2005 Annual Markets Report

ISO New England Inc.

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Section 1
Executive Summary

ISO New England (ISO) is the not-for-profit corporation responsible for the reliable operation of New England's bulk power generation and transmission system. The ISO also administers the region's wholesale electricity markets and manages the comprehensive regional bulk power system planning process.

Each year, the ISO reports on New England's wholesale electricity markets in its *Annual Markets Report*. In assessing the performance of the markets, it is essential to understand that electricity markets respond to the dynamic forces in the regional and national economy and that complex interactions take place among the markets and changing external factors, especially rising fuel costs.[1] An efficient market should produce competitive prices that reflect the underlying supply and demand conditions, support reliable operations, and induce appropriate levels and types of investment to ensure reliability and lowest-cost operation in the long term.

In 2005, the New England wholesale electricity market completed the second full year of operation under Standard Market Design (SMD).[2] New England experienced high fuel costs throughout 2005, particularly in January and in the fall. It also experienced high demand, a record peak hourly load, and stressed energy infrastructure. The wholesale electricity markets met these challenges and continued to perform well during the year. Also in 2005, the ISO made a number of market improvements consistent with the goal of providing a reliable electric power system and competitive and efficient wholesale markets. This summary highlights the state of New England's wholesale electricity markets, the 2005 results and performance of the markets, market improvements made during the year to support system reliability and induce appropriate investment, and recommendations for further improvements.

1.1 State of the Market

The key factors that influence the market price for electricity are supply and demand. Supply is influenced by the cost of fuels used to generate electricity and by transmission constraints. New England's electricity consumption (demand) is driven by economic growth and weather. In 2005, the New England wholesale electricity market continued to be competitive, responding to the changing conditions of supply and demand.

1.1.1 2005 Electricity Prices

Analyses show that electricity prices were consistent with those expected in a competitive market.[3] On average, prices were higher in 2005 than in 2004. Figure 1-1 shows electric energy prices over the six-year period from 2000 to 2005, on both a nominal and a fuel-adjusted basis. As shown in the

[1] From 2000 to 2005, the average price of natural gas increased from about $5/million British thermal units (MMBtu) to $9.75/MMBtu, and the price for No. 6 fuel oil increased from $4/MMBtu to $6.70/MMBtu.

[2] The New England wholesale electricity market was implemented on May 1, 1999, as a single real-time market with a regionwide energy price. The period of May 1999 to February 2003 is referred to as the "Interim Market" period in this report. On March 1, 2003, the Standard Market Design was implemented, replacing the Interim Market. SMD is an energy-market structure that incorporates locational marginal pricing, multiple settlements in the Day-Ahead and Real-Time Energy Markets, and risk management tools to hedge against the impacts of higher differentials in locational marginal prices (LMPs) when transmission congestion occurs.

[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.

figure, the 2005 average actual real-time Hub price of $79.96 per megawatt-hour (MWh) is 47% higher than the 2004 price.[4] After adjusting for fuel costs, electricity prices have remained fairly stable since 2000. The 2005 fuel-adjusted electricity price is still lower than the 2000 price, as shown in the figure.[5]

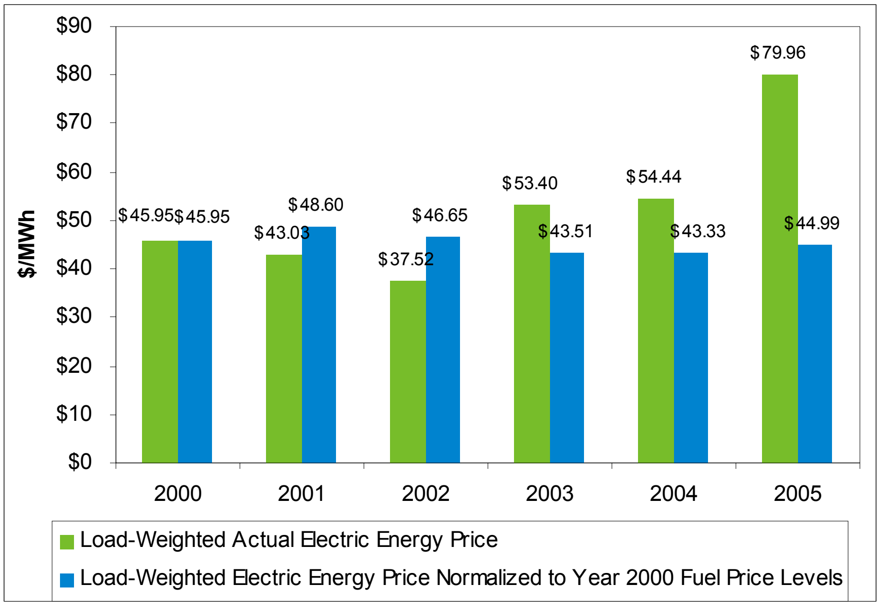

Figure 1-1: Actual and fuel-adjusted average real-time electric energy prices at the Hub, 2000–2005.

1.1.2 Factors Affecting the Price of Electricity

On the supply side, the higher price for electricity in 2005 was driven by the high cost of fuels, particularly natural gas. New England's real-time electricity prices are most often set by generating resources fueled by natural gas and oil and largely driven by the prices for these fuels. In 2005, units burning gas or oil set wholesale electricity prices 87% of the time. From 2004 to 2005, natural gas prices increased by 44%. The region's dependence on gas and oil to generate electricity contributes to the volatility of the region's electricity price.

The 2005 fuel-adjusted electricity price is 4% greater than the 2004 price. This increase is attributable to an increased demand for electricity, especially during the peak hours, and the resultant increase in transmission congestion.[6] In New England, peak electricity consumption has been growing faster than average consumption, influenced by economic growth and weather—the use of air conditioning has risen over time as New England's economy has expanded. These consumption trends cause the need for the capacity of the bulk power system to supply the peaks to grow faster than the need for capacity to meet average load levels, putting additional upward pressure on the electricity price. Consumers,

[4] The Hub is a collection of pricing nodes (pnodes) for which the ISO calculates and publishes prices. The Hub price is intended to represent an uncongested energy price.

[5] The fuel-adjusted model price normalizes electric energy prices for each year to the year 2000 fuel prices. Actual system electric energy prices in PJM Interconnection (PJM) and the New York ISO (NYISO) showed similar year-to-year changes due to varying fuel costs.

[6] A statistical analysis (see Section 3.1.4.3) indicates a strong relationship between electricity prices and both the demand for electricity and the price of fuels.

however, generally do not face retail prices that reflect these higher hourly wholesale prices. The disconnect between the wholesale and retail markets results in highly inelastic wholesale demand. The inefficient allocation resulting from inelastic consumer demand is a significant challenge for the region in controlling electricity costs.[7]

In 2005, the high loads and transmission constraints led to more frequent price separation among the eight New England load zones.[8] These congestion costs further translated to higher electricity prices in import-constrained load zones.

To illustrate how electricity prices respond to changing market conditions, Figure 1-2 shows the daily supply offers and daily peak demand for the peak days of August 30, 2004, and July 27, 2005.[9] The intersection of each supply curve with the corresponding peak demand provides two simulated market-clearing prices. The figure illustrates the impact that changes in supply and demand have on prices. As shown, the simulated hourly electricity price on July 27, 2005, is $226/MWh, a large increase from the simulated August 30, 2004, price of $65/MWh. The figure shows that the year-to-year increase in the price of electricity is the product of both more expensive supply and increased demand.

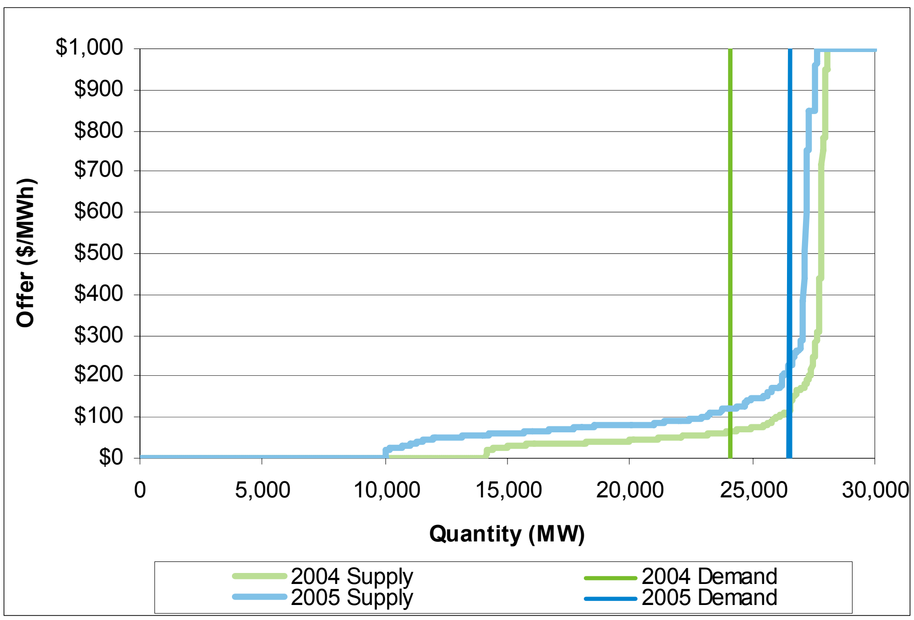

Figure 1-2: Simulated supply and demand balance and resulting impact on price, peak day, 2004 and 2005.

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

[8] New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeastern Massachusetts and Boston (NEMA), and Southeastern Massachusetts (SEMA). These load zones reflect the historical operating characteristics of, and the major transmission constraints on, the transmission system. Load zones are used in pricing electricity for purchase by load-serving entities (LSEs).

[9] The prices of $65/MWh on August 30, 2004, and $226/MWh on July 27, 2005, are the simple result of intersecting the load and supply curves for the peak hours of each year.

1.2 Market Performance and Improvements in 2005

The following is a review of the 2005 performance of the market. Also highlighted are improvements to the market design that support reliable system operations and induce appropriate levels of investment for ensuring long-term system reliability.

1.2.1 Support of Reliable System Operations

The New England wholesale electricity market supported reliable operations throughout 2005, despite significant operational challenges. These challenges included tight system capacity due to high loads during the summer months, fuel-price volatility during the winter months, and uncertainty about the availability of nonfirm gas for electricity generation.[10] System capacity was adequate to meet the record summer loads. The ISO managed several critical power system events related to tight system capacity and transmission contingencies by implementing Master/Local Control Center Procedure No. 2 (M/LCC 2), *Abnormal Conditions Alert*, and Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4) actions.[11] In all cases, the ISO operations staff maintained bulk system reliability throughout New England.

A unique market challenge in New England is to support reliable operations under severe winter conditions when the high demand for natural gas is driven by the coincident demand for heating and electricity generation. This has the potential to affect fuel availability for gas-fired generation units. In 2005, the ISO and its stakeholders applied lessons learned from previous cold snaps by improving operating procedures, increasing regional conservation and demand response, and increasing the amount of dual-fueled generating units in the region.[12] Market signals drove the increase in dual-fueled generation, which was the result of investment by market participants. These measures addressed the threat posed by potential severe winter weather combined with disruptions in the supply of natural gas from the Gulf of Mexico due to Hurricanes Katrina and Rita.

The ISO is committed to finding market solutions to reliability issues. However, reliability requirements continued to necessitate some out-of-market compensation of generation to ensure that adequate capacity remained available. This out-of-market compensation takes two forms.

First, Reliability Agreements, formerly called Reliability Must-Run (RMR) contracts, provide a mechanism for owners to recover fixed costs for generating capacity required to ensure reliability. The majority of the units with Reliability Agreements are in the import-constrained areas of Boston and Connecticut. However, following a Federal Energy Regulatory Commission (FERC) ruling in 2004 that effectively expanded the eligibility for these agreements, units outside of these areas began requesting these agreements during 2005.[13] The net cost of these agreements to wholesale purchasers of power was $240 million in 2005, up from $180 million in 2004. At the end of 2004, approximately 2,100 MW of capacity had Reliability Agreements; by the end of 2005, the capacity under Reliability Agreements had increased to 4,700 MW. Including all agreements effective or pending at FERC, the

[10] *Nonfirm* gas is gas delivered under contracts that include transportation service subject to interruption to avoid interfering with or restricting deliveries having a higher priority.

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

[12] Demand response in wholesale electricity markets refers to resources that reduce their electricity consumption in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale electricity prices.

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

total for 2006 is almost 7,000 MW. The increase in capacity seeking Reliability Agreements demonstrates the need for improvements to the capacity market.

Second, daily reliability costs, for first- and second-contingency and voltage and distribution requirements, totaled $287.5 million during 2005. This was up from $168.9 million in 2004. First-contingency payments are made to generators needed for systemwide reserves or electric energy. Second-contingency payments are made to generators needed to meet local reserve requirements.

Approximately 28% of this total was paid to two generators in Boston. The Boston area is import constrained, and only a limited number of generators can meet reliability requirements for voltage control and local second-contingency coverage. Beginning in late 2004, issues emerged related to the offer behavior of this generation. The generation was offered in a manner that avoided in-merit, market-based economic dispatch, and, instead, the ISO dispatched the generation through the Reserve Adequacy Analysis (RAA) process.[14] Because the generators were required for reliability and did not face significant competition, the participant was able to submit offers above the generators' marginal costs and still be committed. This caused the generators' market-mitigation reference levels, which were based on the few instances when their offers were accepted in merit, to be significantly above their marginal costs.

To address this issue, the ISO made a filing with FERC on April 1, 2005, to change Market Rule 1 by modifying the criteria used to determine when a generator is eligible for a market-based reference level rather than a marginal-cost-based reference level. The rule change was approved by FERC on May 6, 2005.[15] Under the revised criteria, the generators in question are assigned marginal-cost-based reference levels.

In 2004, the ISO developed an action plan to reduce daily reliability costs by upgrading the transmission system and improving the market rules. During 2005, the ISO and participants implemented this plan, conducting ongoing projects to improve the transmission system and implementing the market-rule change mentioned above. These changes began to reduce daily reliability costs in May 2005, and this trend has continued into 2006. In the long run, daily reliability costs are expected to decrease with the implementation of Phase II of the Ancillary Services Market project (ASM II) and the introduction of a forward-capacity market that should induce new entry in load pockets.[16] These costs should also decrease with the completion of major transmission upgrades in Boston and Connecticut.

1.2.2 Implementation of ASM I and the Regulation Market

The ISO implemented Phase I of the Ancillary Services Market (ASM I) project, which included the introduction of a new Regulation Market on October 1, 2005. The Regulation Market is the mechanism for selecting and paying generation needed to manage small changes in system electrical load. ASM I also included changes in the eligibility of dispatchable external energy transactions to set the electric energy price when these transactions are marginal. The re-offer period was also changed

[14] The ISO performs the RAA process at the close of the re-offer period (see Section 1.22) to ensure that adequate resources are committed to meet the ISO's forecasted load and operating-reserve requirements for the Real-Time Energy Market.

[15] For more information on this FERC order, *Order Accepting Tariff Amendments*, see http://www.iso-ne.com/regulatory/ferc/orders/2005/may/er05-767_5-6-05.doc.

[16] The Ancillary Services Market project is an upgrade to SMD that includes changes in reserve markets and the Regulation Market. See more below on ASM Phases I and II and the Regulation Market.

to allow all resources, including those that have cleared in the Day-Ahead Energy Market, to revise their energy supply offers during this period.[17]

The ASM I Regulation Market is satisfying the regulation requirements based on compliance with the control performance standard (CPS) of the Regulation Market. The transition to a new market design coincided with a period of relatively high gas prices, and, as in the electric energy market, costs in the Regulation Market are influenced by fuel costs and other supply conditions. While the ISO observed both market entry and exit during this period, some generators exited the Regulation Market for reasons unrelated to the market, contributing to an increase in the cost of regulation service. The ISO has observed both market entry and exit during the fourth quarter of 2005. Regulation Market costs declined during the first three months of 2006.

1.2.3 Planning and Investment

Total system generation capacity did not change significantly during 2005, with approximately equal amounts of new generation added and existing generation retired. Since generation capacity was adequate to meet the demand, this level of investment was not a cause for immediate concern. However, ISO analyses indicate that the continued growth in demand, compounded by steadily declining load factors, may necessitate that emergency actions be taken to meet peak demand in the 2007 to 2009 timeframe, unless additional generation capacity or demand-response resources become available.[18]

Significant transmission investment activity occurred in 2005, with several important projects underway. These include projects to alleviate congestion within Connecticut and into Boston, as well as projects in northern Vermont, southwestern Rhode Island, and New Hampshire. These transmission projects are required to maintain reliability and will reduce reliability costs.

1.2.4 Other Market Improvements

The ISO worked with its stakeholders during 2005 to improve the New England market rules. The FERC approved two market-rule changes recommended by the ISO's Internal Market Monitoring Unit (INTMMU) in consultation with the Independent Market Monitoring Unit (IMMU). The first change was designed to prevent participants that own generators that do not often run in merit from inappropriately raising market-mitigation reference levels.[19] The second change revised the method for allocating costs associated with real-time second-contingency commitments to more closely assign those costs to participants that cause those costs to be incurred. This change removed a disincentive for making virtual transactions that improve price convergence.[20]

1.3 Summary of 2005 Results

This *2005 Annual Markets Report* includes information about load and demand levels, market-clearing prices, competitive market conditions, and other topics. A summary of the major results follows, with references to the sections in which they are more fully discussed.

[17] After the Day-Ahead Energy Market clears, generators are able to re-offer uncommitted capacity to the market. Submitting a revised incremental energy supply offer during the re-offer period does not have any impact on the financially binding Day-Ahead Energy Market schedules.

[18] The load factor is the ratio of the average hourly load during a year to the peak hourly load. With the increase in air-conditioning use, peak load has been increasing relative to the average load, translating into lower load factors.

[19] FERC approved this rule change on May 6, 2005.

[20] FERC approved this rule change on March 1, 2005.

- **Price levels and fuel costs—**Electricity prices were consistent with those expected in a competitive market. Yearly average natural gas and fuel-oil prices were much higher in 2005 than in previous years, driving electricity prices higher. The average real-time electric energy price at the Hub, weighted by system load, was $79.96/MWh in 2005, whereas the price in 2004 was $54.44/MWh. Hurricanes Katrina and Rita were partly responsible for the rise in fuel prices. Record-breaking summer loads, along with strong growth in average loads, also contributed to higher electric energy prices. (Section 3.1.1.2 and Section 3.1.4.3)

- **Peak load and demand growth—**Growth in the annual actual demand for electricity was greater in 2005 than in the past few years, due largely to weather and regional economic conditions. New England weather in 2005 was marked by extremes, with temperatures that were well below normal during January and periods of very hot weather during the summer. A new record system-peak hourly load of 26,885 MW occurred on July 27, 2005, an increase of 1,537 MW (6%) from the previous record peak, set in August 2002.[21] New England net energy for load (NEL) totaled 136,375,000 MWh in 2005, an increase of 2.9% from 2004.[22] (Section 3.1.2)

- **System capacity growth—**Although the annual growth of peak demand was significant in 2005, the total seasonal system capacity was essentially constant from 2004 to 2005. The total 2005 system capacity for summer was 31,083 MW, and the total for winter was 33,861 MW. New capacity with a summer capability of 92 MW was added to the system in 2005; 81 MW were retired, for a net addition of 11 MW. (Section 3.1.3)

- **Imports and exports—**New England remained a net importer of power during 2005. New England was a net importer from Canada and a net exporter to New York. Import and export quantities both increased from 2004 to 2005, with a larger increase in imports. Net imports from neighboring regions amounted to 6,313,000 MWh for the year, representing 4.6% of the annual NEL in New England during 2005. (Section 3.1.3.6)

- **Day-ahead and real-time prices—**At the Hub during 2005, average day-ahead prices were 2.4% ($1.91/MWh) higher than average real-time prices for the year. In 2004, the difference was 3%. 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 zones was more pronounced in 2005 than in 2003 or 2004. This is consistent with increased peak demand and relatively constant infrastructure. Overall for the year, the difference between the highest average zonal locational marginal prices (LMPs) (those in Connecticut) and the lowest (those in Maine) was $12.33/MWh in the Day-Ahead Energy Market and $9.78/MWh in the Real-Time Energy Market. The differences were greatest during the summer months when high loads caused congestion in the import-constrained zones of Connecticut and NEMA. (Section 3.1.4.7)

- **Actions during capacity deficiencies—**High demand for electricity, along with other events, required the ISO to declare OP 4 on three days in 2005: July 27, August 13, and October 25. On July 27 and August 13, OP 4 was declared due to an increased demand caused by

[21] The temperature at the time of the 2005 peak was 91° Fahrenheit with a dew point of 72°.

[22] *Net energy for load* is the net generation output within an electric power system control area, accounting for energy imports from other areas and subtracting energy exports to others. It includes system losses but excludes the electricity required to operate pumped-storage hydro generators.

extremely hot and humid weather, while on October 25, the cause for OP 4 was the contingency loss of generation and import capacity. On July 27, the day of the record hourly peak system load, OP 4 was declared in Southwest Connecticut only. On October 25, the ISO declared a Reserve-Shortage-Condition Pricing Event, resulting in hourly prices of over $800/MWh throughout the system.[23] (Section 3.1.6)

- **Forward Reserve Market—**The Forward Reserve Market (FRM) buys 10-minute nonsynchronized (nonspinning) reserves (TMNSR) and 30-minute operating reserves (TMOR) from generating resources.[24] Payments to generators providing forward reserves during 2005 totaled about $61 million, while penalties for nonperformance totaled $1.2 million. Since the inception of the market in 2004, the total supply offered has increased, and the clearing price has fallen. Over this time, approximately 1,800 MW to 2,000 MW per auction have been cleared based on system requirements. During this period, FRM prices have declined steadily, from approximately $4.50/kW-Month for the first auction period of January to May 2004, to $2.00/kW-Month for the latest auction period of October 2005 to May 2006, due to increased supply. (Section 3.2)

- **Installed Capacity Market—**Prices for the portion of the Installed Capacity (ICAP) Market settled through the ISO were generally higher and had greater volatility during 2005 than during 2004, ranging from $0.70/kW-Month to zero. This is consistent with increased requirements and constant supply. Supply auction prices were greater than zero in all months except December. The deficiency auction had nonzero prices in half of the months of 2005, with prices increasing to $0.66/kW-Month in January. On average during 2005, 10% of the system capacity requirement was met through the supply and deficiency auctions. The rest was self-supplied (i.e., provided by participants from their own resources) or procured through bilateral contracts. In response to a FERC requirement, in March 2005, the ISO implemented new rules allowing a partial delisting; a single generating unit used this process to delist for four months.[25] (Section 3.3)

- **Regulation Market—**The Regulation Market clearing price averaged $30.22/MWh in 2005. Payments made to generators providing regulation service totaled $69.5 million, including $15 million in real-time opportunity-cost payments. (Section 3.4)

- **Reliability commitments—**To maintain the reliability of the power system, the ISO must at times commit generation to supplement the market-clearing process. Several factors contributed to relatively high levels of reliability commitments in 2005. These included hot summer weather and high loads that caused binding import constraints in Connecticut and Boston, the need for voltage control in Boston during the spring, and the lack of transmission infrastructure and flexible fast-start generators in Connecticut and the Boston area.[26] The

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[23] As defined in Manual M35, the ISO declares a Reserve-Shortage-Condition Pricing Event when the New England Control Area is experiencing a deficiency in total 10-minute operating reserves or a deficiency in operating reserves that has lasted more than four hours. For further information, see http://www.iso-ne.com/rules_proceds/isone_mnls/m_35_definitions_and_abbreviations_(revision_16)_04-07-06.doc.

