2006 Annual Markets Report

June 11, 2007

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Executive Summary

In keeping with its planning, operational, and market administration responsibilities, ISO New England each year reports on the performance of the region's wholesale electricity markets in its *Annual Markets Report*. The 2006 report presented here synthesizes the many facets of bulk power system operation and competitive market outcomes to help the ISO's stakeholders understand the electricity market's response to changing external factors and the complex interactions that take place among the markets.

A key finding in the *2006 Annual Markets Report* is the considerable decrease in average wholesale electricity prices compared with 2005 levels. This decline was primarily attributable to lower prices for natural gas, which New England relies on to fuel a significant amount of the region's installed capacity.

Fuel is the largest variable expense for most electrical generating plants. For this reason, the clearing prices for the electric energy markets rise and fall commensurately with changes in fuel prices, particularly those for natural gas. The fuel-adjusted electric energy price normalizes electricity market clearing prices for these variations. The 2006 average fuel-adjusted electric energy price fell by 5% compared with the 2005 average price. Average actual wholesale prices, which are not adjusted for fuel costs, decreased by 21%. This significant decrease in average actual electric energy prices in 2006 was primarily caused by lower fuel prices.

Also contributing to lower wholesale electric energy prices was an overall decline in average electricity demand throughout the year. Average electricity consumption decreased by approximately 3% due in large part to mild weather patterns. Greater participation in demand-response programs, increased retail prices, and the continued implementation of state-sponsored consumer outreach programs to promote energy efficiency combined to lower overall electricity use even further.[1]

Despite an overall decrease in average electricity use, peak demand increased by 4.6%, and on three occasions during a two-week summer period, electricity demand reached new levels. On August 2, 2006, the region ultimately set a new record for electricity use at 28,130 megawatts (MW), surpassing the previous year's peak by 1,245 MW. In the face of these unprecedented system conditions, the ISO effectively managed the bulk power system, at times implementing long-standing operating procedures to balance supply and demand. Demand-response played a vital role in maintaining system reliability, particularly on August 2 when demand-response resources reduced overall system demand by an unprecedented 625 MW at one point during the day.

The supply picture in New England remained fairly constant in 2006. Increases in capacity imports were offset by reductions in the seasonal production capability of New England's resources. This relatively flat growth in supply and the proven operational importance of demand-response programs underscore the need to broaden the role of demand-side resources, including energy efficiency, conservation, and demand response, to maintain regional reliability.

[1] *Demand response* in wholesale electricity markets occurs when market participants reduce their consumption of electric energy in exchange for compensation based on wholesale market prices. The ISO can request demand-response program participants to reduce demand to maintain system reliability. Participants also can voluntarily reduce demand in response to high wholesale prices. The ISO operates three reliability-activated demand-response programs and two price-activated load-response programs (see Section 4.6).

In 2006, the ISO made significant progress in meeting this need through further structural improvement in wholesale electricity markets. A refined Reserve Market implemented last year now allows certain types of demand-response resources to participate in the Reserve Market. Further, marked progress was made as New England state regulators and other stakeholders agreed on the Forward Capacity Market (FCM) design, which will provide additional opportunities for demand-response resources to participate in the market for capacity and will encourage investment in new generation capacity.

These structural enhancements are important steps in the process of developing the wholesale electricity markets. The 2006 implementation and advancement of well-designed, competitive wholesale markets are proving to be a catalyst for increased demand-response and infrastructure investment to the ultimate benefit of consumers.

The *2006 Annual Markets Report* highlights the state of New England's wholesale electricity markets, presents specific 2006 results, discusses ongoing efforts to improve market performance, and recommends ways to address additional issues facing the region.

1.1 State of the Market

In 2006, New England's wholesale electricity market recovered from external events—including weather extremes and fuel-price volatility—that had contributed significantly to increased wholesale electricity prices in 2005. This resilience demonstrates that the regional wholesale markets are well positioned and able to respond successfully to changing supply and demand conditions. The markets performed well; electric energy market prices declined as a result of decreased energy demand and fuel prices, the system remained reliable through three days of record peak demand in the summer, and market improvements enhanced competition and efficiency.

1.1.1 Factors Affecting the Wholesale Price of Electricity

The interplay between supply and demand determines the price of electricity. Demand is driven by weather, regional economic activity, consumer response to retail prices, and demand-response programs. Supply is affected by the cost of fuels for the existing generation capacity mix and by transmission constraints that preclude the use of the least-cost generation.

During most hours, New England's real-time electricity prices are set by the supply offers submitted by generating resources fueled by natural gas and oil and are driven largely by the prices for these fuels. The region's dependence on gas and oil to generate electricity makes wholesale electric energy prices susceptible to fluctuations in the prices of these fuels. In 2006, lower natural gas prices directly contributed to the lower wholesale prices. From 2005 to 2006, annual average natural gas prices decreased by 25%, while annual average oil prices increased by 11%.

Figure 1-1 shows actual and fuel-adjusted average yearly electric energy prices over the seven-year period from 2000 to 2006. The average 2006 fuel-adjusted electric energy price decreased by approximately 5% compared with 2005 average price. The average fuel-adjusted electric energy price in 2006 was $42.64/megawatt-hour (MWh), the lowest of all years for which the metric has been calculated. The previous minimum annual average price was $43.33/MWh in 2004. Overall, fuel-adjusted prices have remained fairly stable since 2000.

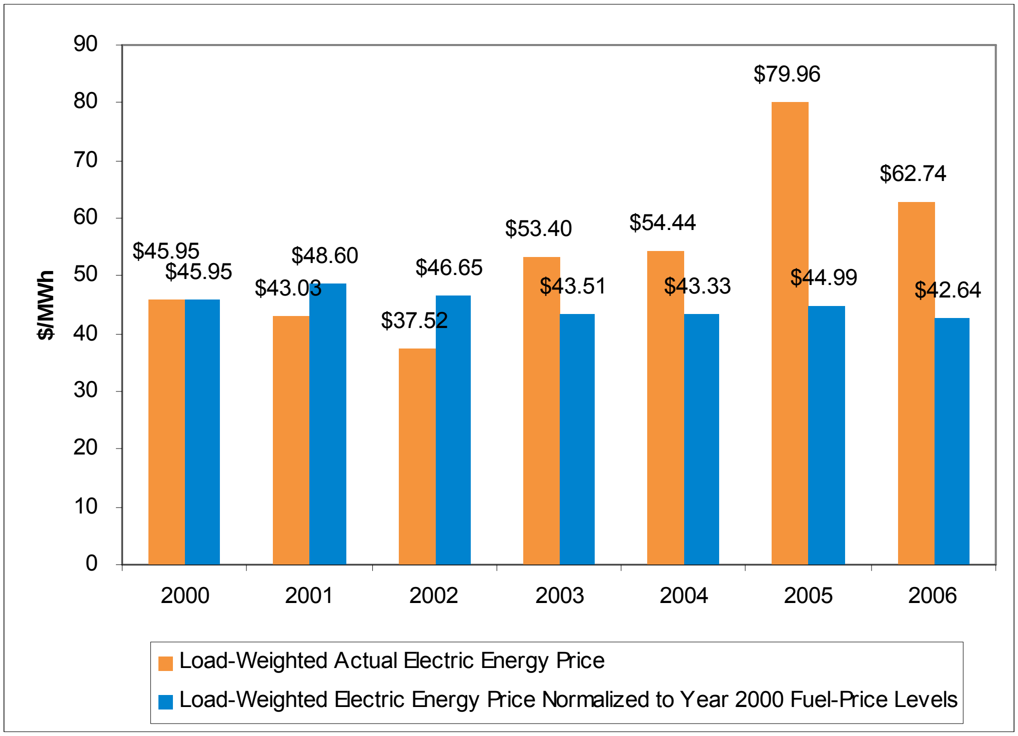

Figure 1-1: Actual and fuel-adjusted average real-time electric energy prices at the Hub, 2000 to 2006.

Aggregate electric energy consumption, which was 3.2% lower in 2006 than in 2005, also contributed to lower wholesale prices. This decrease is directly attributable to more moderate than normal weather and to increases in retail electricity prices.[2] State-sponsored and ISO-supported outreach programs led to greater participation in demand-response programs and improved consumer awareness about the importance of energy efficiency. These efforts also contributed to lower overall energy demand.

While average electric energy consumption declined in 2006, peak consumption grew. In New England, peak electricity consumption has been growing faster than average consumption over the past two decades. In 2006, despite a decrease in average electric energy consumption, peak demand increased by 4.6% from 2005 and set records for peak demand on three days in the summer. Hourly prices reached $1,000/MWh in five hours on these days. Such increasing peak consumption tends to raise capacity costs and puts a premium on demand response during the peak summer season.

[2] For more information on the relationship between load and retail prices, see the forecast model in the ISO's *Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT Report) (2006). Available online at http://www.iso-ne.com/trans/celt/fsct_detail/2006/long_run_forecast_2006.doc.

1.1.2 Wholesale Electricity Prices in 2006

Actual wholesale electricity prices in 2006 were consistent with those expected from a competitive market, as has been the case in previous years.[3] The 2006 average actual real-time Hub price of $62.74/MWh was 21% lower than the 2005 price.[4]

Figure 1-2 shows an all-in cost metric for wholesale electric energy that incorporates other payments to generators associated with the reliable operation of the bulk transmission system.[5] These payments cover energy and capacity market costs, daily reliability costs, Reliability Agreements, and the costs for ancillary services (i.e., for the reserve markets and Regulation Market).[6] The figure shows that electric energy is the largest component of the all-in metric; it accounted for 89% of the total cost in 2006, down from 94% in 2005. The cost structure is likely to change further as refinements in reserve and capacity markets reduce the need for out-of-market compensation.

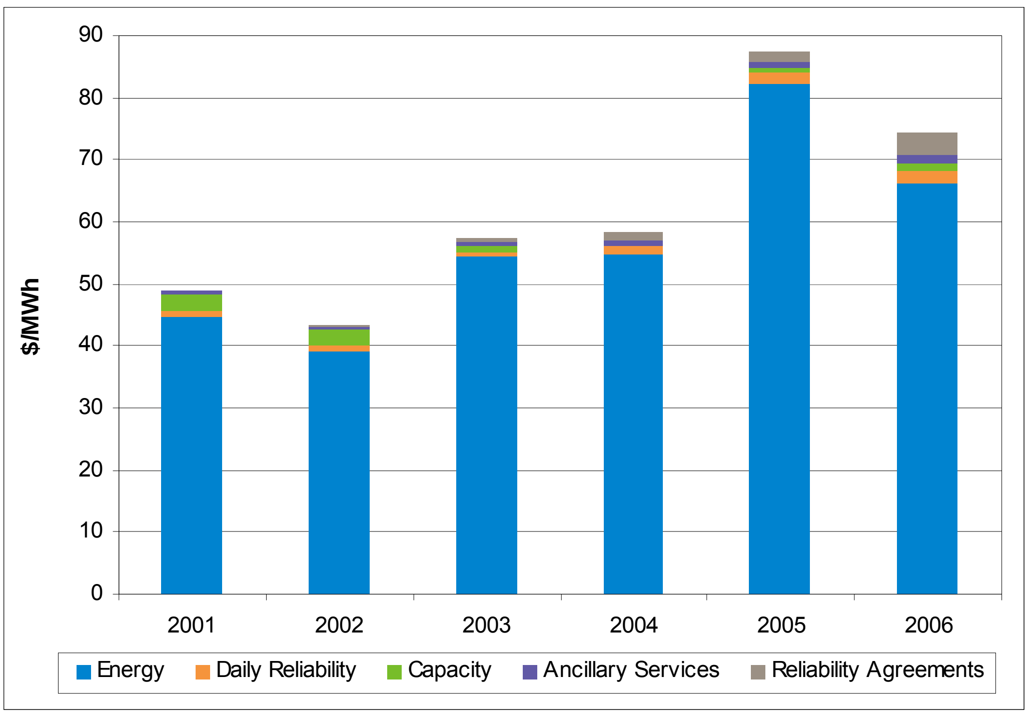

Figure 1-2: All-in wholesale electric energy cost metric for 2001 to 2006.

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[3] The conclusion that the electricity market is competitive is supported by the Lerner Index and Residual Supply Index (RSI) analyses, presented in Section 5.2.

[4] The *Hub* is a collection of locations for which the ISO calculates and publishes prices. The Hub price is intended to represent an uncongested price for electric energy.

[5] The energy component of the all-in wholesale electric energy price is an average of locational prices. This is a slightly different price concept than the load-weighted average hub price shown in Figure 1-1.

[6] Energy, capacity, ancillary services (i.e., reserves and regulation), and first- and second-contingency daily reliability payments are charged to load-serving entities (LSEs), while Reliability Agreements and voltage ampere reactive (VAR) and special-constraint resource (SCR) daily reliability payments are charged to network load.

1.2 Market Performance and Improvements in 2006

The ISO implemented several market refinements during 2006 to improve the operational performance of New England's wholesale electricity markets and produce market signals that guide investment to best meet New England's bulk power system needs. The following review highlights the market's operational performance and the changes affecting system reliability, system planning, resource adequacy, and compensation for regulation and reserve services.

1.2.1 Support of Reliable System Operations

The ISO effectively managed several critical power system events in 2006. These operational challenges included tight system conditions caused by record peak hourly electric energy consumption on three days in the summer, as well as an event that included the coincident outages of key transmission and generation facilities. The ISO maintained reliability throughout these events by implementing Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert* (M/LCC 2), and Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4).[7]

In 2006, growing enrollment in the ISO's demand-response programs increased the ISO's ability to use these vital resource types to maintain reliability. The ISO administers five programs: three real-time demand-response programs that help preserve system reliability and two price-response programs that provide incentives to participants to reduce energy withdrawals from the bulk transmission system in response to forecast prices. For all programs, the combined average monthly enrollment during the summer period increased 47% from 460 MW in 2005 to 675 MW in 2006. As a result of drawing on these assets throughout the year, 52,612 MWh were interrupted, for which program participants were paid a total of $7.8 million.[8] Recognizing the critical role that demand response plays in reducing demand and helping to stabilize prices, the ISO is taking steps to enhance demand-response participation in the locational Forward Reserve Market (FRM) and the Forward Capacity Market.

High generator availability continued in 2006, which contributed to the reliable operation of the system under stressed conditions. After the introduction of markets in 1999, generator availability increased from 81% in 1999 and 2000 to 89% in 2002; it has remained at or near this level ever since.

Nonetheless, reliability needs continued to necessitate out-of-market compensation for generation service to ensure that key capacity remained available. This out-of-market compensation takes two forms. First, *Reliability Agreements*, which are intended as interim measures, provide a mechanism for owners to recover fixed costs for capacity the ISO requires to ensure reliability.[9] They are intended to ensure that generators needed for reliability are recovering adequate revenues until (1) an appropriate market-based mechanism for capacity is implemented (see Section 1.2.4), or (2) the affected generator is replaced by a competitive alternative—either directly or through increased transmission transfer capability into the region where the affected generator is located.

[7] The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/ sysop/index.html.

[8] In addition to the direct demand-response program payments, $40 million in supplemental capacity payments were made to resources under the Southwest Connecticut "Gap" request for proposals (RFP), and $12.3 million in payments were made under the Winter Supplemental Program. (See Section 1.3 and Section 4.6)

[9] Reliability Agreements were formerly called Reliability Must-Run contracts.

Daily reliability payments are the second type of out-of-market compensation and are made to generators that help meet the system's electric energy and reserve requirements or that provide voltage or distribution reliability services. These payments, which allow the generators to recover short-run operating costs, are made in the form of Net Commitment-Period Compensation (NCPC) and tariff charges and credits.[10,11]

Daily reliability payments decreased by 19% in 2006, while Reliability Agreement costs increased by 100% in 2006. Total reliability costs, including Reliability Agreement costs and daily reliability payments, increased 36% over 2005 levels to $715 million.[12]

This level of out-of-market reliability costs is expected to decrease with the ISO's development and implementation of a complete set of markets for electric energy, reserves, and capacity that incorporates demand-side resources. For example, in October 2006, the ISO implemented market enhancements to address system reliability requirements with Phase II of the Ancillary Services Markets project (ASM II). The new Forward Capacity Market will help foster lower reliability costs in the future. Moreover, transmission system improvements in Connecticut and Boston should lower reliability commitments and related costs.

1.2.2 Capacity Market Design Progress

The ISO and regional stakeholders have been developing and negotiating a locational capacity market design dating back to 2002. At that time, the Federal Energy Regulatory Commission (FERC) approved the Standard Market Design (SMD) and charged the New England Power Pool (NEPOOL) with developing a market mechanism to procure capacity. This multiyear endeavor culminated in March 2006 when numerous parties, including the ISO, filed a settlement at FERC to establish a Forward Capacity Market as a replacement to the original Installed Capacity (ICAP) Market.[13,14]

The results of this settlement proposal bring the ISO closer to a complete set of wholesale markets that ensure power system reliability in New England by attracting efficient investment in new and existing power resources. Under the FCM design, the ISO will project the power system's capacity requirements three years in advance and hold an annual auction to purchase resources to satisfy the region's future needs. The FCM is designed to attract new demand-side resources and power plants and provide incentives for maintaining the reliable operation of existing power plants.

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[10]*NCPC* is the methodology used to calculate payments to resources for providing operating or replacement reserves in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total electric energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see Market Rule 1, Section III, Appendix F, *Net Commitment-Period Compensation Accounting* (2005), available online at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_f.pdf . These daily reliability payments are sometimes referred to as *uplift*.

[11]The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (Transmission Tariff) (2005), a part of which is the *Open Access Transmission Tariff* (OATT), and the *Self-Funding Tariff*. These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html. The OATT can be accessed online at http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/section_ii_of_rto_tariff%20-%20cleaned%20-%209-21-06.pdf.

[12] This represents a systemwide total. See Section 4.1.3 and Section 4.3 for details on how these costs are allocated to market participants.

[13] *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* (hereafter cited as SMD Order). FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002). p. 37.

[14] For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

The settling parties agreed to eliminate the ICAP Market on November 30, 2006, and to begin a transition payment mechanism on December 1, 2006, which will provide fixed capacity payments to all existing capacity resources until FCM payments begin—currently scheduled for June 2010. Transition payments will be $3.05/kW-month through May 31, 2008; $3.75/kW-month from June 1, 2008, through May 31, 2009; and $4.10/kW-month from June 1, 2009, through May 31, 2010.

The FCM design was finalized in summer 2006 and presented to market participants during fall 2006. NEPOOL stakeholders reviewed the FCM market rules between December 2006 and February 2007; the ISO filed these rules on February 15, 2007. A FERC Order issued on April 16 conditionally accepted almost all the FCM market rules relating to the qualification of resources and the auction with a few modifications.

1.2.3 Improved Forward Reserve Market and Real-Time Reserve Pricing

ASM II, implemented on October 1, 2006, has brought significant improvements to the New England reserve markets by including locational components and real-time zonal reserve pricing based on the co-optimization of energy and reserves. Local requirements were added to the Forward Reserve Market for the following four reserve zones: Connecticut (CT), Southwest Connecticut (SWCT), Northeast Massachusetts (NEMA)/Boston, and Rest-of-System.[15] The improved market design reflects New England's locational reserve requirements more accurately and provides more efficient price signals for investment in reserve-capable resources in areas where they are most needed. The ISO is closely monitoring the performance of the refined FRM and new real-time reserve pricing.

1.2.4 New Regulation Market

A new Regulation Market was implemented on October 1, 2005, as part of Phase I of the Ancillary Services Markets project (ASM I). In late 2005, after the Regulation Market changes were implemented, regulation costs rose substantially. In response, the Markets Committee of the ISO Board of Directors commissioned the ISO's Internal Market Monitoring Unit (INTMMU) and the Independent Market Monitoring Unit (IMMU) to perform separate evaluations to determine the causes of the increased costs.

The evaluations found that the observed increase in regulation costs was attributable to a combination of factors, including the introduction of a mileage payment, a substantial increase in fuel prices relative to the price of electric energy, the loss of a major supplier, and two procedural biases in the process used to select regulation resources.

In November 2006, the ISO filed with FERC revisions for two elements of the selection software on estimating production and opportunity cost components.[16] The ISO implemented these changes on January 12, 2007. The Regulation Market effectively provided sufficient amounts of regulation to maintain full compliance with North American Electric Reliability Council (NERC) reliability requirements for regulation throughout 2006.[17] The inclusion of a mileage payment in the ASM I Regulation Market design, in particular, attracts generation units that are responsive to regulation-

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[15] *Reserve zones* are geographic areas that have specific reserve requirements necessary for reliable operations of the system.

[16] Specifically, the FERC filing proposed to eliminate the duplicative production cost component from the regulation selector and modify the opportunity cost calculation to more accurately reflect actual cost exposure. See http://www.iso-ne.com/regulatory/ferc/filings/2006/sep/er05-795-003_9-7-06.pdf.

[17] *Control Performance Guide,* Document B-2. (New York: NPCC, March 12, 1999). Available online at https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/B-02.pdf.

control signals. As a result, the ISO was able to reduce the average monthly regulation requirements during 2006, thus improving the efficiency of this market.

1.3 Summary of 2006 Results

This *2006 Annual Markets Report* includes information about supply and demand levels, market-clearing prices, competitive market conditions, and other topics. A summary of the results detailed in the individual sections of this report follows:

- **Wholesale electricity price levels and fuel costs—**Electricity prices were consistent with those expected in a competitive market. After accounting for fuel prices, wholesale electric energy prices fell by 5% compared with 2005 prices. The actual average real-time electricity price at the Hub, weighted by system load, was $62.74/MWh, a decline of 21% from an average of $79.96/MWh in 2005. Declining natural gas prices since 2005, combined with a decreased demand for electricity, resulted in wholesale electric energy prices lower than those in 2005. (Section 3.1.1.2 and Section 3.1.4.3)

- **Peak demand and electric energy consumption—**Annual actual electric energy consumption declined by 3.2% from 2005 to 2006. Approximately half of the decline was attributable to milder than normal weather during 2006, while the other half was attributable to an increase in retail prices, wholesale demand-response programs, and consumer outreach programs. While total consumption declined, peak demand increased. The 2006 peak demand was 28,130 MW, an increase of 1,245 MW over the 2005 peak demand. (Section 3.1.2)

- **System capacity growth—**Growth in annual peak demand was significant in 2006, but the total summer seasonal system capacity available to the ISO increased by a small amount relative to the increase in peak demand. The total system capacity for summer was 31,193 MW in 2006, compared with 31,083 MW in 2005. The 110 MW increase is the combined result of resource ratings, a net reduction in local seasonal claimed capability, and a higher capacity for imports. (Section 3.1.3)

- **Imports and exports—**New England remained a net importer of power during 2006. New England was a net importer from Canada and a net exporter to New York and had little change in volume from 2005. Net imports from neighboring regions amounted to 6,103,000 MWh for the year, representing 4.6% of the annual net energy for load (NEL) in New England.[18] (Section 3.1.3.5)

- **Day-ahead and real-time prices—**During 2006, the yearly average day-ahead price was 2.0% higher than the average real-time price. In 2005, the difference was 2.4%. Each load zone also demonstrated modest price premiums in the Day-Ahead Energy Market over the Real-Time Energy Market. (Section 3.1.4)

- **Zonal price separation—**Price separation among load zones was less pronounced in 2006 than in 2005, although Connecticut locational marginal prices (LMPs) continued to be higher than those in other zones. LMPs were lowest in Maine. Overall for the year, the average difference between the LMPs for Connecticut and Maine was $10.14/MWh in the Day-Ahead

[18] *Net energy for load* is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports and exports.

Energy Market and $8.45/MWh in the Real-Time Energy Market. LMPs in the NEMA/ Boston zone were not higher than those in most zones on average, unlike in 2005. (Section 3.1.4.6)

- **Actions during capacity deficiencies—**High demand for electricity required the ISO to declare OP 4 systemwide on August 1 and 2, 2006. Extreme heat and humidity on these days led to record demand and reserve shortages. On June 19, 2006, the forced outage of a major transmission path in the Boston area required the ISO to declare OP 4 for the NEMA/Boston area. Reliable system operations were maintained during these events, a particularly notable achievement on August 2 given the negative operable capacity margins for that day.[19] The ISO's demand-response programs contributed significantly to system reliability on August 2, when a high of 625 MW were interrupted.

- **Forward Reserve Market auctions—**Two FRM auctions were held during 2006—the first under the preexisting market design, the second under the new market design. The first auction was held for the summer 2006 service period and had no locational requirements. The second auction, for the winter 2006/2007 service period, incorporated the ASM II design change to locational reserve requirements. Forward-reserve requirements for the total system and for the Rest-of-System reserve zone were met in the winter 2006/2007 auction, while requirements for the SWCT, CT, and NEMA/Boston zones were not met. Because offered quantities were short of requirements in the SWCT, CT, and NEMA/Boston reserve zones, the clearing price in these areas was set to the offer cap of $14,000/MW-month. In the Rest-of-System reserve zone, the clearing price for both 10-minute nonsynchronized reserve, or TMNSR, and 30-minute operating reserve, or TMOR, was $4,200/MW-month. Capacity market payments were subtracted from FRM payments beginning in October. After subtracting capacity payments from the Rest-of-System FRM clearing price of $4,200/MW-month, the average price for the eight-month period was $1,336/MW-month. This is consistent with the clearing price trend from previous systemwide auctions. In the CT, SWCT, and NEMA/Boston reserve zones, the average price for the eight-month period was $11,136/MW-month after subtracting capacity payments. (Section 3.3.3)

- **Forward Reserve Market operations—**Payments for forward reserves were about $70 million in 2006. Of this total, $41 million was paid in the last three months of the year, after the market transitioned to adding local requirements. Failure-to-reserve and failure-to-activate penalties for the year totaled $4 million. Almost all of these penalties were paid after adding local requirements and new penalty provisions. (Section 3.2)

- **Real-Time Reserve pricing—**Real-time reserve pricing was introduced as part of ASM II in October 2006. In the last three months of the year, real-time reserve prices were positive about 11% of the time in the CT and SWCT zones and about 4% of the time in the NEMA/Boston and Rest-of-System zones. Opportunity cost payments to resources that provided reserves were $2.9 million; however, these payments were reduced by $1.2 million in charges to resources that had already been paid to provide reserves through the FRM. (Section 3.3.5)

[19] An *operable capacity margin* is the amount of resources that must be operational to meet peak demand plus operating-reserve requirements.

- **Installed Capacity Market—**As in previous years, participants met most of their unforced capacity (UCAP) requirements through self-supply or bilateral transactions.[20] The trend of higher capacity market clearing prices that began in 2005 continued into 2006. Supply auction clearing prices ranged from $0 in May 2006 to $1,200 in July 2006. Deficiency auction prices ranged from $0 early in the year to $2,615 in November 2006. The last ICAP auction was held for November 2006.

  The transition payments of the FCM have replaced the ICAP Market until the FCA begins. (Section 3.2)

- **Regulation Market—**The Regulation Market clearing price averaged $24.02/MWh in 2006. Payments made to generators providing regulation service in 2006 totaled $78.1 million, an increase from $74.8 million in 2005. The 2006 total includes $34.8 million in real-time opportunity cost payments that were introduced as part of the ASM I Regulation Market. Improvement in the response of regulation resources to automatic generation control (AGC) signals helped reduce the regulation requirements in 2006. (Section 3.4)

- **Reliability commitments—**Several factors contributed to relatively high levels of reliability commitments in 2006. A set of dual-fuel resources within the southeastern Massachusetts (SEMA) region required reliability commitments to provide local reliability when the oil price rose above the gas price and these needed resources became uneconomic. Reliability commitments in the NEMA area declined because of the frequent self-scheduling of Mystic units #8 and #9 as required by the Reliability Agreement for these generating resources. (Section 4.1)

- **Daily reliability payments—**Daily reliability payments totaled approximately $232 million in 2006, down from the $287 million paid in 2005. These payments were in addition to electric energy market revenues. Payments to generators in the NEMA load zone decreased dramatically, while payments in the Connecticut and SEMA areas increased. Most second-contingency payments were made to resources in Connecticut and SEMA; much of this increase was attributable to the conditions in SEMA noted previously. Payments for voltage control and support were relatively low through 2006. (Section 4.1.3)

- **Reliability Agreements—**Capacity under Reliability Agreements increased in 2006. As of December 31, 2006, 41% (3,082 MW) of the capacity in Connecticut was under a Reliability Agreement, while 62% (2,213 MW) of the capacity in NEMA was under a Reliability Agreement. Both areas are import constrained. Systemwide, 19% (5,843 MW) of capacity was under Reliability Agreements, and the total net cost was $482 million. During 2006, Phase I of the NSTAR 345 kV Transmission Reliability Project was activated, allowing the termination of a Reliability Agreement for the New Boston generating station.[21] Effective January 2007, the Reliability Agreements involving two generating stations (Mystic units #8 and #9 and Devon units #11 to #14) were also terminated as a result of FERC settlement agreements, removing about 1,400 MW of capacity from Reliability Agreement contracts. (Section 4.3)

[20] *Unforced capacity* is the amount of installed capacity associated with a generating unit, adjusted for availability.

[21] Phase II of the NSTAR 345 kV Transmission Reliability Project was activated in spring 2007.

- **Financial Transmission Rights—**Market participants are able to buy financial instruments that help hedge the price risk of day-ahead congestion caused by constraints on the transmission system. Any participant or nonparticipant that meets a financial assurance requirement can purchase Financial Transmission Rights (FTRs). Participants without load obligations do not need to hedge the cost of congestion, but still purchase FTRs. FTRs were offered to the marketplace in 12 ISO-administered monthly auctions and one 12-month annual auction for 2006. Participation in the auctions was strong, and market participants purchased FTRs that were generally consistent with expected patterns of congestion. Net auction revenues from the annual and 12 monthly auctions totaled about $185 million, a 73% increase over 2005 auction revenues. The FTR market worked as designed in 2006. By the end of the year, all payments owed to FTR holders were paid, including payments for interest accrued during months with FTR shortfalls. Load zone-to-Hub paths were priced competitively, exhibiting small differences between average FTR acquisition costs and average day-ahead congestion costs. During 2006, the ISO worked with participants to design a Long-Term Transmission Right (LTTR) instrument that would span multiple years. (Section 4.5)

- **Demand response—**As of October 2006, 1,348 assets were under ISO demand-response program contracts, comprising over 681 MW of potential demand interruption or curtailment in any hour. During the year, the ISO's demand-response programs reduced energy consumption more than 52,612 MWh, with payments of $7.8 million. This amount was in addition to $40 million in supplemental payments to participants in the ISO's Southwest Connecticut "Gap" request for proposals (RFPs) and $12.3 million in supplemental capacity payments under the Winter Supplemental Program.[22] For the April to September period, demand-response program interruptions were estimated to decrease LMPs by $1.74/MWh during hours with interruptions. Demand-response programs played a critical role in maintaining reliability during the August 2, 2006, peak-load day by providing almost 600 MW of load reductions during the peak hour. Although the level of load interruptions experienced in 2006 represents an improvement over the previous year, efforts underway to integrate demand response more fully into New England's electricity markets will improve the long-run performance of the markets. (Section 4.6)

- **Market power mitigation—**During the year, the ISO exercised its market-mitigation authority eight times as part of its responsibility to monitor the market and ensure efficient and competitive market results. The Internal Market Monitoring Unit, in consultation with the Independent Market Monitoring Unit, intervened in the market to mitigate the behavior of a generating resource that exceeded clearly defined thresholds for economic withholding in the Day-Ahead Energy Market.[23] Six of the remaining seven mitigation events were related to daily reliability payments, and the eighth mitigation event was for economic withholding in the Real-Time Energy Market. Mitigation was imposed because the participants did not adequately explain a supply offer that exceeded conduct and market-impact thresholds. As a

[22] ISO New England Inc. *Request for Proposals for Southwest Connecticut Emergency Capability* (December 1, 2003). Additional information on the RFP can be found in the ISO's *Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability 2004–2008.* (October 4, 2004); available online at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/swct_gap_rfp_fnl_rpt_10-05-04.doc.

[23] *Economic withholding* means that a participant offered generation at a price above approved reference levels, potentially not being selected to produce energy.

result of the mitigation, the generating resource's offer was substituted with a supply offer intended to represent the unit's marginal costs. (Section 5.1.3)

1.4 Conclusions

In 2006, the wholesale electric energy markets demonstrated resiliency and recovered from the external events that had such a significant impact on 2005 market outcomes. Refinements to the Regulation and Reserve Markets along with continued development of the Forward Capacity Market will improve efficiency in operations and investment.

Overall, wholesale electric energy prices decreased compared with 2005 levels, appropriately reflecting declines in natural gas prices. Lower overall electric energy demand and continued high levels of generator availability also contributed to decreases in electric energy costs, again demonstrating the market's capacity to respond effectively to dynamic conditions.

The wholesale electricity markets continued to support reliable operations throughout 2006, despite significant operational challenges. One clear indication of the market's performance in this area was the remarkable 47% increase in demand-response program enrollment in summer 2006 compared with summer 2005.

The existing demand-response programs provide significant reliability benefits, including critical system support during summer peak-demand days. Increasing enrollment is essential to the long-term reliability of the system given the vital role these resources play, particularly at times when the grid is stressed. This point was underscored on August 2, 2006, when the ISO's demand-response programs provided a high of 625 MW of load interruptions during the peak-demand day.

The ISO continued to make substantial progress in 2006 toward the ultimate goal of establishing a complete wholesale electricity market structure that will allow full participation of demand response and encourage infrastructure investment. The incorporation of demand resources into the locational Forward Reserves Market and the Forward Capacity Market will further advance the strategic value of demand participation.

The ISO is working with state and federal agencies and other stakeholders to make additional enhancements to facilitate demand participation in the markets and to encourage efficient infrastructure investment that will improve the long-run performance of New England's wholesale electricity markets.

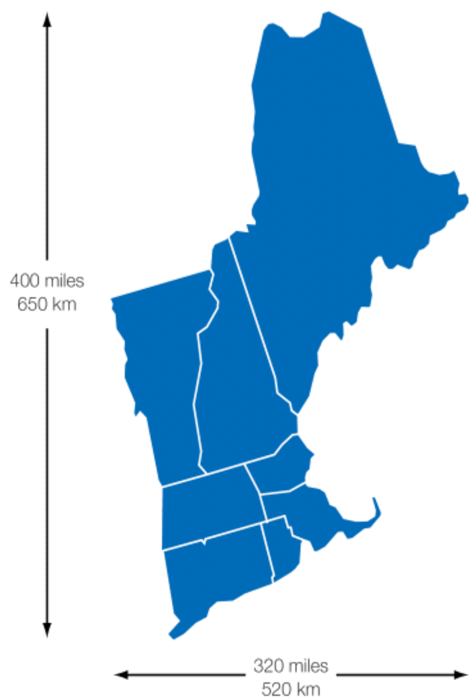
Section 2
Introduction

Created in 1997, ISO New England (ISO) is the not-for-profit corporation responsible for three main functions:

- Day-to-day operation of New England’s bulk power generation and transmission system
- Oversight and administration of the region’s wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process

Since February 1, 2005, the ISO has operated as a Regional Transmission Organization (RTO), assuming broader authority over the day-to-day operation of the region’s transmission system and possessing greater independence to manage the region’s bulk electric power system and competitive wholesale electricity markets. The ISO works closely with regulators and stakeholders, including participants in the marketplace.

Figure 2-1 shows key facts about New England’s power system and electricity markets.



- 6.5 million electricity customers; population 14 million
- 350+ generators
- 8,000+ miles of high-voltage transmission lines
- 12 interconnections with systems in New York and Canada
- 31,000+ megawatts of total supply (includes 650+ megawatts of demand response as of October 2006)
- 132,078,000 megawatt-hours of net energy for load in 2006
- Peak demand: 28,130 megawatts on August 2, 2006 (after approximately 641 megawatts of load reduction from demand-response programs and other actions)
- 280+ participants in the marketplace
- $8.8 billion electric energy market

Figure 2-1: Key facts on New England’s electric power system and wholesale electricity markets.

2.1 Role of Market Monitoring

The market monitoring structure implemented by the ISO relies on two independent market monitoring units: the ISO's Internal Market Monitoring Unit (INTMMU) and Independent Market Monitoring Unit (IMMU), Potomac Economics. The internal market monitor reports administratively to the company's CEO, whereas both market monitors report functionally to the Markets Committee of the ISO board of directors. This reporting structure is analogous to the oversight structure of internal and external auditors in corporate finance. The functional reporting directly to the Markets Committee of an independent board provides the INTMMU with the independence vital to its obligation to inform regulators of any problems that require attention.

Through the following five general monitoring activities, the INTMMU ensures that prices properly reflect competitive supply and demand conditions and assists the Federal Energy Regulatory Commission (FERC) in enhancing the competitiveness of wholesale electricity markets for the benefit of consumers:

- Day-to-day monitoring of participant behavior and market outcomes
- Mitigating participant behavior found to be anticompetitive as outlined in Market Rule 1[24]
- Investigating participant behavior that is not explicitly precluded by existing tariff provisions but that may be considered anticompetitive; making a referral to FERC for further analysis and possible sanctions when such behavior or anticompetitive outcomes are identified[25]
- Evaluating and reporting on existing market rules, operating procedures, and market outcomes and making recommendations for improvements when necessary
- Evaluating new ISO initiatives and market design proposals to ensure that the revisions will support the efficient operation of competitive wholesale electricity markets

The INTMMU fulfills these activities by performing the following specific tasks:

- Identifying potential anticompetitive behavior by market participants
- Implementing the mitigation provisions of Market Rule 1 when appropriate
- Immediately notifying appropriate FERC staff of instances in which the behavior of a market participant may require an investigation and evaluation to determine whether the participant has violated a provision of the tariff, market-behavior rule, or the *Energy Policy Act of 2005* (EPAct)[26]
- Providing support to the ISO in administering FERC-approved tariff provisions related to the ISO-administered markets, including the Day-Ahead and Real-Time Energy Markets, as well as the Installed Capacity (ICAP), Regulation, and Forward Reserve and Real-Time Reserve Markets

[24] ISO New England Inc. *Market Rule 1* and appendixes (2005). Available online at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[25] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (Transmission Tariff) (2005), a part of which is the *Open Access Transmission Tariff* (OATT), and the *Self-Funding Tariff*. These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html.

[26] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*). Available online at http://www.energy.gov/about/EPAct.htm.

- Identifying ineffective market rules and tariff provisions and recommending proposed rule and tariff changes that will promote wholesale competition and efficient market behavior
- Providing comprehensive market analysis to evaluate the structural competitiveness of the ISO-administered markets and the resulting prices to identify whether markets are responding to customers' needs for reliable electricity supply at the lowest long-run cost
- Providing regular reports to the ISO's senior management and board of directors and state and federal regulatory agencies that describe and assess the development and performance of wholesale markets, including performance in achieving customer benefits; providing transparency; and meeting federal reporting guidelines
- Evaluating proposed changes in market rules and market design

The INTMMU seeks regular input from the IMMU to provide an additional, independent review of significant market developments. This structure fosters independence without isolation in support of the ISO's responsibility to ensure that the New England markets and prices are fair, transparent, and competitive.

2.2 About the 2006 Annual Markets Report

Market Rule 1, Section 11.3, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*, requires the ISO to prepare an *Annual Markets Report*. The *2006 Annual Markets Report* covers January 1 to December 31, 2006, the ISO's most recent operating year. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

Section 3 assesses the energy, capacity, reserve, and regulation markets. Section 4 assesses reliability costs, congestion management, and demand response. Section 5 provides a retrospective analysis of market outcomes, and Section 6 presents the ISO operational results. Section 7 summarizes the main conclusions of the report.

Appendix A and Appendix B provide supplemental materials. Appendix A provides electricity market statistics at the zonal and monthly level as well as additional details of the all-in cost metric. Appendix B provides supplemental cost components of the ISO *Self-Funding Tariff* and the *Open Access Transmission Tariff* and the Congestion Revenue Balancing Fund.

Section 3
The Markets

This section of the report contains information about the Day-Ahead and Real-Time Energy Markets, the Installed Capacity Market and Forward Capacity Market, the reserves markets, and the Regulation Market. Background information, market results for 2006, and an analysis of the data are included for each market.

3.1 Electric Energy Markets

The electricity markets operated by the ISO include a Day-Ahead Energy Market and a Real-Time Energy Market, each producing a separate but related financial settlement. This arrangement is known as a *multi-settlement system*. The Day-Ahead Energy Market produces financially binding schedules for the production and consumption of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including generator reoffers of capacity into the market, real-time hourly self-schedules (i.e., operating at a determined output level regardless of price), self-curtailments, transmission or generation outages, and unexpected real-time system conditions. The Real-Time Energy Market balances differences between the day-ahead scheduled amounts of electricity and the actual real-time load requirements. Participants either pay or are paid the real-time locational marginal price (LMP) for the amount of load or generation in megawatt-hours that deviates from their day-ahead committed schedules.

The ISO calculates and publishes day-ahead and real-time LMPs at five types of locations, called *pricing locations*. These include the external interface proxy nodes, load nodes, individual generator-unit nodes, load zones, and a trading hub (Hub). New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA). These eight load zones reflect the historical operating characteristics of, and the major transmission constraints on, the transmission system. The Hub, which contains a specific set of predefined nodes, is used to establish a reference price for electric energy trading and hedging. The Hub is also a location used in the Financial Transmission Rights (FTRs) markets.

The market-clearing process calculates and publishes LMPs at these locations based on supply offers and day-ahead demand bids or real-time load. A generator is paid the price at its node, whereas participants serving demand pay the price at the load zone. This is a load-weighted average price of the zone's load-node prices. (Refer to Section 3.1.1 for more information about how the market price is determined.)

Nodal prices differ among locations as a result of congestion costs and losses. Congestion costs arise because of the need to dispatch individual generators to provide more or less energy to respect transmission constraints. Losses are a result of physical losses that arise as electricity travels through the transmission lines. To compensate for the losses, generators must increase the production of electricity by a small percentage.

If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment (in megawatts) of load. This incremental megawatt of load would be served by the generator with the lowest cost, and energy from that generator would be able to flow to all nodes over the transmission system. When the transmission network becomes congested, the next increment of electric energy in a constrained area cannot be delivered from the least expensive unit on the system. This is because allowing the least expensive unit to meet the next increment of load would violate transmission operating criteria, such as thermal or voltage limits. The congestion component of price is calculated at a location based on the additional cost of redispatching the system (increasing the output of a high-cost generating unit while decreasing the output of a less expensive generating unit to avoid violating transmission limits).

3.1.1 Underlying Drivers of Electric Energy Market Prices

The key factors that influence the market price for electric energy are supply and demand. Supply is in turn influenced by fuel prices and transmission constraints. This section elaborates on each of these factors.

3.1.1.1 Supply and Demand

Market clearing is accomplished by the interaction of supply and demand at each location on the system in both the Day-Ahead Energy Market and the Real-Time Energy Market.

In the Day-Ahead Energy Market, market participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive demand* (i.e., they will buy up to a certain price) at the load zone. They may also offer virtual supply and bid virtual demand (see Section 3.1.2.3) at the Hub, a load zone, or a node. Generating units offer their output at the pricing node specific to their location. The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node. The processing of the Day-Ahead Energy Market results in binding financial schedules and commitment orders to generators. In the Day-Ahead Energy Market, participants have incentives to submit supply offers that reflect their units' marginal costs of production, which are largely driven by fuel costs. Supply offers also incorporate the units' operating characteristics. Separate start-up and no-load offers are also submitted. Demand bids reflect participants' load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations surrounding congestion.

After the Day-Ahead Energy Market clears, the supply at each location can be affected in two ways. First, generators that were not committed in the Day-Ahead Energy Market can request to self-schedule their units for real-time operation. Alternatively, units that were committed can incur a forced outage or request to be decommitted. Second, as part of its Reserve Adequacy Analyses (RAA) (see Section 4.1), the ISO may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage.[27] Finally, all generators have the flexibility to change their incremental energy-supply offers during the reoffer period.

In the Real-Time Energy Market, the ISO dispatches generators to meet the actual demand on the system and to maintain the required operating-reserve capacity. Higher or lower demand than that scheduled day ahead, actual generator availability, and system operating conditions all can affect the level of generator dispatch and therefore the real-time LMPs. In the Real-Time Energy Market, the ISO balances supply and demand, while ensuring sufficient reserves and safe transmission line loadings. Unexpected increases in demand, generating-unit outages, and transmission line outages all can cause the ISO to call on additional generating resources to preserve the balance between supply and demand.

[27] A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after the first facility is lost.

3.1.1.2 Fuel Prices

For most electricity generators, the cost of fuel is the largest production cost variable, and as fuel costs increase, the prices at which generators submit offers in the marketplace increase correspondingly. Over the past five years in New England, new generating capacity has been almost entirely fired by natural gas. Generating units burning natural gas or fuel oil, or capable of burning both natural gas and oil, constitute approximately 61% of electric generating capacity in the region. During most hours, a generator burning one of these two fuels is a marginal unit, which results in New England electricity prices being highly sensitive to changes in the price of fuel oil and natural gas. On average, 2006 natural gas prices were considerably lower than those of 2005, while oil prices increased. The average annual price of fuel oil increased 11% from 2005, and the average annual price of natural gas decreased 25%.

3.1.1.3 Transmission Constraints

In an unconstrained system, all LMPs would be the same at every location, except for marginal losses. However, the patterns of demand (physical and virtual), generator outages, and thermal, voltage, and stability limits on the transmission system all can lead to binding transmission constraints that the ISO must manage.

In the Day-Ahead Energy Market, RAA, and Real-Time Energy Market, generating units are committed to ensure that the levels of cleared, anticipated, and actual demand can be reliably served. The commitment takes into account limits on the transmission system, the need for reserves, and the need to provide contingency coverage. High demand relative to economic supply in a given area may result in binding transmission constraints, which would then require the selection of more expensive generation and would lead to higher market-clearing prices in that area. In contrast, export-constrained areas will experience lower prices relative to unconstrained areas.

3.1.2 Electric Energy Demand in 2006

Demand trends in 2006 were marked by two significant features: high peak demands on hot summer days, including a new record peak-hour demand, and a steep decline in total yearly demand. The net energy for load (NEL) supplied to the system in 2006 was 132,078,000 MWh, a decrease of 3.2% from the 2005 level.[28] Historically, increases and decreases in demand have correlated with changes in economic activity, weather conditions, and consumer preferences (e.g., preferences for using air conditioners or personal computers). Decreases in demand typically have been driven by economic recessions.

Figure 3-1 shows yearly total NEL for 1980 through 2006. Demand declined from 1980 to 1982 and again from 1989 to 1991. The United States economy was in a recession during both these periods.[29] The decrease in demand from 2005 to 2006, however, did not coincide with a recession. This change was also much larger, in both absolute and percentage terms, than the earlier-period decreases.

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[28] *Net energy for load* is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports.

[29] Recession cycle data are from the National Bureau of Economic Research and are available online at http://www.nber.org/cycles/.

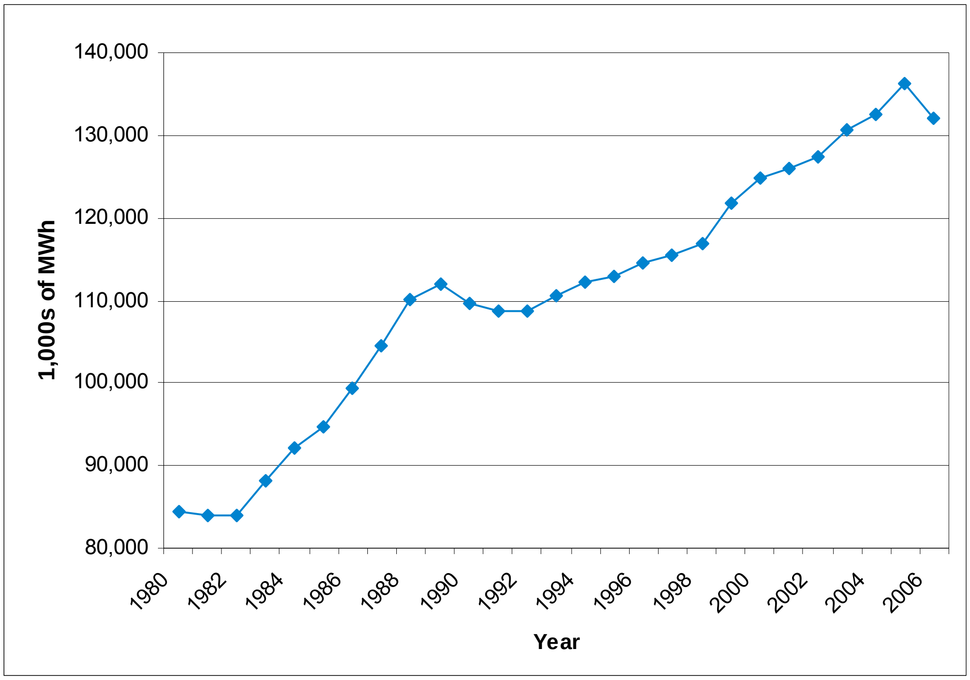

Figure 3-1: New England actual net energy for load, 1980 to 2006.

Since NEL is influenced by weather, the ISO calculates *weather-normalized NEL* (i.e., the NEL that would have been observed if weather were normal). This calculation indicates that after weather normalization, the decrease in NEL from 2005 to 2006 was 1.6%, as shown in Table 3-1.[30] The decrease in weather-normalized demand may be attributable to increases in retail electricity costs. Retail cost increases, along with media coverage of these increases, as well as state-sponsored consumer outreach programs, may have caused consumers to conserve electricity.

Table 3-1
Annual and Peak Electric Energy Statistics, 2005 and 2006

	2005	2006	Change	% Change
Annual NEL (MWh)	136,376,000	132,078,000	−4,298,000	−3.2
Normalized NEL (MWh)	134,625,000	132,480,000	−2,145,000	−1.6
Recorded peak demand (MW)	26,885	28,130	1,245	4.6
Normalized peak demand (MW)	26,545	26,940	395	1.5

[30] The ISO uses statistically derived factors to adjust energy consumption levels to reflect the deviation of actual weather from 20-year average or "normal" levels. In the weather-normalization calculation, consumption is adjusted downward when temperatures are more severe than normal and upward when temperatures are milder than normal. Data for summer months also account for the effect of humidity on consumption levels.

New England weather in 2006 was marked by temperatures that were well above normal during the winter months and periods of hot weather during the summer. January, November, and December in particular had warmer than normal weather, while in February, March, and June, average temperatures were close to normal. Temperatures were slightly above normal in April and slightly below normal in May. July's average temperature tied for the sixth warmest on record. Several days in July had temperatures around 90°F, and some areas reached 96°F on July 18.[31] August temperatures were close to normal on average, although August 1 and August 2 and several other days were particularly hot. Temperatures in September and October were slightly above normal, while November was the fourth warmest on record. December was the warmest on record in many areas.

Several of the summer 2006 hot-weather periods had high loads, and loads exceeded 25,000 MW in 55 hours. The 2006 system-peak hourly demand of 28,130 MW occurred on August 2. Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4), was in effect at this time, resulting in 534 MW of load reductions.[32] Absent these reductions and the Real-Time Price-Response Program interruptions of 107 MW, the peak demand would have been 28,771 MW. The temperature at the time of this peak was 95°F, with a dew point of 74°F. By comparison, demand exceeded 25,000 MW in 28 hours in 2005, did not exceed 25,000 MW at any time in 2003 or 2004, and only exceeded this level in four hours in 2002. The ISO calculates a weather-normalized peak demand for the summer and winter seasons. After weather normalization, the 2006 summer seasonal peak increased by 1.5% over the 2005 weather-normalized peak.

Figure 3-2 and Figure 3-3 show the actual system electrical load for New England over the past five years as load-duration curves, ordering load levels from highest to lowest. The duration curve for each year shows the percentage of time the hourly load was at or above the load levels shown on the vertical axis. Figure 3-3, which includes only the highest 5% of hours, shows that 2006 had much lower loads, with the exception of the top 1% of hours.

[31] The source for temperature data is the Web site of the National Weather Service Forecast Office in Boston, Massachusetts; see http://www.erh.noaa.gov/box/MonthlyClimate2.shtml and http://www.weather.gov/climate/index.php?wfo=box.

[32] The ISO's system operating procedures are available online at http://www.iso-ne.com/rules_proceds/operating/sysop/index.html.

