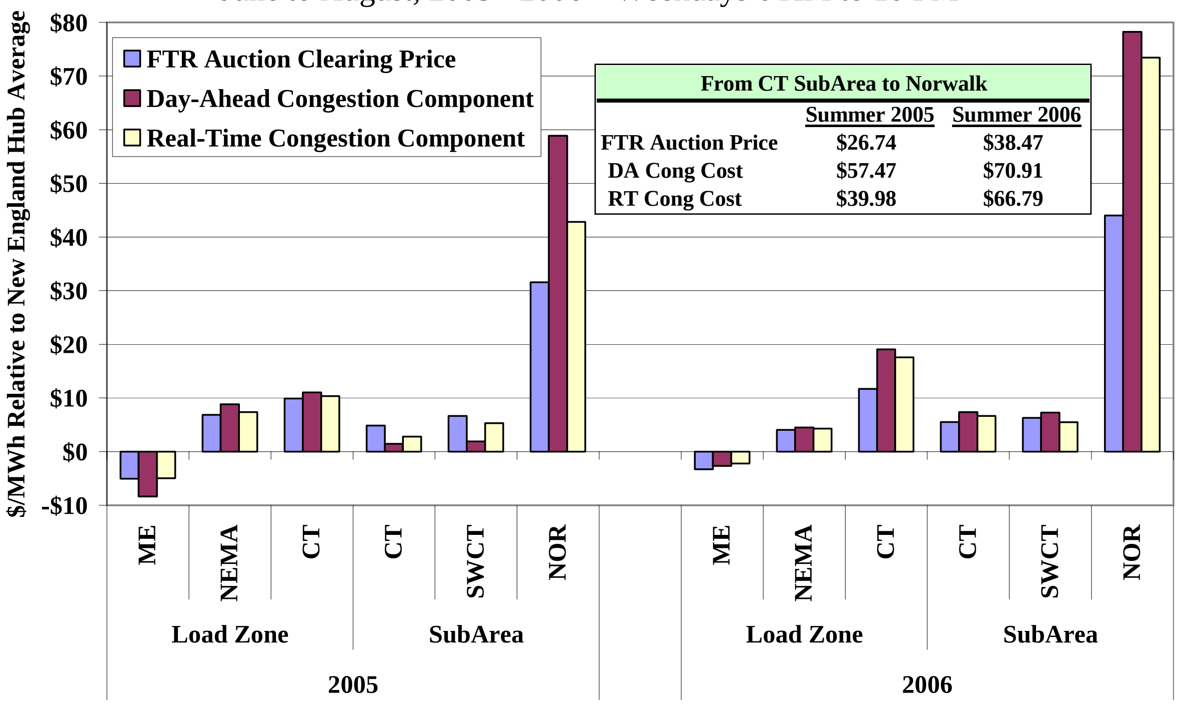
The monthly FTR auction clearing price is the average purchase price from the twelve monthly auctions, reported in dollars per MWh by location. Like the congestion costs, the purchase price for an FTR between two locations is the difference between the prices at the destination and origin points of the FTR. For example, a $-4/MWh FTR price for Maine and $9/MWh FTR price for Connecticut would indicate a total price for an FTR from Maine to Connecticut of $13/MWh. The load zones and sub-areas listed along the horizontal axis are generally ordered in accordance with their historical congestion patterns relative to the hub. Hence, the locations listed toward the left tend to face congestion as they export power to zones toward the right.

During 2006, congestion costs in the day-ahead and real-time markets were relatively consistent with FTR prices. Day-ahead congestion costs were more closely correlated with monthly FTR prices than with annual FTR prices. This is likely because market participants face greater uncertainty in the annual auction regarding congestion levels over the course of the upcoming year than at the time of the monthly auctions. In general, the magnitudes of the zonal FTR prices were greater in the annual auction than in the monthly auctions. This suggests that at the beginning of the year, market participants expected more congestion than actually occurred and revised their expectations prior to the monthly auctions.

Figure 7 also reveals that there continues to be substantially more total congestion on the three interfaces into the Connecticut sub-zones than on the interfaces into Connecticut. The Connecticut load zone is an aggregation of many smaller nodes and the price is a load-weighted average of the smaller nodes. In 2006, approximately one-sixth of the Connecticut load was in the Norwalk-Stamford sub-area, one-third was in the Southwest Connecticut RSP (which does not include Norwalk-Stamford), and one-half was in the Connecticut RSP (which does not include Southwest Connecticut).

The next analysis compares the same results for Summer 2005 and Summer 2006. The analysis focuses on the summer because system peaks generally occur in the summer due to cooling demand and the transmission system is under the greatest stress. Figure 8 shows the FTR clearing prices, day-ahead congestion, and real-time congestion for the peak hours during the summer season. Higher summer loads generally result in higher congestion costs and greater financial risks for market participants, making FTRs most valuable during the summer. Figure 8 shows FTR prices and congestion costs for the three most congested zones during the summers of 2005 and 2006.

Figure 8: FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
Locations Shown Relative to New England Hub Average Price
June to August, 2005 - 2006 – Weekdays 6 AM to 10 PM



In general, the day-ahead and real-time congestion costs were lower during the summer of 2006 in Maine and NEMA/Boston due to lower load levels and natural gas prices. However, all three areas in Connecticut saw higher congestion costs in the summer of 2006, and especially higher congestion costs from the Connecticut sub area into the Norwalk-Stamford load pocket. The figure shows that the average cost of day-ahead congestion from the Connecticut sub area (which does not include Southwest Connecticut) to Norwalk-Stamford increased from $57.47/MWh in 2005 to $70.91 in 2006. The average monthly FTR price for this path was $38.47/MWh in the summer of 2006. Hence, the monthly FTR market did not fully anticipate the higher levels of congestion into Norwalk-Stamford.

Given the volatile nature of congestion patterns, we found that FTRs were valued reasonably well in the FTR auctions. As expected, the monthly auctions generally exhibited more accurate valuations than the 12-month auction. Thus, the FTR market showed signs of adapting to changes in patterns of day-ahead congestion during the study period. We have also reviewed the FTR market processes and did not find any structural or methodological impediments to efficient FTR pricing. However, the practice of discounting payments to FTR holders when net congestion revenues are insufficient may lead to lower auction revenues in the future.

IV. Market Operations

System operation actions can substantially affect market outcomes and overall market efficiency. For example, the system operator's forecast of transmission capacity available to the Day-Ahead market has a direct effect on outcomes in that market, and also affects the efficiency of commitment decisions, total uplift payments, and real-time prices. Supplemental commitments, based in part on operator load forecasts, similarly affect uplift expenses and real-time market outcomes. In addition, operator practices can influence market participant incentives to bid or offer resources in a competitive manner. Therefore, it is important to critically assess the operation of the market.

In this section, we evaluate a number of areas related to the operation of the New England markets. These areas include:

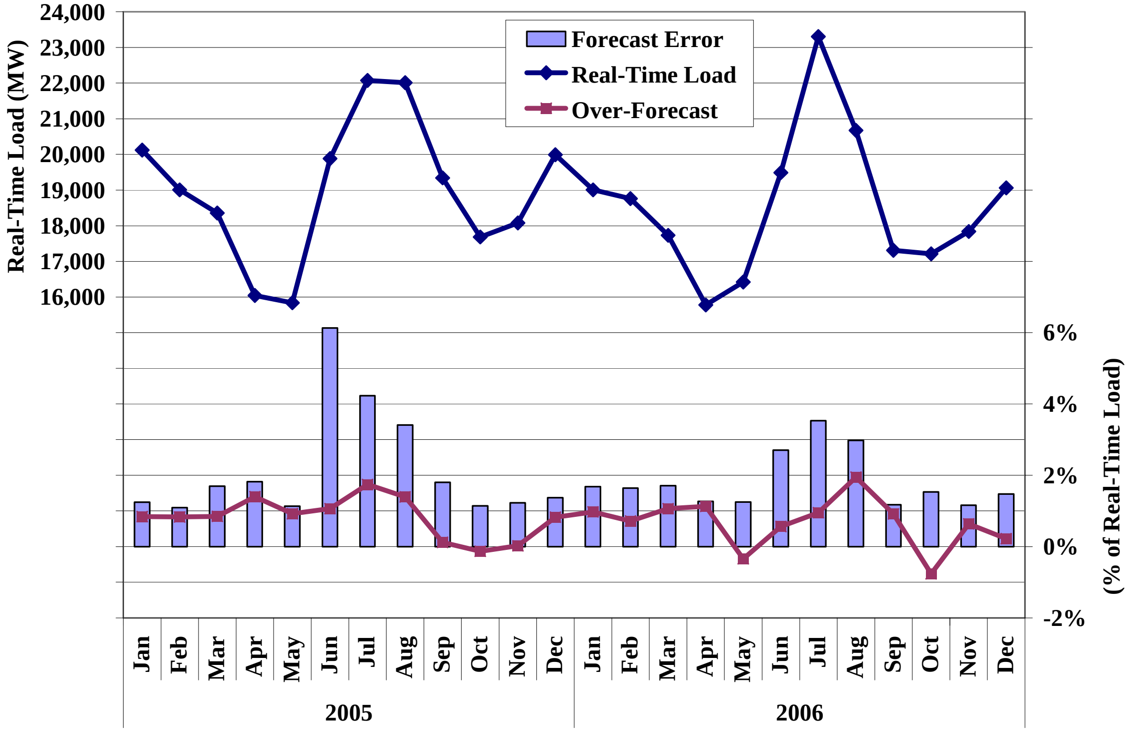
- Accuracy of the ISO's load forecasts and transmission limits,
- Frequency of price corrections,
- Reliability commitment and out-of-merit dispatch, and
- Real-time prices during commitment of fast start units.

These areas include the vast majority of the actions that can substantially affect market outcomes and the efficiency of the market's price signals.

A. Accuracy of ISO Load Forecasts

The accuracy of ISO load forecasts is important for efficient market operations because inaccurate load forecasts can cause the ISO to commit too much or too little capacity. Over-forecasting can lead to excess generator commitments, which may increase uplift costs and depress real-time prices. Under-forecasting can lead to insufficient supply in real-time and inflated real-time prices. Therefore, it is desirable that day-ahead forecasts accurately predict actual loads. Figure 9 summarizes daily peak loads and two measures of forecast error on a monthly basis during 2005 and 2006.

Figure 9: Average Daily Peak Forecast Load and Actual Load
Weekdays, 2005-2006



Note: Over-forecast is the percentage by which the average day-ahead forecasted peak load exceeded average real-time peak load -- a negative percentage value indicates an under-forecast. Forecast error is the average of the absolute difference between the day-ahead forecasted peak load and the actual peak load.

The figure shows a characteristic pattern of high loads during the winter and summer and mild loads during the spring and fall. The 2006 annual peak load of nearly 28 GW occurred on August 2nd, although the average daily peak was highest in July. Forecasted demand tracked actual load closely in most months. Average forecast load was 0.7 percent higher than average actual load in 2006. The average over-forecast was generally close to zero, but ranged as high as 1.9 percent in August and as low as -0.8 percent in October. Given the small size of these average differences, the only potential issue raised by this analysis is that the daily peak forecasted load is generally higher than the daily peak actual load. The ISO should evaluate the load forecasting algorithm to ensure there are no elements of the model that would bias the forecasts unjustifiably.[7]

To measure the average forecast error associated with the daily peak demand, we also calculated the average of the absolute value of the difference between the forecasted peak demand and the actual peak demand. For example, a one percent over-forecast on one day and a one percent under-forecast on the next day would result in an average forecast error of one percent, even though the average forecast load would be the same as the average actual load. Our analysis shows that the forecast error as a percent of the actual peak demand improved from an average of 2.2 percent in 2005 to an average of 1.8 percent in 2006. The forecast error did not change significantly during the non-summer months, but it decreased considerably during the summer. Overall, we find that the load forecasting performance of ISO-NE remains good.

B. Forecasted Transmission Interface Capability

Load pockets such as Connecticut and Boston have historically imported a large share of their power because supply resources in these areas are generally more expensive than in outlying areas. However, imports are limited by the capability of the transmission system. The load that cannot be met by imports must be satisfied from local resources. Like the forecast of load, forecasts of transmission capability help determine the commitment of resources in these areas. While over-forecasting load can cause over-commitment of generation resources, over-forecasting the transfer capability of an interface can cause under-commitment inside the load pocket. Conversely, under-forecasting the transfer capability leads to over-commitment within the load pocket. Thus, it is important to forecast accurately factors that affect the capability of the transmission system.

Transfer capability into load pockets in Connecticut, Boston, and the lower-end of Southeast Massachusetts are calculated to reflect the second-contingency requirements in the area (known as the proxy second-contingency limits). The same methods are used for calculating day-ahead

7 A small bias toward over-forecasting may be justifiable because the costs of under-forecasting (i.e., under-commitment and potential for shortages) are likely larger than the costs of over-forecasting.

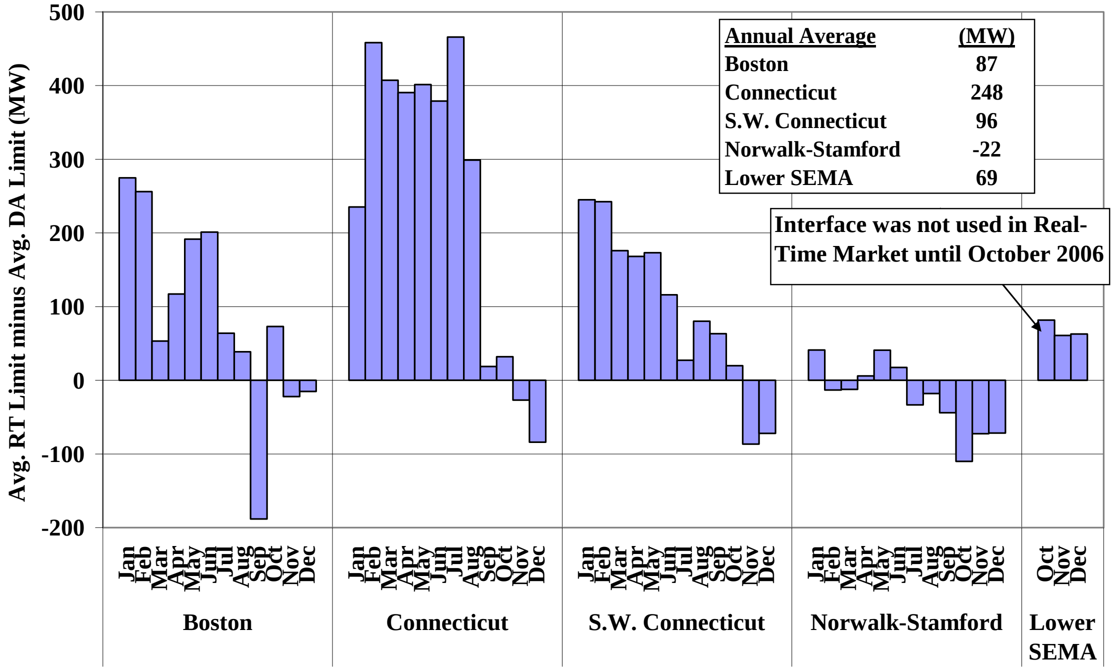
and real-time capability. However, real-time capability is estimated based on actual operating conditions, while day-ahead capability is estimated based on a forecast of the next day's operating conditions. The factors used to calculate the transfer capability include:

- The thermal limits of individual elements that make up the interface and reactive power flows;
- The commitment status of generators that influence the distribution of flows across the interface;
- Outages of key transmission lines and generators;
- The size of the largest generator contingency;
- The quantity of 30-minute reserves available on units on-line and available on off-line quick start resources in the load pocket; and
- The amount of load that can be shed in the event of a contingency.

Naturally, there will always be differences between forecasted and actual conditions that will lead to some differences between day-ahead and real-time capability. In general, most of these differences should be random and result in relatively small differences in capability between the day-ahead and real-time market. However, reliability concerns related to unknown factors in the day-ahead timeframe may justify use of conservative assumptions that would cause day-ahead capability to be lower on average than real-time capability. To evaluate the differences, Figure 10 shows the monthly average real-time transmission transfer capability minus the average day-ahead capability for five key interfaces during 2006. The Lower SEMA interface is shown for the three months when it was modeled in the real-time dispatch software.

A positive value in the chart indicates that more transfer capability was available in real-time than was estimated to be available day ahead. The figure shows that real-time capability has been higher on average than day-ahead capability on four of the five interfaces. Only Norwalk-Stamford showed higher average day-ahead capability. Over the course of 2006, there was a marked decline in the real-time transfer limits relative to the day-ahead transfer limits.

Figure 10: Systematic Differences between Real-Time and Day-Ahead Transmission Limits
Average RT Limit minus Average DA Limit
January to December, 2006



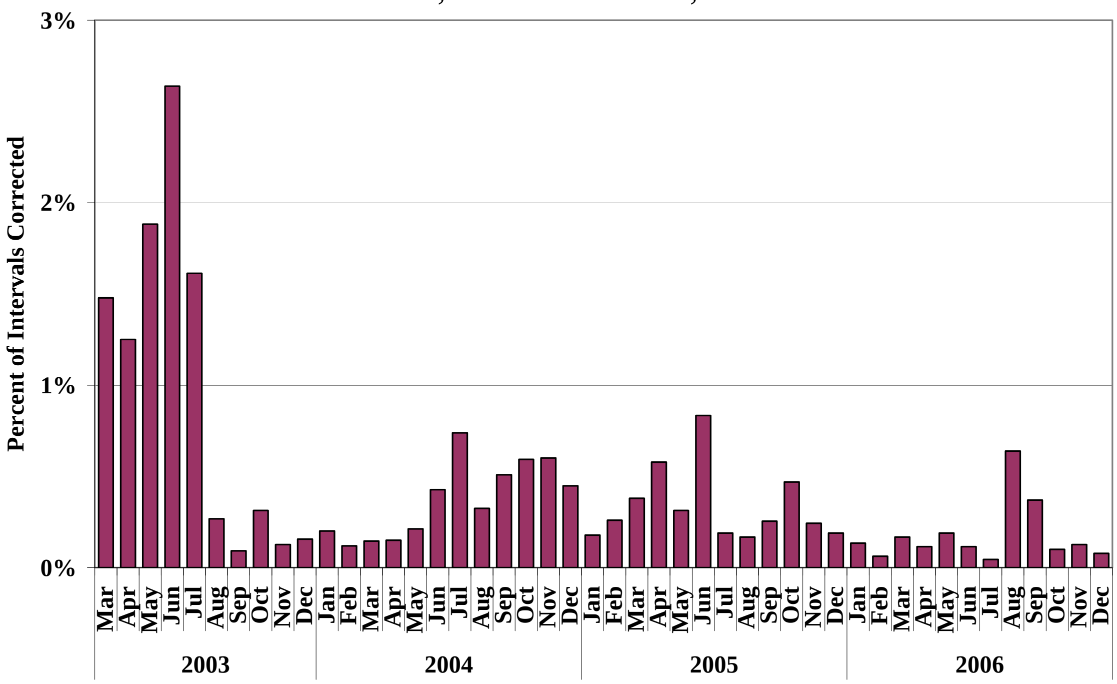
Systematic differences between day-ahead and real-time capability employed in the markets have been declining, which should improve overall market performance. We recommend that the ISO periodically investigate factors that cause these differences to determine whether additional improvements can be made to reduce or eliminate any unjustifiable differences between day-ahead and real-time limits.

C. Price Corrections

This subsection evaluates the rate of price corrections that have occurred during 2006. Price corrections are necessary to address a variety of issues, including software flaws, operations or data entry errors, system failures, and communications interruptions. Although they cannot be completely eliminated because data and communications errors are an inherent issue in electricity markets, a market operator should aim to minimize these corrections. Substantial and frequent corrections raise ISO and market participant costs and can harm the integrity of the market.

Price corrections tend to be more frequent during the transition to new markets or the implementation of significant software changes. Therefore, the rate of price corrections dropped significantly after the initial introduction of SMD in March, 2003. Figure 11 below shows the rate of real-time price corrections in New England from March 2003 through December 2006.

Figure 11: Rate of Real-Time Price Corrections
March, 2003 to December, 2006



The figure shows that New England required a significant number of price corrections in the first five months under SMD. However, since August 2003, the rate has been less than one percent in each month and 0.3 percent in most months. It is particularly notable that the frequency of price corrections was very low during the last three months of 2006 after the initial implementation of real-time reserve markets. Real-time co-optimization of energy and reserves required significant changes to the market software. Major software deployments often lead to more frequent price corrections. These results support the conclusion that the real-time reserve market development and deployment were well-managed and the SMD markets overall are working well.

D. Real-Time Commitment and Pricing of Fast-Start Resources

Fast-start units are generally capable of starting from an offline status and ramping to their maximum output within 10 minutes or 30 minutes of receiving an instruction. This enables them to provide reserves while offline. Areas without significant quantities of fast-start generation must maintain more of their reserves on online units, which can be very expensive. Another benefit of fast-start units is that they ramp to their maximum output level more quickly than baseload units and enable the system operator to respond rapidly to unexpected changes in load.

The real-time dispatch software, called "UDS," is responsible for scheduling generation to balance load, while not exceeding the capability of the transmission system. Based on a short-term forecast of load and other operating conditions, UDS provides advance notice of dispatch instructions to each generator for the next dispatch interval.[8] In general, UDS adjusts the output level of online resources. Most commitment decisions are made prior to the operation of UDS in the day-ahead timeframe. However, UDS is capable of starting fast-start units, which is more efficient than relying exclusively on operators to manually commit such units.[9],[10]

When determining dispatch instructions for most generators, UDS considers only incremental offer prices, since the generator will be online in any case. However, for offline fast-start generators, UDS takes commitment costs into account. Commitment costs include a start-up cost for a unit that is offline and a "no-load" cost reflecting the fixed hourly cost of keeping a unit online.

For instance, suppose UDS needs to schedule an additional 20 MW and has the choice of increasing the output of an online unit with an incremental offer price of $120/MWh or starting up a 20 MW fast-start unit with an incremental offer price of $75/MWh, a no-load offer price of

8 Generators are usually given instructions 15 minutes in advance, but this can be set higher or lower by the operator.

9 Based on its real-time optimization, UDS recommends that individual fast-start units be started. However, the final decision to start a unit remains with the real-time operator.

10 This includes units that are capable of providing 10-minute or 30-minute non-synchronous reserves and have a minimum run time and a minimum down time of one hour or less.

$300/hour, and a start-up offer price of $500 (which UDS amortizes over one hour). The average total offer of the offline unit is $115/MWh = ($75/MWh + $300/hour ÷ 20 MW + $500/hour ÷ 20 MW). Hence, the offline unit is more economic than the available capacity of the online unit.

Although the fast-start unit in this example is committed and dispatched in merit order, the full cost of the decision is not reflected in real-time prices under the current market design. Marginal cost pricing considers only the incremental offer price of the last accepted megawatt. If the last accepted megawatt came from the fast-start unit, the clearing price would be set at the incremental offer price of $75/MWh, even though it cost substantially more to bring the unit online. As a result, the owner of the fast-start unit would receive an NCPC payment to make up the difference between the average total offer of $115/MWh and real-time market revenue.

Additionally, fast-start units may not always set energy prices when they are needed to satisfy energy, operating reserves, or local reliability requirements. When a fast-start unit does not set prices, the price will be set by a lower-cost resource even if committing the fast-start resource was economic. In the example above, therefore, the clearing price determined in the real-time market could even be less than $75/MWh.

The following table summarizes commitment of fast-start units by UDS in 2006. Information is shown separately for fast-start units that are deployed within congested areas because these deployments generally occur under higher price conditions and frequently involve more expensive offers. The table provides additional details for intervals when the average total offer of a deployed fast-start unit exceeds the LMP at its location.[11] The average total offers are used by UDS to establish the economic merit order of offline fast-start units. Hence, when the LMP is less than the average total offer, the LMP does not fully reflect the cost to the system of meeting demand.

11 The average total offer is the sum of incremental, no-load, and start-up offer components averaged over the economic maximum of the unit for the one hour amortization period.

Table 3: UDS Deployment of Fast-Start Units in 2006

	No Congestion	Fast-Start Unit in Congested Area
Total Frequency of Deployments (% of all intervals)	**4.6%**	**0.9%**
Deployments where LMP < Marginal Fast-Start Offer:		
Frequency of Deployments (% of all intervals)	**1.9%**	**0.5%**
Avg. Offer of Marginal Fast-Start Unit ($/MWh)	**$127**	**$201**
Avg. LMP at Marginal Fast-Start Unit ($/MWh)	**$83**	**$165**
Avg. Difference Between Offer and LMP ($/MWh)	**$44**	**$35**

UDS deployed fast-start units in unconstrained areas in 4.6 percent of the intervals in 2006. In many of these intervals, the average total offers of committed fast-start units were lower than the LMP. However, in 1.9 percent of all intervals, at least one fast-start unit had a higher average total offer. In these intervals, the average total offer of the marginal fast-start unit (i.e. the last fast-start unit deployed in merit order) was $127/MWh on average, while the LMP of the marginal fast-start unit was $83/MWh on average. The average difference between the LMP and the cost of the marginal deployment was $44/MWh in these intervals. Similar figures are shown in the table above for units in import-constrained areas.

The fact that fast-start units are routinely committed and dispatched in merit order, but that the underlying costs are not reflected in real-time prices, may lead to inefficient market incentives. First, understated real-time prices will reduce the incentives to fully schedule load through the day-ahead market because the day-ahead prices will tend to be higher than the real-time prices if load is fully scheduled day ahead. The consequences of under-scheduling day ahead are that fewer slow-starting units will be committed and the market will rely more heavily on fast-starting resources in real time to meet the incremental load. This pattern reduces the overall market efficiency and increases the uplift costs borne by market participants.

Second, it does not provide a correct signal to participants that may import or export power to or from New England. The understated price in this case will lead to fewer net imports and increase New England's reliance on the fast-start resources. Finally, it diminishes the price signals that govern new investment in the long term. Hence, we recommend that the ISO evaluate 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. We recognize that the potential complexity of such changes, which would likely not be feasible in the short term.

E. Commitment for Local Congestion and Reliability

In New England, there are several load pockets that import a significant portion of their total consumption of electricity. In order to ensure that these areas can be served reliably, a specified amount of capacity must be committed within the load pocket. Specifically, sufficient online capacity is required to:

- Meet forecasted load in the load pockets without violating any first contingency transmission limits (i.e., ensure the ISO can manage congestion on all of its transmission interfaces).
- Ensure that reserves are sufficient in local constrained areas to respond to a second contingency;
- Support the voltage of the transmission system in specific locations; and
- Manage constraints on the distribution system that are not modeled in the market software (known as Special Constraint Resources ("SCRs")).

The New England market commits resources in the Day-Ahead market based on multi-part offers. In order for a unit to be committed in the Day-Ahead market, demand bids from load serving entities and virtual traders must express a willingness to pay enough for the energy from the unit that it is economic to incur the start-up, no-load, and incremental offer of the unit. However, demand bidders are not willing to pay substantially higher prices day-ahead than they anticipate in the real-time market the following day. Thus, day-ahead market-based commitment is strongly affected by expectations of real-time prices.

To meet local requirements, the ISO may need to commit generation with high commitment costs. Once the commitment costs have been incurred, these generators may be inexpensive providers of energy and reserves in the local area. Because these commitment costs are not reflected in the market prices, the real-time LMPs frequently do not reflect the full value of on-line and quick start capacity in local areas. As in any forward financial market, the day-ahead market prices tend to converge with the real-time prices. Hence, the day-ahead LMPs also do not reflect the full value of on-line and quick start capacity in local areas.

These lower day-ahead market LMPs result in market-based commitments that generally are not sufficient to meet local reliability requirements. The ISO has attempted to increase the extent to which market-based commitments satisfy local reliability requirements by modeling a lower transfer limit into the constrained area to reflect 2nd contingency reliability requirements. This lower limit is referred to as the "proxy 2nd contingency limit". Nonetheless, supplemental commitments are still frequently needed to meet local requirements. Supplemental commitments may occur in either the day-ahead market process or later in the Reliability Adequacy Assessment ("RAA") process. There are two ways in which supplemental commitments are made:

- The commitment software recognizes a need for capacity (but not energy) in a local area and commits the resources with the lowest commitment costs that satisfy the need.
- The operator recognizes a constraint that is not modeled in the software and manually commits resources to manage the constraint. This may not be the lowest-cost method to manage the constraint.