[24] These generators can provide electricity to the system within 10 or 30 minutes in response to a contingency, even if they are not generating prior to the contingency.

[25] Delisting is the temporary removal of a generator from the ICAP Market. The lead participant of the delisted unit may then sell the unit's capacity in an external control area or simply avoid the obligations associated with an ICAP resource. Delisted units are exempt from the requirement to offer generation into the Day-Ahead Energy Market.

[26] Fast-start facilities are generators that can start up and synchronize to the system in less than 30 minutes to serve peak load or help with recovery from a contingency.

offer behavior of two generators in Boston also contributed to the volume of supplemental commitments. (Section 4.1)

- **Net Commitment-Period Compensation (NCPC)—**Payments to generators providing first-contingency or second-contingency operating reserves (reliability payments) totaled approximately $202 million in 2005 (in addition to energy market revenues), up significantly from the $91 million paid in 2004.[27] These payments were in addition to energy-market revenues. Most second-contingency payments were made to resources in Connecticut and Boston, with much of the increase due to the participant offer behavior in Boston noted above, which was resolved with a rule change. Transmission system improvements underway in Connecticut and Boston should reduce the need for second-contingency commitments in future years. As load increases and generators retire, payments may increase again, absent further infrastructure investment. (Section 4.2.1)

- **Voltage and distribution reliability payments—**Per the ISO's *Transmission, Markets, and Services Tariff* (Transmission Tariff), payments to generators providing voltage control and support and distribution system support totaled approximately $85 million in 2005 (in addition to energy-market revenues).[28] Most of these payments were made to generators providing voltage control in the Boston area. These voltage and distribution charges increased from $78 million in 2004; however, the addition of a new 160 megavolt-ampere reactive (MVAR) reactor at North Cambridge (outside Boston) helped to reduce the need for voltage commitments in the fall. Another reactor is scheduled for installation in spring 2006. (Section 4.2.2)

- **Reliability Agreements—**In the absence of a market that accurately reflects the value of capacity in constrained areas, capacity under Reliability Agreements has again increased in 2005. Following the FERC ruling in 2004 that effectively expanded the eligibility for these agreements, generating units outside of the historically constrained area of NEMA and Connecticut entered into Reliability Agreements in 2005. In the import-constrained areas, as of December 2005, 41% of the capacity in Connecticut was under a Reliability Agreement, while 32% of the capacity in NEMA was under a Reliability Agreement. Systemwide, 15% of capacity was under Reliability Agreements, with a total net cost to load of $240 million. Beginning in January 2006, the percentage of capacity in NEMA under these agreements increased to 71% with the addition of Mystic Units 8 and 9. Although Reliability Agreements are meant to ensure that generators deemed necessary for reliable system operation are able to recover their future fixed and variable operating costs, they do not send appropriate investment signals to potential new entrants. While these agreements have been accepted by FERC, they are intended as interim measures to ensure that generators needed for reliability are recovering adequate revenues until an appropriate market-based mechanism for capacity is implemented. (Section 4.4)

- **Financial Transmission Rights (FTRs)—**Market participants are able to buy financial instruments that help them hedge the price risk of day-ahead congestion caused by constraints

[27] Net Commitment-Period Compensation 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 (subject to limitations). 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.

[28] The tariff was effective as of February 1, 2005, and is available at http://www.iso-ne.com/regulatory/tariff/index.html.

on the transmission system. Any participant or nonparticipant that meets a financial assurance requirement can purchase FTRs, and some participants that do not have load, and therefore do not need to hedge the cost of congestion, purchase FTRs. FTRs were offered to the marketplace in 12 ISO-administered monthly auctions and one 12-month auction for 2005. Participation in the auctions was strong, and market participants purchased FTRs generally consistent with expected patterns of congestion. Beginning with the May 2005 auction, participants were allowed to submit negatively priced bids for FTRs. Because allowing negative bids encourages the purchase of counterflow FTRs, FTR capacity in the direction of typical flows has increased. Auction revenues from positively priced FTRs were approximately $143.8 million, while payments to participants that "bought" negatively priced counterbalancing FTRs were approximately $32 million. The FTR market worked as designed in 2005, and FTRs were an effective hedge against congestion: the net auction revenues of $107.2 million were much lower than the $268.8 million in positive congestion-cost offsets paid to FTR holders. (Section 4.6)

- **Demand response—**Demand response can help address short-run reliability problems by reducing supply needs. The Price-Response Program reduces market price spikes and volatility, providing a hedge against price risk, reducing the investment needed to meet peak load, and providing a link between wholesale and retail markets. The ISO implemented a new Day-Ahead Load-Response Program in 2005. As of September 1, 2005, 781 assets were under ISO demand-response program contracts, comprising over 472 MW of potential demand interruption or curtailment in any hour. During the year, the ISO's demand-response programs resulted in reducing energy consumption more than 66,215 MWh, with a total payment in New England of $8.1 million. This amount was in addition to $35.9 million in supplemental payments to participants in the ISO's Southwest Connecticut "Gap" request for proposals (RFP).[29] A total of 330 MW of additional demand-response resources were enrolled in the Winter Response Program, however, they were not activated in 2005. While the level of demand-response energy savings experienced in 2005 represents an improvement over the previous year, further enhancements are still necessary. More fully integrating demand response into the New England electricity markets will improve the long-run performance of the markets. (Section 4.7)

- **Market power mitigation—**The ISO monitors the market to ensure efficient and competitive market results. In specific circumstances, the Internal Market Monitoring Unit, in consultation with the Independent Market Monitoring Unit, may intervene in the market to mitigate behavior that exceeds clearly defined thresholds. During the year, market-mitigation authority was implemented 16 times. The primary intervention occurs when a participant does not adequately explain a supply offer that exceeds a conduct and market-impact threshold. The intervention is to substitute for the participant's supply offer one intended to represent a unit's marginal costs. (Section 5.1)

1.4 Planned Market Improvements

The ISO will continue to monitor the markets and recommend improvements to enhance the reliable and efficient operation of the region's electric power system. Two of the ISO's key recommendations

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

are summarized below. For a more detailed explanation of planned market improvements, refer to Section 3.2 and Section 3.3 and the ISO's *2006 Wholesale Market Plan*.[30]

1.4.1 Capacity Market

A well-designed capacity market is required to ensure long-term resource adequacy. This need was first identified in 2003. The most recent development has been the agreement among the majority of New England stakeholders on a forward-capacity market to replace the locational installed capacity market (LICAP) proposal.[31] This proposal is based on a forward auction the ISO will administer to procure resources for ensuring reliability. This should encourage investment in a variety of new resources, including new baseload power plants, fast-start facilities, alternative energy sources, and demand response.

1.4.2 Ancillary Services Market Phase II Projects

The second phase of the ASM project is scheduled for implementation in 2006. This phase is designed to induce investment in new generation and demand-response resources that can serve peak load. The market design includes a locational Forward Reserve Market and real-time reserve pricing. It also provides for demand-side participation in the energy and reserve markets.

1.5 Additional Issues Facing the Market

While the market continues to function well, a review of the results for 2005 shows two areas of concern that are not likely to be addressed by wholesale market design alone. The first is the declining load factor, related to the lack of linkage between retail prices and wholesale costs and the resultant need to invest in generation and transmission infrastructure needed for only a few hours per year. The second is New England's continued dependence on oil and natural-gas-fired resources, which makes New England electricity costs especially vulnerable to price increases in these fuels. The wholesale electricity markets are sending strong signals about these costs, and the ASM project and proposed capacity market changes will strengthen these signals. However, impediments to responding to these signals remain.

The load data for 2005 show that peak demand continues to increase faster than average demand, even when loads are weather normalized. Because peak loads drive many capacity and transmission investment needs, a greater amount of capacity must be built to serve these loads. Because average demand is growing more slowly, these investments are needed to support relatively few hours of operation. While the electric energy market sends high price signals during these hours, and ASM II and the proposed capacity-market revisions will better reveal these consumption costs during peak-load periods, consumers are unlikely to conserve at times of peak demand without a more direct linkage between wholesale and retail prices. State retail rates should be adjusted to allow customers to see these costs and how they vary with the time of consumption.

The sharp rise in natural gas and oil prices has resulted in a large increase in electricity prices. This makes investing in power generation fueled by other sources much more attractive. However, building these resources in New England is proving difficult. For example, numerous wind projects have been proposed, but many have run into local siting problems. Until New England is willing to

[30] The *2006 Wholesale Markets Plan,* published September 2005, is posted at http://www.iso-ne.com/pubs/whlsle_mkt_pln/index.html.

[31] 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. (FERC LICAP Explanatory Statement).

allow the construction of power plants fueled by resources other than natural gas, it will continue to be vulnerable both to price increases in oil and natural gas and to supply disruptions in the delivery of these two fuels.

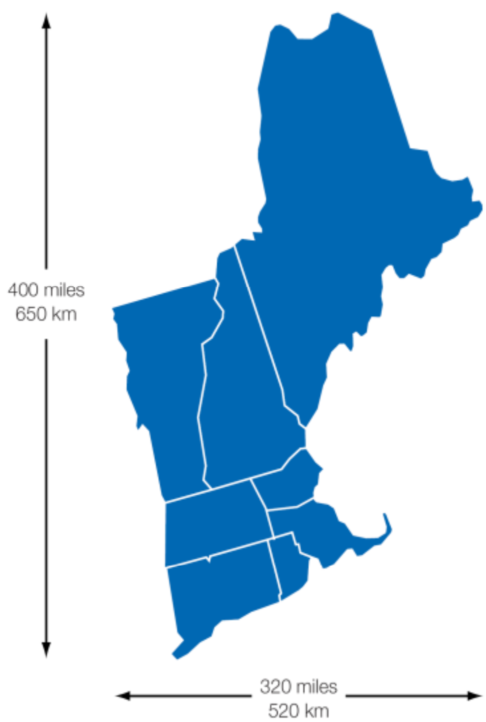
Section 2
Introduction

Created in 1997, the 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 that guides adequate investment in infrastructure

On February 1, 2005, the ISO began operation 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 500+ megawatts of demand response)
- Peak demand: 26,885 megawatts on July 27, 2005 (after approximately 268 megawatts of load reduction from demand-response programs)
- 280+ participants in the marketplace
- $11.2 billion energy market

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

2.1 About Market Monitoring and Mitigation

To support the ISO's responsibility in overseeing that the New England markets and prices are fair, transparent, and competitive, the ISO's Internal Market Monitoring Unit and Independent Market Monitor keep track of the overall performance of the markets. The INTMMU assures that prices properly reflect supply and demand conditions, assisting FERC in enhancing the competitiveness of electricity markets for the benefit of consumers. The ISO works with market participants, state regulators, FERC, and other agencies to correct any market impediments to efficiency or competition the INTMMU identifies. To fulfill the role of market monitoring, the INTMMU performs the following specific tasks:

- Provides 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, Regulation, and Forward Reserve Markets[32]
- Identifies ineffective market rules and tariff provisions and recommends proposed rule and tariff changes that will better promote wholesale competition and efficient market behavior
- Identifies potential anticompetitive behavior by market participants
- Immediately notifies 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 or market behavior rule
- Provides comprehensive market analysis
- Provides regular reports to ISO senior management and the board of directors that describe and assess the development and performance of wholesale markets, including performance in achieving customer benefits; provides transparency; and meets federal reporting guidelines
- Evaluates proposed changes in market rules and market design

The INTMMU seeks regular input from its Independent Market Monitoring Unit, Potomac Economics, to provide an additional, independent review of significant market developments.

2.2 About the *2005 Annual Markets Report*

This *2005 Annual Markets Report*, as required by Section 11.3 of Market Rule 1, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*, is a critical aspect of the market monitoring function.[33] The *2005 Annual Markets Report* covers January 1 to December 31, 2005, the ISO's most recent operating year. The report is an assessment of the wholesale electricity markets the

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

[33] Market Rule 1 and its appendixes are available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

ISO administers, based on market data, performance criteria, and independent studies. The main body of the report describes the development, operation, and performance of market operations and provides a retrospective analysis of market outcomes the ISO has observed. Appendix A of the document provides more details on the New England electricity markets. Appendix B includes additional information about reliability payments. Appendix C describes the administrative and transmission service payments made by participants in 2005, and Appendix D shows details about Transmission Congestion Revenue Fund accounting.

Section 3
Markets

This section of the report contains information about the electric energy markets, Forward Reserve Market, Installed Capacity Market, and Regulation 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, with each market 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 re-offers of uncommitted 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 with load or generation megawatt-hour deviations from their day-ahead committed schedules either pay or are paid the real-time locational marginal price for the energy amount that is sold or purchased from the Real-Time Energy Market. The ISO calculates and publishes day-ahead and real-time LMPs at five types of locations, or pnodes. These pricing locations include the external interfaces, load nodes, individual generator-unit nodes, and the load zones and the Hub, which are collections of pnodes. The market-clearing process calculates LMPs at these locations based on supply offers and demand bids (day-ahead) or load (real-time). A generator is paid the price at its pnode, while participants serving demand in each zone pay a load-weighted average of the load pnodes located in that zone. (Refer to Section 3.1.1 for more information about how the market price is determined.)

New England is divided into the following load zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeastern Massachusetts and Boston (NEMA), and Southeastern Massachusetts (SEMA). These eight load zones reflect the historical operating characteristics of, and the major transmission constraints on, the transmission system.

Transmission systems experience electrical losses as electricity travels through the transmission lines. To compensate for the losses, generators must increase the production of electricity by a small percentage. Nodal prices are adjusted to account for the marginal cost of losses.

If the system were entirely unconstrained and had no losses, all LMPs would be equal and reflect only the marginal energy offer. The generation with the lowest cost 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 the congestion violates transmission operating criteria, such as thermal or voltage limits. The congestion component of price is calculated at a pnode as the difference between the unconstrained energy component of price and the cost of providing an additional, more expensive increment of electric energy to that location.

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, load zone, or pnode. Generating units offer their output at the pnode 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, with zonal prices calculated as a load-weighted average of nodal prices within each zone. 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 request to be decommitted. Second, as part of its Reserve Adequacy Analyses (see Section 4.1), the ISO may be required to commit additional generating resources to support local-area reliability or provide contingency coverage. Beginning with the October 1, 2005, implementation of Phase I of the Ancillary Services Market project, all generators have the flexibility to change their incremental energy-supply offers during the re-offer 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 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.

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 last five years in New England, the added generating capacity has been almost entirely by facilities fired by natural gas. Generating units burning natural gas or fuel oil, or capable of burning both natural gas and oil, constitute approximately 62% 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. The 2005 natural gas and fuel-oil prices exceeded the prices of recent years; the price of fuel oil increased 32% since 2004, and natural gas prices increased by 44%.

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, Reserve Adequacy Analyses, and Real-Time Energy Market, generating units are committed to ensure that the level 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 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 2005 Demand

The total yearly demand in 2005 exceeded that of previous years; the peak hourly load during the year set a new record. The net energy for load supplied to the system in 2005 was 136,375,000 MWh, an increase of 2.9% over the 2004 level.[34] Since NEL is modestly influenced by weather, to more accurately compare load growth across years, the ISO calculates the weather-normalized NEL (i.e., the NEL that would have been observed if weather were normal). After weather normalization, the increase in the NEL from 2004 to 2005 was 1.9%, as shown in Table 3-1.[35] Weather-normalized demand is driven largely by economic growth. Figure 3-1 compares the annual percentage change in weather-normalized NEL to the annual percentage change in personal income (PINC), an indicator of economic growth. The line reflects a simple OLS (Ordinary Least Square) regression intended to indicate the general relationship between income and NEL.

Table 3-1
Annual Electric Energy and Peak Statistics

	2004	2005	Change	% Change
Annual NEL (MWh)	132,522,000	136,375,000	3,853,000	2.9%
Normalized NEL (MWh)	131,753,000	134,224,000	2,471,000	1.9%
Recorded peak load (MW)	24,116	26,885	2,769	11.5%
Normalized peak load (MW)	25,760	26,545	785	3.0%

[34] 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.

[35] 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.

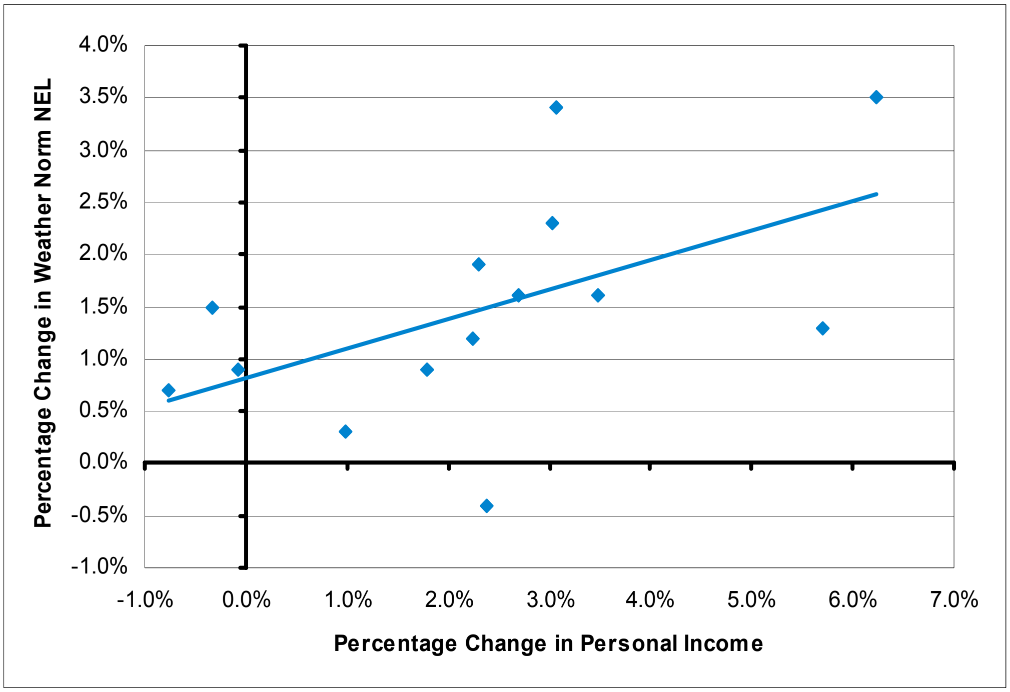


Figure 3-1: Percentage change in personal income compared to weather-normalized NEL, 1992–2005.

Note: The source for real personal income is Economy.com.

New England weather in 2005 was marked by extremes, with temperatures that were well below normal during the winter months and periods of very hot weather during the summer. January and March in particular had colder and snowier weather than normal, while February average temperatures were close to normal. Two periods of especially cold weather occurred during January 2005.[36] The first occurred January 16–22, and the second on January 27. Most eastern gas pipelines issued capacity constraints during the week of January 16–22, and electricity market prices were high. However, the weather was not as severe as during the January 2004 Cold Snap.[37]

While temperatures in April 2005 were just slightly above normal, May 2005 was the coldest May since 1967 in most areas of New England and one of the coldest ever on record. June was significantly warmer than normal inland and slightly above normal in coastal areas. Several days in June had temperatures around 90°F, and some areas reached 94°F or 95°F on June 25 and 26.[38] July temperatures were close to normal on average, but there were some very hot days, particularly July 19 and July 27. August was much warmer than normal overall, as was September. Temperatures in

[36] For more information on the January 2005 cold weather conditions, see http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2005/mar292005/a3_review_of_winter_season_lmp_setting_presentation_03_29_05.ppt.

[37] During January 14–16, 2004, New England experienced extremely low temperatures and a record winter-peak demand. For additional information on the ISO's Cold Snap Task Force and related reports, see http://www.iso-ne.com/committees/comm_wkgrps/inactive/cold_snap_tf/index-p1.html and http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/index.html.

[38] The source for temperature data is the Web site of the National Weather Service Forecast Office in Boston, Massachusetts: http://www.erh.noaa.gov/box/MonthlyClimate2.shtml.

October and November were slightly above normal, while December was slightly colder than normal in most areas.

Several of the summer 2005 hot-weather periods had high loads, and loads exceeded 25,000 MW for a total of 28 hours. The 2005 system-peak hourly load of 26,885 MW occurred on July 27. The temperature at the time of the peak in 2005 was 91°F, with a dew point of 72°F. By comparison, loads did not exceed 25,000 MW at any time in 2003 or 2004, and only exceeded this level in four hours in 2002. After weather normalization, the 2005 summer seasonal peak increased by 3% over the 2004 weather-normalized peak. The ISO calculates a weather-normalized peak load for the summer and winter seasons.

Figure 3-2 and Figure 3-3 show the actual system electrical load for New England over the last four years as load-duration curves, with load levels ordered 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 3-2 shows that in 99.8% of the hours, the hourly loads in 2005 were above the levels for each of the previous three years. Figure 3-3, which includes only the highest 5% of hours, shows that the earlier years had much lower peak loads. High 2005 peak loads were the result of a hot summer and underlying load growth.

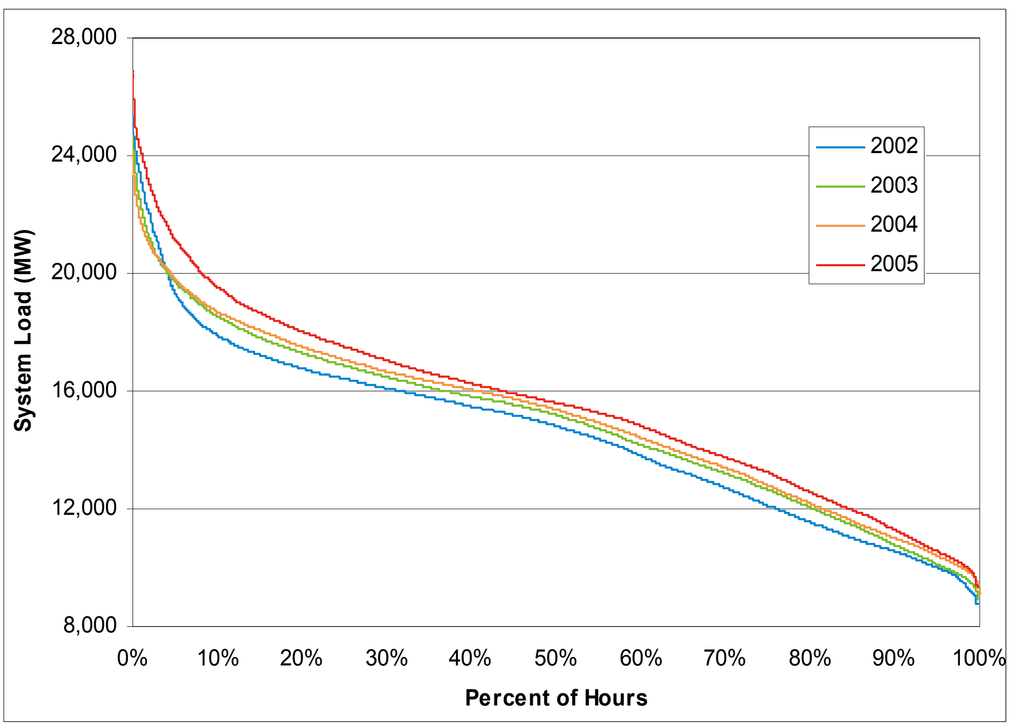


Figure 3-2: New England hourly load-duration curves, 2002–2005.