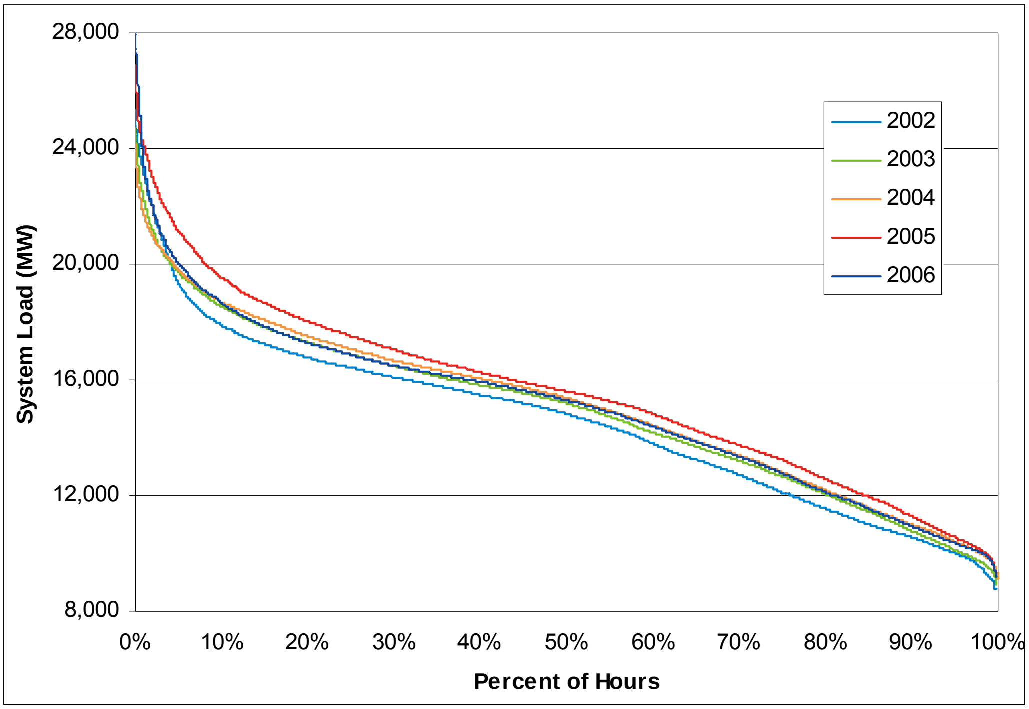

Figure 3-2: New England hourly load-duration curves, 2002 to 2006.

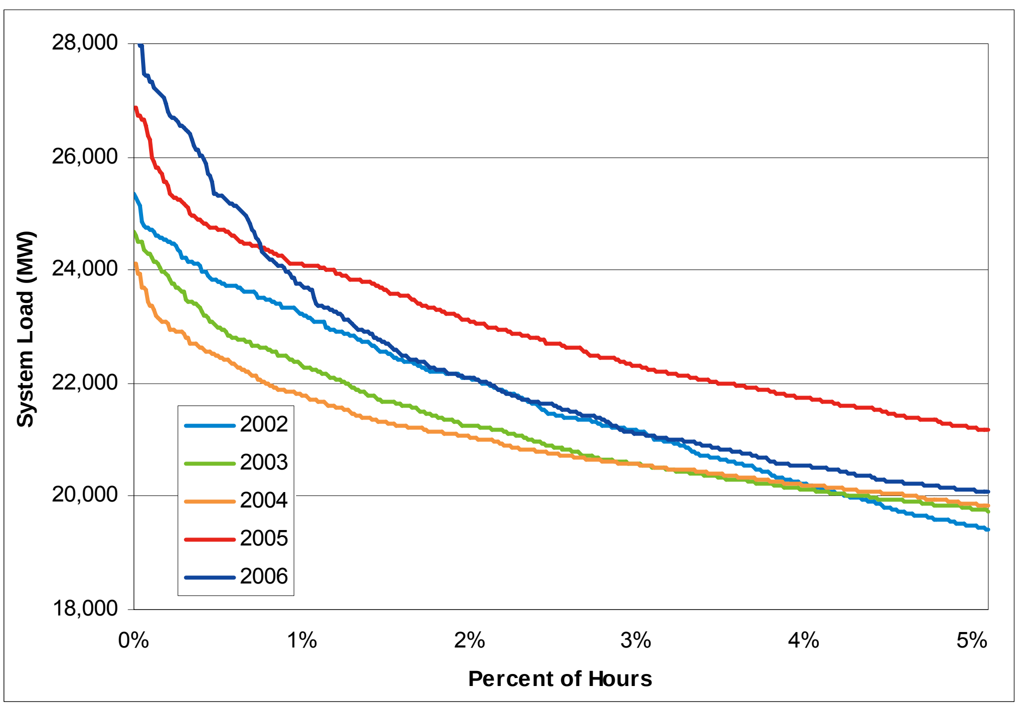

Figure 3-3: New England hourly load-duration curves, top 5% of hours, 2002 to 2006.

3.1.2.1 Load Factor

The *load factor* is the ratio of the average hourly demand during a year to the peak hourly demand. Figure 3-4 shows historical load factors for New England expressed as a percentage. Load factors have fallen significantly over the past 25 years.

New England is a summer-peaking region in which hot weather and the resultant use of air conditioners drives peak consumption. Because summer-peak demand has grown disproportionately compared with average demand, load factors have been declining. For example, on three days in 2006, the peak demand was in excess of the 2005 record peak, while the average demand was down 3.2%. This combination of a decrease in average demand with an increase in peak demand during summer 2006 caused a sharp decline in the load factor. Because this trend of peak electricity consumption growing faster than the average consumption is projected to continue, load factors are likely to continue to decline.

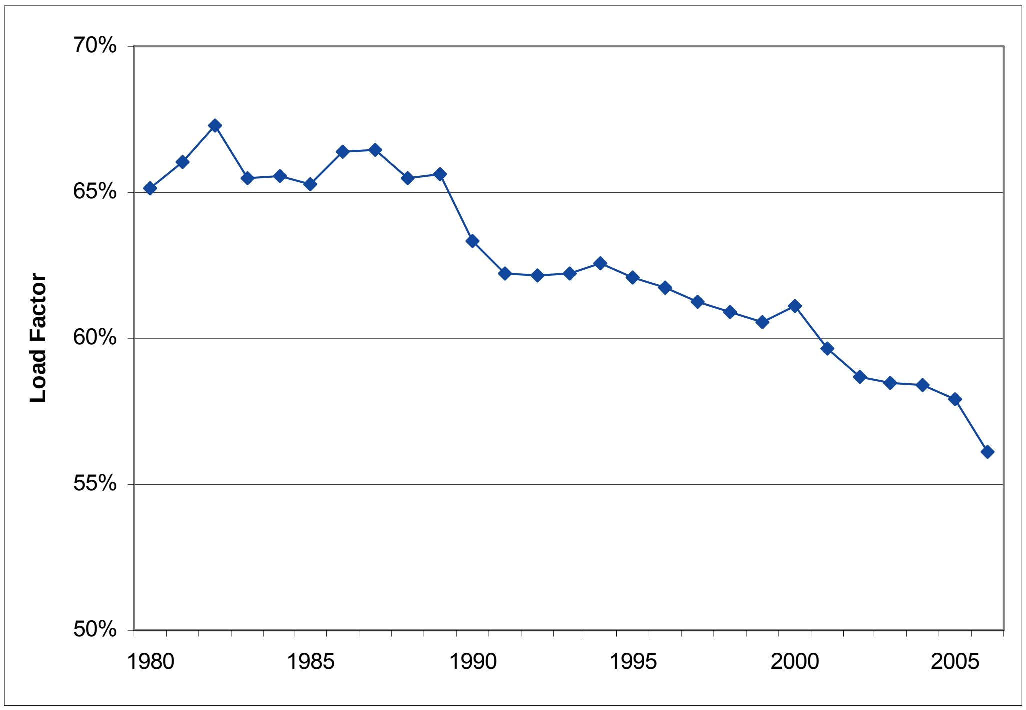

Figure 3-4: New England summer-peak load factor, 1980 to 2006.

The higher electricity consumption in the summer leads to higher wholesale electricity prices and increasing amounts of investment in generation and transmission to meet peak demand for only a small number of hours per year. Additional demand-response resources would decrease peak loads, which would result in higher load factors.[33]

[33] *Demand response* in wholesale electricity markets occurs when market participants reduce their consumption of electric energy in exchange for compensation based on wholesale market prices. The ISO can request demand-response program participants to reduce demand to maintain system reliability. Participants also can voluntarily reduce demand in response to high wholesale prices. The ISO operates three reliability-activated demand-response programs and two price-activated load-response programs (see Section 4.6).

3.1.2.2 Load Obligation

Figure 3-5 compares the 2005 percentages of real-time load obligation (RTLO) cleared in the Day-Ahead Energy Market in each load zone with the 2006 percentages. The average day-ahead load obligation (DALO) in 2006 was 96% of the RTLO, while in 2005, the day-ahead load obligation averaged 95% of the RTLO. Appendix A.1 shows the percentage of RTLO cleared in the Day-Ahead Energy Market in 2006 by load zone and overall.

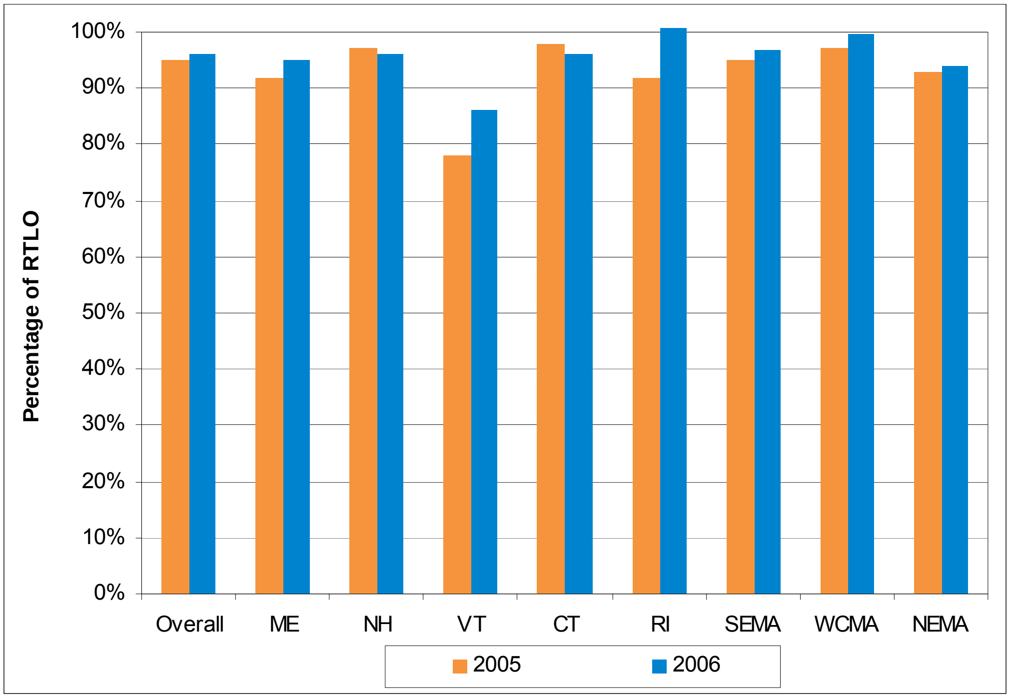

Figure 3-5: Percentage of RTLO cleared in the Day-Ahead Energy Market, 2005 and 2006, by load zone and overall.

3.1.2.3 Day-Ahead Demand and Virtual Trading Trends

Two types of bids can be submitted in the Day-Ahead Energy Market: demand bids at the zonal level and decremental bids at the zonal and nodal levels, often referred to as *virtual demand*. Demand bids may be submitted only by entities that have RTLOs (i.e., they are serving load). Demand bids can be either fixed or price sensitive and are only made at the zonal level. Virtual demand can only be price sensitive, but at the nodal as well as zonal level, and can be submitted by any participant that satisfies the financial assurance requirements.

Both types of bids can be used to hedge the difference between day-ahead and real-time prices. Because load is priced at the zone and demand bids are only zonal, the demand bids are well suited to hedge the price of RTLO. Virtual demand bids can be used to arbitrage differences between day-ahead and real-time prices at a node. They may also hedge a particular load, such as a factory that has elected to receive the nodal LMP.

Virtual trading enables market participants that are not generator owners or load-serving entities (LSEs) to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, and enables arbitrage that promotes price convergence between the Day-Ahead and Real-Time Energy Markets.

Virtual supply offers that clear in the Day-Ahead Energy Market create a financial obligation for the participant to purchase electric energy at the same location during the Real-Time Energy Market. Cleared virtual demand bids create a financial obligation for the participant to sell at the same location in the Real-Time Energy Market. That is, a virtual supply offer in the Day-Ahead Energy Market is "filled" by a purchase in the Real-Time Energy Market, and a virtual demand bid in the Day-Ahead Energy Market is sold in the Real-Time Energy Market. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which the participant's offer or bid clears, plus any applicable transactions costs, including daily reliability cost. Figure 3-6 shows average hourly quantities of fixed and price-sensitive day-ahead demand, and virtual demand and supply, for 2006.

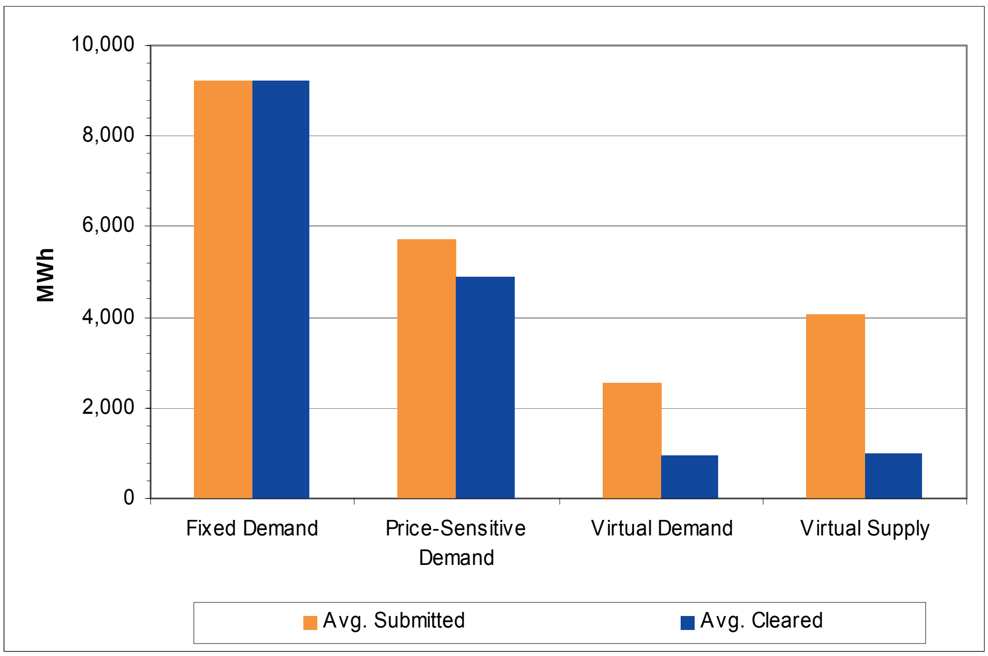

Figure 3-6: Average hourly submitted and cleared demand, virtual demand, and virtual supply, Day-Ahead Energy Market, 2006.

During 2006, 58% of cleared demand bids were fixed bids, insensitive to price, while 30% of the bids were price sensitive. The remaining 12% of cleared day-ahead demand was composed of cleared virtual demand bids representing day-ahead locational purchases of electric energy.

Fixed demand increased, and both bid and cleared price-sensitive demand decreased, in the high-demand periods of June, July, and August, as shown in Figure 3-7. Figure 3-8 shows the total monthly submitted and cleared virtual demand from January 2005 through December 2006. The figure shows that the volumes of both submitted and cleared virtual demand increased in 2006 compared with 2005.

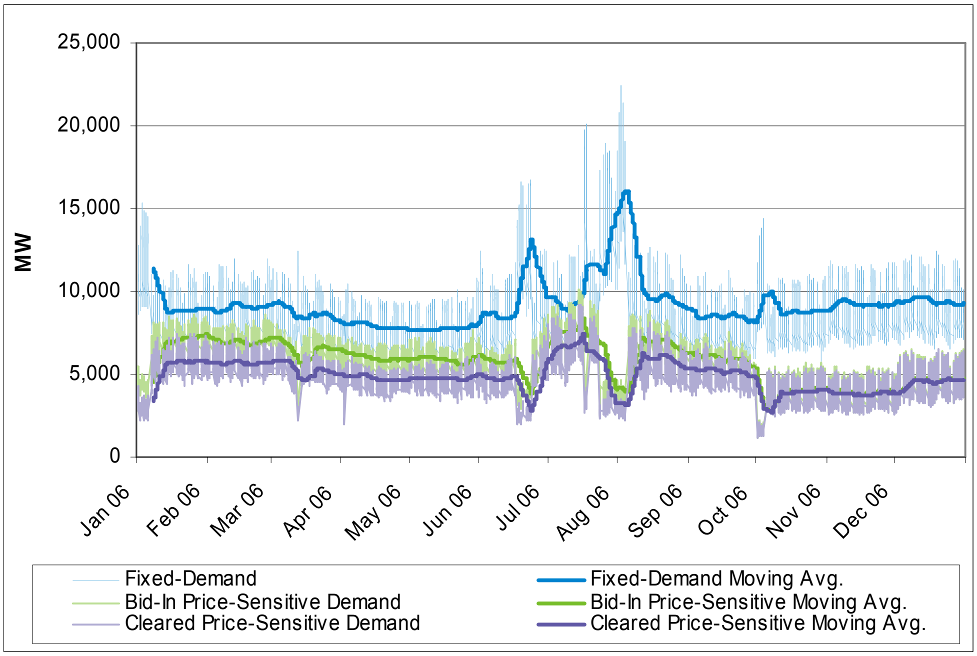

Figure 3-7: Hourly fixed and price-sensitive demand and seven-day moving average.

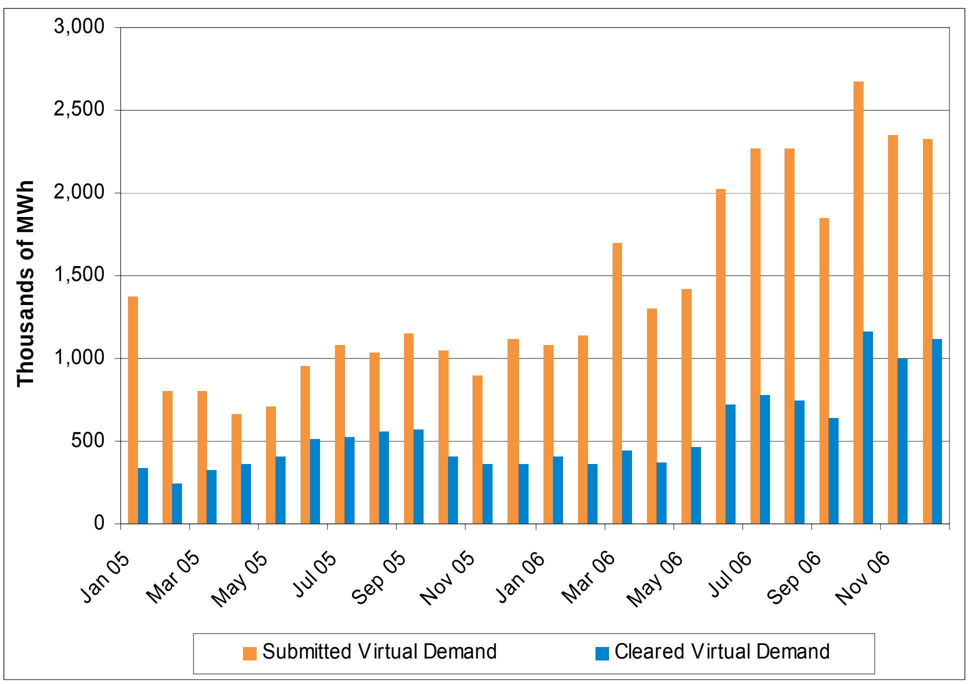

Figure 3-8: Monthly total submitted and cleared virtual demand, January 2005 to December 2006.

Figure 3-9 shows the monthly submitted and cleared virtual supply from January 2005 through December 2006. Similar to the trend in virtual demand, the volume of submitted virtual supply offers increased. Unlike virtual demand, however, the volume of cleared virtual supply decreased for the year. The monthly average number of participants submitting virtual transactions increased from 36 in 2005 to 40 in 2006. Much of the increase in virtual energy (MWh) offered to the day-ahead market, however, was the result of a few participants that increased their virtual trading activity by large percentages to arbitrage the price. This increase in virtual transaction offers is an indication of a more mature market.

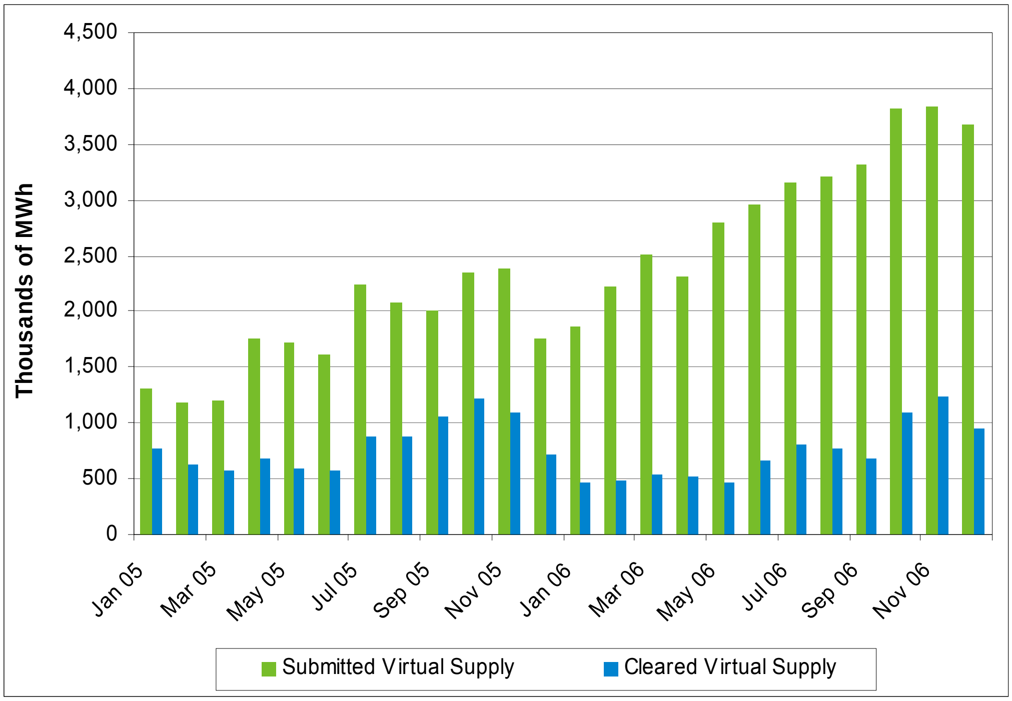

Figure 3-9: Monthly total submitted and cleared virtual supply, January 2005 to December 2006.

3.1.3 Electric Energy Supply in 2006

This section discusses elements of electric energy supply in 2006, including generation capacity, fuel types, self-scheduling, imports and exports, reserve margins, virtual supply, and changes related to the reoffer period.

3.1.3.1 System Capacity

The total 2006 summer system capacity was 31,193 MW, and the total for winter was 34,735 MW.[34] Between 2005 and 2006, summer claimed capability decreased by 44 MW and net capacity imports increased by 154 MW, resulting in a increase in summer system capacity of 110 MW. The 44 MW net decrease in summer claimed capability came from the reactivation of a 14 MW resource, the loss of nine resources with a combined capability of 25 MW, and a 33 MW decrease in capability from net ratings. No new generation resources were added to the system. By comparison, 92 MW of new generation were added in 2005, 656 MW of new generation were added in 2004, 2,949 MW were added in 2003, and 2,786 MW were added in 2002.

Since generation capacity was adequate to meet demand, the disinvestment in 2006 was not a cause for immediate concern. However, ISO analyses indicate that the continued growth in peak demand

[34] *System capacity* includes the capacity physically located in New England adjusted for transfers of capacity between control areas through net purchase and sales.

may require that emergency actions be taken in the 2007 to 2009 timeframe, unless additional generation capacity, demand-side resources, or both become available.[35] As part of the system planning process, the ISO maintains a Generator Interconnection Queue, which tracks the resources that have requested interconnection studies.[36] As of May 4, 2007, 85 projects totaling 10,544 MW were listed in the queue.[37]

Figure 3-10 shows summer capacity (MW) by year and by fuel type for the past five years. Capacity levels were similar in 2003, 2004, and 2005.[38] In 2006, dual-fueled generators capable of burning either oil or natural gas made up 23% of installed capacity, while natural-gas-fired generators made up 25% of installed capacity. Nationwide, about 40% of the existing capacity is gas fired.[39] Many dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas. In most cases, environmental restrictions on emissions from burning oil greatly limit the total number of hours per year a generator can operate on oil.

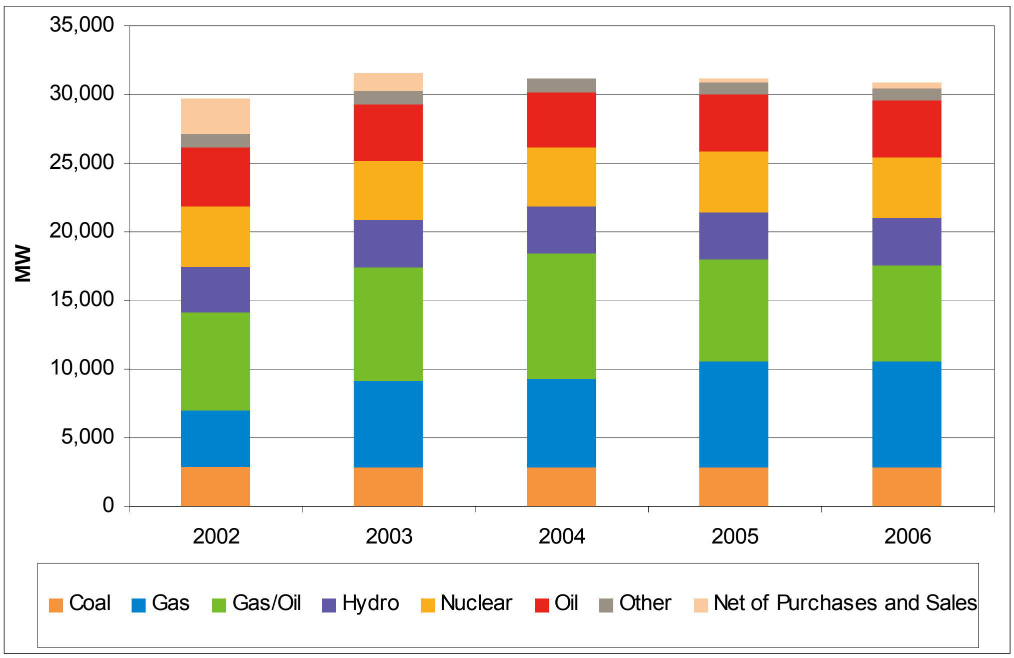

Figure 3-10: System summer capacity by generator type.

Note: Capacity values are for August, summarized from the ISO's forecast reports on capacity, energy, loads, and transmission (CELT Reports). (Available online at http://www.iso-ne.com/trans/celt/report/index.html.)

[35] *2006 Regional System Plan* (hereafter cited as RSP06). (Holyoke: IS0 New England Inc.; October 26, 2006). Available online at http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf or by contacting ISO Customer Service at 413-540-4220.

[36] Additional information on the projects in the Generation Interconnection Queue is available online at the New or Modified Interconnections section of the ISO Web site, http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html.

[37] Presentation by the ISO's Chief Operating Officer at the NEPOOL Participants Committee Meeting. (May 4, 2007). Available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2007/may42007/coo_presentation.pdf.

[38] Detailed information about generating capacity is available in the ISO *Forecast Report of Capacity, Energy, Loads, and Transmission*. See http://www.iso-ne.com/trans/celt/report/index.html.

[39] Energy Information Administration. *Electric Power Generation by Fuel Type* (2005) (hereafter cited as EIA 2005); available online at http://www.eia.doe.gov/fuelelectric.html. The 2005 data are the most recent data available.

Figure 3-11 compares zonal demand and generation for generators within each load zone. Generators within the Maine, Rhode Island, New Hampshire, Vermont, and SEMA load zones produced more power than was used within these zones, while the NEMA, WCMA, and Connecticut load zones all had demand that was greater than the power generated within these zones.

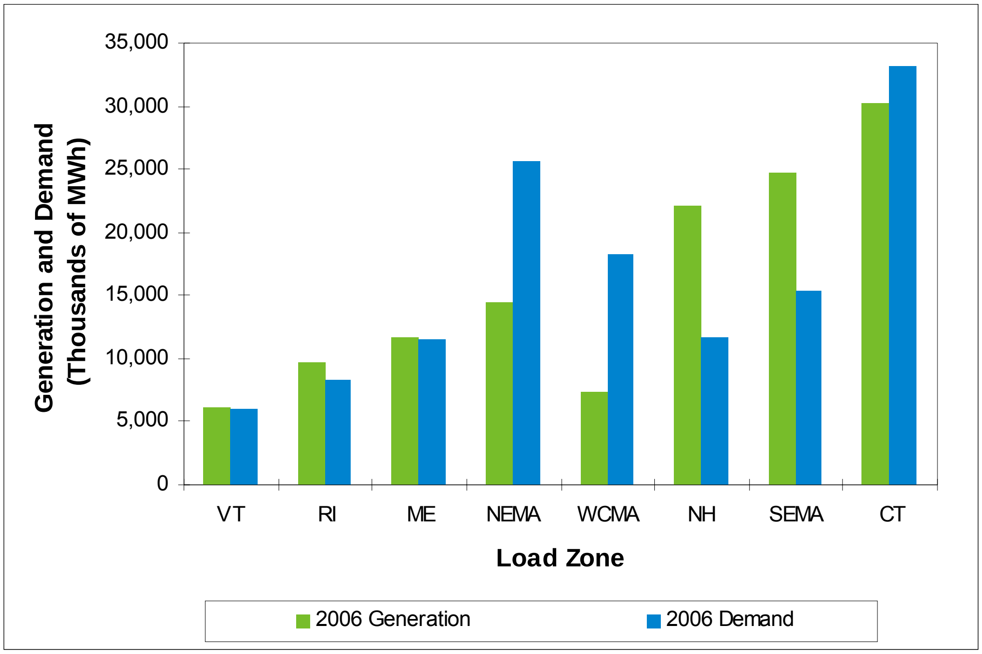

Figure 3-11: Annual generation and electric energy demand by load zone.

3.1.3.2 Generation by Fuel Type

Figure 3-12 shows actual generation by fuel type as a percentage of total generation for 2002 through 2006. The figure shows the fuels used to generate electric power, which differ from the capacity fuel mix shown in Figure 3-10 and the marginal unit by fuel type shown later in Figure 3-21 (see Section 3.1.4.2). The percentage of total generation produced by gas-fired and gas- and oil-fired plants in New England was 42% in 2006. Nationwide, about 19% of electric energy is produced by power plants fueled by natural gas.[40]

NEL decreased by 3.2% from 2005 to 2006. Overall, 2006 generation decreased 2.9%, from 131,877,000 MWh in 2005 to 128,046,000 MWh in 2006. Net imports from other control areas also declined, accounting for the remaining difference between changes in NEL and generation. During 2006, net imports from other control areas totaled 6,188,000 MWh, or about 4.7% of NEL.

[40]EIA 2005.

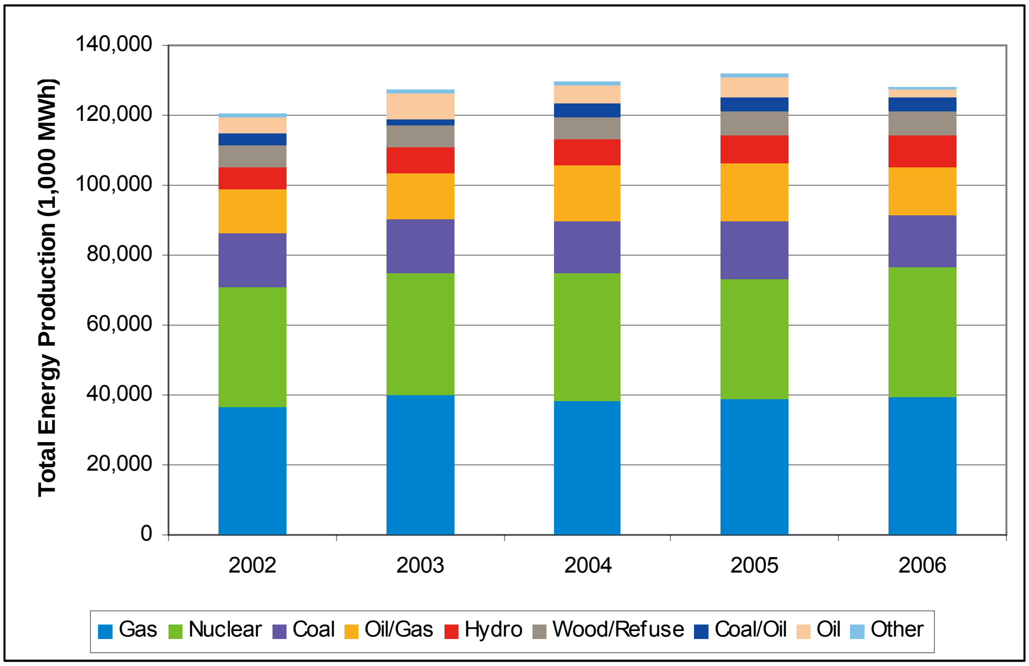

Figure 3-12: New England generation by fuel type.

Note: "Other" includes jet fuel, diesel, composite, and small generation.

3.1.3.3 Renewable Portfolio Standards in New England

Five New England states have established Renewable Portfolio Standards (RPSs) to encourage the development of renewable resources in the region. Maine, Connecticut, and Massachusetts implemented RPSs several years ago, and Rhode Island will do so in 2007. Vermont is implementing regulations for its RPSs that became state law in 2005. A number of other northeastern states, including New York, New Jersey, and Pennsylvania, have also implemented RPSs.

RPSs require competitive retail energy suppliers to procure a certain percentage of their energy from renewable resources over the next five or more years. These resources include small hydro, wind, solar, selected biomass, ocean thermal, and, in some states, fuel cells.[41] To cover their renewable energy requirements, suppliers may buy Renewable Energy Certificates (RECs) created at renewable facilities within the New England region.[42] Alternatively, they may own and operate such resources to create RECs. Suppliers that do not meet their state's RPS requirements with generation are required to meet the requirement by making Alternative Compliance Payments (ACPs) to cover the gap. These funds are to be used to invest in renewable projects within the state. These standards do not apply to municipal utilities.

The specific percentages of electric energy that suppliers must obtain from renewable sources vary by state and year, as do the types of resources included. The RPS requirements in 2006 were 5% for

[41] Pumped hydro is not counted as a renewable resource because the energy for pumping comes mostly from fossil-fueled (i.e., nonrenewable) generating plants.

[42] A *Renewable Energy Certificate* represents the environmental attributes of one megawatt-hour of electricity from a certified renewable generation source for a specific state's RPSs. Providers of renewable energy are credited with RECs, which are sold or traded separately from the electric energy commodity.

Connecticut suppliers, 2.5% for Massachusetts suppliers, and 30% for suppliers in Maine. Rhode Island's RPS requirements start in 2007 at 3%. Vermont's requirement covers just incremental growth from 2005 to 2015. By 2015, the RPS requirements will increase to 14% in Connecticut, 10% in Massachusetts, and 10% in Rhode Island. The requirement in Maine will remain at 30%.

In 2006, renewable resources in New England generated about 9% of the region's total electricity. These resources included wind, refuse, landfill gas, biomass, and conventional hydro generators. The most recent RPS compliance reports completed for Connecticut and Massachusetts are for 2004. These show that suppliers in both states met the RPSs, but in some cases, they paid the ACP because they did not supply all the renewable energy required. Maine, which has a broader definition of what resources count toward meeting its RPS, met its requirement. The ISO's *2006 Regional System Plan* (RSP06) indicates that the New England renewable projects in the ISO Generator Interconnection Queue will not provide sufficient energy to meet the aggregate RPS energy requirements set for New England for 2010.[43] Unless many smaller projects are installed and operating by 2010, or renewable projects outside New England are certified for meeting the New England states' RPSs, the suppliers could fail to meet their RPS goals. RSP06 contains additional information on Renewable Portfolio Standards.

3.1.3.4 Self-Scheduled Generation

Figure 3-13 compares real-time self-scheduled generation with total real-time generation by month for 2006. Self-scheduling is of interest because self-scheduled generators are willing to operate at any price and are not eligible to set clearing prices. Participants may choose to self-schedule the output of their generators for a variety of reasons. For example, those with day-ahead generation obligations may self-schedule in real time to ensure that they meet their day-ahead obligations. Participants with bilateral contracts to provide energy, or fuel contracts that require them to take fuel, also may self-schedule. In addition, participants may self-schedule resources to prevent the units from being cycled off overnight and then started up again the next day. At times, self-scheduling contributes to Minimum Generation Emergencies.[44] Self-scheduled generation averaged between 59% and 70% of total real-time generation per month during 2006, broadly consistent with past trends.

[43] RSP06 is available online at http://www.iso-ne.com/trans/rsp/2006/rsp06_final_public.pdf or by contacting ISO Customer Service at 413-540-4220.

[44] A *Minimum Generation Emergency* is an emergency declared by the ISO in which the ISO anticipates requesting one or more generating resources to operate at or below its economic minimum limit so that it can manage, alleviate, or end the emergency.

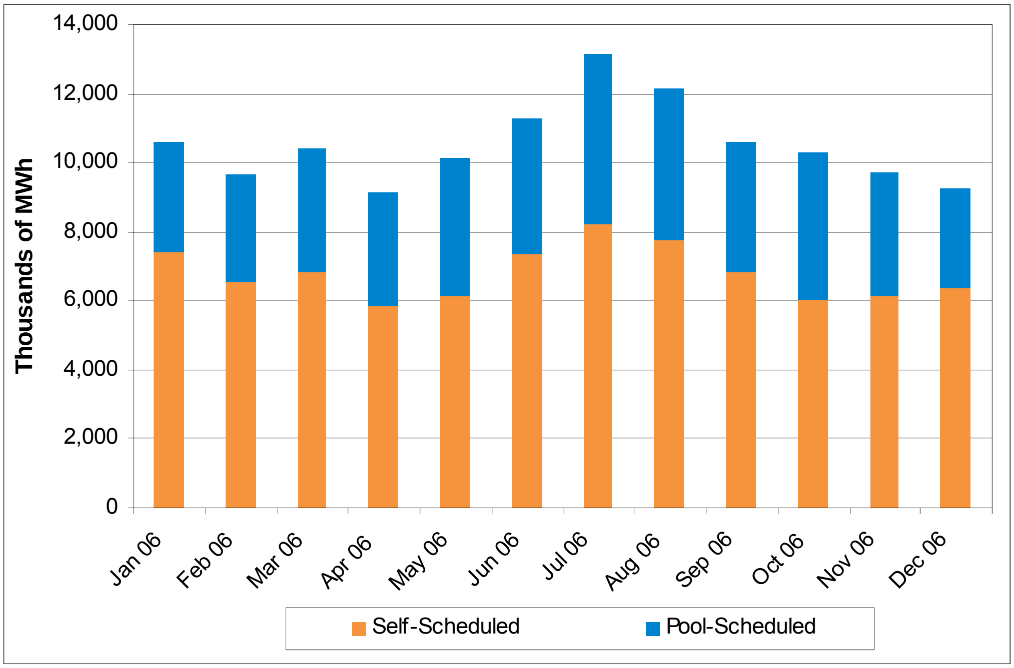

Figure 3-13: Self-scheduled and pool-scheduled real-time generation, 2006 monthly totals.

Table 3-2 shows the percentage of generation that was self-scheduled during 2006 by generator fuel type. Nuclear-fueled generators self-scheduled 99% of their generation, while coal/oil, oil, and jet fuel generators self-scheduled less than 20% of their generation. The percentage of generation self-scheduled is highest in off-peak hours and lowest in on-peak hours. This pattern suggests that participants may use self-scheduling as a tool to prevent generating units from being cycled on and off.

Table 3-2
Percentage of Generation Self-Scheduled by Generator Fuel Type, 2006

Generator Type	% of Generation
Oil	10
Jet Fuel	15
Coal/Oil	18
Gas	42
Oil/Gas	46
Coal	62
Wood/Refuse	77
Hydro	79
Diesel Oil	95
Nuclear	99

3.1.3.5 Day-Ahead Supply Compared with Real-Time Supply

Figure 3-14 shows the amount of supply that cleared in the day-ahead market as a percentage of real-time supply by month for 2005 and 2006. In this figure, supply includes generation plus imports but not virtual transactions. Overall, the amount of supply cleared in the day-ahead market as a percentage of real-time supply increased from an average of 88.2% in 2005 to an average of 91.7% in 2006. Variability from month to month can be attributed to seasonal variations in load and changes in participant offer behavior.

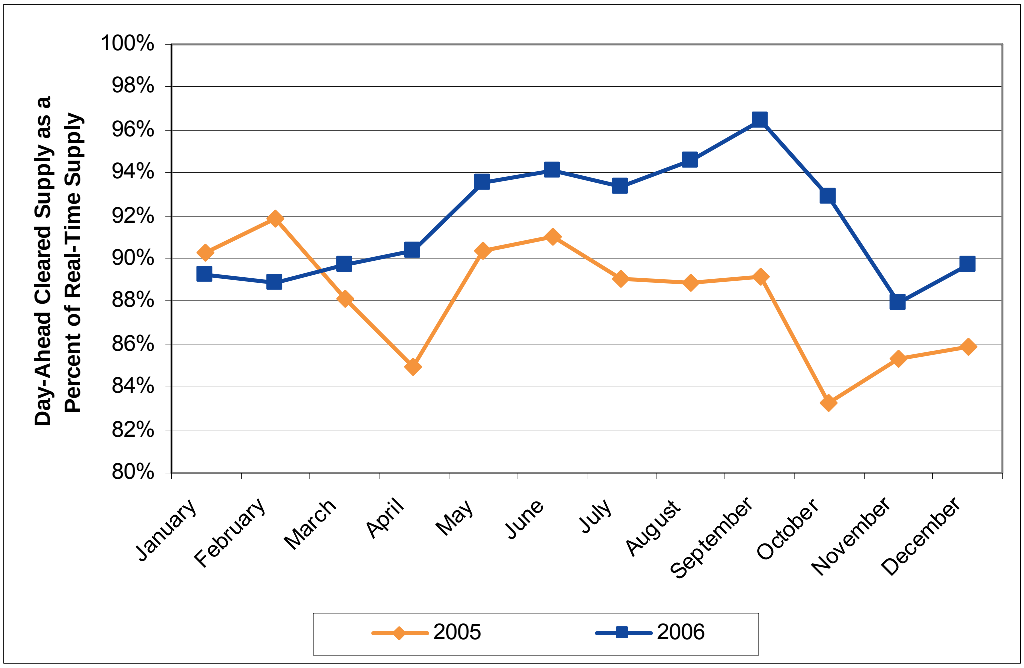

Figure 3-14: Day-ahead cleared supply as a percentage of real-time supply, 2005 and 2006.

3.1.3.6 Imports and Exports

During 2006, New England remained an overall net importer of power; its net imports from Canada exceeded the net exports to New York. Net imports from neighboring regions amounted to 6,090,000 MWh for the year, down from 6,296,000 MWh in 2005. The 2006 net imports represented 4.6% of the annual NEL in New England. In 2006, New England had 878,000 MWh of net exports to New York, compared with 115,000 MWh of net exports in 2005. Net imports from Canada were 6,411,000 MWh in 2005, compared with 6,968,000 MWh in 2006. Figure 3-15 shows net interregional power flows for 2001 through 2006, and Figure 3-16 shows imports and exports by interface for 2006.

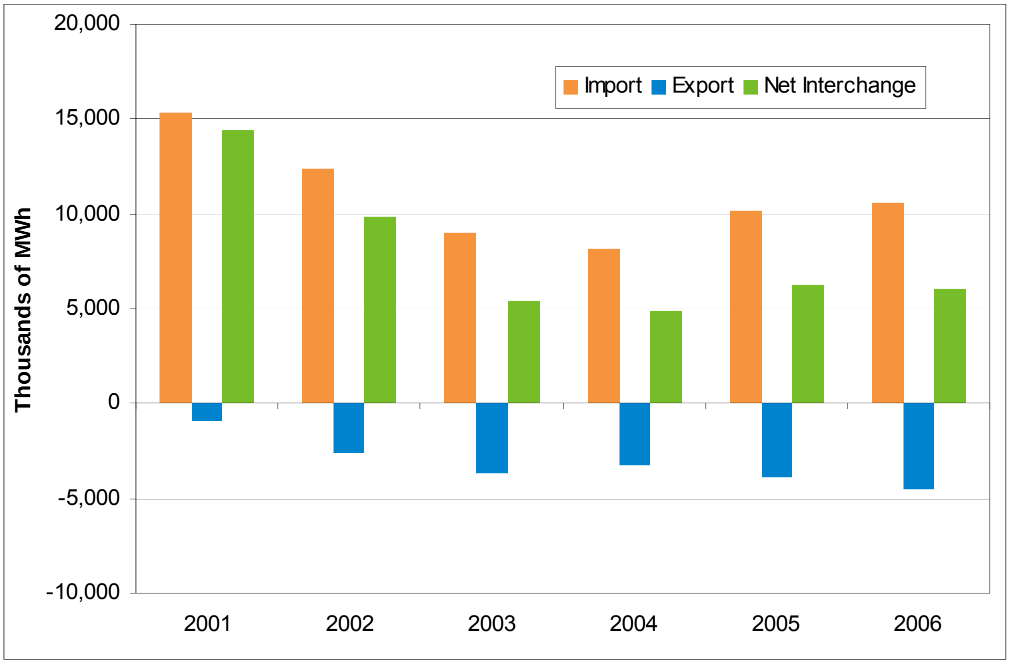

Figure 3-15: New England annual imports, exports, and net interchange, all interfaces.

Although New England is a net exporter to New York overall, a review of the modeled ties shows that New England is a net importer from New York over the alternating current (AC) interface connecting New York to western New England and a net exporter to New York over the Cross-Sound Cable (CSC) interface connecting Connecticut to Long Island. Net exports increased from 2005 to 2006 as a result of both an increase in exports on the CSC and a decrease in imports on the New York AC ties. Prices in Long Island are significantly different from the interface price at the New York ISO's (NYISO) NEPEX, the bus where exports from New York to New England are priced.[45] Much of the transfer of power between New York and New England is the result of contracts, in particular a long-term contract for exports over the CSC.

[45] A *bus* is a point of interconnection to the system.

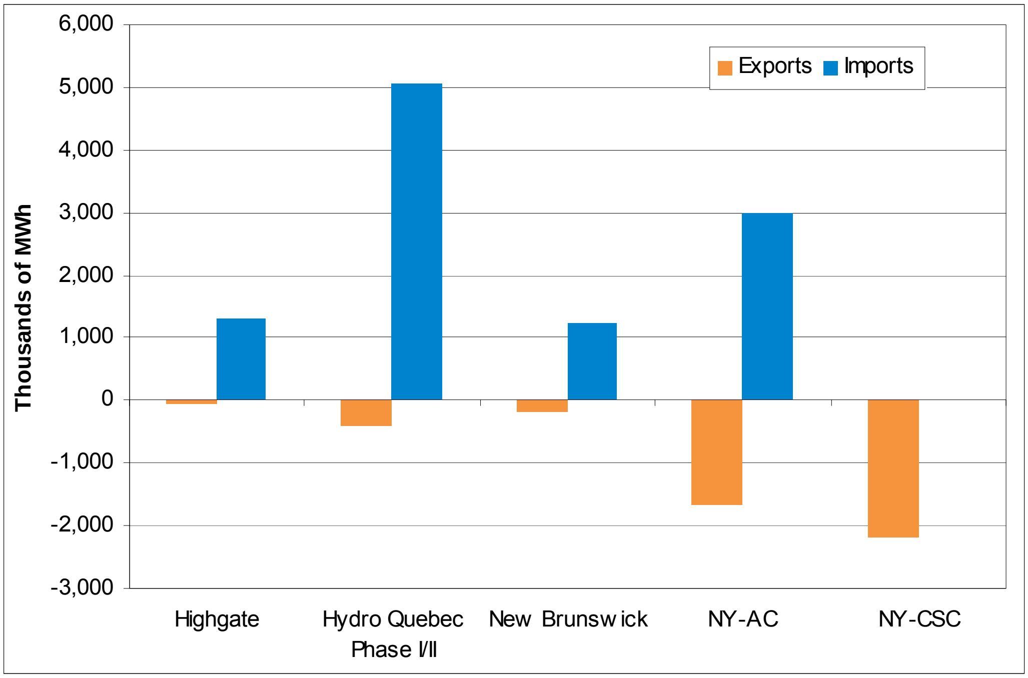

Figure 3-16: New England imports and exports by interface, 2006.

Note: The New York–AC interface is the collection of AC tie lines connected through Connecticut, Massachusetts, and Vermont. The NY–CSC interface is the Cross-Sound Cable.

Figure 3-17 shows the price difference between the ISO New England Roseton pricing location, where exports to New York are priced, and the NEPEX bus.[46,47] The figure also shows the imports and exports on the AC ties with New York. Points on the figure that are above zero indicate hours when prices in New England were higher than prices in New York. The figure shows that no clear relationship exists between these price differences and net interchange with New York. If trading between the two markets functioned well, the data in the figure would be expected to cluster in the upper-right and lower-left quadrants. This would reflect power flowing from low-priced to high-priced areas. One reason the data do not exhibit the expected clustering pattern is that the bulk of the transactions over the intertie are self-scheduled contracts that are insensitive to price. In addition, financial transactions over the intertie may be required to flow against the positive price differential between the areas.

Even with self-scheduling, arbitrage by market participants could result in price convergence between the two pricing locations. The lack of convergence between New England and New York has been previously identified.[48] One of the underlying causes is the time required for approval of a real-time external transaction (sometimes termed *notification time*). A second cause is the duration of the external transaction. Currently, the New York and New England areas require a one-hour notification

[46] The New England Roseton bus and the New York NEPEX bus are proxy buses used to price imports and exports over all seven AC interconnections between the two control areas.

[47] No similar analysis exists for the CSC interface because transmission is not available beyond the long-term contract.

[48] *2005 Annual Markets Report* (hereafter cited as AMR05). (Holyoke: ISO New England Inc.; 2005). p. 36. Available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2005/2005_annual_markets_report.pdf or by contacting ISO Customer Service at 413-540-4220.

period and a one-hour transaction duration. Because of these time requirements, a participant attempting to arbitrage the two markets must believe the price difference will persist for a minimum of two hours.[49,50] These structural requirements, or transaction costs, are likely to be significant factors preventing further convergence of the prices.

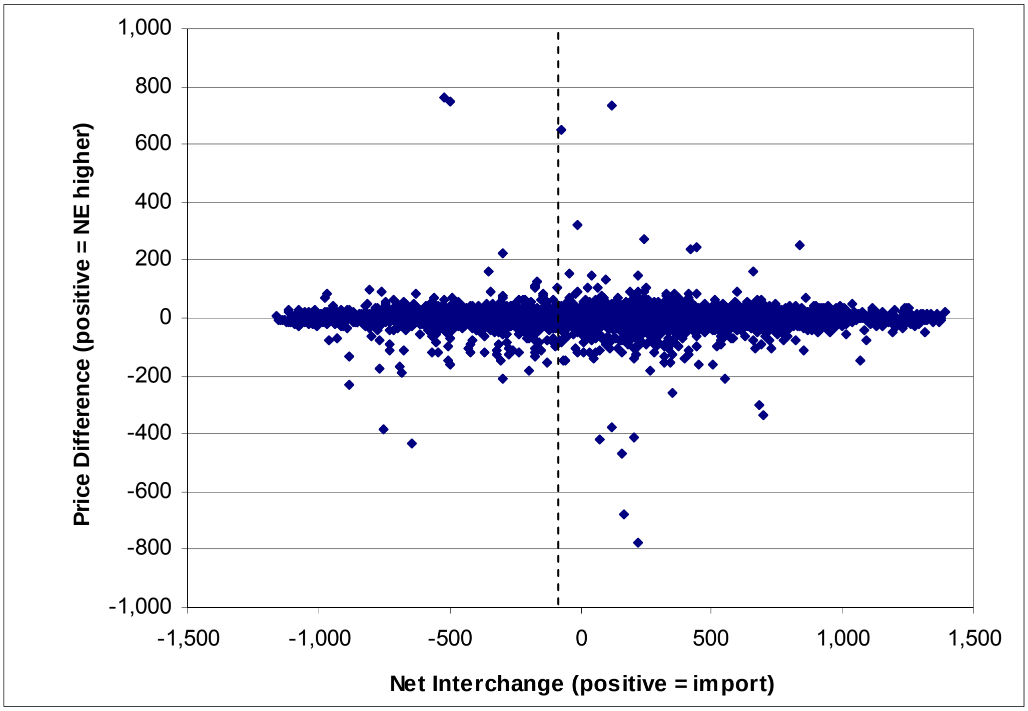

Figure 3-17: New England Roseton LMP minus New York NEPEX locational-based marginal price and net interchange with New York, 2006.