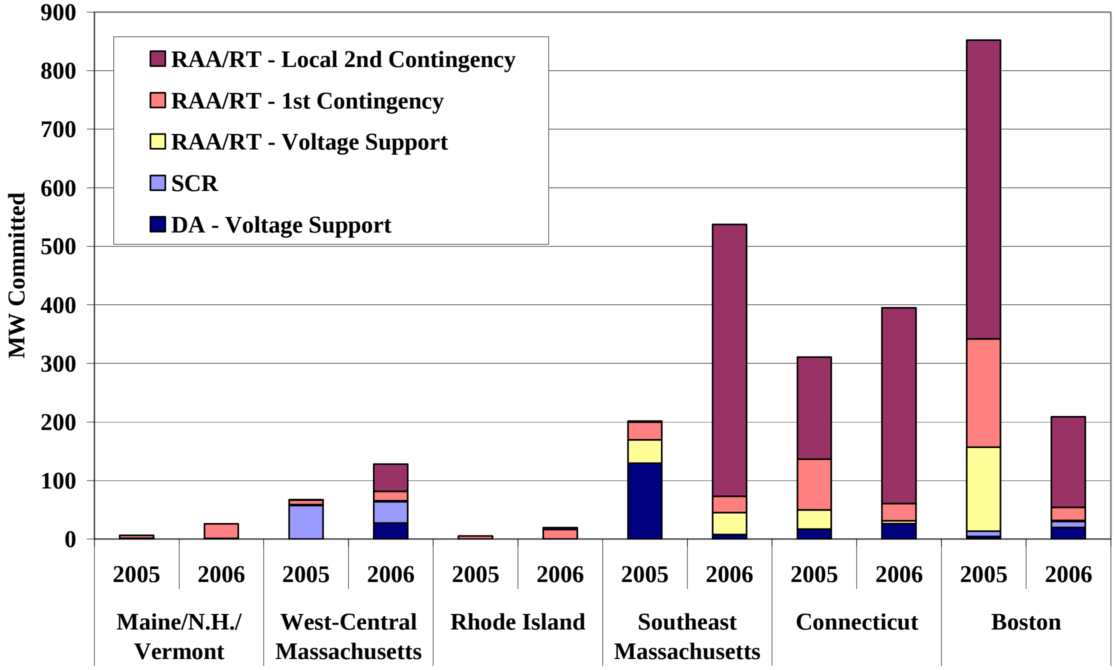
Although it is preferable for the commitment software to make supplemental commitments rather than to do so manually, neither method adequately reflects the cost of maintaining reliability in the LMPs. Furthermore, since these units must be dispatched at or above their economic minimum generation level ("EcoMin"), these commitments generally reduce LMPs by displacing energy that would have been produced by units committed through the market. Thus, supplemental commitment tends to mute locational price signals associated with resolving transmission congestion.

This section provides a detailed summary of supplemental commitment for local reliability. This section also examines self scheduling behavior by market participants that can also have a substantial effect on the LMPs.

1. Generation Committed for Local Needs

Supplemental commitment for local reliability increases the amount of online capacity in a load pocket, and can diminish locational price signals. Hence, it is important to monitor the extent to which these actions occur and the locations where they occur. Figure 12 shows the average amount of capacity committed to satisfy local requirements at the daily peak load in each zone in New England during 2005 and 2006.[12] 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 real-time market.

Figure 12: Commitment for Local Reliability by Zone
Daily Peak Hour, 2005–2006



Note: Capacity committed day-ahead for voltage support that would have been economically committed in the day-ahead market is excluded from the figure.

While in most areas supplemental commitments increased a small amount in 2006, supplemental commitments increased substantially in Southeast Massachusetts and decreased dramatically in Boston. Due to the substantial decrease of supplemental commitments in Boston, total supplemental commitments declined almost 10 percent overall, from an average of 1,440 MW in 2005 to an average of 1,310 MW in 2006.

12 In accordance with its Tariff, the ISO-NE classifies certain day-ahead commitments as Local 2nd Contingency commitments even though they occur as the result of market-based scheduling activity. Since these are not out-of-market commitments, we exclude them from our analyses of supplemental commitment in this section.

In Southeast Massachusetts, supplemental commitment became more frequent due to changes in fuel prices and offers by units needed to ensure local reliability in the Cape Cod area. Beginning in 2006, the ISO is required to maintain sufficient reserves to respond to the two largest contingencies in the area without relying upon load shedding in the Cape Cod area. Under the new criteria, at least one of the units at the Canal plant is usually required to be online. This reliability criterion did not substantially increase the commitment of these units because they were previously often committed economically in the Day-Ahead market or committed for voltage support. However, changes in fuel prices and offers caused these units to be economically committed less frequently in the Day-Ahead market. Therefore, the units were supplementally committed more frequently than in prior years and received higher NCPC payments in 2006.

In Boston, supplemental commitment declined primarily due to a change in behavior by the largest supplier. In 2005, the supplier usually raised its day-ahead offer prices above marginal cost to avoid market-based commitment in the Day-Ahead market. This frequently required ISO-NE to commit some of the supplier's capacity for local reliability. In 2006, most of this supplier's capacity became covered by a reliability agreement with ISO-NE. The agreement stipulated that the capacity be offered at marginal cost. As a result, these units were committed in the Day-Ahead market more frequently, thereby reducing the need for supplemental commitment in Boston. This behavior is discussed in greater detail later in this section.

Commitments in the Boston area for voltage support were much less frequent during 2006 than previous years due to several initiatives that were carried out by the ISO and NSTAR during 2004 and 2005. These included:

- Working with the owners of Mystic 8 and Mystic 9 to increase their ability to produce reactive power by a total of 100 MVar – Completed 4th quarter 2004;
- Working with NSTAR to return a shunt reactor to service with the capability of absorbing 80 MVar – Completed 4th quarter 2004;
- NSTAR quickly repairing a load tap changer in the Woburn 345/115 kV transformer that enables three shunt reactors to be more effective in absorbing reactive power – Completed 4th quarter 2004;

- Revising the ISO's NEMA/Boston area operating guide based on these three upgrades and train operations staff on new procedures – Completed 2nd quarter 2005; and
- NSTAR installing a new 150 MVar shunt reactor to absorb reactive power – Completed 2^{nd} quarter 2005.

ISO-NE has undertaken two additional measures to reduce the need for supplemental commitment in the future. First, by December 2007 the ISO plans to implement Flexible Combined Cycle Modeling, which will allow market participants to offer their combined cycle units under several different configurations. This should enable more efficient commitment, and in some cases, would allow combined cycle units to offer non-spinning reserves while offline.

Second, under Phase II of the Ancillary Services Market Project, the ISO began to operate a Real-Time Reserve Market and a Forward Reserve Market with locational requirements in October 2006. Reserves are needed in the local areas to meet local 2^{nd} contingency protection requirements. Due to the limited quantity of fast-start resources in these areas, a large portion of these reserves must be held by on-line resources. If additional fast-start resources are added in these areas over the longer term, the frequency and quantity of supplemental commitment would be substantially reduced. Supplemental commitment will also become less frequent if online combined cycle and/or steam turbine capacity is used to provide forward reserves in the load pockets, although Figure 24 in Section VI indicates that this was not very frequent in the first three months of operation under ASM II. The reserve markets have substantially improved the economic signals for suppliers to provide reserves in Connecticut and Boston from fast-start units and other low-cost reserve providers.

To the extent that local capacity requirements can be forecasted accurately, it is most efficient to commit units for local reliability in the Day-Ahead market. This allows the software to determine the lowest-cost solution, taking into account the commitments that are needed to meet local requirements. When an additional resource is committed supplementally after the Day-Ahead market, it may no longer be efficient to commit one or more units that were committed in the Day-Ahead market. This can cause some units committed economically through the Day-Ahead market to run out of economic merit in real-time. Therefore, we continue to recommend that the ISO evaluate the feasibility and potential benefits of integrating local capacity requirements in the Day-Ahead market commitment software. In response to this recommendation last year, the ISO has been undertaking an evaluation of this potential change.

The supplemental commitments in Boston, Connecticut, and Lower Southeast Massachusetts have contributed to the unusually low congestion that has prevailed into these zones. Later in this section we examine how much energy runs out-of-merit as a result of these supplemental commitments.

2. Evaluation of 2nd Contingency Commitments

Supplemental commitment for local reliability can significantly affect market outcomes in constrained areas, so it is important that they only be made when actually needed for reliability. This subsection evaluates the performance of ISO-NE in making local 2nd contingency commitments for NEMA/Boston, Connecticut, and Lower Southeast Massachusetts. The evaluation includes local 2nd contingency commitments that were made after the close of the Day-Ahead Market on the evening prior to the Real-Time Market. Such commitments are based on forecasts of operating conditions on the following day. We divided the quantities of 2nd contingency commitments made by the ISO operators between those amounts needed to meet the forecasted 2nd contingency requirements and additional commitments made in excess of the forecasted 2nd contingency requirements ("Additional Commitments").[13] Additional commitments may be made for a variety of reasons, including concern by the operators regarding the forecasted peak load in the constrained area or uncertainty about the status or availability of a key resource in the area. Figure 13 shows the results of this analysis. Local 2nd contingency commitments were made in Lower Southeast Massachusetts throughout 2006, but data on forecasted operating conditions is not available for the period prior to October.

Local 2nd contingency commitments made the evening prior to the Real-Time Market averaged 303 MW per day in Connecticut, 115 MW per day in Boston, and 503 MW per day from October to December in Southeast Massachusetts. The majority of capacity committed for local 2nd contingency protection was explained by the forecasted requirements for the following day.

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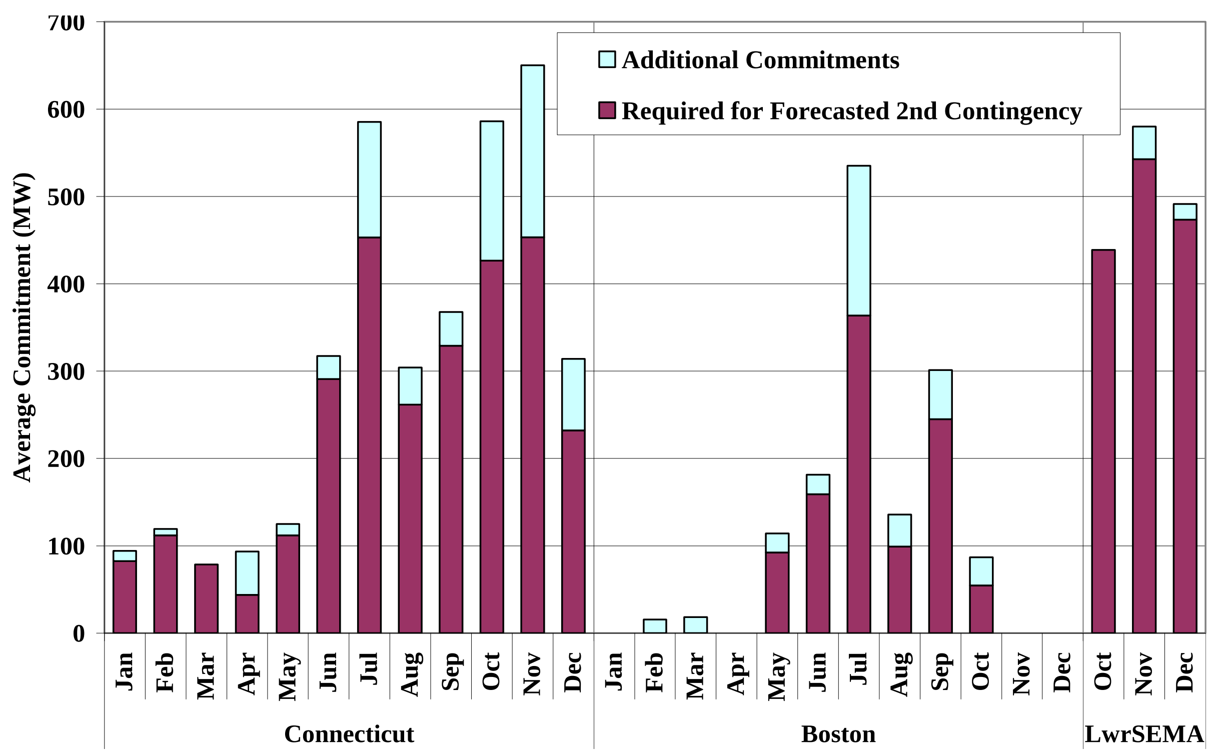
13 If only a portion of a 2nd contingency resource is needed to meet the forecasted 2nd contingency requirements, the entire unit is classified as satisfying the 2nd contingency requirement.

However, Additional Commitments represented 21 percent of the commitments in Connecticut, 27 percent of the commitments in Boston, and 4 percent of the commitments in Lower Southeast Massachusetts. If some of these commitments were not necessary to maintain reliability, ISO-NE should seek ways to minimize them in the future since they can inefficiently mute the transmission congestion into the constrained areas. In Section VI, we evaluate the effects of excess capacity on reserve clearing prices in Connecticut during the first three months of operation with real-time reserve markets, and we find that modest amounts of excess capacity can have a substantial effect on clearing prices.

Figure 13: Local 2nd Contingency Commitments in Constrained Areas
2006



Even when local 2nd contingency commitments appear to be necessary based on forecasted operating conditions, there are several other factors that contribute to over-commitment in constrained areas. First, commitment is naturally lumpy because most generators have significant minimum operating levels and minimum run-times. Hence, operators may have to commit substantially more than is actually required to satisfy the local 2nd contingency requirement in a particular hour. Increased reliance on small-scale, fast-start resources in the future should reduce this source of over-commitment.

Second, sometimes suppliers self-commit after ISO-NE commits resources to meet local 2nd contingency requirements, making some of the commitments by the ISO no longer necessary to satisfy the local 2nd contingency requirement. Self-commitments are analyzed in the following sub-section.

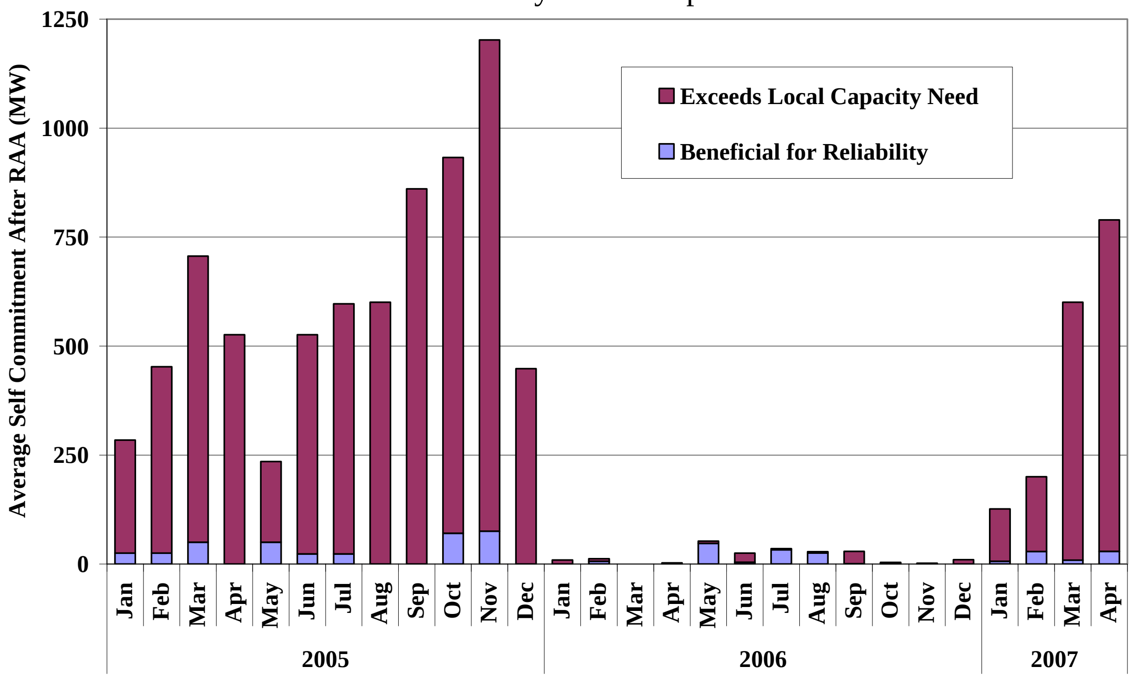
3. Self-Commitment after the RAA

In local areas that are frequently constrained, ISO-NE regularly supplements market-based commitments with additional commitments to ensure reliability. Before committing resources to provide local 2nd contingency protection, the ISO counts the amount capacity that is expected to be online. This count includes capacity committed: (i) through the Day-Ahead Market, (ii) day-ahead for voltage support or other reliability reasons, (iii) in the re-offer period by a self-schedule, and (iv) in the RAA process for a local 1st contingency. If the ISO is still short of the local capacity requirement after these commitments, it will commit additional resources. However, if a supplier commits a generator after local 2nd contingency protection resources are committed in the RAA process, it can lead to surplus capacity in the load pocket. This surplus creates uplift for local 2nd contingency protection commitments that would not have been necessary if the ISO had been aware of all self-commitments when it conducted the RAA process.

In recent years, Boston has been the only area where substantial amounts of capacity have been committed by self-schedules after the RAA process. Figure 14 summarizes the extent to which self-commitment after the RAA process has helped meet remaining local 2nd contingency requirements in Boston versus how often it has led to excess capacity.

In Boston, the average amount of capacity self-committed after the RAA process has varied substantially since January 2005. The quantity of self-commitments was considerable in 2005. It decreased almost to zero in 2006, but resumed in 2007. This pattern is primarily attributable to a change in behavior by a single supplier. In 2005, the supplier usually raised its day-ahead offer prices above marginal cost to avoid market-based commitment in the Day-Ahead market. This frequently required ISO-NE to commit some of the supplier's capacity for local reliability. In 2006, ISO-NE signed a reliability agreement with the supplier that covered most of the supplier's capacity. The reliability agreement stipulated that the supplier's capacity be offered in the Day-Ahead market at marginal cost. As a result, these units were committed in the Day-Ahead market on most days since they are usually economic. In 2007, the reliability agreement expired, and the supplier has resumed the conduct it exhibited in 2005.

Figure 14: Self Commitment after the Resource Adequacy Assessment
Boston – January 2005 to April 2007



Our analysis indicates that only a small quantity of the self commitments helped the ISO meet the local capacity requirement. It can be efficient to have more than the minimum capacity required in each local area, but a large share of these self-commitments occurred after ISO-NE had already committed units for local 2nd contingency protection. If the ISO had known that these units would be self scheduled, it would not have needed to commit as many units for local 2nd contingency protection. In some cases, ISO-NE can de-commit a resource that had been committed in the RAA process if a self-schedule occurs later that eliminates the need for the commitment. However, this process has not been fully effective because self-commitments frequently occur after it is too late to de-commit other resources.

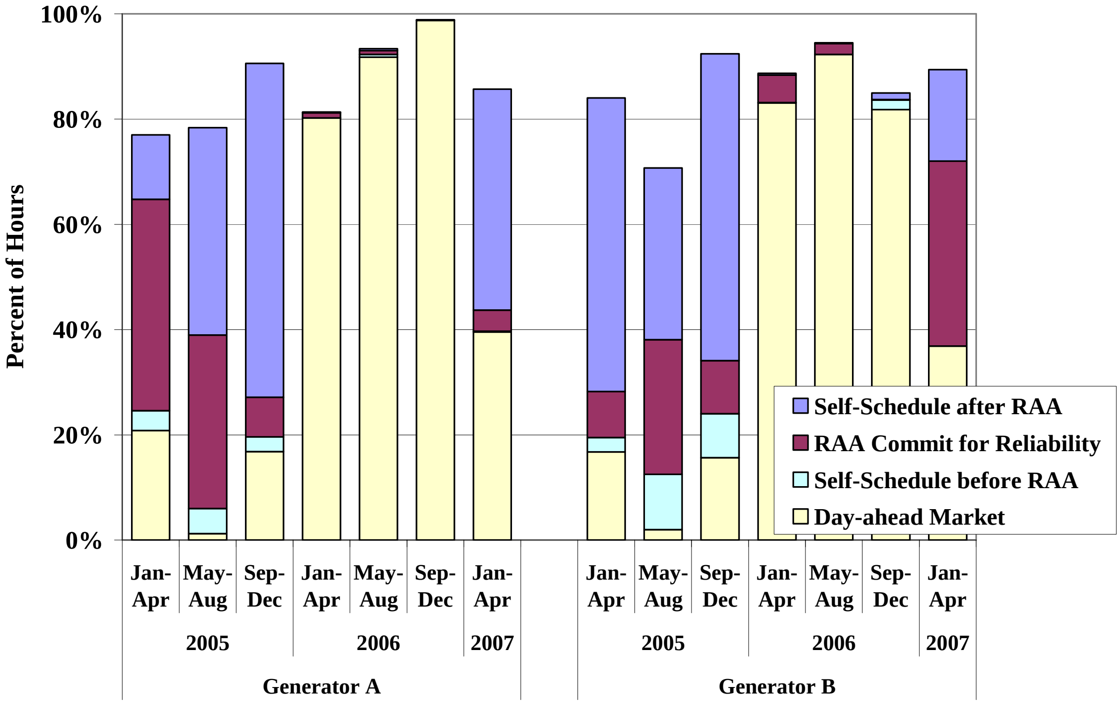
Self-commitment after the RAA process can lead to excess capacity and inefficient market outcomes in constrained areas. The excess capacity mutes congestion into the load pocket, depressing real-time prices and increasing uplift costs. Additionally, this type of self-commitment undermines convergence between day-ahead and real-time prices, because it is difficult for load serving entities to predict when units will choose to self schedule.

While there are some legitimate reasons for self commitment after the RAA (e.g., suffering a forced outage on a unit that had been scheduled in the Day-Ahead market), the rise in this activity is also consistent with incentive problems that result from frequent supplemental commitment. In Boston, local reliability requirements are frequently satisfied outside the normal market process, and these units are paid their offer when the clearing price is not sufficient for them to recover their as-bid cost. Even under perfect competition, units with pay-as-bid incentives rationally offer above marginal cost. Generators frequently committed for local reliability often have some degree of local market power, and thereby a greater incentive to offer above marginal cost. If such units submit high-priced offers in the RAA process and are not committed, they could forego the profitable opportunity to sell energy in the real-time market. However, they do not miss the opportunity because they have flexibility to self-commit the units after the RAA process if they are not selected. Hence, the market rules make this a low-risk strategy.

If the rise in self commitment after the RAA in 2007 is caused by inefficient incentives, the units that are frequently self-committed should be the units that are frequently committed for local reliability (because they can self-schedule when not selected in the RAA process). Figure 15 shows the pattern of commitment of the two units that have frequently self scheduled after the RAA process. These two units account for 92 percent of the unit-hours and 99 percent of the MWh self committed after the RAA in Boston in 2005.

The figure shows that these generators were committed in approximately 85 percent of the hours over the 28 month period, although the way in which they were committed varied significantly. In 2005, these two generators received commitments in the Day-Ahead Market or self-scheduled prior to the RAA approximately 20 percent of the time. In the remaining hours, these generators were frequently committed for reliability in the RAA process. When these units were not committed day-ahead or in the RAA process, they were usually self-scheduled after the RAA, which indicates that the owner deemed them to be economic at the expected real-time prices.

Figure 15: Two Units Most Frequently Self Committed After RAA
Frequency and Reason for Commitment
January 2005 to April 2007



In 2006, the two generators were covered by a reliability agreement. The agreement required the generators to submit offers priced at levels consistent with marginal cost. This led the units to be committed through the Day-Ahead market, thereby reducing the need for local 1st contingency and 2nd contingency commitments in the Boston area. Since the reliability agreement expired at the end of 2006, the supplier has resumed the conduct it exhibited in 2005. As expected, the figure shows that these units are again frequently being committed for local reliability or self-committed by the supplier.

As described above, some of the commitments made in the RAA process become unnecessary after additional units are self committed. This excess capacity depresses real-time prices and results in additional uplift costs. These effects would be avoided if the units were committed in the Day Ahead market or self-committed prior to the RAA process, but generators frequently committed for local reliability have an incentive to wait until after the RAA process to inform ISO-NE of their commitment. We recommend that ISO-NE estimate the additional uplift costs caused by post-RAA self commitment decisions, and consider whether changes to uplift cost allocations would improve market participant incentives and reduce unnecessary uplift costs.

4. Local Reliability Commitment Conclusions

The analysis in this section highlights changes in the supplemental commitment patterns and supports several conclusions. Commitment for local reliability in 2006 became far less frequent in Boston and much more common in Lower Southeast Massachusetts. In Boston, the need to commit units for voltage support was reduced by several transmission upgrades, while the need to commit units for local 1st and 2nd contingency protection was reduced by a change in the behavior of the largest supplier. In Lower Southeast Massachusetts, one of two large units was committed almost continuously for local 2nd contingency protection to ensure reliability for the Cape Cod area. The same units had previously been needed for voltage support prior to 2006, but changes in fuel prices and offers caused these units to be economically committed less frequently in the Day-Ahead market. Therefore, the units were supplementally committed more frequently than in prior years and received higher NCPC payments.

This section evaluates whether commitments made by the ISO and flagged for local 2nd contingency protection were necessary to meet forecasted minimum capacity requirements in constrained areas. It is important for the ISO to avoid making excessive reliability commitments, because unnecessary commitment depresses economic signals in constrained areas. We find that the majority of the ISO's commitments in 2006 were consistent with local reliability requirements under current market processes and procedures.

The third analysis in this section examines the effects of self commitment after the RAA process, which was the primary contributor to excess capacity in 2005. One supplier that was frequently committed for local reliability generally self-committed its units when not committed by ISO-NE. In 2006, a reliability agreement with the supplier effectively mitigated this incentive and reduced the incidence of excess capacity. However, the reliability agreement expired at the end of 2006 and the supplier resumed its prior conduct, which has resulted in excess commitments again in Boston in 2007.

ISO-NE has implemented or is developing several measures to reduce supplemental commitment.

- In October 2006, the ISO implemented reserve markets with locational requirements, which should result in better economic signals for suppliers to provide reserves in Connecticut and Boston, particularly from fast-start units. The new reserve markets are examined in greater detail in Section VI.
- The Flexible Combined Cycle Modeling proposal is being developed to enable suppliers to offer their combined cycle units under several different configurations. This should enable more efficient commitment by reducing the "lumpiness" of combined cycle units, and in some cases, would allow combined cycle units to offer non-spinning reserves while offline.

In addition, we recommend the ISO:

- Consider rule changes to alleviate increased uplift costs and other market effects caused by self-committing generation after the RAA process;
- Minimize any unjustified differences between day-ahead and real-time transmission limits into areas that frequently require reliability commitment; and
- Consider integrating local reliability requirements currently used in the RAA process into the day-ahead market commitment model;

The final recommendation will help limit the over-commitment of generation in New England, improve the convergence of prices in the constrained areas between the day-ahead and real-time market, and restore the incentive for loads to be fully scheduled in the Day-Ahead market. Previously, this would have been difficult to implement since de-listed (i.e., not sold in the capacity market) generators were not obligated to be available for commitment in the Day-Ahead market. However, it is likely that none of the generators in the constrained areas will be delisted during or after the transition to the Forward Capacity Market.

F. Out-of-Merit Dispatch

Out-of-merit dispatch occurs in real time when energy is produced from an output range on a unit whose incremental energy offer is greater than the LMP at its location. Out-of-merit generation tends to reduce energy prices by causing lower-cost resources to set the energy price.

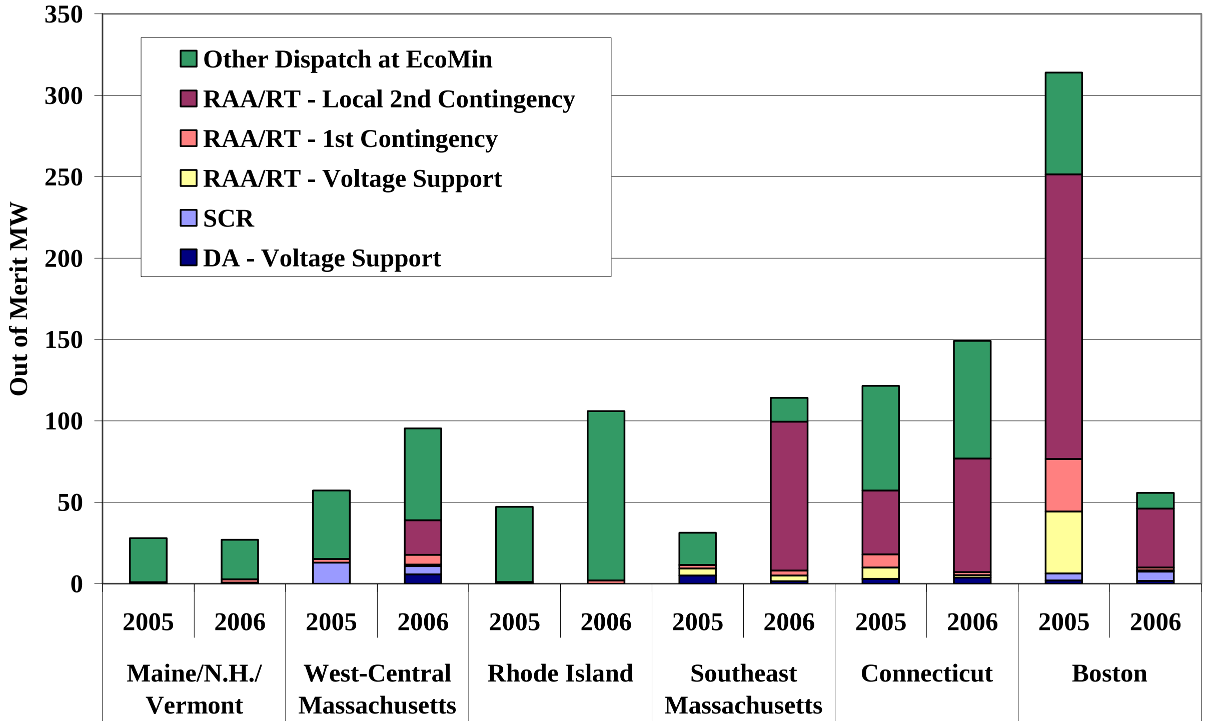
In a very simple example, assume the two resources closest to the margin are a $60/MWh resource and a $65/MWh resource, with the market clearing price set at $65/MWh in the absence of congestion and losses. When a $100/MWh resource is dispatched out of merit, it will be treated by the software as a must-take resource with a $0/MWh offer. Assuming the energy produced by the $100/MWh resource displaces all of the energy from the $65/MWh resource, the energy price will decrease to $60/MWh.