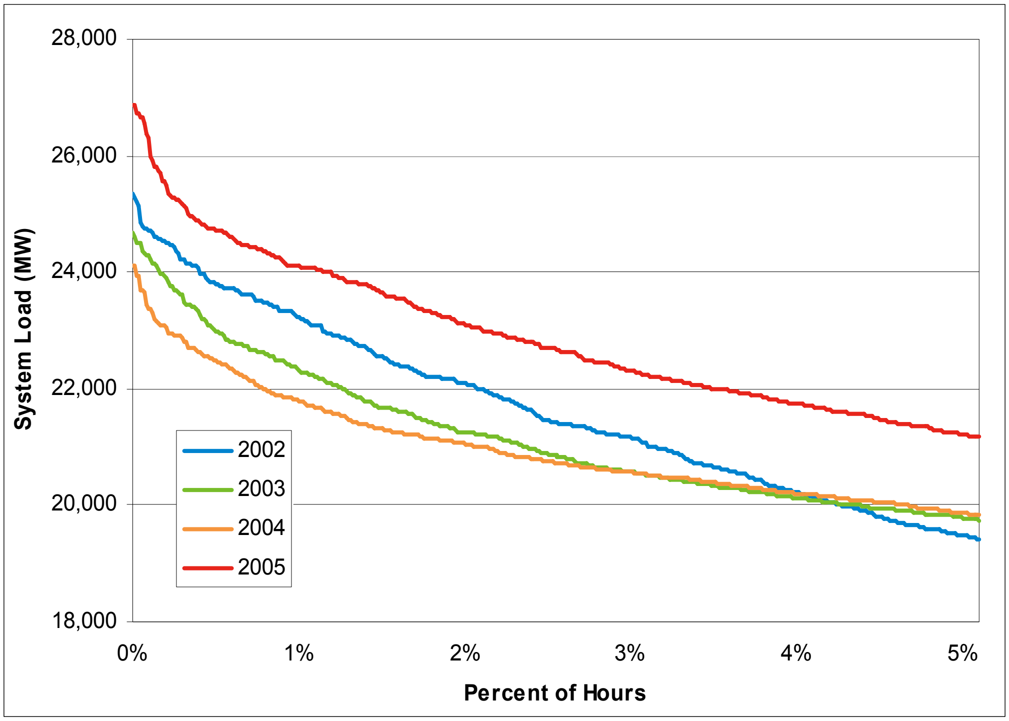


Figure 3-3: New England hourly load-duration curves, top 5% of hours, 2002 to 2005.

3.1.2.1 Load Factors

The load factor is the ratio of the average hourly load during a year to the peak hourly load. Figure 3-4 shows historic load factors for New England expressed as a percentage. Load factors have fallen significantly over the past 25 years. This trend is projected to continue, as peak electricity consumption has been growing faster than the average consumption.

In New England, peak loads now occur during the summer. This peak consumption is driven by hot weather and the resultant increase in the use of air conditioners. With this increased use of air conditioning, summer-peak loads have grown disproportionately compared with average loads. This has driven the overall trend in declining load factors, with small variations in the trend due to differences in extreme weather. 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 loads for only a small number of hours per year.

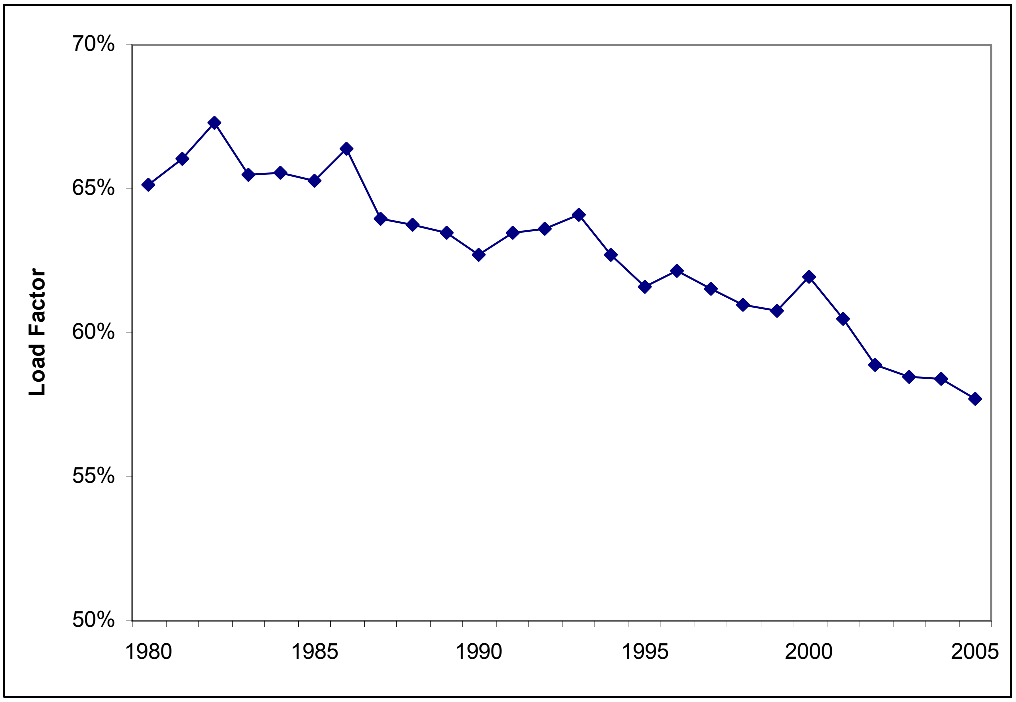


Figure 3-4: New England summer-peak load factor, 1980–2005.

3.1.2.2 Load Obligation

Figure 3-5 compares the 2004 percentages of real-time load obligation (RTLO) cleared in the Day-Ahead Energy Market in each load zone with the 2005 percentages. The low level of day-ahead load obligation in Vermont was due to a large real-time load obligation that was not bid into the Day-Ahead Energy Market in some months. The average day-ahead load obligation in 2005 was 95% of the real-time load obligation, while in 2004, the day-ahead load obligation averaged 97% of real-time load obligation. Appendix A.1 shows the percentage of real-time load obligation cleared in the Day-Ahead Energy Market in 2005 by load zone and overall.

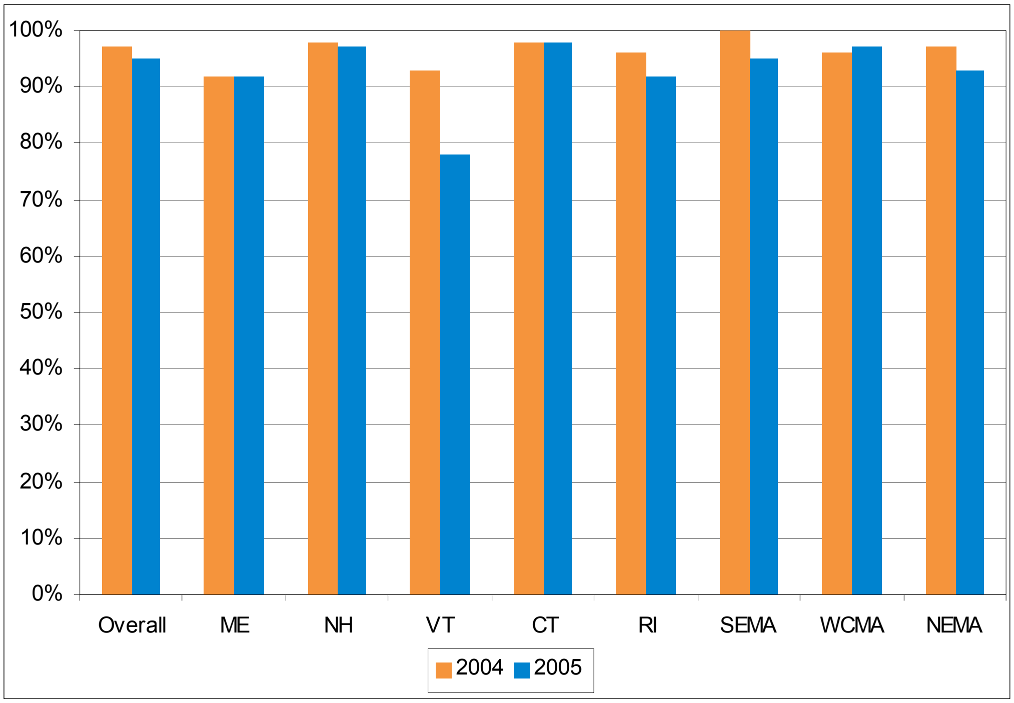


Figure 3-5: Percentage of real-time load obligation cleared in the Day-Ahead Energy Market, 2004 and 2005, by load zone and overall.

3.1.2.3 Day-Ahead Demand and Virtual Trading Trends

Market participants serving load can participate in the Day-Ahead Energy Market by bidding fixed and price-sensitive demand. All participants can bid virtual demand in the Day-Ahead Energy Market and sell virtual supply. All purchases or sales are at the Day-Ahead Energy Market clearing prices. Fixed and price-sensitive demand can be submitted at the load zones, while virtual demand and supply can also be submitted at any pnode. Demand bids that clear in the Day-Ahead Energy Market create price certainty for purchasers because price and quantity are locked in ahead of the Real-Time Energy Market. Virtual demand may represent expected real-time consumption at a pnode and may be used to manage the financial obligations of generating resources. They may also be used to arbitrage day-ahead and real-time prices.

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. Virtual trading also mitigates market power in the Day-Ahead Energy Market by reducing net day-ahead purchases when prices would otherwise rise.

Virtual supply offers that clear in the Day-Ahead Energy Market create a financial obligation for the participant to purchase energy at a particular location in the Real-Time Energy Market. Virtual demand bids create a financial obligation for the participant to sell at a particular 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. An exception to these obligations is a virtual demand bid that is mirrored by consumption at the pnode in real time. When a participant's real-time consumption occurs at the same location as a cleared virtual demand bid, the settlement rules applicable to fixed- and price-sensitive demand bids (with the daily reliability cost-allocation rules being the most important) are applied to the virtual demand bid (see Section 4.2.1.1). 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 daily reliability cost charges. Figure 3-6 shows average hourly quantities of day-ahead demand and virtual supply for 2005.

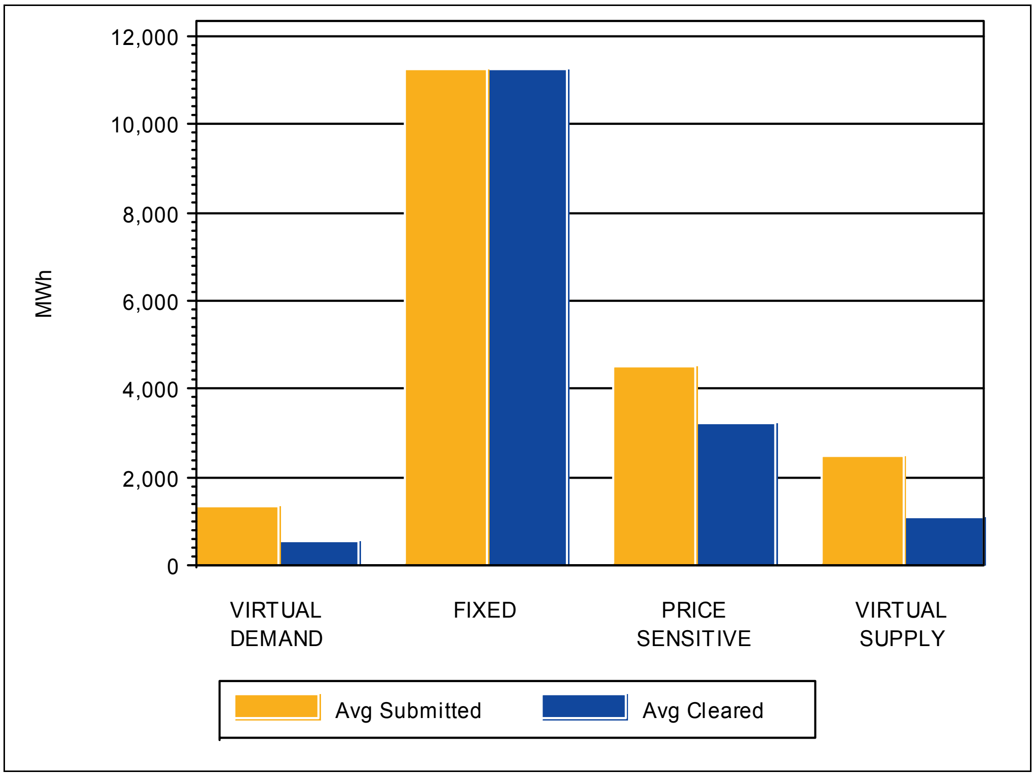


Figure 3-6: Average hourly submitted and cleared demand, virtual demand, and virtual supply, Day-Ahead Energy Market, 2005.

On average, the sum of the hourly cleared fixed-demand bids, price-sensitive demand bids, and virtual demand bids in the Day-Ahead Energy Market represents 97% of hourly actual system real-time load. Seventy-five percent of cleared demand bids during 2005 were fixed bids, insensitive to price, while 21% of the bids were price-sensitive. The remaining 4% of cleared day-ahead demand was composed of cleared virtual demand bids representing day-ahead locational purchases of electric energy. These percentages were the same in 2004. Virtual supply made up 5% of day-ahead cleared supply in 2005, compared with 3% in 2004 and 2% in 2003.

Figure 3-7 plots the fixed demand submitted in the Day-Ahead Energy Market as a percentage of total demand in the Day-Ahead Energy Market (price-sensitive demand plus fixed demand) against the actual real-time peak load each day. The analysis indicates that participants increased the percentage of fixed demand submitted on days when load was high. Assuming that expected loads generally correspond well with actual loads, this behavior is consistent with participants that are seeking to avoid exposure to real-time prices when those prices might reasonably be expected to be high and more volatile than normal due to forecasts of high loads.

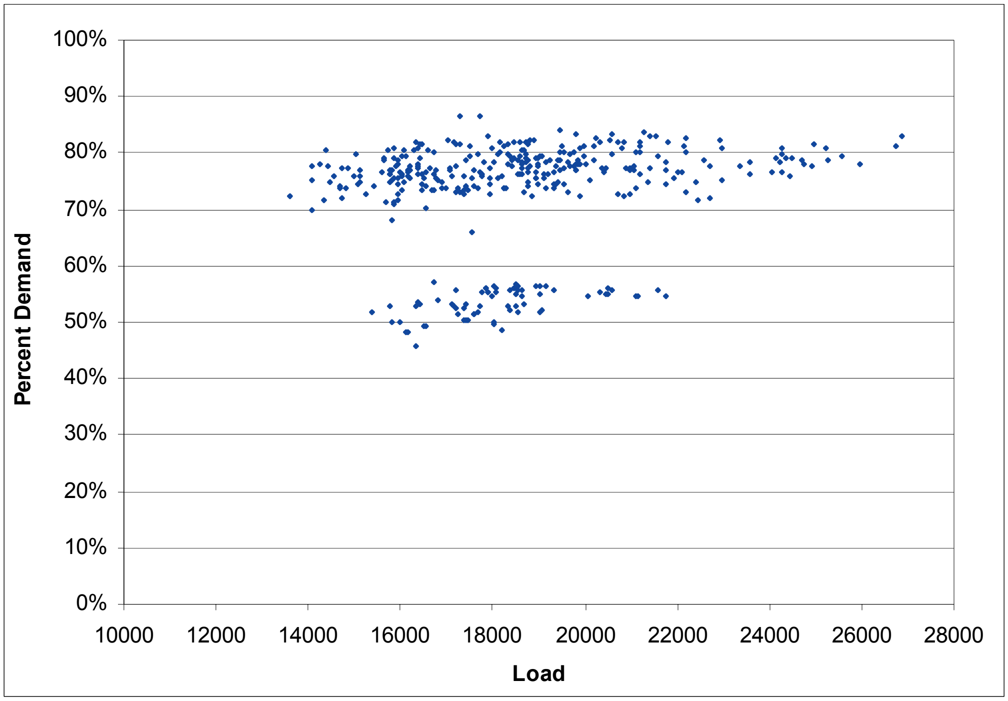


Figure 3-7: Daily-peak actual load compared with bid fixed demand as a percentage of total bid demand, 2005.

Fixed demand decreased, and both bid and cleared price-sensitive demand increased, in early October through mid-December, as shown in Figure 3-8. This change is also depicted in Figure 3-7 as the data points in the lower part of the figure. The increase in price-sensitive demand bids as a percentage of total bids was due to a change in bidding strategy by one participant. The participant began bidding more of its load as price-sensitive rather than fixed. Bidding load as price-sensitive demand rather than fixed demand may help to shield a bidder from potentially high costs in the Day-Ahead Energy Market unlikely to materialize in real time.

Figure 3-9 shows the total monthly submitted and cleared virtual demand from January 2004 through December 2005. The figure shows that the volumes of cleared virtual demand were similar in 2004 and 2005, while the volume of offers submitted declined.

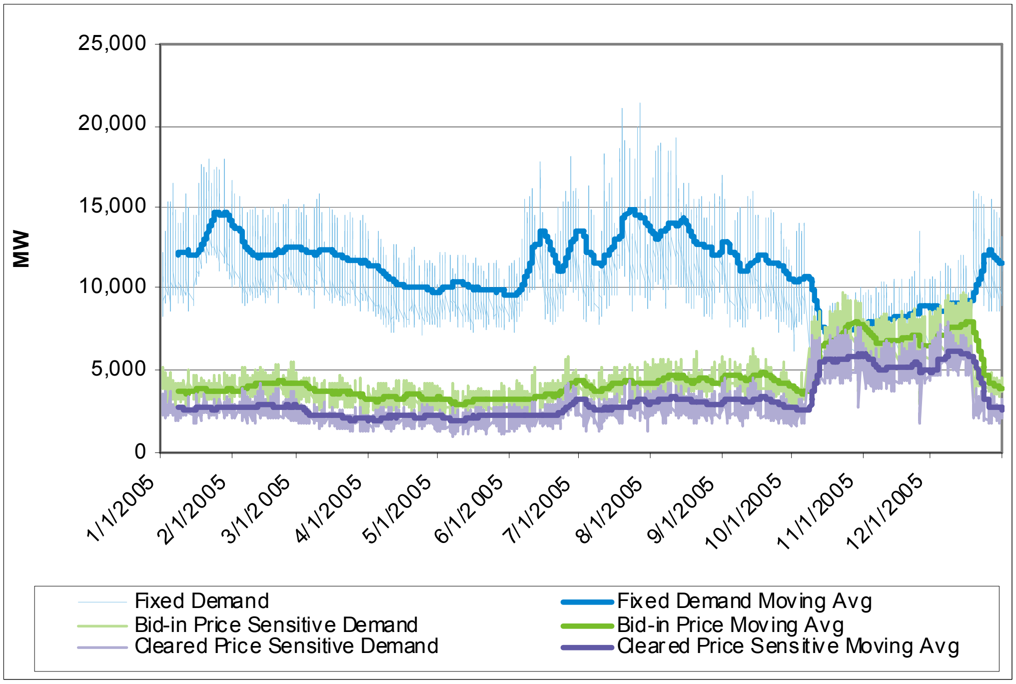


Figure 3-8: Hourly fixed and price-sensitive demand and seven-day moving average.

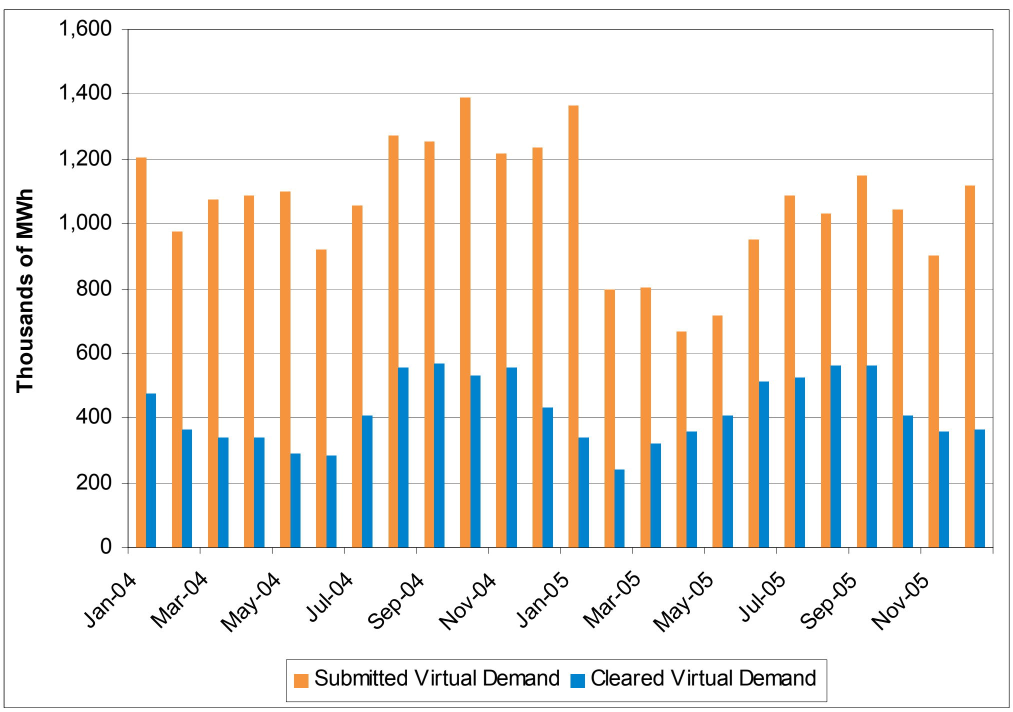


Figure 3-9: Monthly total submitted and cleared virtual demand, January 2004–December 2005.