3.1.3.7 Operable Capacity Margins

The *operable capacity margin* is the sum of generating capacity and net imports minus the sum of load and reserve requirements. It counts as available generation that may have been unavailable due to start-up-time or subarea export constraints.[51] Figure 3-18 shows operable capacity margins for the peak-demand hour of each month in 2006. As usual, margins were low in June, July, and August, which is consistent with summer-peak demand. The capacity margin for the peak-demand hour in

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[49] See the ISO's OP 9, *Scheduling and Dispatch of External Contacts.* (June 1, 2005). Available online at http://www.iso-ne.com/rules_proceds/operating/isone/op9/index.html.

[50] Two solutions to this issue have been proposed. One proposal has been to allow the ISOs to do virtual regional dispatch during the hour so that prices from the two ISOs approach one another. The other proposal has been to reduce both the notification and duration times so that participants have improved trading ability.

[51] To conduct resource planning reliability studies within New England, the region is modeled as 13 subareas and three neighboring control areas. These areas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore (BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); Rhode Island bordering Massachusetts (RI); Southwest Connecticut (SWCT); Norwalk/Stamford (NOR); and Connecticut (CT). Greater Connecticut includes the CT, SWCT, and NOR subareas. Greater Southwest Connecticut consists of the SWCT and NOR subareas. The three neighboring control areas are New York, Hydro-Québec, and the Canadian Maritimes.

August was negative. OP 4 was declared in this hour, and despite the capacity shortage condition, the system maintained reliability.[52] The events of August 2 are discussed in more detail in Section 3.1.6.

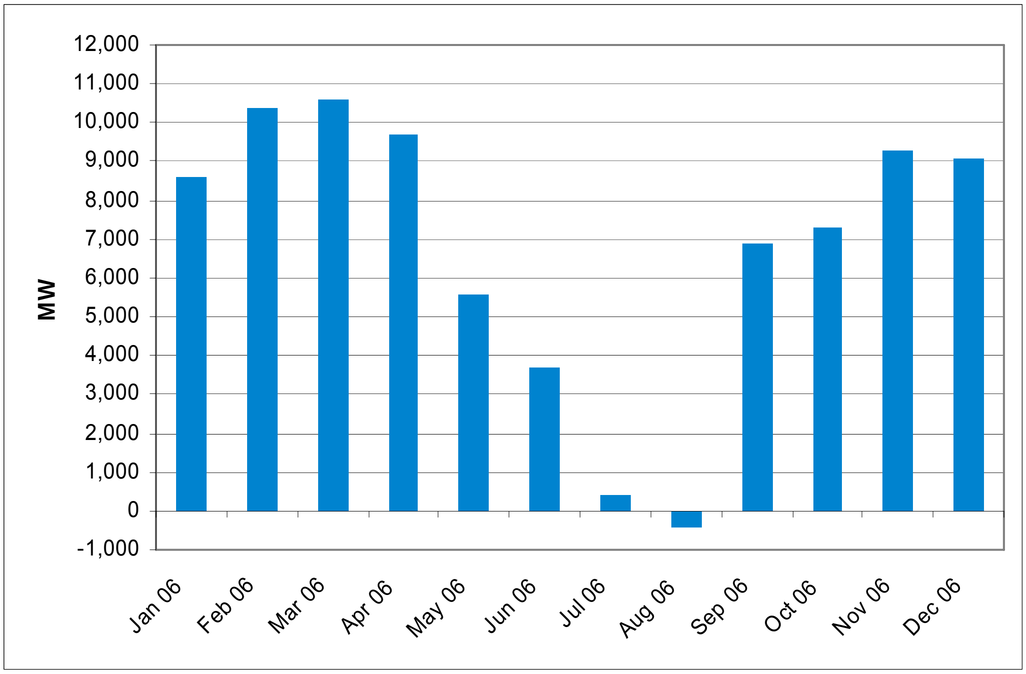

Figure 3-18: Monthly peak-hour operable capacity margins.

3.1.4 Electric Energy Prices in 2006

This section provides information about wholesale electricity prices in New England, including the impact of fuel costs on prices, price separation between load zones, and capacity deficiencies that resulted in price spikes.

3.1.4.1 Annual Real-Time Electric Energy Prices

Figure 3-19 and Figure 3-20 show the real-time system electricity price for New England over the past five years as duration curves with prices ordered from highest to lowest. For the Interim Market period, the system price is the single energy clearing price (ECP). For March 2003 to December 2006, the system price is the load-weighted Real-Time Energy Market LMP. For each year, the duration curve shows the percentage of time the system price was at or above the price levels shown on the vertical axis. The figures show that typical prices during 2006 were much lower than prices during 2005 but higher than those in earlier years. The decline from 2005 was primarily due to decreased fuel prices (as discussed in the next section) and lower demand. The peak prices shown in Figure 3-20 were also lower than in 2005. Appendix A.2 includes LMP summary statistics for on- and off-peak hours and the monthly average day-ahead and real-time LMPs by zone.

[52] The ISO's system operating procedures are available online at http://www.iso-ne.com/rules_proceds/operating/ sysop/index.html.

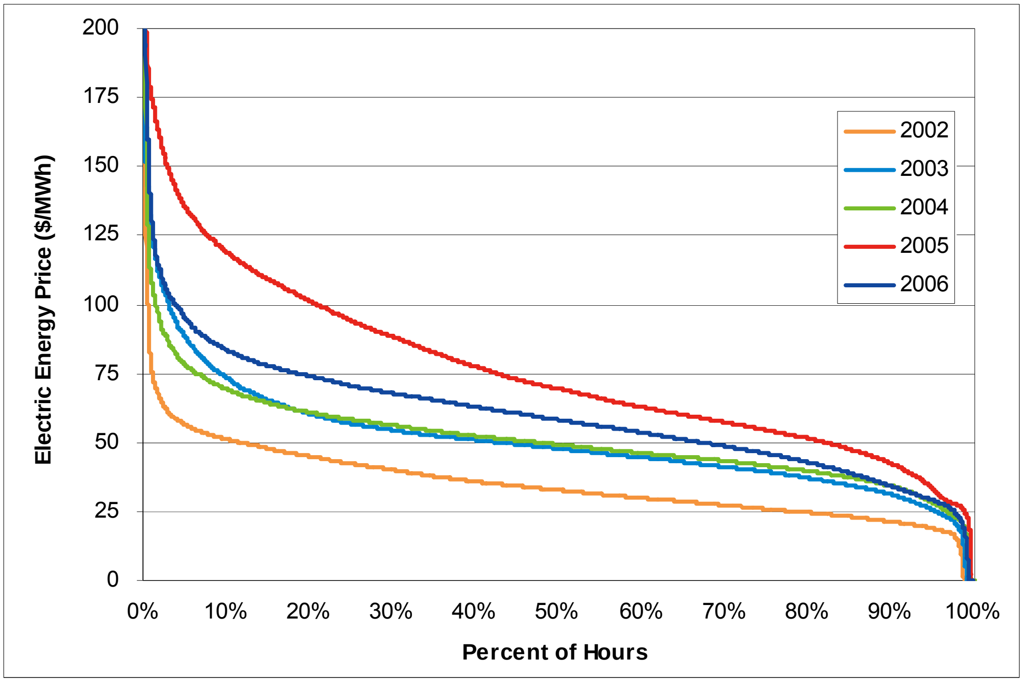

Figure 3-19: System real-time price-duration curves, prices less than $200/MWh, 2002 to 2006.

Note: System price is the single ECP for the Interim Market period ending February 28, 2003, and load-weighted Real-Time Energy Market LMPs for March 2003 to December 2006.

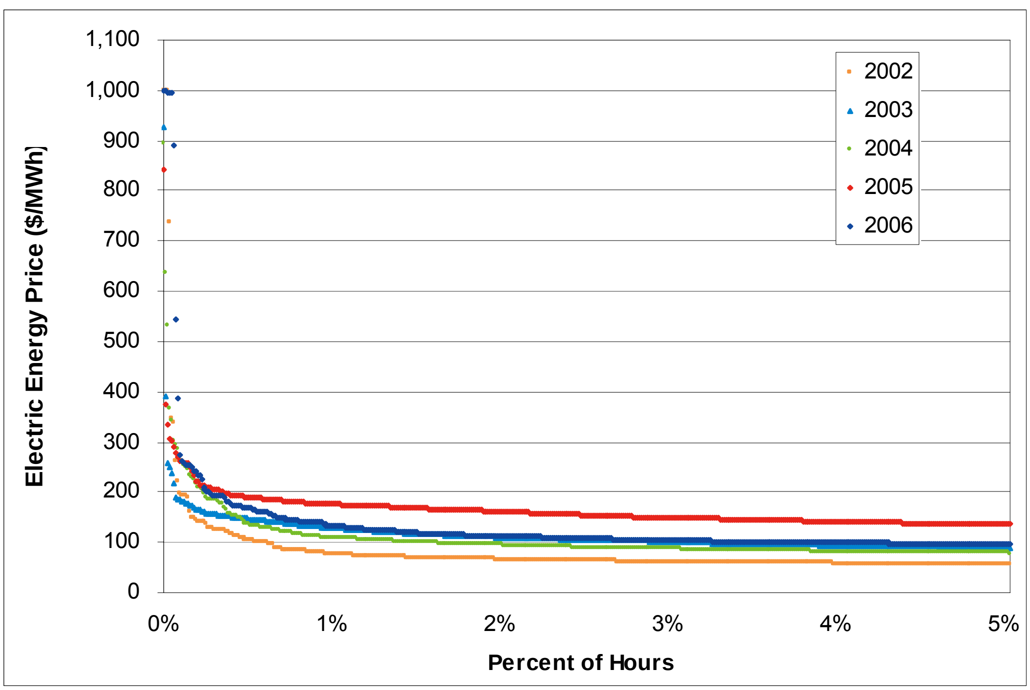

Figure 3-20: System real-time price-duration curves, prices in most expensive 5% of hours, 2002 to 2006.

Note: System price is the single ECP for the Interim Market period ending February 28, 2003, and load-weighted Real-Time Energy Market LMPs for March 2003 to December 2006.

3.1.4.2 Electricity Prices and Fuel Costs

Figure 3-21 shows the marginal, price-setting, input fuels during 2006 as a percentage of pricing intervals in the year. Binding real-time transmission constraints produce instances when the system has more than one marginal generating unit because a marginal unit is located on each side of a constraint—one setting price for the constrained area and one setting price for the unconstrained area. Since the analysis includes each marginal unit, the percentages in the figure total more than 100%. Some types of generating units, such as nuclear power stations, were never marginal during 2006 and are not included in the figure. The figure shows that units burning natural gas were marginal 73% of the time during the period. Units capable of burning both gas and oil, most of which burn gas as their primary fuel, were on the margin 34% of the time. These results show the extent to which the New England electricity prices depend on the offers of units capable of burning natural gas. This dependence on gas and oil to generate electricity contributes to the volatility of the region's electricity price.

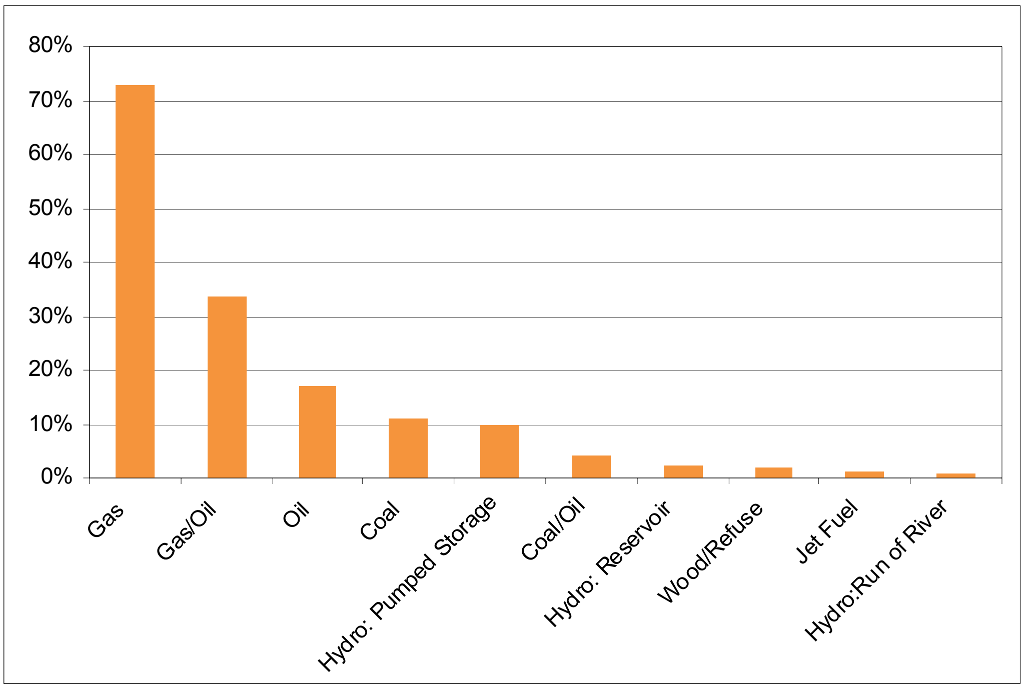

Figure 3-21: Percentage of pricing intervals by marginal fuel type in real time, 2006.

Note: The hourly calculations are the result of summing each five-minute interval in which the fuel type was marginal.

Figure 3-22 shows the daily average real-time system price plotted against the daily average variable production cost of hypothetical power plants burning either natural gas or oil.[53] The gas plant production costs are based on a gas plant with a heat rate of approximately 7,000 British thermal units (Btu) per kilowatt-hour (kWh), while the oil plant production costs are based on a heat rate of approximately 10,500 Btu/kWh.[54] The day-ahead spot prices for fuel are used to calculate each unit's

[53] Averages are not weighted.

[54] A generator's *heat rate*, traditionally reported in Btu/kWh, is the rate at which it converts fuel (Btu) to electricity (kWh) and is a measure of the thermal efficiency of the conversion process.

variable costs. Unexpected system conditions, such as an unplanned generator or transmission line outage, or unexpected high demand levels may cause electricity price spikes unrelated to fuel prices.

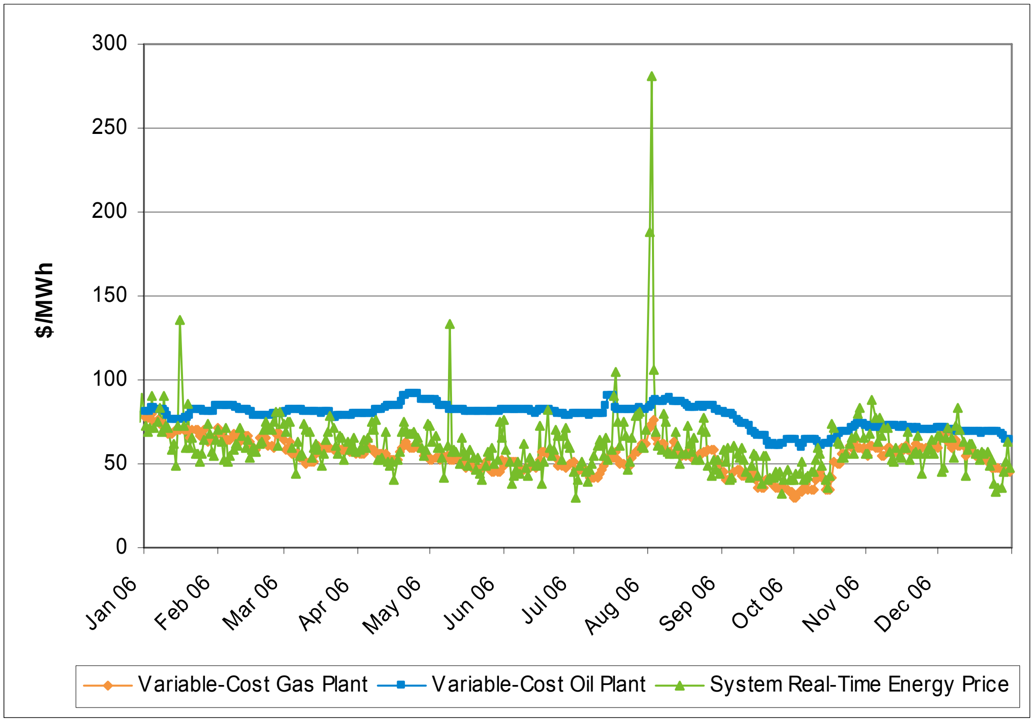

Figure 3-22: Daily average real-time system price of electricity compared with variable production costs.

Since fuel is the largest variable expense for most electricity generating plants, in a competitive market, the electric energy offers that fossil fuel generators make are sensitive to variation in fuel prices. Hence, electricity market clearing prices rise and fall with changes in fuel prices. Figure 3-22 shows the high correlation between gas plant costs and electricity prices.[55] This is consistent with the marginal fuels data shown in Figure 3-21. Electricity prices do not precisely track underlying fuel costs because fuels used by the marginal generators vary, and changing demand levels cause movements along the supply curve.

Table 3-3 shows indices for average annual prices of several fuels for each of the last seven years, each indexed to its value in 2000. Generators that burn natural gas and No. 6 oil (1%) were on the margin a majority of the time in New England, as was shown in Figure 3-21. Natural gas prices were 25% lower in 2006 than in 2005. The lower natural gas prices were the primary cause of the lower overall electricity prices shown in Figure 3-19.

[55] The correlation coefficient of estimated variable costs of a gas plant to daily system real-time energy prices is 0.72.

Table 3-3
Fuel Price Index, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004	2005	2006
Natural gas	1.00	0.88	0.75	1.30	1.37	1.97	1.48
No. 2 oil	1.00	0.84	0.80	0.99	1.32	1.95	2.15
No. 6 oil (1%)	1.00	0.83	0.90	1.09	1.12	1.66	1.84
High-sulfur coal	1.00	1.72	1.11	1.32	2.22	2.38	2.02
Low-sulfur coal	1.00	1.76	1.15	1.35	2.35	2.49	2.22
Jet fuel	1.00	0.82	0.78	0.95	1.31	1.87	2.14
Kerosene	1.00	0.82	0.77	0.95	1.31	1.89	2.15
Diesel	1.00	0.84	0.80	0.98	1.33	1.97	2.27

To help isolate electric energy price differences due to changes in fuel prices, the ISO calculates an average annual electric energy price adjusted for fuel prices. The fuel-adjusted average electric energy price normalizes the electricity market clearing prices for the variation in the prices of fuels used by price-setting generating units. The analysis uses the year 2000 as a base and normalizes the price of the marginal unit in each five-minute interval for the change in its fuel price compared with fuel prices in 2000.

Fuel-adjusted electric energy prices for the Interim Markets period of January 2000 through February 2003 were derived by adjusting each five-minute real-time marginal price (RTMP) by a monthly index of spot-market prices for the fuel used by the generator setting the RTMP. Fuel-adjusted electric energy prices for the Standard Market Design (SMD) period of March 2003 through December 2006 were derived by adjusting the five-minute Hub real-time LMPs the same way the Interim Market prices were adjusted.

Five-minute prices set by hydro plants were adjusted by a monthly index of average electric energy prices to reflect changes in opportunity costs. Nuclear, wood, composite, refuses, and other fuels for which reliable prices were not available were not adjusted. These unadjusted prices should not significantly affect the results because units using these fuels were marginal less than 1% of the time during the seven-year analysis period. The adjusted five-minute electric energy prices were then averaged to the hourly level and weighted by hourly load before calculating the yearly averages.

Table 3-4 and Figure 3-23 show yearly average actual and fuel-adjusted real-time electric energy prices for New England. These averages are load weighted. Actual average real-time electric energy prices in 2006 were lower than in 2005 but higher than in previous years. After adjusting for the price of fuels used to generate electricity, the average electric energy price in 2006 was similar to prices in the previous years. This finding supports the hypothesis that the lower fuel prices contributed to the lower actual electric energy prices in 2006.

Table 3-4
Actual and Fuel-Adjusted Average Real-Time Electric Energy Prices, $/MWh

	2000	2001	2002	2003	2004	2005	2006
Load-weighted actual electric energy price (ECP during Interim Markets; Hub LMP during SMD)	45.95	43.03	37.52	53.40	54.44	79.96	62.74
Load-weighted electric energy price normalized to 2000 fuel-price levels	45.95	48.60	46.65	43.51	43.33	44.99	42.64

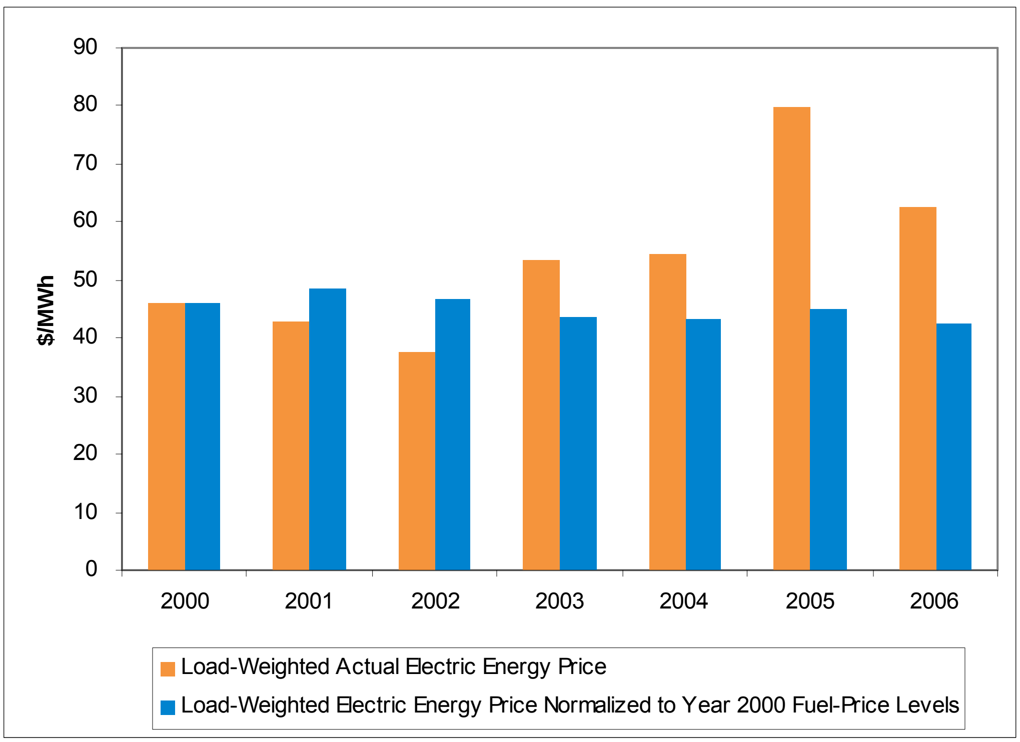

Figure 3-23: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2006.

The variation among fuel-adjusted yearly average prices was less than among average unadjusted prices. Adjusted prices in 2001 and 2002, years with lower overall natural gas prices than 2000, were higher than actual prices, while energy prices in 2003, 2004, 2005, and 2006, when gas prices were higher, were lower after adjustment.

This analysis has limitations. The most significant is that if the relative prices of alternative fuels differed, the marginal generating units could also change. This analysis, however, assumes that the marginal units remained the same, while their fuel prices varied. Second, the analysis does not make any adjustment for changes in offer rules or unit-commitment models over the seven-year period. It also does not account for variations in emissions costs.

3.1.4.3 Electric Energy Prices throughout the Year

Table 3-5 shows the 2006 average, minimum, and maximum LMP values for the Hub and the eight load zones in New England. On average, day-ahead prices exhibited a slight premium over their real-time counterparts. Zonal prices varied from the Hub because of the existence of congestion and losses. During 2006, average prices were similar across the Hub and New England load zones, with the exception of Maine and Connecticut. Average LMPs in Maine were several dollars lower than in other areas, as a result of marginal losses and negative congestion costs on Maine LMPs, while average LMPs in Connecticut were higher than in other areas. Average day-ahead LMP differences between Maine and Connecticut were $10.14/MWh, or about 18%. During high-demand periods, Connecticut is frequently import constrained, which results in congestion and higher prices. Connecticut also experiences relatively high loss components because of its distance from economic generation combined with weak transmission lines.

Table 3-5
Summary LMP Statistics by Zone for 2006, All Hours, $/MWh

Location/ Load Zone	LMP					
	Average		Minimum		Maximum	
	Day Ahead	Real Time	Day Ahead	Real Time	Day Ahead	Real Time
Internal Hub	60.93	59.68	22.02	0.00	217.43	1,015.86
Maine	57.13	56.08	22.03	−2.85	191.46	918.87
New Hampshire	59.23	58.40	22.27	0.00	214.25	95.74
Vermont	61.25	60.14	22.67	0.00	222.66	1,001.11
Connecticut	67.27	64.53	22.05	0.00	311.50	1,057.08
Rhode Island	59.10	58.06	21.27	0.00	214.72	997.77
SEMA	59.49	58.18	21.33	0.00	216.73	1,004.34
WCMA	61.25	60.03	22.17	0.00	218.84	1,015.94
NEMA	60.59	60.43	21.91	0.00	247.50	1,203.91

The day-ahead Hub price averaged $60.93/MWh, while the corresponding real-time price averaged $59.68/MWh, a $1.25/MWh (2.0%) difference.[56] Maximum hourly prices never reached $1,000/MWh in the Day-Ahead Energy Market but exceeded $1,000/MWh for a number of hours in the Real-Time Energy Market.

[56] These average prices are not load weighted.

Figure 3-24 shows the difference between real-time and day-ahead Hub LMPs. Prices in the Real-Time Energy Market are more variable than prices in the Day-Ahead Energy Market as a result of unexpected events, such as generator and transmission contingencies or variations in the actual demand compared with the demand forecast. At the Hub, the day-ahead price was higher than its real-time counterpart 60% of the time. Moderate differences between day-ahead and real-time prices occurred throughout the year.

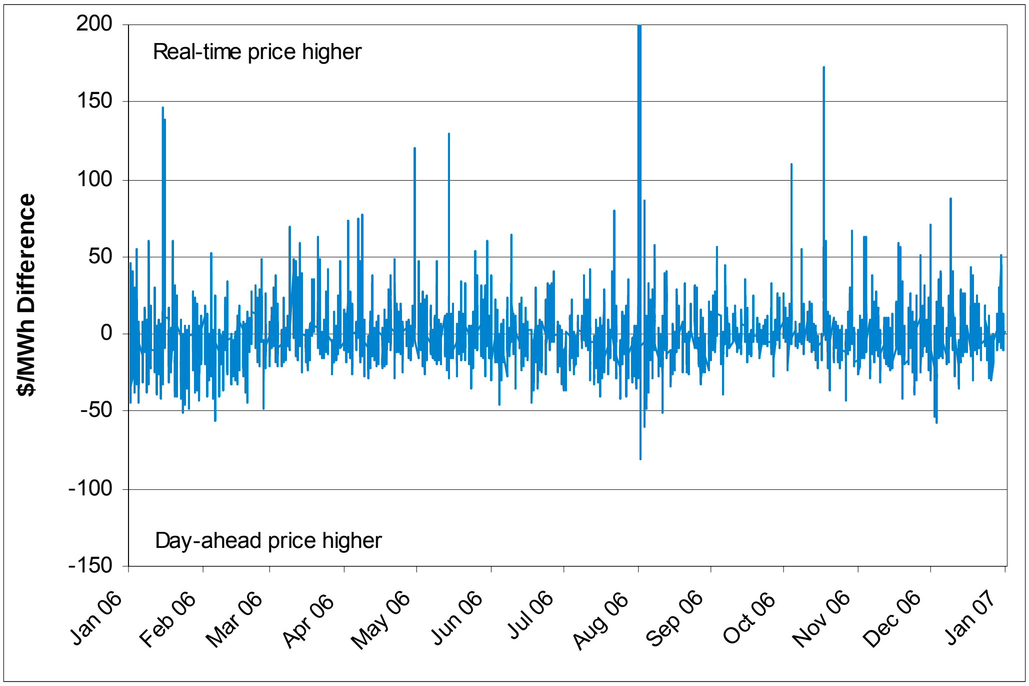

Figure 3-24: Hourly real-time Hub price minus day-ahead price, differences less than $200/MWh, January to December 2006.

The largest difference between day-ahead and real-time prices occurred on August 2, in hour ending (HE) 3:00 p.m.[57] The day-ahead price was $206.09/MWh, while the real-time price was $1,015.86/MWh, a difference of $809.77/MWh. OP 4 was in effect at the time, and a deficiency of 10-minute reserves caused the ISO to declare a Reserve-Shortage Pricing Event.[58] During this event, which spanned four hours, the energy component of the five-minute LMPs was administratively set at $1,000/MWh, resulting in the high real-time price. Congestion and marginal losses caused some locational prices to be higher or lower than $1,000/MWh.

On the maps in Figure 3-25, the average annual nodal LMPs are shown as color gradations from blue, representing $53/MWh, to red, representing prices of $80/MWh and higher. The Norwalk/Stamford area of Connecticut had the highest average prices, while Maine had the lowest prices. Norwalk/Stamford has historically been an area with import constraints and higher prices than other areas. In 2006, work on transmission upgrades as part of the Southwest Connecticut Reliability

[57] LMPs are based on *hour endings*, which denote the preceding hourly time period. For example, the time period of 12:01 a.m. to 12:59 a.m. is "hour ending 1."

[58] The ISO declares a *Reserve-Shortage Pricing Event* when the control area is experiencing a deficiency in total 10-minute operating reserves or if the ISO is taking actions to maintain 10-minute operating reserves. It will also declare this condition when the control area is experiencing a deficiency in total operating reserves that has lasted for at least four hours and the ISO has begun taking actions to maintain or restore operating reserves. See Section 3.3.1 for more information on operating reserves.

Project required outages that contributed to congestion. However, when completed, the project will reduce transmission constraints between Norwalk/Stamford and the rest of Southwest Connecticut. LMPs in northwestern Connecticut are higher than in most other areas because of limited economic generation in the area combined with limited import capacity. In general, electricity flows into northwestern Connecticut; little economic local generation is available to satisfy demand, and the loss component tends to be high.

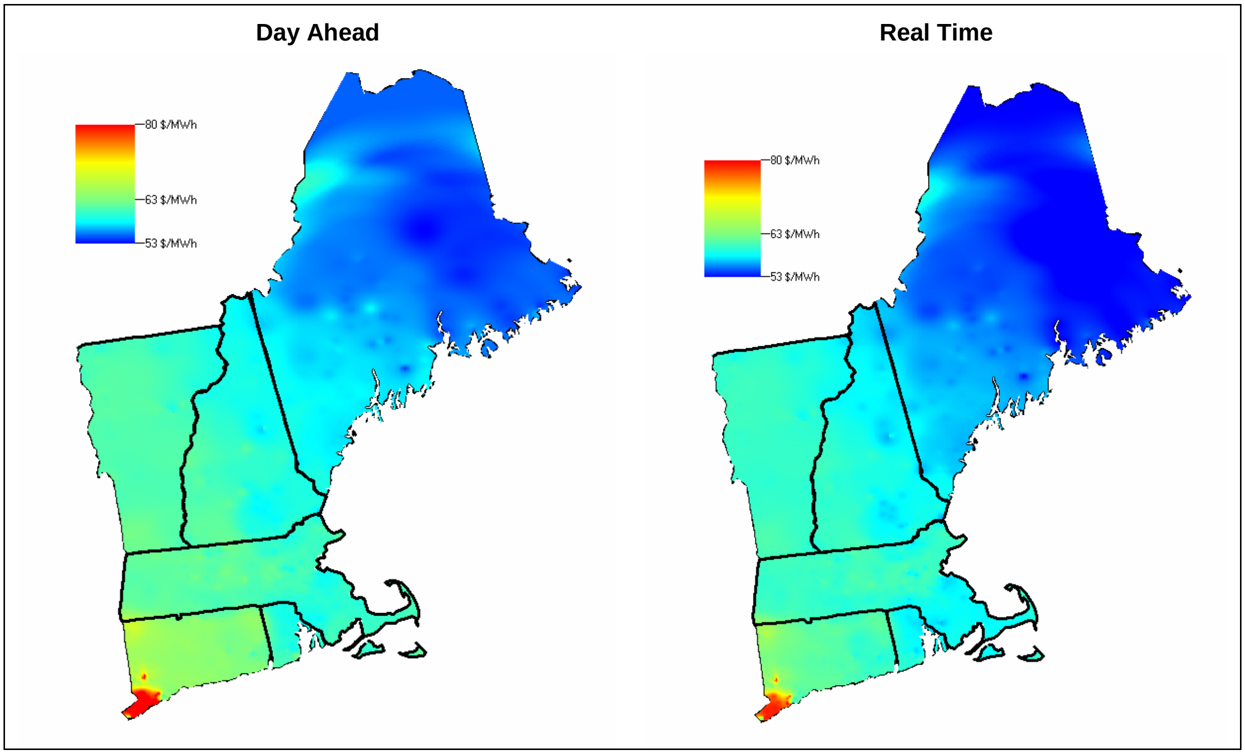

Figure 3-25: Average nodal prices, 2006, $/MWh.

3.1.4.4 Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a context for evaluating price levels in New England. Figure 3-26 compares the 2005 average system prices with the 2006 prices for the three northeastern ISOs—ISO New England, the New York ISO, and PJM Interconnection (PJM).[59] The average prices for 2006 were significantly lower in all three pools. ISO New England and NYISO average prices are calculated hourly system prices based on locational prices and locational loads, while PJM prices are published hourly system prices.[60] New York had the highest average prices, while PJM had the lowest.

[59] PJM Interconnection is the Regional Transmission Organization (RTO) for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

[60] Yearly average system prices are not load weighted. See PJM's Web site at http://www.pjm.com and NYISO's Web site at http://www.nyiso.com.

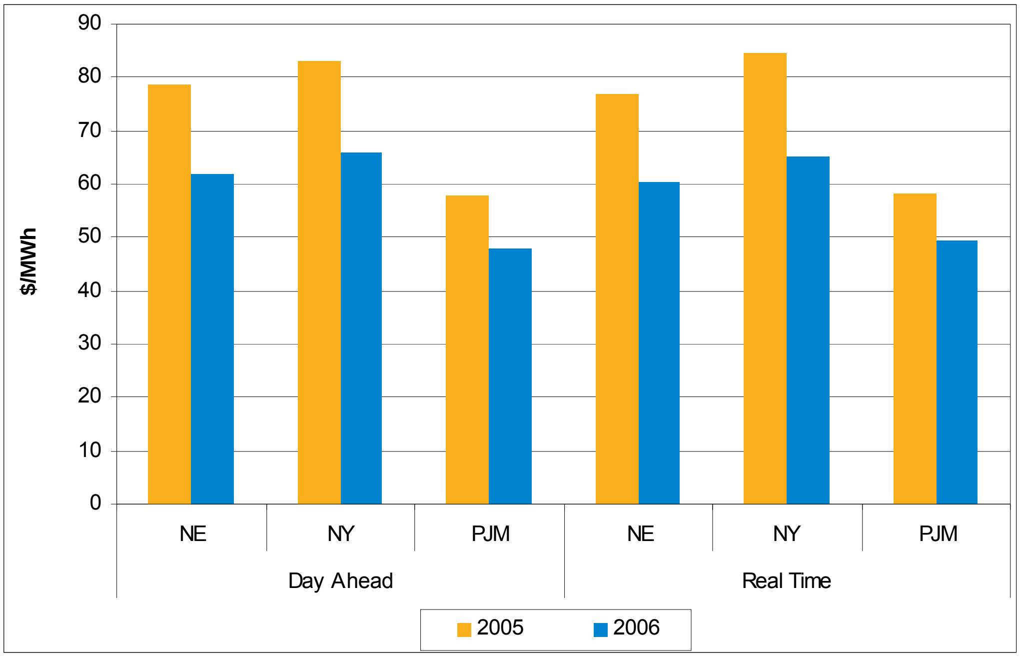

Figure 3-26: Average system prices, 2005 and 2006, ISO New England, NYISO, and PJM.

The variation in average prices among the power pools is affected by a variety of factors, such as transmission congestion, daily and seasonal demand patterns, load concentration in congested areas, and differences in the generator fuel mix. Significant coal and nuclear capacity in the PJM Control Area is a key driver of its lower average system price.[61] This also accounts for the lower price differential between 2005 and 2006 when comparing PJM data with ISO New England and NYISO data. Appendix A.3 shows the yearly average system prices for on- and off-peak periods for ISO New England, NYISO, and PJM.

3.1.4.5 Comparison with Bilateral Prices

In addition to buying and selling electricity through the ISO-administered markets, participants trade electric energy bilaterally through a variety of avenues. These include the Intercontinental Exchange (ICE), an electronic marketplace for energy trading. This section presents comparisons between ISO energy market prices and ICE prices. Convergence of bilateral trading prices with wholesale market prices is an indicator of efficient markets.

Figure 3-27 shows day-ahead Hub LMPs and ICE day-ahead trade prices. The price trends generally are similar. The average difference between ISO and ICE prices for the days that power was traded is $0.04/MWh.[62] However, the bilateral market estimate of the LMPs becomes more inaccurate as system conditions become tighter.

[61] PJM Interconnection. *Capacity by Fuel Type* (December 31, 2006). Available online at http://www.pjm.com/services/system-performance/downloads/capacity-by-fuel-type-2006.pdf.

[62] This number is the simple average of the difference between ISO and ICE prices. It indicates that, on average, ICE day-ahead trade prices were higher than ISO day-ahead LMPs. Data are not available for late July, a time of high load and prices in New England. The standard deviation of the ICE data is 14.87.

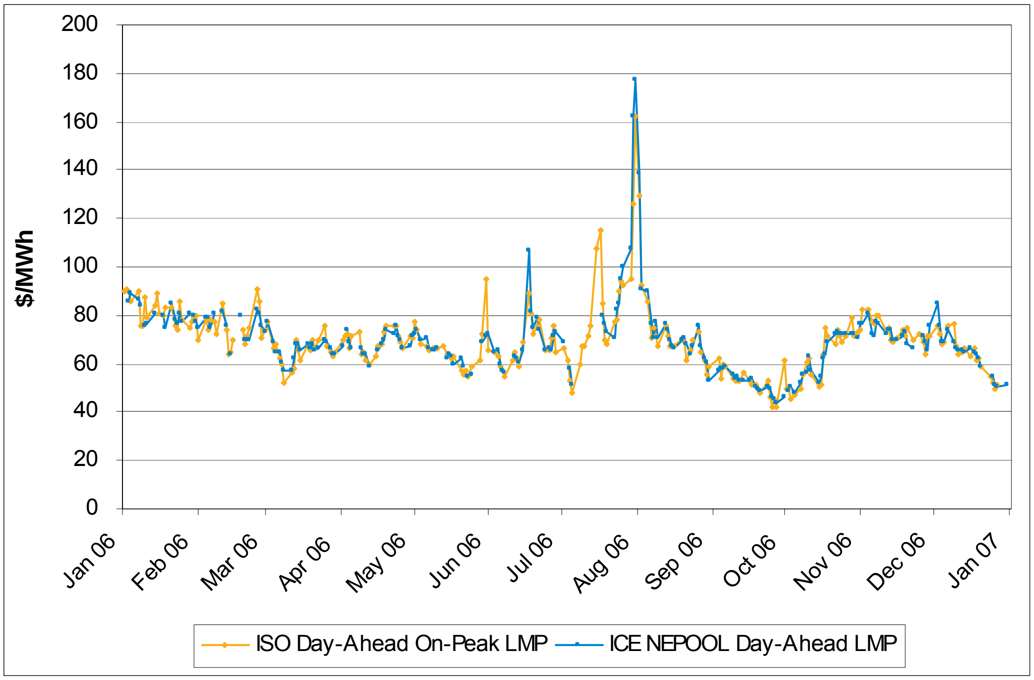

Figure 3-27: Comparison of ISO day-ahead Hub LMPs with ICE day-ahead New England trade prices.

Figure 3-28 compares the monthly average for day-ahead LMPs with the average of the last bid and last offer for each monthly delivery period traded for ICE. Prices were similar in most months but differed by more than $85/MWh in January because of speculation about a gas shortage resulting from the 2005 hurricanes and cold weather, which never materialized.

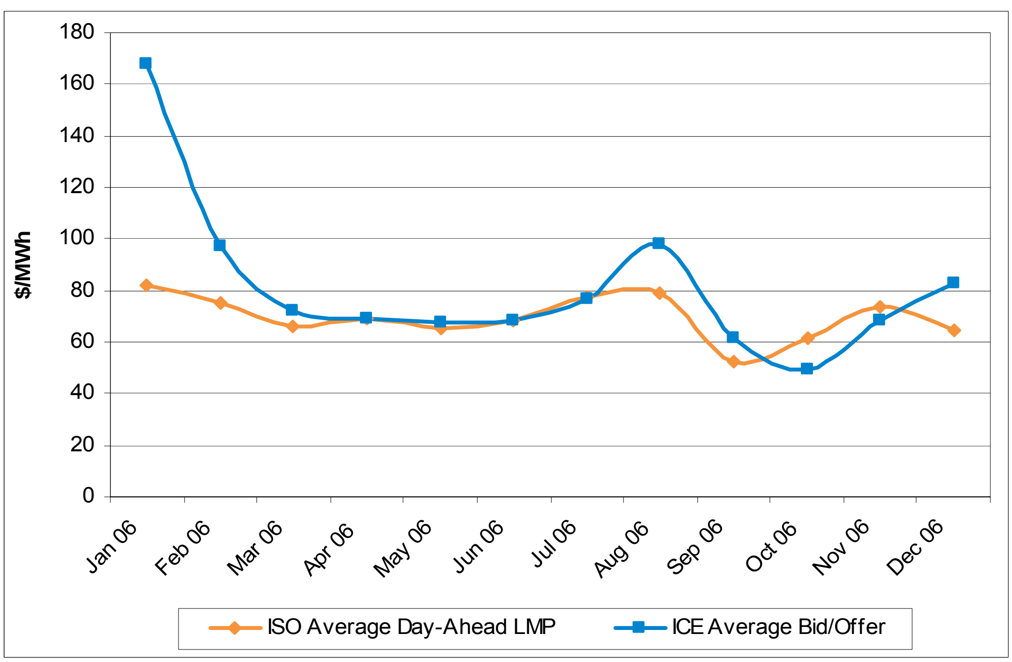

Figure 3-28: Monthly delivery—last ICE bilateral trade compared with day-ahead ISO LMPs.

3.1.4.6 Price Separation—Congestion and Losses

In addition to energy production costs, LMPs reflect the costs of congestion and losses. The inclusion of these costs in the electric energy price and the resulting price separation between locations are key elements of efficient pricing. *Losses* are caused by resistance in the transmission system and are inherent in the existing transmission infrastructure. *Congestion* is caused by transmission constraints that limit the flow of otherwise economic power.

Figure 3-29 shows the average hourly differences between the LMP in each zone and the LMP at the Hub in the Day-Ahead and Real-Time Energy Markets. The results for day-ahead and real-time LMPs are similar. The average LMPs for the Maine, New Hampshire, Rhode Island, and SEMA load zones are less than the Hub LMP, and the LMPs for the Connecticut, Vermont, and WCMA load zones are greater than the Hub LMP. Average LMPs in NEMA were less than the Hub LMP in the Day-Ahead Energy Market but higher in real time. Differences in LMPs among the load zones are due to the joint impact of congestion and losses in the Day-Ahead and Real-Time Energy Markets. The direction and relative relationships are the same in the Day-Ahead and Real-Time Energy Markets, with the exception of NEMA, indicating that the Day-Ahead Energy Market is functioning well.

In 2006, the price separation between Connecticut and other load zones was greater than in 2005. On average in 2006, day-ahead prices in Connecticut were about $6.30/MWh higher than at the Hub, while real-time prices were about $4.80/MWh higher. In 2005, the differences between prices in Connecticut and at the Hub were about $4.50/MWh higher than at the Hub, while real-time prices were about $3.50/MWh higher.

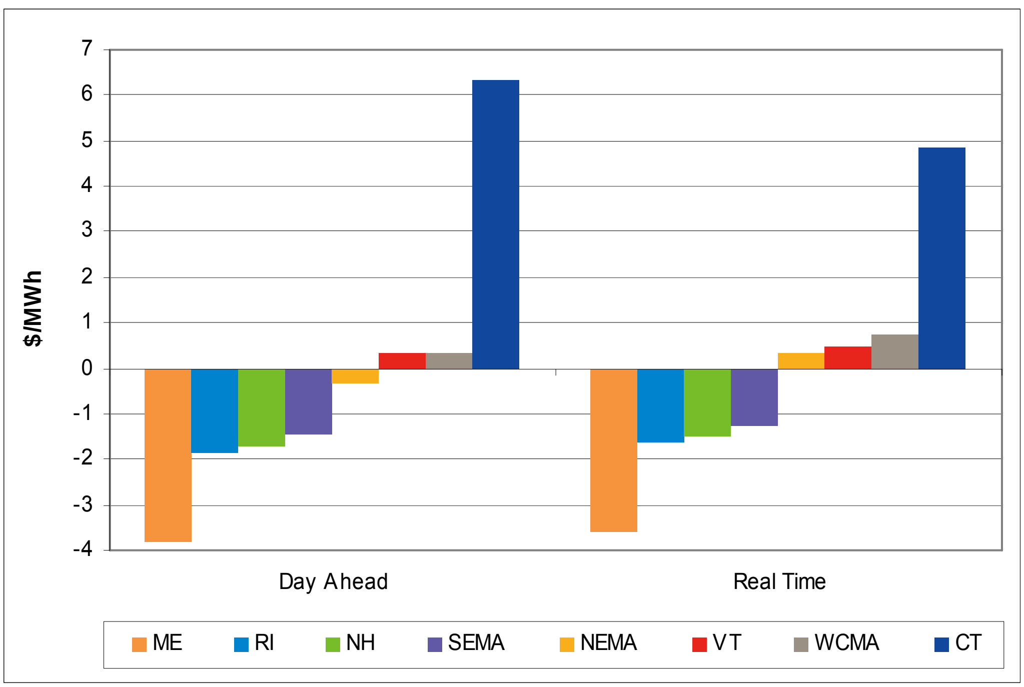

Figure 3-29: Average hourly zonal LMP differences from the Hub, 2006.

Figure 3-30 shows total congestion revenue by quarter since the beginning of SMD. Day-ahead congestion costs were high in the second and third quarters of 2006 when high demand frequently caused binding constraints and congestion in the NEMA and Connecticut load pockets.[63] Total congestion revenues in 2006 were $180 million. Congestion revenues are collected in the Congestion Revenue Fund and used to pay FTR holders. Section 4.5 discusses the Congestion Revenue Fund in more detail.

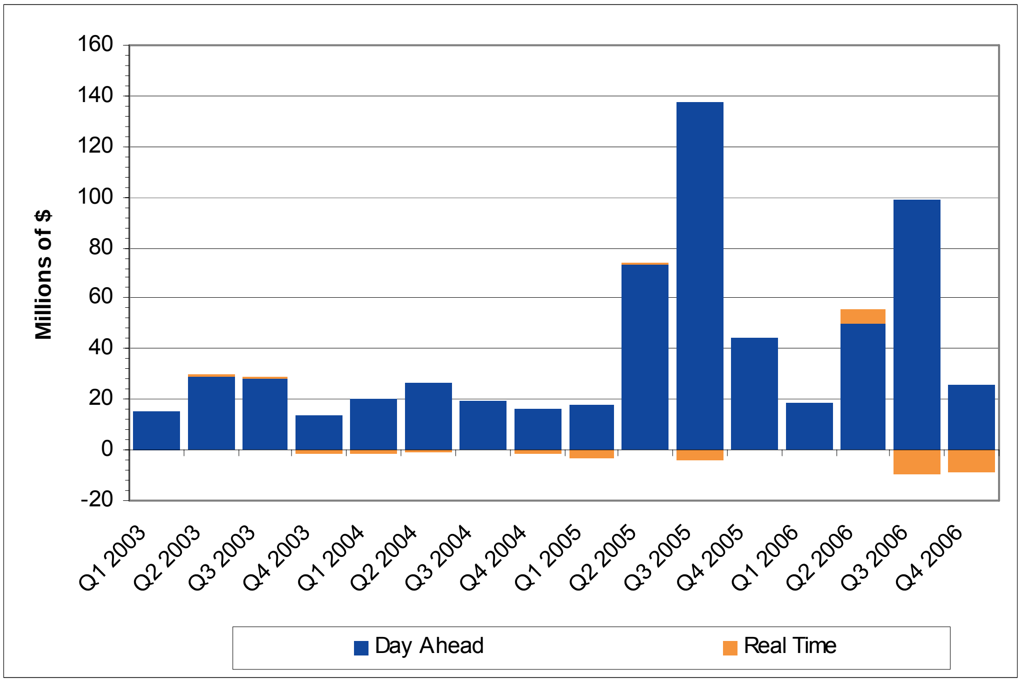

Figure 3-30: Total congestion revenue by quarter.

Table 3-6 and Table 3-7 show the 2006 averages of the congestion component, the marginal loss component, and the sum of the two components for the Hub and each load zone for the Day-Ahead and Real-Time Energy Markets, respectively. These values indicate the relative impact of congestion and marginal losses among the load zones. The proportions of the electric energy, congestion, and loss components of the LMPs are calculated in relation to a distributed reference bus. The distributed reference bus formula incorporates seasonal variations in locational load; it is not a physical interconnection to the system. Because the distributed reference bus varies over time, comparing trends in the differences between LMPs over time is more useful than comparing trends in the values of the congestion and marginal loss components. The reference bus calculation will affect the variation in each component but not have an impact on the nodal prices.

[63] *Load pockets* are areas of the system where the transmission capability is not adequate to import electric energy from other parts of the system and demand is met by relying on local generation (e.g., Southwest Connecticut and the Boston area).

Table 3-6
Average Day-Ahead Congestion Component, Loss Component, and Combined, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−1.85	0.56	−1.30
Connecticut	4.20	0.85	5.05
Maine	−2.95	−2.14	−5.10
NEMA	−1.27	−0.37	−1.64
New Hampshire	−2.40	−0.60	−3.00
Rhode Island	−2.45	−0.68	−3.13
SEMA	−2.15	−0.58	−2.73
Vermont	−1.65	0.67	0.98
WCMA	−1.74	0.76	$−0.98

Table 3-7
Average Real-Time Congestion Component, Loss Component, and Combined, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−1.38	0.61	−0.77
Connecticut	3.11	0.97	4.08
Maine	−2.18	−2.11	−4.28
NEMA	0.29	−0.30	−0.01
New Hampshire	−1.57	−0.48	−2.05
Rhode Island	−1.74	−0.65	−2.39
SEMA	−1.76	−0.50	−2.26
Vermont	−1.01	0.70	−0.31
WCMA	−1.23	0.82	−0.42

Because the relative values of the three LMP components depend on the definition of the distributed reference bus, the dollar value of the congestion component should not be used directly to measure the underlying actual cost of congestion in a location over time. The differences between the LMP congestion components serve as indicators of relative congestion costs. The Hub and most load zones (ME, NH, VT, RI, SEMA, WCMA) experienced negative congestion on average in both the Real-Time and Day-Ahead Energy Markets. This means that the typical Real-Time Energy Market clearing process resulted in constraints, such that an increase in demand could have been met at a lower cost in those locations than in the other load zones. NEMA experienced negative congestion day ahead and positive congestion in real time. The congestion component of Connecticut LMPs was positive both day ahead and in real time. These results are consistent with historical experience showing that NEMA and Connecticut are transmission-constrained areas.