A unit may be dispatched out of merit for three main reasons. First, a unit may run at its EcoMin to satisfy its minimum run time after having run in merit for several previous hours or in anticipation of running in an upcoming hour. Such a unit may also be at its EcoMin when providing reserves. The real-time market software cannot dispatch a unit below its EcoMin, so it will dispatch the unit at its EcoMin if the unit must remain online when its incremental energy offer is above the market price. This is efficient because the software is minimizing cost over the total run-time of the unit. Second, a unit committed for reliability reasons during or after the Day-Ahead market may be out of merit at its EcoMin. Units committed for reliability after the Day-Ahead market are committed without regard to their incremental energy offer and are, therefore, more likely than units committed competitively in the Day-Ahead market to have incremental offers higher than the LMP.

Third, a unit may be dispatched out of merit in real time to satisfy reliability requirements in real time. Similar to the supplemental commitments, operators may request certain units to be run at higher levels than their energy offers would justify. This can be necessary for a number of reasons, including (a) voltage support on transmission or distribution facilities; (b) managing congestion on local distribution facilities; or (c) providing local reserves to protect against second contingencies. Figure 16 summarizes the average out-of-merit dispatch by location for weekday hours (6 AM to 10 PM) during 2005 and 2006.

Figure 16 shows that virtually all of the out-of-merit dispatch outside of the constrained areas is attributable to non-local reliability units being dispatched at EcoMin. However in Boston, Connecticut, and Southeast Massachusetts, most of the out-of-merit dispatch is from units committed in the RAA process for local reliability, particularly local 2nd contingency protection.

Figure 16: Average Hourly Out-of-Merit Dispatch
2005 & 2006 – Weekdays 6 AM to 10 PM



Note: Capacity committed day-ahead for voltage support that would have been economically committed in the day-ahead market is included in the 'Other Dispatch at EcoMin' category.

The average quantity of out-of-merit dispatch from units committed for local reliability (including 1st contingency, 2nd contingency, voltage support, and SCR) declined from an average of 320 MW in 2005 to 255 MW in 2006. The aggregate amount of out-of-merit energy from non-local reliability units (i.e. Other Dispatch at EcoMin) did not change significantly. The "Other Dispatch at EcoMin" category arises partly as a result of the excess capacity that is discussed in the prior sub-section. Excess capacity generally increases the supply on the system and causes higher-cost resources to reduce their output to EcoMin.

The changes in out-of-market dispatch that occurred in 2006 track the changes in supplemental commitments and were caused by the same underlying factors. The new 2nd contingency requirements in Southeast Massachusetts resulted in a substantial increase in out-of-market dispatch in that area. The most notable changes occurred in Boston when out-of-market dispatch decreased sharply due to two factors. First, the reliability agreement with a supplier lead its units to be committed much more frequently in the Day-Ahead market. Second, several transmission enhancements eliminated out-of-market dispatch associated with voltage support in Boston.

Although some resources may need to be dispatched out-of-merit in any system, this should be minimized because it can undermine the efficiency of the locational energy and reserves prices. Furthermore, owners of units that are frequently called out-of-merit order face incentives to offer in excess of marginal costs, which can result in less efficient commitment and dispatch decisions. In addition, when units are offered above marginal costs, it reduces the likelihood that they will be committed economically through the Day-Ahead market, possibility even increasing to the need for supplemental commitments. Hence, it is a pattern that can be self-reinforcing.

G. Uplift Costs

Since the introduction of locational marginal pricing, the markets have not completely reflected the reliability requirements for several New England load pockets. As a result, the ISO has used reliability agreements and supplemental commitment to ensure local reliability. Reliability agreements give the owners of uneconomic generating facilities supplemental payments in order to keep them in service. Supplemental commitments bring uneconomic capacity online at times when market clearing prices are insufficient. Such generators receive additional payments called NCPC ("Net Commitment Period Compensation") payments, which make up the difference between their accepted offer costs and the market revenue. The costs associated with these payments are recovered from market participants through uplift charges. This section summarizes the main sources of uplift charges and how they are allocated among market participants.

The following table summarizes several categories of uplift during 2005 and 2006. The main categories of uplift are:

- Reliability Agreements – The uplift from these are allocated to Network Load in the zone where the generator is located.[14] A large share of the generation in constrained areas is supported by payments from these agreements. In 2006, 62 percent of capacity in Boston and 41 percent of the capacity in Connecticut was covered under reliability agreements.

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14 Network Load includes transmission customers that are served by the Transmission Owner.

- Local 2nd Contingency Protection Resources – In 2006, 84 percent of the uplift from these units was allocated to Real-Time Load Obligations and Emergency Sales in the zone where the generator is located.[15] The remaining uplift, the portion associated with day-ahead rather than real-time commitments, was allocated to day-ahead load schedules in the local zone.
- Special Case Resources – The uplift paid to these resources is allocated to the Transmission Owner that requests the commitment.
- Voltage Support Resources – The uplift paid to these resources are allocated to Network Load throughout New England and Through-and-Out transactions.
- Other supplemental commitment (including local 1st contingency resources) – In 2006, 91 percent of this uplift was allocated to Real-Time Deviations throughout New England.[16] The remaining uplift, which is associated with units committed in Day-Ahead market, is allocated to day-ahead scheduled load throughout New England.

The vast majority of uplift in each of these categories is incurred to address local supply inadequacies. For this reason, it is generally appropriate to allocate these charges to the local customers who derive benefit from their service. The first three categories are allocated on a local basis, while the uplift charges for Voltage Support Resources and other supplemental commitment are allocated to customers throughout New England.

The following table summarizes the total costs of uplift associated with reliability agreements and supplemental commitment. In 2006, uplift costs totaled $715 million, a 35 percent increase from 2005. The increase was driven by a 100 percent rise in reliability agreement costs, while the uplift from supplemental commitment declined 19 percent. The broad changes from 2005 to 2006 in supplemental commitment patterns track the changes in uplift. Uplift costs rose dramatically in Southeast Massachusetts, while the costs of committing units in Boston (for local 2nd contingencies and voltage support) declined sharply.

15 Real-Time Load Obligations includes load customers that are served by the Load Serving Entity.

16 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; generation deviations from day-ahead schedules, which include virtual supply schedules; and generation deviations from the larger of the unit's Economic Minimum and desired dispatch point in each hour.

Table 4: Allocation of Uplift for Out-of-Market Energy and Reserves Costs
2005 & 2006

	Millions of Dollars	
Category of Uplift	**2005**	**2006**
Reliability Agreement		
Connecticut	**$190**	**$223**
Boston	**$26**	**$194**
Other Areas	**$25**	**$65**
Local 2nd Contingencies		
Connecticut	**$42**	**$60**
Boston	**$91**	**$33**
Southeast Massachusetts	**$0**	**$85**
Other Areas	**$0**	**$3**
Special Case Resources	**$10**	**$9**
Voltage Support	**$75**	**$19**
Other (Mostly Local 1st Contingencies)	**$69**	**$25**
Total	**$528**	**$715**

Note: Since information is not publicly available on the breakdown of payments under reliability agreements by load zone, this analysis assumes that the ratio of payments to fixed cost guarantees is the same for Boston, Connecticut, and other areas.

The practice of allocating the uplift costs from “other” supplemental commitments to Real-Time Deviations can discourage virtual trading (i.e. scheduling *incs* and *decs*) and price-sensitive load purchases in the Day-Ahead market. This is important because virtual trading and price sensitive load facilitate price convergence between the markets and mitigate market power in the Day-Ahead market. Hence, Day-Ahead market efficiency has likely improved due to the reduced uplift from “other” supplemental commitments, which declined from $69 million in 2005 to $25 million in 2006. As a result, the average allocation of uplift to Real-Time Deviations declined from $1.91/MWh in 2005 to $0.74/MWh in 2006 (see Table 4). Over the same period, convergence improved by a similar amount between day-ahead and real-time prices at the New England Hub.

The costs of the “other” supplemental commitments are caused by a number of factors, including under-scheduling of load in the Day-Ahead market, scheduling of net virtual supply, increase in real-time net exports, changes in transmission limits in real-time, and other factors. Because the allocation of these costs can have a significant effect on the incentives of participants in the Day-Ahead market and ultimately affect the efficiency of market outcomes, we recommend that ISO-NE evaluate how these costs are allocated. Likewise, socializing voltage support commitment costs that primarily benefit a local area can lead to inefficient short-term and long-term incentives and should, therefore, also be re-evaluated by ISO-NE. To the maximum extent possible, the costs associated with these classes of supplemental commitments should be allocated in a manner that reflects the cause of the costs. For example, under-scheduling load in the Day-Ahead market can contribute "other" commitments while over-scheduling load does not.

H. Market Operations – Conclusions

In general, we conclude that the markets operated well during 2006. Price corrections have been rare, and load forecasting has been relatively accurate. However, substantial quantities of supplemental commitments continue to occur in several constrained areas of New England. These commitments are necessary, in part, because these areas do not have a large quantity of fast-start resources that can help meet the capacity requirements of the local area while offline.

Supplemental commitments and out-of-merit energy dispatch create four issues in the New England market. These issues are:

- Inefficiencies created because supplemental commitments are made with the objective of minimizing commitment costs (i.e., start-up, no-load, and energy costs at EcoMin), rather than minimizing the overall production costs.
- Dampening of economic signals to invest in areas that would benefit the most from additional investment in generation, transmission and demand response resources.
- Substantial additional uplift costs that are difficult for participants to hedge and can be quite volatile.
- Incentives created for generators frequently committed for reliability to avoid market-based commitment to seek additional payments through the reliability commitment process.

ISO-NE has implemented or is pursuing several additional measures to minimize reliance on supplemental commitments in load pockets include:

- Developing a new Combined Cycle unit dispatch process to gain additional unit flexibility and non-spin capability in load pockets;

- Implementation of real-time ancillary services markets to provide better incentives for resources in the load pockets, particularly for new fast-start units.

In addition to these measures, we recommend the following changes to reduce further inefficiencies associated with supplemental commitments. We recommend that the ISO:

- Re-evaluate the allocation of uplift costs associated with supplemental commitments for voltage support, local 1st contingencies and market-wide capacity needs. We recommend that these costs be allocated in a manner that reflects the causes of the costs to the maximum extent possible. In the case of local 1st contingencies and voltage support commitments, for example, this may result in a more targeted allocation to the areas affected by the commitments. Such a change should improve participant's incentives and the efficiency of market outcomes.
- Evaluate the underlying assumptions in the calculation of the import limits to constrained areas to minimize any unjustified inconsistencies between the day-ahead and real-time limits. This will improve the efficiency of the day-ahead commitment and tighten convergence between day-ahead and real-time market outcomes; and
- Consider incorporating local reliability commitment criteria currently used in the RAA process into the Day-Ahead market model.
  - ✓ To the extent that the commitment of a particular unit to satisfy a local requirement is known, it is most efficient to commit the unit as part of the overall cost minimization that occurs in the day-ahead market software.
  - ✓ This should improve price convergence and reduce incentives to under-schedule load in the day-ahead market (since the additional supply will be scheduled in the day-ahead market).
  - ✓ However, we recognize that issues related to the de-listing of units needed to meet these requirements would need to be evaluated and resolved.
- Consider rule changes to alleviate increased uplift costs and other market effects caused by self-committing generation after the RAA process.

V. Regulation Market

Regulation is the capability of specially equipped generators to increase or decrease their output on a moment-to-moment basis in response to signals from the ISO. The system operator uses regulation capability to maintain the balance between actual generation and load in the New England Control Area. The Regulation market provides a market-based system for satisfying the system's Regulation requirements.

The ISO determines the quantity of Regulation capability required to manage the system based on historical performance and ISO-NE, NERC and NPCC control standards. Requirements may be adjusted by ISO-NE as needed to assure continued compliance with these standards. The average quantity of Regulation capacity scheduled has been reduced in each of the last two years. The ISO indicates that improved generator responsiveness to operator signals has permitted reductions in the quantity of regulation required. The average quantity of Regulation scheduled by the ISO has declined from 153 MW in 2004 to 143 MW in 2005 to 134 MW in 2006.

Generally speaking, ISO-NE maintains a schedule for acquiring Regulation that ranges from 80 MW to 250 MW depending upon season and time of day. The ISO has historically acquired about 20 MW more Regulation in summer and winter months than it has acquired in spring and fall. During Emergency Conditions, the ISO may deviate from the Regulation Requirement to maintain system reliability.

On October 1, 2005, the ISO implemented modifications to the Regulation market. Under the revised Regulation market design, the ISO pays generators that provide Regulation service using a three-part compensation mechanism: (1) the Regulation Clearing Price ("RCP") is paid to generators based on the amount of Regulation capacity that they make available (referred to informally as a Regulation "capacity payment"); (2) additional payments are made to generators based on actual performance (informally called a "mileage payment"); and, (3) generators are eligible for unit-specific energy opportunity costs incurred while providing Regulation service ("Lost Opportunity Costs" or "LOC payments"). The Regulation market selects suppliers for the upcoming hour with an objective of minimizing consumer payments.

Regulation expenses increased substantially after the market design changes were implemented in October 2005. In some cases, the increase can be traced to market design elements and changes in the behavior of Regulation suppliers. Other portions of the increase can be attributed to broader factors affecting New England's energy markets. Regulation expenses fell during 2006 relative to the high levels in late 2005. Just as with the increase in late 2005, the decreases over 2006 can be linked to supplier responses to the Regulation market and to broader changes in energy markets.

In this section of the report we evaluate the market for regulation. Our evaluation focuses on (a) the overall costs of procuring regulation and related market outcomes, (b) the effects of the market design changes implemented in 2005, and (c) the pattern of supply offers from regulation providers. The report also describes several market design changes that were made in January 2007 to address issues that arose during the first year of operation under the new market design.

A. Regulation Market Design Changes

One of the most significant changes implemented in the revised Regulation market was the use of a consumer-payment minimizing objective to select suppliers, while the previous design used a system-cost minimizing objective. The main feature of the system-cost minimizing approach was that it set a clearing price based on an *ex ante* estimate of the marginal cost to the system of providing regulation. Lost opportunity cost payments augment the payment of the clearing price to the extent that the clearing price does not cover the *ex post* calculation of as-bid costs of the units selected to provide regulation.

The new consumer-payment minimizing objective compensates generators based on the capacity set aside to provide regulation, the actual mileage of the unit, as well as the opportunity cost of not selling energy. The energy opportunity cost is not reduced to account for the net revenues the supplier receives from the regulation market. This approach selects the set of regulation offers that are expected to require the lowest total payments from these three categories. This sub-section discusses the specific design changes and summarizes them in Table 5.

First, a mileage payment was added to pay generators based on the amount they move when regulating. The payment is equal to 10 percent of the mileage (i.e. the up and down distance measured in MW) times the RCP. Based on historic patterns of regulation deployment, this formula is expected to generate mileage payments and capacity payments of similar magnitude in the long term. Second, the RCP is now based on the highest accepted offer price. It was previously based on the *ex ante* estimate of the marginal cost of the highest-cost unit accepted.

Third, the method for selecting the resources to provide regulation has changed. While the model selects the resources with the lowest rank price to provide regulation under both designs, the formula for determining the rank price has changed under the new market design. Under the new design, the rank price is the sum of the following five quantities:

Estimated capacity payment – In the first iteration of the model, this is the offer price of each unit. But since the RCP is set by the highest accepted offer, the subsequent iterations set this equal to the higher of the offer price and the previous iteration’s highest priced accepted offer.

Estimated mileage payment – This is equal to the estimated capacity payment.

Estimated lost opportunity cost payment – This is the estimated opportunity cost from operating at the set point rather than at the most economic dispatch level given the unit’s offer prices and the prevailing LMP.

Estimated production cost change – This is similar to the estimated opportunity cost, but ramp rate limitations are included in the estimate of the units’ most economic dispatch level.

The look ahead penalty – This measures the maximum possible change in the energy offer price within the regulating range relative to the set point. This is included in order to avoid selecting units that would earn large opportunity cost payments if they were to regulate into a range of their energy offer priced at extreme levels.

Under the new design, the ranking process iterates until the set of units selected to provide regulation does not change for two consecutive iterations. However, the iteration process is subject to the constraint that if the RCP rises from one iteration to the next, the model will use the previous iteration to rank units.

The timing of the selection process has changed under the new market design. Previously, the regulation market model would rank units and perform its selection after 6 PM on the evening before the operating day. The estimated lost opportunity costs were derived from day-ahead market LMPs and energy offers submitted for the real-time market. Under the new market design, the ranking process is performed at the beginning of each hour of the operating day, and sometimes within the hour. The estimated lost opportunity costs, production cost change, and look-ahead penalty are derived from the latest available real-time LMPs. Within the operating hour, units are selected to provide regulation according to the ranking determined at the top of the hour. The following table summarizes the market design changes that occurred under Phase 1 of ASM.

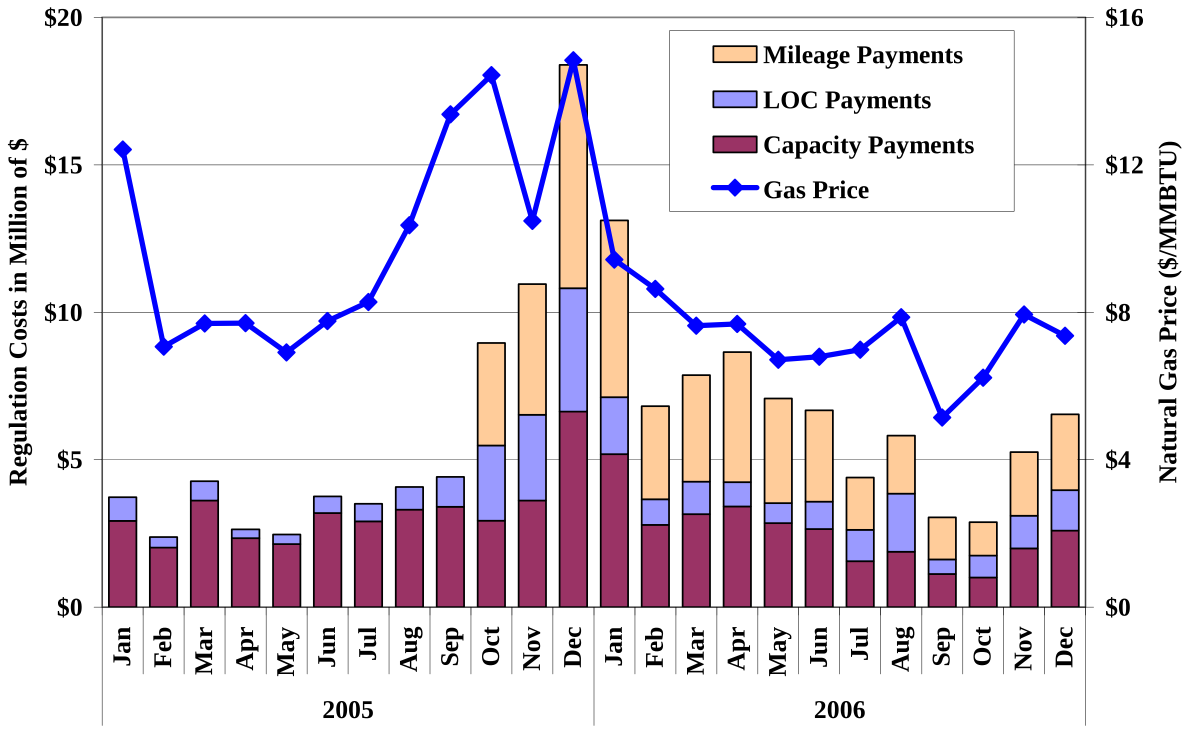
Table 5: Summary of Regulation Market Design Changes
Under Phase I of ASM

	Prior Market	New Market
Payments to Regulation Units:		
Components of Payment	**Capacity Pymt + LOC Pymt**	**Capacity Pymt + LOC Pymt + Mileage Pymt**
Determination of RCP	**Marginal Rank Price**	**Highest Accepted Offer Price**
Capacity Payment	**Regulation Capability MWh * RCP**	
Mileage Payment	**None**	**10% * Mileage MW * RCP**
LOC Payment	**Energy LOC minus (RCP - Offer Price)**	**Energy LOC**
Selection of Regulation Units:		
Components of Rank Price	**= Offer Price + Est. Energy LOC (based on DA LMP)**	**= Est. Capacity Pymt (= Offer price in first iteration) + Est. Mileage Pymt (= Offer price in first iteration) + Est. Energy LOC (based on RT LMP) + Est. Production Cost Change + Look Ahead Penalty**
Iterations	**None**	**After the first iteration, offer prices are replaced with MAX{offer price , last iteration RCP}**

B. Regulation Market Expenses

Figure 17 summarizes regulation market costs during 2005 and 2006 from the three categories of expenses: 1) capacity payments, 2) lost opportunity cost payments, and 3) mileage payments. The figure also shows the monthly average natural gas prices.

Figure 17: Regulation Market Expenses
2005-2006



Regulation market expenses averaged $3.5 million per month during the first nine months of 2005, but rose substantially from October through the end of 2005, and totaled $18.4 million in December 2005. In January 2006, regulation expenses were $13.1 million, which was still high by historical standards. Average monthly regulation expenses decreased over most of 2006, but increased modestly in November and December 2006. Regulation market expenses averaged $6.4 million per month in 2006.

Trends were similar across the components of Regulation expenses, with each element peaking in value in December 2005 and decreasing during 2006. LOC payments rose sharply in August

2006 due to high load conditions and high energy prices. These movements in LOC payments generally track fluctuations in the energy market.

Input fuel prices can affect regulation market expenses, so Figure 17 shows the monthly average natural gas price. Generators may consume more fuel to produce a given amount of electricity when they provide regulation, leading the costs of providing regulation to be correlated with the price of fuel. We expect market participants to reflect these costs in their regulation offer prices. Since capacity payments and mileage payments are both a function of the RCP, they are both directly affected by increased RCPs. Rising natural gas prices can also lead to larger opportunity costs for regulation providers, as energy market prices tend to be higher when fuel costs are higher.

The results in Figure 17 are consistent with these expectations. The variation in regulation costs is related, in part, to fluctuations in natural gas prices. Some of the increased regulation costs are also due to other factors, which are discussed further in this section.

C. Discussion of Regulation Market Changes and Regulation Costs

Our previous assessment of the wholesale market included a detailed analysis of the initial experience with the new market design.[17] In addition to the broader market conditions that may have contributed to the increased costs of regulation in late 2005, our analysis identified two elements of the new market design and participant behavior that also contributed to the increase in regulation expenses. In this section we review these issues in the context of 2006 market results.

The first of the two elements was the addition of the mileage payment, which created a new source of revenue for regulation providers. The mileage payment is a function of the RCP and is designed to be roughly equal in magnitude to the capacity payment. Thus, market participants can expect to receive approximately twice the revenue for a given RCP under the new market design. The implication of this is that a competitive supplier should be willing to lower its offer

[17] Potomac Economics, Ltd., *2005 Assessment of the Electricity Markets in New England*, July 2006.

price by roughly 50 percent. However, in the period immediately after the market changes, the largest suppliers increased their offers and other suppliers' offers were largely unchanged. Not surprisingly, the initial effect of these offers was that the sum of the capacity and mileage payments in the new market was significantly higher than the capacity payment in the older market.

The second factor identified in our previous review concerned the process by which regulation resources are selected. As described above, regulation resources are selected based on the overall rank price, which includes estimates of the resources' opportunity costs and its offer price. We concluded that a bias in the rank price caused the selection process to over-weight estimated lost opportunity costs. The source of this bias was that the estimated production cost component of the rank price is very similar to the estimated *LOC* component (i.e., it is a redundant component). As a result, the market would not always select the offers that lead to the lowest estimated payments by consumers. Additionally, we concluded that the Look Ahead Penalty component for some resources was not a good estimator of potential LOC payments.

On the basis of these findings, we recommended the elimination of the Production Cost Component and a substantial change to the Look-Ahead Penalty jointly with the Internal Market Monitor, who had conducted and independent review of the regulation market. In November 2006, the ISO filed a proposal with FERC to make these changes to the Regulation Market Selector Process. In early January 2007, FERC accepted the proposed changes to become effective on January 12, 2007.[18] These changes should improve the selection of resources to provide regulation, the participants' incentives, and the overall efficiency of the market.

D. Regulation Offer Patterns

This section of the report reviews regulation market offers in 2005 and 2006 in order to assess the effects of the market design changes implemented in 2005. Inclusion of data from before the regulation market changes provides a useful baseline for comparison. Coverage of 15 months of experience with the new market design enables a more complete analysis and reaction to the

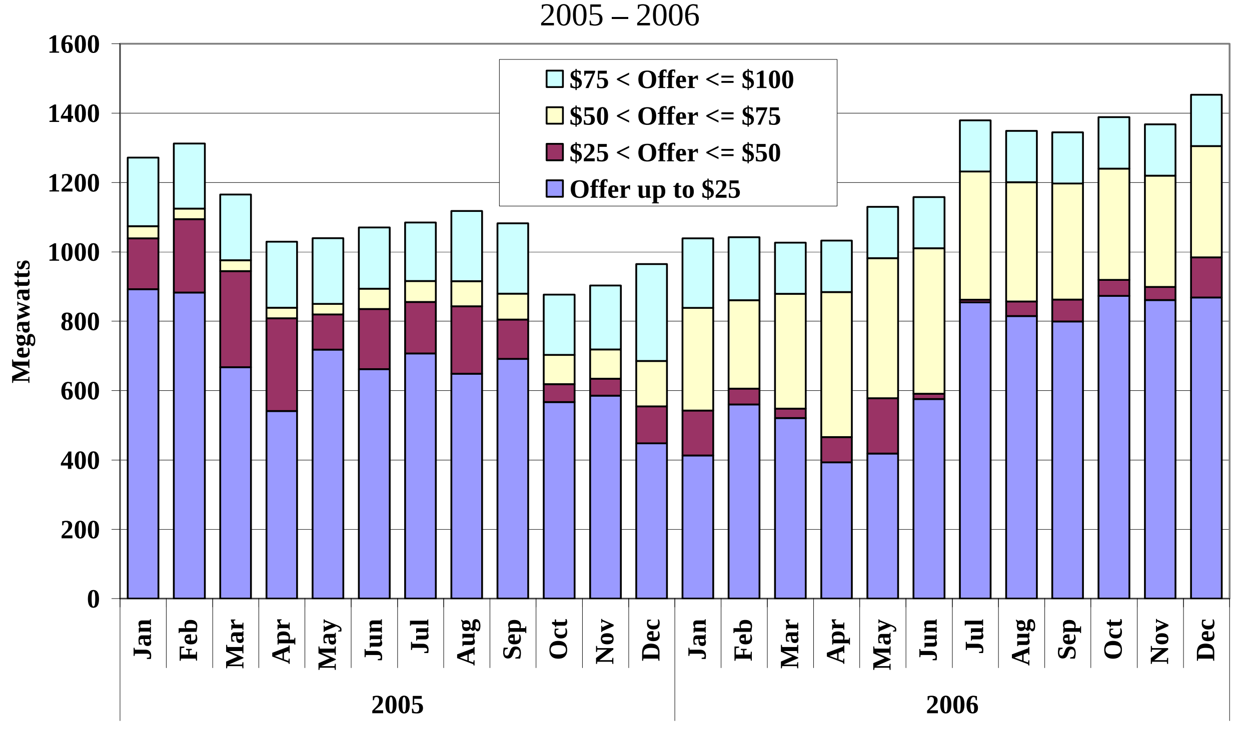
[18] See FERC docket no. ER07-201-000.

regulation market design, as market participants have had time to gain experience with and adapt to the changed rules.