3.1.3 2005 Supply

This section discusses elements of electric energy supply in 2005, including generation capacity, fuel types, self-scheduling, imports and exports, reserve margins, virtual supply, and changes related to the re-offer period.

3.1.3.1 System Capacity

The total 2005 system capacity for summer was 31,083 MW, and the total for winter was 33,861 MW. New capacity with a summer capability of 92 MW was added to the system in 2005. This included an 86 MW upgrade project at an existing generating station and one new generating unit. By comparison, 656 MW of new generation were added in 2004, 2,949 MW were added in 2003, and 2,786 MW were added in 2002. One generator with a summer capability of 73 MW retired during 2005, along with six small generators with a total summer capability of 8 MW. Total system generation capacity did not change significantly during 2005, with a net increase of 11 MW.

Since generation capacity was adequate to meet the demand in 2005, this level of investment was not a cause for immediate concern. However, ISO analyses indicate that the continued growth in demand may require that emergency actions be taken to meet peak demand in the 2007 to 2009 timeframe, unless additional generation capacity or demand-response resources or both become available.[39]

Figure 3-10 shows summer capacity in megawatts, by year and fuel type, for the past five years. Capacity levels were similar in 2003, 2004, and 2005.[40] In 2005, dual-fueled generators, capable of burning both oil and natural gas, made up 28% of installed capacity, while natural-gas-fired generators made up 19% of installed capacity. Many dual-fueled generators capable of burning both oil and 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. As part of the Winter 2005/2006 Action Plan, during 2005, participants increased dual-fuel function and flexibility at four large dual-fueled generators with a total capacity of approximately 1,450 MW. Section 3.1.7 discusses the plan in more detail.

Figure 3-11 compares zonal demand with summer claimed capability (SCC) and generation for generators within each load zone.[41] Generators within the Maine, New Hampshire, and SEMA load zones produced more power than was used within these zones, while the Vermont, Rhode Island, NEMA, WCMA, and Connecticut load zones all had demand that was greater than the power generated within these zones. As the figure shows, some areas with similar SCC levels had very different levels of demand.

[39] ISO New England, *2005 Regional System Plan*, available at http://www.iso-ne.com/trans/rsp/2005/05rsp.pdf.

[40] 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.

[41] The summer claimed-capability rating is a generating unit's maximum dependable load-carrying ability during the summer, excluding the capacity required for station use.

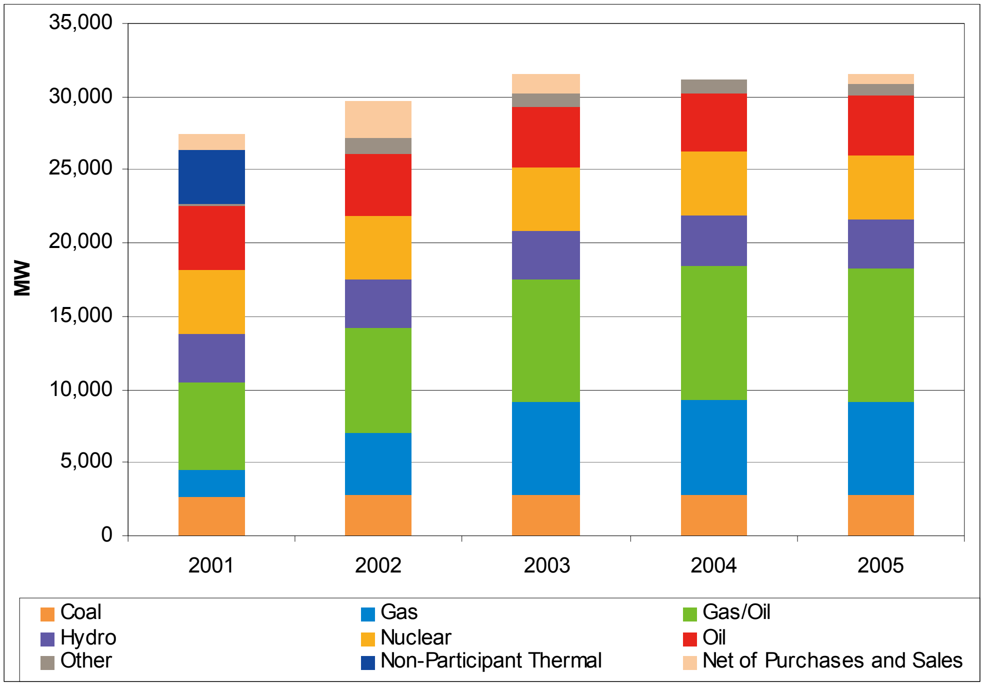


Figure 3-10: System summer capacity by generator type.

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

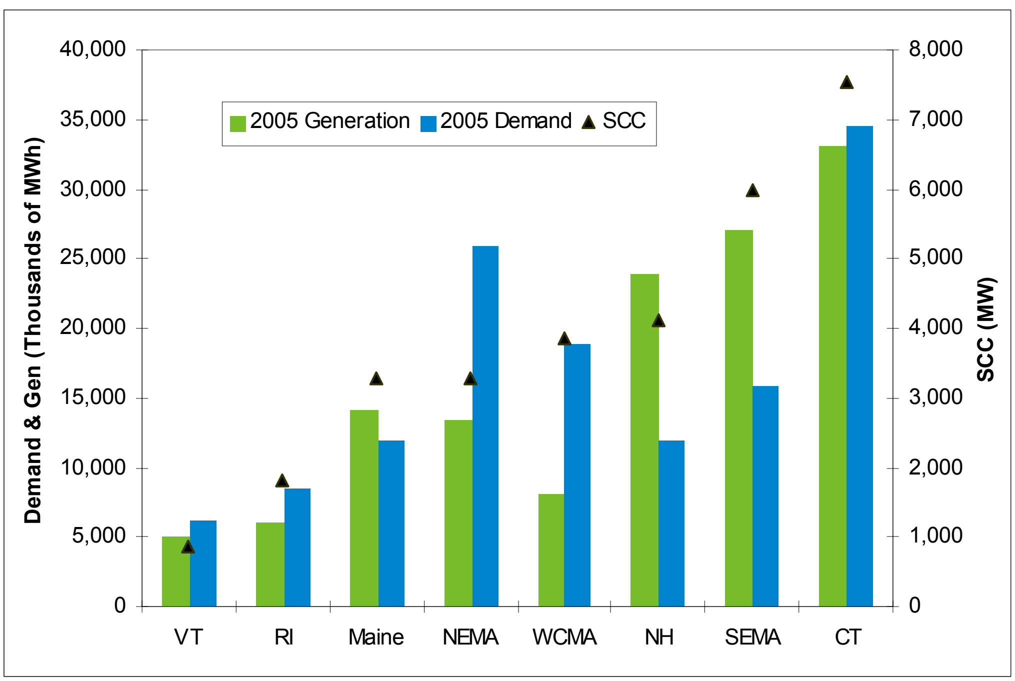


Figure 3-11: Summer claimed capability, generation, and demand by load zone.

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 2005. The figure shows the fuels used to actually generate electric power, which differs from the capacity fuel mix shown in Figure 3-10 and the marginal unit by fuel type shown later in Figure 3-24 (Section 3.1.4.3). The percentage of total generation produced by gas-fired and gas/oil-fired plants in New England was 42% in 2005. Nationwide, about 18% of electric energy is produced by power plants fueled by natural gas.[42]

Overall, 2005 generation increased 1.8% from 128,145,000 MWh in 2004 to 130,417,000 MWh in 2005, while actual NEL increased by 2.9%. Net imports from other control areas provided 6,313,000 MWh, or about 4.6% of NEL, making up the difference between load growth and the increase in generation.

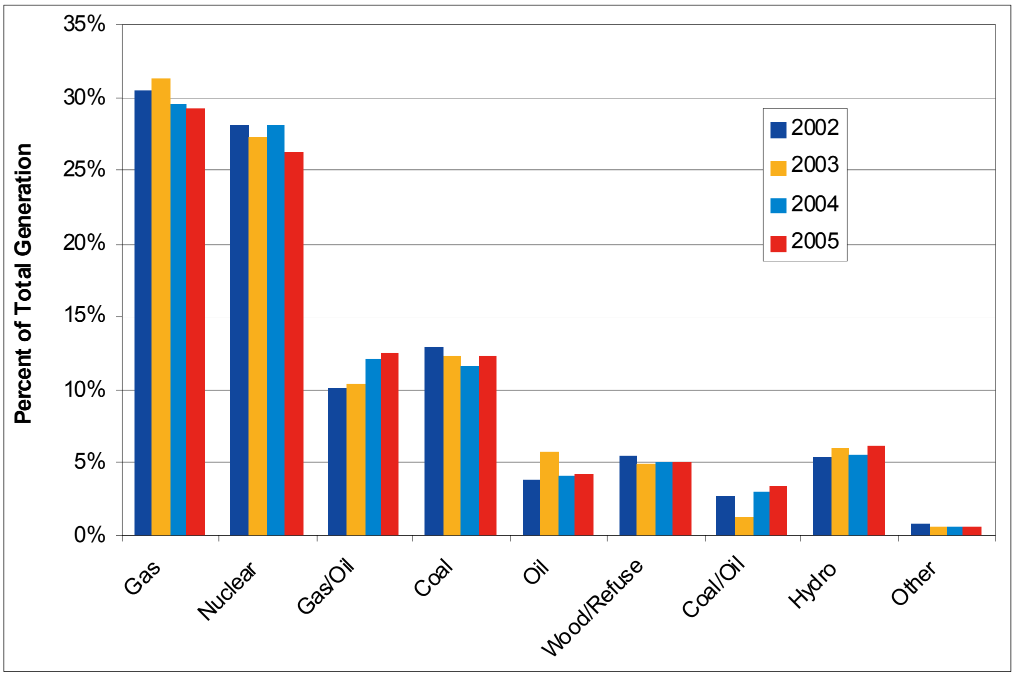


Figure 3-12: New England generation by fuel type.

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 passed legislation in 2005 establishing RPSs, which requires the development of regulations to implement

[42]The source for this data, available at http://www.eia.doe.gov/fuelelectric.html, is the Energy Information Administration. Data are for 2004, the most recent year available.

the legislation by September 2006. 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.[43] To cover their renewable energy requirements, suppliers may buy renewable energy credits (REC) created at renewable facilities within the New England region. 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 (ACP) 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 2005 were 4.5% for Connecticut suppliers, 2.0% 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 2013. By 2014, the RPS requirements will increase to 14% in Connecticut, 9% in Massachusetts, and 8.5% in Rhode Island. The requirement in Maine will remain at 30%.

In 2005, renewable resources in New England generated about 10% 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 since they did not supply all the renewable energy required. Maine, which has a less stringent definition of what resources count toward meeting its RPS, met its requirement. The ISO's *2005 Regional System Plan* (RSP05) 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. [44, 45] Unless many smaller projects are installed and operating by that date, or renewable projects outside of New England are certified for the New England states RPSs, the suppliers could be short of their RPS goals. If this occurs, they will have to pay the ACP to meet the requirement's shortfall and thus drive up the price of electricity at the retail level. The *2005 Regional System Plan* contains additional information on RPSs.

3.1.3.4 Self-Scheduled Generation

Figure 3-13 compares real-time self-scheduled generation with total real-time generation by month for 2005. Self-scheduling is of interest because self-scheduled generators are price-takers (i.e., generators willing to operate at any price and 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. However, self-scheduling may not be cost-effective for some generators and, at times, contributes to minimum generation emergencies. Self-scheduled

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

[44] RSP05, published October 20, 2005, can be obtained by contacting ISO Customer Service. The document is also available at http://www.iso-ne.com/trans/rsp/2005/05rsp.pdf.

[45] The ISO Generator Interconnection Queue is the list of requests for the interconnection of generation projects.

generation averaged between 51% and 65% of total real-time generation per month during 2005, broadly consistent with past trends.

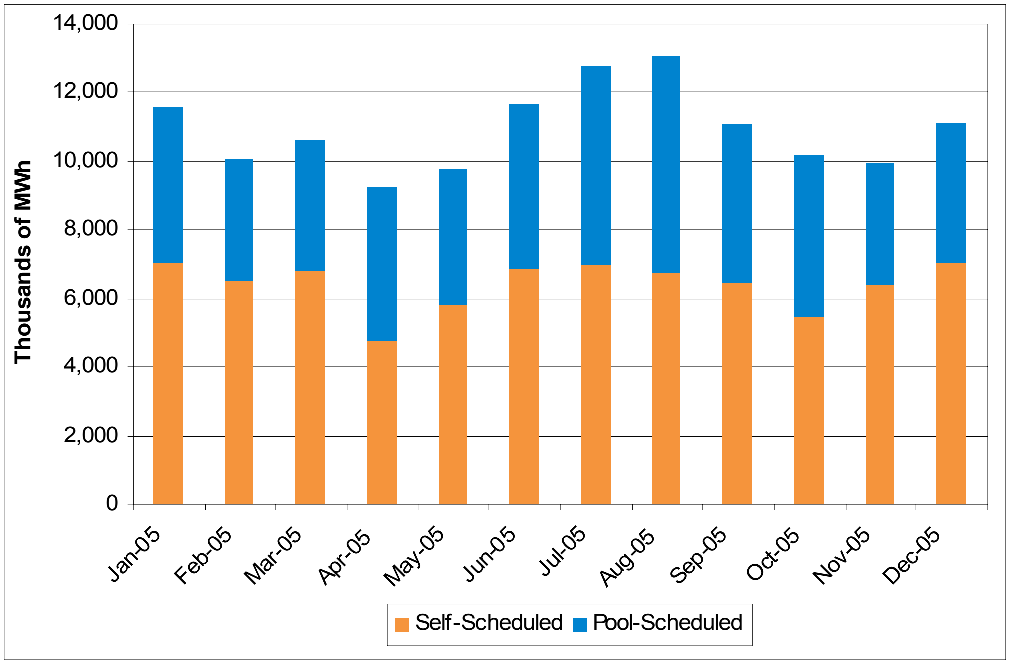

Figure 3-13: Real-time generation—self-scheduled and pool-scheduled, 2005 monthly totals.

Table 3-2 shows the percentage of generation that was self-scheduled during 2005 by generator fuel type. Nuclear-fueled generators self-scheduled 99% of their generation, while diesel 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.

Table 3-2
Percentage of Generation Self-Scheduled by Generator Fuel Type, 2005

Generator Type	Percentage of Generation
Oil	9%
Diesel oil	11%
Jet fuel	17%
Gas	32%
Coal/oil	32%
Gas/oil	40%
Coal	62%
Wood/refuse	76%
Hydro	81%
Nuclear	99%

3.1.3.5 Re-offer Period Changes

ASM I provided several important market enhancements. Generators clearing in the day-ahead market were provided with the option to revise and resubmit their incremental energy offers during the re-offer period, which runs from 4:00 p.m. to 6:00 p.m. of the day before the operating day.[46] This market enhancement was intended to mitigate fuel and operational risk exposure for generators. This section describes the use of this market enhancement from October 1, 2005, to December 31, 2005.

Thirty generators, owned by nine participants, revised and resubmitted their incremental energy offers (which had cleared in the day-ahead market) at least once during the re-offer period. Most of these generators were either exclusively or primarily natural-gas-fired units. The fact that most of the units that took advantage of the tool were gas-fired units is consistent with the stated objective of this new tool, that is, to alleviate fuel-price risk.

Figure 3-14 illustrates the magnitude of daily revisions to incremental energy offers clearing in the day-ahead market. Data points above $0/MWh indicate that, on average, generators *increased* their incremental energy offers during the re-offer period, while data points below $0/MWh indicate that generators *decreased* their incremental energy offers during the re-offer period. The data suggest that the revisions to incremental energy offers were relatively small; generators clearing in the day-ahead market tended to *lower* their incremental energy offers by approximately $10/MWh. Large deviations from the mean occurred on days with significant uncertainty in the natural gas markets. The evidence supports the idea that generators used this new tool to manage fuel-price risks.

[46] This market enhancement was supported by the NEPOOL Participants Committee at its October 14, 2005, meeting. See *ISO New England Inc. and New England Power Pool, Ancillary Services Market Phase I*, Docket No. ER05-795-001, filed April 7, 2005.

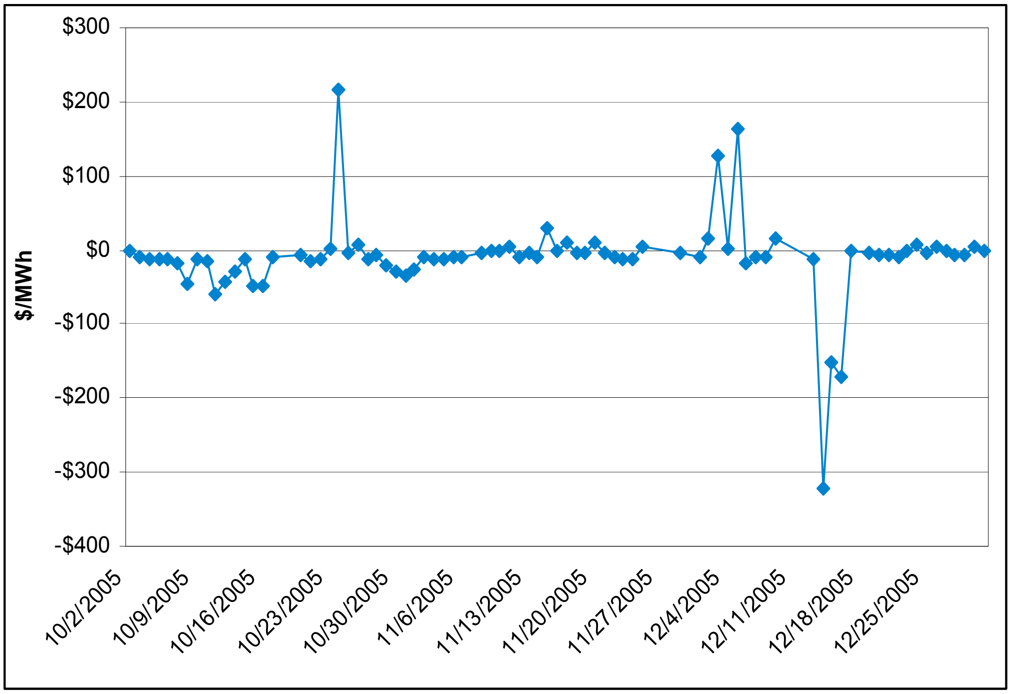

Figure 3-14: MW-weighted average change between re-offer and day-ahead incremental energy offers.

Figure 3-15 shows the average daily generation affected by such changes. This plot shows a downward trend in the revisions generating units made to incremental energy offers during the analysis period. Use peaked in mid-October and was virtually nonexistent in late December.

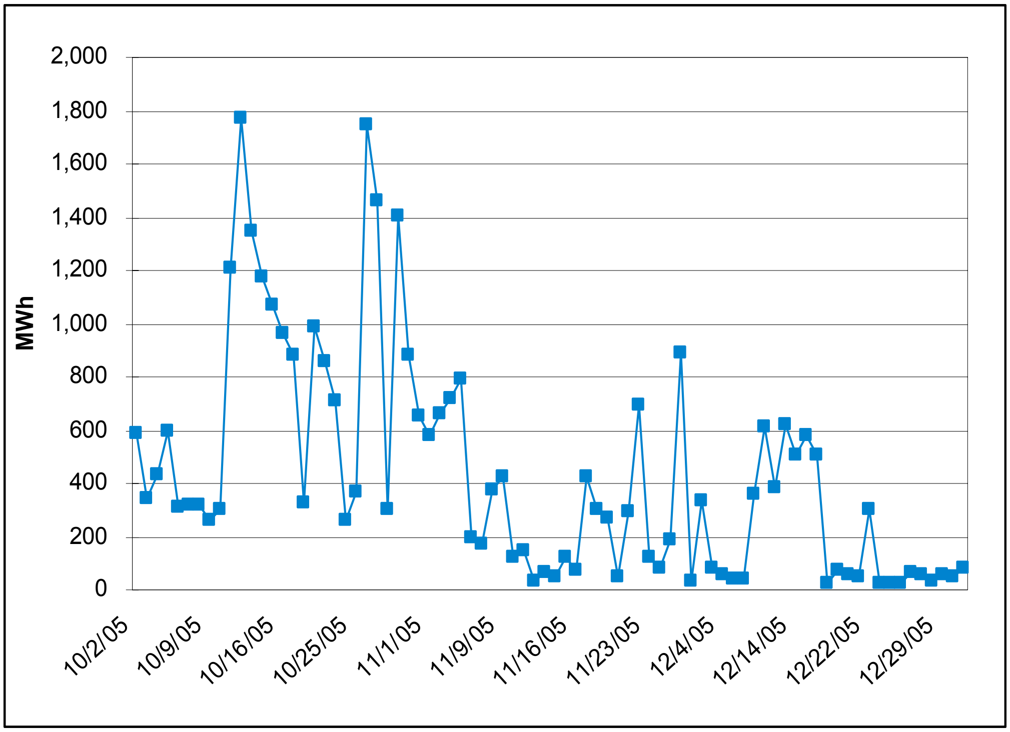

Figure 3-15: Average daily generation (MWh) with revised incremental energy offers.

3.1.3.6 Imports and Exports

During 2005, New England remained a net importer of power from Canada and a net exporter to New York. Net imports from neighboring regions amounted to 6,313,000 MWh for the year, representing 4.6% of the annual NEL in New England during 2005. Import and export quantities both increased from 2004 to 2005, with a larger increase in imports. In 2004, New England had 111,000 MWh of net exports to New York, compared with 99,000 MWh of net exports in 2005. Net imports from Canada were 5,019,000 MWh in 2004, compared with 6,411,000 MWh in 2005. Figure 3-16 shows net interregional power flows for 2001 through 2005, and Figure 3-17 shows imports and exports by interface for 2005.