The marginal loss component of the LMP reflects the change in transmission losses for the entire system when one additional megawatt of power is injected at that location. System losses are related to transmission voltage and the distance between generation and load. An additional injection of electricity at a location that is estimated to decrease system losses results in a positive marginal loss component for that location, increasing the LMP. Electricity at that location has additional value because it results in smaller losses. An additional injection at a location that is estimated to increase system losses results in a negative loss component for that location, lowering the LMP. Exporting zones generally have negative loss components, while importing zones generally have positive marginal loss components. An additional injection in an exporting zone increases losses, which increases the amount of power shipped long distances. Injections into an importing zone reduce losses, which reduces the need for power to travel long distances.

Day-ahead and real-time loss components were positive in the Connecticut, Vermont, and WCMA load zones and at the Hub. They were negative in the NEMA, Rhode Island, SEMA, New Hampshire, and Maine load zones. Although the NEMA and Rhode Island importing zones had small negative losses, Maine, an exporting zone, had the most negative loss component, indicative of its long distance from the major load centers in New England. While Rhode Island and NEMA are importing zones, they are adjacent to the exporting zone of SEMA; therefore, power does not need to travel long distances to reach Rhode Island and NEMA.

Similar to congestion pricing, marginal loss pricing and accounting can result in a surplus collection of marginal loss revenue. These revenues are maintained in the Marginal Loss Revenue Fund. The revenues in the fund are allocated to load-serving entities according to each participant's monthly share of the real-time load obligation, net of bilateral trades. In 2006, a total of $87.7 million was returned to load-serving entities from the Marginal Loss Revenue Fund.

3.1.4.7 All-In Wholesale Electricity Market Cost Metric

The *all-in* wholesale electricity cost is the annual total of the energy, daily reliability, capacity, ancillary service, and Reliability Agreement components.[64] Figure 3-31 shows the all-in wholesale electricity cost in New England over the past six years. Figure 3-32 shows the same information on a $/MWh basis. Total all-in wholesale electricity costs were much lower in 2006 than in 2005 as a result of decreased fuel costs and milder weather.

[64] FERC uses a similar all-in metric that does not include Reliability Agreement costs.

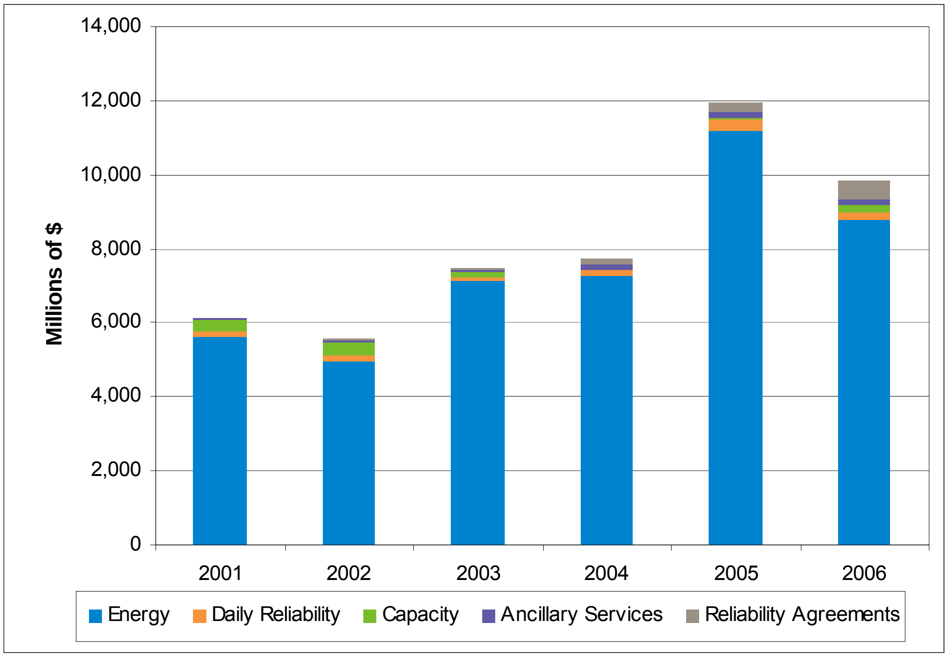

Figure 3-31: New England wholesale electricity market cost metric—electric energy, daily reliability, capacity, ancillary services, and Reliability Agreement totals, 2001 to 2006.

Note: Over time, the names and definitions of all-in cost components have changed. See Appendix A.4 for a description of these components for each period. Electric energy costs for the Interim Markets period = (ECP X system load). Electric energy costs for the SMD period = (real-time load obligation X real-time LMP).

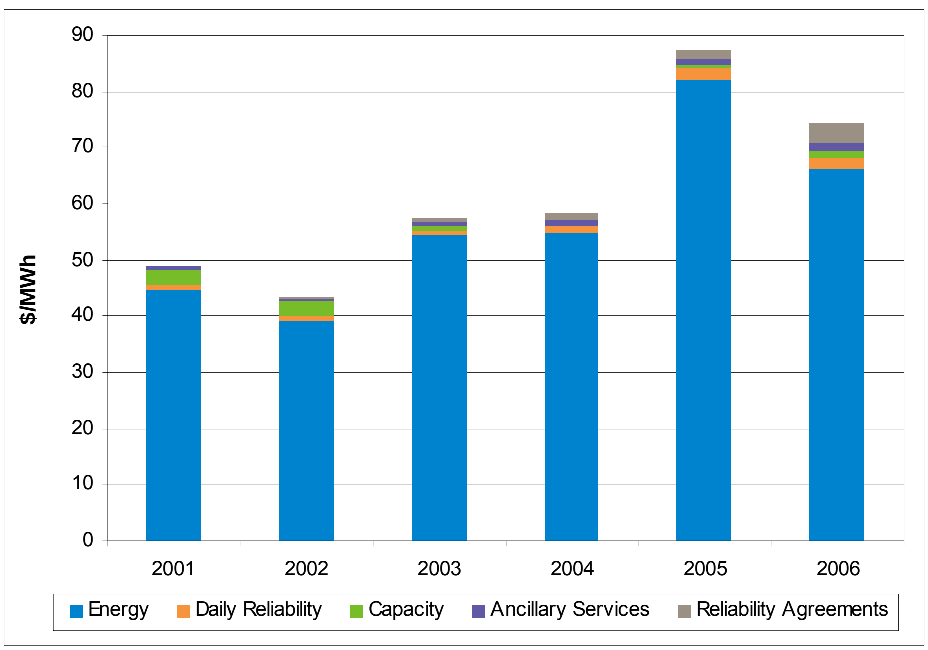

Figure 3-32: New England wholesale electricity market cost metric—electric energy, daily reliability, capacity, ancillary services, and Reliability Agreements, $/MWh, 2001 to 2006.

Note: Electric energy costs for the Interim Markets period = (ECP X system load). Electric energy cost for the SMD period = (real-time load obligation X real-time LMP).

Energy costs are by far the largest component of the all-in wholesale cost metric, accounting for 89% of the total in 2006. Daily reliability and Reliability Agreement costs combined made up 7.3% of the total metric in 2006, compared with 4.4% in 2005. Capacity costs and ancillary services as a percentage of the total metric were both higher in 2006 relative to 2005, but combined, they accounted for a small percentage of the total metric.

3.1.5 Energy Market Volumes

Table 3-8 and Table 3-9 present information about the MWh quantity of electricity transactions in the Day-Ahead and Real-Time Energy Markets. Participant transactions to buy and sell electricity executed by submitting bids and offers into the Day-Ahead and Real-Time Energy Markets are settled at the applicable day-ahead or real-time LMPs. Participants also may enter into contracts with each other at mutually agreed-on prices. Some of these contracts are submitted for scheduling in either the Day-Ahead or Real-Time Energy Market. Participants may enter into *internal* contracts, under which electric energy is bought and sold for generation and delivery within the New England area, or they may enter into *external* contracts, under which either generation or delivery occurs outside New England.

External contracts may be submitted with or without a price. *With-price* contract purchases and sales will not flow unless transfer capacity is available, conforming arrangements with the external system are in place, and the New England LMP is above the specified price level for purchases or below the specified price levels for sales. *Without-price* contracts flow under the assumption that transfer capacity and conforming arrangements with the external system are available.

External contracts in the Day-Ahead Energy Market also may be submitted as *up-to-congestion* contracts. These contracts do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts. Participants with real-time external transactions are always considered willing to pay congestion charges. *Wheel-through* contracts, in which both generation and delivery occur outside New England, also are submitted into the market system for scheduling.

In New England, the volume of electricity traded exceeds actual load. Day-ahead load obligations (MWh) settled at the day-ahead LMP are close to actual load; in some hours, quantities exceed actual load. Also, internal bilateral contract quantities typically are greater than actual load. These numbers show that the Day-Ahead Energy Market is widely used to settle expected real-time load and generation obligations. Internal bilateral contracts cover much of either day-ahead or actual real-time load obligations. Most import contracts generally are without-price contracts, which are equivalent to self-scheduled imports.

Table 3-8
Day-Ahead and Real-Time Energy Market Quantities Traded by Transaction Type, January to June 2006, MWh

Transaction Type by Market	Jan 06	Feb 06	Mar 06	Apr 06	May 06	Jun 06
Day Ahead						
Load obligation—day-ahead LMP[a]	11,525,205	10,491,959	10,966,559	9,691,844	10,236,966	11,597,012
Bilateral—export with price[b]	*25,404*	*9,240*	*11,940*	*21,156*	*51,029*	*127,174*
Bilateral—export without price	*181,853*	*195,943*	*246,012*	*241,016*	*249,959*	*293,917*
Bilateral—export up-to congestion	*–*	*250*	*–*	*–*	*88*	*105*
Bilateral—internal for market, day ahead (IBM)	6,174,705	6,299,176	6,331,008	5,945,803	6,065,259	6,042,732
Bilateral—import with price	*274,078*	*143,565*	*103,957*	*240,716*	*128,154*	*133,226*
Bilateral—import without price	*794,455*	*790,433*	*691,702*	*459,194*	*325,989*	*386,932*
Bilateral—import up-to congestion	8,428	7,783	12,094	3,478	16,477	18,804
Total day-ahead MWh	**18,776,871**	**17,732,916**	**18,105,320**	**16,341,035**	**16,772,844**	**18,178,706**
Real Time						
Adjusted load-obligation deviation—real-time LMP[c]	244,882	241,309	361,377	300,100	487,850	359,579
Adjusted load-obligation deviation—lower than day ahead	(828,404)	(635,265)	(645,041)	(601,082)	(617,808)	(963,497)
Adjusted load-obligation deviation—higher than day ahead	1,073,286	876,574	1,006,418	901,182	1,105,658	1,323,076
Bilateral—export with price	*1,127*	*–*	*–*	*2,685*	*15,472*	*28,127*
Bilateral—export without price	*282,952*	*269,293*	*344,994*	*337,351*	*434,587*	*576,150*
Bilateral—internal for market, additional to day-ahead IBMs	84,074	114,142	84,162	100,547	105,192	118,308
Bilateral—internal for load, real-time	46,089	42,153	44,081	38,302	39,984	45,161
Bilateral—import with price	*85,219*	*35,931*	*26,201*	*115,612*	*74,657*	*47,362*
Bilateral—import without price	*1,226,446*	*1,146,408*	*1,045,491*	*788,537*	*612,959*	*732,406*
Bilateral—through	4,366	1,972	2,068	1,088	1,695	1,195
Total real-time MWh	**1,691,076**	**1,581,915**	**1,563,379**	**1,344,187**	**1,322,337**	**1,304,012**
Net energy for load (000s of MWh)	***11,509***	***10,508***	***11,010***	***9,630***	***10,239***	***11,331***

(a) The *day-ahead load obligation for energy* is equal to the megawatt-hours of demand bids, virtual demand bids, and external transaction sales cleared in the Day-Ahead Energy Market. It is settled at the day-ahead LMP. The figure reported here is the systemwide total of participants' locational load obligations. It is reported here as a positive number; however, it is calculated on an individual participant level as a negative number.

(b) Exports are included in load obligation.

(c) The *real-time adjusted load-obligation deviation* is the difference between real-time and day-ahead load obligations. It is settled at the real-time LMP. The figure reported here is the systemwide total of participants' locational adjusted load-obligation deviations. Adjusted load-obligation deviation may be negative (indicating a lower load obligation cleared day ahead) or positive (indicating a higher load obligation cleared day ahead). The signage used here is reversed from the signage used in participant-level calculations. Because much of the real-time deviations from day ahead at the participant level net to zero when the systemwide total is calculated, the total of negative deviations and the total of positive deviations are shown here to give a sense of the magnitude of activity in the Real-Time Energy Market.

Table 3-9
Day-Ahead and Real-Time Energy Market Quantities Traded by Transaction Type, July to December 2006, MWh

Transaction Type by Market	Jul 06	Aug 06	Sep 06	Oct 06	Nov 06	Dec 06
Day Ahead						
Load obligation—day-ahead LMP[(a)]	13,849,808	13,153,825	10,735,107	11,052,154	10,857,964	11,929,364
Bilateral—export with price[(b)]	*51,634*	*46,822*	*82,102*	*121,025*	*62,614*	*35,081*
Bilateral—export without price	*410,599*	*411,873*	*263,908*	*177,759*	*226,720*	*241,821*
Bilateral—export up-to congestion	*270*	*3,752*	*4,172*	*7,116*	*13,363*	*429*
Bilateral—internal for market, day ahead	6,541,403	7,014,555	7,101,429	7,178,578	6,768,888	7,252,960
Bilateral—import with price	*178,288*	*103,203*	*24,721*	*78,666*	*127,530*	*76,872*
Bilateral—import without price	*757,919*	*861,425*	*245,974*	*423,932*	*690,229*	*1,038,367*
Bilateral—import up-to congestion	14,814	12,967	50,573	58,157	27,358	45,861
Total day-ahead MWh	**21,342,232**	**21,145,975**	**18,157,804**	**18,791,486**	**18,471,970**	**20,343,423**
Real Time						
Adjusted load-obligation deviation—real-time LMP[(c)]	275,628	(63,414)	108,376	(186,789)	(143,728)	(137,715)
Adjusted load-obligation deviation—lower than day ahead	(1,064,138)	(1,216,205)	(1,033,597)	(1,367,176)	(1,246,247)	(1,336,462)
Adjusted load-obligation deviation—higher than day ahead	1,339,766	1,152,791	1,141,973	1,180,387	1,102,519	1,198,747
Bilateral—export with price	*26,204*	*2,152*	*22,190*	*24,482*	*12,811*	*6,484*
Bilateral—export without price	*745,612*	*733,562*	*549,914*	*479,415*	*422,239*	*511,860*
Bilateral—internal for market, additional to day-ahead IBMs	105,062	109,580	111,031	95,433	81,103	98,147
Bilateral—internal for load, real time	56,030	50,751	39,413	–	–	–
Bilateral—import with price	*149,437*	*28,385*	*925*	*29,821*	*56,407*	*7,659*
Bilateral—import without price	*1,046,641*	*1,124,438*	*467,148*	*695,035*	*1,048,798*	*1,287,784*
Bilateral—through	1,150	–	224	2,553	1,642	1,855
Total real-time MWh	**1,633,948**	**1,249,740**	**727,117**	**636,053**	**1,044,222**	**1,257,730**
Net energy for load (000s of MWh)	***13,364***	***12,380***	***10,240***	***10,383***	***10,231***	***11,252***

(a), (b), (c) See notes for Table 3-8.

3.1.6 Critical Power System Events

The high demand for electricity coincident with other events required the ISO to declare OP 4 on three days in 2006. The ISO also issued Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert* (M/LCC 2), on several occasions. The M/LCC 2 procedure alerts power system operations, maintenance, construction, and test personnel, as well as market participants, when the power system is facing a critical event or when such conditions are anticipated.[65] In 2006, the market worked as expected under these stressed conditions. This section briefly discusses the events of the days in 2006 when OP 4 actions were activated.

3.1.6.1 June 19, 2006, OP 4 in Boston

On Monday, June 19, at 3:12 p.m., a major transmission path (Ward Hill transformer, 394 and 397 transmission lines) was forced out of service. At 4:06 p.m., the ISO implemented M/LCC 2 for the Boston area. At 4:48 p.m., OP 4 Actions 1–5, 7, 8, 10, 12, and 13 were implemented in the NEMA/Boston area, which included reducing voltage by 5%. At 8:00 p.m., OP 4 Actions 12 and 13 were canceled, and at 9:00 p.m., all actions of OP 4 except Action 1 were canceled. On Tuesday, June 20, all transmission was restored at 9:20 a.m., all OP 4 actions in NEMA/Boston were canceled at 11:00 a.m., and, finally, M/LCC 2 was canceled at 11:00 p.m.

This event caused constraints in Boston, Northeast Massachusetts, and New Hampshire. At approximately 3:40 p.m. on June 19, the transformer at Ward Hill was isolated, and the lines were returned to service, which left a constraint in New Hampshire and Northeast Massachusetts. Final real-time zonal prices reached as high as $286.48/MWh for hour ending 17 in the New Hampshire load zone and $387.88/MWh for hour ending 16 in the NEMA load zone. Hourly nodal prices in these zones were as high as $625/MWh in New Hampshire and $405/MWh in NEMA.

3.1.6.2 August 1 and 2, 2006, OP 4 and Reserve-Shortage-Condition Pricing

Extreme heat and humidity led to all-time system demand records on Tuesday, August 1 and Wednesday, August 2. Peak demand was 27,476 MW for hour ending 5:00 p.m. on August 1 and 28,130 MW for hour ending 3:00 p.m. on August 2. These high demand levels, coupled with generator outages and reductions, resulted in implementation of M/LCC 2 from 6:00 a.m. on August 1 until 9:00 p.m. on August 3. In response to the capacity deficiencies, OP 4 was implemented on both August 1 and 2. As prescribed by the operating procedure, the reliability-based demand-response programs were activated. In total, the reliability-based demand-response programs and the price-activated programs provided a maximum of 625 MW of load reduction during the OP 4 event and 597 MW of load reduction during the peak hour. Over these two days, two reserve-shortage events occurred, the first in hours ending 5:00 p.m. through 7:00 p.m. on August 1 and the second during hours ending 1:00 p.m. through 6:00 p.m. on August 2. The ISO called for emergency energy transactions during the shortages and also purchased a total of 2,750 MWh of emergency energy from the New York Control Area.[66]

[65] M/LLC 2 considers abnormal conditions to exist when the reliability of the New England Control Area is degraded. These conditions relate to forecasts of operating-reserve shortages, low transmission voltages or reactive reserves, the inability to provide some types of first-contingency protection, solar magnetic disturbances, and credible threats to the security of the power system. For additional information, see http://www.iso-ne.com/rules_proceds/operating/mast_satllte/MLCC_2.doc.

[66] *Emergency energy* transactions involve the ISO's buying and selling of energy from market participants or other control areas as a result of emergencies either within the New England Control Area or within the other control areas. See Manuals 11 and 28 for further discussion of emergency energy at http://www.iso-ne.com/rules_proceds/isone_mnls/m_28_market_rule_1_accounting_(revision_26)_12_01_06.doc.

3.1.7 Preparations for Extreme Winter Weather

The ISO took several steps during 2006 to prepare for the potential for extreme weather during winter 2006/2007. On October 20, 2006, FERC approved permanent changes to Market Rule 1 designed to help maintain reliable operations during cold winter weather.[67] The changes are as follows:

- Allowing daily changes to start-up and no-load offers rather than allowing changes only twice per month
- Tightening market-monitoring conduct thresholds in constrained areas for start-up and no-load offers to 25% rather than 50% over the reference level

For winter 2006/2007 and subsequent winters, the ISO filed with FERC an updated version of Appendix H, *Operations during Cold-Weather Conditions*, containing the following provisions:[68]

- A revised day-ahead market timeline will close the Day-Ahead Energy Market by 9:00 a.m. when a cold-weather event is declared.
- Under the revised day-ahead market timeline, gas-fired units must notify the ISO by the close of the reoffer period that they have confirmation of a nomination or evidence of sufficient fuel supplies to meet their energy schedules.
- No new economic outages will be granted to capacity resources when a cold-weather warning or event is declared, and all economic outages for capacity resources will be canceled for the day that a cold-weather event is declared.
- Generators that encounter extraordinary fuel expense will be compensated.

These provisions will enable the ISO to forecast, schedule, and operate the system with greater certainty and will facilitate higher unit availability during cold-weather conditions.

3.1.8 Electric Energy Markets Conclusions

New England's electricity markets functioned well in 2006. On average, electricity spot-market prices were 21% lower in 2006 than in 2005. Prices were driven mainly by fuel costs and lower demand resulting from milder average weather and conservation actions undertaken by end users. Units burning natural gas were marginal 73% of the time during the period. Units capable of burning gas and oil, most of which burn gas as their primary fuel, were on the margin 34% of the time. With the region's continued dependence on gas and oil, electricity prices remained vulnerable to the volatility in the fuel markets.

Transmission congestion and binding constraints led to frequent price separation among the eight load zones on many days in 2006. Average LMPs were highest in the Connecticut load zone and lowest in the Maine load zone: the difference between the average day-ahead LMPs in Maine and Connecticut was $10.14/MWh. Binding constraints were generally caused by heavy loads and lack of economic generation in the load pockets of Southwest Connecticut and Boston. Congestion costs were high in the second and third quarters of 2006, when high loads frequently caused binding constraints and congestion in the NEMA and Connecticut load pockets.

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[67] See http://www.iso-ne.com/regulatory/ferc/orders/2006/oct/er06-1464-000.doc. and http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_h_11-27-06.pdf for more information on these market rule changes.

[68] Appendix H can be accessed at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_h_11-27-06.pdf.

Load factors continued their downward trend in 2006. In New England, like most of the country, the hourly demand for electricity is not responsive to wholesale electricity prices (*inelastic demand*). This inelasticity of consumer demand is a significant challenge for the region in controlling electricity costs.[69] Until retail pricing of electricity is more closely linked to the wholesale price of electricity, thus providing incentives for consumers to conserve at times of peak demand, the trend in declining load factors is not likely to reverse.

Investment in new generation was minimal in 2006. Because generation capacity was adequate to meet demand in 2006, the low level of investment was not a cause for immediate concern. However, the growth in demand may require the ISO to take emergency actions to meet peak demand in the 2007 to 2009 timeframe, unless generation capacity, demand-side resources, or both are added.

3.2 Capacity Markets

New England's installed capacity requirements are calculated each year based on the Northeast Power Coordinating Council (NPCC) resource adequacy standard.[70] With input from stakeholders, the ISO converts the capacity requirements into reliability requirements for the New England Control Area. A generating unit's installed capacity rating is adjusted to reflect the probability that a resource will be unavailable to serve load as a result of forced outages. This adjusted value of a resource is referred to as *unforced capacity* (UCAP). Two resources may have the same installed capacity rating, but the resource with a lower forced-outage rate will have more of the UCAP commodity to sell. Each participant responsible for serving load is allocated UCAP requirements on the basis of its share of the previous year's system peak demand. Participants can meet their UCAP obligations through bilateral transactions, self-supply, resource-backed external transactions, Hydro-Québec Interconnection Capability Credits, or the purchase of UCAP in either the supply or deficiency auctions administered by the ISO.

3.2.1 Forward Capacity Market

In 2002, when FERC approved the SMD design, it concurrently ordered the New England Power Pool (NEPOOL) to develop a locational mechanism to procure capacity.[71] A multiyear negotiation process to address the lack of a locational component in the capacity market design culminated in March 2006 with numerous parties, including the ISO, filing a settlement at FERC as a replacement for the existing Installed Capacity (ICAP) Market (discussed later).[72] The settlement established a Forward Capacity Market (FCM) for which the ISO will project power system requirements three years in advance and hold an annual auction to purchase power resources to satisfy the region's future needs. The FCM is designed to complement the current energy markets, promote investment in new and existing power resources needed to meet growing consumer demand, attract new conservation and energy-efficiency programs, and maintain the reliable operation of existing power plants. The results of this settlement proposal bring the ISO closer to a long-standing objective—a complete set of wholesale markets that ensure power system reliability in New England by attracting investment in new and existing power resources.

[69] This topic is further addressed in the ISO's *Electricity Costs White Paper* available at http://www.iso-ne.com/pubs/whtpprs/index.html.

[70] For more information on NPCC, see http://www.npcc.org.

[71] SMD Order, p. 37.

[72] For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

The FCM design was finalized during spring and summer 2006 and presented to market participants during fall 2006. The NEPOOL stakeholder review of the FCM market rules occurred during November and December 2006 and January 2007, and the ISO filed FCM market rules on February 15, 2007, as required by the Settlement Agreement.

3.2.1.1 Forward Capacity Auctions

The Forward Capacity Auctions (FCAs) will take place about three years and four months before the beginning of the capacity commitment periods to provide a planning period for developing new resources.[73] The first Forward Capacity Auction is scheduled to be held in February 2008.

Before each auction, potential bidders must submit to the ISO a predefined package of qualification materials. Each bidder specifies the location and capacity of its existing resources and the location and capacity of its potential projects that could be completed by the beginning of the commitment period. This is the capacity that the bidder will offer at the starting price.[74] Supply and demand resources both can offer capacity into the auction. Qualification for the February 2008 auction is ongoing, and the final determination of eligible auction participants will take place by November 1, 2007. In accordance with the FCM market design, the ISO's determinations on eligibility will be filed with FERC 90 days before the FCM auction.

Existing capacity that has not been delisted must participate in the auction each year and will be assigned a one-year commitment. New capacity that clears the auction can have a commitment period ranging from one to five years, which the supplier can choose at the time of qualification. Both new and existing capacity resources will be paid the same market-clearing price in the first year. New capacity that elects a multiyear commitment period will receive an indexed price in the years following the first year.

The FCA will use a simultaneous descending-clock auction to determine the market-clearing prices and the capacity suppliers for each zone. The descending-clock auction is an iterative auction procedure in which the auction manager announces prices for each of the locational products being procured. The bidders then indicate the quantities of each product they wish to supply. Products with excess supply iterate through the process with lower prices until supply equals demand for each product. Reconfiguration auctions will be conducted to allow minor quantity adjustments to the Installed Capacity Requirement, to procure deferred capacity from the FCA on the basis of market power criteria, and to facilitate the trading of commitments made in the forward auction.

3.2.1.2 Forward Capacity Market Payments

Power resources that win in the FCM auction must be available to serve New England's power grid when consumers most need electricity. A resource that does not perform when the ISO calls on it to do so may lose a significant percentage of its monthly FCM payment. This feature should help address reliability concerns raised by the ISO, the states, and the attorneys general during the cold

[73] The region will have shorter planning periods for the initial auctions transitioning to the target planning period of about 40 months (three years and four months) by the June 1, 2016, auction. The first FCA will be held February 2008 for a capacity commitment period beginning June 1, 2010 (about 28 months).

[74] Before an auction will begin, the starting price for the auction will be specified as twice the cost of new entry (CONE). For the initial auction, the CONE is $7.50/kW-month.

snap that occurred in January 2004 (January 2004 Cold Snap) when some generators did not produce needed electricity.[75]

FCM payments will be reduced when prices in the electric energy market go above a level that is usually associated with high electricity demand. This *peak-energy rent* (PER) deduction has three functions. First, it prevents over-collection of revenue from two separate markets (electric energy and capacity). Second, it encourages a resource to produce during periods of high demand because a resource that is not producing electricity during these time periods is still subject to the PER payment deduction. And third, it reduces the incentive to exercise market power. This provision helps to provide efficient price signals and thereby to reduce overall wholesale costs of electricity.

Because FCM payments currently are not scheduled to begin until June 2010, two and one-half years after the first FCM auction, steps must be taken to ensure power system reliability and payment certainty until the auction commitment year. The settling parties agreed to eliminate the ICAP Market on November 30, 2006, and to begin a transition payment mechanism on December 1, 2006, which provides capacity payments negotiated as part of the settlement to all listed capacity resources until FCM payments begin. Transition payments will be $3.05/kW-month through May 31, 2008; $3.75/kW-month from June 1, 2008, through May 31, 2009; and $4.10/kW-month from June 1, 2009, through May 31, 2010. In December 2006, total FCM transition payments were $101,378,566 on the basis of 33,239 MW of UCAP supply. Consistent with the market principle that units should be paid only for performance, transition payments are based on a generator's history of unavailability at times of peak demand.

3.2.2 Installed Capacity Market

In the ICAP Market, generators received compensation for investing in generating capacity in New England. Load-serving entities, the market participants with load obligations, made ICAP payments to generators across New England to ensure the availability of sufficient generation capacity for the reliable operation of the bulk power grid.

For the January through November 2006 obligation months, the ISO conducted a supply auction in the middle of each month for the following month for participants to transact UCAP. After the supply auction, the ISO conducted a deficiency auction to allow any load-serving participant that had not procured sufficient UCAP to cover its monthly UCAP requirement. Participants were required to offer in the deficiency auction any UCAP in excess of their UCAP requirement. Market Rule 1 required market participants still deficient after the completion of a deficiency auction to pay a monthly deficiency charge of $6.66/kW-month. Generators delisted as qualified ICAP resources were not required to participate in these auctions (see Section 3.2.3).

Most load-serving entities met their ICAP Market requirements through self-supply or bilateral contracts with ICAP suppliers; relatively small amounts were traded through the supply and deficiency auctions, as shown in Figure 3-33. Over the January through November 2006 obligation months, approximately 84% of the system requirement was met by participants that either owned entitlement to capacity or procured it bilaterally. Over the period, about 7% of the system requirement was transacted in the supply auction; the remaining 9% was obtained in the deficiency auction.

[75] See the *Final Report on Electricity Supply Conditions in New England during the January 13–16, 2004, "Cold Snap."* (Holyoke: ISO New England Inc.; October 12, 2004). Available online at http://www.iso-ne.com/pubs/spcl_rpts/2004/final_report_jan2004_cold_snap.pdf.

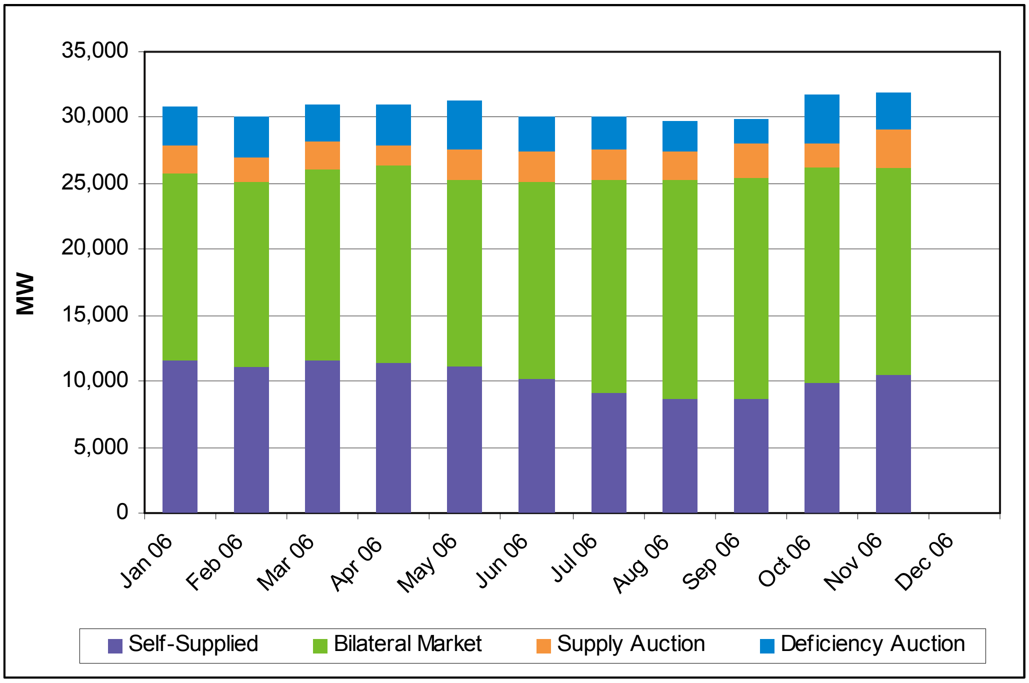

Figure 3-33: Sources of capacity (MW) in the 2006 ICAP Market.

Note: The ICAP Market was replaced with FCM transition payments for December 2006.

Table 3-10 provides the clearing prices and cleared quantities for the ICAP Market auctions during 2006. Figure 3-34 shows clearing prices in the supply and deficiency auctions since April 2003. Deficiency-auction prices were $0/MW-month from September 2005 through April 2006, increasing to $77/MW-month in May. The high prices in June, August, October, and November are attributable to increased projected peak demand and reduced operable capacity. The prices for the supply auction exhibited more volatility during 2006 than in previous years and, in general, were higher than in 2005.

Table 3-10
ICAP Market Summary for 2006

Obligation Month	Supply Auction		Deficiency Auction	
	Cleared (MW)	Clearing Price ($/MW-Month)	Cleared (MW)	Clearing Price ($/MW-Month)
Jan	4,925	$100.00	2,912	$0.00
Feb	4,540	$50.00	3,089	$0.00
Mar	4,298	$10.00	2,851	$0.00
Apr	3,746	$10.00	2,975	$0.00
May	4,879	$0.00	3,713	$77.00
Jun	5,022	$100.00	2,528	$2,750.00
Jul	4,127	$1,200.00	2,420	$0.00
Aug	4,843	$400.00	2,253	$2,250.00
Sep	5,181	$490.00	1,988	$520.00
Oct	5,551	$260.00	3,790	$1,996.00
Nov	6,506	$380.00	2,787	$2,615.00
Dec	N/A	N/A	N/A	N/A

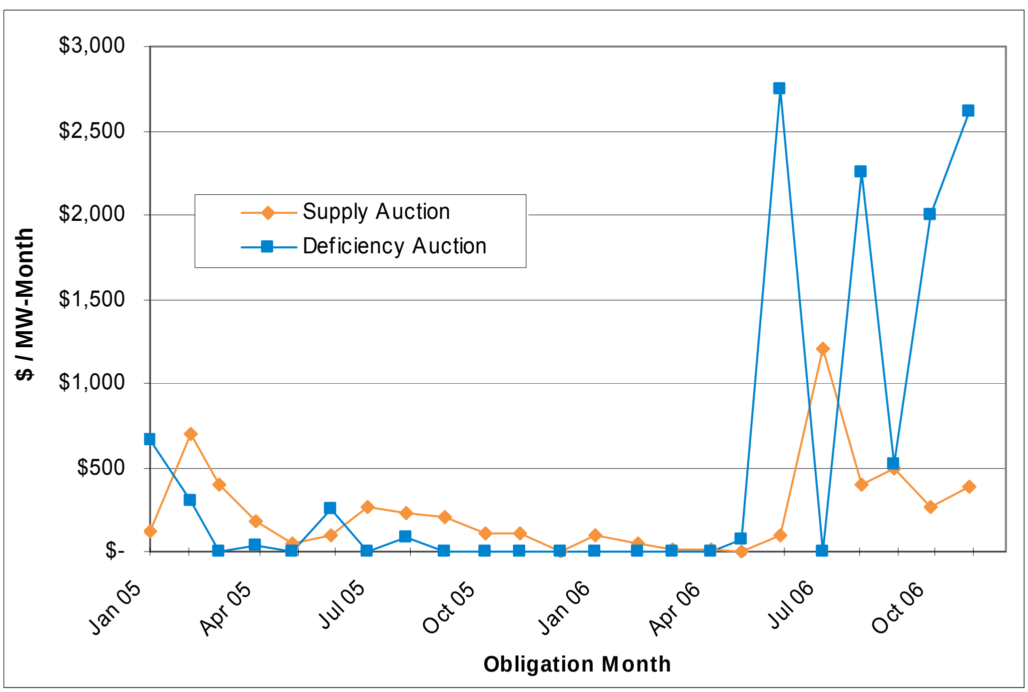

Figure 3-34: Auction clearing prices, April 2003 to November 2006.

Figure 3-35 shows the submitted and cleared deficiency-auction quantities. The capacity offered into the deficiency auctions and the relative quantities offered at zero and nonzero prices varied widely over the year. The megawatts cleared in the deficiency auction varied over the course of the year, from 3,790 MW in October to 1,988 MW in September.

Figure 3-35: ICAP deficiency-auction quantities, 2006.

3.2.3 Delisted Capacity

Market participants with lead-participant responsibility for a generating unit may delist the unit or a portion of a generator as a qualified ICAP resource. The lead participant may then sell the capacity as unforced capacity in an external control area or simply avoid the obligations associated with an ICAP resource. Units or portions of generators that are delisted are exempt from the requirement to offer generation into the Day-Ahead Energy Market.

Figure 3-36 shows total delisted capacity by month, and Table 3-11 shows delisted capacity by month and load zone. The total delisted capacity in 2006 was considerably less compared with 2005. April, May, and June 2006 had no delisted capacity, and the Vermont, NEMA, and Connecticut load zones had no delisted capacity throughout the year.

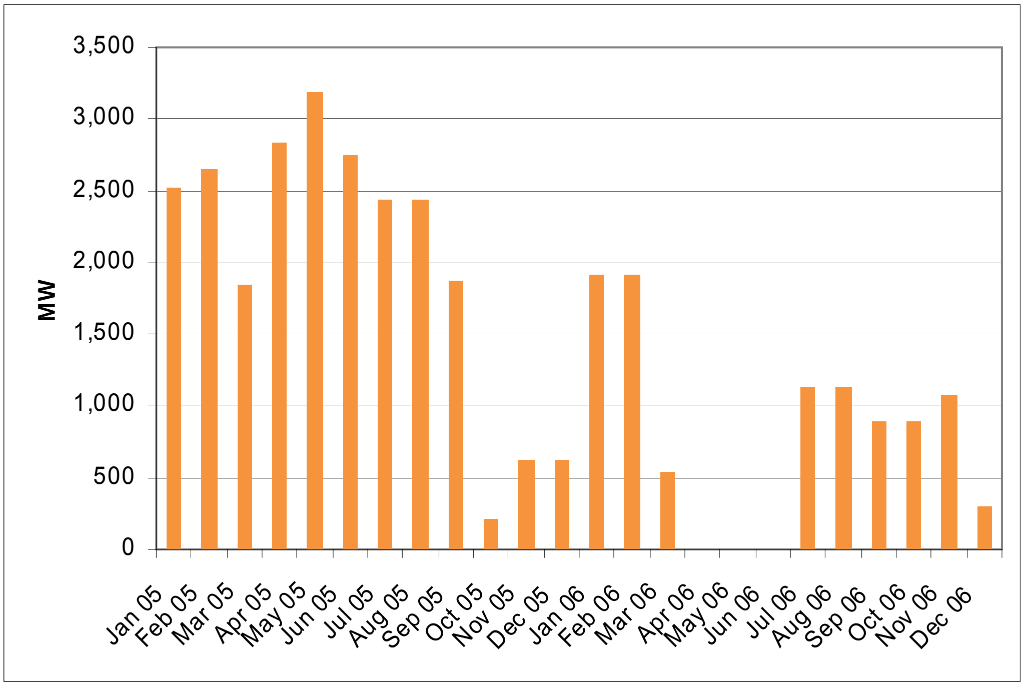

Figure 3-36: Total delisted capacity, January 2005 to December 2006.

Table 3-11
Delisted Capacity by Load Zone, January 2005 to December 2006, MW

Month	ME	NH	VT	CT	RI	NEMA	SEMA	WCMA	Total
2005									
Jan	184	522	0	656	0	560	501	100	2,523
Feb	184	522	0	783	0	560	501	100	2,649
Mar	0	522	0	656	0	560	0	100	1,838
Apr	0	522	0	818	0	1,397	0	100	2,837
May	0	522	0	447	0	2,217	0	0	3,187
Jun	0	522	0	0	0	2,217	14	0	2,753
Jul	0	201	0	0	0	2,217	14	0	2,432
Aug	0	201	0	0	0	2,217	14	0	2,432
Sep	0	201	0	0	0	1,658	14	0	1,872
Oct	0	201	0	0	0	0	14	0	215
Nov	0	522	0	0	0	0	14	94	630
Dec	0	522	0	0	0	0	14	94	630
2006									
Jan	0	522	0	0	268	0	1,034	94	1,919
Feb	0	522	0	0	268	0	1,034	94	1,919
Mar	0	522	0	0	0	0	14	0	536
Apr	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0
Jul	75	522	0	0	233	0	14	288	1,132
Aug	75	522	0	0	233	0	14	288	1,132
Sep	75	522	0	0	0	0	14	288	899
Oct	75	522	0	0	0	0	14	288	899
Nov	106	543	0	0	0	0	68	366	1,083
Dec	0	0	0	0	0	0	0	293	293

3.2.4 Capacity Markets Conclusions

The ICAP Market experienced activity that was similar to previous years. Participants met most of their UCAP requirements through self-supply or bilateral transactions, and small amounts of installed capacity cleared in the ISO-administered auctions. High prices in the deficiency auctions can be attributed to increased projected peak demand and reduced operable capacity. The system overall had no delisted capacity in April, May, and June 2006. As a replacement for the current ICAP Market, a multiyear transition mechanism was implemented, which compensates new and existing resources in the interim period between December 2006 and May 2010.

3.3 Reserve Markets

This section provides an overview of the reserve markets and a summary of 2006 data for the reserve auctions, markets, and pricing levels.

3.3.1 Overview of Operating Reserves

In addition to the generating capacity that is used to produce power to meet demand, the system must also have operating reserves available to produce power if required as a result of a contingency or if demand is much higher than forecast. *Operating reserves* are the unloaded capacity of generating resources that can be converted into electric energy within 10 or 30 minutes. Reserves can also be provided by demand-side resources.

ISO operating procedures require reserve capacity to be available (i.e., electrically synchronized to the system and at rated capability) within 10 minutes to meet the first-largest system contingency and within 30 minutes to meet one-half of the second-largest system contingency. In general, capacity equal to one-half of the 10-minute reserve requirement must be synchronized to the power system, or spinning (*10-minute spinning reserve*, TMSR), while the rest of the 10-minute requirement may be nonsynchronized. The entire 30-minute requirement may be nonsynchronized (*10-minute nonsynchronized reserve,* TMNSR, and *30-minute operating reserve*, TMOR) or the higher-quality TMSR. In addition to being able to meet systemwide requirements, 30-minute reserves must be available to meet the local second contingency for the constrained areas of Northeast Massachusetts/Boston, Connecticut, and Southwest Connecticut.[76]

In most hours, ample reserves are available to meet systemwide requirements from off-line fast-start resources and from the unloaded capacity of on-line resources that are operating below their maximum output levels.[77] At these times, redispatching or committing resources to create systemwide reserves is not necessary. The ISO will commit resources to provide reserves if necessary, which is sometimes required to meet local second-contingency requirements. Refer to Section 4.1 for more information on these commitments.

3.3.2 History of Reserve Markets and Pricing in New England

Reserve markets in New England have evolved since the implementation of wholesale markets in May 1999. The Interim Markets period, SMD, and Phase II of the Ancillary Services Markets project (ASM II) have had various structures for providing forward and real-time reserves. Table 3-12 and the sections that follow summarize the structure of the reserve markets during the different market periods.

[76] The local areas of NEMA/Boston, CT, and SWCT have no 10-minute reserve requirement. Local first-contingency recovery requirements can be met by operating at the N-1 import-interface limit.

[77] *Fast-start* resources are those that can start up and be at full load in less than 30 minutes, which helps with recovery from contingencies and assists in serving peak demand.

Table 3-12
Market Periods and Associated Reserve Markets

Market Period	Forward Reserve Market?	Real-Time Reserve Market?
Interim Markets (May 1999–February 2003)	No	Yes
Standard Market Design (March 2003–November 2003)	No	No
SMD with Forward Reserve Market (December 2003–September 2006)	Yes (systemwide requirement)	No
SMD with Ancillary Services Markets Phase II (October 2006–present)	Yes (systemwide and local requirements)	Yes (pricing co-optimized with all energy and reserve products)

3.3.2.1 Interim Markets Period Reserves Markets

The Interim Markets period included a real-time reserve market for TMSR, TMNSR, and TMOR. During this period, the electric energy market and the reserve market were cleared separately. Resources were selected for reserve payment using the intersection of the reserve offer curve and reserve requirements to determine reserve prices. Although reserve prices were usually $0, they could be positive in hours when sufficient reserve was available. At these times, while only resources that were designated as providing reserves were paid the reserve clearing price, all resources that had unloaded capacity and the ability to produce power within 30 minutes provided reserves. Because of the low prices and lack of uniform pricing for resources providing reserves, the market did not provide adequate price signals for developing resources capable of producing reserves.

Another design weakness of the Interim Markets was that they did not fully value the tradeoffs between the different energy and reserve products, a process called *co-optimization*. Co-optimization between energy and spinning reserve was limited, and nonspinning reserves were not included. One result of the lack of full co-optimization was that prices for the slower, and thus lower-quality, reserve would occasionally exceed prices of the higher-quality products. For example, 30-minute operating-reserve prices could exceed the price of TMSR or even the price of electric energy.

3.3.2.2 Standard Market Design Reserve Markets

Reserve markets were not included in SMD when it was implemented in March 2003, although reserve requirements and the use of reserves in real time by control room operators continued as they had before SMD. The ISO and its stakeholders recognized the need for a reserve market that would provide incentives for reserve-capable resources and developed the Forward Reserve Market (FRM) in response to this need.

The systemwide, resource-based FRM was implemented in December 2003. The FRM was used to acquire generating resources to satisfy the requirements for TMNSR and TMOR for New England. FRM auctions were held twice a year, one month in advance of each of the semiannual service periods of June 1 through September 30 and October 1 through May 31. Generating units with

TMNSR and TMOR capacity were eligible to offer it into the auctions. Generating units selected in each auction during December 2003 through September 2006 were obligated to offer energy into the Day-Ahead Energy Market at or above the forward-reserve strike price for the service period. Failure to do so resulted in a penalty charge equal to the electric energy price minus the strike price.

The initial FRM was designed in a simplified form to achieve rapid implementation. This resulted in three design compromises. First, the initial FRM did not reflect local reserve requirements. As a result, the initial FRM acquired many resources that did not serve local needs, and local reliability commitments had to make up the difference. Second, the initial FRM was designed to make unit-specific awards and did not allow a supplier to designate a substitute unit when the original unit was unavailable. This was coupled with a flexible penalty that was zero whenever electric energy prices fell below the strike price. This resulted in relatively low penalties and, in practice, lowered the market value by not adequately discriminating between good and poor performers. Third, the initial FRM did not allow demand resources to compete in the market.

3.3.2.3 Ancillary Services Markets Reserve Markets

ASM II was implemented on October 1, 2006, to address both the lack of a real-time reserve market and the known design compromises of the initial FRM. Four reserve zones that reflect existing transmission constraints were defined: Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston, and Rest-of-System. Local requirements for these zones were added to the FRM, and real-time zonal reserve pricing was introduced. The recognition of local reserve requirements provides proper price signals for investment in reserve-capable resources in the areas where they are most needed.

Under ASM II, both the FRM and real-time reserve pricing allow certain demand resources to compete to provide reserve. This required the creation of a new asset class called *asset-related demand,* which is dispatchable or nondispatchable physical load that has been modeled within the ISO's dispatch and settlement systems. Dispatch and settlement software was enhanced to recognize the unique operating characteristics of demand resources.[78]

When ASM II was implemented, FRM obligations changed from being resource specific to portfolio based. Additionally, participants with reserve obligations are now required to assign resources on an hourly basis. Auction and service-period schedules remained unchanged. In the ASM II Forward Reserve Market, participants who offer into a forward-reserve auction are not required to have resources capable of providing reserves; reserve obligations incurred in the auction can be met with bilateral transactions or any reserve-capable resource in the participant's portfolio. Because forward-reserve resources can be assigned until midnight of the day before the operating day, the requirement for such resources to submit electric energy offers that exceed the strike price was changed from the Day-Ahead Energy Market to the reoffer period for the Real-Time Energy Market. Forward-reserve resources retain the obligation to be available to produce electric energy in real time when called on by the ISO.

Because participants can assign substitute resources for meeting a forward-reserve obligation, either from within a supplier's portfolio or through the bilateral market, more significant penalties for failing to meet an obligation are now invoked. The new penalty for failing to designate a resource to

[78] Currently only asset-related demand resources that are 5 MW or larger can participate in the reserve markets. A pilot project is underway to assess whether the 5 MW limit can be reduced. See Section 4.6.5 for additional details.

meet a reserve obligation is 1.5 times the forward-reserve payment rate, in addition to the loss of the forward-reserve payment for the hour that the participant would otherwise have received.[79] The penalty rate for failing to activate when called on by the ISO is 2.25 times the forward-reserve payment rate, or the hourly price for electric energy, whichever is higher.

ASM II also introduced real-time reserve pricing. For each of the four reserve zones, real-time reserve clearing prices are calculated every five minutes during the operating day. The real-time market does not include reserve offers. Reserve prices are calculated based on a jointly optimized economic dispatch of electric energy and the designation of operating reserve using the energy offer prices and reserve-constraint penalty factors when applicable. Hourly integrated reserve clearing prices are calculated from the five-minute prices. When reserves are ample, the real-time reserve price will be $0. However, if available reserves in a reserve zone or systemwide are short, or if reserve requirements are met through a redispatch of the system, nonzero real-time reserve prices may result. When the system is redispatched, the redispatch cost determines the reserve clearing price. When insufficient reserves are available or the cost of redispatch exceeds the reserve-constraint penalty factor for the type and location of reserve, the zonal real-time reserve price is set to the appropriate reserve-constraint penalty factor. Reserve-constraint penalty factors are based on the amount of redispatch costs the system is willing to endure to maintain reserves, and they are determined on the basis of the energy offer cap of $1,000/MWh. Table 3-13 shows New England's reserve-constraint penalty factors.[80]

The reserve-constraint penalty factors are cumulative. For example, if both systemwide total 30-minute and 10-minute reserves are short, the dispatch software will incur costs of up to $950/MWh to maintain reserves. If electric energy prices were $1,000/MWh, the software would instruct resources as inexpensive as $50/MWh to reduce output to maintain the reserve. If electric energy prices were $950/MWh, the software would instruct resources as inexpensive as $0/MWh to reduce output to maintain the reserve.

Table 3-13
New England Reserve-Constraint Penalty Factors

Constraint	Reserve-Constraint Penalty Factor
Systemwide TMSR constraint	$50
Systemwide total 10-minute reserve constraint	$850
Systemwide total 30-minute reserve constraint	$100
Local 30-minute reserve constraint	$50

[79] *The forward-reserve payment rate* is the auction price for the applicable reserve product in the applicable reserve zone, measured in $/MW-month, divided by the number of on-peak hours in the applicable month.

[80] *Reserve Constraint Penalty Factors* (RCPFs) are the rates, in $/MWh, that are used within the real-time dispatch and pricing algorithm to reflect the value of operating-reserve shortages and are defined in Section III.2.7a of Market Rule 1, available online at http://www.iso-ne.com/regulatory/tariff/sect_3/section_iii-market_rule1_effective_01-12-07.pdf.

As a result of the ASM II energy and reserve market improvements, the cost of redispatching resources to create reserves is also reflected in real-time electric energy LMPs. In hours when reserves are short, a 1 MW drop in demand will free up 1 MW of capacity, creating reserve. Thus, an opportunity cost of foregone reserve should be reflected in the price of electric energy. The opportunity cost is reflected by adding the reserve-constraint penalty factor to the cost of the marginal resource. In hours when redispatch prevents a reserve shortage, the electric energy price will include the redispatch cost.

The co-optimization of real-time reserve products and electric energy allows the system to provide consistent reserve prices; less valuable products will never be priced higher than more valuable reserve products. This is often referred to as *price cascading*. The TMNSR price will always be equal to or higher than the TMOR price, and the TMSR price will always be equal to or higher than the TMNSR price. Prices also cascade among reserve locations. The SWCT price will always be equal to or higher than the CT price, and the SWCT, CT, and NEMA/Boston prices will always be equal to or higher than the Rest-of-System price.

In conjunction with the revised reserve markets, additional performance monitoring and auditing for resources with claimed reserve capability was implemented. Beginning in January 2007, a failure to perform either during normal operations or during audits may result in a cap being placed on the megawatt value of reserve credit allowed to the failing resource. All resources that claim to have 10- or 30-minute off-line reserve capability will be tested, and their claimed 10-minute and claimed 30-minute reserve values will be capped at the megawatt value produced in the test. In addition, performance during normal operations will be monitored. A failure to start or a failure to provide the requested amount within the prescribed time could result in a cap on the reserve credit the resource is allowed.