Competition should be robust in New England's regulation market because in most hours the amount of regulation capability available in New England far exceeds the amount required by the ISO. Selection of units to provide regulation is limited to those units that are online at the time the service is needed, since offline units cannot provide regulation service. However, in the day-ahead timeframe, market participants with regulation-capable resources can submit offers in anticipation of being committed. The prospect of regulation market payments may influence a market participant's energy and other ancillary services offers. For these reasons we separately provide information on regulation offers from all units, and then on offers only from committed units.

Figure 18 shows monthly averages of the quantity of regulation offered into the market by all resources. A subsequent figure examines regulation offered by units that are committed. The differing colors on the bars in the chart show the average quantities offered by offer price range.

Figure 18: Monthly Average Supply of Regulation from All Resources
2005 – 2006



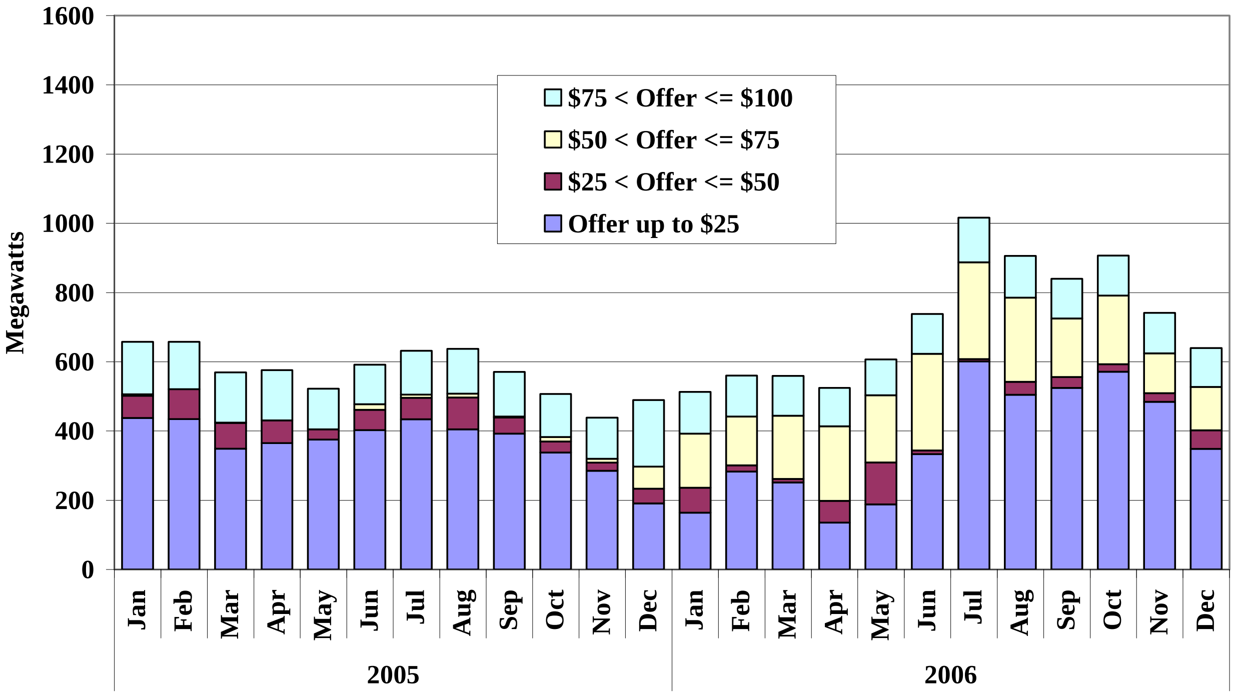
Under both the old market design in place through September 2005, and the new market design, there have been significant variations in the prices and quantities of regulation offers. From February to April 2005, there was a drop in regulation capability offered into the market due to the exit of several units from the market. In October 2005, there was a significant decrease in the quantity of low-price offers that coincided with the change in market design. Once the new market design was in place, total offer quantities showed several months of steady increase. However, the offer prices increased substantially, particularly those from the largest suppliers.

June and July 2006 saw significant increases in regulation offers priced under $25/MW. In June, six units that had been offering above $25/MW decreased their offer prices below $25/MW. The July increase was due to: the entry of several units that did not previously participate in the regulation market, higher offer quantities from several other units, and reduced offer prices from several other units. This increase in offer quantities and lower offer prices account for the reduction in regulation costs in 2006.

On average, only about 56 percent of the regulation offered day-ahead is available to the hourly selection process. Regulation-capable capacity can be unavailable in a given hour for at least two reasons: (a) the capacity is on a resource that was not committed prior to the regulation auction, or (b) the capacity is held on a portion of a resource that was self-scheduled for energy. Naturally, more regulation capacity tends to be available during the high-load portion of the day because more units have been committed and are on-line. The increase in committed resources in peak hours is partly mitigated by the fact that energy self schedules tend to increase during high-load hours and output ranges that are self-scheduled for energy are not available for regulation service.

Figure 19 shows the quantity of regulation offers from online resources only. As before, the differing colors on the bars in the chart show the average quantities offered by offer price range.

Figure 19: Monthly Average Supply of Regulation from Committed Resources
2005 - 2006



Because the figure is limited to resources actually available to provide regulation, the changes in offer quantities and prices should more closely correspond to market outcomes. The introduction of the new market design in October 2005 was followed by a reduction in total quantity available to the market and an increase in regulation offer prices, particularly from the largest suppliers. The patterns can be explained by increasing fuel costs, higher opportunity costs for providing regulation, market participant unfamiliarity with the market design, and the lack of contestability of the market. Offer quantities increased and offer prices decreased, which was likely due to fuel price reductions and the market participants gaining experience with the market.

November and December of 2006 show a drop in available regulation capability due to a low-cost regulating unit being committed much less frequently. Note that the decrease in quantities offered does not appear in the prior figure. This indicates that the resource was still offering into the regulation market and would have been available to provide regulation if the resource had been committed for energy or reserves. These changes indicate some of the complexity of the interactions between energy market and ancillary services markets.

During 2006, significantly more regulation capability was offered into the market than was actually procured by ISO-NE. This supply overhang would generally limit concerns about the exercise of market power in the regulation market because demand can easily be supplied without the largest regulation supplier. However, supply may be tight in the regulation market when energy demand is high and the regulation market must compete with the energy market for resources. High energy prices during peak-demand periods can lead resources to incur large opportunity costs when providing regulation service, thereby increasing prices for regulation. Likewise, regulation supplies may be tight in low-demand hours when many regulation-capable resources are off-line.

E. Conclusions and Recommendations

On October 1, 2005, a new regulation market was introduced as part of the Phase 1 Ancillary Services Market project. Regulation costs rose substantially after the introduction of the new regulation market, particularly in December 2005. We attributed the increase in costs to the substantial increase in natural gas prices that occurred in the fourth quarter of 2005, continuing high offer prices for regulation, and a bias in the regulation selector which led to the selection of resources with higher offer prices and, therefore, increased the RCP in some hours.

Market results for 2006 offered additional support for these conclusions. Reductions in fuel costs have contributed to reductions in regulation offer prices, LOC payments and regulation expenses. The bias in the regulation selector process may have limited competitive pressures on regulation offer prices and resulted in higher regulation expenses in 2006, although we did not seek to separately estimate the potential costs of this issue for this report. In late 2006, the ISO proposed changes to the Regulation Market Selector Process which should eliminate the bias and increase market efficiency. The changes went into effect in early 2007.

In the long-term, we recommend that the ISO continue to evaluate potential market design changes that would enhance the performance of the regulation market. This may take the form of both incremental changes to the current design, as well as more fundamental market design changes. Given the complex interaction of the regulation market with the energy market, particularly with respect to commitment decisions made in the day-ahead market, we continue to recommend that the ISO consider day-ahead and real-time regulation markets that are co-optimized with the energy market.

VI. Reserve Markets

This section of the report provides an assessment of the first three months under Phase II of ISO-NE's Ancillary Services Markets ("ASM II"). ASM II, which began operation in October 2006, included two primary market enhancements. First, a real-time reserve market with locational requirements was integrated with the existing real-time energy market. Second, locational requirements were added to the existing forward reserve market in which suppliers sell reserves that must be provided in the real-time market. These enhancements should better enable the wholesale market to meet the reliability needs of the system and thereby reduce the need for intervention by the ISO.

Under ASM II, the real-time market software co-optimizes the scheduling of reserves and energy. This enables the real-time market to reflect the re-dispatch costs that are incurred to maintain reserves in the clearing prices of energy and reserves. Previously, the energy-only market did not recognize the trade-offs between scheduling a resource for energy or reserves. It is particularly important to consider such trade-offs during tight operating conditions, because efficient scheduling reduces the likelihood of a reserve shortage. When available reserves are not sufficient to meet the required levels, the real-time model will be short of reserves and set the reserve clearing price at the level of the Reserve Constraint Penalty Factor ("RCPF").

Suppliers sell reserves into the Locational Forward Reserve Market ("LFRM") auction on a seasonal basis. Suppliers satisfy their LFRM obligations by providing reserves in real-time from online resources with unused capacity or offline resources capable of starting quickly (i.e. fast-start generators). The LFRM is intended to attract investment in capacity that is able to provide reserves at relatively low cost, particularly fast-start generation.

This section evaluates the following areas in the first three months of operation under ASM II:

- Real-Time Reserve Market
- Reserve Constraint Penalty Factors
- Forward Reserve Market

F. Real-Time Reserve Market

1. Real-Time Reserve Requirements

Under ASM II, the real-time market is designed to satisfy the system's reserve requirements, including locational requirements to maintain minimum reserve levels in certain areas. There are four geographic areas with real-time reserve requirements: Boston, Southwest Connecticut, Connecticut, and the entire system (i.e. all of New England).

In addition to the different locations, the reserve markets recognize three categories of reserve capacity:

- 10-Minute Spinning Reserves ("TMSR"),
- 10-Minute Non-Spinning Reserves ("TMNSR"), and
- 30-Minute Operating Reserves ("TMOR").

Sufficient reserves must be held in the New England reserve zone to protect the system in case contingencies (e.g. generator outages) occur. The ISO must hold an amount of 10-minute reserves (i.e. TMSR plus TMNSR) equal to the largest generation contingency on the system, which averaged 1,278 MW. Based on system conditions, the operator determines how much of the 10-minute reserve requirement to hold as TMSR. During intervals with 10-minute spinning reserve constraints, ISO-NE held an average of 39 percent of the 10-minute reserve requirement in the form of TMSR

The ISO must hold an amount of 30-minute reserves (i.e. TMSR plus TMNSR plus TMOR) equal to the largest generation contingency on the system plus half of the second-largest contingency on the system. The 30-minute reserve requirement averaged 1,856 MW. Since higher quality reserves may always be used to satisfy requirements for lower quality products, the entire 30-minute reserve requirement could be satisfied with TMSR or TMNSR.

In each of the three local reserve zones, the ISO must schedule sufficient resources to maintain service in case the two largest local contingencies occur within a 30-minute period. First, this requires the ISO to dispatch sufficient energy in the local area to prevent cascading outages if the largest transmission line contingency occurs. Second, the ISO must schedule sufficient 30-minute reserves in the local area to maintain service if a second contingency occurs after the largest transmission line contingency. Alternatively, the local 30-minute reserve requirement can be met with 10-minute reserves or by *importing reserves*, which results from producing additional energy within the local area in order to unload transmission into the area. Although ISO-NE is not the first RTO to co-optimize energy and reserves in the real-time market, it is the first to optimize the level of imported reserves to constrained load pockets.

2. Real-Time Reserve Market Design

Under ASM II, the real-time market software jointly optimizes reserves and energy schedules. By co-optimizing the scheduling of energy and reserves, the market is able to reflect re-dispatch costs that are incurred to maintain reserves in the clearing prices of both energy and reserves. For example, if a $40 per MWh combined cycle unit is backed down to provide reserves when the LMP is $50 per MWh, the marginal re-dispatch cost is $10 per MWh and the reserve clearing price will be no lower than $10 per MWh. The marginal system cost used to schedule the reserves and set reserve clearing prices includes both the redispatch cost (if any) and the offer price for the resource. When excess reserves are available without incurring any costs, reserve clearing prices will be $0 per MWh.

Higher quality reserve products may always be used to satisfy lower quality reserve requirements, ensuring that the clearing prices of higher quality products are never lower than the clearing prices of lower quality products. For instance, if TMOR is available to be scheduled at a marginal system cost of $5 per MWh and an excess of TMNSR is available at no cost, the real-time market will fully schedule the TMNSR to meet the 30-minute reserve requirement. If the zero-cost TMNSR is exhausted before the requirement is met, the real-time market will then schedule TMOR and set the clearing prices of TMNSR and TMOR at $5 per MWh.

When multiple reserve constraints are binding, the clearing price of the highest quality product will be the sum of the underlying marginal system costs for each product. For example, suppose the marginal system costs were $3 per MWh to meet the 10-minute spinning reserve constraint, $5 per MWh to meet the 10-minute reserve constraint, and $7 per MWh to meet the 30-minute reserve constraint. In this case, the TMSR clearing price would be $15 per MWh because a megawatt of TMSR would help satisfy all three constraints. Likewise, the TMNSR clearing price would be $12 per MWh because a megawatt of TMNSR would help satisfy two of the constraints.

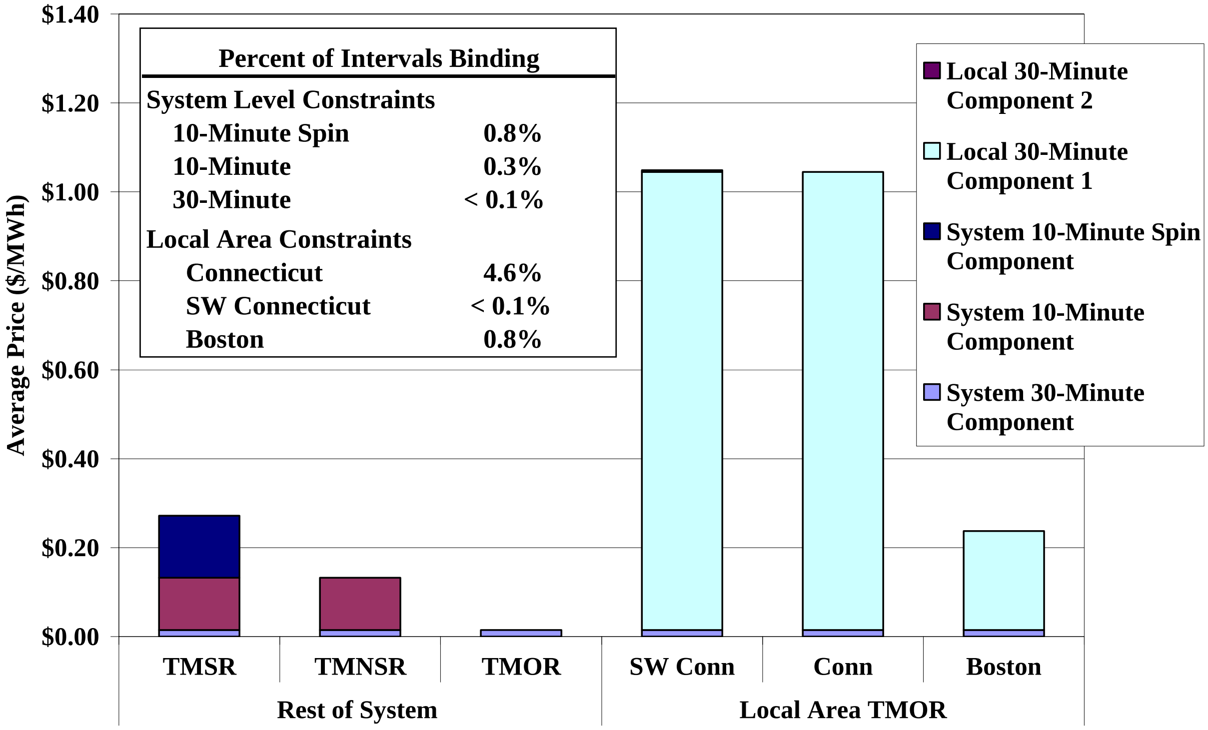
ISO-NE is the first RTO to include the level of imported reserves to constrained load pockets in the co-optimization of energy and reserves. Since local reserve requirements can be met with reserves on internal resources or import capability that is not used to import energy, allowing the real-time model to import the efficient quantity of reserves is a substantial improvement over other market designs. This enhancement is particularly important in New England where the market meets a large share of its local area reserve requirements with imported reserves. For example, imported reserves satisfied 71 percent of the Boston requirement and 39 percent of the Connecticut requirement during constrained intervals.

The marginal system costs that the market incurs to satisfy reserve requirements are limited by Reserve Constraint Penalty Factors ("RCPFs"). There is an RCPF for each real-time reserve constraint. The current RCPFs are $100 per MWh for the system-level 30-minute reserve constraint, $850 per MWh for the system-level 10-minute reserve constraint, $50 per MWh for the system-level 10-minute spinning reserve constraint, and $50 per MWh for the local 30-minute reserve constraints. When available reserves are not sufficient to meet a requirement or when the marginal system cost of maintaining a particular reserve requirement exceeds the applicable RCPF, the real-time model will be short of reserves and set clearing prices based on the RCPF. For example, if the marginal system cost of meeting a local area reserve requirement were $75 per MWh, the real-time market would not schedule sufficient reserves to meet the local requirement and the reserve clearing price would be set to $50 per MWh. This would require the operator to intervene in order to maintain the full level of reserves in the local area. The RCPFs are analyzed in greater detail later in this section.

3. Real-Time Reserve Market Results

Figure 20 summarizes average reserve clearing prices during the first three months of operation under ASM II. Outside the constrained areas, prices are shown for all three service types. In the three local reserve zones, prices are shown for TMOR only. Each price is broken into components associated with the underlying requirements. For example, the Southwest Connecticut price is based on the costs of meeting three requirements: the Southwest Connecticut 30-minute reserve requirement, the Connecticut 30-minute reserve requirement, and the system-level 30-minute reserve requirement. Likewise, the system-level TMSR price is based on the costs of meeting three requirements: the 10-minute spinning reserve requirement, the 10-minute reserve requirement, and 30-minute reserve requirement.

Figure 20: Average Reserve Clearing Prices by Product and Location
October to December, 2006



Reserve clearing prices were relatively low in the real-time market during the first three months of operation under ASM II. Outside the local constrained areas, the average TMSR clearing price was 27 cents per MWh. The 27 cents per MWh for TMSR results from an average of 14 cents per MWh for the 10-minute spinning reserve component, 12 cents per MWh for the 10-minute reserve component, and 1 cent per MWh for the 30-minute reserve component.

In the local areas, the most significant costs resulted from the Connecticut area 30-minute reserve requirement. The TMOR clearing price in Connecticut of $1.04 per MWh resulted from an average of $1.03 per MWh for the Connecticut 30-minute reserve component and 1 cent per MWh for the system 30-minute reserve component. In Southwest Connecticut, the clearing price was nearly identical to the rest of Connecticut because the Southwest Connecticut area requirement was infrequently binding. TMNSR and TMSR clearing prices are not shown in the local areas because they can also be derived from the underlying requirements. For instance, the average clearing price of TMSR in Connecticut was $1.30 per MWh. This is based on 27 cents per MWh for TMSR outside of Connecticut plus the Connecticut 30-minute reserve component of $1.03 per MWh.

As described in more detail in the next sub-section, these relatively low real-time reserve prices are largely due to the excess capacity available in each of the relevant areas, which caused the reserve constraints to not bind and the price to be $0 per MWh in most hours.

4. Unit Commitment and the Real-Time Reserve Market

The adequacy of reserves in real-time is determined in the unit commitment process. The majority of supply resources are committed in the day-ahead market based on economic criteria or self schedules. In the RAA process, additional resources may be committed for reliability reasons based on projections of real-time conditions, which may differ from actual real-time conditions for several reasons. Between the start of the RAA process and real-time operation, forecasted demand and local import capability may change significantly, generators may self commit, and capacity may be lost due to an outage. Thus, the RAA process may commit more or less capacity than is necessary to satisfy reliability criteria in real-time. This section evaluates the relationship between the adequacy of committed generation and reserve clearing prices in real-time.

In real-time, we can assess the adequacy of supply to meet demand for energy and reserves in the reserve zone by looking at the quantity of Excess Capacity. We define Excess Capacity as the amount of capacity in the reserve zone that is online or capable of starting within 30 minutes relative to the amount of capacity that is required to meet load and reserve requirements in the reserve zone.

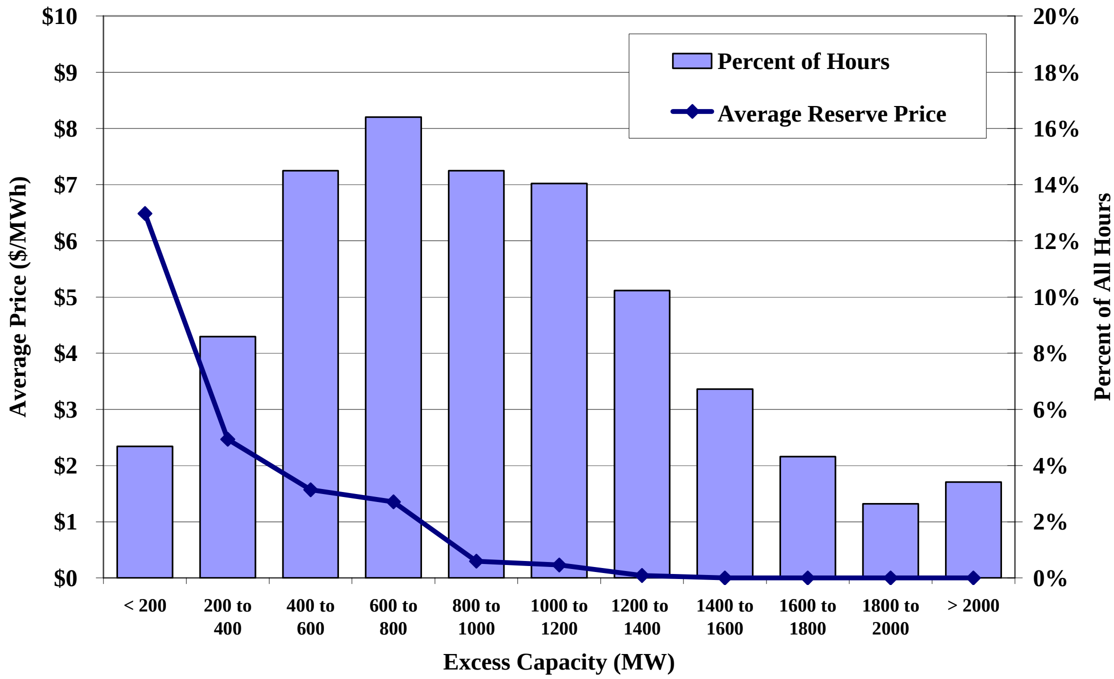
Excess Capacity = Online Reserves +
Offline Reserves Deployable within 30 minutes +
Imported Reserves –
Reserve Requirement

Thus, Excess Capacity includes online capacity, offline reserves deployable within 30 minutes, and imported reserves not necessary to meet the energy demand and reserve demand in the reserve zone.

Error! Reference source not found. summarizes the relationship of Excess Capacity to reserve clearing prices in Connecticut. The histogram shows the frequency of hours when Excess Capacity was in each range of values during the period. For example, Excess Capacity was between 400 MW and 600 MW in approximately 14 percent of the hours during the period. The line shows the average TMOR clearing price in the hours that correspond to each category of Excess Capacity. For example, when Excess Capacity was between 400 MW and 600 MW, the average TMOR clearing price was approximately $1.55 per MWh.

Error! Reference source not found. shows there is a strong correlation between the local reserve clearing price and the amount of local Excess Capacity. In the Connecticut reserve zone, when Excess Capacity is less than 0 MW (i.e. there is a shortage), the Connecticut TMOR clearing price rises to the RCPF ($50 per MWh). When Excess Capacity is between 0 MW and 200 MW, the Connecticut TMOR clearing price averages approximately $6.50 per MWh. When Excess Capacity increases to between 200 MW and 400 MW, the Connecticut TMOR clearing price declines to an average of about $2.50 per MWh. This shows that reserve clearing prices in the local area decline rapidly as the amount of Excess Capacity rises. This relationship is expected because the marginal cost of supplying reserves is very low for most units.

Figure 21: Excess Capacity and Average TMOR Price in Connecticut
October to December, 2006



There are many days when Excess Capacity occurs in Connecticut and other local areas as a result of normal market activity without supplemental commitment. For example, Excess Capacity arises when a relatively large quantity of generation in the local area is economic at the prevailing day-ahead prices, which induces a high level of commitment by the market. Excess Capacity raises concerns only when it results from supplemental commitment for reliability. Significant amounts of Excess Capacity resulting from supplemental commitment may indicate that the ISO has committed more resources than ultimately needed to satisfy the reliability requirements and dampen local clearing prices for energy and reserves.

There are at least three factors that tend to increase the amount of Excess Capacity in reserve zones when the ISO must engage in supplemental commitment. First, the size of the shortage forecasted in the RAA process may be significantly smaller than the sizes of the generators that are available to be committed for reliability. For example, if the ISO forecasts a 50 MW shortfall and the smallest generator available to address the shortage is 250 MW, committing the generator will lead to 200 MW of Excess Capacity. Second, the ISO may forecast a transitory shortage that may require the commitment of a generator with a minimum run time much longer than the shortage (e.g., 12 or 24 hours). Even though this commitment is required to prevent a shortage in the peak hour(s), it creates Excess Capacity in the remaining hours of the generator's minimum run time. Third, some of the ISO's second contingency commitment requirements are not reflected in the locational reserve requirements, such as the requirement for Norwalk-Stamford. The commitments made to satisfy these requirements can result in Excess Capacity in relative to the defined local reserve requirements.

This evaluation indicates that supplemental commitment contributes to Excess Capacity, which dampens real-time reserve clearing prices in local areas. Since outcomes in the day-ahead market are driven primarily by expectations of real-time prices, low real-time reserve prices reinforce the tendency of the day-ahead market to under-commit in local areas. Hence, the ISO seeks means to minimize supplemental commitments while continuing to operate with the objective of maintaining reliability at the lowest possible cost. Additionally, when a sufficient amount of experience has been gained with the current market, the ISO should evaluate whether any changes should be made to the locational requirements to improve their consistency with the reliability requirements of the system.

G. Reserve Constraint Penalty Factors

In the real-time market, the Reserve Constraint Penalty Factors ("RCPFs") limit the cost that the model may incur to meet the reserve requirements. Consequently, if the cost of maintaining the required level of a particular reserve exceeds the applicable RCPF, the real-time market model will incur a reserve shortage and set the reserve clearing price based on the level of the RCPF.[19] For example, suppose an online generator with a $60 per MWh incremental offer could be backed down to provide reserves when the LMP is $160 per MWh. In this case, the marginal cost to the system of providing reserves from this unit is the opportunity cost of the unit not

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19 If only one reserve constraint is binding, the reserve clearing price will be set equal to the RCPF of the reserve that is in shortage. However, if multiple reserve constraints are binding, the reserve clearing price will be set equal to the sum of binding constraint shadow prices. For example, if the market is short of Connecticut reserves and the marginal cost of meeting 30-minute reserves at the system-level is $10 per MWh, the Connecticut reserve clearing price is equal to the sum of the two shadow prices, which is $60 per MWh ($50 per MWh for the Connecticut area and $10 per MWh for the system requirement).

providing energy at the LMP. This opportunity cost is equal to the difference between the LMP and the incremental offer of the unit or $100 per MWh in this example ($160 per MWh LMP minus $60 per MWh incremental cost). If the RCPF is $50 per MWh, the market will not back the unit down to provide reserves and the system would be short of reserves since the marginal system cost of doing so ($100 per MWh) exceeds the RCPF ($50 per MWh).

The RCPF levels are important because they determine how the real-time market responds under tight operating conditions. When it is not possible to meet the reserve requirements, the RCPFs prevent the model from incurring extraordinary costs for little or no benefit. However, if the RCPFs are not sufficiently high, the market may not schedule all available resources to meet reliability requirements. In such cases, like the example above, the operator will likely intervene to maintain reserves and significantly affect market prices in the process. It is important to evaluate the RCPF levels that are currently used by ISO-NE to determine whether any modifications are warranted.