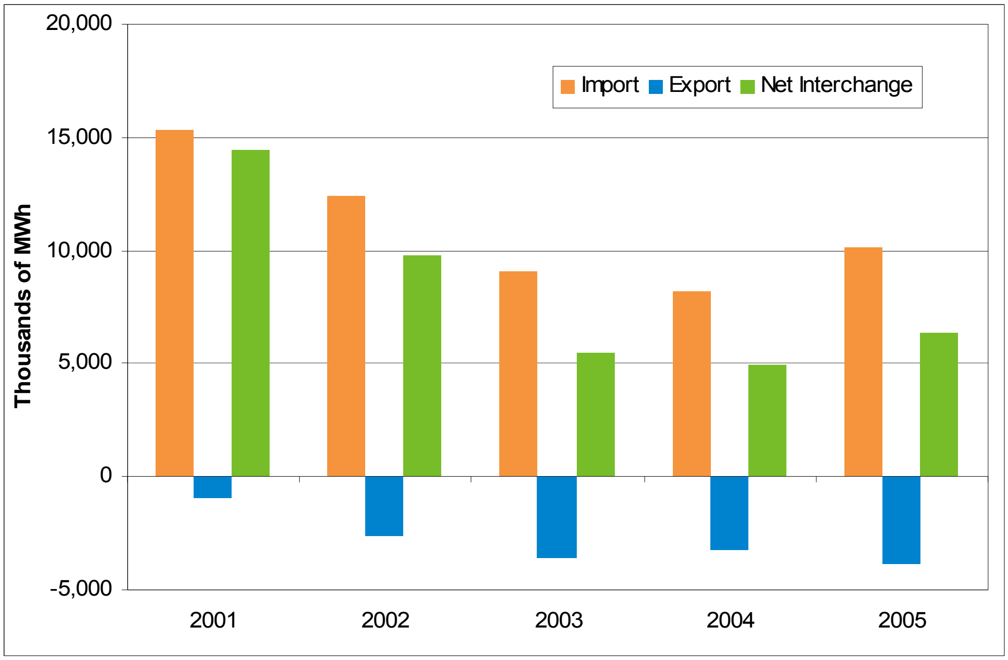

Figure 3-16: New England annual imports, exports, and net interchange, all interfaces.

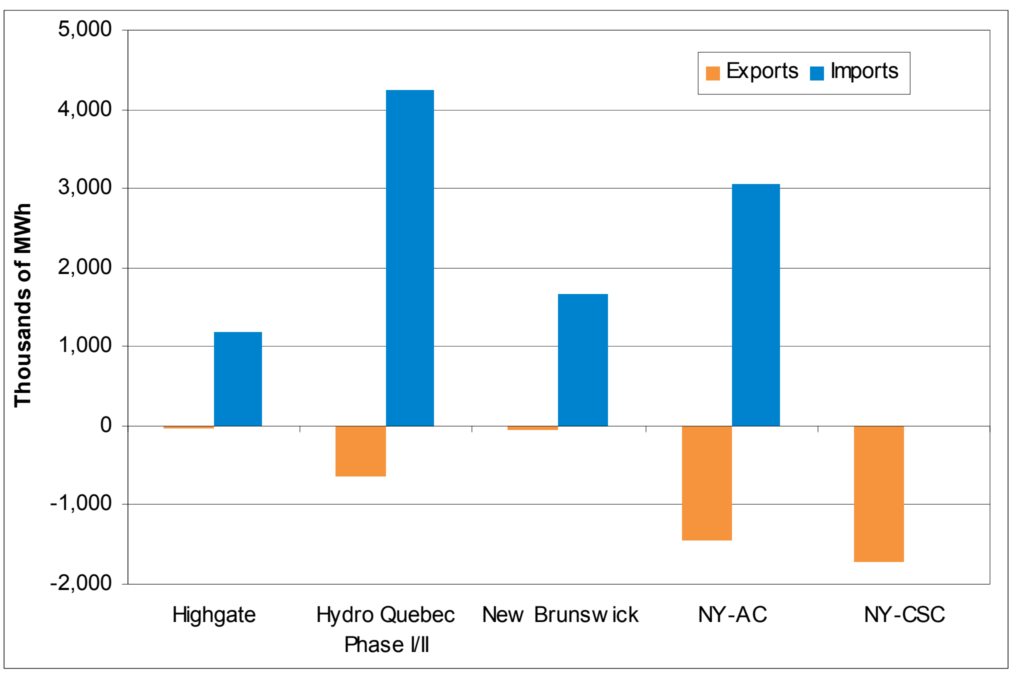

Figure 3-17: New England imports and exports by interface, 2005.

Note: The NY–alternating current (AC) interface is the collection of AC tie lines connected through Connecticut, Massachusetts, and Vermont. The NY–CSC interface is the recently constructed Cross-Sound Cable.

New England is a net exporter to New York overall. However, looking at the modeled ties separately shows that New England is a net importer from New York over the AC interface connecting New York with western New England and a net exporter to New York over the CSC interface. During the year, an inverse relationship existed between fuel prices (oil and natural gas) and the New York–New England AC interface, along with a positive relationship between fuel prices and flows across the NY–CSC net interchange. This indicates that as fuel prices in New England increase, imports to New England over the AC interface increase, and exports to New York over the CSC also increase.

Figure 3-18 shows the price difference between the ISO New England's Roseton bus, where exports to New York are priced, and the NYISO's NEPEX bus, where exports from New York to New England are priced.[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 there is no clear relationship between New England and New York 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.

The lack of efficient arbitrage between New England and New York has been previously identified and is the subject of an Inter-Hour Transaction Scheduling pilot project.[48,49] This project is examining whether a reduction in scheduling times will improve price convergence. Also, as discussed more fully in Section 3.1.5, the bulk of import contracts are self-scheduled and are thus not price sensitive. This explains the lack of correlation of import and export flows with price differentials between New England and New York. In addition, the nature of the financial transactions that include both areas is such that it may require the physical power flows, reserved in advance, to flow against the positive price differential between the areas.

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

[48] Patton, David and Pallas LeeVanSchaick. June 2005. *2004 Assessment of the Electricity Markets in New England*. Independent Market Monitoring Unit, ISO New England, Potomac Economics, Ltd.

[49] Additional information on this pilot is available in the ISO's *2006 Wholesale Markets Report* posted at http://www.iso-ne.com/pubs/whlsle_mkt_pln/index.html.

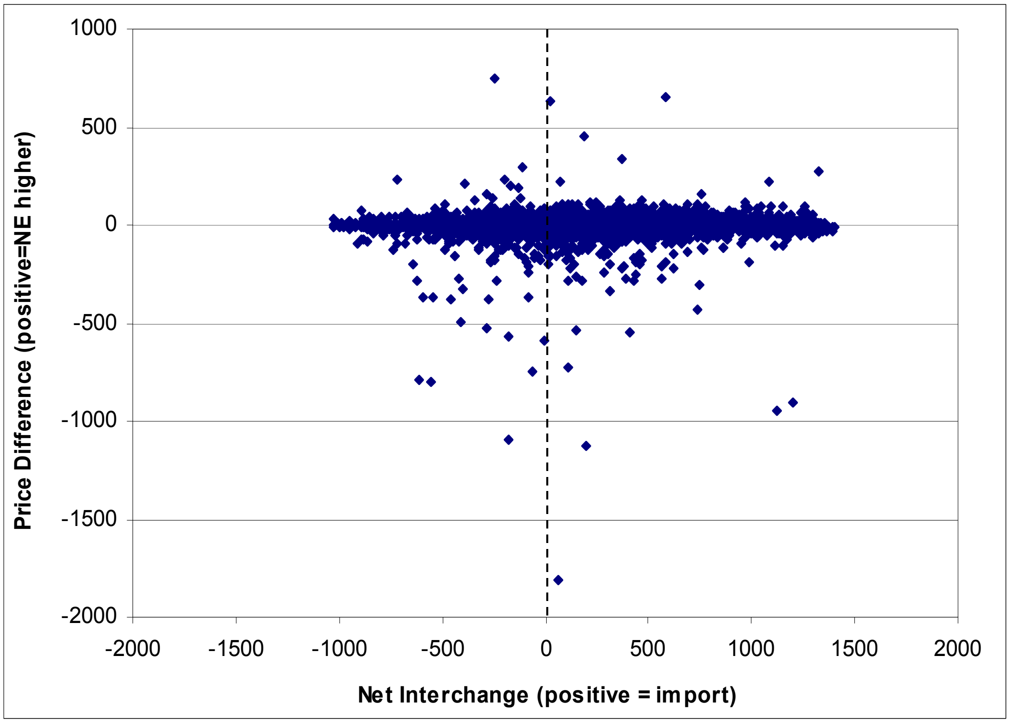

Figure 3-18: New England Roseton LMP minus New York NEPEX locational-based marginal price and net interchange with New York, 2005.

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 includes generation that may have been unavailable due to start-up-time or subarea-export constraints.[50] Figure 3-19 shows operable capacity margins for the peak-load hour of each month in 2005. As usual, margins were low in June, July, and August, which is consistent with summer-peak loads.

[50] 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); and 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 is comprised of the SWCT and NOR Subareas. The three neighboring control areas are New York, Hydro-Québec, and the Canadian Maritimes.

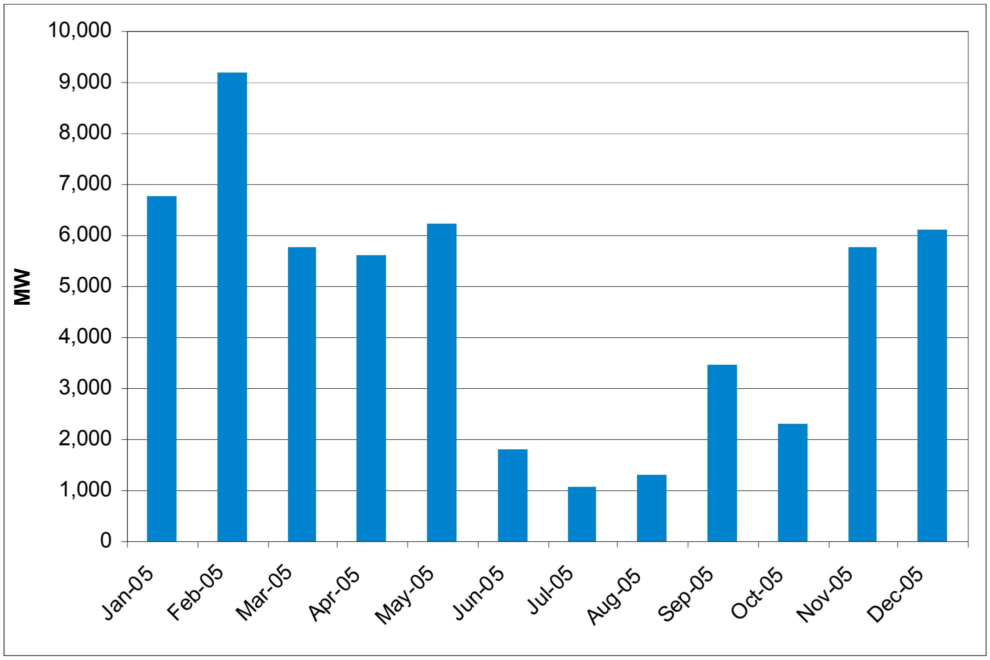

Figure 3-19: Monthly peak-hour operable capacity margins.

3.1.3.8 Virtual Supply

Figure 3-20 shows the total monthly submitted and cleared virtual supply from January 2004 through December 2005. The figure shows that the volume of both submitted and cleared virtual supply increased modestly.

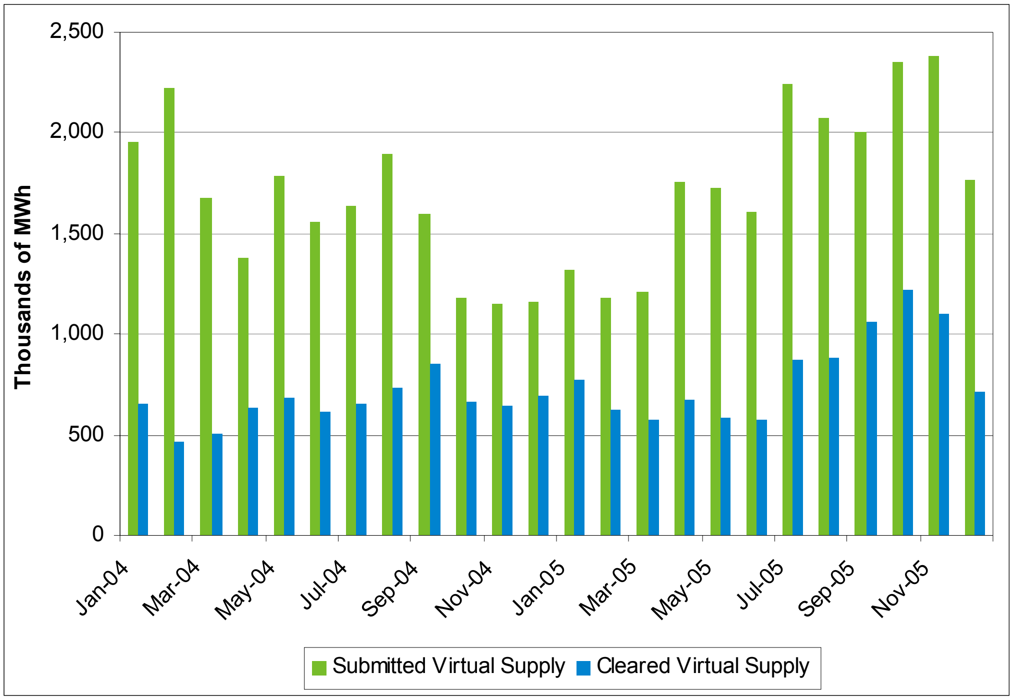

Figure 3-20: Monthly total submitted and cleared virtual supply, January 2004–December 2005.

3.1.4 2005 Electric Energy Prices

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

3.1.4.1 Impact of Supply and Demand

Figure 3-21 shows the supply-offer curves and demand for the 2004 and 2005 peak days. The supply curve represents an ascending price-ordered set of offers from suppliers and typically represents the incremental cost of electricity. The market price is obtained at the intersection of the demand and supply curves. As illustrated in the figure, the simulated hourly electricity price on July 27, 2005, is $226/MWh, a large increase from the simulated August 30, 2004, price of $65/MWh.[51]

[51] The prices of $65/MWh on August 30, 2004, and $226/MWh on July 27, 2005, are the simple result of intersecting the load and supply curves for the peak hours of each year. The actual real-time on-peak LMPs at the Hub and load zones on those days ranged from $38.18/MWh to $126.71/MWh on August 30, 2004, and $65.51/MWh to $931.10/MWh on July 27, 2005.

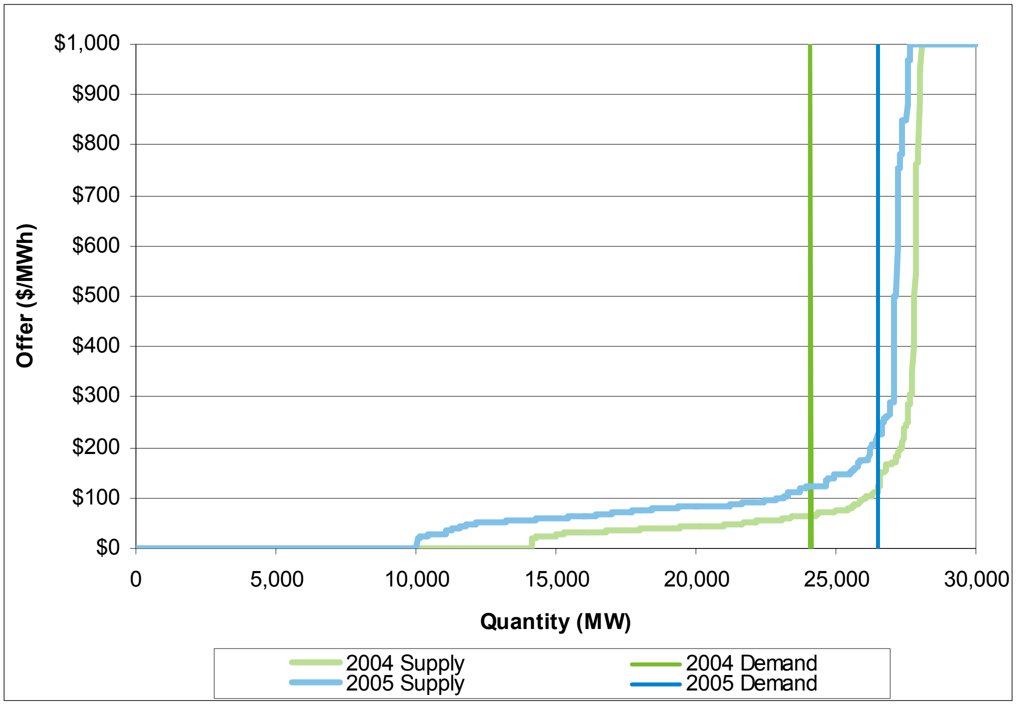

Figure 3-21: Supply-offer curves and demand, peak day 2004 and 2005.

3.1.4.2 Annual Real-Time Electric Energy Prices

Figure 3-22 and Figure 3-23 show the real-time system electricity price for New England over the last four years as duration curves with prices ordered from highest to lowest. For the Interim Market period ending February 28, 2003, the system price is the single energy-clearing price (ECP). For March 2003 to December 2005, 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 2005 were much higher than prices during previous years. This is due primarily to increased fuel prices (as discussed in the next section). The peak prices shown in Figure 3-23 were also higher than in earlier years, although hourly system prices never reached $1,000/MWh. The NEMA real-time LMP, however, reached $1,078/MWh on August 8, 2005.[52] 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.

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[52] Although an offer cap of $1,000/MWh exists, LMPs may exceed $1,000/MWh due to the inclusion of congestion and marginal-loss components.

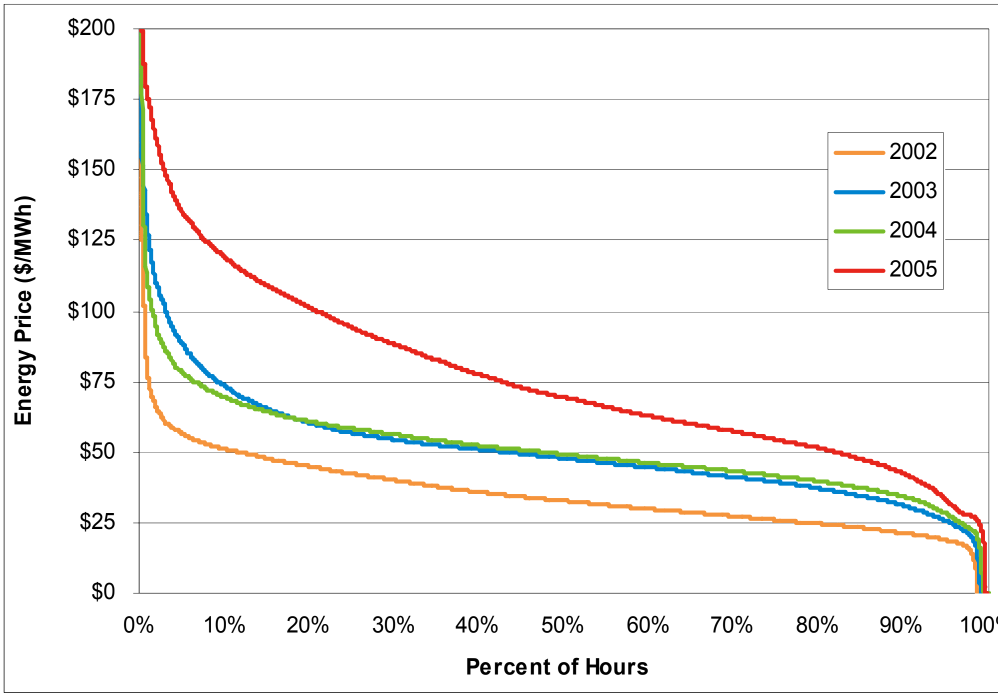

Figure 3-22: System real-time price-duration curves, prices <$200/MWh, 2002–2005.

Note: System price is the single energy-clearing price for the Interim Market period ending February 28, 2003, and load-weighted Real-Time Energy Market LMPs for March 2003 to December 2005.

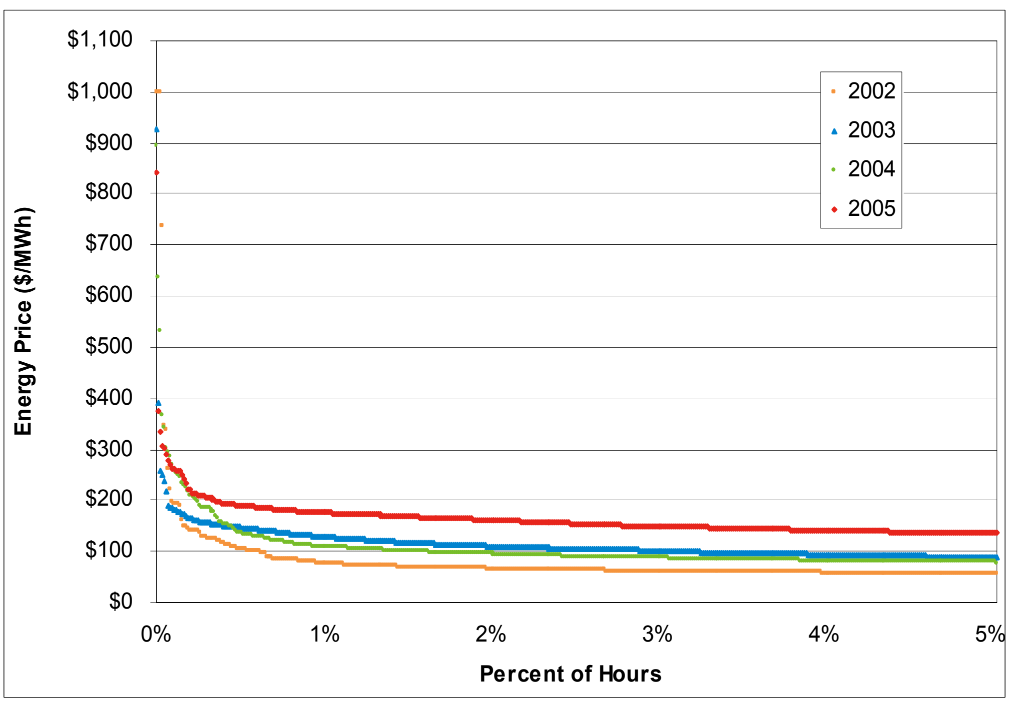

Figure 3-23: System real-time price-duration curves, prices in most expensive 5% of hours, 2002–2005.

Note: System price is the single energy-clearing price for the Interim Market period ending February 28, 2003, and load-weighted Real-Time Energy Market LMPs for March 2003 to December 2005.

3.1.4.3 Electricity Prices and Fuel Costs

Figure 3-24 shows the marginal, or price-setting, fuels during 2005 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 there is a marginal unit 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 2005 and are not included in the figure. The figure shows that units burning natural gas were marginal 54% of the time during the period. Gas/oil units, most of which burn gas as their primary fuel, were on the margin 33% 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.