3.3.3 Forward Reserve Market Auctions

Two FRM auctions were held in 2006. The first was held in April for the summer period of June 1 through September 30, 2006, and was for systemwide forward reserve. The second, for the winter period of October 1, 2006, through May 30, 2007, occurred in August after the implementation of ASM II, and for the first time, reflected both systemwide and local requirements. Table 3-14 shows auction requirements for each of the systemwide forward-reserve auctions.[81]

[81] Operating Procedure 8, *Operating Reserves and Regulation* (OP 8), available at http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html, gives the ISO authority to change the replacement-reserve requirement as appropriate for reliable system operation. In 2006, the ISO reduced the replacement-reserve requirement to zero because of the implementation of shared activation reserves, longer NERC and NPCC recovery time allowances, and the expectation of import capacity over ties. Additional details on the justification of the zero-replacement reserve requirement can be found in a May 19, 2007, memo from the ISO to the Markets Committee and Reliability Committee, available online at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2006/apr112006/a12b_iso_memo_03_31_06.doc,

Table 3-14
Forward-Reserve Auction Requirements, Pre-ASM II Auctions, MW

Auction Period	10-Minute Forward-Reserve Operating Requirement	30-Minute Forward-Reserve Operating Requirement	Replacement Reserve (added to the 30-Minute Requirement)	Total Requirement (not accounting for deratings)
January 1–May 30, 2004	600	600	300	1,500
June 1–September 30, 2004	700	600	300	1,600
October 1, 2004–May 30, 2005	600	600	300	1,500
June 1–September 30, 2005	700	600	300	1,600
October 1, 2005–May 30, 2006	750	700	350	1,800
June 1–September 30, 2006	700	700	0	1,400

Table 3-15 shows clearing prices for the six systemwide auctions that have occurred since December 2003. Requirements were met in all the auctions. Clearing prices were lower in each successive auction; the clearing price for the first auction, winter 2004/2005, was $4,495/MW-month, while the clearing price for the summer 2006 auction was $1,402/MW-month. Prices for 10-minute and 30-minute products were the same in each of the auctions. This occurred because many 10-minute forward-reserve offers were lower than the 30-minute forward-reserve offers. Thus, 10-minute forward-reserve resources were substituted for many 30-minute forward-reserve resources.

Table 3-15
Forward-Reserve Auction Results, Pre-ASM II Auctions

Auction Period	10-Minute Forward Reserve			30-Minute Forward Reserve		
	Total Supply Offers (MW)	Cleared MW	Clearing Price ($/MW-Month)	Total Supply Offers (MW)	Cleared MW	Clearing Price ($/MW-Month)
January 1–May 30, 2004	1,908	1,624	$4,495	1,566	252	$4,495
June 1–September 30, 2004	2,196	1,678	$4,075	1,782	285	$4,075
October 1, 2004–May 30, 2005	2,298	1,514	$3,690	1,568	349	$3,690
June 1–September 30, 2005	3,016	1,375	$2,400	2,229	596	$2,400
October 1, 2005–May 30, 2006	3,053	1,449	$2,000	1,534	736	$2,000
June 1–September 30, 2006	2,081	1,181	$1,402	1,011	441	$1,402

The rules for the revised Forward Reserve Market recognize that constrained regions have local TMOR requirements. The SWCT, CT, and NEMA/Boston reserve zones have local reserve TMOR requirements. To recognize North American Electric Reliability Council (NERC) requirements that reserve sources be geographically dispersed, the market also recognizes a TMOR requirement outside the constrained regions in the Rest-of-System reserve zone.[82] Thus, New England comprises four reserve regions. In addition, systemwide requirements exist for TMNSR and TMOR. Resources from all regions can serve these total system needs.

The FRM requirements are shown in Table 3-16. Reserve that clears in SWCT counts toward both the SWCT and CT requirements. Reserve that clears in any of the local reserve zones (Rest-of-System, SWCT, CT, and NEMA/Boston) counts toward the total system requirement in addition to the local requirement. While requirements are in place for the total system, all supply falls into one of the four reserve zones; no supply is classified as being located in the total system.

Table 3-16
Winter 2006/2007 Forward-Reserve Auction Requirements: Target and Cleared by Reserve Zone

Location Name	Product Type	Target Reserve Requirement (MW)	Cleared Reserve Requirement (MW)	Cleared Shortfall Target (MW)
Total system	TMNSR	700	700	0
Total system	TMOR/TMNSR	1,400	1,400	0
Rest-of-System (outside SWCT, CT, NEMA/Boston)	TMOR	798	798	0
SWCT	TMOR	550	394	(156)
CT	TMOR	1,340	659	(681)
NEMA/Boston	TMOR	1,200	607	(593)

The FRM auction reduces the quantity of reserve capacity required from local resources by the amount of spare transmission capacity that is expected to allow energy to flow into the reserve zone after a contingency occurs. This spare transmission capacity is referred to as *external reserve support*. A region with enough external reserve support to resolve any local contingency would have a zero local reserve requirement. In the winter 2006/2007 auction, only the NEMA/Boston reserve zone had external reserve support, of 290 MW, counted toward its reserve requirement. NEMA/Boston area reserve requirements are expected to decline in coming years when a transmission upgrade is completed and fully operational.[83]

Table 3-17 shows offered and cleared supply along with clearing prices. Forward-reserve requirements for the total system and for the Rest-of-System reserve zone were met in the winter

[82] For more information on this requirement, see *Operating Reserve Criteria,* Document A-06 (New York: NPCC; February 6, 2006). Available online at https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/A-06.pdf.

[83] *RSP06,* Table 1-1, shows more details of the requirements for the NEMA reserve zone.

2006/2007 auction, while requirements for SWCT, CT, and NEMA/Boston were not met. In SWCT, all 394 MW of offers cleared. The cleared quantity was still 156 MW short of the requirement of 550 MW. In the CT reserve zone, all 265 MW of offers cleared. The CT reserve zone was only 681 MW short of its requirement because the SWCT capacity is able to respond to a contingency in CT as well as in SWCT. All offers, a total of 317 MW, cleared in NEMA/Boston. NEMA/Boston also has external reserve support of 290 MW, so a total of 607 MW were counted toward the requirement of 1,200 MW.

Because offered quantities were short of requirements in the SWCT, CT, and NEMA/Boston reserve zones, the clearing price in these areas was set to the offer cap of $14,000/MW-month as directed in the *Forward Reserve Manual*, Section 2.6.1. In the Rest-of-System reserve zone, the clearing price for both TMNSR and TMOR was $4,200/MW-month.

In the Rest-of-System reserve zone, the lower-quality product, TMOR, continues to have the same price as the higher-quality product, TMNSR, as shown in Table 3-17. This is consistent with the observed surplus of offered TMNSR because that surplus is used in the systemwide TMOR market.

Table 3-17
Winter 2006/2007 Forward-Reserve Auction Supply:
Offered and Cleared by Reserve Zone and Product Type

Reserve Zone	Product Type	Total Supply Offers (MW)	Cleared Supply (MW)	Clearing Price ($/MW-Month)
Rest-of-System (outside SWCT, CT, NEMA/Boston)	TMNSR	948.48	565.60	$4,200
Rest-of-System (outside SWCT, CT, NEMA/Boston)	TMOR	735.40	232.40	$4,200
SWCT	TMNSR	90.00	90	$14,000
SWCT	TMOR	304.00	304	$14,000
CT	TMOR	265.00	265	$14,000
NEMA/Boston	TMNSR	60.00	60	$14,000
NEMA/Boston	TMOR	257.00	257	$14,000

The Forward Capacity Market transition payment of $3,050/MW-month was subtracted from FRM payments beginning in December 2006. In October and November 2006, the monthly ICAP supply auction clearing prices were subtracted. After subtracting the FCM payment and ICAP payments from the FRM clearing price of $4,200/MW-month, the average price for the eight-month period is $1,336/MW-month. This is consistent with the clearing price trend from previous systemwide auctions. In the CT, SWCT, and NEMA/Boston reserve zones, the average price for the eight-month period was $11,136/MW-month after subtracting capacity payments.

3.3.4 Forward Reserve Market Operating Results

The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve service period. It is set such that a generating resource offering electric energy at this level would be expected to operate at an annual capacity factor of 2% to 3%.[84] The forward-reserve strike price changes monthly with fuel-price indices and is calculated as a heat rate times a fuel index. The forward-reserve heat rate is fixed in the auction notice and does not change during the forward-reserve service period. The threshold price calculation uses the lesser of an index for No. 2 fuel oil and an index for natural gas. Throughout 2006, the natural gas index was the lower of the two indices.

Participants must meet their cleared portfolio-based obligations by assigning them to eligible generating or dispatchable asset-related demand resources. They do this by offering or bidding them into the Real-Time Energy Market at a $/MWh rate that is greater than or equal to the forward-reserve threshold price. Before ASM II, participants met their obligation by offering the specific resources that had cleared in the auction into the Day-Ahead Energy Market at a price greater than or equal to the forward-reserve threshold price. Table 3-18 shows monthly threshold prices and the heat rates and fuel indices used to derive them.

Table 3-18
Forward-Reserve Heat Rates, Fuel Indices, and Threshold Prices, 2006

Obligation Month	Forward-Reserve Heat Rate (MMBtu/MWh)[(a)]	Monthly Forward-Reserve Fuel Index ($/MMBtu)	Monthly Forward-Reserve Threshold Price ($/MWh)
Jan	13.600	$12.49	$169.86
Feb	13.600	$8.84	$120.22
Mar	13.600	$8.03	$109.21
Apr	13.600	$7.75	$105.40
May	13.600	$7.75	$105.40
Jun	14.419	$6.38	$91.99
Jul	14.419	$6.51	$93.87
Aug	14.419	$7.76	$111.89
Sep	14.419	$6.84	$98.63
Oct	14.367	$4.86	$69.82
Nov	14.367	$8.27	$118.82
Dec	14.367	$8.41	$120.83

(a) MMBtu stands for million Btu.

[84] For each service period, a forward-reserve heat rate is established on the basis of a historical study and announced before the forward-reserve auction. The forward-reserve strike price is calculated using the forward-reserve heat rate defined for the service period and the forward-reserve fuel index, which changes with market conditions. Forward-reserve assumptions are posted on the ISO's Web site, at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/cal_assump/2006/index.html.

Table 3-19 shows the percentage of hours in each month with on-peak LMPs that equaled or exceeded the threshold price. A threshold price can be lower than the LMPs if the fuel index used in the calculation of the threshold price was lower than actual prices or if LMPs were often set by generators that burned a higher-priced fuel than the fuel used in the fuel index. The threshold price can also be lower than the LMP if system conditions caused LMPs to be set by generators with higher heat rates than used in the threshold price. When the LMP exceeds the threshold price, resources that bid at or above the threshold price can be dispatched for electric energy rather than remain unloaded to provide reserves.

Table 3-19
Percentage of On-Peak Hours with Real-Time LMP Greater than or Equal to FRM Threshold Price, 2006

Month	Hub (%)	CT (%)	NEMA (%)
Jan	1	4	1
Feb	0	1	0
Mar	3	4	3
Apr	3	3	3
May	1	5	6
Jun	6	24	12
Jul	19	46	23
Aug	8	23	7
Sep	0	3	0
Oct	21	43	22
Nov	1	1	1
Dec	1	2	1

LMPs exceeded the threshold price in many hours during July and October 2006. In July, LMPs were often set by oil-fueled generators. Because both No. 6 and No. 2 fuel oil prices exceeded natural gas prices during July, these LMPs exceeded the threshold price, which was based on natural gas.

Natural gas prices increased during October 2006, from about $4/MMBtu at the beginning of the month to about $8/MMBtu at the end of the month. Although the natural gas index used for calculating the October threshold price was close to actual natural gas prices in early October, it was much lower than actual natural gas prices later in the month. This resulted in a threshold price that was frequently exceeded by LMPs in the second half of October.

The clearing price from the forward-reserve auction is converted into an hourly payment rate based on on-peak hours.[85] Forward-reserve generating units selected in the auctions (before ASM II) or assigned daily forward-reserve obligations (after ASM II) are paid this hourly price. Penalties are assessed if a participant does not offer an available, forward-reserve-capable resource into the energy market at or above the threshold price, or if an assigned resource is not able to provide energy within 10 or 30 minutes if called on during real-time operations.[86,87]

Payments for forward reserves were about $70 million in 2006. Of this total, $41 million was paid in the last three months of the year, after the transition to local requirements. Payments are reduced by any failure-to-reserve or failure-to-activate penalties. Penalties for the year totaled $3.6 million. The majority of these penalties, $3.2 million, were failure-to-reserve penalties paid after the transition to local requirements. There were no failure-to-activate penalties in October through December, and only about $175,000 in the rest of the year. All costs relating to compensating generating resources in the FRM are allocated based on real-time load obligations. Figure 3-37 shows FRM payments and penalties for 2006.

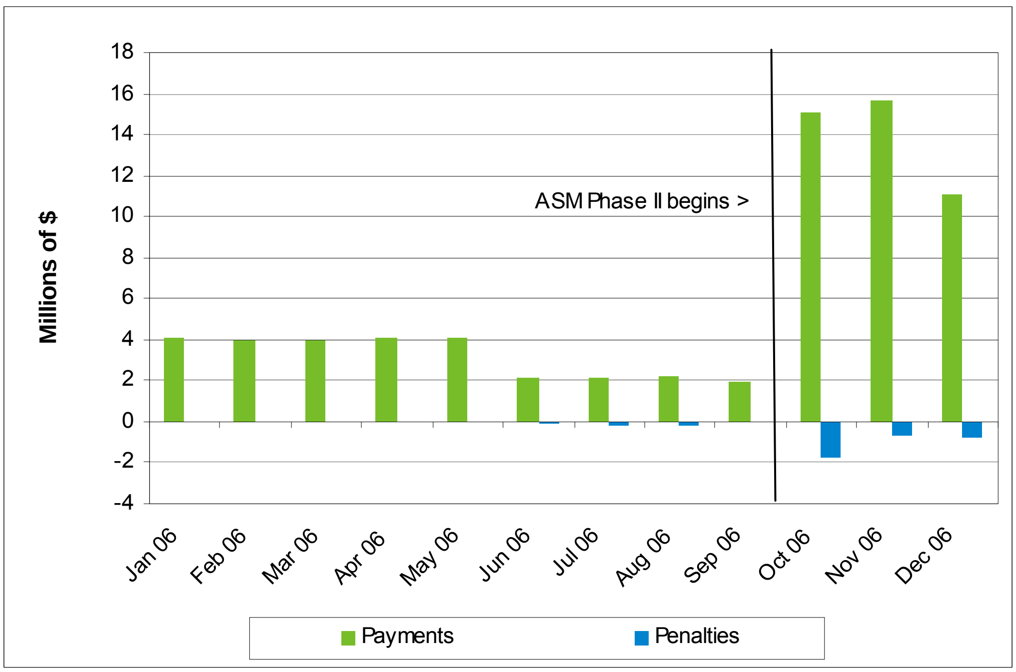

Figure 3-37: Forward Reserve Market payments and penalties, January to December 2006.

Immediately after the implementation of the ASM II Forward Reserve Market, some participants failed to assign resources to meet the forward-reserve obligations incurred in the auction. The ISO's Market Support Services posted information on the ISO Web site to clarify how participants should

[85] Since the implementation of ASM II, the auction clearing price is adjusted to reflect payments made in the Installed Capacity Market before being converted to an hourly rate.

[86] After ASM II, participants receive exceptions to the failure-to-reserve penalty for periods when the unavailability is due to scheduled annual maintenance.

[87] After ASM II, failure-to-activate penalties are applied only when control room operators have approved a contingency unit-dispatch software case.

assign resources to meet their forward-reserve obligations. By mid-October, participants improved their assignment of daily forward-reserve obligation to resources.

3.3.5 Real-Time Reserve Pricing Results

Resources providing real-time reserves are designated in the ISO's Energy Management System in real time. Reserve credits are calculated from these product-specific designations and the product-specific clearing prices for reserves. Reserve charges are calculated on the basis of participants' zonal load obligation and reserve prices in the load zone.[88]

Table 3-20 shows the frequency with which real-time reserve prices were greater than $0/MWh in each zone. As expected, positive prices were only observed during periods of reserve scarcity. Positive prices occurred in SWCT and CT more frequently during late October through mid-November as a result of transmission system outages. Positive reserve prices occurred only rarely in the Rest-of-System zone. Prices were positive in at least one reserve zone in 238 hours, or 11% of the time in October through December 2006.

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[88] See the ISO's Market Rule 1 (2005), 7304G–7304H, for a complete explanation of the calculation of the real-time reserve charge. Available online at http://www.iso-ne.com/regulatory/tariff/sect_3/section_iii-market_rule1_effective_01-12-07.pdf.

Table 3-20
Hourly Real-Time Reserve Prices and Percentage of Hours in Price Range, October 1 to December 31, 2006

Reserve Zone	Price Range	TMSR (%)	TMNSR (%)	TMOR (%)
ROS	$0	96.5	99.2	99.9
ROS	$0.01–$10.00	2.7	< 1	< 1
ROS	$10.01–$25.00	0.5	< 1	< 1
ROS	$25.01–$49.99	< 1	< 1	0.0
ROS	$50	0.0	0.0	0.0
ROS	> $50	< 1	0.0	0.0
NEMA/Boston	$0	95.6	98.3	99.0
NEMA/Boston	$0.01–$10.00	2.8	< 1	< 1
NEMA/Boston	$10.01–$25.00	0.8	0.5	< 1
NEMA/Boston	$25.01–$49.99	0.8	0.8	0.6
NEMA/Boston	$50	0.0	0.0	0.0
NEMA/Boston	> $50	< 1	0.0	0.0
CT	$0	89.4	91.9	92.5
CT	$0.01–$10.00	6.1	3.9	3.7
CT	$10.01–$25.00	2.9	2.7	2.4
CT	$25.01–$49.99	1.3	1.3	1.1
CT	$50	< 1	< 1	< 1
CT	Over $50	< 1	0.0	0.0
SWCT	$0	89.3	91.7	92.4
SWCT	$0.01–$10.00	6.1	4.1	3.8
SWCT	$10.01–$25.00	3.0	2.7	2.4
SWCT	$25.01–$49.99	1.3	1.3	1.1
SWCT	$50	< 1	< 1	< 1
SWCT	Over $50	< 1	0.0	0.0

Payments to resources that provided real-time reserves totaled $2.9 million in 2006. Resources assigned to meet forward-reserve obligations are often designated as reserve resources in real time.[89]

[89] Real-time reserve pricing is possible in all hours; forward-reserve obligations are for weekday on-peak hours only.

When real-time reserve payments are positive and a resource that has been assigned for forward reserve is also designated for real-time reserve, double payment is avoided by subtracting, on a megawatt-for-megawatt basis, the real-time reserve credit. These adjustments, referred to as *forward-reserve energy obligation charges*, were $1.26 million in 2006, leaving a net of $1.66 million in real-time reserve revenues. Table 3-21 shows real-time reserve credit payments by month.

Table 3-21
Real-Time Reserve Credits and Forward-Reserve Obligation Charges, October to December 2006, $

Month	Real-Time Reserve Credit	Forward-Reserve Energy Obligation Charge
Oct	2,092,507	-906,494
Nov	494,126	-260,296
Dec	335,632	-93,421
Total	2,922,266	-1,260,211

3.3.6 Reserve Market Conclusions

The New England reserve markets underwent significant changes during 2006. While market performance cannot be assessed on the basis of three months of operation, the revised Forward Reserve Market and new real-time reserve pricing appear to be working as designed.

The ISO will monitor the quantities of reserve clearing in the SWCT, CT, and NEMA/Boston reserve zones and the impact of the auction-clearing price cap. The quantity of supply offered in local areas may increase in future auctions, as it did in the earlier systemwide auctions. Thus, the failure to meet reserve requirements in the first auction is not necessarily a signal that the price cap is set too low.

3.4 Regulation Market

Regulation is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[90] This system balancing also maintains proper power flows into and out of the New England Control Area. The Regulation Market is the mechanism for selecting and paying generation needed to manage this system balancing.

On October 1, 2005, the ISO implemented modifications to the Regulation Market.[91] The market changes included adding a service payment and improving the calculation of opportunity costs. The Regulation Market clearing price is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide regulation

[90] The *Eastern Interconnection* is one of North America's major AC grids that during normal system conditions interconnects transmission and distribution infrastructure synchronously operating (at 60-hertz average) east of the Rocky Mountains and south to Florida, excluding Québec and the portion of the system located in the Electric Reliability Council of Texas (ERCOT).

[91] See the ISO's 2003 through 2005 *Annual Markets Reports* for a detailed description of the SMD Regulation Market, available in the ISO archive that can be accessed online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

includes a regulation capacity payment, a service payment, and unit-specific opportunity cost payments. Unit-specific opportunity cost payments are not included as a component of the regulation clearing price (RCP) as they were in the Regulation Market before October 1, 2005.

Load-serving entities pay for regulation service based on real-time load obligations. Market participants may satisfy regulation requirements by providing the service from their own resources, through internal bilateral transactions for regulation, or by purchasing regulation from the market.

3.4.1 Regulation Performance

The primary objective of the Regulation Market is to provide the necessary resources and market-based compensation to allow the ISO to meet NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0) for control areas (NERC balancing authorities).[92] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[93]

> *Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six non-overlapping periods per hour) during a calendar month is within a specified limit, referred to as L_{10}.*[94]

For the New England Control Area, the CPS 2 annual average compliance target is 92% to 97%. Figure 3-38 shows the CPS 2 compliance each month from January to December 2006 and the 90% lower monthly limit. The ISO has continually met its CPS 2 targets.

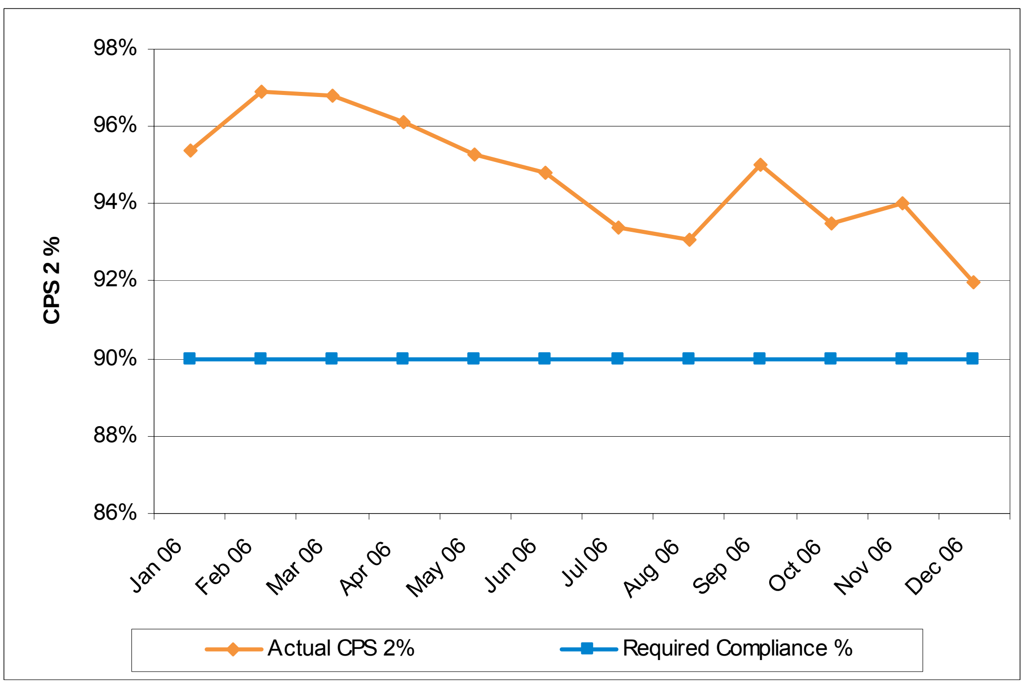

Figure 3-38: CPS 2 compliance.

[92] This standard (effective April 1, 2005) can be accessed online at http://www.nerc.com/~filez/standards/Reliability_Standards.html#Resource_and_Demand_Balancing.

[93] For more information on NERC's Control Performance Standard 2, see the NERC Web site at http://www.nerc.com/~oc/rs.html.

[94] The *area control error* of the New England Control Area is the actual net interchange minus the biased scheduled net interchange.

The ISO periodically evaluates the regulation requirements necessary to maintain CPS 2 compliance. The regulation requirements (posted on the ISO's Web site) are determined by hour and vary by time of day, day of week, and month.[95] Figure 3-39 shows a time-weighted monthly average of the regulation requirements. In the figure, the requirements for June 2001 through February 2003 have been converted from REGS (the regulation requirement of the Interim Market) to megawatts of regulation to be consistent with present market requirements. Figure 3-39 shows a gradual downward trend of the average monthly requirements over the period. The ISO has been able to reduce the requirements, in part, because of the overall improvement in the response of the regulation resources to the regulation-control signals. Regulation requirements are lower during spring and fall than in summer and winter.

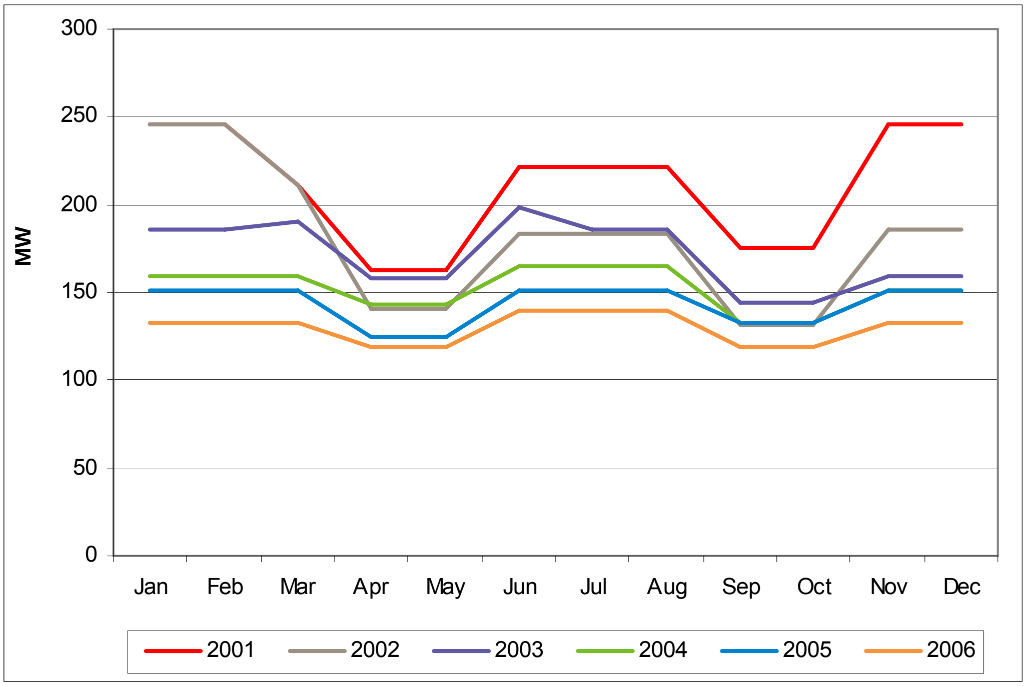

Figure 3-39: Monthly average regulation requirements.

Note: Requirements shown in the plot for January 2001 to February 2003 were converted from REGS to MW for consistency.

New England has approximately 2,358 MW of installed regulation capacity. The pool of resources available for regulation on an hourly basis is a subset of all regulation-capable generators that submit an offer for regulation; are on line, producing energy, and are dispatchable; and have appropriate real-time parameters. In general, about 23%, or just over 557 MW, of the installed regulation capability is available to provide regulation in a given hour.

3.4.2 Regulation Market Results

The hourly Regulation Market clearing price averaged $24.02/MWh (unweighted) over the year. Payments to generators for providing regulation totaled $78.1 million, including $34.8 million in service credit payments, $13.1 million in real-time opportunity cost payments, and $30.2 million in regulation capacity credits. During 2005, total payments to generators for providing regulation were

[95] The Web site address for the ISO's regulation requirements is http://www.iso-ne.com/sys_ops/op_frcstng/dlyreg_req/index.html.

$74.8 million. Figure 3-40 shows total regulation payments by month from March 2003 through December 2006. Costs increased after implementation of the market modifications in October 2005. In early 2006, shifts in supply, combined with a reduction in fuel costs, led to a substantial reduction in Regulation Market costs. The increased regulation opportunity cost payments in early August 2006 reflect the scarcity pricing events that took place during that month (refer to Section 3.1.6).

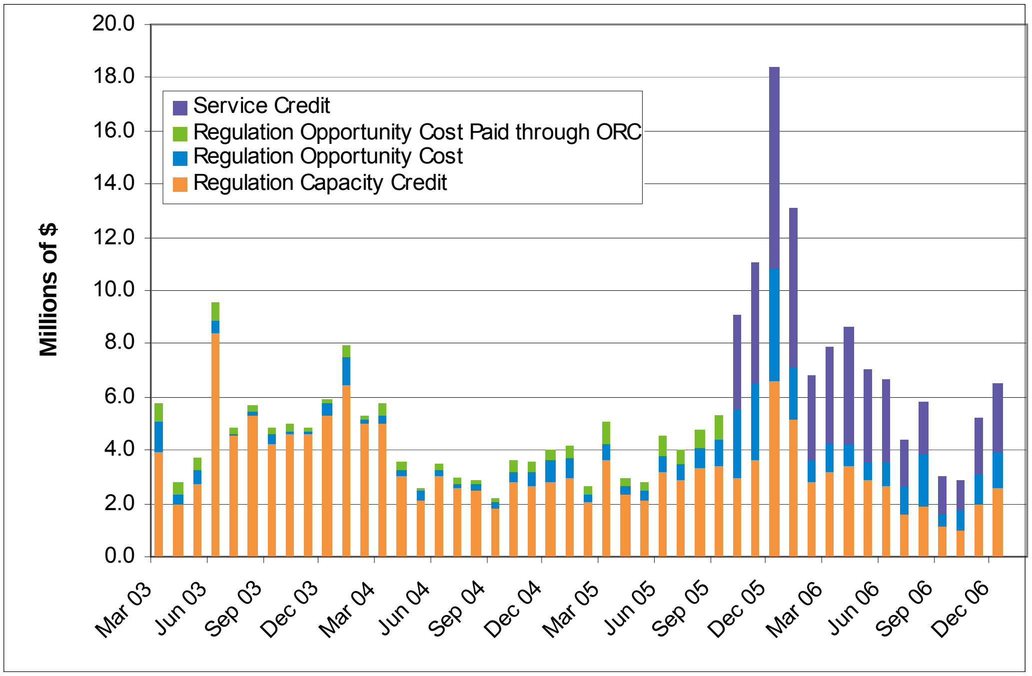

Figure 3-40: Total regulation payments by month.

As Figure 3-41 illustrates, average 2006 regulation prices were highest during the morning peak hours. The prices declined during the midday and evening peak hours and increased slightly in the late evening. These prices correspond to the availability of regulation units; many are available during the day, whereas supply becomes tighter overnight as units are decommitted.

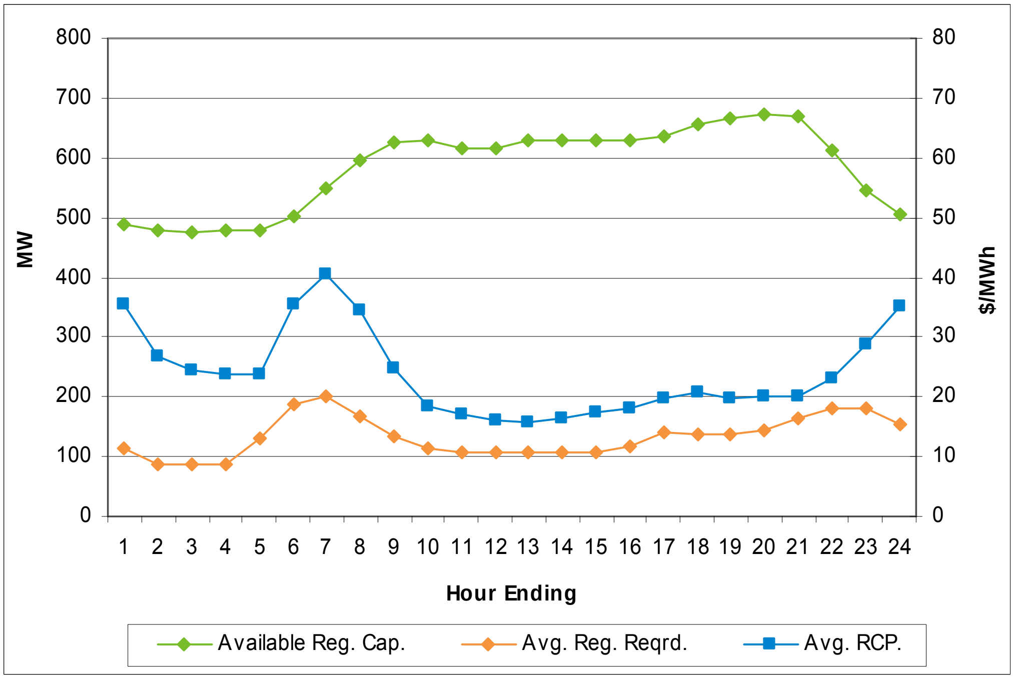

Figure 3-41: Average hourly regulation clearing prices, average regulation requirements, and available regulation capacity, 2006.

Table 3-22 summarizes information about clearing prices in the Regulation Market during the year.

Table 3-22
Regulation Market Clearing Prices, Summary Statistics, 2006, $/MWh

Month	Average	Median	Minimum	Maximum
Jan	44.13	39.56	5.00	100.00
Feb	25.62	20.84	0.00	97.57
Mar	27.96	22.96	0.00	92.48
Apr	36.96	31.29	0.00	95.04
May	30.66	27.00	0.00	76.90
Jun	23.61	20.00	0.00	86.60
Jul	14.29	13.00	0.01	63.37
Aug	16.62	12.33	0.01	75.00
Sep	12.05	11.96	0.00	50.86
Oct	10.96	10.00	0.00	47.54
Nov	20.19	11.86	1.34	100.00
Dec	25.27	14.00	0.00	100.00

3.4.3 Regulation Market Analysis and Market Revisions

Regulation Market costs increased substantially in late 2005 and early 2006 following the implementation of the new design. The new design included an additional revenue stream in the form of a service payment for units providing regulation. Because of this, an initial increase in regulation costs was anticipated; however, costs more than doubled in the early months of the newly designed market. During the initial months of the ASM I Regulation Market redesign operation, regulation offers were substantially unchanged from offers made under the previous market design. Since the service payment is designed to match the regulation capacity payment, the unchanged regulation offers contributed to much higher costs. As the market matured and regulation suppliers adjusted to the new payment structure, regulation offer prices declined, and regulation clearing prices decreased throughout 2006.

As in the electric energy market, prices and opportunity costs in the Regulation Market are influenced by fuel costs and other supply conditions. Because generators experience a loss of thermal efficiency when providing regulation service, their costs are higher when regulating compared with when simply providing electricity. Fuel-contract provisions can also affect the cost of regulation, particularly for natural gas units.[96] The early months after the implementation of the ASM I Regulation Market design in fall 2005 coincided with a period of relatively high natural gas prices. The ISO observed both entry and exit from the Regulation Market during this period, including the exit by some generators for reasons unrelated to the market. This change in supply contributed to an increase in the cost of regulation service. The available regulation supply in November and December 2005 was further reduced because fewer generators were on line and eligible to provide regulation as a result of negative spark spreads created by the high gas prices relative to oil prices.[97] Figure 3-42 shows the marginal cost of a hypothetical gas-fired generator and periods of negative spark spreads compared with available regulation supply. After the implementation of the new market design, supply declined during the frequent periods of negative spark spreads.

[96] When a unit is regulating, its fuel consumption is difficult to predict accurately. Consequently, a gas unit is likely to use a different amount of gas than nominated. Depending on the pipeline conditions, this may result in imbalance penalties, which would be a cost when providing regulation.

[97] *Negative spark spread* is the uneconomic conversion of natural gas to electricity occurring when the wholesale price of electricity (LMP) is less than the cost (fuel price times heat rate) of producing the electricity. Also see Section 5.2.6 on implied heat rates.

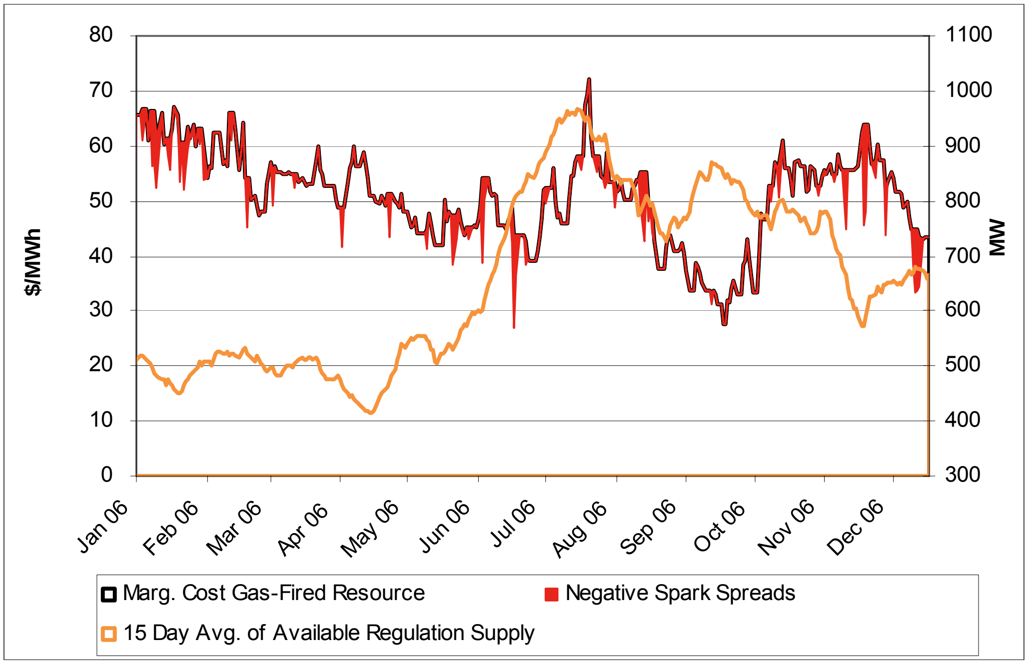

Figure 3-42: Negative spark spreads compared with regulation supply.

These conditions led to higher costs in the first months of the new market beyond what was anticipated and triggered in-depth reviews of market performance by both the Internal and Independent Market Monitoring Units. Although the market costs declined in early 2006 and have not returned to the levels experienced in November and December 2005, costs increased during periods of negative spark spreads and light loads, such as those experienced in November and December 2006.

3.4.4 Resource Selection Bias

The Regulation Market uses a selector program that assesses and ranks the offers from potential regulation suppliers for the upcoming hour. Regulation providers are selected on the basis of this ranking each hour. The reviews by the market monitors identified minor inefficiencies in the regulation-selection process, and the ISO proposed reforms to two elements of the selection software. These revisions were filed with FERC in November 2006.[98,99]

The first inefficiency is that the rank price overestimates opportunity costs by including the duplicative elements of the estimated changes to the opportunity and production costs. These redundant components may lead to the suboptimal selection of units to provide regulation and increased consumer payments, particularly when the number of on-line regulation-capable units is limited. The second identified bias in the regulation-selection process is that the look-ahead penalty tends to overestimate the magnitude of unit-specific opportunity costs, which will inappropriately

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[98] These reforms were approved in early 2007 and were implemented by the ISO on January 12, 2007.

[99] David Patton and Pallas LeeVanSchaick. *2005 Assessment of the Electricity Markets in New England.* (Fairfax, VA: Potomac Economics, Ltd., 2006). Available online at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2006/oct17182006/a9_reg_mkt_excerpt_from_2005_immu_report.pdf.

inflate the rank price of certain units and, at times, make them virtually ineligible for regulation selection.

In response to detecting these weaknesses in the Regulation Market selector process, the ISO proposed the following two main changes: reform the selector process to eliminate the production cost component and introduce a 17% coefficient to reduce the effect of the look-ahead penalty. These reforms improve the efficiency of the Regulation Market. They will also reduce the impact of increased fuel prices on regulation selection. Because higher fuel prices raise some units' estimated lost-opportunity costs, and these costs were "twice weighted" in the previous selector process, eliminating the production cost component will less likely lead to selecting units with relatively low estimated lost-opportunity costs and higher regulation supply offers. This should decrease regulation clearing prices and consumer payments. The reforms will improve the selection of regulation resources to meet the market design objective of minimizing consumer payments. Specifically, eliminating the redundant production cost component and adjusting the look-ahead penalty promote competitive bidding behavior that will potentially reduce consumer payments for regulation.

As part of its evaluation of the revisions to the Regulation Market rules, the ISO simulated consumer payments under the originally implemented design and those under the proposed market-rule revisions, which FERC approved and the ISO implemented on January 12, 2007. The simulation estimates that under the revised design, annual consumer payments would have been reduced by about $6 million during 2006.

3.4.5 Regulation Market Conclusions

The Regulation Market performed effectively in 2006 to provide sufficient amounts of regulation, and the New England Control Area fully complied with NERC reliability requirements for regulation.

The ISO and the external market monitor identified minor biases in the selection process and proposed market-rule revisions to address these shortcomings. In November 2006, the ISO filed with FERC revisions to two elements of the selection software. FERC approved these changes in early 2007, which the ISO implemented on January 12, 2007. The ISO will continue to monitor Regulation Market performance.

Section 4
Reliability Costs, Congestion Management, and Demand Response

This section discusses a number of additional programs and procedures the ISO administers to provide system reliability, manage transmission congestion costs, and incorporate demand-side resources. These include reliability commitments, Net Commitment-Period Compensation (NCPC), tariff payments, Peaking Unit Safe Harbor (PUSH) activity, and Financial Transmission Rights. The section also discusses demand- and price-response programs and the credits generators receive for reducing excess generation. Appendix B provides additional data on tariff charges and transmission congestion revenues.

4.1 Daily Reliability Commitments and Costs

The requirements for ensuring the reliability of New England's bulk power system reflect standards developed by NERC, NPCC, and the ISO through open stakeholder processes. These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures.[100] To meet these requirements, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market. Resources that the ISO requires to operate but that do not recoup their offers through electric energy market revenues are paid first-contingency and second-contingency Net Commitment-Period Compensation (also referred to as *first-* and *second-contingency reliability payments*), voltage reliability cost payments, and distribution reliability cost payments.[101] This section discusses the process for making reliability commitments and includes total annual data on reliability commitments and generation for 2006 and annual reliability payments and cost allocations for the year. Data are compared with 2005 results.

4.1.1 Reliability Commitment Process

While some commitments may be made immediately after the Day-Ahead Energy Market clears, most are made through a commitment process called the Reserve Adequacy Analysis (RAA) process. The process is designed to maximize the opportunity for the market to respond and minimize the ISO's supplemental commitments to meet reliability criteria. The RAA begins after the reoffer period closes at 6:00 p.m. and is updated periodically throughout the operating day; commitments may be added or cancelled if reliability needs change during the operating day as a result of market response or other changed system conditions.

The first part of the RAA process is to evaluate the set of generator schedules produced by the Day-Ahead Energy Market solution, any self-schedules that were submitted during the reoffer period, and the availability of resources for commitment near real time. The ISO will then commit additional generation if the Day-Ahead Energy Market generation schedule, in combination with self-scheduled

[100] For more information on NERC, see http://www.nerc.com. For more information on NPCC, see http://www.npcc.org. The ISO's system operating procedures are available online at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

[101] *NCPC* is the methodology used to calculate payments to resources for providing operating or replacement reserves in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see Market Rule 1, Section III, Appendix F, *Net Commitment-Period Compensation Accounting*, at http://www.iso-ne.com/regulatory/tariff/sect_3/appendix_f_operating_reserve_accounting_redone_1-18-06.doc. Also see Appendix B in this document.

resources and off-line fast-start generation that can be committed, does not meet the real-time forecasted demand and reserve requirements. When multiple generators are available to meet the RAA requirements, the ISO process minimizes start-up, no-load, and electric energy offers to operate at minimum output. The ISO uses a seven-step plan for committing generators to meet the following requirements during the RAA process:

1. Meet the local reliability requirements of the local transmission companies and manage the constraints not reflected in the ISO systems and reliability criteria. Local transmission owners and distribution companies request these commitments for distribution support.

2. Provide reactive power and capacity (VAR) to control voltage during periods of light demand when voltage can increase to unacceptable levels. Generators must also be available to support voltage in the event of a contingency during a high-demand period.

3. Meet transmission first-contingency requirements for local or import-congested areas.

4. Specifically meet the transmission or generator second contingencies in import-congested areas.[102]

5. Meet the systemwide regulation requirement when the Day-Ahead Energy Market commitments do not provide sufficient regulating capability to meet the real-time requirement. RAA commitments for regulation are unusual.

6. Meet the systemwide requirement for spinning reserves when the Day-Ahead Energy Market commitments do not provide sufficient spinning capability to meet the real-time requirement. RAA commitments for systemwide spinning reserves are unusual.

7. Meet the systemwide requirement for operating reserves when the Day-Ahead Energy Market commitments do not provide sufficient capacity to meet the real-time requirement. RAA commitments for systemwide operating reserves are unusual.

In the RAA commitment process, the constraint that can be met by the fewest generators is solved first. This minimizes real-time reliability commitments. The generation committed to solve the first constraint can offset the need to commit additional generation for meeting the local, regional, and systemwide requirements. This process helps to meet system reliability requirements while minimizing the capacity committed.

4.1.2 Reliability Commitment Results

Figure 4-1 shows total electric energy produced (MWh) by the commitment categories of self-scheduled generation, economic pool-scheduled generation, and reliability commitments. Energy output from reliability commitments was 5.9% of total generation in 2006, ranging from a low of 3.2% in January to a high of 8.3% in June. Generators providing energy from reliability commitments can be compensated through energy market revenues and daily reliability payments. The figures in this section include all megawatt-hours for the commitment period from each unit with a reliability commitment, irrespective of its in-merit portion.

[102] In general, second-contingency protection is provided for areas of New England where contingencies can lead to instability, uncontrolled separation, or cascading outages that have an impact on areas outside New England. Second-contingency coverage is also provided where ISO operators would not be able to safely restore an area to meet reliability criteria within 30 minutes following a first-contingency event.

Figure 4-2 shows the electricity output that resulted from reliability commitments in the Day-Ahead Energy Market, the RAA process, and the Real-Time Energy Market. Overall in 2006, the total electricity produced by generating units committed for reliability decreased from 8.7 million MWh in 2005 to 7.4 million MWh in 2006. Energy output from reliability commitments made during the Day-Ahead Energy Market were higher in 2006 than in 2005, and energy output from reliability commitments made during the RAA process and Real-Time Energy Market were lower.

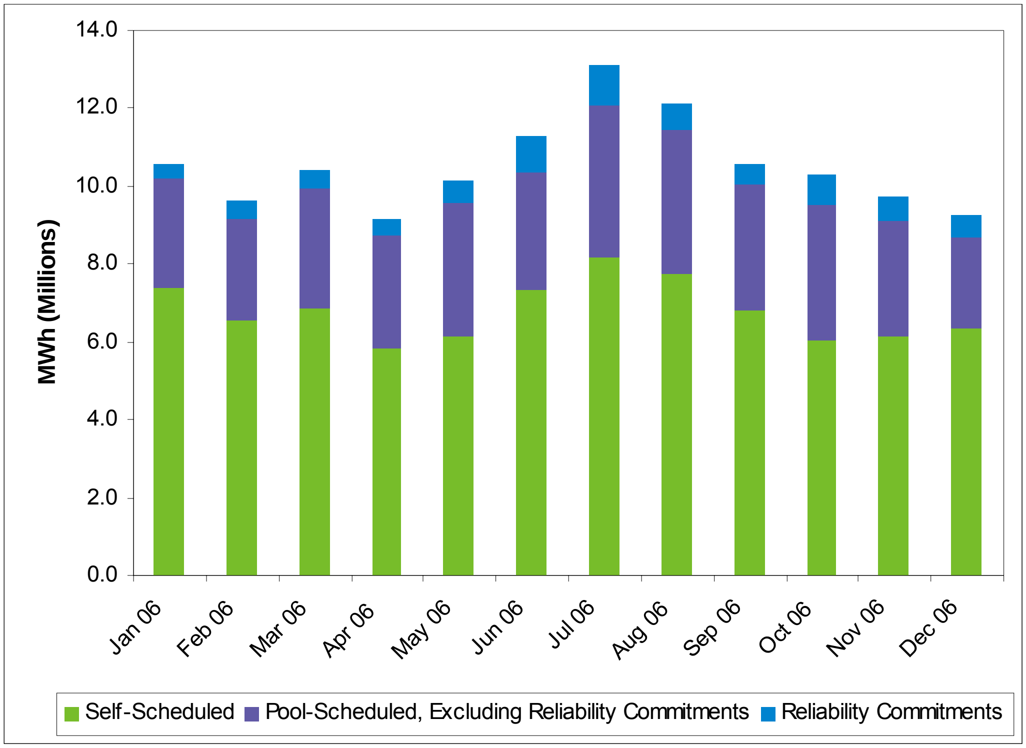

Figure 4-1: Electricity output from self-scheduled, economic pool-scheduled, and reliability commitments.

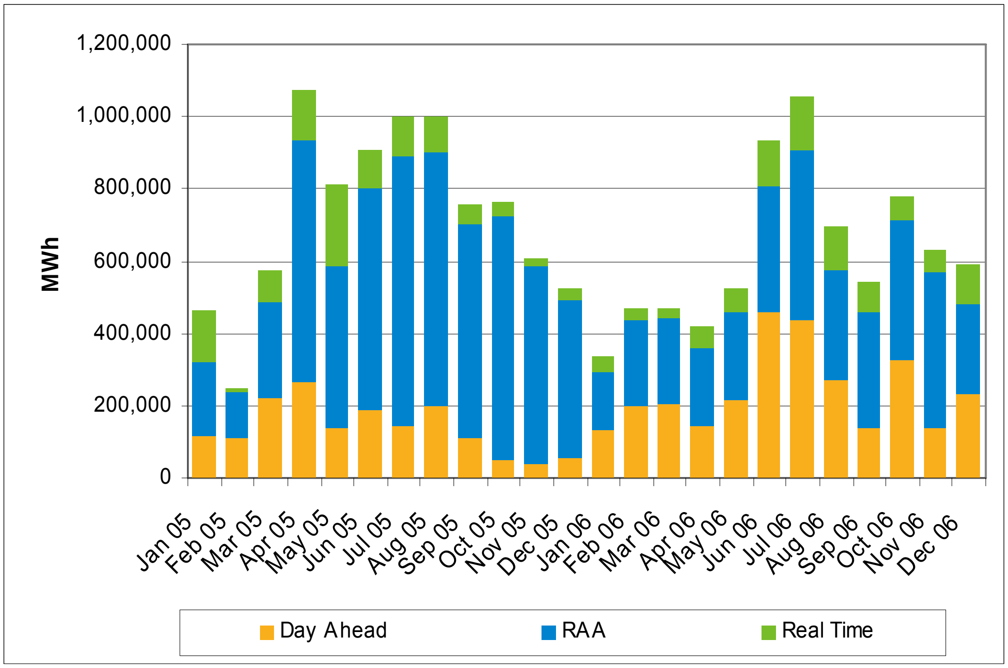

Figure 4-2: Total monthly electricity output from reliability commitments day ahead, RAA, and real time.

Figure 4-3 shows total electricity output from commitments made to supply local second-contingency reserves by month and load zone. Only Connecticut and NEMA have daily evaluations of second-contingency reserve requirements in the operating procedures. Other areas are evaluated on a case-by-case basis when temporary transmission or resource outages significantly change the flows of energy relative to normal operations.