We performed two analyses to evaluate the RCPFs. Both analyses seek to determine whether the RCPFs are set at levels consistent with the value of the local reserves as demonstrated by the costs that the ISO regularly incurs to maintain local reserves. The first analysis compares the RCPF in Connecticut to the re-dispatch costs incurred to maintain Connecticut-area reserves in the real-time market. The second analysis compares the RCPF in Connecticut to the NCPC costs associated with local 2nd contingency commitments incurred to maintain Connecticut-area reserves.

1. RCPFs and Real-Time Dispatch

As discussed above, the real-time market may experience a shortage of reserves if the model does not schedule the required level of reserves because reserves are available at a marginal system cost that exceeds the RCPF. In this case, the ISO is required to take additional actions to maintain the required level of reserves if the reserves are available.

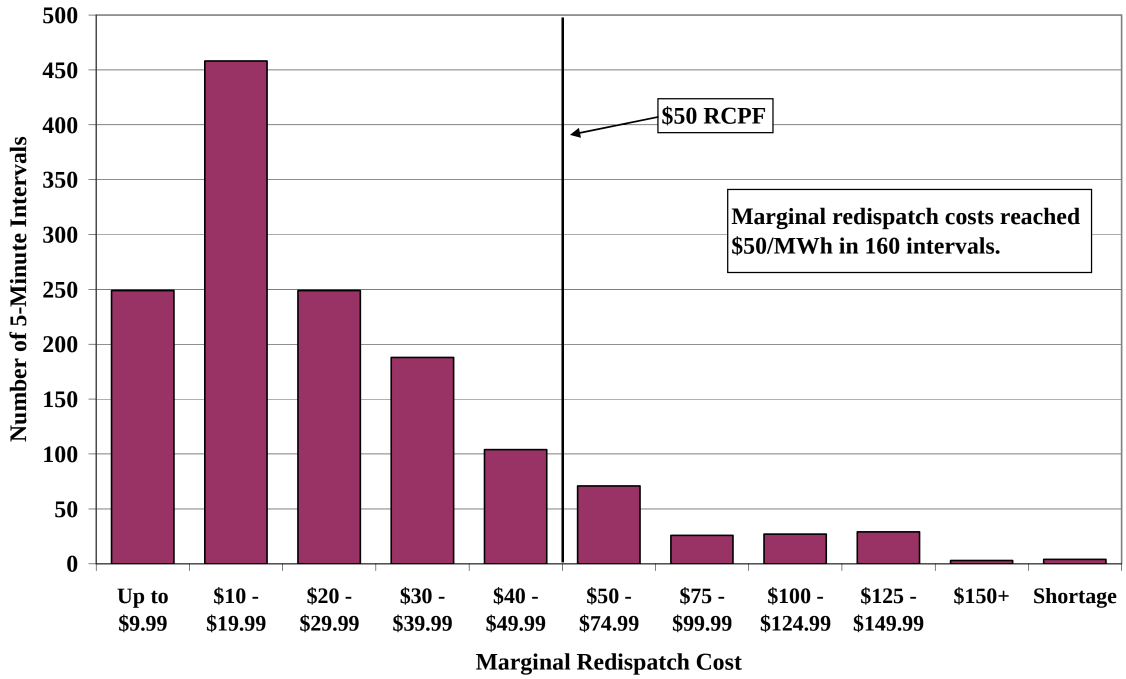
There are at least two ways for the ISO to maintain the required level of reserves when the real-time model chooses to go short. First, the operator can manually adjust the dispatch of certain units in order to provide more reserves in a local area. In the example above, the operator could manually adjust downward the dispatch level of the unit that is capable of providing reserves at an opportunity cost of $100 per MWh. Second, the operator can impose a transmission constraint[20] in the real-time market that forces the model to import a certain amount of reserves (i.e., hold the reserves as import capability on the transmission interface). When possible, the operators use real-time transmission constraints to maintain reserves rather than manual dispatch instructions.

The following analysis compares the local-area RCPF ($50 per MWh) to the marginal re-dispatch costs incurred to meet the Connecticut-area reserve requirement during the first three months under ASM II. The marginal re-dispatch costs that are counted in this analysis include: (i) the shadow price of the local reserve constraint, which is limited by the RCPF, and (ii) the shadow price of any transmission constraint that is intended to provide imported reserves (i.e. a proxy second contingency constraint). Each bar shows the how frequently the marginal re-dispatch costs were in each range shown on the x-axis.

In most intervals, the marginal cost of meeting the Connecticut reserve requirement was less than the RCPF of $50 per MWh. However, there were 160 intervals when the marginal cost of maintaining local reserves exceeded the RCPF. In these intervals, the real-time model was short of reserves in Connecticut in 38 intervals and met the reserve requirement by imposing the proxy second contingency limit in 122 intervals. The figure also shows a brief period when the proxy second contingency limit was violated in real-time implying a local reserve shortage.

[20] This is called a proxy second contingency limit. This type of constraint reduces the limit of the interface below the first contingency limit (the normal limit). The difference between the proxy second contingency limit and the first contingency limit is the amount of reserves that are imported (i.e. held on the interface).

Figure 22: Marginal Re-Dispatch Costs to Meet Connecticut Reserve Requirements
October to December, 2006



This analysis indicates that the RCPF was not sufficiently high to maintain reserves in Connecticut under normal operating conditions during shoulder months. As a result, the ISO was compelled to take additional actions to maintain reserves in a substantial number of intervals.

2. Cost of Maintaining Reserves in the Unit Commitment Process

In the day-ahead market, units are committed economically given bids from physical and non-physical demand, offers from physical and non-physical supply, and transmission constraints. Hence, greater demand in the day-ahead market results in more unit commitment. If load does not fully purchase in the day-ahead market or if incs (virtual supply) are scheduled in larger quantities than decs (virtual demand), the amount of capacity that is committed in the day-ahead market or available offline may not be sufficient to meet local-area reserve requirements.

Most supplemental commitment takes place in the RAA process after the day-ahead market in the evening prior to the real-time market. If insufficient resources are anticipated to be online and available to meet forecasted reliability requirements, the ISO must supplementally commit additional resources.

The following analysis compares the local-area RCPF to the uplift costs incurred to satisfy Connecticut-area reserve requirements in the RAA process. Each bar shows the number of days when the uplift from NCPC payments per megawatt-hour of reserve requirement satisfied was in each range shown on the x-axis. For example, if a \$100k uplift payment results when the ISO commits a unit to meet a 200 MW reserve shortfall lasting 4 hours, the figure would treat this as \$125 per MWh = (\$100k ÷ 200 MW ÷ 4 hours).

Figure 23: Uplift Cost per MWh Reserves Needed
Connecticut, October to December 2006

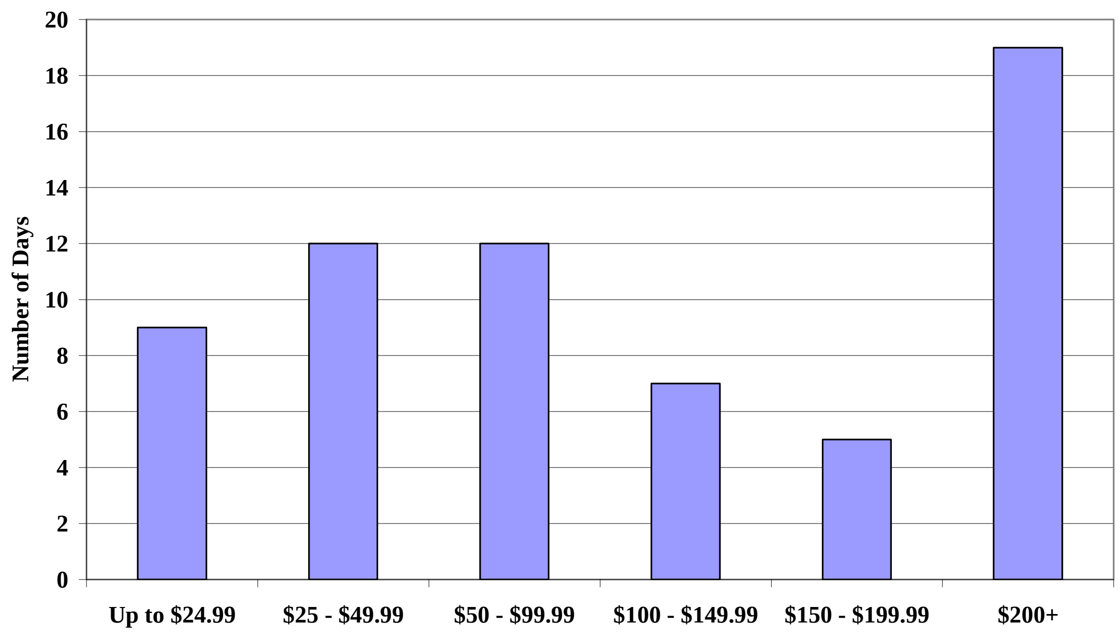


Figure 23 shows that the uplift costs from local 2nd contingency commitments per megawatt-hour of Connecticut-area reserve requirements satisfied exceeded the RCPF on nearly half of the days from October to December 2006. The figure indicates that the RCPF is set at a level that is lower than the costs routinely incurred to ensure a sufficient level of reserves in the Connecticut area.

In general, the potential risk of price spikes arising from real-time shortages is a factor that encourages LSEs and other participants to buy more in the day-ahead market. This potential should cause loads to bid-up day-ahead clearing prices. Higher day-ahead prices should, in turn, lead to additional market-based commitment in the day-ahead market and reduce the need for supplemental commitments through the RAA process. The current level of the local RCPFs limits the size of real-time price spikes to a level that appears to be lower than the true value of reserves, which is evidenced by the costs that the ISO incurs to maintain reserves. It also limits the extent to which the day-ahead reflects the need for capacity in local areas.

3. Reserve Constraint Penalty Factors – Conclusions

The previous two analyses indicate that the cost of maintaining local reserves frequently exceeds the local RCPF. This is reflected in real-time operations when the operator must take additional actions to maintain local reserves. There were a substantial number of intervals when the operator attempted to maintain reserves by imposing a proxy second contingency limit, which causes the real-time market model to import reserves. The value of reserves is also reflected in the RAA process when it is necessary to commit generators for local reliability. While generators are committed in order from least expensive to most expensive, there is no limit on the costs that can be incurred to satisfy local reserve requirements. Our analysis indicated that on many days, the NCPC costs incurred by the ISO were substantially higher than the RCPF.

A higher RCPF may more accurately reflect the value of local reserves in the real-time market and increase incentives for more market-based day-ahead commitment in the local areas. This would, in turn, reduce the need for supplemental commitment in the RAA process and shift more of the local reliability costs from NCPC payments to higher market clearing prices. To the extent that a higher RCPF would better reflect the true value of reserves, increasing the RCPF would improve market-based signals for investment in areas where local reserves are most valuable. However, the analysis in this report covers only the first three months of market operation during a relatively light load season. Hence, we recommend that the ISO continue to monitor the effects of the current local RCPFs, and determine whether the local RCPF levels are appropriate after experience is gained during the summer.

H. Locational Forward Reserve Market

Each year, the ISO holds two auctions for Forward Reserves, one for the summer capability period (the four months from June through September) and one for the winter capability period (the eight months from October through May). Suppliers that sell in the Forward Reserve auction satisfy their obligations by providing reserves in real-time from online resources or offline resources capable of starting quickly (i.e. fast-start generators). Under the ASM II project, locational requirements were added to the previously existing Forward Reserve Market. Because the cost of maintaining local reserves at reliable levels varies greatly across New England, the addition of locational requirements should significantly improve the economic signals generated by the Forward Reserves Market. This section evaluates the results of the first forward reserve auction with locational requirements and examines how suppliers satisfied their obligations in the real-time market during the first three months of operation.

1. Background on Forward Reserve Market

The ISO purchases several reserve products on behalf of load serving entities in the Forward Reserve Market auction. There two categories of forward reserve capacity: 10-Minute Non-Spinning Reserves ("TMNSR") and 30-Minute Operating Reserves ("TMOR"). The forward reserve market has five geographic zones: Boston, Southwest Connecticut, Connecticut, Rest of System (i.e. areas outside Connecticut and Boston), and the entire system (i.e. all of New England). With two exceptions, the reserve products sold in the forward reserve market are consistent with the ones sold in the real-time market. First, the forward reserve market has no requirement for 10-Minute Spinning Reserves ("TMSR"). Second, the forward reserve market has a minimum requirement for reserves in Rest of System, while there is no corresponding requirement in the real-time market. The additional reserve zone is intended to ensure that some reserves are provided outside local areas.

Forward reserves are cleared through a cost-minimizing uniform-price auction, which sets clearing prices for each category of reserves in each reserve zone. Prior to ASM II, suppliers sold forward reserves at the unit level, which required them to provide the reserves in real-time from the same unit. Suppliers now sell forward reserves at the portfolio level, allowing them the flexibility to shift where they hold the reserves on an hourly basis. The new market design also allows suppliers the flexibility to trade their obligations prior to the real-time market. The flexibility added by portfolio offers and bilateral trading enables suppliers to satisfy their obligations more efficiently.

Forward reserve obligations may be satisfied in real-time with reserves of equivalent or higher quality. When obligations are met with reserves of equivalent quality, the reserve provider receives the forward reserve payment instead of real-time market revenue based on the reserve clearing price. When obligations are met with reserves of higher quality, the reserve provider receives the forward reserve payment in addition to real-time market revenue based on the difference in clearing prices between the higher and lower quality products. For example, if Boston TMOR obligations are satisfied in the real-time market with Boston TMSR, the reserve provider will receive the forward reserve payment for Boston TMOR plus the revenue from the price difference between Boston TMSR and Boston TMOR.

2. Auction Results for Winter 2006/2007 Capability Period

The first Locational Forward Reserve Market ("LFRM") auction was held in August 2006, procuring forward reserves for the eight months from October 2006 to May 2007. The auction had the following minimum purchase requirements. The TMNSR requirement was 700 MW for the entire system. The TMOR requirements were 1,400 MW for the entire system, 910 MW in Boston, 550 MW in Southwest Connecticut, 1340 MW in Connecticut, and 798 MW in Rest of System (i.e. areas outside Connecticut and Boston). An offer of a high quality reserve product is capable of satisfying multiple requirements in the auction. For instance, one megawatt of TMNSR sold in Southwest Connecticut contributes to meeting four distinct requirements: the system-level TMNSR requirement, the system-level TMOR requirement, the Connecticut TMOR requirement, and the Southwest Connecticut TMOR requirement.

The following table summarizes the quantities purchased in the forward reserve auction towards each requirement. For each location and category of capacity, the table shows the purchase quantity as a percent of the purchase requirement. Binding reserve requirements are shown in bold.

Table 6: LFRM Procurement by Region
2006-2007 Winter Capability Period

	TMNSR Procured		TMNSR & TMOR Procured	
Location	(MW)	(As % of Req.)	(MW)	(As % of Req.)
NEMA/Boston	60	--	**317**	35%
SWCT	90	--	**394**	72%
CT (includes SWCT)	90	--	**659**	49%
ROS	566	--	**798**	100%
All New England	716	102%	1,774	127%

The table shows that the TMOR requirements were not satisfied in the three local reserve zones. When there is a shortage in the Forward Reserve auction, the clearing price for all products that can satisfy the requirement that is in shortage will be the offer-cap level of $14,000 per MW-month. All reserves sold in the constrained areas cleared at this price level, regardless of quality.

Outside of Connecticut and Boston, the forward reserve requirements were satisfied. The TMOR requirement for Rest of System was binding and the marginal offer was priced at $4,200 per MW-month. Both the TMNSR and TMOR requirements for all of New England were exceeded by the amounts sold in the auction. This occurred because the quantity of reserves sold to meet the TMOR requirements for Boston, Connecticut, and Rest of System exceeded the TMOR requirement for the all of New England by 27 percent and the TMNSR requirement for all of New England by 2 percent.

3. LFRM Obligations in the Real-Time Market

Forward reserve providers satisfy their obligations in the real-time market by designating individual resources to provide specific quantities of forward reserves in each hour from 7:00 AM to 11:00 PM, Monday through Friday. Resources designated to provide forward reserves must be fast-start units or units that are online. These resources must be capable of ramping quickly enough to provide the specified quantity of reserves in 10 minutes for TMNSR and 30 minutes for TMOR. The designated resources must offer the designated quantity of incremental energy at a minimum price level.[21] Resources designated to provide forward reserves forfeit any NCPC payments that they would otherwise receive. Forward reserve providers can arrange bilaterally for other suppliers to meet their obligations, although bilateral trading of obligations (distinct from transactions involving other products) was not significant during the first three months of operation. Suppliers that do not meet their forward reserve obligations incur a Failure to Reserve Penalty.[22]

There are several types of costs that suppliers consider when designating units to provide forward reserves. First, suppliers with forward reserve obligations face the risk of financial penalties if their resources fail to deploy during a reserve pick-up.[23] Suppliers can reduce this risk by meeting their obligations with resources that are more reliable. Second, suppliers with forward reserve obligations forego the value of those reserves in the real-time market. For instance, suppose that real-time clearing prices are $10 per MWh for TMOR and $15 per MWh for TMNSR. A supplier that has TMOR obligations would be paid $0 if scheduled for TMOR or $5 per MWh if scheduled for TMNSR. Hence, this cost is the same regardless of whether the supplier is ultimately scheduled for TMOR, TMNSR, TMSR, or energy in the real-time market.

Third, suppliers may forego profitable energy sales as a result of offering incremental energy at the Threshold Price. For instance, suppose the Threshold Price is $130 per MWh and a supplier designates a generator that has incremental costs of $80 per MWh to provide forward reserves. Because the supplier is required to offer at $130 per MWh, the supplier will not be scheduled to sell energy when the LMP is between $80 per MWh and $130 per MWh. The magnitude of this

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21 This level, known as the "Threshold Price," is equal to the monthly fuel index price posted prior to each month multipled by a constant of approximately 14.4 MMbtu per MWh. Hence, if the monthly natural gas index price is $8 per MMbtu, it would result in a Threshold Price of approximately $115 per MWh. The month fuel index price is based on the lower of the natural gas or diesel fuel index prices in dollars per MMbtu.

22 The Failure to Reserve penalty is equal to the number of megwatts not reserved times 1.5 times the Forward Reserve Payment Rate, which is the forward reserve clearing price (adjusted for capacity payments) divided by the number of obligation hours in the month.

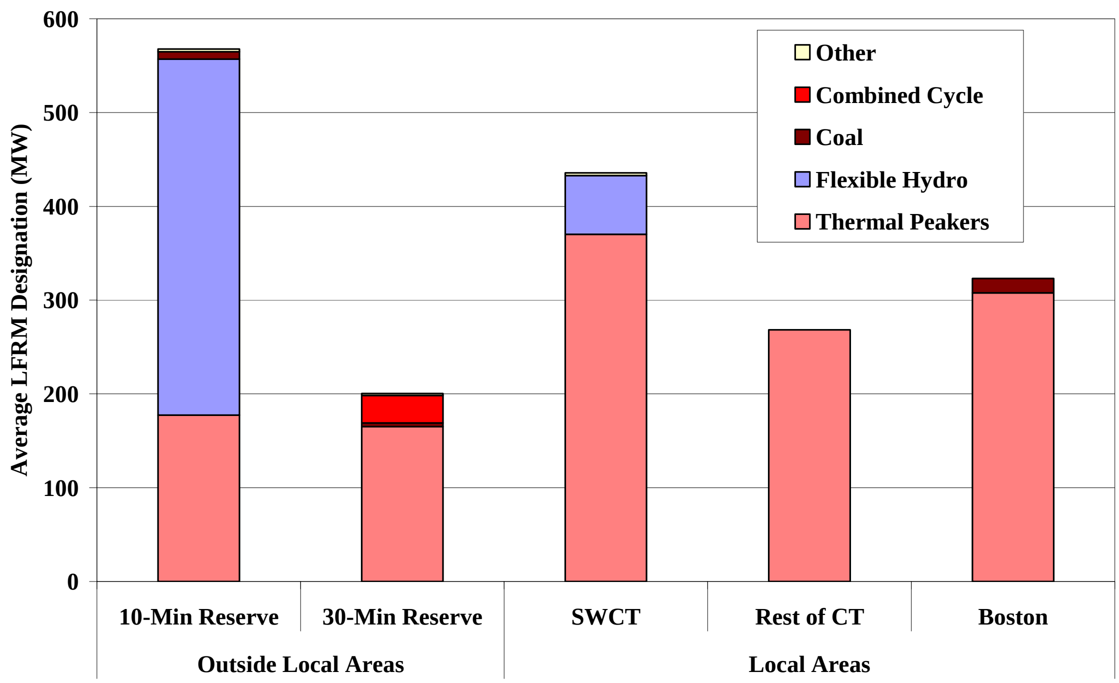
23 The Failure to Activate penalty is equal to the number of megawatts that does not respond times the sum of the Forward Reserve Payment Rate and the Failure to Activate Penalty Rate, which is 2.25 times the higher of the LMP at the generator's location or the Forward Reserve Payment Rate.

opportunity cost decreases for units that have high incremental costs (this opportunity cost is zero for units that have incremental costs greater than the Threshold Price).

The previous three cost categories may be incurred by all units that provide forward reserves, but there are additional costs that are only faced by units that must be online to provide reserves. In order to provide reserves from a non-fast start unit, a supplier may have to commit a unit that would otherwise be unprofitable to commit. When energy prices are high and the unit is profitable to operate the unit based on the energy revenues, this type of cost is zero. However, when energy prices are low, the commitment costs incurred by some units may far exceed the net revenue that they earn from the energy market. Because fast-start resources do not face this cost, it is generally most economic to meet forward reserve obligations with fast-start units.

The following analysis evaluates how market participants satisfied their forward reserve obligations during the first three months of operation under ASM II. The figure shows the average amount of reserves designated in each region by type of resource.

Figure 24: LFRM Designations by Resource Type
October to December, 2006



The figure indicates that approximately 97 percent of forward reserve obligations were satisfied by hydro and thermal peaking resources capable of providing offline reserves. In some cases, these units were online and providing energy (which is acceptable as long as they offer in accordance with the forward reserve rules). The majority of combined-cycle capacity that was designated to provide forward reserves was fast-start capacity. The frequent designation of fast-start resources to provide forward reserves confirms that it is generally more costly to provide forward reserves from non-fast-start resources.

Other than fast-start and hydro resources, coal-fired steam units were the next most commonly used type of unit used to satisfy forward reserve obligations. Coal units have two characteristics that can make them relatively efficient providers of forward reserves. First, it is nearly always economic to commit coal-fired units, so suppliers do not face significant costs from committing them uneconomically. Second, most coal-fired units have a small emergency range that they can use to provide spinning reserves. Production of energy in the emergency range is generally relatively costly so they do not incur an opportunity cost by offering a small amount of incremental energy at the Threshold Price.

In summary, the preponderance of forward reserves is provided by fast-start units as non-fast-start resources likely face much higher costs of providing forward reserves. In the first forward reserve auction with locational requirements, clearing prices in the local areas rose to the cap of $14,000 per MW-month and non-fast-start units were still not used to meet a substantial portion of the obligations. In the next sub-section, we examine the profitability of using online capacity to satisfy LFRM obligations.

4. Profitability of Satisfying LFRM Obligations with Online Capacity

In the first three months of operation under ASM II, the overwhelming majority of forward reserve obligations were met with fast-start units. In Boston and Connecticut, where fast-start resources are not sufficient to meet the locational forward reserve requirements, the LFRM auction did not meet all of the reserve requirements and the forward reserve clearing prices rose to the cap of $14,000 per MW-month. Given the lack of participation from non-fast-start units, it is reasonable to evaluate whether such units can profitably sell forward reserves.

We estimated the profits that would have been earned from meeting forward reserve obligations with a combined cycle unit, a natural gas-fired steam unit, and a diesel oil-fired steam unit. The estimates considered the revenue from forward reserve sales at $14,000 per MW-month versus (i) the opportunity cost that result from offering incremental energy at the Threshold Price, (ii) the cost of running unprofitably when the unit's commitment costs exceed the revenue from the day-ahead and real-time markets, and (iii) the value of Transition Payments not received for capacity sold in the forward reserve market. The estimates did not consider the cost of financial penalties for units that fail to respond in a reserve deployment. The results show:

- Gas-fired combined cycle units would have earned profits of $500 to $5,000 per MW-month, depending on the time of year given the seasonal variations in market clearing prices.
- Oil-fired and gas-fired steam units would not have been profitable.

The estimates assume one unit is always used to satisfy the forward reserve obligation, although it would be more efficient for a supplier to share the obligation between several types of units. On days when energy and reserve clearing prices are low, a supplier could designate combined cycle units to provide forward reserves. When energy prices are higher, the supplier could shift its obligations to higher-cost steam units. Most suppliers cannot do this because they do not have combined cycle units and steam units in the same portfolio. This suggests that liquid bilateral trading of forward reserve obligations could expand the participation in the forward reserves market by suppliers that do not own different types of units.

Although our estimates suggest that suppliers with combined cycle technology are likely to participate in the forward reserve market if clearing prices remain near $14,000 per MW-month, there are at least two factors that discourage their participation in Connecticut and Boston. First, units under reliability agreements do not have a financial incentive to participate in the forward reserve market. Hence, as these agreements expire, it is likely that participation in the forward reserve market will increase. Second, units that are frequently committed for local reliability and receive substantial NCPC payments have disincentives to provide forward reserves because they would be required to forgo the NCPC payments. Hence, increases in the forward reserve cap or changes that would reduce the need for supplemental commitment could potentially expand participation in the forward reserve market. Until the non-fast start resources that are frequently committed for local reliability participate in the forward reserve market, this market will not likely reduce the supplemental commitments and NCPC costs as was envisioned.

VII. Competitive Assessment

This section evaluates the competitive performance of the New England wholesale markets in 2006. 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 inadequate generation resources or insufficient transmission capability. We identify 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 New England markets.[24] In this section we address four main areas:

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

In addition, we report on our examination of market performance during record load conditions on August 1st and 2nd, during which energy market prices reached $1000 MWh for 8 hours. Such high load conditions may present suppliers with incentives to exercise market power.

A. Market Power and Withholding

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

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24 See, *e.g.*, *2004 Assessment of the Electricity Markets in New England*, *2002 Competitive Assessment of the Energy Market in New England*, and *2001 Competitive Assessment of the Energy Market in New England*.

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 overwhelms the opportunity cost of lost sales for the supplier. The larger a supplier is relative to the market, the more likely it is that the supplier will have the incentive to withhold resources to raise prices.

Other than the size of the market participant, there are several additional factors that affect whether a market participant has market power. First, if a supplier has already sold power in a forward market, then it will not be able to sell that power at an inflated clearing price in the spot market. Thus, forward power sales by large suppliers reduce their incentive to raise price in the spot market. Second, the incentive to withhold partly depends on the impact the withholding is expected to have on clearing prices. The nature of electricity markets is that when demand levels are high, a given quantity of withholding has a larger price impact than when demand levels are lower. Thus, large suppliers are more likely to possess market power during high demand periods than at other times.

Third, in order to exercise market power, a large supplier must have sufficient information about the physical conditions of the power system and actions of other suppliers to know that the market may be vulnerable to withholding. Since no supplier has perfect information, the conditions that give rise to market power (e.g., transmission constraints and high demand) must be reasonably predictable. The next section defines market conditions where certain suppliers possess market power.

B. Structural Market Power Indicators

The first step in a market power analysis is to define the relevant market, which includes the definition of a relevant product and the relevant geographic market where the product is traded. Once the market definition is established, it is possible to assess conditions where one or more large suppliers could profitably raise price. This sub-section of the report examines structural aspects of supply and demand affecting market power. We examine the behavior of market participant in later sections.

1. Defining the Relevant Market

Electricity is physically homogeneous, so each megawatt of electricity is interchangeable even though the characteristics of the generating units that produce the electricity vary substantially (*e.g.*, electricity from a coal-fired plant is substitutable with electricity from a nuclear power plant). Despite this physical homogeneity, the definition of the relevant product market is affected by the unique characteristics of electricity. For example, it is not generally economic to store electricity, so the market operator must continuously adjust suppliers' output to meet demand in real time. The lack of economic storage options limits inter-temporal substitution between spot and forward electricity markets.

In defining the relevant product market, we must identify the generating capacity that can produce the relevant product. In this regard, we consider two categories of capacity: (i) on-line and quick start capacity available for deployment in the real-time spot market, and (ii) off-line non-quick start capacity available for commitment in the next 24-hour timeframe. While only the former category is available to compete in the real-time spot market, both of these categories compete in the day-ahead market, making the day-ahead market less susceptible to market power. In general, forward markets are less vulnerable to market power because buyers can defer purchases if they expect prices to be lower in the spot market. The market is most vulnerable to the exercise of market power in the real-time spot market, when only on-line and fast-start capacity is available for deployment. The value of energy in all other forward markets, including the day-ahead market, is derived from the value of energy in the real-time market. Hence, we define the relevant product as energy produced in real time for our analysis.