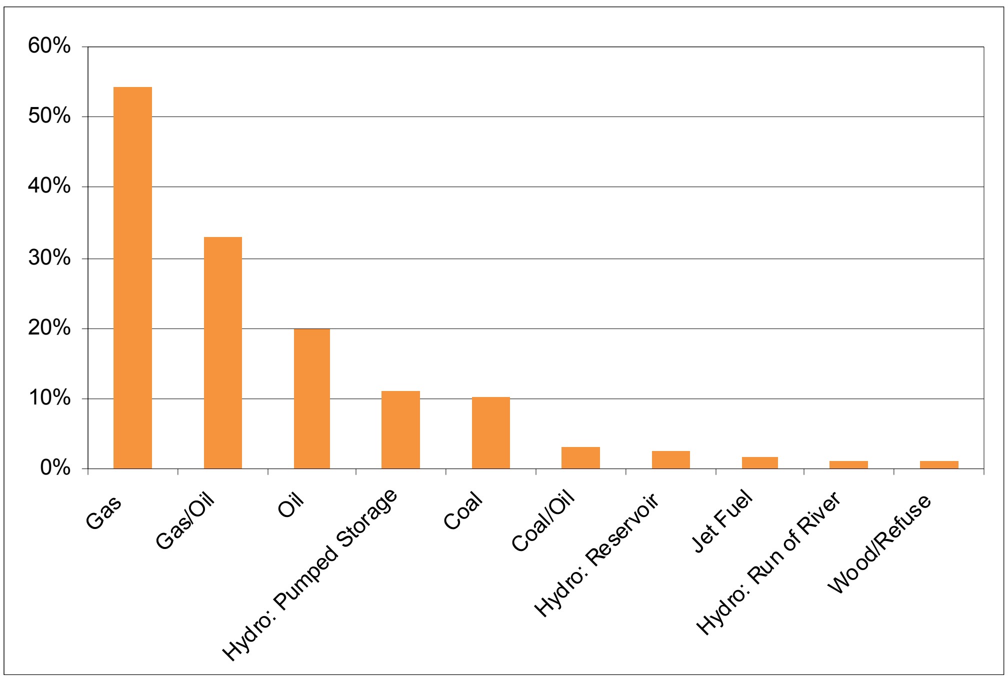

Figure 3-24: Marginal fuels in real time, 2005, percentage of pricing intervals.

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

Figure 3-25 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 Btu/kilowatt-hour (kWh), while the oil plant production costs are based on a heat rate of approximately

[53] Averages are not weighted.

10,500 Btu/kWh.[54] The day-ahead spot prices for fuel are used to calculate each unit's variable costs. Unexpected system conditions, such as an unplanned generator or transmission line outage, may cause electricity price spikes unrelated to fuel prices. The late-January spikes in the variable costs of a gas-fired generator were caused by high natural gas prices, however.

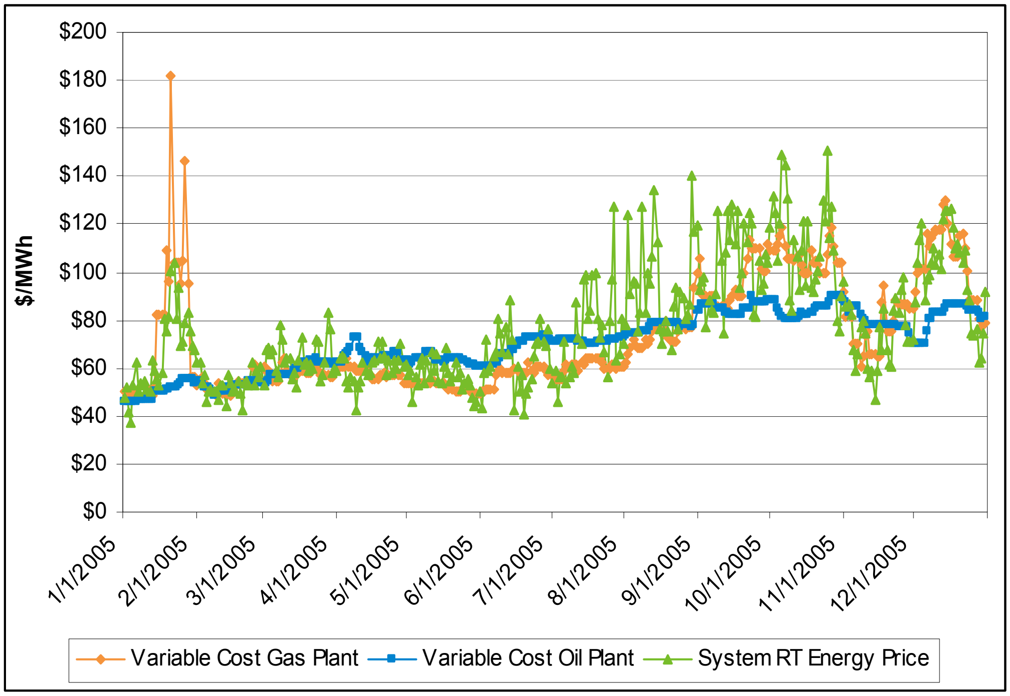

Figure 3-25: Daily average real-time system price of electricity compared with variable production costs.

Since fuel is the largest variable expense for most electricity generating plants, in a competitive market the energy offers made by fossil fuel generators are sensitive to variation in fuel prices. Hence, electricity-market clearing prices rise and fall with changes in fuel prices. Figure 3-25 shows this relationship, with gas plant costs and electricity prices highly correlated. This is consistent with the marginal fuels data shown in Figure 3-24. Because the fuels used by marginal generators vary, and because changing demand levels cause movements along the supply curve, electricity prices are not expected to perfectly track underlying fuel costs, but rather, more loosely correlate with fuel costs.

Table 3-3 shows average annual fuel prices for natural gas and No. 6 oil for each of the last six years, each indexed to its value in the year 2000. These two fuels are shown because they are on the margin a majority of the time in New England, as was shown in Figure 3-24. Natural gas prices were 44% higher in 2005 than in 2004. Oil prices increased 32% from 2004 to 2005. These data suggest that the electricity price changes shown in Figure 3-22 are due primarily to the large change in fuel costs.

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

Table 3-3
Fuel Price Index, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004	2005
Natural gas	1.00	0.88	0.75	1.30	1.37	1.97
No. 6 oil (1%)	1.00	0.83	0.90	1.09	1.12	1.66

To help isolate electricity price differences due to changes in fuel prices, the ISO calculates an annual electricity price adjusted for fuel prices. The fuel-adjusted 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 year 2000 fuel prices.

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 energy prices for the SMD period of March 2003 through December 2005 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 without reliable prices 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 five-year analysis period. The adjusted five-minute energy prices were then averaged to the hourly level and weighted by hourly load before calculating the yearly averages.

Table 3-4 and Figure 3-26 show yearly average actual and fuel-adjusted real-time electricity prices for New England. These averages are load weighted. Actual real-time electricity prices in 2005 were much higher than in previous years. After adjusting for the price of fuels used to generate electricity, the electricity price in 2005 was similar to prices in the previous years. ISO analysis suggests that the $1.66 increase in fuel-adjusted prices was largely caused by increases in both average and peak loads from 2004 to 2005, with no similar increase in supply. This finding supports the hypothesis that the higher actual electricity prices in 2005 were caused primarily by higher fuel prices.

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

	2000	2001	2002	2003	2004	2005
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
Load-weighted electric energy price normalized to year 2000 fuel-price levels	$45.95	$48.60	$46.65	$43.51	$43.33	$44.99

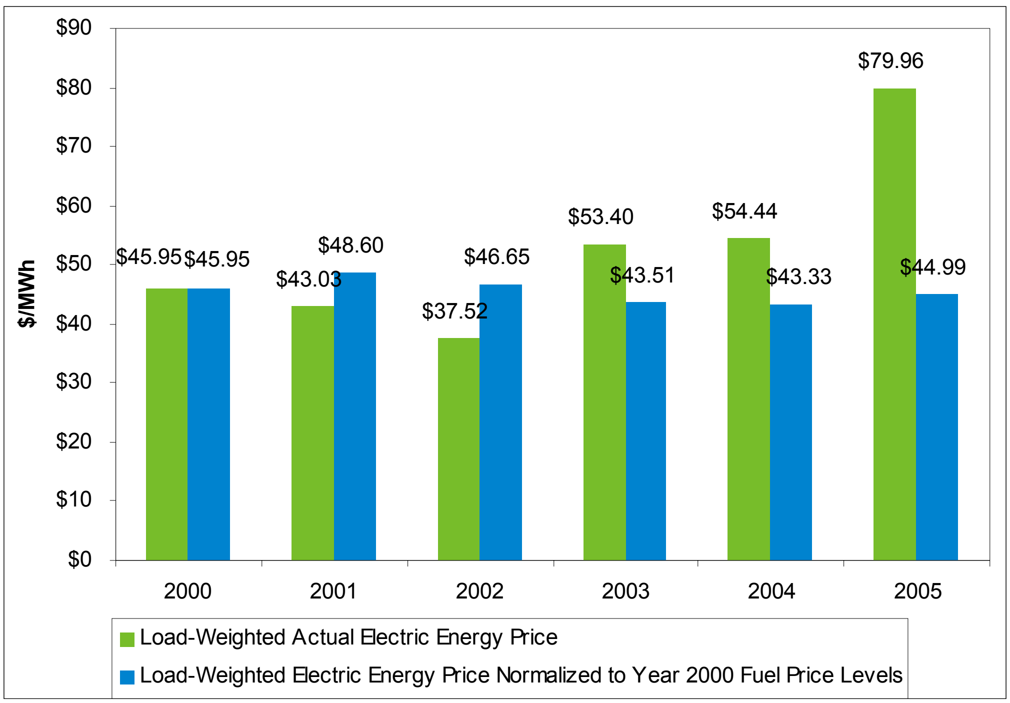

Figure 3-26: Actual and fuel-adjusted average real-time electric energy prices, 2000–2005.

The variation among fuel-adjusted yearly average prices was less than among 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, and 2005, 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 five-year period. It also does not account for variations in emissions costs.

Regression analysis was used to estimate the relationship of average daily real-time prices at the Hub to natural gas and fuel-oil prices and system net energy for load. Using the model's estimated parameters to calculate annual load-weighted averages of the real-time Hub prices produces results very similar to the actual load-weighted average prices for 2004 and 2005. The actual prices are $54.44 for 2004 and $79.96 for 2005, while the weighed average of the model's predicted prices are $53.45 and $78.11, respectively for 2004 and 2005. (See Appendix A.3 for additional information.)

The estimated impact that changes in load have on average daily real-time Hub prices can be calculated by multiplying the change in the average daily system NEL of 11.5 GWh by the estimated parameter associated with system NEL. This yields an estimated price impact of about $1.10. A 95% confidence band on this price impact is between $0.93 and $1.28. This represents about 4% of the actual increase in load-weighted average real-time prices at the Hub between 2004 and 2005.

3.1.4.4 Electric Energy Prices throughout the Year

Table 3-5 shows the 2005 average, minimum, and maximum LMP values for the Hub and the eight load zones in New England. Generally, day-ahead prices exhibited a slight premium over their real-time counterparts. Zonal prices varied from the Hub according to zonal supply/demand balance and the existence of congestion. During 2005, 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, due to the effects 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 $12.33/MWh, or about 17%. During high-demand periods, Connecticut is frequently import-constrained, which results in congestion and higher prices. Connecticut also experiences relatively high loss components, due to a combination of its distance from economic generation and weak transmission lines.

Table 3-5
Summary LMP Statistics by Zone for 2005, All Hours

Location/Zone	LMP ($/MWh)					
	Average		Minimum		Maximum	
	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time
Internal Hub	$78.55	$76.64	$26.82	$0.00	$194.67	$856.06
Maine Load Zone	$70.82	$70.38	$12.85	$0.00	$183.89	$779.45
New Hampshire Load Zone	$75.30	$74.46	$26.12	$0.00	$189.91	$844.64
Vermont Load Zone	$78.79	$77.47	$6.74	$0.00	$195.65	$852.42
Connecticut Load Zone	$83.15	$80.16	$26.65	$0.00	$247.91	$865.94
Rhode Island Load Zone	$76.19	$74.55	$26.30	$0.00	$191.15	$827.72
SEMA Load Zone	$76.09	$74.44	$26.38	$0.00	$190.17	$838.73
WCMA Load Zone	$78.74	$77.06	$26.79	$0.00	$194.85	$857.52
NEMA Load Zone	$79.85	$76.98	$26.54	$0.00	$323.78	$1,078.48

The day-ahead Hub price averaged $78.55/MWh, while the corresponding real-time price averaged $76.64/MWh, a $1.91/MWh or 2.4% difference.[55] Maximum hourly prices never reached $1,000/MWh in the Day-Ahead Energy Market and exceeded $1,000/MWh only in NEMA in the Real-Time Energy Market.

Figure 3-27 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 due to 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 but were more pronounced in the second half of the year. The increase in volatility during the latter half of the year arises from regular summer-period volatility combined with gas-price uncertainty due to hurricane-related natural gas supply interruptions.

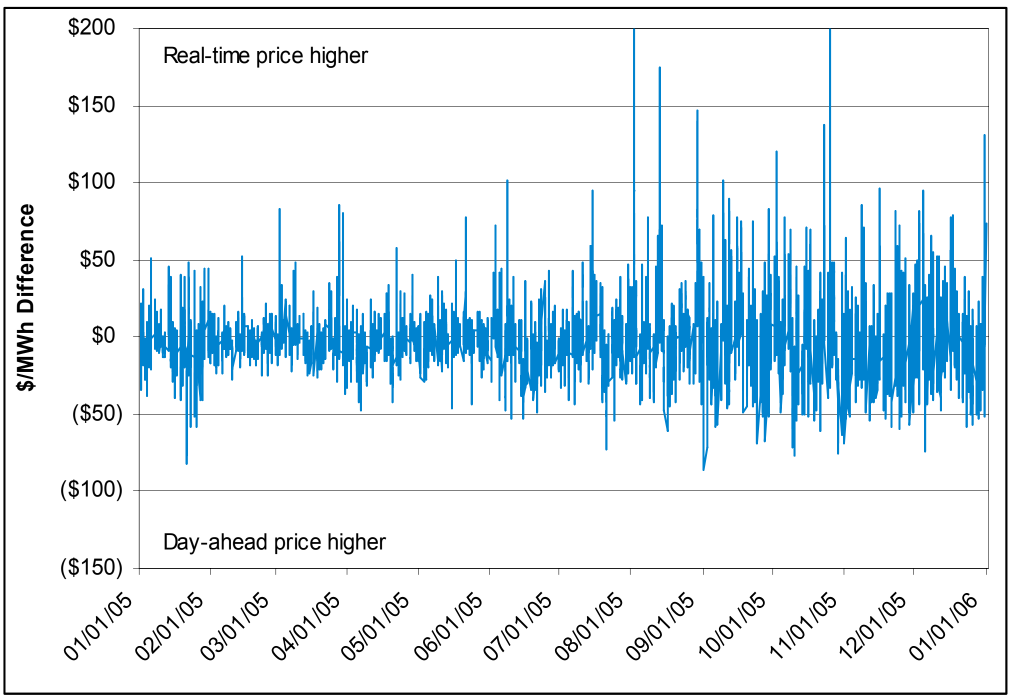

Figure 3-27: Hourly real-time Hub price minus day-ahead price, differences less than $200/MWh, January–December 2005.

The largest difference between day-ahead and real-time prices occurred on October 25, in hour ending (HE) 7:00 p.m.[56] The day-ahead price was $130.77/MWh, while the real-time price was $856.06/MWh, a difference of $725.29/MWh. OP 4, *Action during a Capacity Deficiency*, was in effect at the time, and a deficiency of 10-minute reserves caused the ISO to declare a Reserve-

[55] These average prices are not load-weighted.

[56] LMPs are based on hour endings. For example, the time period of 12:01 a.m. to 12:59 a.m. is "hour-ending 1."

Shortage Pricing Event.[57] During this event, which spanned portions of two hours, five-minute LMPs were $1,000/MWh, resulting in the high real-time price.

On the maps in Figure 3-28, the average annual nodal LMPs are shown as color gradations from blue, representing $70/MWh, to red, representing prices of $90/MWh and higher. The Norwalk/Stamford area of Connecticut had the highest prices, while Maine had the lowest prices. Norwalk/Stamford has historically been an area with import constraints and higher prices than other areas. In 2005, work on transmission upgrades as part of the Southwest Connecticut Reliability 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 due to a combination of limited economic generation in the area and limited import capacity. In general, electricity flows into northwestern Connecticut; little economic local generation is available to satisfy load, and the loss component tends to be high.

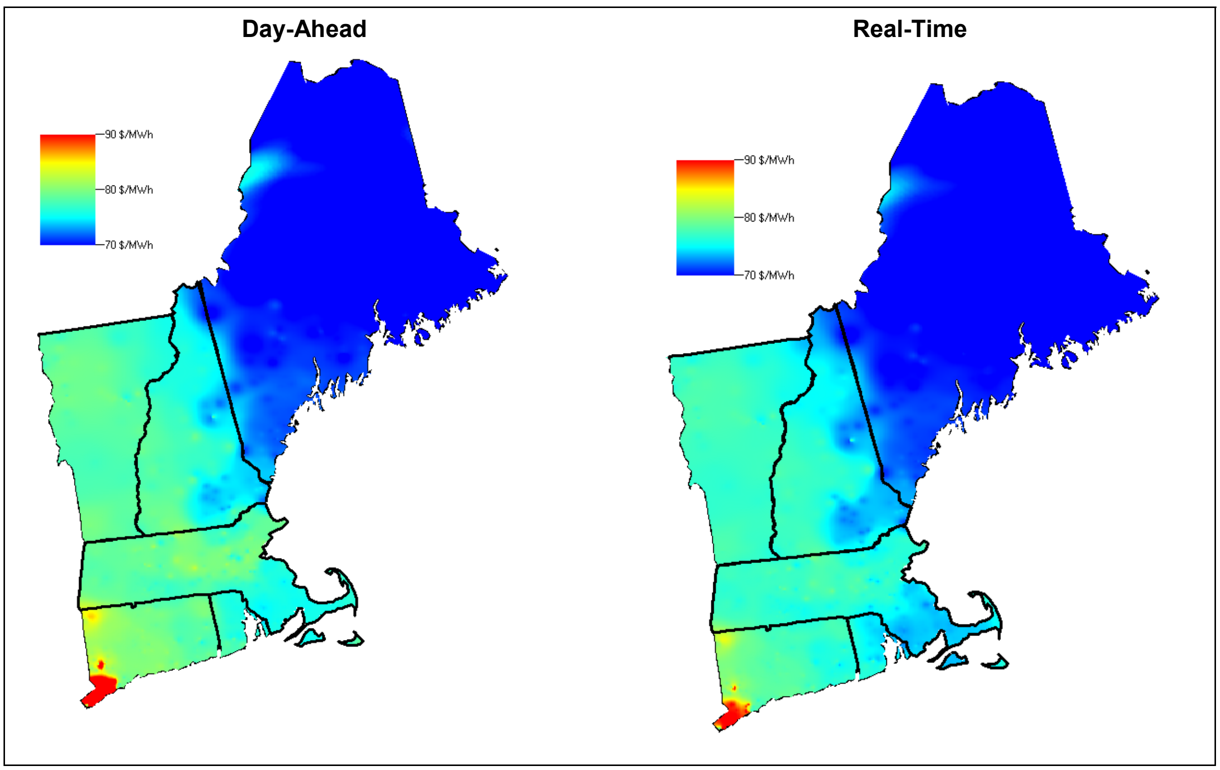

Figure 3-28: Average nodal prices, 2005, $/MWh.

[57] The ISO will declare a Reserve-Shortage Pricing Event when the control area is experiencing a deficiency in total 10-minute operating reserves, or 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.

3.1.4.5 Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a context for evaluating price levels in New England. Figure 3-29 compares the 2004 average system prices with the 2005 prices for the three northeastern ISOs—ISO New England, the New York ISO (NYISO), and PJM Interconnect (PJM). The prices for 2005 were significantly higher in all three pools. ISO New England and NYISO prices are calculated hourly system prices based on locational prices and locational loads, while PJM prices are published hourly system prices.[58] New York had the highest prices, while PJM had the lowest.

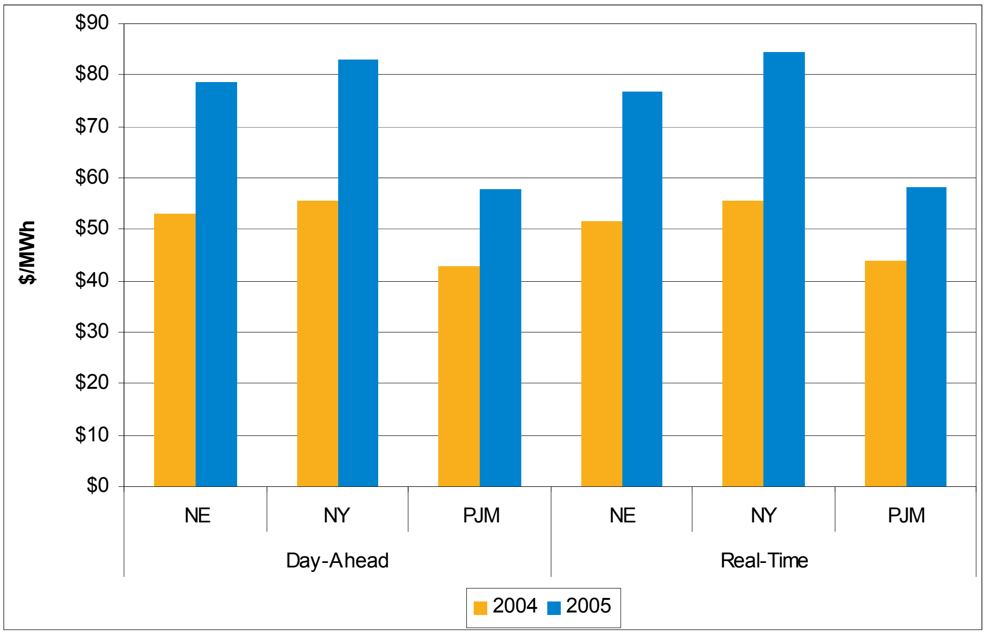

Figure 3-29: Average system prices, 2004 and 2005, ISO New England, NYISO, and PJM.

Variation in average prices among the power pools is affected by a variety of factors, such as transmission congestion, daily and seasonal load 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.[59] Appendix A.4 shows the yearly average system prices for on- and off-peak periods for ISO New England, NYISO, and PJM.

3.1.4.6 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

[58] Yearly average system prices are not load-weighted. PJM's Web site is available at http://www.pjm.com. NYISO's Web site is available at http://www.nyiso.com.

[59] See http://www.pjm.com/services/system-performance/operations-analysis.html.

(ICE), an electronic marketplace for energy trading. This section presents comparisons between ISO energy-market prices and ICE prices.

Figure 3-30 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 −$3.47/MWh.[60] The standard deviation of the differential is $15.40/MWh, suggesting that the bilateral market often does not accurately estimate the LMPs. In addition, the bilateral market estimate of the LMPs becomes more inaccurate as system conditions become tighter. Figure 3-31 compares monthly-average real-time 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 exceeded $20/MWh in November.