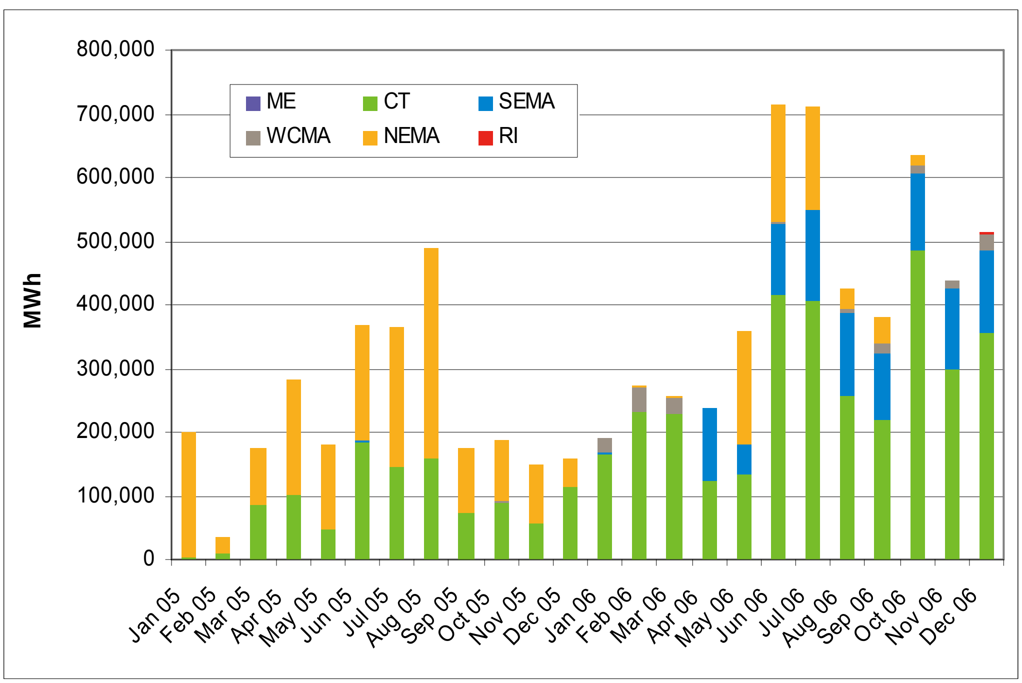

Figure 4-3: Total monthly electricity output from second-contingency commitments by load zone, 2005 and 2006.

In late 2005, the price of oil became more expensive than the price of natural gas, resulting in a shift in the economics of electricity generation for the SEMA area. Because of this reversal in fuel prices, particular oil-fired local resources were no longer being committed in economic-merit order. In January 2006, ISO Operations determined that without a unique set of local generating units on line, NERC, NPCC, and ISO reliability criteria standards would not be met without pre-second-contingency load shedding. As a result, the supplemental commitment of generating resources in the SEMA load zone has become common, as shown in Figure 4-3. The ISO is working with transmission owners and other market participants to develop a plan to strengthen the local transmission system and other options that could decrease the need for out-of-market commitments in that area.

Throughout 2005 and into the first quarter of 2006, the majority of second-contingency commitments were made in the NEMA and Connecticut load zones.[103] During the second half of 2006, electric energy from second-contingency commitments in the Connecticut zone increased relative to 2005 levels, while energy from second-contingency committed resources in NEMA dropped off. The increase in commitments in the Connecticut area was partly due to outages associated with the construction of the 345 kV reliability project and various transmission outages for line maintenance. During 2006, 62% of the megawatt-hours from second-contingency committed resources were from resources located in the Connecticut load zone, 19% were from SEMA resources, and 12% were from resources in the NEMA load zone. This represents a shift from the distribution of energy for second-contingency commitments in 2005, when resources in the NEMA load zone generated the majority of energy from second-contingency committed units.

Figure 4-3 also shows that electric energy was produced by resources in the WCMA load zone in several months during 2006.[104] This output is attributable to resources committed to support second contingencies in western Massachusetts caused by transmission system outages that occurred on individual days during January through March and June through December. These resources were committed on the basis of an analysis that is performed when particular transmission elements are out of service.

Figure 4-4 shows, by month and by load zone, the total electric energy output from commitments made during the reporting period to provide reactive power. These commitments provide high-voltage control or low-voltage support. The commitments for voltage control are generally needed when demand levels are low, while the commitments for voltage support are needed during high-demand periods.

[103] Within Connecticut, commitments are first made to solve constraints in the Norwalk/Stamford area, then Southwest Connecticut, and finally the rest of Connecticut because commitments made in one of the subareas may also resolve constraints in the larger area.

[104] Because of the quantity of electric energy produced from the supplementally committed resources in WCMA relative to other load zones, the values for the second-contingency supplemental commitments in the WCMA load zone are visible only in four of the 12 months when energy was produced.

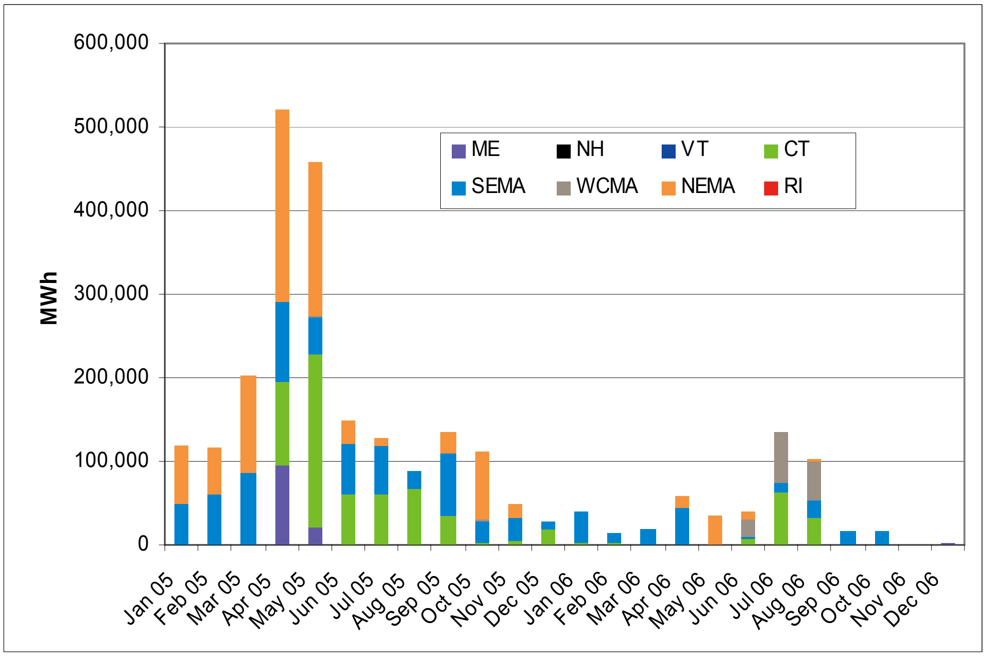

Figure 4-4: Total monthly electricity output from voltage commitments by load zone, 2005 and 2006.

The total output produced for voltage support and control in 2006 decreased substantially relative to 2005, dropping from 2.1 million MWh in 2005 to under 500,000 MWh in 2006. The largest decrease was in the NEMA load zone, followed by the Connecticut load zone. The Southwest Connecticut 345 kV Reliability Project is expected to reduce the need for reliability commitments within Connecticut. Phase 1 of the project was put into service in October 2006 and improved transmission between the Norwalk/Stamford subarea and the rest of Southwest Connecticut. Phase 2 of the project, scheduled for completion in December 2009, will improve transmission between Southwest Connecticut and the rest of Connecticut.

4.1.3 Reliability Commitment Costs

First-contingency and second-contingency NCPC, voltage reliability cost payments, and distribution reliability cost payments are made to eligible pool-scheduled generators whose output is constrained above or below the economic level, as determined by the LMP and in relation to their offers. This compensation is based on a generator's submitted offers for providing electric energy, including start-up and no-load costs. This ensures that generators providing energy needed for reliability but experiencing lost opportunity costs or overall revenue shortfalls are paid for any expenses not recovered through their daily energy payments. In the electric industry, these payments are sometimes referred to as *uplift*. If a generator operates in economic-merit order, most of its compensation will be from the electric energy market.

Table 4-1 illustrates the relationship between physical commitment categories and financial settlement categories. The following sections provide greater detail on payments for first- and second-contingency reliability and for voltage and distribution reliability services.

Table 4-1
Relationship between Physical Reliability Commitments and Daily Reliability Cost Payments

Physical Commitments	Financial Settlement			
	First-Contingency Reliability Costs	Second-Contingency Reliability Costs	Voltage Reliability Costs	Distribution Reliability Costs
Systemwide and regional first-contingency (stability, thermal)	X			
Systemwide and regional out-of-merit energy	X			
Regional second-contingency in import-constrained areas		X		
Reactive power for voltage control or voltage support			X	
Local transmission support				X

4.1.3.1 Daily Reliability Payments

Owners of eligible resources may receive reliability payments if the ISO commits them for first- or second-contingency coverage, voltage support or voltage control, or distribution system reliability. These reliability payments are calculated in both the Day-Ahead Energy Market and Real-Time Energy Market. First-contingency reliability payments are paid to eligible units that provide operating reserves and are not flagged, or designated, to provide second-contingency reliability or to meet requirements for voltage or distribution reliability. First-contingency payments are made to generating units the ISO has committed to ensure systemwide reliability (e.g., to supply replacement reserves), for which decommitment would pose a threat to the reliability of the system. First-contingency reliability payments are made to generators that are on line for several reasons. These include generators committed to provide systemwide stability or thermal support and generators supplying systemwide electric energy in peak hours that must stay on during later hours to satisfy minimum run-time requirements. While generators committed to provide energy may have been in merit during peak hours, they may be out of merit in other hours and receive reliability payments. Or, electric energy market revenues may have been insufficient to cover start-up costs.

Figure 4-5 shows total monthly reliability payments for 2005 and 2006 by financial settlement category. The dollar value of payments made for second-contingency reliability commitments has increased. These higher payments are offset by larger decreases in first-contingency payments and payments for voltage services resulting in a lower total value of daily reliability payments relative to 2005.

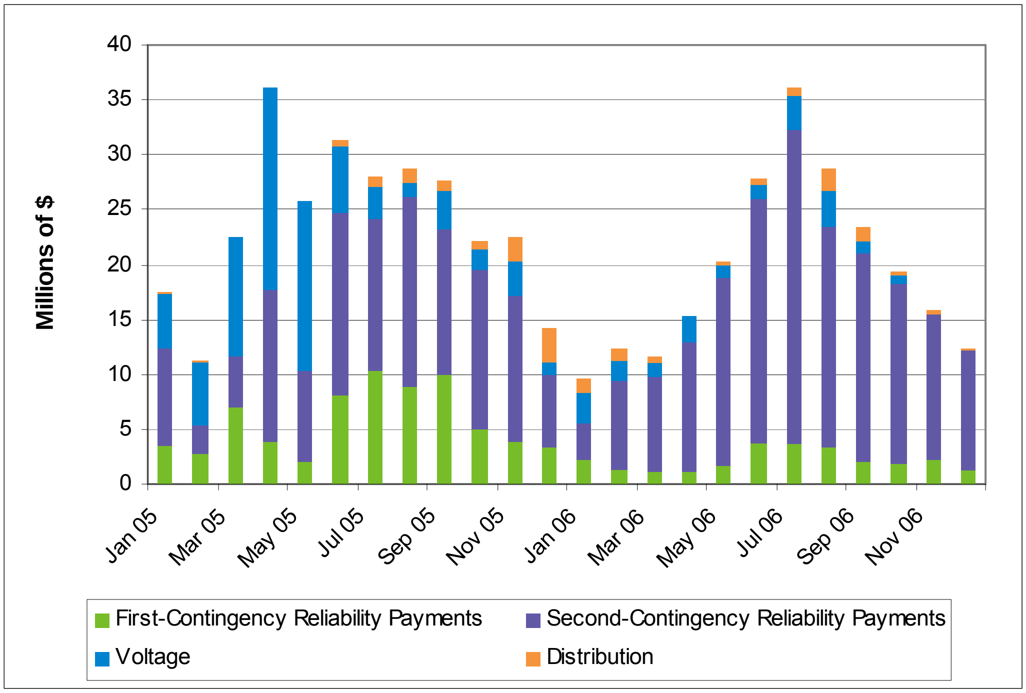

Figure 4-5: Daily reliability payments by month, January 2005 to December 2006.

Table 4-2 shows the total daily reliability payments by category for 2005 and 2006 and the percentage change between years. Total payments in 2006 are down 19% ($54.8 million) compared with 2005 payments. First-contingency and voltage payments are both down by large percentages, dropping from a combined total of $144 million in 2005 to $44.2 million in 2006. Approximately half of the change in first-contingency payments was due to the offer behavior of a participant representing a generating station, whose resources received daily reliability payments in 2005 and then entered into a Reliability Agreement contract in 2006. The decrease in voltage payments is attributable to the same generating station in addition to transmission infrastructure improvements in the Boston area that went into service during 2006. Second-contingency payments, which make up the largest portion of total payments in both years, is the only daily reliability service payment category that increased, growing 35% from $133.5 million in 2005 to $179.9 million in 2006.

Table 4-2
Total Daily Reliability Payments, 2005 and 2006, Millions $

Payment Type	2005	2006	Difference	% Change
First-contingency reliability payments	68.7	25.2	−43.6	−63%
Second-contingency reliability payments	133.5	179.9	46.2	35%
Distribution	10.0	8.6	−1.4	−14%
Voltage	75.3	19.0	−56.2	−75%
Total	287.5	232.7	−54.8	−19%

Table 4-3 shows the breakdown of second-contingency payments for 2005 and 2006 by the load zone requiring commitments for second-contingency protection.[105] The NEMA load zone showed a significant decrease in second-contingency payments, dropping from $90.8 million in 2005 to $32.5 million in 2006. All other load zones requiring commitments for second-contingency protection during the year had higher payments. This increase is most pronounced for the SEMA load zone, where payments grew from less than $0.5 million to $85 million. The Connecticut load zone experienced an increase of about 40%, growing from $42 million in 2005 to almost $60 million in 2006. Payments for second-contingency protection in the WCMA load zone grew from $0.1 million in 2005 to $2.9 million in 2006. The increase in payments to resources outside Boston more than offset the 64% decrease in payments made to generators in the Boston area.

Table 4-3
Second-Contingency Reliability Payments by Load Zone, 2006, Million $

Load Zone	2005			2006		
	Day Ahead	Real Time	Total	Day Ahead	Real Time	Total
CT	3.1	39.0	42.0	2.5	56.8	59.34
SEMA	0.0	0.3	0.3	4.4	80.8	85.2
WCMA	0.0	0.1	0.1	0.0	2.9	2.9
NEMA	3.4	87.4	90.8	2.3	30.2	32.5
System Total	6.5	127.0	133.5	9.2	170.7	179..9

The increase in payments to resources supporting second contingencies in SEMA was the result of the requirement to commit resources for second-contingency reliability, as mentioned in Section 4.1. The reliability commitments and resulting daily reliability payments paid to support the WCMA load zone were the result of temporary transmission outages. These temporary outages in turn resulted in import restrictions that required local generation to provide second-contingency support until the transmission infrastructure was back in service.

4.1.3.2 Daily Reliability Cost Allocations

The out-of-market costs associated with daily reliability payments to generators are allocated to market participants. The allocation of voltage and distribution payments is governed by the ISO *Open Access Transmission Tariff* (OATT), whereas the allocation of first- and second-contingency payments is governed by Market Rule 1. According to the ISO tariff, all New England transmission owners share voltage payments on the basis of network load, and distribution payments are assigned directly to the transmission owner requesting the generator commitment. First-contingency reliability costs in the Day-Ahead Energy Market are charged to participants in proportion to their day-ahead load obligations. In the Real-Time Energy Market, participants whose real-time load deviates from

[105] This information is presented in a slightly different form than in previous years' *Annual Markets Reports,* in which payments were tracked by the region where a resource was physically located. This year's report presents second-contingency payments made on the basis of the reliability region supported. The change is made to maintain consistency with the method used for allocating costs to load obligation, which is based on the region requiring second-contingency protection. A small payment made to a resource providing second-contingency support to the Maine load zone in 2005 is excluded from the table.

the day-ahead schedule and participants whose generators deviate from day-ahead schedules or do not follow real-time dispatch instructions are charged in proportion to these deviations. Second-contingency reliability costs in the Day-Ahead and Real-Time Energy Markets are charged to participants in proportion to their load obligations in the respective markets.

Table 4-4 shows the average allocation of first-contingency reliability charges by month for 2006. These averages are calculated using data from days with charges. Table 4-5 shows the average allocation of second-contingency charges by month. Allocations shown for Connecticut are for the entire state and are not subarea specific.

Table 4-4
Average First-Contingency Daily Reliability Allocations for Days with Charges, $/MWh

Month	Day Ahead	Real Time
Jan	0.04	0.93
Feb	0.01	0.65
Mar	0.03	0.41
Apr	0.03	0.51
May	0.02	0.71
Jun	0.01	1.35
Jul	0.04	1.24
Aug	0.01	1.14
Sep	0.03	0.71
Oct	0.01	0.51
Nov	0.01	0.66
Dec	0.02	0.36
Annual Average	0.02	0.76

Table 4-5
Average Second-Contingency Daily Reliability Allocations for Days with Charges, $/MWh

Month	CT		SEMA		WCMA		NEMA	
	Day Ahead	Real Time	Day Ahead	Day Ahead	Day Ahead	Real Time	Day Ahead	Real Time
Jan	0.07	1.33	1.10	7.95		0.64		
Feb	0.37	1.17		5.45		1.13		2.26
Mar	0.53	1.36		5.82		0.78	0.59	
Apr	0.35	1.74	7.93	7.95				
May	0.10	1.93	2.89	6.91			1.40	5.08
Jun	0.40	2.28	4.00	6.22			0.67	3.82
Jul	0.15	2.43	1.08	5.51		0.01	1.30	4.51
Aug	0.28	1.88	3.58	8.40		0.29	0.59	3.13
Sep	0.31	2.70		5.95		0.46	0.93	3.56
Oct	0.17	3.30	5.51	5.60	0.45	0.41	1.46	2.69
Nov	0.32	2.84	4.25	5.39		0.50		
Dec	0.17	1.65	3.76	4.61		0.63		
Annual Average	0.27	2.05	3.79	6.31	0.45	0.54	0.99	3.58

4.1.4 Daily Reliability Commitment and Costs Conclusions

The ISO continues to need out-of-market commitments and associated payments to maintain reliable operation of the system. Electric energy market outcomes play an important role in the need for out-of-market commitments for reliability. To the extent that market outcomes and resource self-scheduling result in the commitment of resources needed for local reliability, the ISO does not have to manually commit resources for second-contingency or voltage services. These market-based effects and participant self-scheduling caused the majority of the changes in output generated by resources committed for second-contingency and voltage services.

Total daily reliability payments for the year declined from $287.5 million in 2005 to $232.7 in 2006 as a result of large decreases in payments made for voltage support and control and first-contingency coverage. While overall payments are down, payments for second contingency are up 35%. During 2005, the majority of payments were made to support resources in the NEMA and Connecticut load zones, while in 2006, the majority of payments were made to resources in the SEMA and Connecticut load zones. The reduction in payments made to NEMA resources is primarily the result of Reliability Agreement that led to higher levels of self-scheduling. The increase in payments to the SEMA load zone was caused by the increase in commitments necessary to meet the local reliability requirements.

These daily reliability payments reflect out-of-merit operation that dampens price signals emanating from constrained areas on the system and decreases the incentives for flexible, fast-start capacity to locate and operate in those areas. The ISO and transmission-owning utilities will continue to take steps to reduce the need for out-of-market payments, while ensuring that generators necessary for reliable operation of the system are compensated for their costs. Additional transmission projects are underway in the Connecticut area that should reduce the need for out-of-merit operations. However, cost-effective infrastructure improvements will never completely eliminate the need for out-of merit operations. The ISO will continue to refine market rules with respect to out-of-merit operation to ensure that generating units following dispatch instructions are fairly compensated and that appropriate price signals are sent to local resources.

4.2 Minimum Generation Emergency Credits

The ISO declares a *Minimum Generation Emergency* when it anticipates the need to request that one or more generating resources operate at or below their economic minimum level to alleviate excess generation relative to load levels.[106] During times when a Minimum Generation Emergency has been declared, prices are set to zero. Generators dispatched above their economic minimum levels during Minimum Generation Emergencies are paid special credits.[107]

The credits are separate from reliability credits, and related charges are allocated to participants with real-time generation obligations. Table 4-6 shows the Minimum Generation Emergency credits by month.

Table 4-6
Minimum Generation Emergency Credits

Month	Dollars
Jan	0
Feb	53,883
Mar	0
Apr	0
May	19,183
Jun	77,575
Jul	71,956
Aug	0
Sep	67,126
Oct	45,800
Nov	0
Dec	48,752
Total	384,274

[106] For more information on Minimum Generation Emergency credits, see Market Rule 1, Appendix F, on NCPC accounting. Available online at http://www.iso-ne.com/regulatory/tariff/sect_3/app_f_npcp_accounting_effective_04_01_06.doc.

[107] *Order Accepting Amendments to the Minimum Generation Emergency Credits and Charges Rules and Granting Waiver*. FERC Docket Nos. ER05-870-000 and ER05-870-001. 112 FERC ¶ 61, 301 (September 16, 2005). Available online at http://www.iso-ne.com/regulatory/ferc/orders/2005/sep/er05-870-0009-16-05.doc.

4.3 Reliability Agreements

Reliability Agreements provide eligible generators with monthly fixed-cost payments for maintaining capacity that provides reliability services. These contractual arrangements, which are subject to FERC approval, provide financial support to ensure that units needed for reliability will continue to be available. Reliability Agreements are paid for by network load in the zone in which the generating units are located, with the exception of one agreement in the Boston area needed for distribution support for which a specific participant pays. The need for these agreements suggests that the current market prices do not fully and appropriately signal the need for new infrastructure.

Most Reliability Agreements are for full cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through electric energy offers made at short-run marginal cost. Variable costs not covered by energy market revenues are compensated through daily reliability payments. All capacity market revenues and energy market revenues received in excess of variable costs serve to reduce the monthly fixed-cost payment.[108] Thus, the generator recovers no more than its fixed and variable costs.

During 2004, FERC rulings effectively expanded generators' eligibility for cost-of-service Reliability Agreements.[109] Generators that meet the eligibility criteria in Market Rule 1 and are needed for reliability are entitled to recover their cost of service and do not need to apply for retirement to qualify for a Reliability Agreement. Following these rulings, applications for cost-of-service agreements increased, and more generators entered into Reliability Agreements.

4.3.1 Reliability Agreement Results

As of December 31, 2006, Reliability Agreements were in effect for 14 generating stations, comprising 6,294 MW of capacity.[110] This represents 19% of the total systemwide capacity. As shown in Table 4-7, the percentage of capacity with Reliability Agreements is considerably higher in the NEMA and Connecticut load zones (62% and 41%, respectively) than in other areas. During 2006, additional capacity was contracted under Reliability Agreements with the addition of Mystic units #8 and #9 and the West Springfield gas turbines. This increased capacity was partially offset by the termination of the Reliability Agreement with the New Boston generating unit. Figure 4-6 shows the increase in generating capacity with Reliability Agreements since 2002. Between 2005 and 2006, the total capacity under Reliability Agreements increased by 24%.

[108] The Reliability Agreement with the NRG Energy Devon units includes a provision that limits the credits against net fixed-cost payment from revenues in excess of cost to 65% of the difference between market revenues and unit costs.

[109] *Order on Compliance Filing and Establishing Hearing Procedures*, FERC Docket Nos. ER03-563-030, EL04-102-000, 107, FERC ¶ 61,240, (June 2, 2004).

[110] These 14 stations include Mystic 8 and 9, Kendall Steam Units and Jet, West Springfield 3 and GTs, Berkshire Power, Devon, Middletown, Montville, Milford, New Haven Harbor, Bridgeport Harbor, Bridgeport Energy, Pittsfield/Altresco, Wallingford, and Salem Harbor. The Salem Harbor station has a FERC Settlement Agreement preventing the shutdown of the units before October 1, 2008, with guaranteed payment of $6.75 million distributed over a two-year period ending July 2007.

Table 4-7
Percent of Capacity under Reliability Agreements, Effective and Pending, December 2006

Zone	2005 Reliability Agreements (MW)	2006 Reliability Agreements (MW)	2006 Summer Seasonal Claimed Capability (SCC) (MW)	2006 Capacity under Reliability Agreements as % of 2006 Summer SCC
Maine	0	0	3,085	0%
New Hampshire	0	0	903	0%
Vermont	0	0	4,086	0%
Connecticut	3,082	3,082	7,465	41%
Rhode Island	0	0	1,819	0%
SEMA	0	0	5,996	0%
WCMA	472	547	3,858	14%
NEMA	1,165	2,213	3,594	62%
New England Total	4,719	5,843	30,806	19%

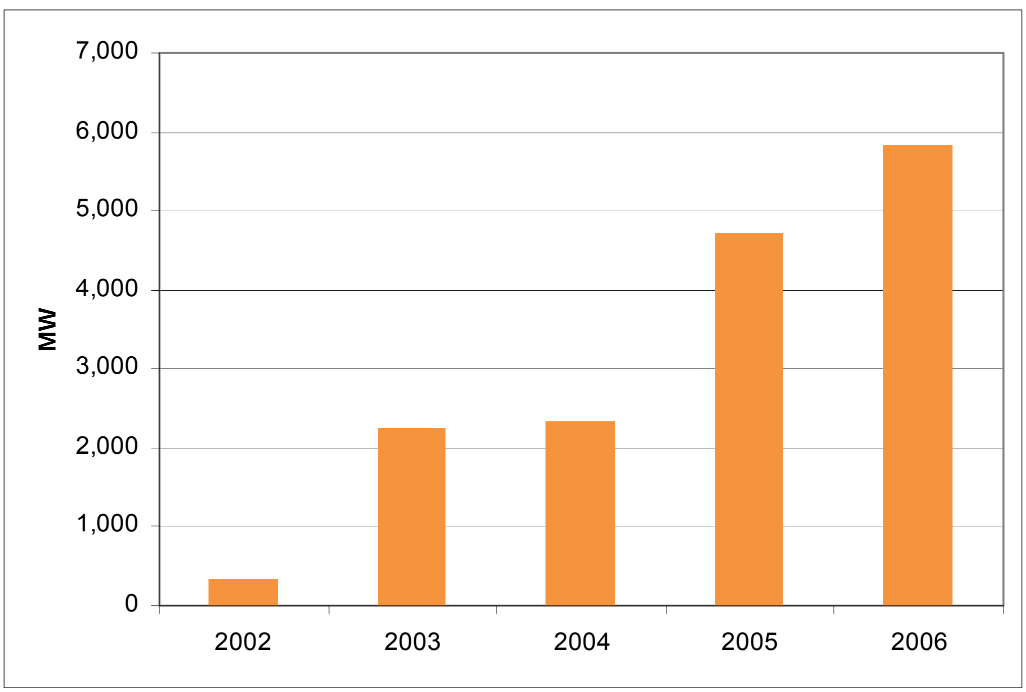

Figure 4-6: Generating capacity with FERC-approved Reliability Agreements.

The total annualized fixed-cost requirement for all resources with Reliability Agreements effective December 31, 2006, was $666.9 million, an increase of almost 50% over the 2005 level of $450.8 million.[111] The actual Reliability Agreement payments made to a generating unit with a Reliability Agreement are reduced by the market revenues that exceed its offers. This results in Reliability Agreement payments plus market revenues that are equal to FERC-approved fixed and variable costs. Table 4-8 shows the annual sum of monthly net payments for 2003 through 2006.

Table 4-8
Net Reliability Agreement Payments, System Total, Million $

	2003	2004	2005	2006
Payment	83.4	177.9	240.5	482.0

The increase in net Reliability Agreement payments can be attributed to the combined effect of additional capacity with Reliability Agreements and lower wholesale electric energy prices. The additional capacity is due to the Reliability Agreement with Mystic units #8 and #9. The stipulated bidding behavior of these units resulted in large decreases in the daily reliability payments these units received, which explains a large portion of the decrease in daily reliability payments (as shown previously in Table 3-1).[112] Lower electric energy prices can lead to higher net Reliability Agreement payments because market revenues contribute less to the recovery of fixed costs, therefore increasing out-of-market payments.

4.3.2 Reliability Agreement Conclusions

An increasing number of units have sought Reliability Agreements, and the associated costs have increased rapidly. Lower LMPs in 2006 reduced the level of market-based fixed-cost recovery by resources with Reliability Agreements. This effect, combined with the additional capacity covered by Reliability Agreements, resulted in a doubling of net costs relative to 2005. While total capacity under Reliability Agreements increased 24%, the Reliability Agreement for the New Boston generation resource was terminated effective November 2006. In addition, effective January 1, 2007, the Reliability Agreements for Mystic units #8 and #9 and the Devon Station units were terminated.[113]

Reliability Agreements do not send useful investment signals to potential new entrants. While FERC has accepted Reliability Agreements, they are intended as interim measures to ensure that generators needed for reliability are recovering adequate revenues until a market-based mechanism is implemented that appropriately compensates generators providing reliability services.

[111] A full year of annualized fixed cost is included in this total for resources with Reliability Agreements effective as of December 31, 2006, regardless of when the agreement became effective during the year. Many of the agreements have 2005 and 2006 payments that were made "subject to refund." Refunds will be made by several generators after FERC approval of settlement agreements that have been filed.

[112] These daily reliability payments (i.e., uplift) are different from net Reliability Agreement payments that are associated with the contracts formerly known as Reliability Must-Run contracts.

[113] The termination of the Devon Agreement is effective, and the termination of the Mystic Agreements is effective subject to FERC approval. The Norwalk Harbor units #1 and #2 have been given a *determination of need*. Therefore, contracts with these or other generating units could offset some of the decrease in Reliability Agreement capacity resulting from the Reliability Agreement terminations in early 2007.

4.4 Peaking Unit Safe Harbor Bidding

On April 25, 2003, FERC issued its *Order Accepting, in Part, Requests for Reliability Must-Run Contracts and Directing Temporary Bidding Rules* (Devon Order).[114] The Devon Order directed the ISO to replace the existing rules covering mitigation in chronically congested areas, referred to as *Designated Congestion Area* (DCA) rules, with new rules that apply special mitigation formulas to units in DCAs with low capacity factors (i.e., an annual capacity factor of less than 10% in 2002).

On June 1, 2003, the ISO implemented *Peaking Unit Safe Harbor* offer rules, which allow owners of low-capacity-factor generating units located in DCAs to include levelized fixed costs in their electric energy offers without risk for mitigation. The rules were intended to increase opportunities for fixed-cost recovery and to produce signals for investment through higher LMPs in these areas during periods of electric energy scarcity.[115]

As of the end of 2006, 42 generating units in the congested areas of NEMA and Connecticut met the low-capacity-factor (based on 2002 capacity factors) and DCA-location criteria for PUSH treatment. This total includes multiple units at the same station. Of these 42 generating units, 16 were offering their generation under PUSH rules with positive fixed-cost adders. Fourteen had Reliability Agreements and offered their generation under the terms of those agreements and not as PUSH units.

PUSH units are often dispatched out of merit to provide local reserves, not as part of the systemwide economic dispatch. When operated this way, PUSH units are compensated through first- and second-contingency reliability payments for any shortfalls between their offers and their electric energy market revenues. In 2006, PUSH units received approximately $34.3 million in second-contingency reliability payments and $1.96 million in first-contingency reliability payments.

Since the PUSH mechanism was established, several significant changes have taken place in the New England markets. First, FERC approved a new locational Forward Reserves Market, which the ISO implemented on October 1, 2006 (as previously discussed in Section 3.3). In the first FRM auction, generating units in constrained areas that are providing reserves are being paid $14.00/kW-month. Thus, this new market is clearly compensating generators with resources in constrained areas and providing strong investment signals for new resources. Second, also on October 1, 2006, the ISO implemented a new real-time dispatch system, which provides for the co-optimization of energy and reserves (see Section 3.3.5). As a result, LMPs now reflect additional costs associated with redispatching the system to provide real-time reserves in constrained areas. Finally, starting on December 1, 2006, the FERC-approved Forward Capacity Market settlement agreement has been providing generators with transition payments that started at $3.05/kW-month and will increase thereafter (see Section 3.2.1). Absent a modification to the PUSH mechanism to account for this additional revenue, generators owning eligible PUSH units may receive excess revenues to the detriment of customers in the New England region.

[114] 103 FERC ¶ 61,082 (Apr. 25, 2003).

[115] Additional information about PUSH is available online at http://www.iso-ne.com/markets/mktmonmit/implmnt/push_imp/index.html.

Given these changes and the additional compensation and economic signals they provide, the ISO and NEPOOL proposed to eliminate the PUSH bidding mechanism.[116] FERC accepted this proposal, which has an effective date of June 19, 2007, subject to refund and further order.[117]

4.5 Financial Transmission Rights

Financial Transmission Rights are financial instruments that entitle the holder to a share of the electric energy market congestion revenues. The holder of an FTR is entitled to receive, or required to make, payments based on the FTR megawatt quantity and the difference between the congestion components of the day-ahead LMPs at the FTR's location of origin (*source*) and delivery (*sink*) points. FTRs can be purchased by any participant or by a nonparticipant that meets the registration and financial-assurance criteria. FTRs are not associated with actual physical flows of electricity. The ISO conducts auctions for annual FTRs and monthly FTRs. In addition, during 2006, the ISO worked with participants to design a Long-Term Transmission Right (LTTR) instrument that would span multiple years.

FTRs are paid through the ISO settlement system. In any hour, an FTR may result in either payments due (positive target allocations) or payments owed (negative target allocations). Specifically, a participant holding an FTR defined from Point A to Point B will be entitled to compensation only if the hourly congestion component of the LMP at Point B is higher than that at Point A. If the hourly congestion component is higher at Point A, the FTR becomes an obligation, and the FTR holder is obligated to make a payment to the ISO. FTR holders with positive target allocations are paid from the Congestion Revenue Fund. This fund collects congestion revenues generated by the Day-Ahead and Real-Time Energy Markets and payments from FTR holders with negative target allocations.

Participants are allowed to submit negatively priced bids for counterflow FTRs that, if cleared, result in a payment to the participant during the auction settlement.[118] Before the May 2005 monthly auction, only bids of $0 and higher were allowed. Allowing negative bids encourages the purchase of counterflow FTRs, which increases the capacity for FTRs available in the direction of typical flows.

FTRs can be acquired in three ways:

- **FTR auction**—The ISO conducts periodic auctions to allow bidders to acquire and sell monthly and longer-term FTRs. FTRs purchased in long-term auctions can be sold into the monthly auctions.

- **Secondary market**—The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought and sold on a bilateral basis.

- **Unregistered trades**—FTRs can be exchanged bilaterally outside the ISO-administered process. However, the ISO compensates only FTR holders of record and does not recognize business done in this manner for settling day-ahead congestion.

[116] The joint filing by the ISO and NEPOOL can be found online at http://www.iso-ne.com/regulatory/ferc/filings/2006/nov/er07-219-000_11-14-06_push.pdf.

[117] *Order Accepting and Amending Tariff Revisions and Establishing Reporting Requirement*. FERC Docket No. ER07-219-000. 118 FERC ¶ 61,018 (January 12, 2007). Available online at http://www.iso-ne.com/regulatory/ferc/orders/2007/jan/er07-219-000_1-12-07_push.pdf.

[118] Participants can submit negatively priced bids for counterflow FTRs if they believe that the negative target allocation they will owe, which will be based on daily day-ahead congestion patterns, will be less than the amount they will receive in the auction settlement.

The FTR auction clearing process includes a simultaneous feasibility test intended to ensure that the transmission system can support the awarded set of FTRs during normal system conditions and, subsequently, that enough congestion revenue will exist to cover FTR holders. At times, however, actual transmission system conditions differ from the assumptions used in the auction process, and revenues collected are not adequate to meet FTRs with positive target allocations.

When congestion revenues fall short at the end of the month, all holders of FTRs with positive target allocations receive a prorated share of their entitlements, even when congestion on the path of a specific FTR is adequate to meet the entitlements for that FTR's holder. If more money is collected in the congestion revenue fund in a month than is required to pay positive FTR allocations, the money is held in the fund's cumulative balance until the end of the year. At the end of the year, the extra funds are first used to pay any positive allocation shortfalls that occurred during the year. Any remaining funds are allocated to entities that paid transmission congestion costs during the year.

4.5.1 Financial Transmission Rights Auction Results

The annual auction for FTRs covering the 2006 calendar year was held in December 2005 and offered 50% of the system's transmission capacity. In addition, FTR auctions were held for each month in 2006. In each of these auctions, the remaining balance, up to 95% of the transmission system capacity, was made available. The number of participants bidding in each auction ranged from 40 participants in the September 2006 auction to 29 participants in the January-to-December annual auction. Auction revenues for the 12 monthly auctions and the single 12-month auction covering 2006 totaled $185 million.

Figure 4-7 shows the on-peak awarded transmission capacity (MW) and auction revenues for the annual auctions held in 2004, 2005, and 2006. The quantity of capacity awarded has remained fairly constant, while the revenues have ranged in magnitude from about $32 million in 2005 to $83 million in 2006. The annualized revenue from the two six-month auctions that took place in 2004 was about $45 million. A likely explanation of the 150% increase in annual on-peak auction revenues between 2005 and 2006 is that in December 2005, when the annual auction was held, there was still uncertainty about prices and congestion costs as a result of the fall 2005 hurricanes.

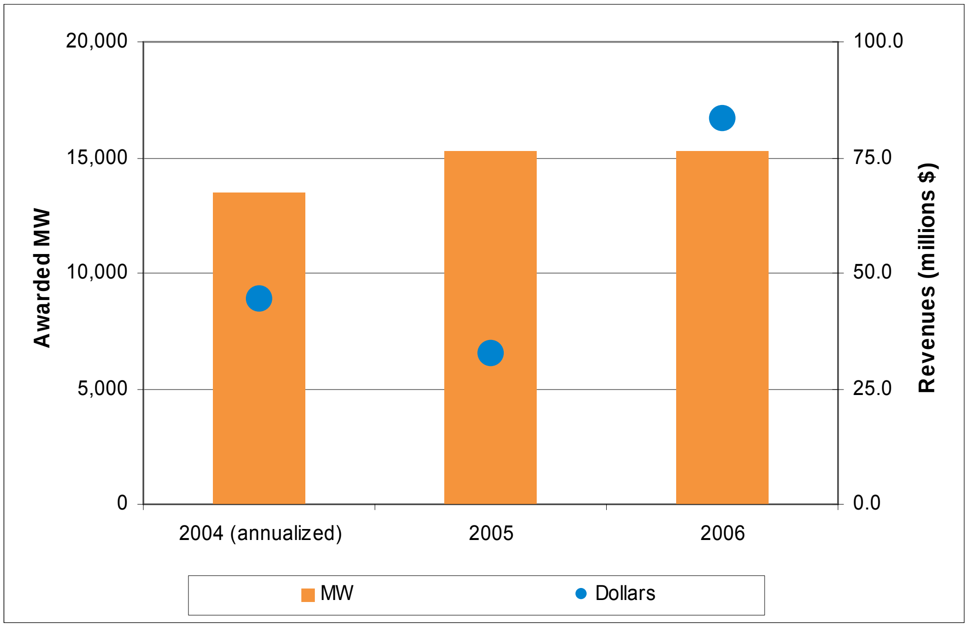

Figure 4-7: On-peak FTR annual auction results.

Note: Two six-month auctions took place in 2004. To more readily compare the results of these auctions, the figure shows the average of the awarded transmission capacity and the sum of auction revenues.

Figure 4-8 shows the total cleared on-peak auction revenues from the monthly auctions. Revenues in 2005 showed a different pattern than those in 2004 and 2006. In all years, auction revenues peak during the summer when the likelihood of congestion is highest. The years 2004 and 2006 showed similar patterns of FTR revenues in the shoulder months, whereas in 2005, a second peak in FTR revenues occurred during the fall. This is attributed to expectations of high prices due to upward price pressure on input fuels as result of hurricanes Katrina and Rita.

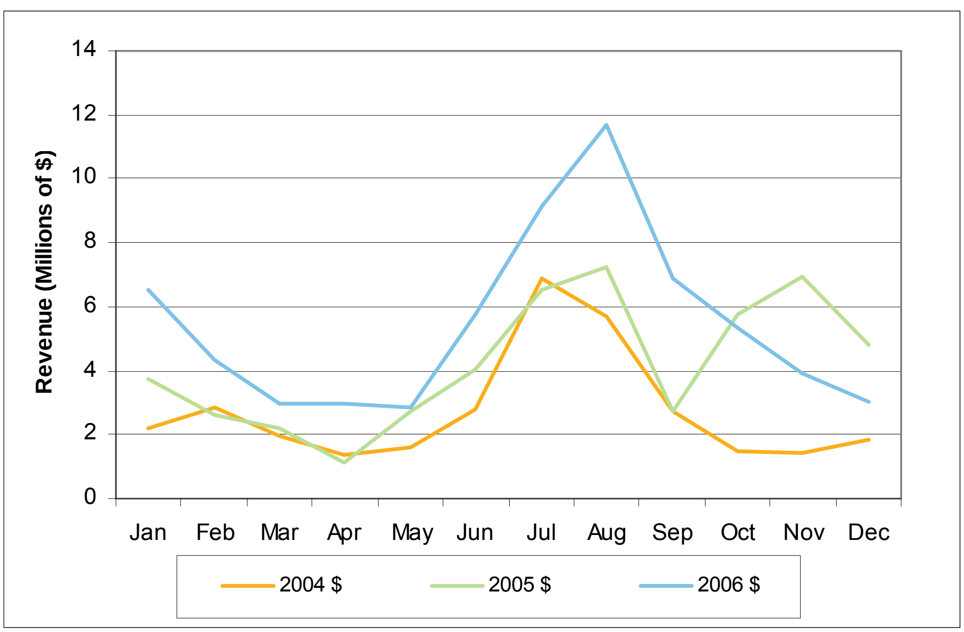

Figure 4-8: Monthly cleared on-peak FTR auction revenues.

Figure 4-9 shows the total cleared on-peak FTRs by month. The total monthly transmission capacity (MW) acquired in the auctions showed a similar pattern in all years, while total awarded capacity was somewhat higher in 2006. The total amount of FTRs sold may exceed the expected peak demand or generation capacity because it is a financial, not physical, market. In particular, the sale of counterflow FTRs by financial customers permits other customers to purchase FTRs in excess of the nominal interface limit. This is because counterflow FTRs in one direction counterbalance FTRs flowing in the opposite direction; in net, the interface limits are respected. This is similar to the way that transactions over an external interface in one direction can exceed an interface limit, while net transactions remain below the limit. Holders of these counterbalancing FTRs receive payment during the auction process for taking the FTRs, but they must assume the risk of holding an FTR with an expected negative target allocation.

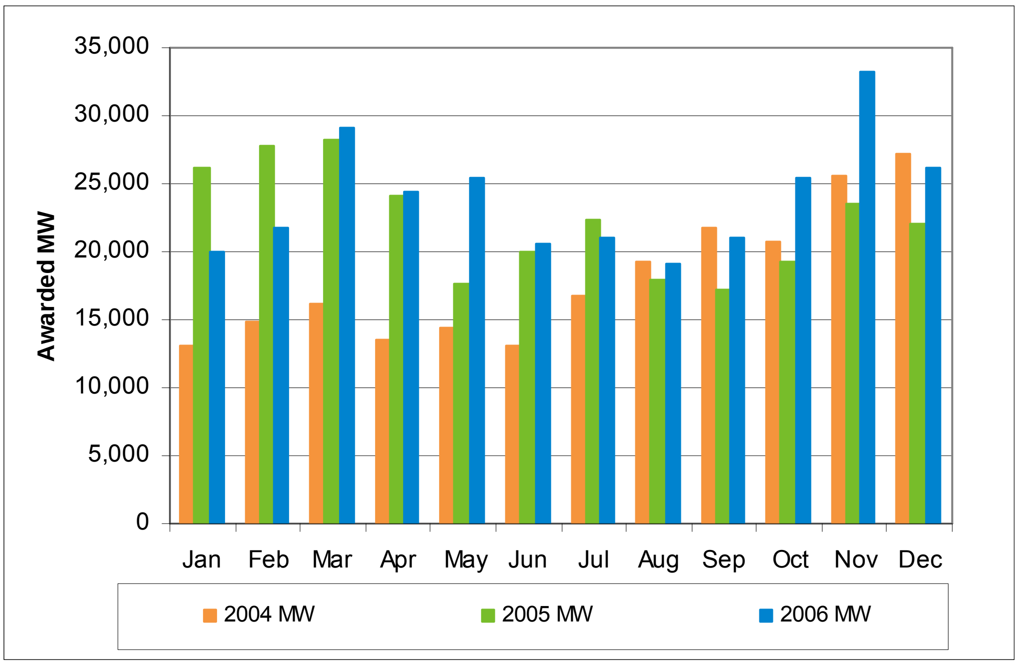

Figure 4-9: Monthly cleared on-peak FTRs, MW.

Market Rule 1 specifies that auction revenues must first be allocated to entities eligible for Qualified Upgrade Awards (QUAs). Auction revenues are then allocated to entities through the Auction Revenue Rights (ARR) process. The ARR process further allocates ARR dollars to three categories, as follows:

- **Excepted transactions**—special grandfathered transactions (listed in Attachments G and G-2 of the ISO *Open Access Transmission Tariff*)[119]

[119] Appendix C to Market Rule 1 provides that holders of certain contracts, called Excepted Transactions, have an option to be assigned ARRs in the initial stage of the allocation process. Excepted Transactions are listed in Attachments G and G-2 to the *Open Access Transmission Tariff*. Such ARRs are from the generation sources/external nodes to the node(s) of the load consistent with the Excepted Transaction. This option is available on request for the earlier of 10 years following the SMD effective date or termination of the Excepted Transaction.

- **NEMA contracts**—other long-term contracts that include delivery in northeastern Massachusetts

- **Load share**—the ARR allocation paid to congestion-paying entities in proportion to their real-time load obligation at the time of the system's coincident peak for the month

Table 4-9 shows total distribution of auction revenue for 2004, 2005, and 2006 between QUA awards and the three ARR categories. The largest portion of auction revenue was returned to those entities that paid for congestion on the system in the load-share category of ARR distributions.

Table 4-9
Total Auction Revenue Distribution, 2004, 2005, and 2006, $

Type of Revenue	2004	2005	2006
QUA dollars	3,080,554	1,624,928	3,029,487
Excepted transaction dollars	130,445	260,935	278,913
NEMA contract dollars	2,859,480	4,592,240	5,215,541
Load-share dollars	85,630,838	100,712,872	176,471,802
Total auction revenue	91,701,317	107,190,974	184,995,743

In 2006, 85% of the revenue generated by the FTR auctions was returned to congestion-paying entities in the NEMA and Connecticut load zones. Figure 4-10 shows the distribution of ARR dollars by load zone.

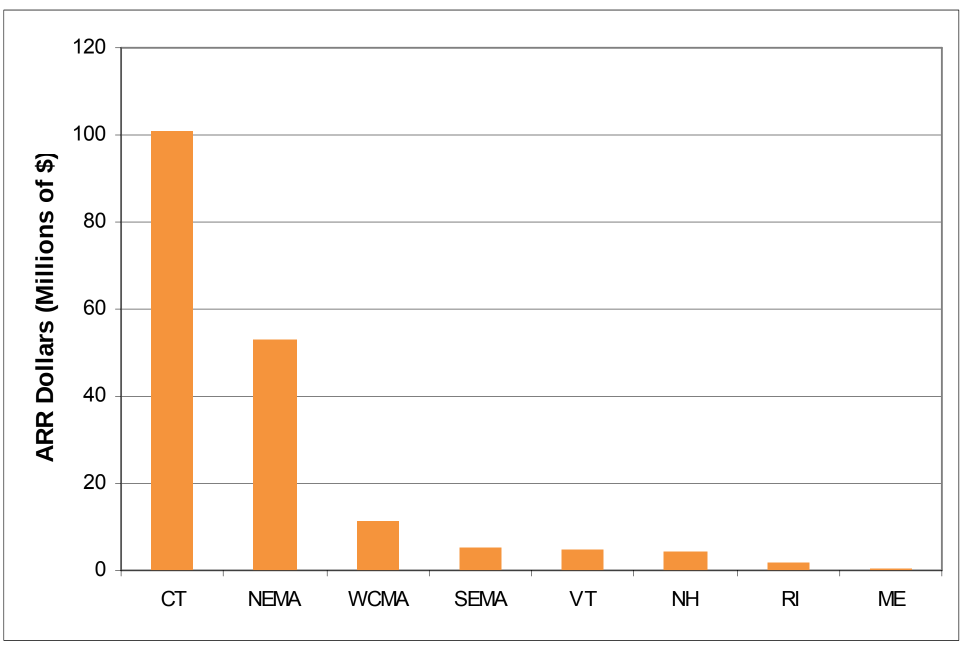

Figure 4-10: ARR distribution by load zone, January to December 2006.

Figure 4-11 and Figure 4-12 show the average expense of acquiring, average revenue from holding, and hypothetical average net revenue of a 1 MW on-peak and off-peak FTR from each load zone to the Hub.[120] In a competitive market, the expected profits of holding an FTR should approach $0. An on-peak FTR would have resulted in an average net loss for the VT, WCMA, and NEMA load zones, while the remaining paths showed small net profits. The average net revenue was less than $1/MWh in absolute value for each load zone. Off-peak FTRs had smaller net revenues in absolute value, and only the ME, NH, CT, and WCMA load zones had average net-positive returns for an FTR. These results suggest that a competitive market for FTRs exists between the Hub and load zones.

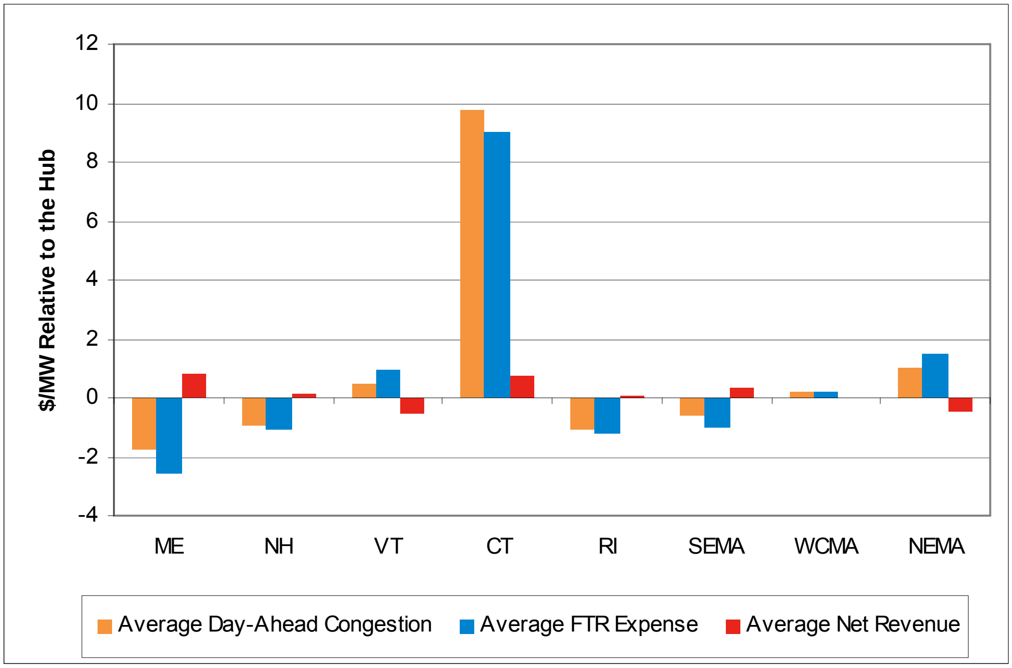

Figure 4-11: Day-ahead average congestion costs, FTR expenses, and net revenues relative to the Hub, on-peak hours.

[120] The FTR auction prices are converted to an annual $/MWh value calculated as the annual average cost of a 1 MW FTR in each of the monthly auctions, plus the cost of a 1 MW FTR in the annual auction divided by the number of hours for the FTR class type (on or off peak) [Annual average FTR cost + (cost of FTR/total hours for FTR class type)]. These prices are based on the FTR auction clearing prices, which are calculated and published for each node and load zone even if no FTRs are transacted in an auction.