The second dimension of the market to be defined is the geographic area in which suppliers compete to sell the relevant product. In electricity markets, the relevant geographic market is generally defined by the transmission network constraints. Binding transmission constraints limit the extent to which power can flow between areas. When constraints are binding, a supplier within the constrained geographic area faces competition from fewer suppliers. There are a small number of geographic areas in New England that are generally recognized as being persistently constrained and therefore restricted at times from importing power from the rest of New England. When these areas are transmission-constrained they constitute distinct geographic markets that must be analyzed separately. These geographic markets are:

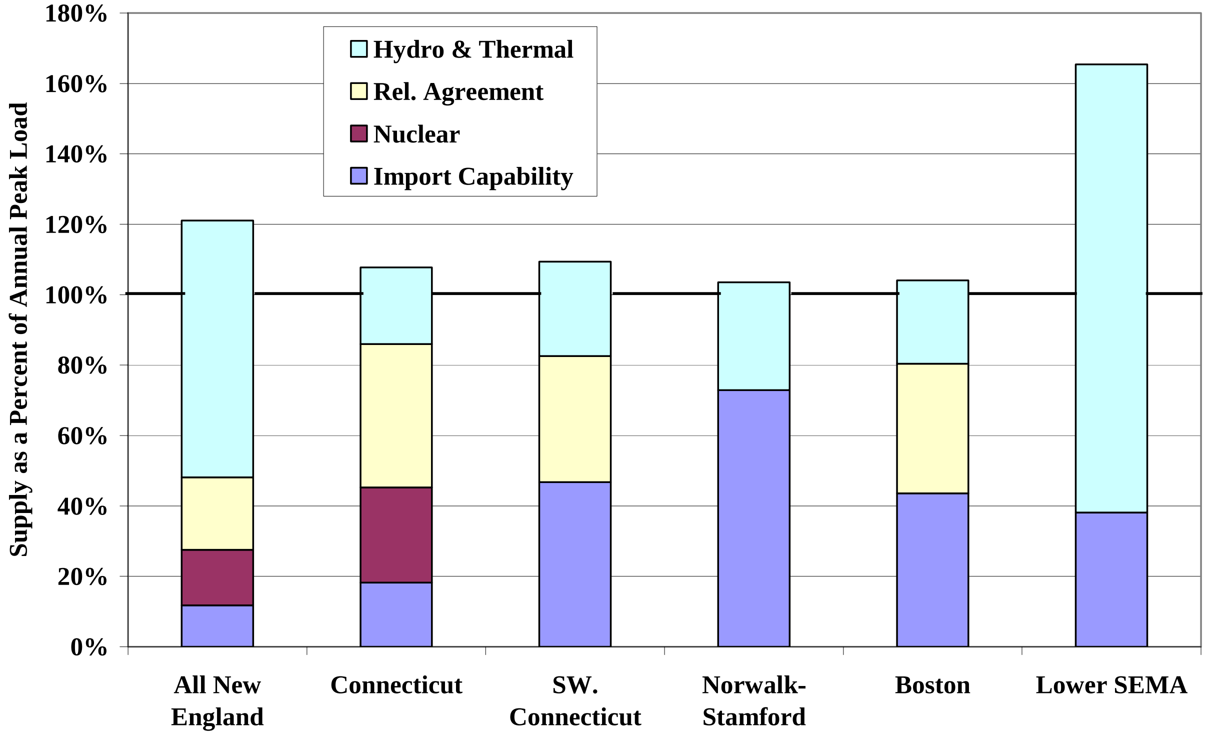
- All of New England;
- All of Connecticut;
- The southwest portion of Connecticut;
- The Norwalk-Stamford area within southwest Connecticut;
- NEMA/Boston; and
- Lower Southeast Massachusetts.

2. Installed Capacity in Geographic Markets

This section provides a summary of supply resources and market shares in the geographic submarkets identified above. Each market can be served by a combination of native resources and imports. Native resources are limited by the physical characteristics of the generators in the area, while imports are limited by the transfer capability of the transmission grid. Figure 25 shows several categories of supply relative to the load in each of the six regions of interest.

For each region, Figure 25 shows import capability and three categories of installed summer capability: (i) nuclear units, (ii) units with reliability agreements, and (iii) all other generators. These resources are shown as a percentage of 2006 peak load, although a substantial quantity of additional capacity (typically more than 1800 MW) is also necessary to maintain operating reserves in New England. The figure shows that while imports can be used to satisfy 12 percent of the load in the New England control under peak conditions, the five load pockets can serve larger shares of their peak load with imports. Norwalk-Stamford, which has the largest import capability relative to its size, can rely on imports to serve more than 70 percent of its load under peak conditions.

Figure 25: Supply Resources versus Summer Peak Load in Each Region
2006



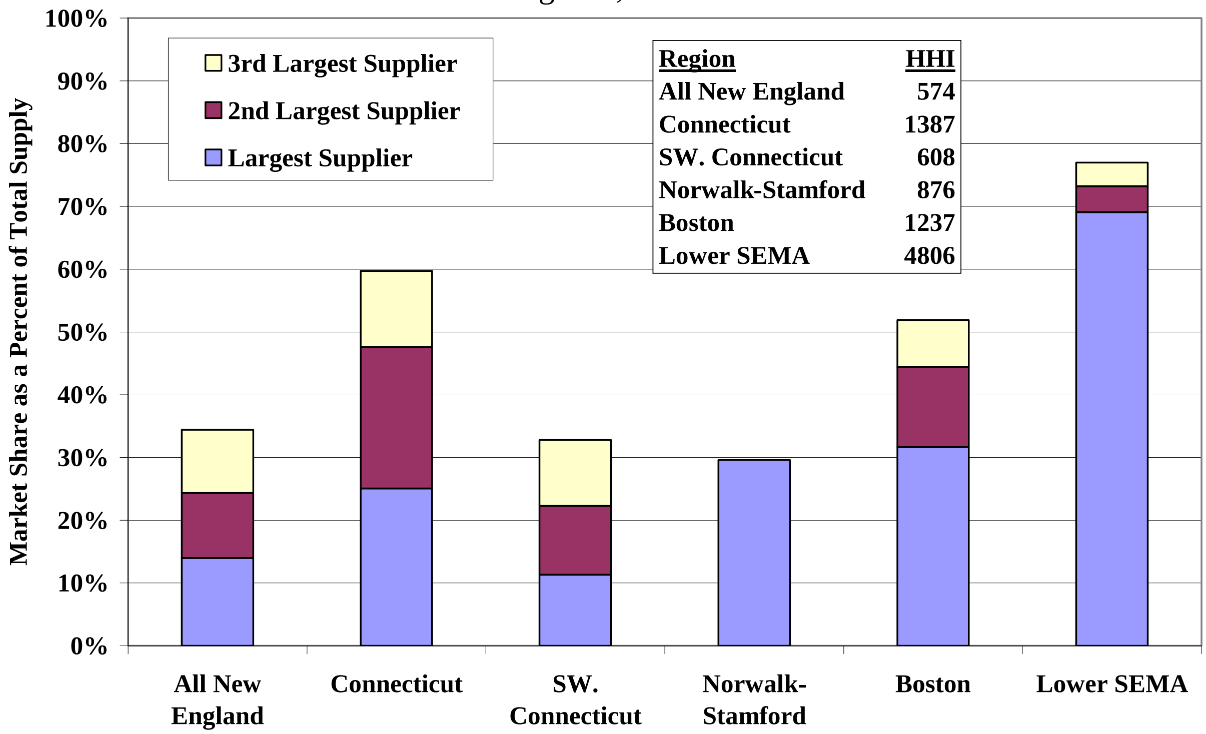
The figure also shows the margin between peak load and the total available supply, including both imports and native resources. Areas with lower margins may be more susceptible to withholding than other areas. For example, the total supply able to serve Norwalk-Stamford exceeds the annual peak load by only 3.5 percent, and supply serving NEMA/Boston exceeds the annual peak by just 4 percent. Thus, even a small reduction in supply or import capability in these areas can lead to a shortage under peak conditions.

Internal generation is shown separately for nuclear capacity and capacity under reliability agreements because these resources are likely to pose fewer market power concerns. In order to exercise market power successfully in an electricity market, it is important to be able to withhold capacity only at times when it will be profitable because the lost revenue on withheld units can be very costly. Nuclear generators cannot be dispatched up and down in a way that would allow the owner of the unit to profitably withhold. Thus, the owner of nuclear generation would have to also own significant amounts of non-nuclear capacity that could be withheld from the market. Units with reliability agreement contracts are obligated to offer their units at short-run marginal costs on a daily basis which makes it unlikely that such units could be used to economically withhold. The short-run marginal costs are reviewed by the ISO's internal Market Monitoring department and are monitored on an on-going basis daily by that department using agreed-to fuel indices.

While it is possible for a market participant to physically withhold a unit that is under a reliability agreement, the fixed cost payments will decrease if the unit fails to meet their target available hours as specified in the reliability agreement. Suppliers may have an incentive to report availability greater than actually exists. While units may report themselves as available when in fact they are not in order to avoid a reduction to their target available hours, if the units are called upon during such a period, the supplier incurs a significant non-performance penalty. The target availability hours provisions of a reliability agreement, in conjunction with the non-performance penalties set out in those agreements, provide a substantial disincentive to inaccurately report the unit's availability status, or to withhold the unit. Areas within Connecticut rely heavily on nuclear and units under reliability agreements, which reduces the quantity of capacity that may be withheld to exercise market power.

The previous figure shows that the capacity margins can be as low as 3.5 percent in some areas. Market power is generally of greater concern in areas where capacity margins are small. However, the extent of market power also depends on the market shares of the largest suppliers. For each region, Figure 26 shows the market shares of the largest three suppliers coinciding with the annual peak load hour on August 2, 2006. The remainder of supply to each region comes from smaller suppliers and import capability. We also show the Herfindahl-Hirschman Index ("HHI") for each region. The HHI is a standard measure of market concentration calculated by summing the square of each participant's market share. In our analysis, we assume imports are highly competitive by treating the market share of imports as zero in the HHI calculation. For example, in a market with two suppliers and import capability, all of equal size, the HHI would be close to 2200 $[(33\%)^2 + (33\%)^2 + (0\%)^2]$. This assumption will tend to understate the true level of concentration because, in reality, the market outside of the area will not be perfectly competitive.

Figure 26: Installed Capacity Market Shares for Three Largest Suppliers
August 2, 2006



The figure indicates a substantial variation in market structure across New England. The largest suppliers have market shares ranging from 14 percent in all New England and 11 percent in Southwest Connecticut, to 69 percent in Lower Southeast Massachusetts. Likewise, there is variation in the number of suppliers that have significant market shares. For instance, Norwalk-Stamford had only one native supplier in the summer of 2006, while the top three suppliers in Southwest Connecticut had virtually equal market shares.

The HHI figures suggest that only Lower Southeast Massachusetts is highly concentrated.[25] The HHI for Norwalk-Stamford is low, 876, which is counter-intuitive since there is only one supplier and there is a very low excess capacity margin in the area. However, because 70 percent of the load can be served by imports, the only supplier possesses a 30 percent market share. Of the remaining areas, Connecticut and NEMA/Boston have the highest HHI statistics with 1387 and 1237, respectively.

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

While HHI statistics can be instructive in generally indicating the concentration of the market, it does not allow one to draw reliable conclusions regarding potential market power in wholesale electricity markets due to the special nature of the electricity markets. In particular, it does not consider demand conditions, load obligations, or the heterogeneous effects of generation on transmission constraints based on their location. In the next sub-section, we introduce a "pivotal supplier analysis," which is more reliable for evaluating market power in electricity markets.

3. Pivotal Supplier Analysis

While HHI statistics can provide reliable competitive inferences for many types of products, this is not generally the case in electricity spot markets.[26,27] The HHI's usefulness is limited by the fact that it reflects only the supply-side, ignoring demand-side factors that affect the competitiveness of the market. The most important demand-side factor is the level of load relative to available supply-side resources. Since electricity cannot be stored economically, production must match demand on a real-time basis. When demand rises, an increasing quantity of generation is utilized to satisfy the demand, leaving less supply that can respond by increasing output if a large supplier withholds resources. Hence, markets with higher resource margins tend to be more competitive, which is not recognized by the HHI statistics.

A more reliable means to evaluate the competitiveness of spot electricity markets and recognize the dynamic nature of market power in these markets is to identify when one or more suppliers are "pivotal". A supplier is pivotal when the output of some of its resources is needed to meet demand in the market. A pivotal supplier has the ability to unilaterally raise the spot market prices to arbitrarily high levels by offering its energy at a very high price level. Hence, the market may be subject to substantial market power abuse when one or more suppliers are pivotal and they have the incentive to take advantage of their position to raise prices. The Federal

26 It is true that the DOJ and FTC evaluate the *change* in HHI as part of its merger analysis. However, this is only a preliminary analysis that would typically be followed by a more rigorous simulation of the likely price effects of the merger. It is also important to note the HHI analysis employed by the antitrust agencies is not intended to determine whether a supplier has market power.

27 For example, see Severin Borenstein, James B. Bushnell, and Christopher R. Knittel, "Market Power in Electricity Markets: Beyond Concentration Measures," *Energy Journal* 20(4), 1999, pp. 65-88.

Energy Regulatory Commission has adopted a form of pivotal supplier test as an initial screen for market power in granting market-based rates.[28] This section of the report identifies the frequency with which one or more suppliers were pivotal in various areas within New England during the study period.

Even small suppliers can be pivotal for brief periods. For example, all suppliers are pivotal during periods of shortage. This does not mean that all suppliers should be deemed to have market power. As described above, suppliers must have both the *ability* and *incentive* to raise prices 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.

To identify the areas where market power is a potential concern most frequently, Figure 27 shows the portion of hours where at least one supplier was pivotal in each region during 2006. The figure also shows the impact of excluding nuclear units and units under reliability agreements from the analysis. As discussed above, such units are unlikely to be engaged in economic or physical withholding.

Including all capacity, the pivotal supplier analysis raises substantial concerns regarding four of the five load pockets shown in Figure 27. The only area that does not raise potential concerns is Southwest Connecticut, where the ownership of capacity is much less concentrated than the other load pockets. Potential local market power concerns are most acute in Lower SEMA,[29] where one supplier owns nearly 90 percent of the capacity.

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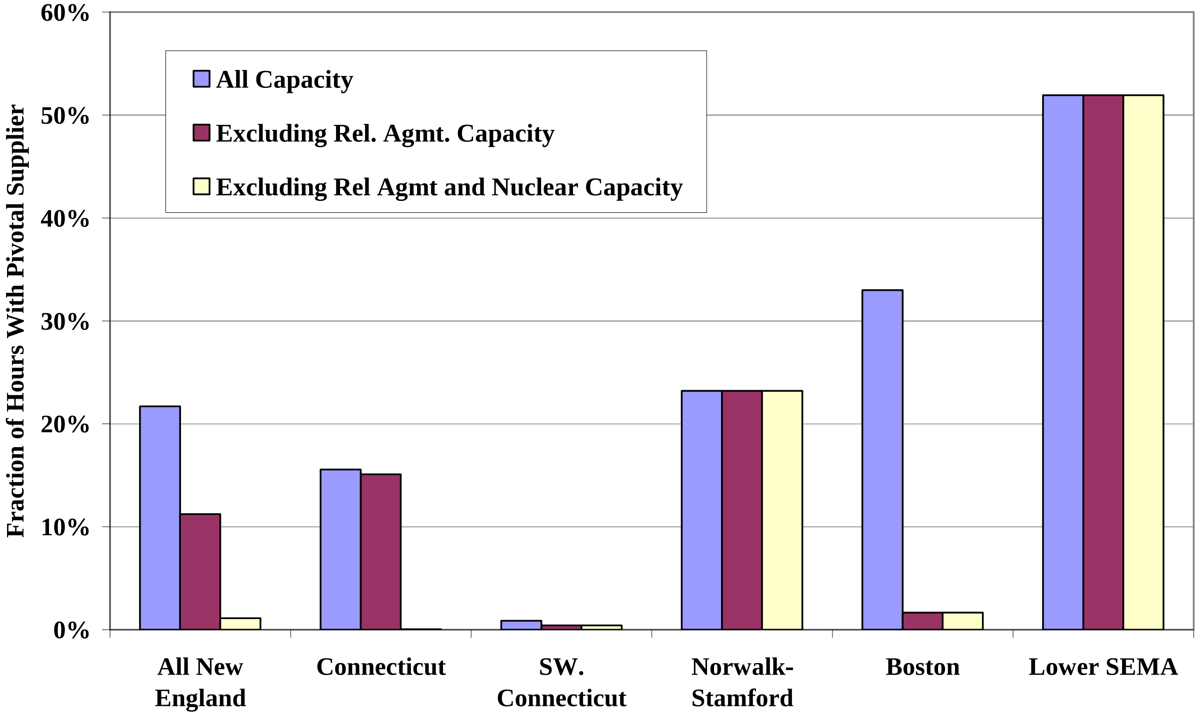
28 The FERC test is called the "Supply Margin Assessment". For a description, see: Order On Rehearing And Modifying Interim Generation Market Power Analysis And Mitigation Policy, 107 FERC ¶ 61,018, April 14, 2004.

29 Lower SEMA data shown only reflects the period from October 1 through December 31, 2006. Prior to that time congestion into the Lower SEMA area was not managed with transmission constraints in the real-time dispatch model, which would eliminate the potential gains from strategic withholding.

Figure 27: Frequency of One or More Pivotal Suppliers by Type of Withheld Capacity
All Hours – 2006



Note: Lower SEMA includes only the period from October to December 2006.

Boston exhibited the second-highest pivotal supplier frequency, however most of the largest supplier's capacity in Boston was under a reliability agreement during 2006. As a result, the pivotal supplier frequency for Boston decreases dramatically when we exclude capacity under reliability agreements. This limits potential market power concerns in Boston to a relatively narrow (but still significant) set of hours.

Although Connecticut had a pivotal supplier in 16 percent of the hours in 2006, the largest supplier in Connecticut owns only nuclear capacity. In order to exercise market power, the largest supplier would need to withhold from non-nuclear resources in order to raise the clearing prices paid for its nuclear production.[30] Therefore, it is appropriate to exclude the nuclear capacity from the pivotal supplier frequency for Connecticut, which leaves no hours with pivotal suppliers in Connecticut.

30 Assuming that the supplier cannot reduce its nuclear output substantially without taking a unit out of service.

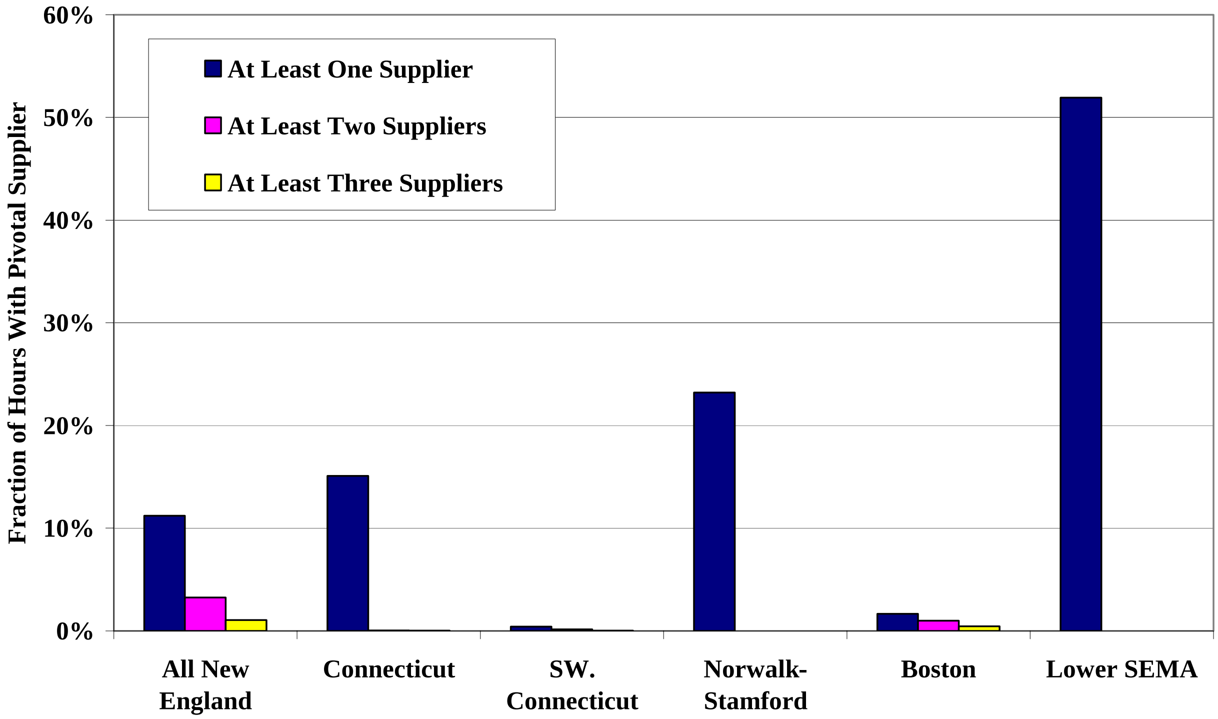
The extent of market power for the entirety of New England depends on how reliability agreements and nuclear capacity affect the incentives of large suppliers. Excluding reliability agreement capacity from the pivotal supplier analysis reduces the pivotal frequency from 22 percent to 11 percent of the hours in 2006. Further, excluding nuclear capacity would reduce the pivotal frequency to just one percent of hours. However, the rationale for excluding nuclear capacity from the analysis does not apply to the largest suppliers in New England. These suppliers have large portfolios with a combination of nuclear and non-nuclear capacity, and while they are not likely to physically withhold their nuclear capacity from the market, their nuclear capacity would earn more revenue if they withheld their non-nuclear capacity. Accordingly, New England as a whole warrants further review.

The pivotal supplier summary indicates the greatest potential for market power in Lower SEMA and Norwalk-Stamford. In addition to having amongst the highest pivotal supplier frequencies of any areas, the suppliers in these areas own no capacity covered by reliability agreements or nuclear capacity. Therefore, the pivotal supplier results are the same for all three scenarios. Therefore, we focus particular attention on these areas in this section.

A close examination is also warranted for all of New England, and Boston might be a concern under extremely tight demand conditions. The market shares in Figure 26 indicate that there are areas with several dominant suppliers, suggesting that during certain periods, several suppliers might be pivotal simultaneously. Figure 28 shows the number of pivotal suppliers during hours when one or more supplier is pivotal in each region.

The frequencies shown in Figure 28 are the same as those in the previous figure. But this figure also shows the frequency with which two or three suppliers were pivotal in a single hour. In the five load pockets, it is very uncommon for more than one supplier to be pivotal at the same time. In the case of Connecticut, the only pivotal supplier owns exclusively nuclear capacity, which is not expected to provide that supplier with an incentive to withhold. In All New England, the second-largest supplier was pivotal much less often than the largest.

Figure 28: Frequency of One or More Pivotal Suppliers
Excluding Capacity under Reliability Agreements -- All Hours in 2006



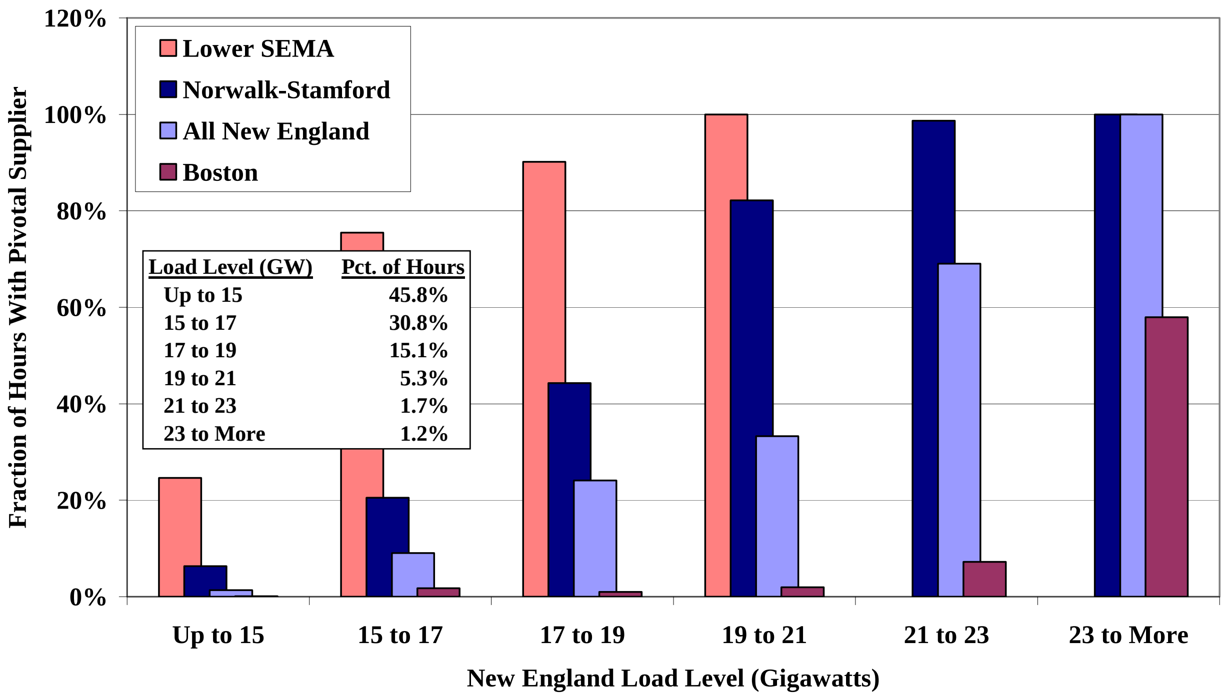
*Lower SEMA data only from the period October – December, 2006.

Since the relevant market includes capacity able to serve demand in the real-time market, it excludes non-fast-start capacity that is off-line. Thus, there will be some variation in the market shares on a daily basis due to differences in the unit commitments. However, there was little variation in the identity of the largest supplier in each area under most conditions in 2006. Therefore, each area had a single supplier that was most likely to have market power. Accordingly, the next sub-section will closely examine the behavior of the largest single supplier for each load pocket and the two largest suppliers for all of New England.

As described above, market power tends to be more prevalent as the level of demand grows. In order to strategically withhold, a dominant supplier must be able to reasonably foresee its opportunities to raise prices. Since load levels are relatively predictable, a supplier with market power could focus its withholding strategy on periods of high demand.

To assess when withholding is most likely to be profitable, Figure 29 shows the fraction of hours when a supplier is pivotal at various load levels. The bars in each load range show the fraction of hours when a supplier was pivotal in Lower SEMA, Norwalk-Stamford, All New England, and NEMA/Boston. The bars are arranged according to the frequency with which a supplier is pivotal. For example, Lower SEMA on the left had the highest frequency of a supplier being pivotal and is, therefore, shown on the far left. Southwest Connecticut and Connecticut are not shown because there was very little congestion on the interfaces into these areas and infrequent instances of a supplier being pivotal during 2006. Lower SEMA is analyzed only for the period from October to December 2006 because the constraints into that area were not modeled prior to October. In the timeframe studied for Lower SEMA, there were no hours with load higher than 21 GW. Hence, no bars are shown for Lower SEMA at the highest load levels.

Figure 29: Frequency of One or More Pivotal Suppliers by Load Level
Excluding Capacity under Reliability Agreements – 2006



*Lower SEMA data only from the period October – December, 2006.

Figure 29 indicates that the largest supplier in Lower SEMA was pivotal in every hour in which the load exceeded 19 GW in New England, and in almost 80 percent of all hours in which load was greater than 15 GW in New England. Even in hours in which load falls below 15 MW system-wide, in nearly 25 percent of the hours Lower SEMA had a single supplier that is pivotal for the market.

The analysis indicates less potential for market power in the other three areas. The supplier in Norwalk-Stamford was pivotal in the majority of hours when the load exceeded 19 GW in New England. In all of New England, the largest supplier was pivotal in each of the hours when load exceeded 23 GW, and the majority of hours when load exceeded 21 GW.

In NEMA/Boston, a supplier was pivotal in just 7 percent of hours when load ranged from 21 to 23 GW, but the majority of hours when load exceeded 23 GW. In Boston, the largest supplier is different from the largest supplier of capacity that is not covered by reliability agreements. Nonetheless, our analyses in the next section still focus on the largest supplier overall, because that supplier was pivotal in the real-time most frequently. Reliability agreements for resources in NEMA/Boston greatly reduce the number of hours in which the largest supplier is pivotal at lower load levels. This suggests that the potential for market power in Boston will increase greatly in 2007 due to the expiration of the largest supplier's reliability agreement with ISO.