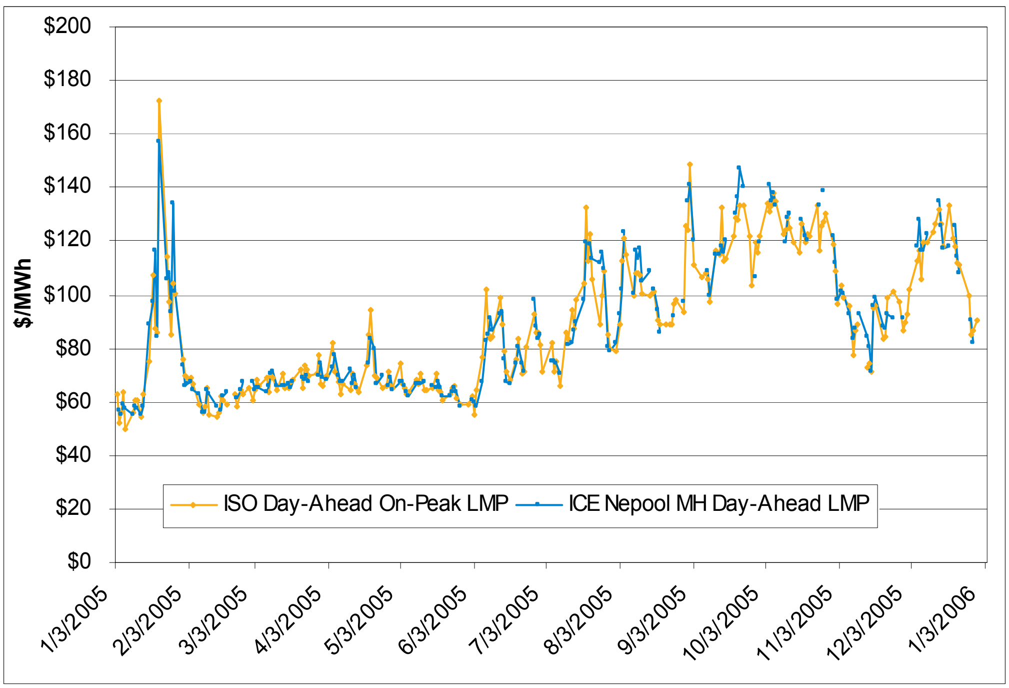

Figure 3-30: Comparison of ISO day-ahead Hub LMPs to Intercontinental Exchange day-ahead New England trade prices.

[60] 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.

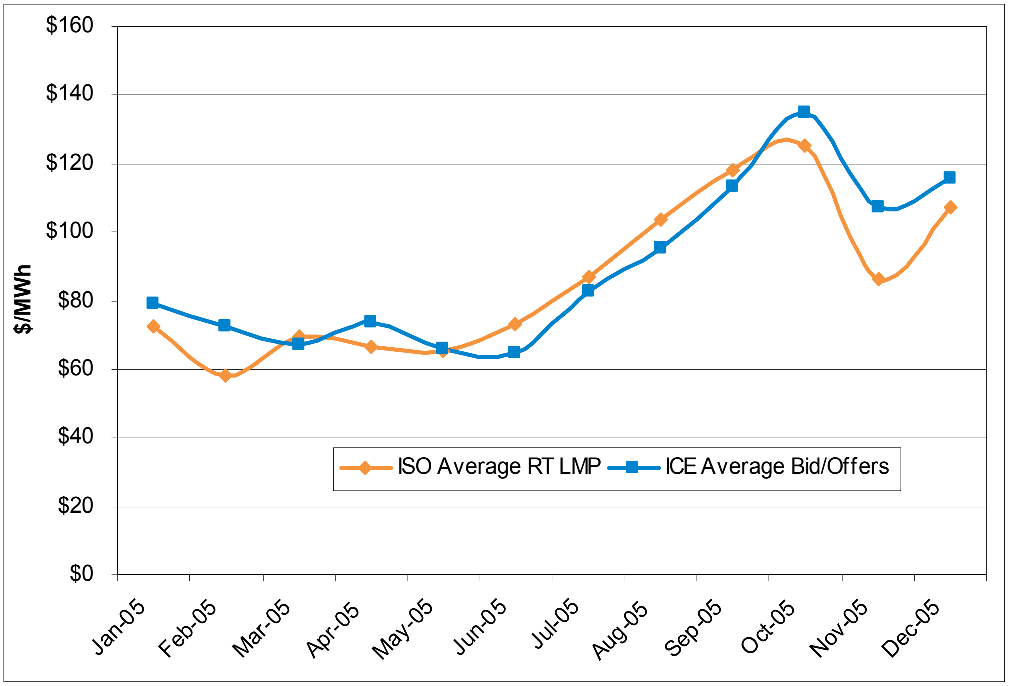

Figure 3-31: Monthly delivery—last ICE bilateral trade compared with real-time ISO LMPs.

3.1.4.7 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 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 3-32 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 for 2005. The LMPs for the Maine, New Hampshire, Rhode Island, and SEMA load zones are less than the Hub LMP, and the LMPs for NEMA, Connecticut, Vermont, and WCMA load zones are greater than the Hub LMP. These differences 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 indicating the Day-Ahead Energy Market is functioning well. As noted in Section 3.1.2.2 on load obligation, in Vermont, a large real-time load obligation was not bid into the Day-Ahead Energy Market in some months. This caused the difference in congestion between day-ahead and real-time that is reflected in Figure 3-32.

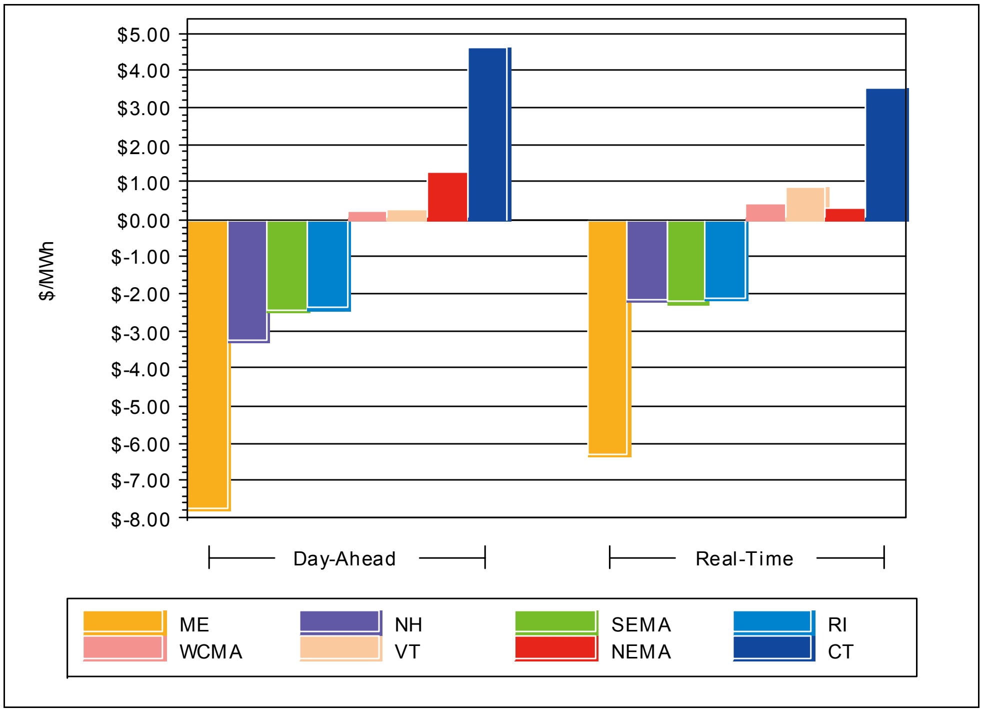

Figure 3-32: Average hourly zonal LMP differences from the Hub, 2005.

In 2005, the price separation among the load zones was greater than in 2004. On average in 2005, day-ahead prices in Connecticut were about $4.50/MWh higher than at the Hub, while real-time prices were about $3.50/MWh higher. In 2004, the difference between prices in Connecticut and at the Hub was less than $1.00/MWh in both markets. Day-ahead price differences between NEMA and the Hub have increased by about $1.00/MWh, while real-time price differences were similar in 2004 and 2005.

Figure 3-33 shows total congestion revenue by quarter since the beginning of SMD. Congestion costs were high in the second and third quarters of 2005, when high loads frequently caused binding constraints and congestion in the NEMA and Connecticut load pockets. Total congestion revenues in 2005 were $266 million. Congestion revenues are collected in the Congestion Revenue Fund and used to pay FTR holders. Section 4.6 discusses the Congestion Revenue Fund in more detail.

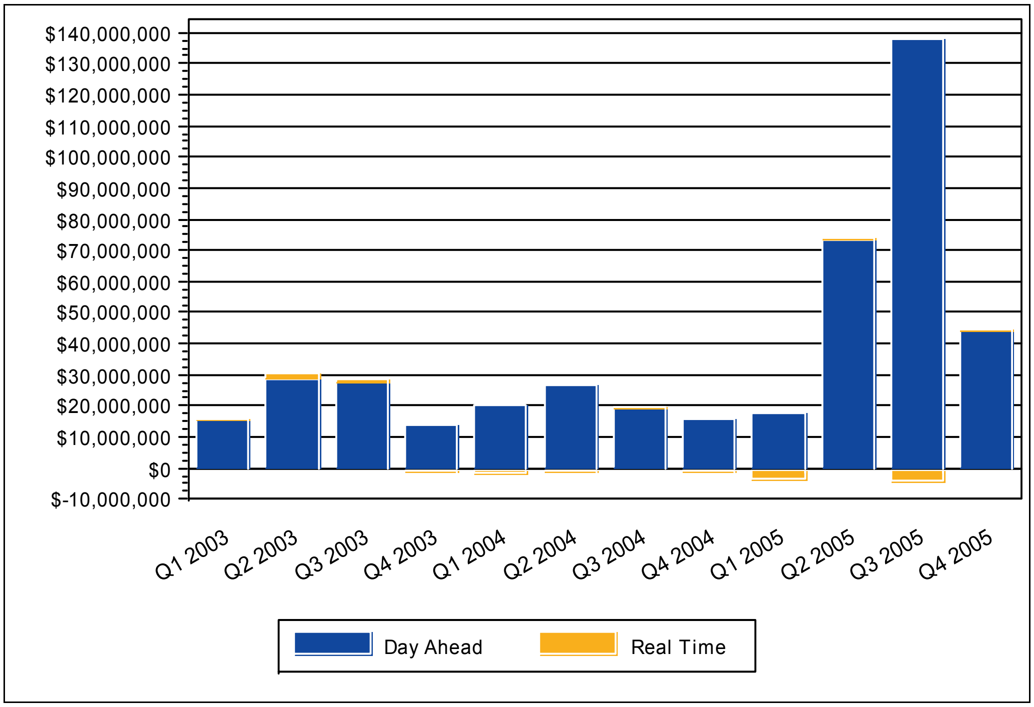

Figure 3-33: Total congestion revenue by quarter.

Table 3-6 and Table 3-7 show the 2005 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, it is more useful to compare trends in the differences between LMPs over time, rather than trends in the values of the congestion and marginal loss components. The reference bus calculation will affect the variation in each component, but the change in LMPs will reliably show the net impact of the components.

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. Rather, differences in the congestion components between locations indicate relative congestion costs. The Hub and most load zones (ME, NH, VT, RI, SEMA, WCMA) experienced negative real-time congestion on average. 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. Connecticut and NEMA experienced positive real-time congestion. These results are consistent with historical experience that shows NEMA and Connecticut to be transmission-constrained areas.

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

Location	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	$-1.23	$0.94	$-0.29
Connecticut Load Zone	$2.80	$1.51	$4.32
Maine Load Zone	$-4.08	$-3.93	$-8.02
NEMA Load Zone	$1.31	$-0.30	$1.01
New Hampshire Load Zone	$-2.66	$-0.88	$-3.54
Rhode Island Load Zone	$-1.87	$-0.77	$-2.64
SEMA Load Zone	$-1.79	$-0.95	$-2.74
Vermont Load Zone	$-1.56	$1.52	$-0.04
WCMA Load Zone	$-1.25	$1.15	$-0.10

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

Location	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	$-0.88	$0.92	$0.04
Connecticut Load Zone	$1.98	$1.58	$3.56
Maine Load Zone	$-2.33	$-3.89	$-6.23
NEMA Load Zone	$0.65	$-0.27	$0.38
New Hampshire Load Zone	$-1.35	$-0.79	$-2.14
Rhode Island Load Zone	$-1.22	$-0.83	$-2.05
SEMA Load Zone	$-1.21	$-0.95	$-2.16
Vermont Load Zone	$-0.53	$1.40	$0.87
WCMA Load Zone	$-0.68	$1.14	$0.46

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. If an additional injection of electricity at a location is estimated to decrease system losses, the loss component for that location will be positive, increasing the LMP. Electricity at that location has additional value, because it results in smaller losses. If an additional injection at a location is estimated to increase system losses, the loss component for that location will be negative, lowering the LMP. Exporting zones generally have negative loss components, while importing zones generally have positive loss components. An additional injection in an exporting zone increases losses, which increases the amount of power shipped long distances. Injections in an importing zone reduces losses, which reduces the need for power to travel long distances.

Real-time loss components are positive in the Connecticut, Vermont, and Western/Central Massachusetts load zones and at the Hub. They are negative in the NEMA, Rhode Island, Southeastern Massachusetts, New Hampshire, and Maine load zones. Although importing zones, NEMA and Rhode Island 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, so power does not need to travel long distances to reach Rhode Island and NEMA.

The methods for calculating the marginal loss component and accounting for losses can result in the collection of more revenue from load than is required to pay generators. These revenues are collected in the Marginal Loss Revenue Fund. The revenue is returned to load-serving entities according to each participant's monthly share of the real-time load obligation, net of bilateral trades. In 2005, a total of $98.8 million was returned to load-serving entities from the Marginal Loss Revenue Fund.

3.1.4.8 All-In Wholesale Electricity Market Cost Metric

The *all-in* wholesale electricity cost is the annual total of the energy, uplift, capacity, and ancillary service components and is a standard electricity market metric defined by FERC.[61, 62] Figure 3-34 shows the all-in wholesale electricity cost in New England over the last four years. Figure 3-35 shows the same information on a $/MWh basis. Total all-in wholesale electricity costs were much higher in 2005 than in previous years as a result of increased fuel costs and increased demand. Capacity costs in 2004 and 2005, as reflected in the ISO-administered auctions, were very small and are not discernible in the figures.

[61] From May 1, 1999, to June 30, 2001, uplift 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, uplift included economic and noneconomic NCPC. Payments for VAR control were included in noneconomic NCPC. From March 1, 2003, to December 31, 2005, uplift included first- and second-contingency NCPC and Voltage and Distribution reliability payments. See Section 4.2 for additional information.

[62] From May 1, 1999, to February 28, 2003, ancillary services included payments for Automatic Generation Control, 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, 2005, ancillary services included Regulation Market and Forward Reserve Market payments.

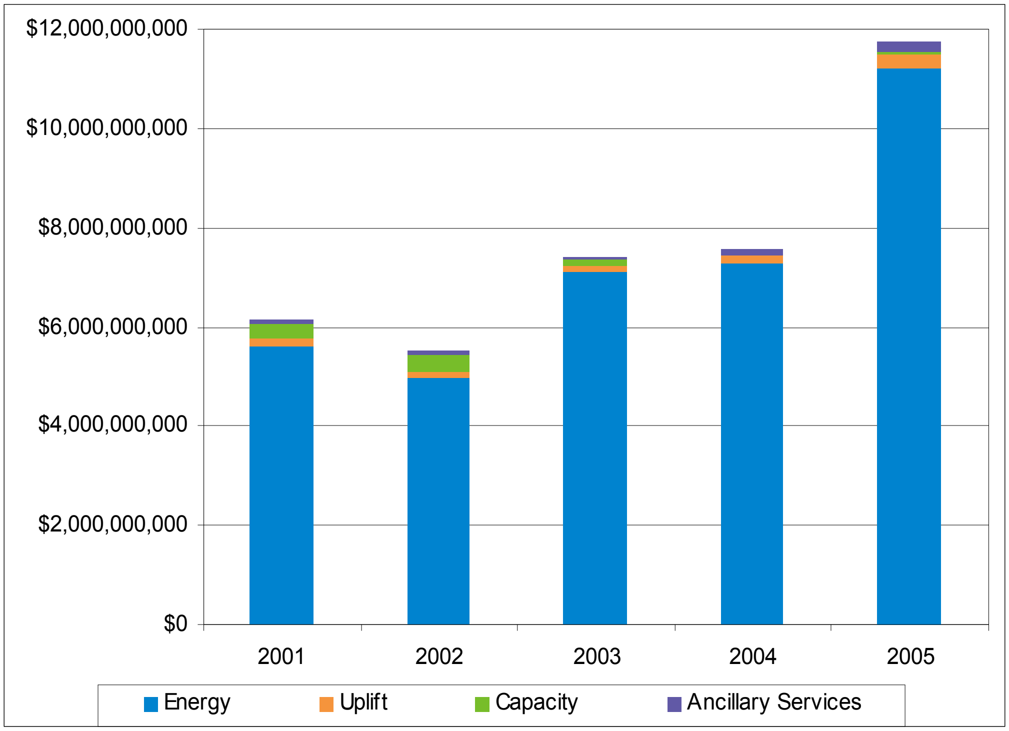

Figure 3-34: New England wholesale electricity market cost metric: energy, uplift, capacity, ancillary services totals, 2001–2005.

Note: Energy costs for the Interim Markets period = Energy Clearing Price * System Load; Energy costs for the SMD period = Real-Time Load Obligation * Real-Time LMP.

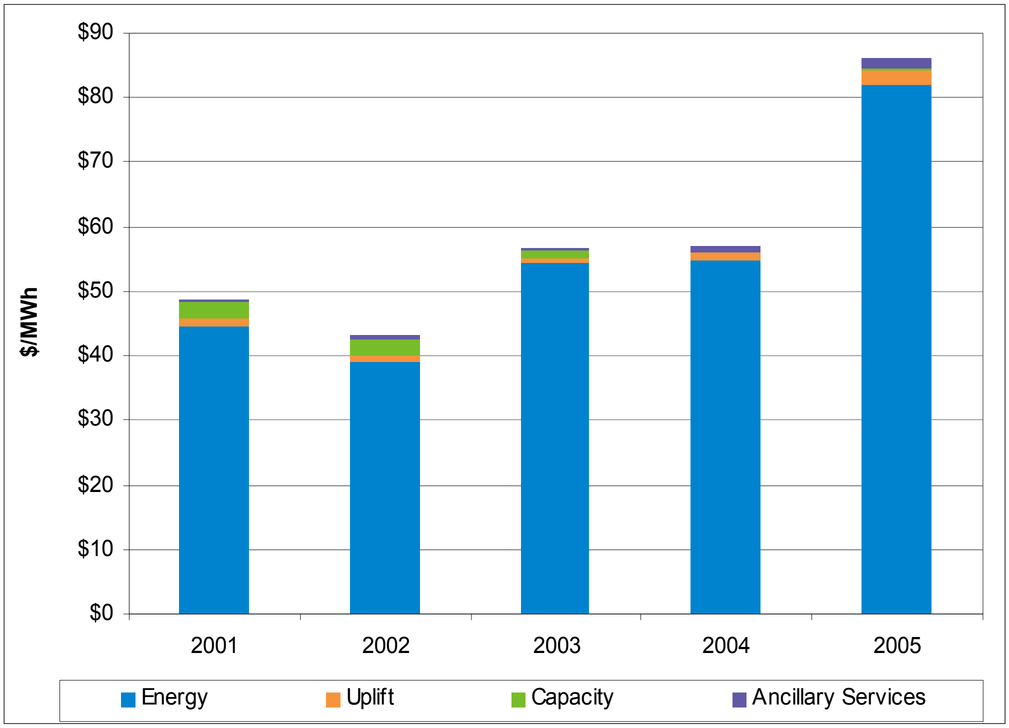

Figure 3-35: New England wholesale electricity market cost metric: energy, uplift, capacity, ancillary services $/MWh, 2001–2005.

Note: Energy costs for the Interim Markets period = Energy Clearing Price * System Load.. Energy cost for the SMD period = Real-Time Load Obligation * Real-Time LMP.

Table 3-8 shows the market cost metric for 2004 and 2005 in $/MWh and percentages. Energy costs are by far the largest component of the all-in wholesale cost metric, accounting for 95% of the total in 2005. Uplift and capacity costs as a percentage of the total metric were both up in 2005 relative to 2004, but combined, account for a small percentage of the total metric.

Table 3-8
New England Wholesale Electricity Market Cost Metric: 2004 and 2005

$/MWh	2004	% of Tot.	2005	% of Tot.
Energy	$54.75	96.0%	$82.05	95.3%
Uplift	$1.27	2.2%	$2.11	2.5%
Capacity	$0.06	0.1%	$0.51	0.6%
Ancillary Services	$0.96	1.7%	$1.46	1.7%
Total	$57.05	100.0%	$86.13	100.0%

The FERC market-cost metric for New England presented in Figure 3-34 and Figure 3-35 includes the cost of real-time energy, capacity-market costs, ancillary services, and uplift. Analyzing this metric provides a useful measure of the trends in wholesale electricity prices over time and a comparison across wholesale markets. In the New England wholesale electricity markets, additional revenues and charges are associated with serving wholesale loads that are not included in the FERC-defined metric. These are shown in Table 3-9 and include revenues and charges related to the Marginal Loss Revenue Fund, FTR and Auction Revenue Rights (ARR) allocations, the Congestion Revenue Fund, and Reliability Agreements.[63] By accounting for revenues returned to load as well as all costs, the presentation of these revenues and charges provides a more complete picture of the costs associated with serving wholesale loads in the region.

Table 3-9
Wholesale Electricity Market Price Components, $000's, January 2005–December 2005

Month	NEL 000's of MWh	FERC Tot. Value ($000's)	FERC $/MWh	Day-Ahead Marg. Loss Rev.	Real-Time Marg. Loss Rev.	Monthly FTR Auction	Long-Term FTR Auction	ARR Alloc.	Neg. Target Alloc.	Pos. Target Alloc.	Cong. Rev. Fund.	Reliab. Agrmts.	Total Other Costs[(a)]	Oth. Costs $/MWh
Jan	12,235	866,206	$70.80	-890	-8,630	4,916	3,531	-4,774	970	-10,503	-1,886	18,635	1,369	$0.11
Feb	10,537	618,914	$58.74	-2,339	-5,082	3,649	3,531	-6,841	621	-3,431	-599	17,447	6,956	$0.66
Mar	11,332	793,437	$70.02	-3,274	-5,470	2,886	3,531	-6,395	1,935	-4,289	-493	21,017	9,448	$0.83
Apr	9,829	675,928	$68.77	-820	-5,228	1,640	3,531	-5,087	10,755	-32,113	-5,187	16,290	-16,219	-$1.65
May	10,006	638,673	$63.83	273	-6,402	3,497	3,531	-7,044	2,765	-12,547	-2,061	23,533	5,545	$0.55
Jun	11,870	876,975	$73.88	1,196	-9,635	5,108	3,531	-8,469	8,497	-34,793	-8,232	25,578	-17,219	-$1.45
Jul	12,961	1,096,929	$84.63	602	-13,199	8,176	3,531	-11,446	7,069	-41,056	-9,682	23,885	-32,120	-$2.48
Aug	13,332	1,395,228	$104.65	-6,741	-7,711	8,718	3,531	-12,149	8,514	-46,621	-11,707	20,083	-44,083	-$3.30
Sep	11,198	1,275,903	$113.94	-3,115	-10,521	4,105	3,531	-7,296	4,592	-27,974	-6,703	22,158	-21,223	-$1.90
Oct	10,677	1,285,905	$120.44	-2,578	-10,245	7,189	3,531	-10,497	5,555	-26,945	-4,499	12,140	-26,349	-$2.47
Nov	10,463	853,595	$81.58	-1,706	-664	8,510	3,531	-11,942	1,434	-8,485	-1,626	20,653	9,705	$0.93
Dec	11,944	1,262,577	$105.71	-2,560	2,833	6,422	3,531	-9,919	5,094	-16,559	-3,326	22,952	8,468	$0.71

(a) "Total Other Costs" and "Other Costs" show total other revenues and charges.