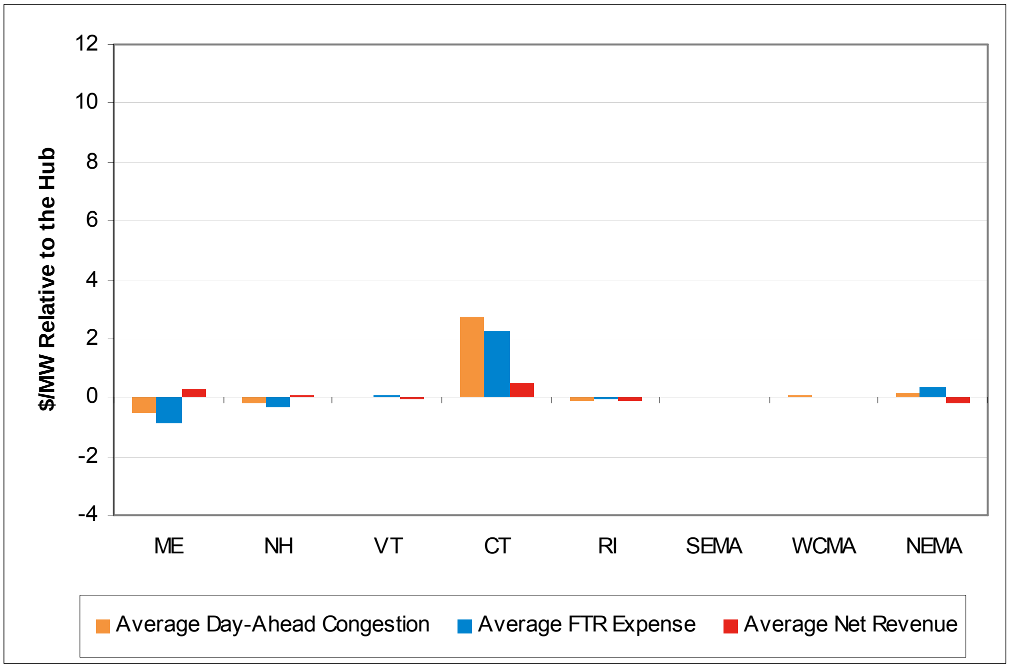

Figure 4-12: Day-ahead average congestion costs, FTR expenses, and net revenues relative to the Hub, off-peak hours.

4.5.2 Financial Transmission Rights Funding Results

The Transmission Congestion Revenue Fund consists of four components, as shown in the following formula:

Transmission Congestion Revenue Fund	=	Day-ahead + real-time congestion revenue	+	Absolute value of the sum of negative FTR target allocations over all hours in the month	+	Excess monthly congestion revenue from previous months	+	Fund adjustments

Table 4-10 shows the Transmission Congestion Revenue Fund monthly revenues, allocations, and allocations paid in 2006. The first three data columns of the table show the amount each component (including FTRs with negative allocations) contributed to the Transmission Congestion Revenue Fund for each month of 2006. The next three columns show the positive target allocations participants held, the amount of positive target allocations actually paid from the fund to FTR holders, and the percentage of positive allocations paid out. Appendix B shows more details about Congestion Revenue Fund accounting.

Table 4-10
Transmission Congestion Revenue Fund, 2006, $

Month	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Allocation Collected (Paid by Participants)	Positive Target Allocation (Owed to Participants)	Actual Positive Allocations Paid to Participants	Percent of Positive Target Allocation Paid
Jan	8,482,947	(45,654)	3,859,347	13,206,535	12,456,331	94%
Feb	6,426,191	42,568	4,093,738	9,792,448	9,792,448	100%
Mar	3,900,694	52,409	3,553,199	7,346,818	7,346,818	100%
Apr	2,477,238	(13,436)	804,468	2,846,401	2,846,401	100%
May	18,191,348	5,064,030	3,569,219	22,826,059	22,826,059	100%
Jun	28,873,231	652,375	5,628,188	35,180,417	35,180,417	100%
Jul	45,230,102	(4,296,732)	4,052,640	39,039,485	39,039,485	100%
Aug	39,612,396	(1,111,819)	4,146,669	36,792,136	36,792,136	100%
Sep	13,816,202	(4,434,297)	3,272,974	17,720,938	12,707,110	72%
Oct	12,862,599	(3,031,332)	6,670,916	17,945,792	16,555,617	92%
Nov	5,640,217	(782,076)	5,689,557	10,785,854	10,585,704	98%
Dec	6,906,105	(4,897,001)	4,789,755	11,671,987	6,808,831	58%

FTR holders were paid 100% of their positive FTR target allocations in 2006, as was the case in 2005. Overall, the Congestion Revenue Fund had a surplus of $6 million after paying out all FTR allocations. As required by Market Rule 1, these revenues were distributed to entities that paid transmission congestion costs during 2006. Payments owed to FTR holders with positive target allocations totaled $225.2 million, while available funds from congestion revenue and negative FTR allocations totaled $229.7 million.

Although FTR holders were paid 100% of their positive FTR target allocations in 2006, during five months of the year, congestion revenues were inadequate to pay all positive target allocations. The shortfalls were made up with surpluses from other months and paid, with interest, in January 2007.[121] The shortfall in monthly congestion revenues was greatest in December 2006 when only 58% of the $11.6 million in positive allocations was paid.

4.5.3 Financial Transmission Rights Conclusions

Net FTR auction revenues totaled $184.9 million in 2006, about a 70% increase over the 2005 total of $107.2 million. This increase in FTR revenues is driven by the results of the annual auction held in December 2005 for FTRs that hedge congestion for the entire calendar year of 2006. The pattern of FTR revenues returned to the single summer peak after a double peak in 2005. The double peak in 2005 was caused by uncertainty of electric energy prices in the monthly auctions and congestion costs

[121] Monthly surpluses are retained for settlement at the end of the year.

associated with fall 2005 hurricanes. This uncertainty may also have resulted in higher revenues for the 2006 annual FTR auction that was held in December 2005. FTR holders had positive target allocations totaling $225.2 million, all of which were eventually paid. Negative target allocations, which are liabilities for FTR holders, totaled $50.1 million. FTRs to the Hub were valued in a pattern consistent with historical congestion patterns, and revenues from an FTR to the Hub from each of the load zones were generally very close to the cost to procure the FTR per megawatt-hour. No zone-to-Hub path had an average net revenue greater then $1/MWh in absolute value for either an on-peak or off-peak FTR. This suggests that the FTR markets are maturing and reasonably competitive.

4.6 Demand Response

Demand response in wholesale electricity markets takes place when participants reduce their consumption of electric energy from the high-voltage transmission system in exchange for compensation based on wholesale market prices.[122] The ISO can request demand-response program participants to reduce demand as a result of the need to maintain system reliability. Participants also can voluntarily reduce demand in response to high wholesale prices. Demand and price response can help improve grid reliability by quickly reducing demand during emergency conditions. Both types of demand response also can reduce spot-market price spikes and provide a hedge against price risks for wholesale purchasers. Along with a well-designed market, ample supply, and robust transmission infrastructure, demand-response resources are important aspects of a wholesale market.

4.6.1 Demand-Response Programs

The ISO operates three reliability-activated demand-response programs and two price-activated load-response programs for the New England wholesale electricity market. During 2006, the ISO administered the following programs:

- **Real-Time 30-Minute Demand-Response Program—**requires demand resources to respond within 30 minutes of the ISO’s instructions to interrupt.

- **Real-Time 2-Hour Demand-Response Program—**requires demand resources to respond within two hours of the ISO’s instructions to interrupt.

- **Real-Time Profiled-Response Program—**designed for participants with loads under their direct control that are capable of being interrupted within two hours of the ISO’s instructions to interrupt. Individual customers participating in this program are not required to have an interval meter. Instead, participants are required to develop and submit to the ISO for approval a monitoring and verification plan for each of their individual customers.

- **Real-Time Price-Response Program—**involves voluntary load reductions by program participants that are eligible for payment when the forecast hourly real-time LMP is greater than or equal to $100/MWh and the ISO has transmitted instructions that the eligibility period is open.

- **Day-Ahead Load-Response Program (DALRP)—**an optional program that allows a participant in any of the real-time programs to offer interruptions concurrent with the Day-Ahead Energy Market. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.

[122] Demand resources include sites enrolled individually and collections of multiple sites enrolled by one customer.

The Real-Time Demand-Response Programs are activated during zonal or systemwide capacity deficiencies to help preserve system reliability (Reliability Programs). Reliability Program resources are called on in accordance with the ISO's OP 4, which establishes criteria and guidelines for actions during capacity deficiencies.[123] The OP 4 guidelines contain 16 actions that can be implemented individually or in groups depending on the severity of the situation. The Real-Time Two-Hour Demand-Response and Real-Time Profiled-Response Programs are activated at OP 4 Action 3, and the Real-Time 30-Minute Demand-Response Program is activated at Actions 9 and 12. The resources activated at Action 12 (typically customer-owned emergency generators) may have environmental permit limitations that require the system operator to implement voltage reductions before operating. The Real-Time Price-Response and Day-Ahead Load-Response Programs provide program participants an incentive to reduce demand in response to real-time and day-ahead LMPs.

The Day-Ahead Load-Response Program went into effect on June 1, 2005. Therefore, 2006 is the first year with complete results for this program. A participant that wants to participate in the Day-Ahead Load-Response Program must first register a resource in one of the Real-Time Demand-Response Programs. It may then choose the day-ahead option and can make offers to reduce its demand in response to the day-ahead LMP. DALRP offers are evaluated after the Day-Ahead Energy Market has cleared. Offers that are lower than the day-ahead LMP will clear in the DALRP, and participants with offers that clear will be paid the day-ahead LMP. Day-ahead cleared resources that show deviations in real time will be settled with the participant at the real-time LMP.

4.6.2 Southwest Connecticut "Gap" Request for Proposals

On December 1, 2003, the ISO issued a Request for Proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut for 2004 to 2008 (SWCT Gap RFP).[124] The stated goal was to improve the reliability of the bulk electric power system in Southwest Connecticut through summer 2007. The majority of the resources selected under this RFP are participating in the 30-Minute Real-Time Demand-Response Program. These resources receive supplemental capacity payments expected to total $128 million over the four-year contract term. The ISO contracted with seven companies to provide resources over the four-year period. The following resource types were eligible to respond to the RFP:

- Fast-start generation (new or incremental capacity from existing resources)
- Demand-reduction resources
- Emergency-generation resources
- Conservation and load-management projects

Some selected resources were in service by June 2004, while others were scheduled to be available at a later date. About 260 MW will be available by June 2007.

4.6.3 Winter Supplemental Program

The ISO developed and implemented the Winter Supplemental Program (WSP) to encourage participation by additional real-time demand-response resources during winter 2005/2006. Increasing

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[123] OP4 is available online at http://www.iso-ne.com/rules_proceds/operating/isone/op4/OP4_RTO_FIN.doc.

[124] Additional information on the ISO's *Request for Proposals for Southwest Connecticut Emergency Capability* can be found in the *Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability 2004-2008* (October 4, 2004), available online at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/swct_gap_rfp_fnl_rpt_10-05-04.doc.

the quantity of these resources throughout New England improves the reliability of the electricity grid. The program was developed as one of several initiatives in response to uncertainties in fuel supply and delivery caused by the impact of Hurricanes Katrina and Rita. A total of 330 MW of additional demand-response resources were enrolled in the Real-Time Demand-Response Program by December 2005. Resources enrolled in the program were activated for audit purposes in January and February 2006.

4.6.4 Demand-Response Program Participation

Figure 4-13 shows demand- and price-response program enrollments by month for 2005 and 2006. Overall enrollment in 2006 increased 50%, from an annual monthly average of 430 MW in 2005 to 646 MW in 2006.

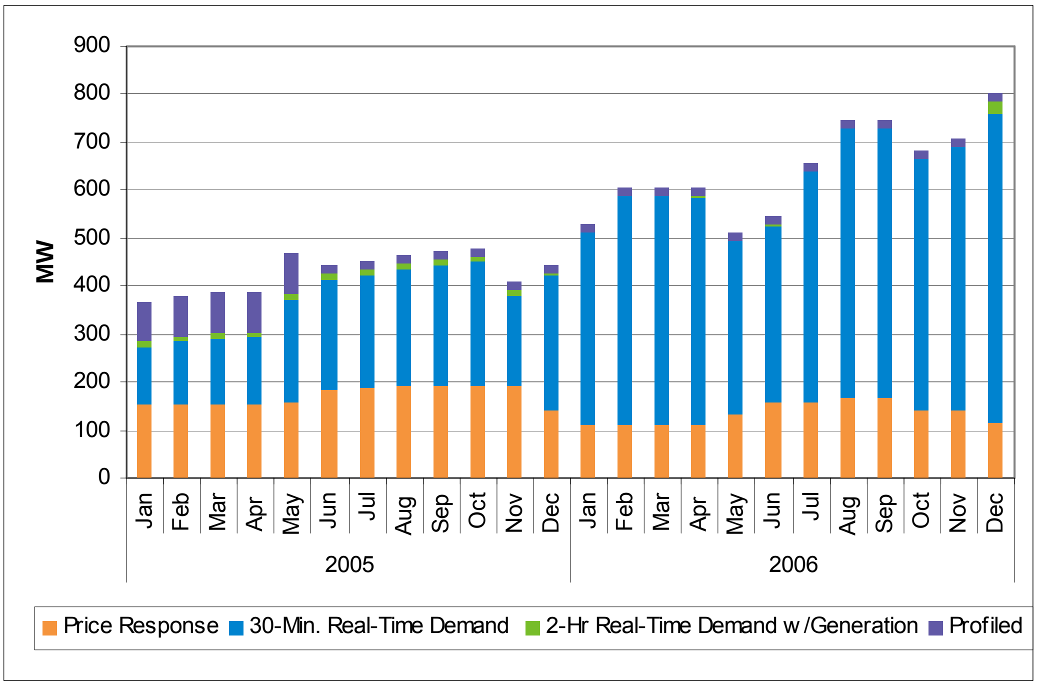

Figure 4-13: Monthly enrollments in demand- and price-response programs, 2005 and 2006.

The average enrollment for the 2006 summer period (June through September) was 675 MW, an increase from the 460 MW 2005 level. During 2006, enrollments in the 30-Minute Demand-Response Program increased, while enrollment in the Real-Time Price-Response Program dropped relative to 2005.

Table 4-11 shows a regional breakdown of ready-to-respond assets for October 2005 and October 2006.[125] Much of the increase in ready-to-respond assets occurred in Connecticut but outside Southwest Connecticut.

[125] Assets in ready-to-respond status are registered in the demand-response program, are approved by the ISO, have all the required metering systems installed and operational, and have provided sufficient data to the ISO such that a customer baseline can be established and the demand-reduction calculation enabled.

Table 4-11
Ready-to-Respond Assets for October 2005 and 2006, MW

Zone	Ready to Respond, October 2005					Ready to Respond, October 2006				
	804 Assets 479.6 MW					1,348 Assets 681.3 MW				
	Assets	Real-Time Price	Real-Time 30-Min	Real-Time 2-Hour	Profiled	Assets	Real-Time Price	Real-Time 30-Min	Real-Time 2-Hour	Profiled
Rest of CT	47.0	36.7	24.3	-	-	294.0	14.1	184.2	-	-
SWCT	300.0	3.8	230.6	1.0	-	424.0	0.9	211.2	-	-
ME	7.0	37.5	-	1.0	11.0	16.0	10.0	80.6	-	11.0
NEMA	112.0	44.2	2.8	0.8	-	161.0	45.9	10.5	-	-
NH	7.0	18.1	-	-	-	13.0	15.8	2.0	-	-
RI	90.0	12.5	-	-	-	141.0	17.6	0.9	-	-
SEMA	102.0	10.4	0.5	-	-	116.0	11.1	9.3	-	-
VT	18.0	7.5	0.1	-	5.9	23.0	7.6	5.4	-	5.9
WCMA	121.0	21.8	0.1	9.0	-	160.0	19.6	17.9	-	-
Total	804.0	192.4	258.4	11.9	16.9	1,348.0	142.4	522.0	-	16.9

Table 4-12 shows the results of all demand-response programs combined, including interruptions resulting from ISO event activations and from participation in the Day-Ahead Load-Response Program. In total, $7.8 million in payments were made to participants for curtailing a total of 52,612 MWh during the year.[126] These payments are in addition to approximately $40 million in supplemental capacity payments made to participants with supplemental capacity contracts issued under the SWCT Gap RFP and an additional $12.3 million in supplemental capacity payments issued under the Winter Supplemental Program.

[126] The 52,612 MWh includes interruptions related to the Winter Supplemental Program.

Table 4-12
Summary of 2006 Results for All Load-Response Programs

Month	Number of Days with Interruptions	MWh Interrupted	Payment ($)
Jan	21	8,962	1,122,146
Feb	20	5,774	809,608
Mar	18	4,402	305,134
Apr	13	1,180	118,030
May	13	865	182,856
Jun	17	2,430	274,584
Jul	20	6,336	681,575
Aug	23	9,490	3,375,477
Sep	15	2,776	224,465
Oct	12	896	71,340
Nov	19	2,137	195,385
Dec	20	7,364	480,027
Total	211	52,612	7,840,627

Real-time load interruptions occurred on a total of 211 distinct days in 2006. Real-time load interruptions can be caused by either an ISO event activation or participation in the Day-Ahead Load-Response Program that obligates resources to interrupt load in real time. Table 4-13 presents the monthly breakdown by interruption program of the DALRP. Resources activated in the DALRP receive a day-ahead payment based on the number of cleared megawatts. They also receive a real-time payment based on the difference between their actual number of interrupted megawatts and the amount cleared day ahead.[127] Participants in the DALRP in 2006 demonstrated greater real-time reduction in network load than the quantity cleared day ahead.

[127] Real-time deviations from the day-ahead cleared quantities are counted as part of the Real-Time Demand-Response Program during hours when an ISO event is activated in the resources' load zone. The level of interruption in megawatt-hours and program payments are included in the real-time program analysis.

Table 4-13
Day-Ahead Load-Response Program Interruptions and Payments, 2006

	Reliability			Price		
	Day-Ahead Cleared (MWh)	Actual Day-Ahead Program Interruptions (MWh)	Day-Ahead Program Payments ($)	Day-Ahead Cleared (MWh)	Actual Day-Ahead Program Interruptions (MWh)	Day-Ahead Program Payments ($)
Jan	727.8	3,274.4	237,541			
Feb	969.3	3,870.5	266,700			
Mar	1,184.4	4,081.4	272,735			
Apr						
May						
Jun	8.0	147.5	8,095			
Jul	5.4	689.2	52,803			
Aug	32.0	3,759.5	448,560			
Sep	40.7	1,267.5	68,565			
Oct	12.3	455.1	27,228			
Nov	19.8	781.9	54,923			
Dec	205.0	6,686.6	419,829	19.7	156.1	9,850
Total	3,204.7	25,013.6	1,856,979	19.7	156.1	9,850

Table 4-14 shows the interruptions (MWh) and payments associated with the Real-Time Load-Response Programs.[128] The Real-Time Price-Response Program experienced the most activity and had a total of 162 days with interruptions. Of the 162 days, 151 days were the result of ISO price-response event activations, whereas the remaining 11 days were the result of the Day-Ahead Demand-Response Program. Participation in the voluntary price-response events depends on the electric energy price levels and the business condition for each customer. The Real-Time Price-Response Program resulted in 23,766 MWh of load curtailments in 2006. The number of resources that curtailed load and the total load curtailed varied from event to event.

[128] Payments and interruptions for resources that are deviations from a day-ahead cleared megawatt quantity are counted as part of the real-time program when the ISO activates an event in the resources' load zone.

Table 4-14
Real-Time Program Interruptions and Payments, 2006

	Reliability Programs				Price-Response Program	
	Demand-Response		Profiled-Response			
	Real-Time Program Interruptions (MW)	Real-Time Program Payments ($)	Real-Time Program Interruptions (MW)	Real-Time Program Payments ($)	Real-Time Program Interruptions (MW)	Real-Time Program Payments ($)
Jan	724.7	362,357			4,962.4	522,249
Feb	880.7	440,372			1,023.1	102,537
Mar	0.0	0			320.9	32,399
Apr	0.0	0			1,179.9	118,030
May	0.0	0			864.9	182,856
Jun	0.0	8			2,282.1	266,480
Jul	0.0	0			5,646.9	628,772
Aug	1,939.5	1,834,338	119.4	83,188	3,671.9	1,009,390
Sep	11.7	5,851			1,496.7	150,049
Oct	0.0	0			441.1	44,113
Nov	0.0	0			1,354.9	140,462
Dec	0.0	0			521.1	50,348
Total	3,556.7	2,642,925	119.4	83,188	23,766.0	3,247,685

The 30-Minute and Two-Hour Real-Time Demand-Response Programs were activated on a total of six days in 2006. Three of the activations took place during the summer months when OP 4 actions were declared. Assets participating in the Winter Supplemental Program were activated one day in January and one day in February for audit purposes. A limited number of assets with supplemental capacity agreements in Southwest Connecticut were activated for audit purposes in September.

Figure 4-14 shows the effect of the ISO's load-reduction programs on the record peak-demand day of August 2, 2006. The peak-shaving effect can be seen as the actual demand drops below the projected demand without the load-response effect curve.[129] The maximum hourly interruption of 625 MW occurred during hour ending 16 (between 3:00 p.m. and 4:00 p.m.). During the peak hour (hour ending 15), these programs provided 597 MW of load reduction. Demand- and price-response program interruptions played a critical role in allowing the ISO to maintain system reliability on this high-demand day that had negative capacity margins.

[129] The difference between the projected load and actual load also includes the reduction in demand resulting from other OP 4 actions; however, the majority of the load reductions are from demand-response program interruptions.

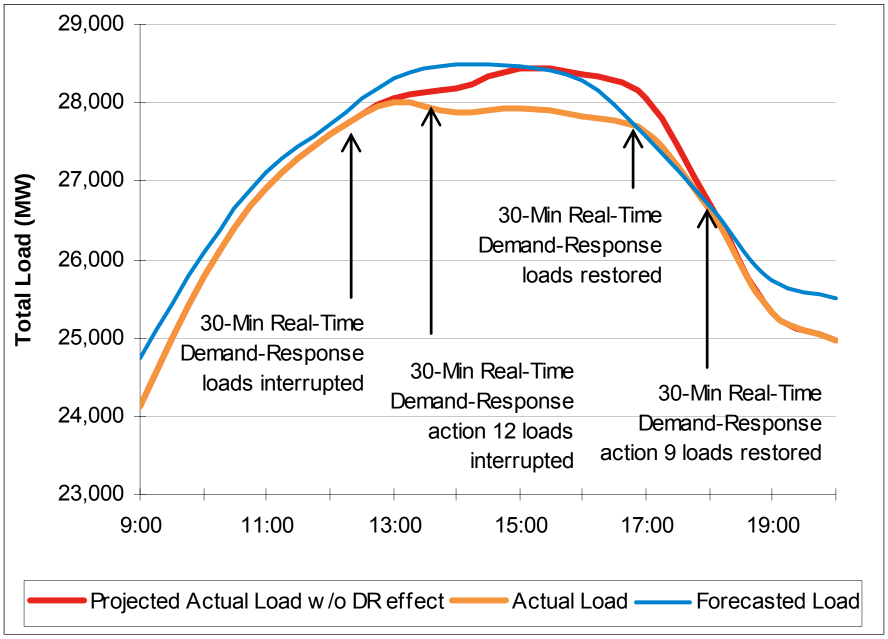

Figure 4-14: Effect of demand-response interruptions on August 2, 2006, loads.

Table 4-15 shows the estimated impact of all demand- and price-response program interruptions on zonal LMPs and the system average.[130] The analysis performed to generate these estimates uses hourly simulations of real-time LMPs with and without these program interruptions.

Table 4-15
Estimated Effects of All Load-Response Program Interruptions on Real-Time LMPs

Zone	Interrupted MWh	Observed Average Real-Time LMP ($/MWh)	Average Real-Time LMP Decrease ($/MWh)
ME	8,021	80.57	0.64
NH	78	145.00	3.03
VT	663	120.82	2.31
CT	4,733	98.44	1.86
RI	0	147.86	1.81
SEMA	383	145.33	1.76
WCMA	513	122.32	2.19
NEMA	3,970	138.09	1.47
Total/ Average	18,361	114.39	1.74

[130] This analysis was done for the *Semi-Annual Status Report on Load-Response Programs of ISO New England Inc.*, FERC Docket No. ER03-345 (December 31, 2006), and only covers the period from April to September 2006.

4.6.5 Demand-Response Reserves Pilot Project

On November 29, 2005, FERC approved ISO tariff revisions to establish the Demand-Response Reserves Pilot Program (DRR Pilot).[131] The DRR Pilot consists of two distinct subprojects with concurrent timelines to meet its objectives and address two specific goals: to determine the ability of demand resources to respond to reserve-activation events compared with off-line and on-line generation resources; and to evaluate lower-cost, two-way communication alternatives to the current combination of SCADA (supervisory control and data acquisition) and Electronic Dispatch Remote Intelligent Gateway technology that is presently required to connect dispatchable resources to the ISO. The experience gained in the DRR Pilot will help the ISO achieve the following long-term goals:

- Determine how and when to allow demand-response resources to participate in all wholesale electricity markets (including electric energy, capacity, and reserves) to the greatest extent possible.
- Ensure that the energy, capacity, and reserve products provided by market resources (i.e., generation and demand-response assets) are functionally equivalent for meeting the needs of the system operators.
- Recognize the behavioral and technological differences between generation and demand-response resources to reduce barriers to entry and to encourage all potential resources to participate in as many of the markets as practicable.

Approximately 23 MW of demand-response resources participated in the DRR Pilot for the winter 2006/2007 season. Activation of the DRR Pilot resources started on October 2, 2006. Additional resources will be selected to participate in the DRR Pilot for the upcoming summer 2007 season. Resources from among various demand-response resource types are participating in the DRR Pilot, including weather-sensitive loads, non-weather-sensitive loads, emergency generation, and load-reduction resources. The results of the DRR Pilot will be used to determine the types of demand-response resources that can provide functionally equivalent, nonsynchronized operating reserves using alternative telemetry.

4.6.6 Demand-Response Program Conclusions

The demand- and price-response programs played an important role in managing system reliability on the record peak-demand day. Without these interruptions, the peak demand would have been hundreds of megawatts higher. Overall, the total value of payments made to participants in 2006 was about $60.1 million: $7.8 million in demand- and price-response program payments, $40.0 million in supplemental capacity payments associated with the SWCT Gap RFP, and $12.3 million under the Winter Supplemental Program.[132] Capacity enrolled in the programs increased by about 100 MW in 2006. The total value of payments increased relative to 2005 as a result of higher supplemental capacity payments under the Southwest Connecticut RFP. The demand- and price-response program payments decreased relative to 2005 because fewer days experienced interruptions, which resulted in lower overall megawatt-hours of interruption.

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[131] *Letter Order Accepting ISO New England, Inc.'s Filing of 1st Revised Sheet 7014 et al. to FERC Electric Tariff, and Amendments to Appendix E of Market Rule 1 to Establish a Demand-Response Reserve Pilot Program*, FERC Docket No. ER05-1450-000 (November 28, 2005).

[132] The annual supplemental payments associated with the SWCT Gap RFP translate to $12.62/kW-Month, which is based on the average capacity provided from June to September 2006.

The ISO's demand- and price-response programs help provide an important linkage between the wholesale markets and end-use customers and produce more efficient outcomes. While participation is still modest relative to total demand, the increased participation and activation relative to the activity of previous years is encouraging. A further increase in participation is an important objective and essential to the long-run success of the New England markets, which will require increased incentives and improved coordination between the wholesale electricity markets and retail-rate design at the state level.

All the ISO's demand- and price-response programs are scheduled to end on June 1, 2010, when the first commitment period for the Forward Capacity Market begins. Many of the resources currently participating in the Real-Time Demand-Response Program are expected to continue to provide qualified capacity as demand resources in the Forward Capacity Market. In addition, several New England states are planning to implement some form of dynamic retail pricing, which should provide similar price-responsive behavior in the wholesale energy market as the Real-Time Price-Response and Day-Ahead Load-Response Programs.

Section 5
Oversight and Analysis

This section covers market monitoring and generator performance and includes an analysis of competitive market conditions.

5.1 Market Monitoring and Mitigation

Market Rule 1 provides for the monitoring and, in specifically defined circumstances, the mitigation of behavior that interferes with the competitiveness and efficiency of the energy markets and daily reliability payments. As specified in the rule, the ISO monitors the market impact of specific bidding behavior (i.e., offers and bids). Whenever one or more participants' offers or declared generating-unit characteristics exceed specified offer thresholds and market-impact thresholds, or are inconsistent with the behavior of competitive offers, the ISO substitutes a default offer for the offer submitted by the participant. These criteria are applied each day to all participants in constrained areas. A less-restrictive set of thresholds is applied each day to systemwide pivotal suppliers. This section discusses how the ISO mitigates economic withholding, which is one behavior that interferes with the competitiveness and efficiency of the markets. It also summarizes the results of the market monitoring and mitigation and resource audits that took place in 2006.

5.1.1 Economic Withholding

Economic withholding occurs when a supplier offers output to the market at a price above its full incremental costs. If the offer is also above the market price, the output is not sold. For example, during periods of high demand and high market prices, all generation capacity with full incremental costs that do not exceed the market price should be either producing energy or supplying operating reserves. Failing to do so would be an example of economic withholding.

A conduct-impact test for triggering mitigation is used in New England. First, supplier conduct is tested to determine whether the supplier may have attempted withholding. If it fails this conduct test, a test for market impact is applied. If a supplier fails this test by increasing market prices by more than a defined threshold, mitigation is imposed. The mitigation imposed for economic withholding is to replace the supplier's offer with a reference level intended to represent its full incremental costs.

5.1.2 *Energy Policy Act* and Federal Energy Regulatory Commission Market-Behavior Rules

The *Energy Policy Act of 2005* grants FERC broad authority to regulate manipulative or fraudulent behavior in the energy markets. FERC implemented its new authority by amending its existing regulations to prohibit any entity from directly or indirectly conducting the following tasks in connection with the purchase or sale of electric energy or transmission services subject to its jurisdiction:

- Using or employing any device, scheme, or artifice to defraud
- Making any untrue or misleading statement
- Engaging in any fraudulent or deceptive act, practice, or course of business

These rules are intended to merge with the enhanced civil penalty authority extended to FERC as a component of the EPAct. If the Internal Market Monitoring Unit finds a potential violation of EPAct or the market-behavior rules, it makes a referral to FERC.

On January 17, 2007, FERC approved five settlements of enforcement matters, assessing civil penalties totaling $22.5 million. NRG Energy (NRG) agreed to pay a $500,000 civil penalty to settle violations of FERC market-behavior rules that resulted from the misrepresentation of the status of a generating facility.[133] FERC staff found that NRG intentionally misrepresented that the generating plant was available when it was not. The staff investigation concluded that the misrepresentation resulted from the actions of a single employee and did not involve NRG senior management. NRG took immediate corrective action, including reporting the incident to FERC and the ISO. In addition to the civil penalty, NRG agreed to undertake a one-year compliance program that involves submitting semiannual filings containing the results of plant-outage audits for the previous six-month period.

5.1.3 Market Monitoring and Mitigation Results

Mitigation was triggered eight times during 2006, as shown in Figure 5-1. Six mitigation events were attributable to the bidding strategy of one participant to maximize NCPC revenue. One mitigation event was for economic withholding in the Real-Time Energy Market, and the remaining mitigation event was for economic withholding in the Day-Ahead Energy Market. This represented the first time a generating resource had been mitigated in the Day-Ahead Energy Market. In addition to taking these specific actions, the INTMMU had nearly daily discussions with individual participants concerning specific market behavior. The systemwide thresholds did not trigger mitigation of electric energy suppliers that were pivotal in 2006. As energy, capacity, regulation, and reserve markets develop, the ISO will evaluate the market monitoring provisions to maintain efficient market outcomes.

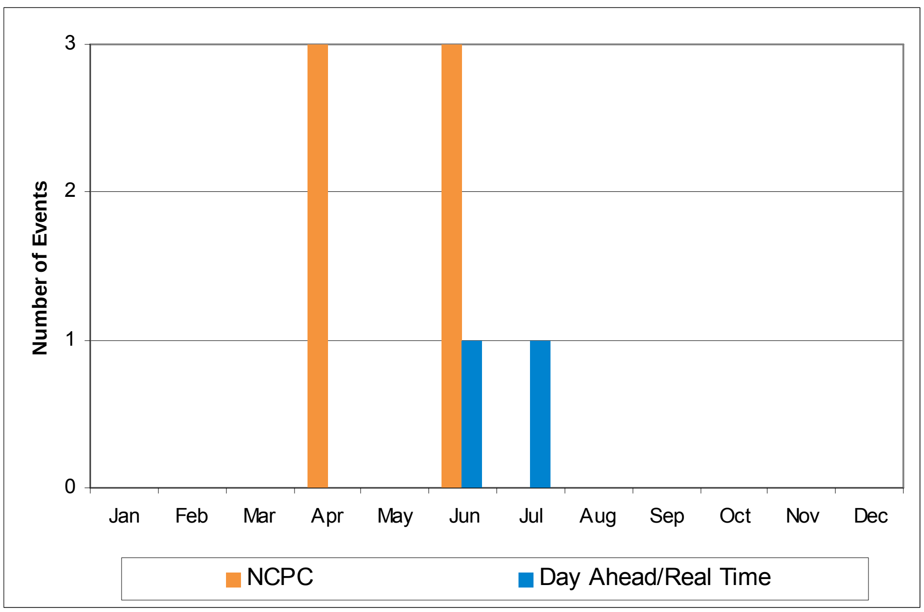

Figure 5-1: Mitigation events in 2006.

[133] *Order Approving Stipulation and Consent Agreement Re: NRG Energy, Inc.* FERC Docket No. IN07-6-000. 118 FERC ¶ 61,025 (January 17, 2007). Available online at http://elibrary.ferc.gov/idmws/doc_info.asp?document_id=4471974.

5.1.4 Resource Audits

Market Rule 1, Appendix A, Section 4.2.2, authorizes the ISO to verify forced outages and thus monitor the physical withholding of resources.[134] The INTMMU uses all available data to determine whether a plant inspection is warranted. If an inspection is appropriate, the ISO contacts both the plant management and the lead participant to coordinate access to the plant and a visual inspection of the reported cause of the forced outage. If the results of a plant inspection suggest that the resource owner has physically withheld the resource, the ISO obtains appropriate additional information. If the completed review shows that physical withholding has taken place, the ISO may impose sanctions, as outlined in Appendix B of Market Rule 1.[135]

During 2006, the INTMMU requested detailed plant information and operator logs for a number of cases. In each case, the INTMMU monitored for potential physical withholding of a resource and determined that a plant inspection was not warranted. The INTMMU visited a number of plants during the year as part of its routine information-gathering process.

5.2 Analysis of Competitive Market Conditions

This section presents analyses of competitive market conditions during 2006. It includes analyses of market share, pricing efficiency, and market entry.

5.2.1 Herfindahl-Hirschman Index for the System and Specific Areas

Market concentration is a function of the number of firms in a market and their respective market shares. One measure of market concentration is the *Herfindahl-Hirschman Index* (HHI). The HHI is calculated by summing the squares of the individual market shares of all market participants. The HHI reflects the distribution of the market shares, giving proportionately greater weight to the market shares of the larger firms, in accordance with their relative importance in competitive interactions. For electricity markets, shares are measured by megawatts of generating capacity.

The HHI is not a sufficient indicator of market concentration in wholesale electricity markets. The metric also does not account for contractual entitlements to generator output that reduce the level of market power associated with any given supply-ownership concentration, as measured by the HHI. In addition, the HHI ignores the effect that transmission constraints can have on the market. Load pockets that result from these constraints may be less competitive than the systemwide HHI would suggest.

These limitations notwithstanding, HHI is still a useful indicator to monitor. Market concentration measured by the HHI is conventionally divided into three regions, broadly characterized as follows, which provide a framework for market-concentration analysis:

- *Not concentrated* (HHI below 1,000)
- *Moderately concentrated* (HHI between 1,000 and 1,800)
- *Highly concentrated* (HHI above 1,800)

[134] This section of Market Rule 1, Appendix A, can be accessed online at http://www.iso-ne.com/regulatory/tariff/sect_3/appendix_a_mkt_monitoring_redone_1-18-06.doc.

[135] Market Rule 1, Appendix B, can be accessed online at http://www.iso-ne.com/regulatory/tariff/sect_3/Market_Rule_1_Appendix_B_06-01-05.DOC.

Although these classifications are imprecise in that a low-concentration index does not guarantee that a market is competitive, higher values indicate greater potential for participants to exercise market power.

Figure 5-2 shows the HHI for New England internal resources based on summer capabilities and the responsibilities of the lead participant to offer the generating unit to the market. The values shown were developed from participant information collected by the INTMMU. The marketwide HHI indicates the following results:

- A steady decline from the opening of wholesale electricity markets in New England
- A slight increase in winter 2002/2003 when a participant was assigned certain generators with previously unclassified generator ownership
- A slight upward movement during the third quarter of 2003 due to the beginning of the commercial operation of a large generating facility owned by an existing participant
- Little variation during 2004
- A decrease in January 2005 following the divestiture of USGen New England, Inc.'s approximately 4,000 MW asset portfolio due to USGen's bankruptcy. (Dominion Energy Marketing acquired about 2,700 MW of thermal units from USGen, while TransCanada Power Marketing and Brascan Energy Marketing purchased hydro units.)
- An increase in June 2005 due to the transfer of assets between companies. Because the participant company that received the assets already owned significant generation, the transfer resulted in its having the largest portfolio in New England.
- Little variation during 2006

Despite the modest increase from 2004, the HHI for 2006 of about 700 is well below the U.S. Department of Justice benchmark for an unconcentrated market.

Figure 5-2: Herfindahl-Hirschman indices for New England, May 1999 to December 2006.

As part of its market assessment function, the ISO also develops an HHI for each load zone. These are shown in Figure 5-3. At the zonal level, concentrations are all highly or moderately concentrated. The Vermont and NEMA load zones have the highest HHIs, indicating the highest potential for market-power concerns. The Vermont calculation should be viewed with caution because this state has a relatively small capacity to generate electricity, significant import capability, and vertically integrated utilities. The NEMA load zone, which frequently needs out-of-merit operation for transmission support, has an HHI in the highly concentrated range; however, the HHI for this load zone declined significantly in 2005 and increased only slightly in 2006.

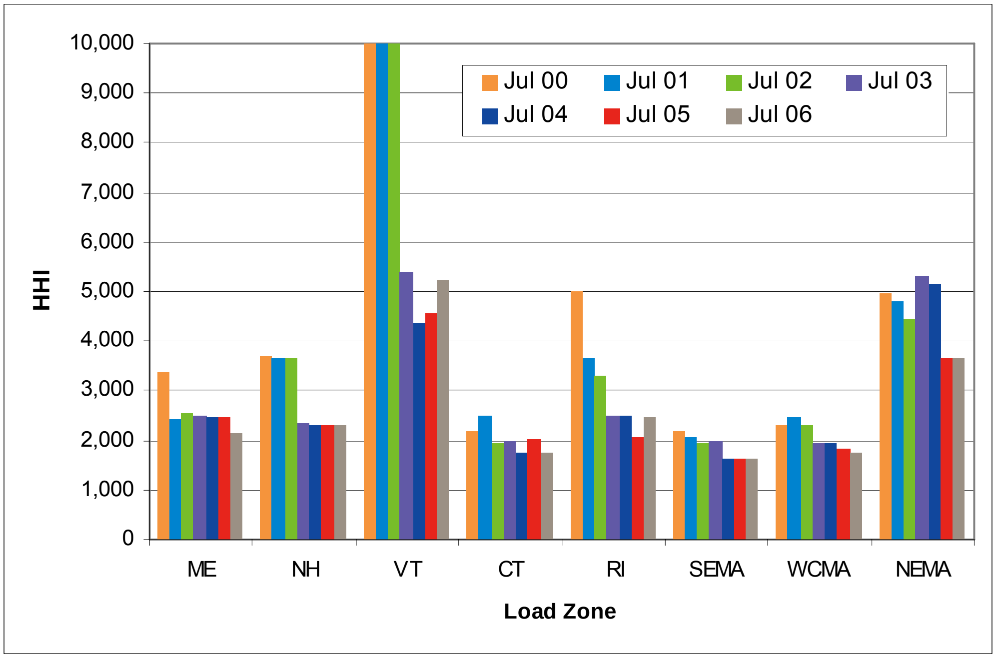

Figure 5-3: Herfindahl-Hirschman indices by load zone.

5.2.2 Market Share by Participant Bidder

Figure 5-4 shows generation capability for the 12 lead participants with the largest portfolios during 2006. The largest portfolio at the beginning of the year was 4,800 MW, while the largest portfolio at the end of the year was 4,700 MW, owned by the same participant.

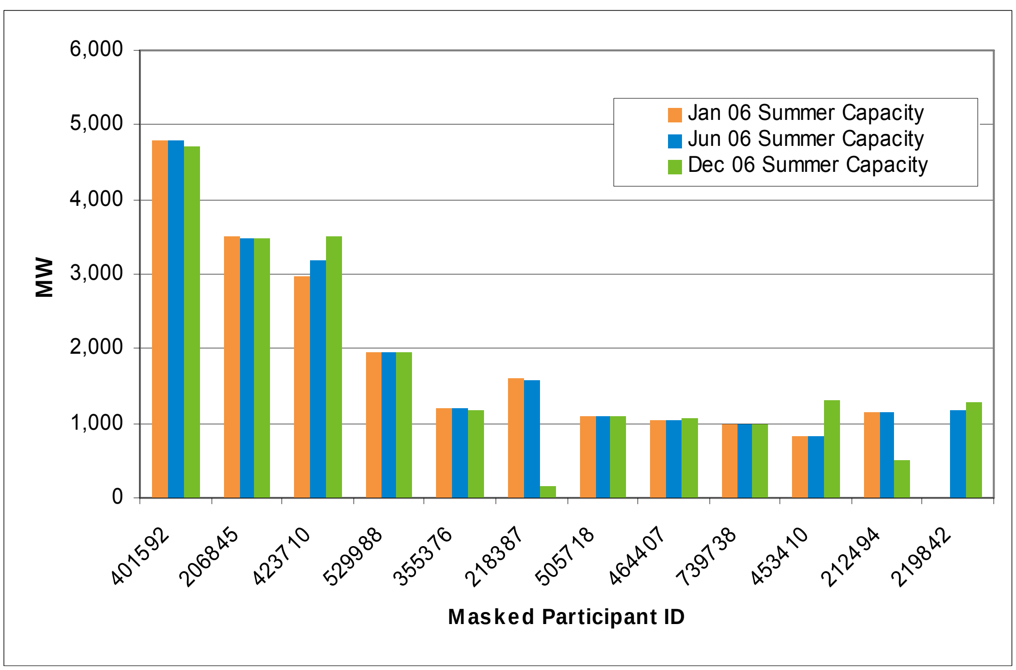

Figure 5-4: Generation capacity by lead participant, 2006.

5.2.3 Forward Contracting

Estimates of the level of forward contracting and self-supply generation in New England are important in evaluating how well New England's markets are working. Forward contracting not only insulates load from short-term price volatility, it also serves as an incentive for generators to offer generation at marginal cost.[136]

Calculations for January through December 2006 show that, on average, at least 51% of total real-time load obligation was either forward contracted or covered by a physical hedge through the ISO's settlement system. For each month of 2006, as shown in Figure 5-5, the degree of forward contracting was at least 40% of real-time load obligation. In 2005, the average was 57%. These calculations tend to understate the degree of forward contracting that actually takes place to the extent that bilateral contracts exist but are not settled through the ISO's centralized settlement system. Conversations between the INTMMU and market participants suggest that the drop in hedging through the settlements system during 2006 reflects an increased use of bilateral contracts settled independently of the ISO. Hence, while these numbers are useful, they are only indicative of the forward positions held by participants.

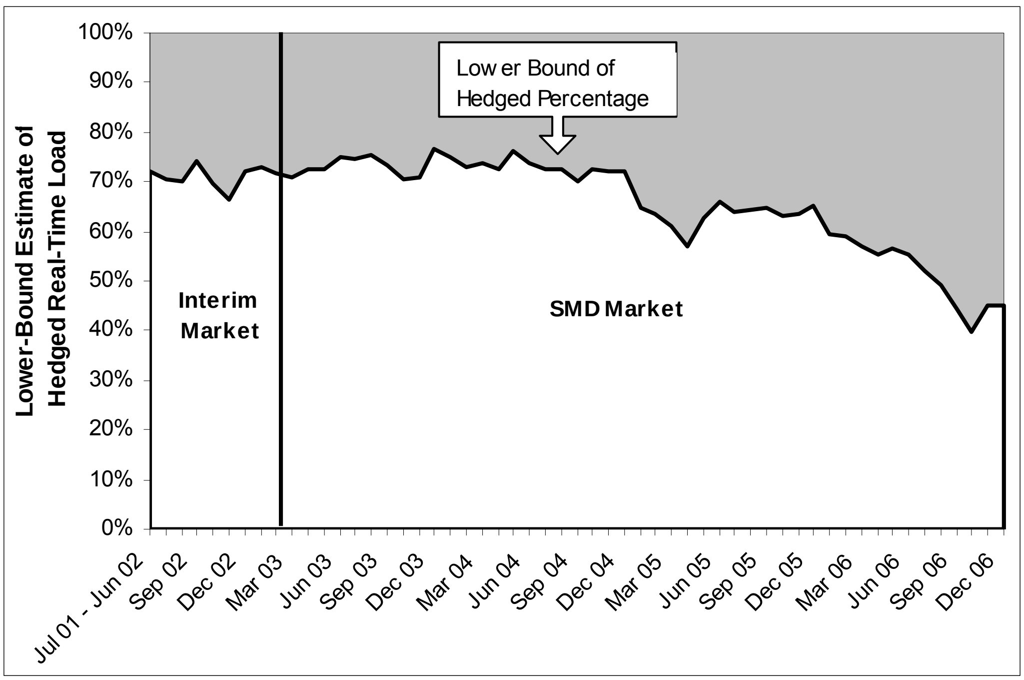

Figure 5-5: Lower bound of real-time load as hedged through the ISO settlement system.

[136] David Newbery, "Power Markets and Market Power," *The Energy Journal* 16:3 (1995).

5.2.4 Residual Supply Index

The *Residual Supply Index* (RSI) measures the hourly percentage of load (MWh) that can be met without the largest supplier. It indicates the potential of individual bidders to influence the market-clearing price. The index is computed as follows:[137]

$$\text{RSI} = \frac{(\text{total supply} - \text{largest seller's supply})}{(\text{total demand})}$$

If the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. If the RSI exceeds 100%, alternative suppliers have sufficient capacity to meet demand. A pivotal supplier can in theory unilaterally drive price above the competitive level, subject to prevailing offer caps. The profit-maximizing offer of the pivotal supplier may be below the offer cap if the demand not met by other, nonpivotal suppliers is price sensitive.

The RSI is a more robust indicator of market competitiveness than the HHI. Electricity markets are characterized by rapidly changing market conditions and continuous balancing of essentially nonstorable supply and inelastic demand. Studies conducted by the California ISO suggest an inverse relationship between the RSI and the price-cost markup, which is the market metric developed in the competitive benchmark analysis (described in Section 5.2.5). That is, as RSIs fall, markups tend to rise.[138]

On July 9, 2003, FERC accepted the ISO's request to implement a pivotal-supplier trigger for evaluating a pivotal supplier's energy-supply offers for possible mitigation.[139] In this proposal, a pivotal supplier is defined as a market participant whose aggregate energy-supply offers for a particular hour are greater than the New England supply margin.[140] The calculation of the RSI, described previously, is consistent with the requirements outlined in the FERC docket.

Table 5-1 shows the number of hours in each month of 2006 that the RSI was below 100% and below 110%. RSIs are generally lowest during high-demand periods. This analysis shows that pivotal suppliers existed during some hours in 2006; the RSI was below 100% during 154 hours of 2006, most of which were on high-demand summer days. As Table 5-2 shows, 2006 had fewer hours with pivotal suppliers than 2005. This is due to the lower demand during 2006.

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[137] *Total supply* is defined as the total of generators' economic maximums. *Demand* is defined as actual load.

[138] Anjali Sheffrin, *Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition* (California ISO, November 19, 2001). Revision is available online at http://www.caiso.com/docs/2001/11/20/20011201556082796.pdf.

[139] *Order on Proposed Tariff Revisions.* FERC Docket No. ER03-849-000. 104 FERC ¶ 61,039 (July 9, 2003). In this docket, FERC noted that a structural problem exists when suppliers become pivotal; they have market power because at least a portion of their offers must be accepted to maintain reliability, no matter how high the offer price. FERC found it reasonable to evaluate the supply offers of pivotal suppliers to determine whether the suppliers are attempting to exercise market power in the unconstrained pool and, thus, whether their offers should be mitigated. See http://www.iso-ne.com/regulatory/ferc/orders/2003/jul/General_Mitigation_Order_070903.pdf.

[140] The supply margin for an hour (i.e., the available generation beyond the amount needed to meet demand for that hour) is the total of energy-supply offers for that hour, up to and including the economic maximum, minus the total system load (as adjusted for net interchange with other control areas and including operating reserve).

Table 5-1
Residual Supply Index, 2006

Month	Number of Hours RSI <100%	Number of Hours RSI <110%	Average Monthly RSI	Maximum RSI	Minimum RSI
Jan	0	0	149	199	110
Feb	1	1	145	196	114
Mar	0	0	149	199	116
Apr	0	0	143	195	111
May	0	27	134	178	101
Jun	31	118	136	191	90
Jul	83	204	127	184	82
Aug	39	76	137	198	78
Sep	0	4	146	195	109
Oct	0	3	139	326	107
Nov	0	15	141	200	104
Dec	0	0	149	199	111
Total	154	448	141	326	78

Table 5-2
Residual Supply Index, 2004, 2005, and 2006

Year	Number of Hours RSI <100%	Number of Hours RSI <110%	Average Monthly RSI
2004	43	247	141
2005	311	865	138
2006	154	448	141

The RSI analysis is consistent with other analyses that show relatively good market performance in New England since it shows that only 1.8% of total hours during 2006 had pivotal suppliers. This RSI analysis is somewhat conservative and may overstate the number of hours in each month that one or more suppliers were pivotal. It does not take into account contractual relationships that affect the amount of load obligation a supplier may have in any hour and that obligation's influence on market behavior.[141] The ISO will continue to monitor the existence of pivotal suppliers and assess their influence on the market.

[141] Richard Green, "The Electricity Contract Market in England and Wales." *Journal of Industrial Economics* XLVII:1 (1999) : 107–124.

5.2.5 Competitive Benchmark Analysis

In 2002, the INTMMU developed a tool (the ISO model) for conducting competitive benchmark analyses. The ISO model evaluates the competitive performance of New England's wholesale electricity markets using a method similar to one developed by Bushnell and Saravia of the University of California Energy Institute.[142] The ISO uses this tool to identify trends in the competitiveness of New England's wholesale electricity market.

The *competitive benchmark* (benchmark price) is an estimate of the market-clearing price that would result if all market participants acted as price-takers, offering their electric energy at incremental marginal cost, and if the market operated with perfect efficiency in an unconstrained system. The benchmark price can be compared with either actual market prices or other market measures. The benchmark price accounts for production costs, including environmental and variable operations and maintenance (O&M) costs, unit availability, and net imports. It thus represents the estimated incremental costs associated with the least expensive generating unit not needed to serve demand in a given hour.

Table 5-3 compares the benchmark price with two other measures of the wholesale market price: the ISO's real-time LMP at the Hub and the bid-intercept price. The latter is the price at which market demand intersects the aggregate supply curve, derived from the supply offers from all generating units but ignoring unit-operating constraints. Comparing the two market-based prices with the benchmark over time can help assess the competitiveness of the market.

The metric used to compare the total costs derived from the different market-price outcomes is the *Quantity-Weighted Lerner Index* (QWLI). The conventional *Lerner Index*, defined as the price-cost margin in percentage terms, is widely used to assess the competitiveness of market outcomes. In this analysis, the QWLI represents the percentage increase in the annual total cost relative to the benchmark estimate of total cost, as a percentage of total cost (see equation in the footnote).[143] This metric is more appropriate than using a simple arithmetic average of hourly Lerner indices.

Table 5-3 shows that the QWLI for 2006 remained unchanged from 2005 to 2006 for both the real-time Hub price and the aggregate bid-intercept price. The 2006 results are consistent with outcomes expected in a competitive market, with either measure having small markups. While the QWLI is a useful and intuitive measure of market competitiveness, it is subject to an uncertain amount of modeling error because of the necessary simplifying assumptions and the need to rely on estimates of generator-input cost and efficiency (e.g., environmentally limited units are not explicitly considered, hydroelectric units are assumed to be perfectly competitive). Thus, it is more appropriate to examine trends and large movements in the QWLI than to place emphasis on modest year-to-year changes. The results of the model suggest that the market continued to behave competitively through 2006.