Based on the pivotal supplier analysis in this sub-section, market power is most likely to be a concern in Lower SEMA at all load levels, in Norwalk-Stamford and in All of New England when New England load is relatively high (e.g., greater than 17 GW), and in NEMA/Boston when load rises to super-peak levels (e.g., above 23 GW). The following sections examine the behavior of pivotal suppliers under various load conditions to assess whether the behavior has been consistent with competitive expectations.

C. Economic Withholding

Economic withholding occurs when a supplier raises its offer prices substantially above competitive levels to raise the market price. Therefore, an analysis of economic withholding requires a comparison of actual offers to competitive offers.

Suppliers lacking market power maximize profits by offering resources at marginal costs. A generator's marginal cost is the incremental cost of producing additional output, including inter-temporal opportunity costs, incremental risks associated with unit outages, fuel, additional

O&M, and other incremental costs attributable to the incremental output. For most fossil-fuel resources, marginal costs are closely approximated by their variable production costs (primarily fuel inputs, labor, and variable operating and maintenance costs). However, at high output levels or after having run long periods without routine maintenance, outage risks and expected increases in O&M costs can create substantial additional incremental costs. Generating resources with energy limitations, such as hydroelectric units or fossil-fuel units with output restrictions as a result of environmental considerations, must forego revenue in a future period when they produce in the current period. These units incur an inter-temporal opportunity cost associated with producing that can cause their marginal costs to be much larger than their variable production costs.

Establishing a proxy for units' marginal costs as a competitive benchmark is a key component of this analysis. This is necessary to determine the quantity of output that is potentially economically withheld. The ISO's Internal Market Monitoring Unit calculates generator cost reference levels pursuant to Attachment A of Section III of the ISO's Tariff. These reference levels are used as part of the market power mitigation measures and are intended to reflect the competitive offer price for a resource. The Internal Market Monitoring Unit has provided us with cost reference levels, which can be used as one competitive benchmark for our analysis of economic withholding.[31]

1. Measuring Economic Withholding

We measure 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. 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. Therefore, the output gap for any unit would generally equal:

31 In the case of one unit, variable cost estimates were used instead of the reference level because the reference level substantially understated the unit's marginal costs.

$Q_i^{econ} - Q_i^{prod}$ when greater than zero, where:

Q_i^{econ} = Economic level of output for unit i; and

Q_i^{prod} = Actual production of unit i.

To estimate Q_i^{econ}, the economic level of output for a particular unit, it is necessary to evaluate all parts of the unit's three-part reference level: start-up cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time. We employ a three-stage process to determine the economic output level for a unit in a particular hour. In the first stage we examine whether the unit would have been economic *for commitment* on that day if it had offered its at marginal costs – i.e., whether the unit would have recovered its actual start-up, no-load, and incremental costs running at the dispatch point dictated by the prevailing LMP (constrained by its EcoMin and EcoMax) for its minimum run time. If a unit was economic for commitment, we then identify the set of contiguous hours during which the unit was economic to have online. Finally, we determine the economic level of incremental output in hours when the unit was economic to run. In all three steps, the marginal costs assumed for the generator are the reference levels for the unit used in the ISO's mitigation measures plus a threshold.[32]

In hours when the unit was not economic to run and on days when the unit was not economic for commitment, the economic level of output was considered to be zero. To reflect the timeframe in which commitment decisions are actually made, this assessment is based on day-ahead market outcomes for non-quick start units, and based on real-time market outcomes for quick start units.

Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some adjustments are necessary to estimate the actual output gap because some units are dispatched at levels lower than their three-part offers would indicate. This can be due either to transmission constraints, reserve considerations, or changes in market conditions between the time when unit

32 For incremental energy offers, the thresholds are $25/MWh or 50 percent of the reference level. For no-load and start-up offers, the threshold is 25 percent of the reference level.

commitment is performed and real-time. Therefore, we adjust Q_i^{prod} upward to reflect three-part offers that would have made a unit economic to run, even though the unit may not have been fully dispatched. For example, if the ISO manually reduces the dispatch of an economic unit, the reduction in output is excluded from the output gap. Hence the output gap formula used for this report is:

$Q_i^{econ} - \max(Q_i^{prod}, Q_i^{offer})$ when greater than zero, where:

Q_i^{offer} = economic output level of i based on its offer and the clearing price.

By using the greater of actual production or the output level offered at the clearing price, units whose ramp limitations are binding are excluded from the output gap. In addition, portions of resources that are offered above marginal costs due to a forward reserve market obligation are not included in the output gap.

It is important to recognize that the output gap will tend to overstate the amount of potential economic withholding because some of the offers that are included in the output gap may reflect legitimate operating conditions, risks, or preferences of the unit's owner. Hence, we generally seek to evaluate trends in the output gap results that would indicate significant attempts to exercise market power rather than changes in the legitimate factors that may produce changes in the output gap.

The output gap may also overstate the amount of economic withholding because it can include suppliers that do not have market power, but are raising their offer prices due to the pay-as-bid incentives provided by NCPC. If a unit is uneconomic at its offer price in the day-ahead market, but required to run for reliability, it is guaranteed payment of its full offer price. Participants expecting a resource to be committed for reliability have incentives to raise the offer prices of such units above marginal cost and contribute to the output gap. In some cases, the supplier may face competition from many other suppliers and, therefore, may simply be attempting to receive the full market value for this reliability service. Full market value in this context reflects the marginal system cost incurred by the ISO to satisfy the reliability requirement. In other cases, the supplier may face little or no competition and this conduct may reflect economic withholding. Below we examine additional data to distinguish between economic withholding and conduct that may be considered competitive.

In this section we evaluate the output gap results relative to various market conditions and participant characteristics. The objective is to determine whether the output gap increases when those factors prevail that can create the ability and incentive for a pivotal supplier to exercise market power. This allows us to test whether the output gap varies in a manner consistent with attempts to exercise market power. Based on the pivotal supplier analysis from the previous sub-section, the level of market demand is a key factor in determining when a dominant supplier is most likely to possess market power in some geographic market. In this section, we examine output gap results for the following four geographic markets:

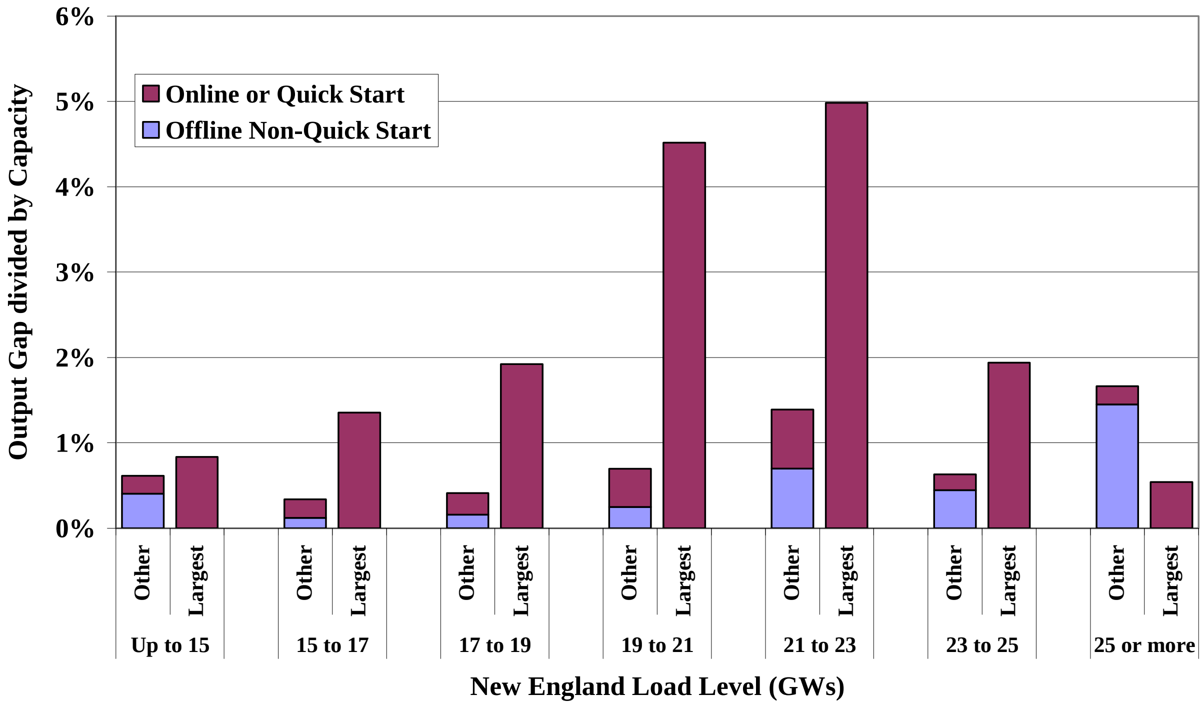
- NEMA/Boston;
- Lower SEMA;
- Connecticut, focusing on Norwalk-Stamford; and
- All of New England.

2. Output Gap in NEMA/Boston

Figure 30 shows output gap results for the NEMA/Boston area by load level. Based on the pivotal supplier analysis in the previous sub-section, the largest supplier can expect that its non-reliability agreement capacity is pivotal in most hours when load exceeds 23 GW. Output gap statistics are shown for this supplier compared with all other suppliers in the area.

Two aspects of Figure 30 raise potential concerns. First, the output gap of the largest supplier in Boston is substantially higher than the output gap of other suppliers under nearly all conditions. Second, the output gap of the largest supplier rises with load up to 23 GW. However, one fact that diminishes market power concerns is that the output gap of largest supplier declines at the highest load levels. The largest output gap values occurred in hours when load ranged from 19 to 23 GW, hours when the non-reliability agreement capacity of the largest supplier was almost never pivotal. Nevertheless, the results of Figure 30 warrant additional evaluation.

Figure 30: Average Output Gap by Load Level and Type of Supplier
NEMA/Boston – 2006



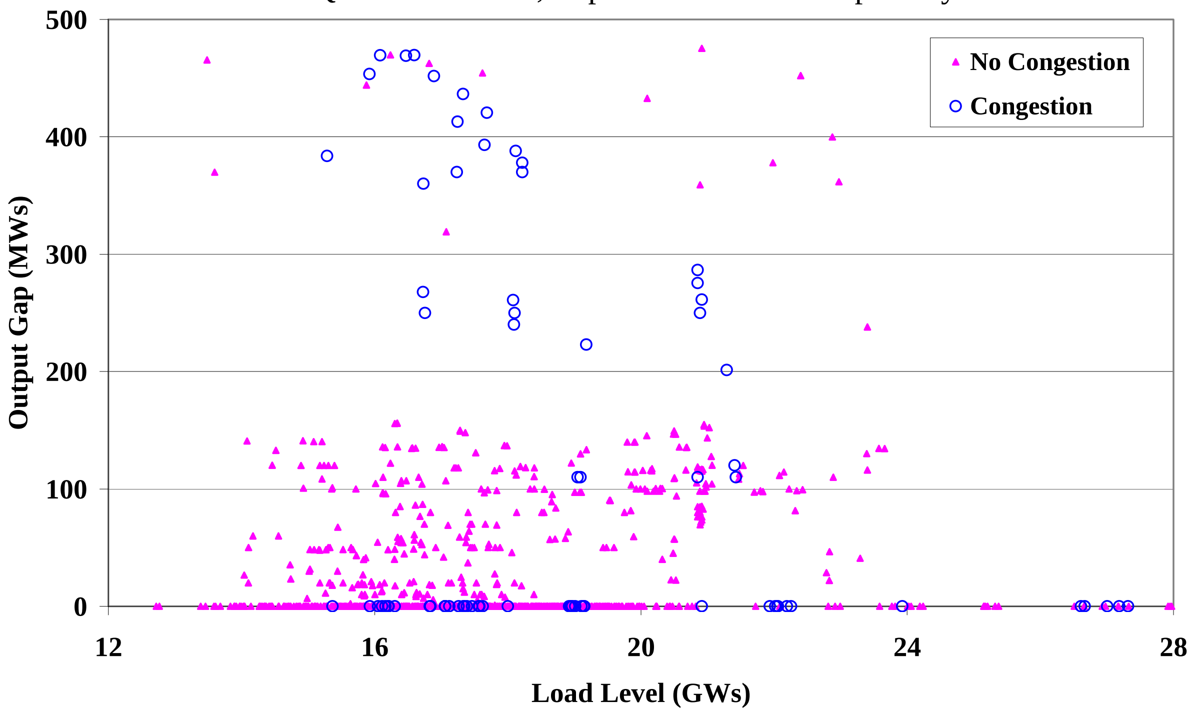
The output gap of the largest supplier was associated with one generator that was frequently committed for local reliability reasons. The fact that the supplier increased its offer prices (contributing to the output gap results reported in this section) is consistent with the "pay-as-bid" incentives that a supplier faces when it receives compensation based primarily on its offer price instead of the market-clearing price. Even in pay-as-bid markets that are perfectly competitive, firms with no market power will rationally raise their offer above marginal costs. Although offers by competitive suppliers in pay-as-bid markets will rise above marginal costs, one cannot conclude that all increases in offer prices by suppliers that face pay-as-bid incentives are competitive. To the extent suppliers hold resources needed to meet local reliability requirements, they may have local market power that can be exercised by inflating the NCPC payments that they receive when committed for reliability.

Because the output gap could indicate an attempt to exercise market power by raising prices or an attempt to increase NCPC payments, the next analysis is intended to distinguish between strategies. In particular, it is useful to analyze the conditions under which the conduct occurred.

A strategy to increase uplift payments is likely to be effective under a variety of market conditions whereas a strategy to raise clearing prices is likely to be profitable only during periods of NEMA/Boston area congestion under high load conditions.

The following analysis examines the correlation between the load levels in New England and the output gap of the largest supplier, while separately indicating hours with congestion into NEMA/Boston. Figure 31 shows the output gap associated with on-line and quick start units of the largest supplier on an hourly basis for the highest three load hours of each day. Hours with real-time congestion into NEMA/Boston are denoted with open dots, while the remaining days are shown with solid triangles.

Figure 31: Hourly Output Gap of Largest Supplier in NEMA/Boston versus Load
On-Line and Quick Start Units, Top Three Load Hours per Day – 2006



There was congestion into Boston in 7 percent of the hours shown in Figure 31. There were 8 hours with congestion into Boston when the largest supplier's online units had an output gap of more than 400 MW, and another 18 congested hours in which the largest supplier's online units had an output gap of between 200 to 400 MW. While the output gap may have had a substantial price impact in these hours, the pattern of behavior is consistent in congested and uncongested hours.

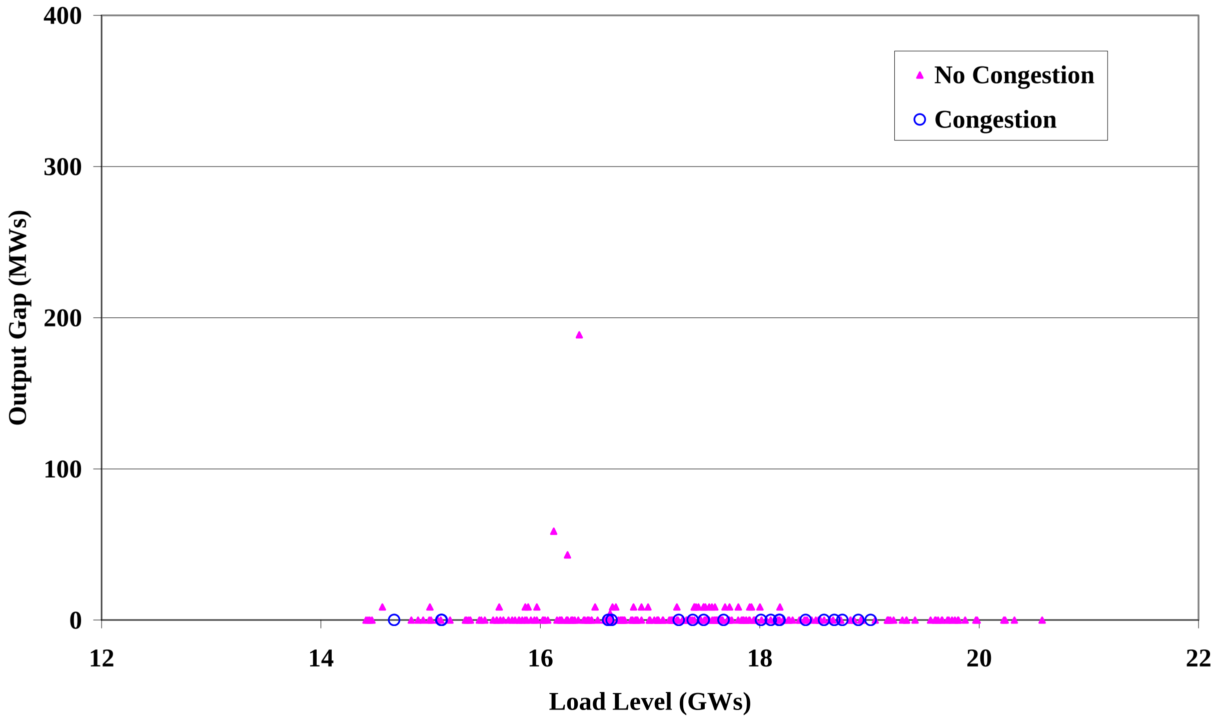
The pivotal supplier analysis from the previous sub-section indicates that the largest supplier was almost never pivotal when load was below 23 GW. However, the figure shows that the most significant output gap quantities that coincided with congestion occurred when load was between 16 GW and 18 GW. Moreover, the output gap was never significant when load exceeded 21 GW and there was congestion into Boston. If the output gap indicated an attempt to exercise market power by raising prices in the area, we would expect to see it concentrated at higher load levels and primarily occurring in congested hours.

The output gap shown in Figure 31 was associated with a single non-reliability agreement generator in the largest supplier's portfolio. This generator is frequently committed for reliability and received real-time NCPC payments on *all* of the days when it had a non-zero output gap in the presence of congestion. Therefore, the output gap is likely explained by the pay-as-bid incentives faced by any supplier whose unit is frequently committed for reliability. However, this still raises concerns about market efficiency, because pay-as-bid incentives result in substantial inefficiencies in LMP markets. LMP markets, like other types of uniform price auctions, are most efficient when suppliers have incentives to offer at marginal cost. To the extent that a supplier may not face competition to satisfy a local reliability requirement, the market power mitigation measures are designed to remedy attempts to inflate an NCPC payment by raising the offer prices for a unit.

3. Output Gap in Lower SEMA

The pivotal supplier analysis in the previous section indicated that the largest supplier in Lower SEMA was pivotal in the majority of hours from October to December 2006. The following analysis examines output gap patterns to determine whether there is evidence of economic withholding. Figure 32 shows the output gap identified in the Lower SEMA during the three highest load hours of each day from October to December 2006. That period was when the Lower SEMA constraint was used to manage real-time congestion. In the figure, hours with real-time congestion into Lower SEMA are denoted with open dots, while the remaining days are shown with solid triangles.

Figure 32: Hourly Output Gap of Largest Supplier in Lower SEMA versus Load
On-Line and Quick Start Units, Top Three Load Hours per Day,
October to December 2006



As the figure shows, the output gap of the largest supplier's online and quick-start units was not significant during congested hours. In addition, the output gap did not increase under higher load levels. Therefore, there is no evidence of economic withholding to raise clearing prices in the Lower SEMA area.

4. Output Gap in Connecticut

In this sub-section, we examine potential economic withholding in Connecticut, especially within the Norwalk-Stamford load pocket. Based on the pivotal supplier analysis above, there is significant potential for market power in Norwalk-Stamford. The results of that analysis indicated that the largest supplier was likely to be pivotal in the majority of hours when load exceeds 17 GW. The pivotal supplier analysis also indicated that suppliers outside Norwalk-Stamford were rarely pivotal, even under peak load conditions. Hence, we present the Norwalk-

Stamford output gap analysis first, and then show the output gap analysis for the remainder of Connecticut. Figure 33 summarizes output gap results for the largest supplier in Norwalk-Stamford by load level.

Figure 33: Hourly Output Gap of Largest Supplier in Norwalk Stamford versus Load
Top Three Load Hours per Day, 2006

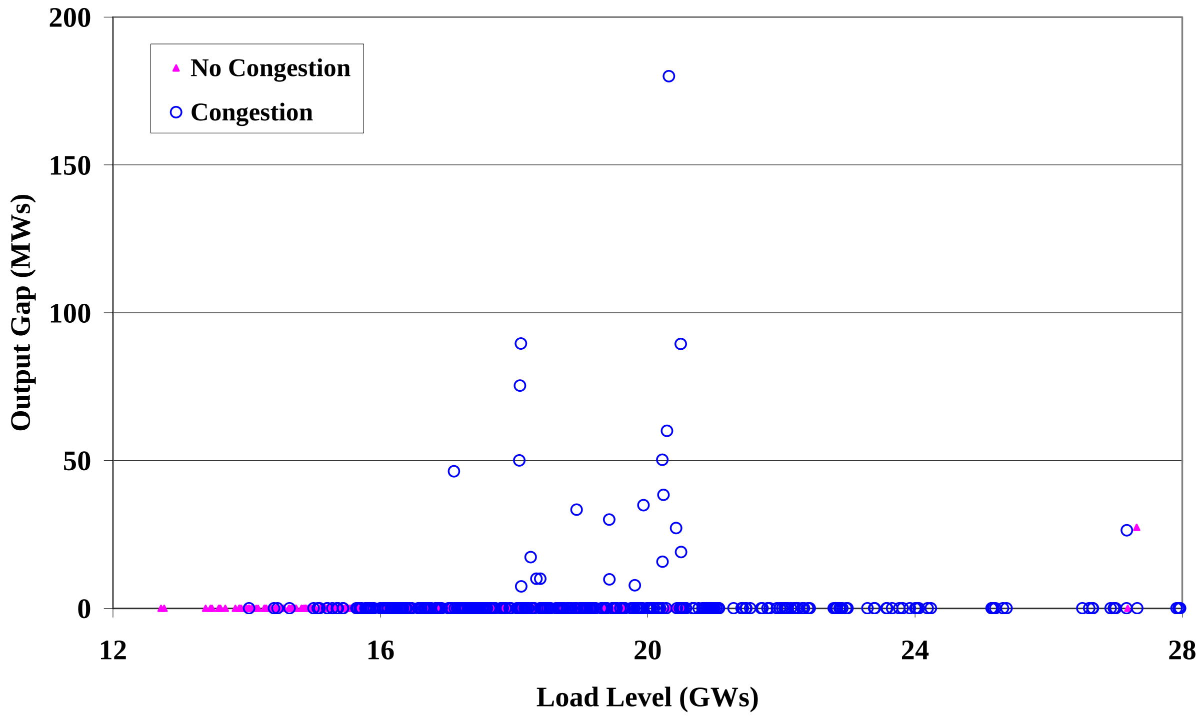


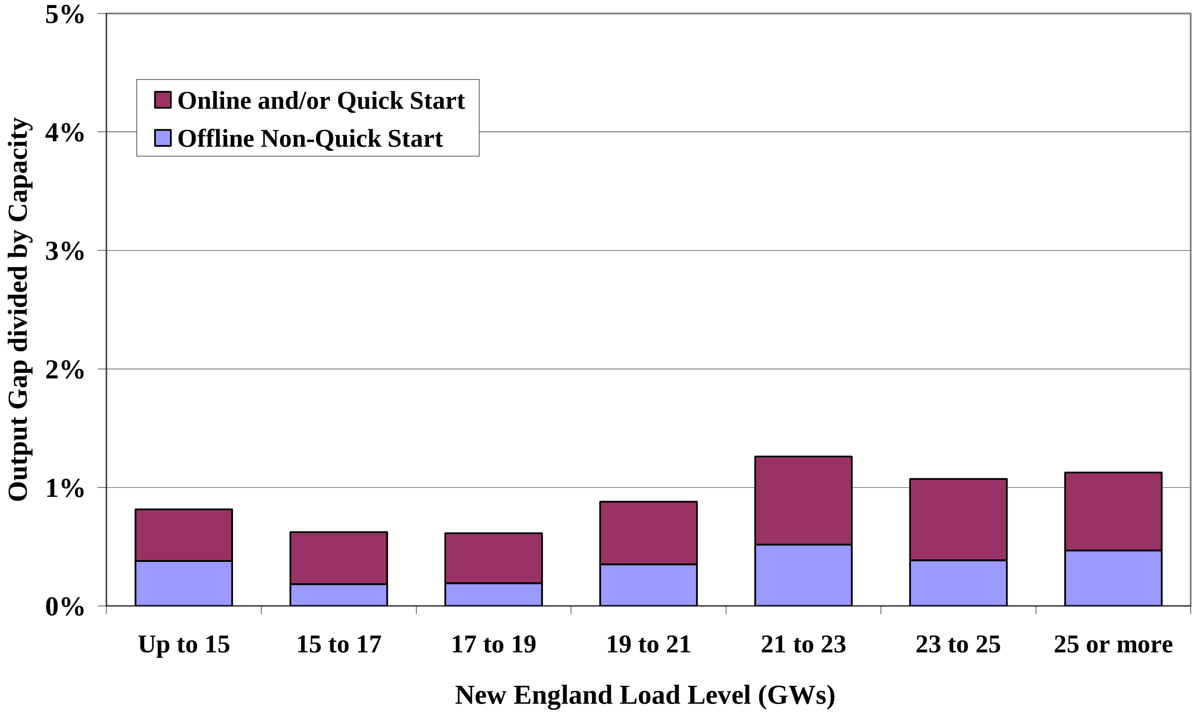
Figure 33 shows 23 hours when the largest supplier in Norwalk-Stamford had a positive output gap. All of these hours occurred when New England load was greater than 17 GW, when the largest supplier was likely to be pivotal. Furthermore, all but one of these hours occurred during periods of congestion into Norwalk-Stamford, indicating that their conduct likely had a significant impact on clearing prices. These facts raise potential concerns about the conduct of the largest supplier in Norwalk-Stamford, although these concerns are mitigated somewhat by the fact that there was no output gap in 96 percent of the hours when load exceeded 17 GW.

As with the largest suppliers in Boston and Lower Southeast Massachusetts, the generators of the largest supplier in Norwalk-Stamford are frequently committed for local reliability, which makes it more difficult to differentiate an attempt to economically withhold resources in order to raise clearing prices from an attempt to receive larger NCPC payments. A supplier receives NCPC payments when market revenues are not sufficiently high for the supplier to recover its start-up, no-load, and incremental offers. This makes the supplier indifferent to the level of clearing prices, unless another online unit in the supplier's portfolio can benefit from higher clearing prices. In general, units that receive NCPC payments will not benefit from higher clearing prices because each dollar of additional revenue from the higher LMP would correspond to a dollar reduction in the NCPC payment. We found that all of the online units in the largest supplier's portfolio received NCPC payments on all of the days when a non-zero output gap is shown in Figure 33. This correspondence is an indication that the output gap in Figure 33 reflects the largest supplier's attempts to garner larger NCPC payments rather than to raise LMPs.

To assess the extent of these attempts, we reviewed the incremental offer patterns of the two largest units in the Norwalk-Stamford in greater detail. We found that the median difference between the incremental offer and the reference level was approximately $24/MWh for both of these units. Given that these units are typically subject to the $25/MWh constrained area conduct test as part of ISO-NE's market power mitigation measures, this pattern suggests that the supplier typically raises its offers as much as the conduct test allows. The conduct increases NCPC payments to the supplier without the potential for being mitigated by ISO-NE.

Our next analysis focuses on the remainder of Connecticut. The pivotal supplier analysis in the previous section indicates that there is little cause for concern regarding potential market power in this area. This finding is confirmed by the following analysis, which examines conduct of suppliers in this area in 2006. The results of this analysis, presented in Figure 34, include the output gap results for Connecticut (excluding Norwalk-Stamford) by load level. This analysis does not separately show large suppliers and other suppliers since no suppliers were found to be pivotal after excluding capacity under reliability agreements and nuclear units.

Figure 34: Average Output Gap by Load Level
Connecticut (excluding Norwalk-Stamford) – 2006

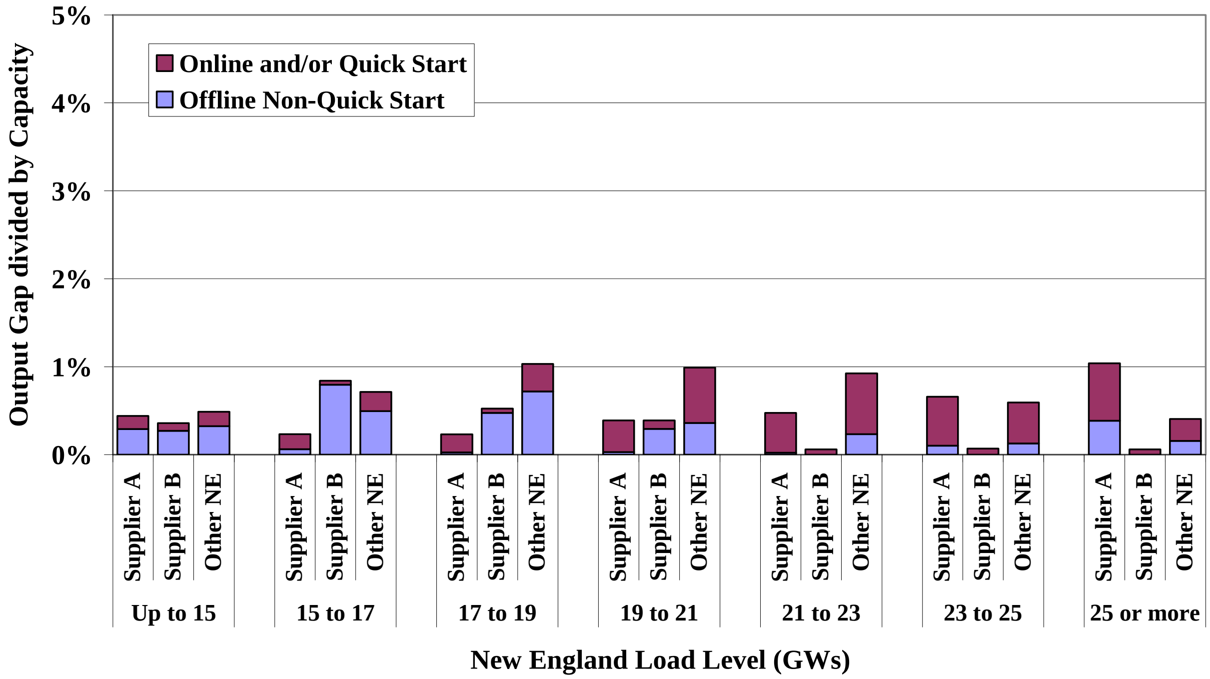


The average output gap for this zone was generally near one percent under all load conditions, which is generally consistent with expectations for a workably competitive market. Thus, the areas of Connecticut outside of the Norwalk Stamford load pocket do not show evidence of substantial economic withholding. This result may be due, in part, to two factors. First, large amounts of capacity in Connecticut are under reliability agreements that effectively reduce the incentives for their owners to withhold resources in the spot market. Second, frequent supplemental commitments for local reliability reduce the potential for tight conditions when suppliers are more likely to have the ability to raise prices substantially by withholding. As these conditions change, it will be important to monitor the competitive conditions and suppliers' conduct within Connecticut.

5. Output Gap in All New England

Figure 35 summarizes output gap results for all of New England by load level, excluding capacity from hydro and nuclear resources. Suppliers are divided into three categories. Supplier A has the largest portfolio in New England and was pivotal in approximately 11 percent of the hours during 2006 (excluding capacity under reliability agreements). Supplier B was pivotal during a smaller, but still significant, number of hours (approximately 3 percent). All other suppliers are also shown as a group for reference.

Figure 35: Average Output Gap by Load Level and Type of Supplier
Excluding Nuclear and Hydro Capacity
All of New England – 2006



The figure shows that the region-wide output gap was low for each of the three groups shown, and relatively steady across load levels. Supplier A exhibits a small output gap under all load conditions. While the output gap tends to increase as load increases above 19 GW, the output gap is still relatively low at the highest load levels. Thus, the output gap analysis provides little evidence of economic withholding by Supplier A. Supplier B's output gap levels are relatively low and tend to decrease as loads increase, a pattern that does not indicate economic withholding by Supplier B. The output gap levels of other suppliers were relatively low and tend to decline as load levels increase. In fact, at most load levels, the output gap of the other suppliers were slightly higher than for Suppliers A and B. Overall, these results indicate that economic withholding was not q significant concern in New England in 2006.

D. Physical Withholding

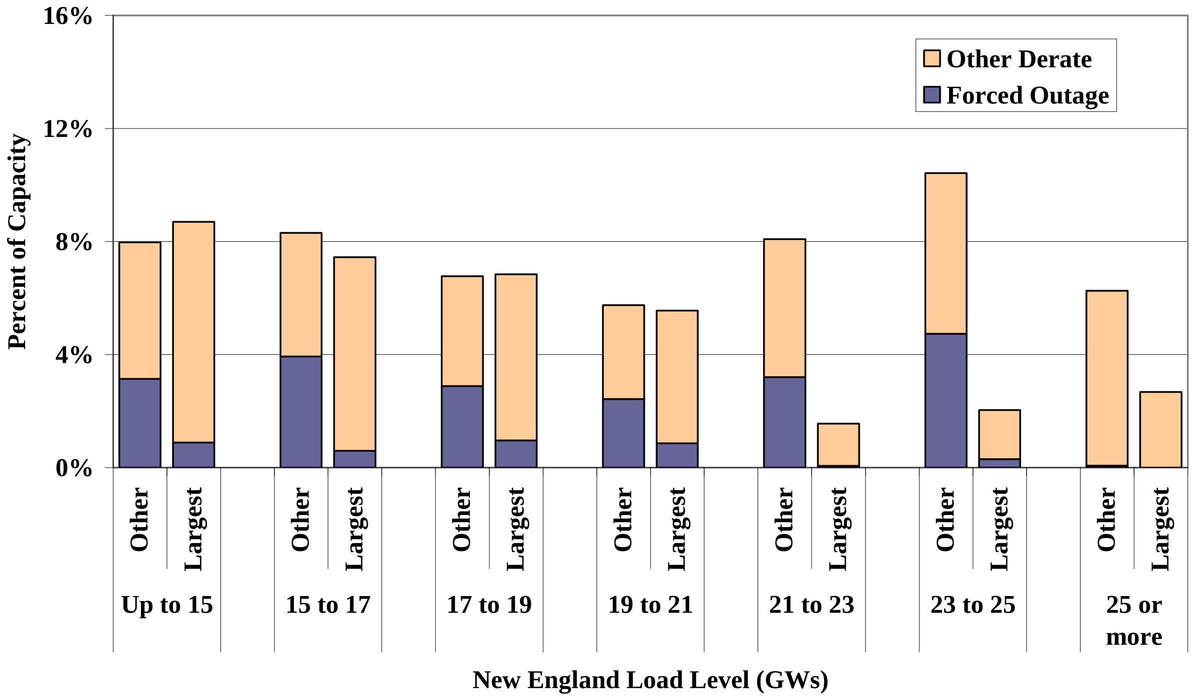
This sub-section of the report examines forced outages and other non-planned deratings to assess whether they have occurred in a manner that is consistent with the exercise of market power. In this analysis, we evaluate the four geographic markets examined in the output gap analysis above.

1. Potential Physical Withholding in NEMA/Boston

Figure 36 shows forced outages and other deratings in the NEMA/Boston area for various load levels. Based on the pivotal supplier analysis, the non-reliability agreement capacity of the largest supplier can be expected to be pivotal in most hours when New England load exceeds 23 GW. We compare these statistics for the largest supplier to all other suppliers in the area. The figure shows "other deratings," which include reductions in the hourly capability of a unit from its maximum seasonal capability that are not logged as forced outages or planned outages. These deratings can be the result of ambient temperatures or other factors that affect the maximum capability of a unit.

The figure shows the largest supplier's physical deratings as a percentage of its portfolio. These deratings are generally close to 8 percent at low load levels, but consistently decrease as load levels increase. The average physical deratings of other suppliers are generally higher than that of the largest supplier and also show a tendency to rise at very high load levels. This increase is due, in part, to increases in the forced outage rates at higher load levels. This pattern sometimes occurs when units fail to start that are seldom committed, except under relatively high load conditions. Additionally, the forced outage rate never exceeds the industry average of 5 percent under any load level.

Figure 36: Forced Outages and Deratings by Load Level and Supplier
NEMA/Boston - 2006

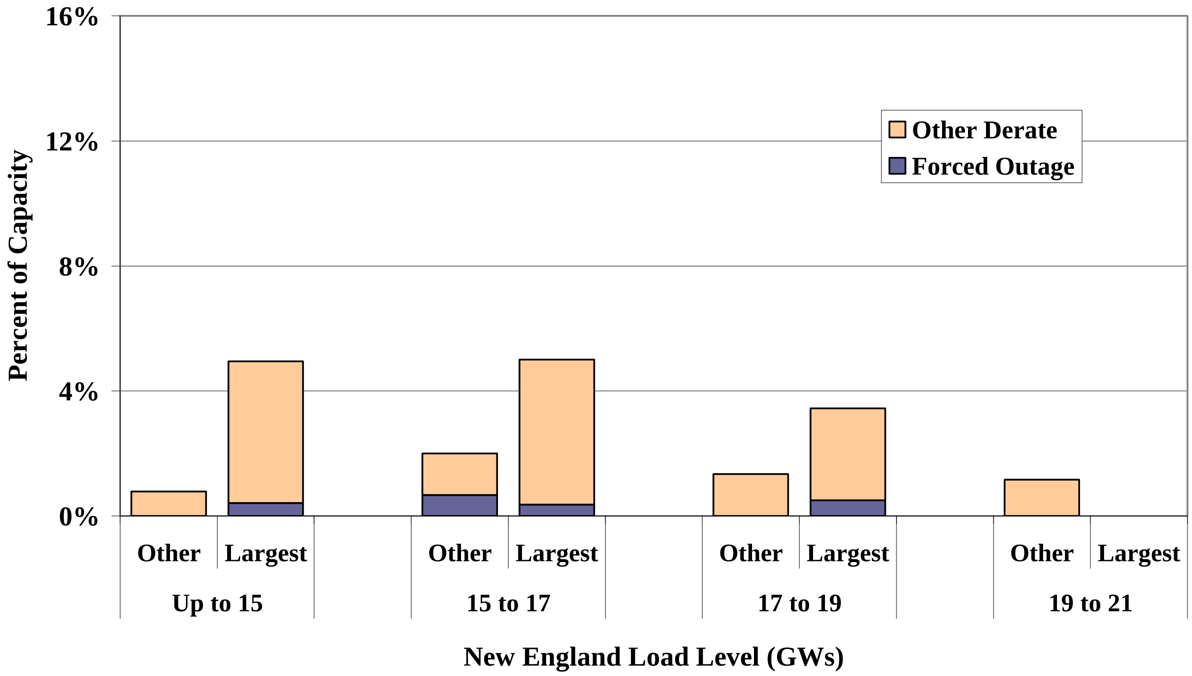


Overall, Figure 36 suggests that the pattern of deratings and outages is consistent with a competitive market. First, the large supplier shows levels of outages and deratings that are generally lower than for other suppliers. Second, the large supplier shows a general decline in the level of outages and deratings as load increases to the highest load levels. Even though running units more intensely under peak demand conditions increases the probability of an outage, the results shown in the figure suggest that the largest supplier increased the availability of its capacity available during periods of high load when it is most valuable to the market.

2. Potential Physical Withholding in Lower SEMA

Figure 37 summarizes forced outages and other deratings in the Lower SEMA area at various load levels from October to December 2006. These statistics are shown for the largest supplier compared with all other suppliers in the area. Based on the pivotal supplier analysis for Lower SEMA, the largest supplier can be expected to be pivotal in 80 percent of the hours when load exceeds 15 GW. This result indicates a potential market power concern in Lower SEMA under moderate or high load conditions.

Figure 37: Forced Outages and Deratings by Load Level and Supplier
Lower SEMA – October-December 2006



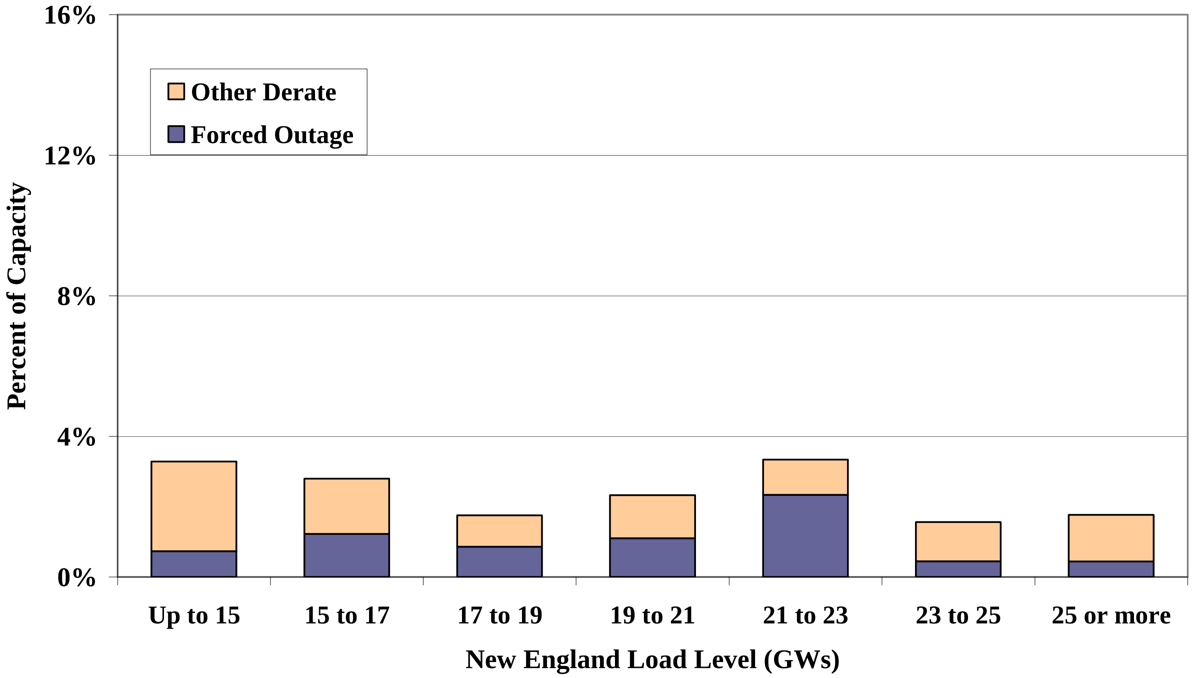
While the largest supplier has a higher rate of forced outages and other deratings than the other suppliers in Lower SEMA, the rates of the largest supplier are lower than suppliers in New England more broadly. As load levels rise above 17 MW, the forced outages and other deratings decline. These patterns suggest efforts to increase unit availability as load rises rather than any attempt at physical withholding. However, in comparing these results to the other figures in this section, one must consider that the three months shown in Figure 37 are characterized by lower load levels, lower ambient temperatures, and generally lower stress on generating units. Overall, the outage and deratings results for Lower Southeast Massachusetts do not raise concerns of strategic withholding.

3. Potential Physical Withholding in Connecticut

As in the prior section, we analyze potential physical withholding separately in the Norwalk-Stamford load pocket, and then in the remaining areas of Connecticut. Figure 38 and Figure 39 summarize forced outages and other deratings in these areas by load level. When load levels rise above 17 GW, the largest supplier in Norwalk-Stamford is pivotal almost 60 percent of the time.

Hence, it is important to evaluate how the patterns of outages and deratings change as load rises above 17 GW.

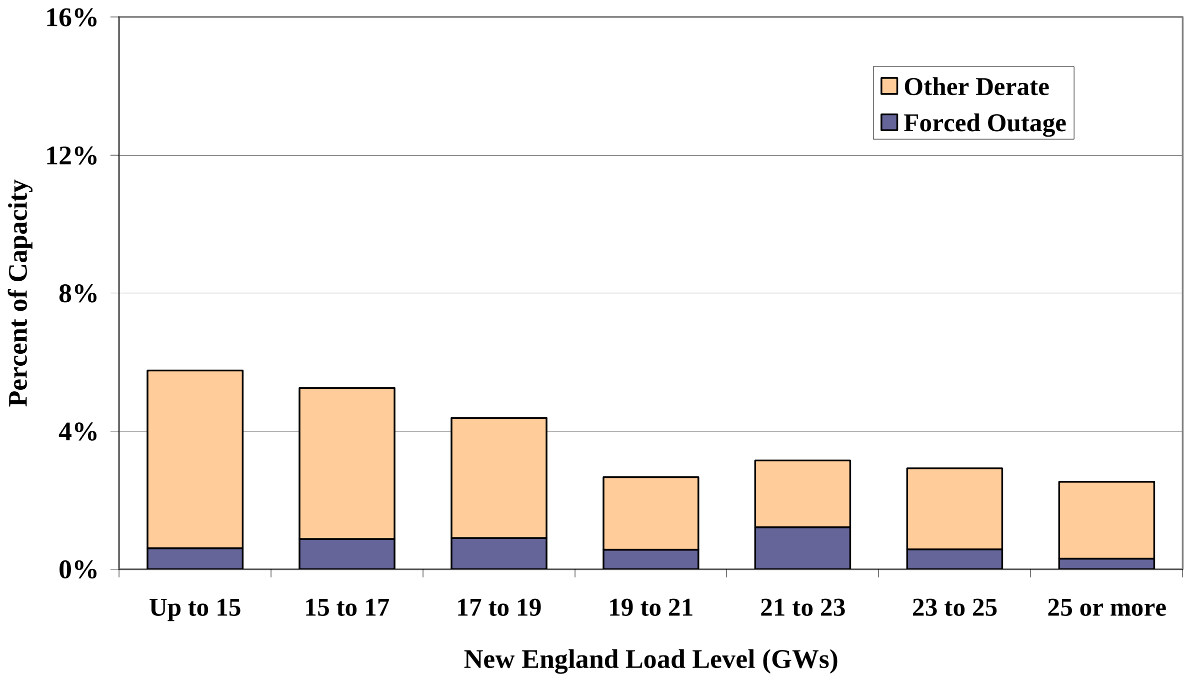
Figure 38: Forced Outages and Deratings by Load Level, Largest Supplier
Norwalk-Stamford – 2006



While the pivotal supplier analysis indicates significant potential for the exercise of market power in Norwalk-Stamford, Figure 38 shows that the physical derating and forced outage quantities are comparable to other areas and show a tendency to decline at load levels above 17 GW. Overall, the pattern of forced outages and other deratings does not provide significant evidence of physical withholding in Norwalk-Stamford.

Figure 39 summarizes physical deratings results for the portion of Connecticut outside Norwalk-Stamford by load level. The sum of forced outages and other deratings were at levels comparable to other regions and declined substantially at higher load levels. Overall, the quantities shown in the figure do not provide evidence of systematic physical withholding.

Figure 39: Forced Outages and Deratings by Load Level and Supplier
Connecticut (except Norwalk Stamford) – 2006

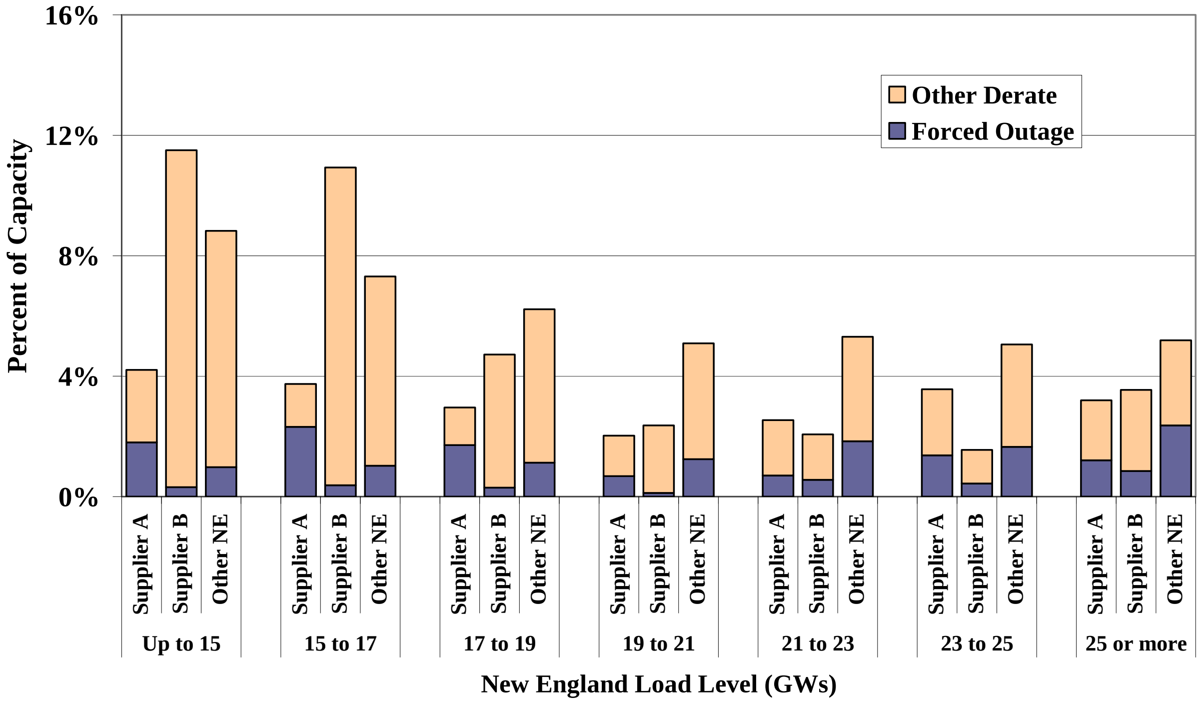


4. Potential Physical Withholding in All New England

Having analyzed each of the constrained areas in New England, Figure 40 summarizes the physical withholding analysis for all of New England by load level. The results of this analysis are shown for three groups of supply. Supplier A has the largest portfolio in New England and was pivotal in approximately 11 percent of the hours during 2006 (excluding capacity under reliability agreements). Supplier B was also pivotal during approximately 3 percent of the hours and is shown separately in the figure. All other suppliers are shown as a group for comparison purposes.

The figure shows that Supplier A had lower levels of forced outages and other non-planned deratings relative to other suppliers in 2006. However, Supplier A exhibits a modest increase in deratings when loads exceed 23 GW. This is explained primarily by the fact that two large units in the portfolio of Supplier A are limited by environmental regulations that lead to output restrictions under hot weather conditions. Supplier B exhibits higher rates of forced outages and other non-planned deratings when load is below 17 GW, but this decreases to around 2 or 3 percent at load levels over 19 GW. At the highest load levels, there is an increase in the rate of deratings for Supplier B, which was primarily the result of the total derating of one large unit. This derating coincided with the peak loads on August 2nd and is discussed in the following section.

Figure 40: Forced Outages and Deratings by Load Level and Supplier
All New England – 2006



As a group, the other New England suppliers show higher derating levels under low load conditions, but derating levels decrease as load levels increase. These patterns generally suggest that New England suppliers have increased the availability of their resources under peak demand conditions rather than physically withholding resources. The increased availability is particularly notable when we consider the effects of high ambient temperatures on thermal generators. Naturally, ambient temperature restrictions on thermal units vary along with load and are difficult to distinguish from physical withholding through a review of market data. It is beyond the scope of this report to determine whether individual outages and other deratings were warranted. However, the overall quantity of capacity subject to the deratings was consistent with expectations for a workably competitive market, so we find little evidence to suggest that these deratings constituted an exercise of market power.

Shortage pricing was in effect during the two highest load days in 2006. Since tight supply conditions may present exceptionally strong incentives to withhold, we examine market conditions during the shortage pricing periods in the next sub-section.

E. Review of Shortage Pricing Hours

On August 1st and 2nd, New England experienced record loads in excess of 28 GW, requiring the deployment of all available generation. Significant stress was put on the New England power system, which ran short of operating reserves for eight hours. Despite the high demands, the system performed well and there were no involuntary interruptions of service. Nevertheless, under peak operating conditions, there is greater potential for the exercise of market power, because even small amounts of physical withholding can produce a significant price effect. This section of the report examines more closely the eight hours when shortage pricing occurred for signs that market power was exercised.

Outages and deratings are a normal occurrence in any power system, but they may raise competitive concerns when they occur under peak operating conditions. We systematically reviewed available outage logs and operations data to determine whether the use of generation resources was consistent with competitive expectations. While data analysis alone cannot determine whether a particular outage was valid, such an analysis can often indicate whether an additional, more detailed investigation may be warranted.

The following table summarizes the supply of available resources during each of the eight hours of shortage pricing.

Table 7: Resource Availability during Reserve Shortage Conditions - August 1 and 2, 2006

Date	Hour Ending	Average LMP at NE Reference Bus	Actual Load	Available Operating Reserves	Operating Reserve Shortage	Outages and Deratings	Other Capacity Unavailable to ISO	Net Imports from Canada	Net Exports to NY	NE Border Price minus NY Border Price
August 1	17	$936	27,467	1,733	335	2215	467	2,316	947	$761
	18	$1,000	27,144	1,952	116	2067	754	2,318	923	$750
August 2	13	$543	27,961	1,952	88	2308	499	2,213	537	$323
	14	$1,000	28,122	1,714	326	2385	281	2,214	176	$735
	15	$1,000	28,130	1,648	392	2373	245	2,312	513	$650
	16	$1,000	28,101	1,438	601	2653	321	2,316	730	$224
	17	$1,000	27,951	1,683	357	2228	634	2,315	784	$79
	18	$389	27,432	1,937	103	2137	662	2,315	1053	-$116

Table 7 indicates that between 2,000 MW and 2,700 MW of capacity in New England, almost 7.6 percent of total capacity, was unavailable due to a forced outage or other derating. This level is consistent with other high demand periods that are shown in Figure 40. Another 1.6 percent of the capacity in New England was not fully deployed for energy or 30-minute reserves. This unavailable capacity was primarily capacity on units that were dragging below their instructed level or ramping after a trip or partial outage. Of the total unused capacity, 25 percent came from small individual reductions of less than 10 MW or 10 percent of the capacity of the unit, and 62 percent came from large individual reductions of more than 100 MW on a particular unit.

While the amount of capacity affected by outages and deratings was substantial on August 1st and 2nd, the amount was typical. Figure 40 showed the tendency for deratings to decrease at high load levels as suppliers take more actions to make capacity available during the peak demand conditions. This decrease is particularly notable since the physical capability of thermal generators typically declines as ambient temperatures rise. Hence, if deratings stay constant as temperatures rise, it represents an attempt by suppliers to make more capacity available.

While the amount of outages and deratings was not unusual, it was still large relative to the size of the reserves shortage, which ranged as high as 601 MW. In most of the hours, there were multiple suppliers that had unused capacity (due to an outage, derating, or other reason) that exceeded the size of the reserve shortage.

We examined outages and deratings at the individual supplier level to determine whether any of the outages or deratings quantities were anomalously large, which might suggest that suppliers sought to exercise market power. The largest individual unit outage was from an older vintage unit that is owned by the sixth largest competitor in New England. This unit accounted for 20 percent of the unused capacity during the period. The three largest suppliers in New England had unused capacity of 10 percent, 11 percent, and 5 percent. As mentioned above, the largest supplier was affected by environmental limitations on two units, while the second largest supplier experienced the derating of one large unit for several hours. While the amounts of unused capacity are large enough to have had significant price effects, the outcomes are not inconsistent with operations under stressful conditions, and there is no reason to think the capacity was unavailable for improper reasons.

After reviewing information on the outages and deratings during the peak event, we find no patterns that raise concerns. However, this review is limited to outage logs and operating data, and a formal audit would be required to determine whether a particular outage is valid.

From an efficiency standpoint, the usage of external interfaces raises concerns. Table 7 indicates that while the interfaces with Canada were almost fully used for imports, the average interchange with New York was 330 MW of exports over the Cross Sound Cable and 378 MW of exports across the AC tie lines. The table shows that the price on the New England side of the border exceeded the price on the New York side by as much as $760/MW during the reserve shortage. In all but one of the reserve shortage hours, the quantity of power exported to New York exceeded the size of the reserve shortage. The net exports include 3,750 MWh of emergency imports, primarily from New York, that the ISO-New England scheduled during the period, which reduced the level of uneconomic exports. Without these, the level of exports to New York would have been much higher and the reserve shortage in New England would have been much more significant. For instance, in Hour Ending 14, the average reserve shortage was 326 MW, but without the emergency imports, the average reserve shortage would have been 1,393 MW. This episode underscores the potential benefits of coordinating the interchange between New York and New England during peak load events. Better coordination would also mitigate market power during peak operating conditions.

F. Conclusions

Based on the analyses of potential economic and physical withholding in this section, we find little evidence of withholding that might indicate market power abuses during 2006. The pivotal supplier analysis suggests that market power concerns exist in a number of areas in New England. However, the abuse of this market power is limited by the ISO-NE's market power mitigation measures and the large amount of capacity under reliability agreements. Nonetheless, the ISO should continue to monitor closely for potential economic and physical withholding, particularly in constrained areas.