[142] James Bushnell and Celeste Saravia, *An Empirical Analysis of the Competitiveness of the New England Electricity Market.* (Berkeley: University of California Energy Institute, January 2002). The study report is available online at http://www.iso-ne.com/pubs/spcl_rpts/2003/Empirical_Assessment_of_Competitiveness_of_NE_Market_(Bushnell).pdf.

[143]
$$\mathrm{QWLI}_1 = \frac{\sum(\mathrm{LMP}\times\mathrm{load}) - \sum(\mathrm{benchmark\ price}\times\mathrm{load})}{\sum(\mathrm{LMP}\times\mathrm{load})}$$

$$\mathrm{QWLI}_2 = \frac{\sum(\mathrm{bid\ intercept\ price}\times\mathrm{load}) - \sum(\mathrm{benchmark\ price}\times\mathrm{load})}{\sum(\mathrm{bid\ intercept\ price}\times\mathrm{load})}$$

Table 5-3
ISO Model Market Price Measures

Price Measure	2006 Price ($/MWh)	Quantity-Weighted Lerner Index (%)			
		2003	2004	2005	2006
Competitive benchmark price	$59.75				
Real-time Hub price	$62.74	9	3	6	6
Aggregate bid-intercept price	$59.77	−4	−6	1	1

5.2.6 Implied Heat Rates

The market prices for electricity and fuel can be used to derive the heat rate that would allow a generator to break even if it were producing electricity. This *implied heat rate* is useful because it shows a generator's needed efficiency for profitably burning a particular fuel at prevailing market prices. Comparing a generator's heat rate with the heat rates of existing resources can indicate the likelihood of the generator's dispatch and the relative economics of various fuels and generation technologies. For example, if the price of a fuel rises at a rate greater than that of electricity, even generators with high thermal efficiency may not be able to recover fuel costs or to earn additional revenues while producing electricity. This will be reflected in a falling implied heat rate.

Table 5-4 shows volume-weighted average heat rates at full load for New England generators burning various types of fuel. The table shows the average heat rate for all generators in each fuel category and the estimated heat rates for the most efficient generator. Dual-fueled generators are included in the category of the fuel they burn most frequently.

Table 5-4
Average Heat Rate by Generator Fuel Type, Btu/kWh

Generator Fuel Type	Estimated Average Heat Rate	Estimated Most Efficient Heat Rate
Coal	9,700	8,700
Jet fuel	13,300	12,600
Kerosene	13,000	11,100
Natural gas	8,200	6,900
No. 2 fuel oil	14,700	11,100
Diesel	12,200	11,000
No. 6 fuel oil	10,500	9,200

The implied heat rate is the ratio of the day-ahead Hub LMP in each hour and the next-day price for the applicable fuel. This rate approximates the thermal efficiency that would be required to recover fuel costs and earn additional revenues on the conversion of that fuel to electricity. For example, if the day-ahead LMP were $60/MWh and the day-ahead fuel price were $6/MMBtu, the implied heat rate would be 10 MMBtu/MWh, or 10,000 Btu/kWh. Generators with actual heat rates lower than the implied heat rate recover fuel costs and earn additional revenues on their conversion of fuel to electricity.

Figure 5-6 reports the monthly average implied heat rates for price points on two major interstate natural gas pipelines in New England. The data suggest that gas-fired generators with a thermal heat rate less than 8.2 MMBtu/MWh, the average in New England, typically were recovering fuel costs. The monthly averages obscure the daily fluctuations in implied heat rates that would place specific units in or out of economic-merit order on a given day.

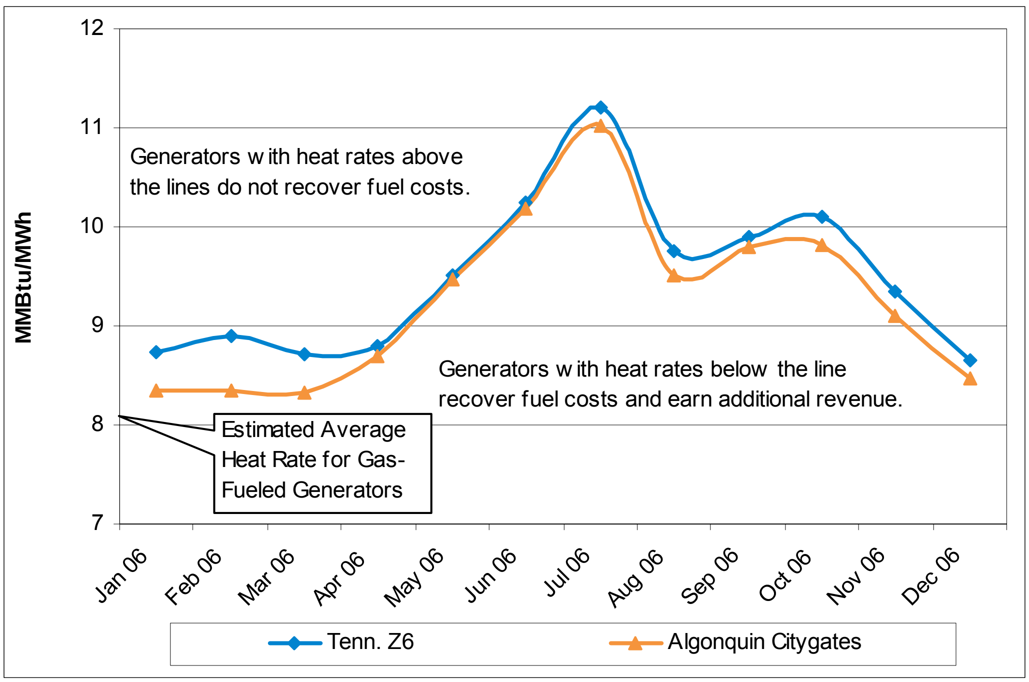

Figure 5-6: Monthly average implied heat rates in New England, natural gas and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type to the fuel price. For each month, an average of all days in the month was calculated.

Figure 5-7 reports the implied heat rates for selected petroleum-based fuels. The results show that the average No. 2 fuel oil, jet fuel, and diesel-fueled generators did not recover fuel costs based on average monthly prices. This is consistent with ISO observations of oil-fired unit operations; most run only when electricity prices are relatively high. Figure 5-8 shows that the average coal-fired generator typically recovered fuel costs.

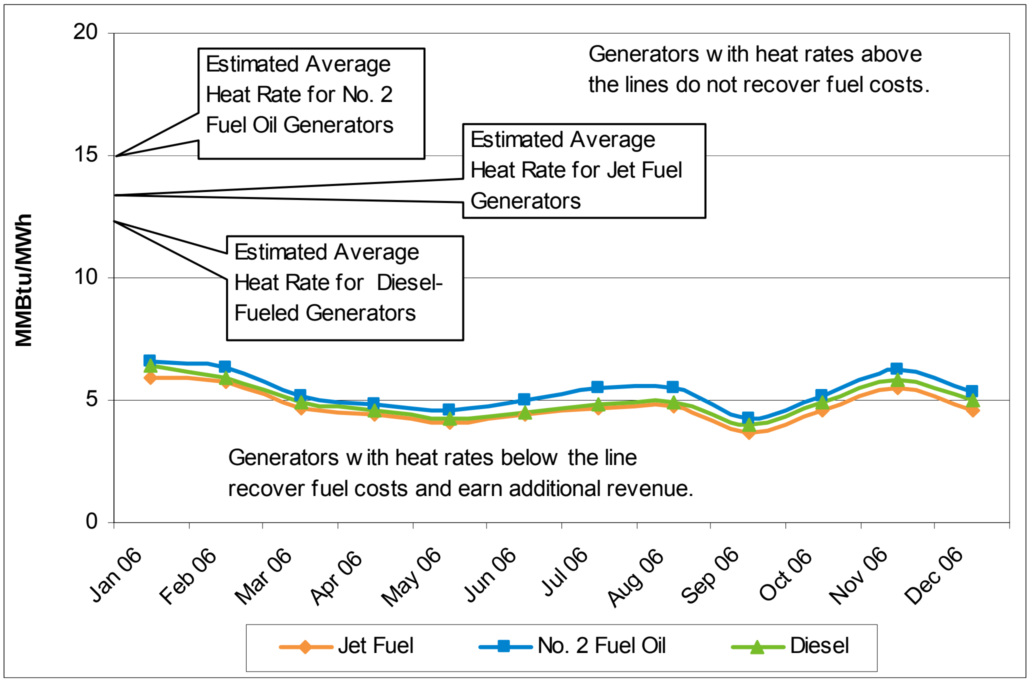

Figure 5-7: Monthly average implied heat rates in New England, petroleum-based fuels and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type to the fuel price. For each month, an average of all days in the month was calculated.

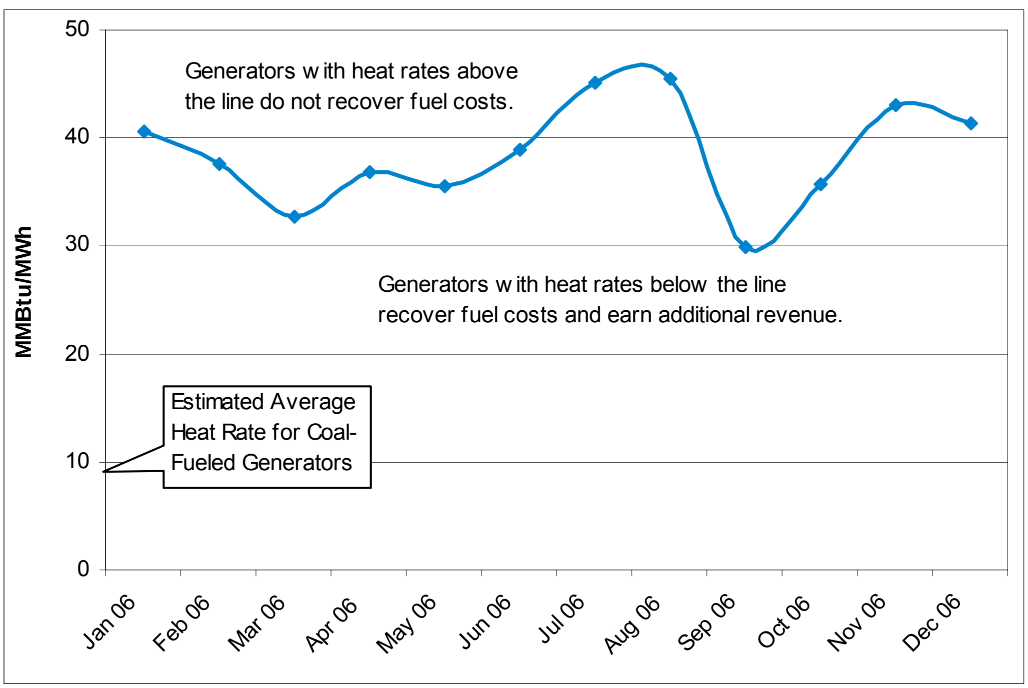

Figure 5-8: Monthly average implied heat rates in New England, coal and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type to the fuel price. For each month, an average of all days in the month was calculated.

5.2.7 Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit seeking to enter the market. In the long run, the revenues from the energy, capacity, regulation, and reserve markets must be expected to cover the costs of a proposed new generating plant, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market, eventually putting upward pressure on prices. On the other hand, revenues above this level should lead to new entrants and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel for fossil units) contributes to the recovery of its fixed costs, including nonvariable operating and maintenance expenses and capital costs. This margin can be estimated, given the variable costs of a typical new generating unit, hourly energy-clearing prices in New England, and revenue estimates for capacity and ancillary services.

Table 5-5 presents an estimate of the theoretical maximum net revenues for two hypothetical gas-fired generators in New England during 2006. This estimate is a metric developed by FERC for comparison across power pools. It represents an upper bound of revenue and is not informative about actual financial conditions for many generators in New England. Gas-fired generators were modeled because they represent the typical new unit that has been brought on line in New England. Daily marginal costs were calculated for each hour using spot-fuel prices, the assumed heat rates, and other production costs for both an efficient combined-cycle natural-gas-fired plant with a heat rate of 7,000 Btu/kWh and a typical gas-fired combustion-turbine unit with a heat rate of 10,500 Btu/kWh. It was assumed that the generator ran each hour the price was above its marginal cost, ignoring commitment costs, ramping constraints, and start-up and minimum run times. However, by ignoring start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations overstate actual net revenues.

Table 5-5
Yearly Theoretical Maximum Revenue for Hypothetical Generators
Net of Variable Costs per MW, 2006

Generator	Marginal Cost Formula	Heat Rate (Btu/kWh)	($/MW-Year)			
			2006 Net Energy Revenue	Approximate Revenue from Capacity Sales[(a)]	Approximate Ancillary Services Revenue[(b)]	Approximate Theoretical Max. Revenue
Representative combined cycle/ gas fired	(Daily fuel cost x heat rate) + (VOM[(c)] of $1/MWh)	7,000	$100,969	$479	$2,600	$104,048
Representative combustion turbine/ gas fired	(Daily fuel cost x heat rate) + (VOM[(c)] of $3/MWh)	10,500	$24,422	$479	$22,667	$47,568

(a) The revenue from capacity sales is a weighted average of ICAP supply and deficiency auction clearing prices, adjusted for forced-outage rate.

(b) The revenue from ancillary services is based on the Regulation Market for combined-cycle units and the Forward Reserve Market for combustion-turbine units. Forward-reserve revenues equal auction revenues minus performance penalties.

(c) Variable operations and maintenance costs.

Under these assumptions, the combined-cycle plant would have earned a theoretical maximum of about $104,000/MW in the electric energy, capacity, regulation, and reserve markets during 2006, net of variable costs. The combustion-turbine plant would have earned a theoretical maximum of approximately $24,000/MW in the electric energy market. If it participated in the Forward Reserve Market, it could have earned an additional $22,000/MW. Capacity market revenues were negligible for the year. For this analysis, unit outages were represented by reducing energy revenues by 5%.

The net revenue of the representative combined-cycle generator in 2006 decreased 8% from the 2005 estimate. For the representative combustion turbine, the estimated net revenue decreased almost 11% between 2005 and 2006. For both years, the analysis was performed using LMPs at the Hub, although LMPs in some zones were higher or lower than those at the Hub. In addition, new entry costs would have likely been higher in some subareas, such as Southwest Connecticut and Boston. Capacity revenues were the same throughout the system. FRM revenues for the Rest-of-System zone were used for the post-ASM II period.

In addition to fuel and other variable costs accounted for in the net-revenue analysis, in the long run, new entrants must on average earn enough to cover their nonvariable costs, which include fixed O&M costs, taxes, depreciation, debt repayment, and a competitive return on investment.

5.2.8 Summary of Competitive Market Conditions Analyses

Overall, on the basis of the preceding analyses, the ISO concludes that New England's wholesale electricity markets continue to be competitive. The competitive benchmark analysis indicates that the observed bidding behavior is consistent with a competitive market. The market share, residual supply index, and HHI analyses indicate that New England's wholesale electricity markets continue to be structurally competitive. High demand during the summer and a modest increase in market concentration resulted in an increase in the number of hours in which suppliers were pivotal. Approximately 5% of the hours during the year had an RSI of less than 110%. These analyses have not fully considered transmission constraints that may create local concentrations of generator ownership. The INTMMU monitors for the existence of pivotal suppliers in constrained areas and is prepared to intervene if a pivotal supplier is judged to be exercising market power.

5.3 Generating-Unit Availability

Table 5-6 illustrates the annual Weighted Equivalent Availability Factors (WEAF) of the New England generating units for 1995 to 2006.[144] As shown, availability decreased from 1995 to 1997 and then began increasing again in 1999 to just above 1995 levels. The decrease from 1996 through 1998 can be attributed to the outage of nuclear units during this period. The New England system WEAF increased to a high of 89% in 2002, decreased slightly to 88% in 2003, and remained at 88% through 2005. In 2006, it increased to 89%.

[144] The term *weighted* means that averaging is proportional to unit size, so that a 100 MW unit counts 10 times more than a 10 MW unit. *Equivalent* means that both deratings (partial outages) and full-unit outages are counted proportionally to the available megawatts.

Table 5-6
New England System Weighted Equivalent Availability Factors, %[(a)]

	1995	1996	1997	1998	1999[(b)]	2000	2001	2002	2003	2004	2005	2006
System average	79	78	75	78	81	81	87	89	88	88	88	89
Fossil steam[(c)]	81	81	84	81	79	78	83	85	87	86	86	88
Coal	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*84*	*83*	*88*	*84*
Coal/oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*84*	*88*	*88*	*85*
Oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*84*	*84*	*84*	*89*
Gas/oil	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*91*	*87*	*84*	*91*
Wood/refuse	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*94*	*93*	*93*	*93*
Nuclear	63	53	32	53	82	89	92	91	91	94	89	93
Jet engine	88	92	94	93	70	88	95	94	94	97	95	96
Combustion turbine	94	92	96	92	90	83	89	92	93	97	95	95
Combined cycle	90	92	92	89	83	80	85	90	85	86	86	84
Pre-1999 combined cycle	*90*	*92*	*92*	*89*	*91*	*89*	*96*	*92*	*91*	*92*	*92*	*92*
New (installed 1999–2004) combined cycle	*n/a*	*n/a*	*n/a*	*n/a*	*47*	*67*	*76*	*89*	*84*	*84*	*86*	*81*
Hydro	83	88	86	86	81	81	96	96	95	94	94	96
Pumped storage	97	94	97	91	86	86	95	87	92	90	92	91
Diesel	90	94	90	89	88	88	98	98	98	95	98	99

(a) The statistics for 1995 to April 1999 were calculated from the NEPOOL Automated Billing System (NABS). NABS data are representative of traditional, cost-based system dispatch. The system captured actual run-time megawatt-per-hour information and outage information as defined in the billing rules. The NEPOOL Settlements Department primarily used the data for payment to the generators. Using statistical analysis approved by the NEPOOL Power Supply Planning Committee, generators were allotted a certain amount of maintenance outage weeks per year to perform scheduled maintenance. Outages that ran over this amount or were out of service any other time were considered unplanned or forced outages. Statistics for May 1999 to 2005 were based on competitive bid-based dispatch and were calculated from a Short-Term Outage Database. The ISO Operations Department populates this database using information it receives from generators; it records scheduled and unplanned outages as they occur in real time.

(b) Data are represented for May through December 1999.

(c) Beginning in 2003, the ISO began separating the "fossil-steam" category into the five categories as noted. In this context, "n/a" stands for "not calculated."

Figure 5-9 illustrates that the spring and fall months continue to have the greatest number of outages, while the summer period has the least. This figure shows total outages in megawatts during the monthly peak-demand days in 2006 and the amount of capacity on outages as a percentage of total available seasonal claimed capability. The figure shows how the system reacts to electrical peak demands. Less capacity is on outage during periods of high demand (summer- and winter-peak periods) than during the spring and fall low-demand periods.

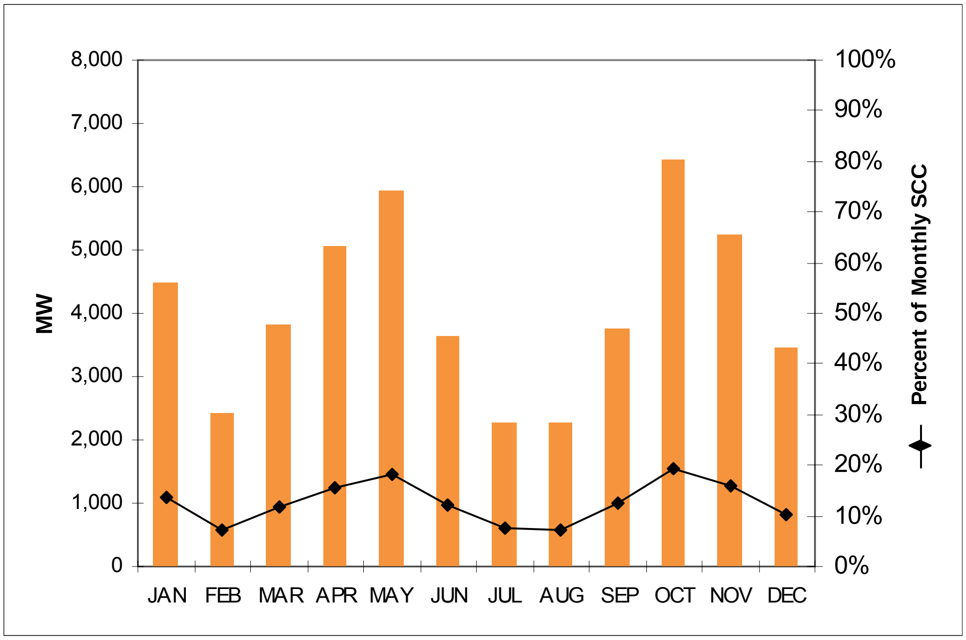

Figure 5-9: Generator-unit total outages during peak-demand days, January to December 2006.

Figure 5-10 illustrates how the availability of the New England generating units tracks monthly demand. Specifically, Figure 5-10 illustrates the monthly WEAF and the monthly peak demand as a percentage of the annual peak demand. Similar to the information presented in Figure 5-9, the average availability for the New England generating units is lowest during the months that have the lowest peak demand. When New England experiences the highest peak demand, the average availability of New England generators is the greatest. This is consistent with outage scheduling procedures that limit outages for annual inspections to lower-demand periods.

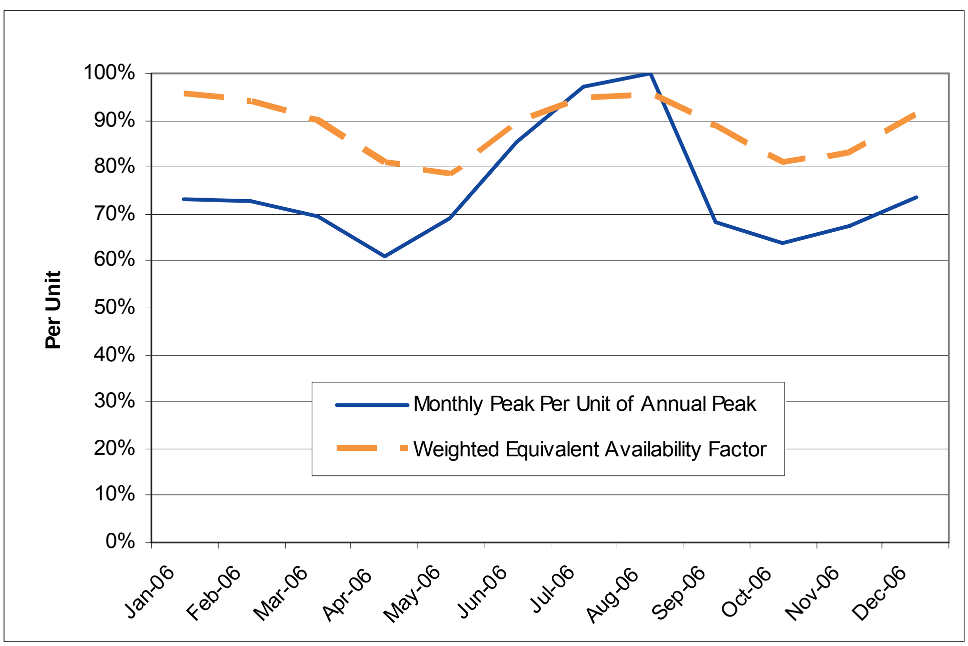

Figure 5-10: Monthly peak demand and monthly average availability (WEAF).

Figure 5-11 shows the average generation capacity (MW) on outage during each weekday peak for 1996 to 2006. The total amount of capacity on outage had been growing slightly from a low in 1998 until a peak in 2005, coincident with increases in system claimed capability. Between 2005 and 2006, the total capacity on outage decreased 10%. The high unplanned outages during 1996 and 1997 are due to extended outages of several nuclear plants during those years.

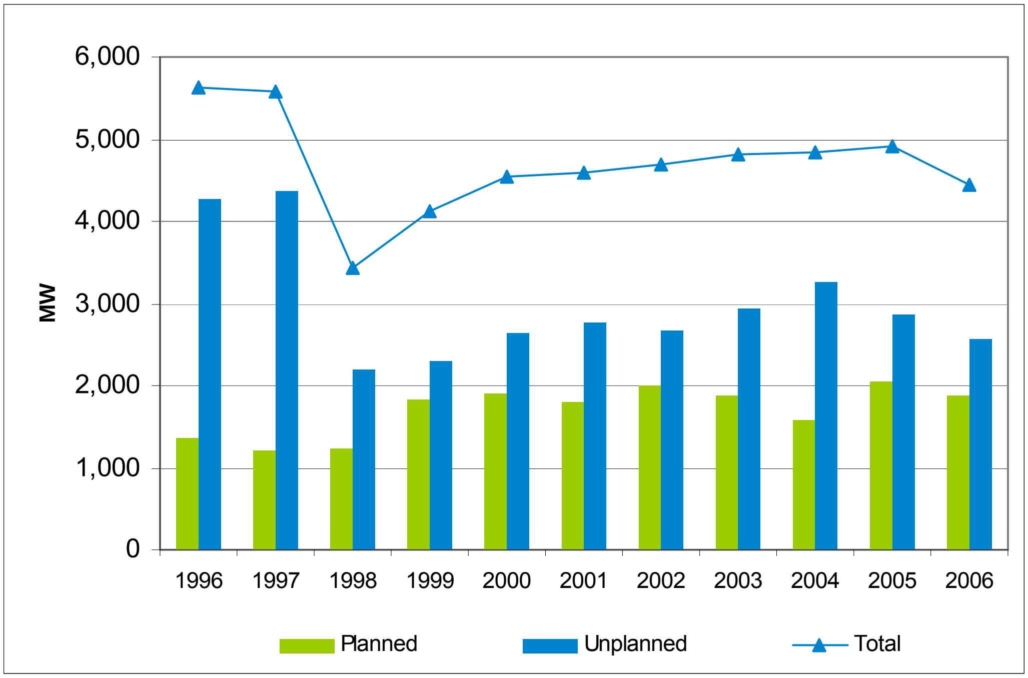

Figure 5-11: Average megawatts of outage each weekday.

Each day, the ISO commits generators that will be on line for the next day. Commitment quantities are based on forecast electrical loads and expected levels of generator availability. Between the time of commitment and the next day's peak demand, some generators experience operational problems and are forced off line. The number of generators reporting these problems has decreased since the introduction of a financial day-ahead market. Figure 5-12 shows that the loss of overnight capacity decreased significantly with the advent of the SMD's financially binding day-ahead market. For the Interim Market period, the plot compares the generator commitments made at 6:00 p.m. with the actual real-time availability of the committed generators. For SMD, the plot compares commitments in place at 10:00 p.m. (resulting from Day-Ahead Energy Market commitments as well as supplemental commitments made as part of the Reserve Adequacy Analysis) with the actual real-time availability of the committed generators. Because overnight capacity loss has decreased, fewer replacement commitments are required to address this reliability need. Lower levels of overnight capacity loss and generator outages are beneficial because they reduce the cost of committing additional generators each day to ensure that sufficient levels of generation will be available if some of the committed generators are lost as a result of forced outages.

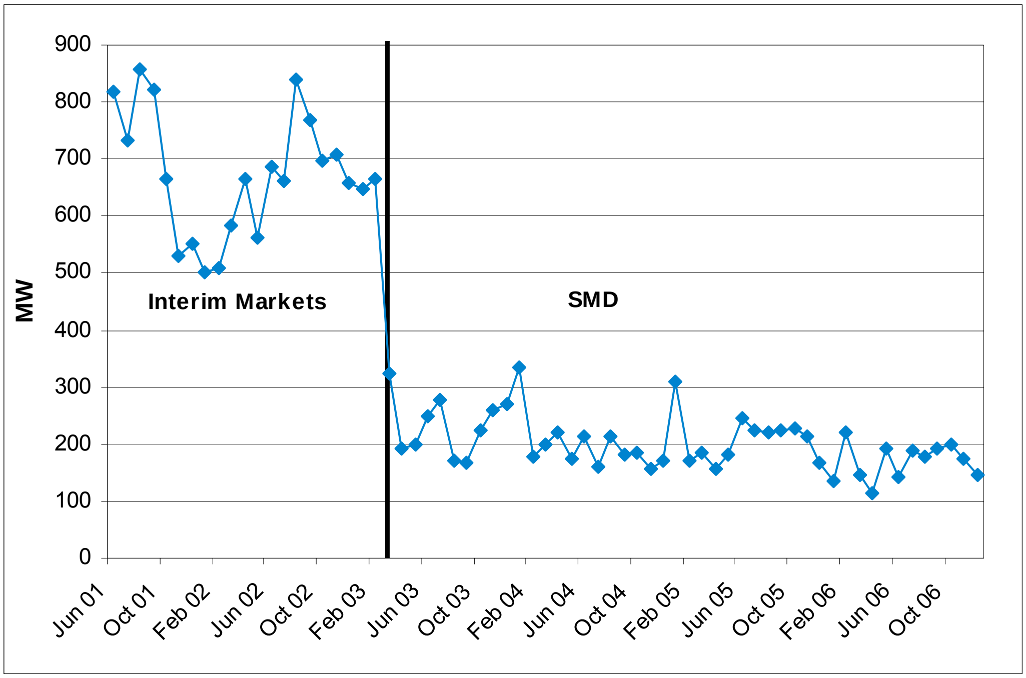

Figure 5-12: Average monthly overnight capacity loss.

Section 6
ISO Operations

This section highlights the enhancements to the markets and ISO operations, audit activities during 2006, the Quality Management System (QMS), and administrative price revisions.

6.1 Audits

The ISO participated in several audits during 2006. The following audits were conducted to ensure that the ISO had followed the approved market rules and procedures and to provide transparency to New England stakeholders:

- **SAS 70 Type 2 Audit—**In October 2006, the ISO successfully passed a SAS 70 Type 2 Audit, which resulted in an "unqualified opinion" about the design and operating effectiveness of controls.[145] Developed by the American Institute of Certified Public Accountants, the SAS 70 Audit is used by service organizations, such as Regional Transmission Organizations, to provide assurance to the wholesale electricity marketplace regarding the validity and integrity of controls and systems used in the "bid-to-bill" business processes.

  The ISO's SAS 70 Type 2 Audit is a rigorous and detailed examination of the business processes and information technology used for activities related to bidding into the market, accounting, billing, and settling the market products of energy, regulation, transmission, capacity, and reserves. Conducted by the auditing firm PricewaterhouseCoopers LLP, the Type 2 Audit covered a 12-month period, from October 1, 2005, through September 30, 2006. The SAS 70 Type 2 Audit includes the auditor's opinion on the effectiveness of controls tested and the fairness of the description of the controls contained in the audit report prepared by the ISO and whether the controls were suitably designed to achieve specified controls objectives. The ISO conducts SAS 70 Type 2 Audits annually.[146]

- **Reviews of the Ancillary Services Markets Project Phase II—**The ISO elected to conduct an internal audit of Phase II of the Ancillary Services Markets project. This audit assessed the systems development process, application test planning and results, the development of business and related controls procedures, and the production migration process. New procedures in the Market Administration and Settlements areas were also reviewed before the implementation of ASM II.

- **Market-System Software Recertification—**Before the implementation of SMD in 2003, all market-system clearing engines were certified by an outside consultant, PA Consulting. The ISO underwent a similar certification in 2004, early 2005, and 2006 related to ASM II implementation. PA Consulting issued a compliance certificate for each SMD module it audited

[145] A SAS 70, *unqualified audit opinion* is issued when three conditions are met: the audit firm determines that the description of the controls in the ISO audit report (see footnote below) fairly represents the relevant aspects of the service organization's controls; the overall design of the controls is sufficient to meet the specified control objectives; and the firm has collected and evaluated sufficient competent evidence through applied tests to specific controls and determines that the controls are operating with sufficient effectiveness to provide reasonable assurance that the control objectives were achieved during the test period.

[146] PricewaterhouseCoopers. *Report on Controls Placed in Operation Pertaining to the Market Administration and Settlements Processes and Systems of ISO New England Inc. and Tests of Operating Effectiveness for the Period October 1, 2005 to September 30, 2006, Prepared Pursuant to Statement on Auditing Standards No. 70, as Amended*. October 27, 2006. This report is available to participants on request through the ISO external Web site. See http://www.iso-ne.com/aboutiso/audit_rpts/2006/index and html http://www.iso-ne.com/aboutiso/audit_rpts/SAS70Request.do.

after conducting detailed tests and analyses of the applicable mathematical formulations. The certificates provide assurance that the software is operating as intended and is consistent with Market Rule 1 and associated manuals.

In 2006, PA Consulting issued the following certifications related to the implementation of ASM II:

- Locational Forward Reserve, issued June 20, 2006
- Locational Marginal Price Calculator, issued October 10, 2006
- Scheduling, Pricing and Dispatch—Unit Dispatch System, issued October 10, 2006
- Scheduling, Pricing and Dispatch—Day Ahead Market, issued October 10, 2006

PA Consulting also issued the following certifications in 2006 related to the Winter Readiness Release:

- Locational Marginal Price Calculator, issued December 15, 2006
- Scheduling, Pricing and Dispatch—Unit Dispatch System, issued December 15, 2006

All certificates are available to participants on request through the ISO external Web site.[147]

6.2 Quality Management System

As part of its commitment to efficient markets and reliability, the ISO has implemented a Quality Management System based on the internationally recognized quality standard, ISO 9001:2000.[148] The QMS encompasses ISO initiatives and process improvements that enhance the ISO's ability to run efficient markets, ensure that operations conform to the approved market rules, and provide increased transparency to market participants. These characteristics are essential for the New England electricity markets. Such efforts are especially important given the complexity of electricity markets and electricity market operations.

In 2006, several important continual improvement projects were successfully implemented as part of the ISO's ongoing Operational Excellence program. The newly developed causal analysis process serves to complement the corrective and preventive action program known as *CAPA*. This new process has contributed to more effectively resolving identified issues. In addition, ISO senior management periodically assesses QMS effectiveness through a formal management review process that was institutionalized during the year.

6.3 Administrative Price Corrections

The ISO continually monitors the processes for calculating locational marginal prices. The ISO takes actions to ensure that the resulting day-ahead and real-time LMPs are as accurate as reasonably possible. Price corrections are made in the event of a data error, a software program limitation or error, or a hardware or software outage. Generally, these corrections affect LMPs at only a few

[147] See http://www.iso-ne.com/aboutiso/audit_rpts/2006/index.

[148] International Organization for Standardization, Geneva, Switzerland. Information about the standard is available online at http://www.iso.org/iso/en/aboutiso/introduction/index.html.

individual price nodes or for a limited number of five-minute intervals and do not significantly change the hourly LMPs at the Hub or load zones. In total, corrections to LMPs were required in 190 hours (2.2%) during 2006 down from 293 hours in 2005.

Price corrections at inactive (*dead)* buses accounted for price changes in 94 hours in 2006. A *dead bus* results when a bus becomes islanded for a period of time, typically because of a transmission system outage or routine switching and tagging. These buses are not associated with any load, and therefore the prices at those nodes do not have an impact on zonal prices or the Hub price. The ISO's pricing software includes dead-bus logic to assign a price from the nearest active bus to the dead bus. However, at times, because of the limitation of the automated dead-bus logic, the software is unable to find a suitable active node to map to the dead bus. This results in an incorrect price of $0. When this occurs, the ISO manually maps and assigns the correct price to the dead-bus price node. The ISO is working to improve the dead-bus logic and reduce the need to make this type of price correction.

In 2006, price corrections to five-minute LMPs were required in 81 hours because of data errors or software limitations. The LMP calculator runs every five minutes and requires information from an approved unit dispatch system (UDS) case for the five-minute period in question. If the required UDS case has not been approved before the scheduled execution of the LMP calculator, a mismatch of data can occur, resulting in an incorrectly calculated LMP for that five-minute interval. This problem typically occurs for one of two reasons. One reason is that the status of a constraint changes between the time when the UDS case accesses data and when the LMP calculator produces results for the five-minute period. The other reason is that the data sent to the LMP calculator may not reflect the actual constraints because a UDS case was not properly approved or does not fully reflect actual system conditions for the applicable five-minute periods. This issue typically affects only one five-minute interval and therefore has a minor impact on the hourly integrated LMPs.

In 2006, scheduled system maintenance required price corrections in two hours, while unplanned outages resulted in price corrections in 13 hours. Corrections to hourly prices are required when hardware or software systems are unavailable. Systems can be unavailable for brief periods when switching from primary to backup systems to conduct routine maintenance and for periods of unplanned outages resulting from hardware or software failures. When this happens, the ISO manually calculates prices for the missing data intervals.

The ISO also continuously monitors the processes for calculating regulation clearing prices (RCPs). In total, price corrections to RCPs were required in 22 hours during 2006, which is 0.3% of the hours in the year. Data errors resulted in RCP corrections in nine hours, scheduled system maintenance required RCP corrections in seven hours, and unscheduled maintenance resulted in RCP corrections in six hours.

Section 7
Conclusions

During 2006, the wholesale electricity markets in New England performed well and recovered from the extreme events in 2005. Data from the *2006 Annual Markets Report* clearly demonstrate the extent of this recovery; electric energy prices in 2006 were 5% lower than those in 2005 when the cost of fuel is accounted for and 21% lower when comparing actual wholesale electric energy prices. This decrease was the result of the competitive market's effective response to lower natural gas prices and lower average demand for electricity.

Further, the wholesale electricity markets continued to support reliable operations throughout 2006, despite operational challenges. These challenges included tight system conditions during three days of record-breaking demand in the summer, as well as an event in which coincident outages of key transmission and generation facilities occurred. In all cases, bulk system reliability was maintained throughout New England.

Key to the reliable operation of the system was the noteworthy growth of the ISO's demand-response programs. Summer-period enrollments increased 47%, from 460 MW in 2005 to 675 MW in 2006. This increase proved critical to system reliability in the summer of 2006 when these programs were called on to relieve strain on the bulk power grid. In one example, a maximum of 625 MW responded on August 2, which helped to maintain system reliability. High levels of generator availability continued to be important to reliable system operation, increasing nearly 10%—from 81% in 2000 to 89% in 2006—in response to market incentives.

The ISO's continued improvements to New England's wholesale electricity markets brought the region closer to the ultimate goal of establishing a complete wholesale electricity market structure that facilitates full participation by demand resources and encourages infrastructure investment. In November 2006, revisions to the Regulation Market were filed with FERC and ultimately implemented by the ISO on January 12, 2007. Phase II of the Ancillary Services Markets project, implemented on October 1, 2006, brought significant improvements to the New England reserve markets. In addition, in March 2006 and with numerous parties, the ISO filed a settlement agreement at FERC to establish a Forward Capacity Market that replaces the original Installed Capacity Market.

Future enhancements will achieve even greater results by more fully incorporating demand participation in the markets and stimulating efficient infrastructure investment. The ISO will continue its work with state and federal agencies and other stakeholders to devise and implement initiatives that improve the long-run performance of the New England electricity markets.

Appendix A
Electricity Market Statistics

This statistical appendix presents information and data about the New England electricity markets in more detail than in the body of the report.

A.1 Percentage of Day-Ahead Compared with Real-Time Load Obligation

Table A-1 presents statistics on the percentage of real-time load obligation cleared in the Day-Ahead Energy Market for 2006, by zone and overall. The overall category compares total system day-ahead to total system real-time load obligations, not accounting for zonal distinctions.

Table A-1
Percentage of Real-Time Load Obligation Cleared in the Day-Ahead Energy Market, 2006

Zone	Average	Minimum	Maximum	Std. Dev.
Overall	96	88	107	3
Maine	95	82	108	3
New Hampshire	96	51	113	5
Vermont	86%	50	109	14
Connecticut	96	82	111	4
Rhode Island	101	78	126	7
SEMA	96	77	110	5
WCMA	100	84	117	5
NEMA	95	85	115	6

A.2 Electric Energy Prices

Tables A-2 to A-5 show 2006 LMP summary statistics for on- and off-peak hours and the monthly average day-ahead and real-time locational marginal prices by zone. On-peak hours are all hours between 7:00 a.m. and 11:00 p.m. during weekdays that are not NERC holidays. All other hours are off-peak hours.

Table A-2
LMP Summary Statistics, On-Peak Hours, January to December 2006

Location	Avg. Day-Ahead LMP ($/MWh)	Avg. Real-Time LMP ($/MWh)	Min. Day-Ahead LMP ($/MWh)	Min. Real-Time LMP ($/MWh)	Max. Day-Ahead LMP ($/MWh)	Max. Real-Time LMP ($/MWh)
Internal Hub Load Zone	69.41	68.51	33.22	13.11	217.43	1,015.86
Maine Load Zone	64.54	63.75	33.24	12.38	191.46	918.87
New Hampshire Load Zone	67.16	67.16	33.60	12.70	214.25	995.74
Vermont Load Zone	70.00	69.37	34.22	13.09	222.66	1,001.11
Connecticut Load Zone	79.52	76.52	33.88	16.25	311.50	1,057.08
Rhode Island Load Zone	66.87	66.08	32.09	12.81	214.72	997.77
SEMA Load Zone	67.45	66.38	32.18	12.79	216.73	1,004.34
WCMA Load Zone	69.82	69.07	33.45	13.18	218.84	1,015.94
NEMA Load Zone	69.41	70.81	33.07	12.79	247.50	1,203.91
NB–NE External Node	61.76	59.29	2.95	11.07	170.18	771.69
NY–NE AC External Node	70.25	69.27	28.46	13.05	220.95	981.28
HQ Phase I/II External Node	66.10	65.07	32.63	12.33	228.90	967.34
Highgate External Node	65.94	64.67	33.38	11.75	211.34	935.17
Cross-Sound Cable External Node	74.90	72.50	33.82	13.75	222.03	1,006.42

Table A-3
LMP Summary Statistics, Off-Peak Hours, January to December 2006

Location	Avg. Day-Ahead LMP ($/MWh)	Avg. Real-Time LMP ($/MWh)	Min. Day-Ahead LMP ($/MWh)	Min. Real-Time LMP ($/MWh)	Max. Day-Ahead LMP ($/MWh)	Max. Real-Time LMP ($/MWh)
Internal Hub	53.48	51.93	22.02	0.00	120.66	244.24
Maine Load Zone	50.63	49.35	22.03	−2.85	116.40	235.62
New Hampshire Load Zone	52.26	50.70	22.27	0.00	118.44	238.96
Vermont Load Zone	53.56	52.03	22.67	0.00	119.91	248.27
Connecticut Load Zone	56.52	53.99	22.05	0.00	211.17	245.37
Rhode Island Load Zone	52.28	51.01	21.27	0.00	118.27	238.23
SEMA Load Zone	52.50	50.99	21.33	0.00	118.40	239.94
WCMA Load Zone	53.72	52.09	22.17	0.00	121.01	245.34
NEMA Load Zone	52.84	51.32	21.91	0.00	158.49	238.36
NB–NE External Node	48.87	47.40	0.00	−3.79	112.29	226.22
NY–NE AC External Node	53.48	51.82	22.16	0.00	118.76	260.73
HQ Phase I/II External Node	51.62	50.46	21.63	0.00	117.01	233.08
Highgate External Node	50.73	49.93	21.81	0.00	112.82	236.52
Cross-Sound Cable External Node	55.28	52.88	22.02	0.00	212.86	231.47

Table A-4
Monthly Average Day-Ahead LMPs by Zone, 2006

Month	Hub	Maine	NH	VT	CT	RI	SEMA	WCMA	NEMA
Jan	74.36	69.99	71.53	74.74	78.31	71.57	71.70	74.62	71.53
Feb	70.74	65.89	67.90	71.06	74.39	68.23	68.37	71.07	68.08
Mar	60.55	57.91	58.68	60.46	63.55	59.26	59.52	60.73	59.07
Apr	60.88	58.75	59.56	60.84	61.98	60.06	59.95	61.04	59.89
May	56.34	53.43	55.68	56.27	62.45	55.14	55.48	56.53	57.76
Jun	58.41	53.90	56.39	57.77	67.86	56.24	56.51	58.66	63.56
Jul	63.38	58.91	62.16	64.49	78.41	61.28	61.32	63.89	65.49
Aug	67.23	61.16	64.99	68.69	80.81	64.83	64.69	67.76	65.33
Sep	45.41	43.71	45.07	46.45	51.32	44.16	44.43	45.70	47.03
Oct	53.65	50.24	52.32	53.12	61.79	52.03	51.95	54.09	52.63
Nov	64.02	59.37	61.99	64.21	67.36	61.53	62.18	64.33	62.31
Dec	56.65	52.74	54.86	57.30	59.08	55.27	58.19	57.03	54.81

Table A-5
Monthly Average Real-Time LMPs by Zone, 2006

Month	Hub	Maine	NH	VT	CT	RI	SEMA	WCMA	NEMA
Jan	70.25	66.26	67.58	70.31	73.02	67.80	67.99	70.41	67.76
Feb	65.56	62.27	63.75	65.36	66.89	64.08	64.27	65.72	64.00
Mar	62.84	60.56	61.14	62.54	63.71	61.81	62.14	62.98	61.61
Apr	62.33	59.76	60.89	62.07	62.66	61.57	61.18	62.47	61.27
May	56.05	53.81	55.54	56.02	59.53	54.84	55.34	56.50	66.63
Jun	53.67	50.10	53.41	54.29	61.17	52.08	52.38	54.15	57.25
Jul	57.58	52.91	57.38	59.65	71.86	55.01	55.12	58.31	59.06
Aug	70.12	62.30	67.05	72.03	83.75	67.49	66.79	70.95	68.67
Sep	45.68	43.72	45.69	47.49	51.85	44.20	44.34	45.98	48.87
Oct	54.33	50.87	53.47	54.45	59.26	52.26	52.26	54.50	54.22
Nov	62.20	58.10	60.68	61.90	63.28	60.94	61.38	62.41	61.39
Dec	55.68	52.53	54.30	55.60	56.94	54.75	55.19	56.05	54.38

A.3 Average Electric Energy Prices for ISO New England, NYISO, and PJM, 2006

Table A-6 shows yearly average system prices for ISO New England, NYISO, and PJM.

Table A-6
ISO New England, NYISO, and PJM Average Electric Energy Prices, 2006, $/MWh

Control Area	Day Ahead			Real Time		
	All	On Peak	Off Peak	All	On Peak	Off Peak
ISO New England	61.80	71.04	53.44	60.48	70.12	51.75
NYISO	65.70	77.92	54.63	64.94	79.23	52.09
PJM	48.10	58.86	38.36	49.27	60.69	38.94

A.4 Description of All-In-Cost Metric Components

Daily Reliability Payments: From May 1, 1999, to June 30, 2001, daily reliability included energy uplift and congestion uplift. Payments for VAR (voltage ampere reactive) control were included in congestion uplift. From July 1, 2001, to February 28, 2003, daily reliability included economic Net Commitment-Period Compensation and noneconomic NCPC. Payments for VAR control were included in noneconomic NCPC. From March 1, 2003, to December 31, 2006, daily reliability included first-contingency NCPC and second-contingency NCPC and voltage and distribution reliability payments. See Section 4.1.3 for additional information on NCPC.

Ancillary Services: From May 1, 1999, to February 28, 2003, ancillary services included payments for automatic generation control (AGC), 10-minute spinning reserves, 10-minute nonspinning reserves, and 30-minute reserves. From March 1, 2003, to December 31, 2003, ancillary services included Regulation Market payments. From January 1, 2004, to December 31, 2006, ancillary services included Regulation Market and Forward Reserve Market payments.

Capacity: From May 1, 1999, to November 30, 2006, capacity included payments to resources in the ICAP markets. This does not include payments from the bilateral markets or payments associated with self-supplied installed capacity. From December 1, 2006, to December 31, 2006, capacity included Forward Capacity Market transition payments.

Appendix B
Other Tariff Charges, Minimum Generation Emergency Events, and the Congestion Revenue-Balancing Fund

Appendix B provides supplemental cost components of the ISO *Self-Funding Tariff* and the *Open Access Transmission Tariff*, minimum generation emergency events, and the Congestion Revenue-Balancing Fund.

B.1 Other Tariff Charges

In 2006, participants paid for administrative and transmission services under the ISO *Self-Funding Tariff* and the *Open Access Transmission Tariff* (both of which are part of the Transmission Tariff).

The ISO *Self-Funding Tariff* contains rates, charges, terms, and conditions for the functions the ISO carries out. These services are as follows:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**scheduling and administering the movement of power through, out of, or within the control area

- **Schedule 2: Energy Administration Service (EAS)—**charges for services the ISO provides to administer the energy markets

- **Schedule 3: Reliability Administration Service (RAS)—**charges for services the ISO provides to administer the reliability markets

Total payments under each ISO schedule are shown in Table B-1.

Table B-1
ISO *Self-Funding Tariff* Charges

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2006 Total	$20,619,125	$60,185,003	$28,273,126

Transmission services were paid for under the OATT. These services are as follows:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**involves scheduling and administering the movement of power through, out of, or within the New England Control Area.

- **Schedule 2: Reactive Supply and Voltage Control (VAR)—**provides reactive power to maintain transmission voltages within acceptable ranges. Schedule 2 also includes calculations for capacity costs (CC).

- **Schedule 8: Through or Out Service (TOUT)—**includes transactions that go through the New England Control Area or originate on a Pool Transmission Facility (PTF) and flow over the PTF before passing out of the New England Control Area. Transmission customers pay the PTF rate for TOUT service reserved for it with respect to these transactions.

- **Schedule 9: Regional Network Service (RNS)—**is an ISO accounting service for regional network services. RNS allows network customers to efficiently and economically use their resources, internal bilateral transactions, and external transactions to serve their network load located in the New England area.

- **Schedule 16: System Restoration and Planning Service (Black Start)—**plans for and maintains adequate capability for the restoration of the New England Control Area following a blackout.

- **Schedule 19: Special-Constraint Resource (SCR) Service of the *Open Access Transmission Tariff* —**includes the payments and charges for the out-of-merit commitment or operation of resources at the request of transmission owners or distribution companies to manage constraints not reflected in the ISO systems.

Total payments under each OATT schedule are shown in Table B-2.

Table B-2
OATT Charges

Date	Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2006 Total	$21,929,682	$12,057,097	$19,201,863	$2,769,640	$481,239,331	$9,091,921	$8,397,047

B.2 Transmission Congestion Revenue Fund

Table B-3 shows details about the accounting for the Transmission Congestion Revenue Fund.

Table B-3
Details of the 2006 Transmission Congestion Revenue Fund, $

Fund Adjustments	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation (paid in by participants)	Positive Target Allocation (paid out to participants)	Amount Paid Out to Positive Allocations	Monthly Fund Surplus or Shortfall	Interest	Ending Balance	Cumulative Balance for Year End	Percent Positive Allocations Paid
159,691	8,482,947	(45,654)	3,859,347	(13,206,535)	(12,456,331)	(750,204)	0	0	0	94%
24,600	6,426,191	42,568	4,093,738	(9,792,448)	(9,792,448)	794,650	20,140	814,790	814,790	100%
115,379	3,900,694	52,409	3,553,199	(7,346,818)	(7,346,818)	274,863	15,264	290,127	1,104,917	100%
277,684	2,477,238	(13,436)	804,468	(2,846,401)	(2,846,401)	699,553	11,443	710,995	1,815,912	100%
54,934	18,191,348	5,064,030	3,569,219	(22,826,059)	(22,826,059)	4,053,473	14,946	4,068,418	5,884,331	100%
34,933	28,873,231	652,375	5,628,188	(35,180,417)	(35,180,417)	8,310	24,692	33,002	5,917,332	100%
1,764	45,230,102	(4,296,732)	4,052,640	(39,039,485)	(39,039,485)	5,948,288	66,127	6,014,415	11,931,748	100%
(8)	39,612,396	(1,111,819)	4,146,669	(36,792,136)	(36,792,136)	5,855,101	142,158	5,997,259	17,929,007	100%
52,231	13,816,202	(4,434,297)	3,272,974	(17,720,938)	(12,707,110)	(5,013,828)	73,697	(4,940,132)	18,002,703	72%
53,434	12,862,599	(3,031,332)	6,670,916	(17,945,792)	(16,555,617)	(1,390,175)	77,467	(1,312,708)	18,080,171	92%
38,006	5,640,217	(782,076)	5,689,557	(10,785,854)	(10,585,704)	(200,150)	75,224	(124,926)	18,155,394	98%
9,972	6,906,105	(4,897,001)	4,789,755	(11,671,987)	(6,808,831)	(4,863,155)	96,006	(4,767,149)	18,251,400	58%