[63] During the ARR process, auction revenues are awarded primarily to congestion-paying load-serving entities.

3.1.5 Energy Market Volumes

Table 3-10 and Table 3-11 present information about the quantity of electricity transacted in the Day-Ahead and Real-Time Energy Markets. Participant transactions to buy and sell electricity 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 upon 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 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 of 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 to be willing to pay congestion charges. *Wheel-through* contracts, in which both generation and delivery occur outside of 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 very 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. This may be due to net imports from New York not being well correlated with differences in New York and New England prices.

Table 3-10
MWh Quantities Traded in the Day-Ahead and Real-Time Energy Markets by Transaction Type, January–June 2005

Transaction Type by Market	Jan 05	Feb 05	Mar 05	Apr 05	May 05	Jun 05
Day Ahead						
Load Obligation – Day-Ahead LMP[a]	12,193,457	10,642,404	11,077,163	9,523,485	9,788,800	11,575,760
Bilateral – Export With Price[b]	*2,053*	*8,742*	*3,811*	*16,252*	*29,616*	*30,376*
Bilateral – Export Without Price	*51,950*	*172,045*	*196,698*	*222,432*	*297,981*	*359,013*
Bilateral – Export Up-To Congestion	*14,191*	*16,870*	*3,690*	*16,175*	*50*	*4,261*
Bilateral – Internal for Market, Day Ahead (IBM)	9,086,897	8,329,332	8,515,963	8,012,760	7,994,581	8,473,556
Bilateral – Import With Price	89,898	45,909	167,766	159,140	72,303	182,201
Bilateral – Import Without Price	573,399	504,111	637,084	578,217	380,863	437,908
Bilateral – Import Up-To Congestion	75	0	2,766	1,417	0	1,257
Total Day-Ahead MWh	**21,943,727**	**19,521,756**	**20,400,743**	**18,275,018**	**18,236,546**	**20,670,683**
Real Time						
Adjusted Load-Obligation Deviation – Real-Time LMP[c]	156,806	50,022	422,859	607,941	635,387	750,309
Adjusted Load-Obligation Deviation – lower than Day Ahead	*-989,722*	*-731,977*	*-847,715*	*-807,381*	*-775,940*	*-1,040,046*
Adjusted Load-Obligation Deviation – higher than Day Ahead	*1,146,528*	*781,999*	*1,270,575*	*1,415,321*	*1,411,327*	*1,790,355*
Bilateral – Export With Price	*0*	*0*	*0*	*0*	*11,573*	*16,559*
Bilateral – Export Without Price	*123,536*	*214,935*	*241,609*	*607,941*	*414,804*	*478,851*
Bilateral – Internal for Market – Additional to Day-Ahead IBMs	384,837	327,418	353,305	-807,381	332,841	348,275
Bilateral – Internal for Load, Real-Time	52,062	45,413	47,740	1,415,321	40,586	50,193
Bilateral – Import With Price	46,372	41,138	104,443	338,139	106,098	145,039
Bilateral – Import Without Price	815,172	670,681	857,397	317,721	570,222	599,952
Bilateral – Through	6,585	0	1,714	41,465	1,137	4,603
Total Real-Time MWh	**1,461,834**	**1,134,673**	**1,787,458**	**163,065**	**1,686,271**	**1,898,371**
Net Energy for Load (000's of MWh)	**12,235**	**10,537**	**11,334**	**9,829**	**10,006**	**11,871**

[(a)] The day-ahead load obligation for energy is equal to the megawatt-hours of demand bids, decrement 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 3-11
MWh Quantities Traded in the Day-Ahead and Real-Time Energy Markets by Transaction Type, July–December 2005

Transaction Type by Market	Jul 05	Aug 05	Sep 05	Oct 05	Nov 05	Dec 05
Day Ahead						
Load Obligation – Day-Ahead LMP	12,726,255	13,106,399	11,466,697	10,564,119	10,534,445	11,740,747
Bilateral – Export With Price	*20,749*	*24,843*	*132,495*	*60,126*	*135,193*	*62,908*
Bilateral – Export Without Price	*282,191*	*302,117*	*251,913*	*198,135*	*229,958*	*184,065*
Bilateral – Export Up-To Congestion	*12,064*	*6,648*	*1,284*	*200*	*2,680*	*654*
Bilateral – Internal for Market, Day Ahead	8,435,110	8,541,483	8,349,380	7,828,340	7,665,768	8,287,101
Bilateral – Import With Price	195,947	209,405	186,745	256,919	249,776	249,991
Bilateral – Import Without Price	471,268	484,626	404,536	394,830	508,515	767,425
Bilateral – Import Up-To Congestion	298	4,151	16,081	3,822	6,848	12,732
Total Day-Ahead MWh	**21,828,878**	**22,346,064**	**20,423,440**	**19,048,030**	**18,965,352**	**21,057,997**
Real Time						
Adjusted Load-Obligation Deviation – Real-Time LMP	643,729	597,774	170,078	418,008	292,276	368,002
Adjusted Load-Obligation Deviation – lower than Day Ahead	*-1,194,043*	*-1,150,845*	*-1,086,537*	*-873,185*	*-800,864*	*-859,626*
Adjusted Load-Obligation Deviation – higher than DA	*1,837,772*	*1,748,620*	*1,256,614*	*1,291,194*	*1,093,140*	*1,227,628*
Bilateral – Export With Price	*6,226*	*4,117*	*15,819*	*19,005*	*2,626*	*0*
Bilateral – Export Without Price	*443,941*	*438,828*	*473,679*	*340,018*	*469,847*	*325,901*
Bilateral – Internal for Market – Additional to Day-Ahead IBMs	342,557	364,833	334,829	338,349	306,192	329,272
Bilateral – Internal for Load, Real Time	57,590	60,029	48,737	43,883	42,953	47,980
Bilateral – Import With Price	102,083	151,637	84,011	193,994	158,249	114,943
Bilateral – Import Without Price	669,997	731,800	672,831	770,950	865,447	1,126,873
Bilateral – Through	1,997	1,650	5,659	314	601	2,662
Total Real-Time MWh	**1,817,954**	**1,907,723**	**1,316,145**	**1,765,499**	**1,665,719**	**1,989,733**
Net Energy for Load (000's of MWh)	**12,961**	**13,353**	**11,198**	**10,677**	**10,463**	**11,944**

[(a), (b), (c)] See notes for Table 3-10.

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 occasions in 2005. The ISO also issued M/LCC 2, an *Abnormal Conditions Alert,* on several occasions. This 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.[64] In 2005, the market worked as expected under these stressed

[64] 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-

conditions. Because prices during some of these events were higher than in surrounding periods, selected events are briefly discussed in this section.

3.1.6.1 January 21, 2005, Cold-Weather Warning and M/LCC 2

In response to tight capacity conditions brought on by very cold weather, the ISO implemented M/LCC 2 from 5:00 p.m. on Thursday, January 20, through 11:00 p.m. on Friday, January 21. On January 20, 2005, the ISO issued a Cold-Weather Warning for January 21, 2005, with a special notice reading, "Sufficient capacity may not be available to meet the forecasted demand and reserves requirement."[65] Prior to issuing this notice, the ISO followed the procedure outlined in Appendix H to Market Rule 1, which is triggered by an ISO determination that a capacity deficiency is forecast.[66] As required by the procedure, the ISO communicated with the natural gas pipeline suppliers and gas-fired generators. It developed a seven-day capacity forecast and reviewed the weather forecast and unit availability. The ISO closely monitored the situation and performed a cold-weather analysis before 11 a.m. each day.

The special notice was elevated to a Cold-Weather Warning because the expected capacity margin ranged from 0 MW to 1,000 MW. The conditions never deteriorated to a Cold-Weather Event, as the forecasted capacity margin never fell below 0 MW, which would have triggered an OP 4 condition. The ISO evaluated the conditions that caused the January 20 warning and subsequent actions. This review can be found on the ISO's Web site under Special Reports.[67]

Day-ahead LMPs were in the $150/MWh to $200/MWh range during most on-peak hours at the Hub and load zones on January 21, while real-time prices reached a high of about $160/MWh in hour ending 6:00 p.m.

3.1.6.2 July 27, 2005, OP 4 in Southwest Connecticut

High loads and loss of generation in Southwest Connecticut caused the ISO to initiate M/LCC 2 in that subarea on Tuesday, July 26, 2005, at 10:00 a.m.

On Wednesday, July 27, temperatures in the low 90s and very high humidity levels resulted in record hourly electricity usage in New England. A new record peak load of 26,885 MW was set in the hour ending 3:00 p.m. At 12:33 p.m., the ISO initiated OP 4, Actions 1 to 5, 7 to 10, and 12 in Southwest Connecticut to maintain adequate reserves in that area. In addition, certain generators across the region were postured to maintain required capacity margins. Both M/LCC 2 and OP 4 were cancelled at 6:30 p.m. on July 27.

Real-time LMPs were very high in the Connecticut and NEMA load zones in the afternoon of July 27, with Connecticut prices reaching $430/MWh and NEMA prices reaching $931/MWh. LMPs at nodes in Southwest Connecticut exceeded $800/MWh in three hours in the afternoon. Maximum prices at the other load zones and the Hub were less than $200/MWh.

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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.

[65] The ISO posts notices on its Web site to notify participants of events, including cold-weather events, software outages, and minimum generation emergencies. Appendix H to Market Rule 1 (see below) includes the definitions for the various cold-weather events and conditions.

[66] The Appendix H used for winter 2005/2006 expired automatically on April 15, 2006. It is available in the ISO Web site archive at http://www.iso-ne.com/regulatory/tariff/sect_3/_Appendix_H/index.html. The ISO and its stakeholders are considering what provisions should be included in a new Appendix H, expected to be put in place prior to winter 2006/2007.

[67] See http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/index.html.

3.1.6.3 August 8, 2005, M/LCC2

High loads and lack of available generation in the Boston area caused the ISO to initiate M/LCC 2 in the NEMA area on Monday, August 8 at 8:00 a.m. M/LCC 2 was cancelled on Thursday, August 11, at 11:00 p.m. Hourly real-time LMPs in the NEMA load zone reached $1,006/MWh in hour ending 4:00 p.m. and $1,078/MWh in hour ending 5:00 p.m. Prices at the Hub and other load zones were under $200/MWh.

3.1.6.4 August 13, 2005 OP 4

On Saturday, August 13, extremely high loads due to hot, humid weather created a regionwide capacity shortage that necessitated the implementation of both M/LCC 2 and OP 4, Actions 1 and 6, at 4:15 p.m. The ISO cancelled both M/LCC 2 and OP 4 at 7:00 p.m. that evening.

Real-time LMPs were around $300/MWh at the Hub and most load zones, with a high of $366/MWh in the Connecticut load zone and a low of $274/MWh in the Maine load zone.

3.1.6.5 October 25, 2005, OP 4 and Reserve-Shortage-Condition Pricing

On Tuesday, October 25, the loss of the Hydro-Québec Phase II line (Comerford–Sandy Pond) in conjunction with the contingency loss of large amounts of generation on the system caused the ISO to declare M/LCC 2 and various OP 4 actions between 5:50 p.m. and 8:00 p.m. for the New England region. Additionally, the deficiency of 10-minute reserves between 6:40 p.m. and 7:30 p.m. caused the ISO to declare a Reserve-Shortage-Condition Pricing Event. During this event, the first of its kind since the inception of SMD, five-minute LMPs were $1,000/MWh, which resulted in one hour of real-time LMPs in excess of $800/MWh throughout most of the system. Service was not interrupted during this event.

3.1.7 Preparations for Extreme Winter Weather

The ISO took several steps during 2005 to prepare for the potential of extreme weather during winter 2005/2006. On November 30, 2005, FERC approved changes to Market Rule 1 designed to help maintain reliable operations during cold winter weather.[68] The changes, as listed below, were part of the Winter 2005/2006 Action Plan and were temporary, effective December 1, 2005, through March 31, 2006:

- 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% over the reference level rather than 50% above it
- For deviations due to emergency energy transactions, providing an exemption from being allocated operating-reserve charges, intended to encourage imports during times of tight power supply
- Allocating real-time operating-reserve costs related to posturing generators according to participants' real-time load obligations, rather than to real-time load-obligation deviations, as is the case with other real-time operating-reserve charges

[68] See http://www.iso-ne.com/regulatory/ferc/filings/2005/nov/er06-89-000_11-21-05.pdf.

- Implementing a winter supplemental demand-response program, which included incentive payments to demand resources

The ISO also put into place Operations for Cold Weather Conditions, Appendix H to Market Rule 1 (see Section 3.1.6.1). A unique market challenge in New England is to support reliable operations under severe winter conditions when the coincident demand for natural gas for heating and generating electricity has the potential to decrease the availability of fuel for gas-fired generation units. Because of this, these cold-weather operations focus on improving the coordination between the ISO, the operators of natural-gas-fired generation, and the operators of natural gas pipelines. Also in 2005, the ISO developed a new procedure, Operating Procedure No. 21, *Actions during an Energy Emergency* (OP 21).[69] OP 21 was designed to further mitigate the reliability impacts resulting from fuel-supply shortages or other abnormal system conditions associated with a prolonged "Energy Emergency."

3.1.8 Electric Energy Markets Conclusions

New England's electricity markets functioned well in 2005, although, on average, electricity spot-market prices were 47% higher in 2005 than in 2004. Prices were driven mainly by high fuel costs, with units burning gas or oil setting the wholesale electricity price 87% of the time. With the region's continued dependence on gas and oil, electricity prices will remain 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 high-load days in 2005. Prices in all areas were significantly higher in 2005 than in previous years. This is consistent with increased demand and relatively unchanged infrastructure. 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 $12.33/MWh. The binding constraints were generally caused by heavy loads and lack of economic generation in the load pockets of Southwest Connecticut and Boston. Congestion costs in 2005 were much higher than in 2003 and 2004, particularly in the summer months when peak loads set a new record.

Also contributing to higher prices in 2005 were high electricity consumption and record peak loads, which led to increased transmission system congestion, import constraints, and congestion costs. The increased load was due to extremes in the weather and increased economic growth. Summer-peak loads have been growing faster than average loads as the use of air conditioning has increased. This leads to a trend of declining load factors, which requires investment in resources needed for very few hours during the year.

However, in New England, like most of the country, the hourly demand for electricity is not responsive to wholesale electricity prices. Partly because retail prices do not vary with wholesale power costs, this inelasticity of consumer demand is a significant challenge for the region in controlling electricity costs.[70] Until retail pricing of electricity is more closely linked to the wholesale pricing of electricity, which would provide incentives for consumers to conserve at times of peak demand, the trend in declining load factors is not likely to reverse.

Since generation capacity was adequate to meet demand in 2005, the low level of investment was not a cause for immediate concern. However, continued growth in demand may require that emergency

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[69] See http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.

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

actions be taken to meet peak demand in the 2007 to 2009 timeframe, unless generation capacity. demand-response resources, or a combination of both are added.

3.2 Forward Reserve Market

The Forward Reserve Market, which was implemented in December 2003, is used to acquire generating resources to satisfy the requirements for 10-minute nonspinning reserves (TMNSR) and 30-minute operating reserves (TMOR) for New England. These generators can provide electricity to the system within 10 or 30 minutes in response to a contingency, even if they are not generating prior to the contingency.

FRM auctions are 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 may offer it into the auctions. Generating units selected in each auction are obligated to offer electricity into the Day-Ahead Energy Market at or above the forward-reserve strike price for the service period. Failure to do so can result in a penalty charge. The formula for determining the forward-reserve strike price is fixed for the duration of the forward-reserve service period. It is set such that a generating resource bidding electric energy at this level would be expected to operate at an annual capacity factor of 2% to 3%.[71] 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 forward-reserve fuel index is a combination of forward-price indices for natural gas and No. 2 fuel oil. All costs related to compensating generating resources in the FRM are allocated to load based on real-time load obligations.

Forward-reserve generating units selected in the auctions are paid the auction-clearing price and may be required to provide energy when the real-time LMP reaches or exceeds the strike price. Generating units must respond to the ISO’s dispatch signal within either 10 minutes (for TMNSR) or 30 minutes (for TMOR). Penalties are assessed if a forward-reserve generating unit does not provide reserves by offering into the Day-Ahead Energy Market at or above the strike price, or if the unit is not able to provide energy within 10 or 30 minutes if called upon during real-time operations.

3.2.1 Forward Reserve Market Auction Requirements and Results

Table 3-12 shows the Forward Reserve Market auction requirements. The 10-minute requirement is equal to one-half of the system’s first contingency. The 30-minute requirement is equal to one-half of the second contingency, and the replacement reserve is equal to one-quarter of the second contingency. The total purchase amounts are greater than the requirements because the purchases account for the class average EFORd (equivalent forced-outage rate demand) and the failure-to-start rates for the resources submitting offers, as described in ISO New England Manual M-36.[72,73]

[71] For each service period, a forward-reserve heat rate is established and announced prior to 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 that changes with market conditions.

[72] A forced outage is an unplanned outage. By definition, a forced outage cannot be scheduled. For more information, refer to ISO Operating Procedure No. 5, *Generation Maintenance and Outage Scheduling* (OP 5), at http://www.iso-ne.com/rules_proceds/operating/isone/op5/index.html.

[73] Manual M-36 is available on the ISO Web site at http://www.iso-ne.com/rules_proceds/isone_mnls/index.html. Additional information about Forward Reserve Market auction assumptions is available at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/cal_assump/index.html.

Table 3-12
Forward-Reserve Auction Requirements

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

Table 3-13 shows the results of each FRM auction since the implementation of the FRM. Prices for 10-minute and 30-minute products were the same in each of the five 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. A comparison of the requirements shown in Table 3-12 and the cleared quantities shown in Table 3-13 shows a downward trend in the number of megawatts cleared from the 10-minute supply and a corresponding increase in the quantity cleared from the 30-minute supply. The first auction implemented was for a shorter period than the standard winter auction period. Due to increased supply, prices have steadily fallen from $4,495/MW-Month in the first auction to $2,000/MW-Month for the October 2005 to May 2006 period.

Table 3-13
Forward-Reserve Auction Results since Market Inception

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

Figure 3-36 shows that the total volume of 10-minute reserves offered into the market has been increasing with each successive auction.

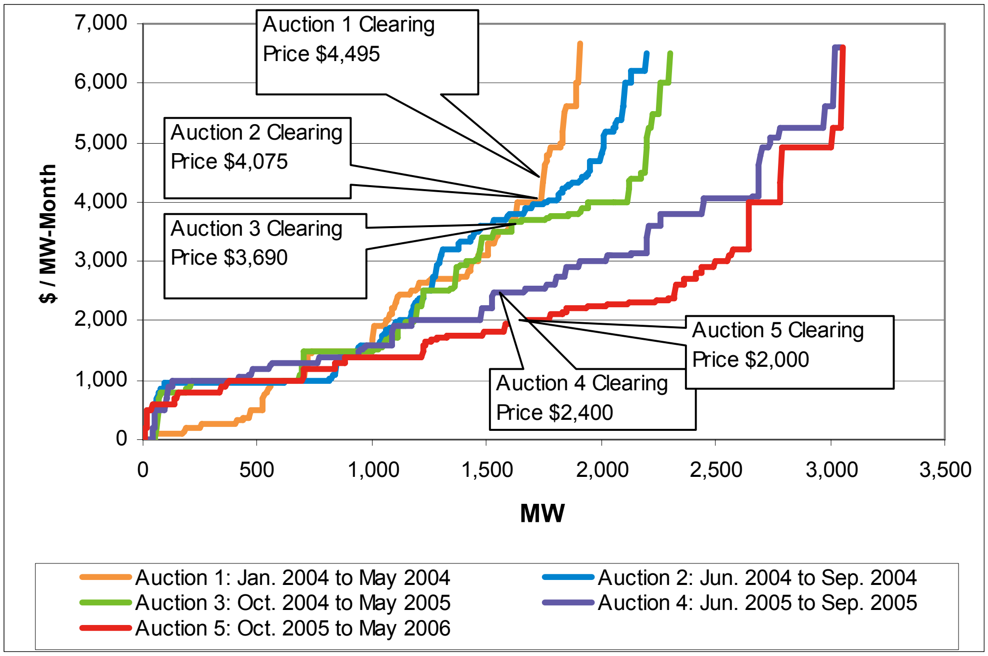

Figure 3-36: Supply stack, 10-minute reserve auction.

Because of the physical characteristics needed for resources to provide reserve products, not all resources can offer into the Forward Reserve Market. Across all fuel types, a total of 58 units cleared in the winter 2005/2006 auction, down two units from the summer 2005 auction. Table 3-14 shows the resource mix by fuel type of units clearing in the forward-reserve auctions. Gas-fired capacity saw a large increase between the summer 2004 auction and the winter 2004/2005 auction, with the number of cleared megawatts increasing from 88 MW to 184 MW. Between the summer 2004 auction and the winter 2004/2005 auctions, FRM capacity from hydro units increased by 23% to 1,019 MW. In the summer 2005 auction, only four hydro units cleared the market, while the winter auction resulted in nine hydro units clearing the market. Figure 3-37 shows each resource type as a percentage of total cleared megawatts for each auction. Across all auctions, the combination of hydro and jet fuel accounts for between 60% and 80% of all capacity clearing the markets.

Table 3-14
Generation Cleared in Forward-Reserve Auctions by Fuel Type, MW

Generator Fuel Type	Auction 1: Winter 2004[a]	Auction 2: Summer 2004	Auction 3: Winter 2004/2005	Auction 4: Summer 2005	Auction 5: Winter 2004/2006
Coal	63	63	63	14	13
Diesel oil	9	34	28	13	30
Gas	150	119	69	88	184
Hydro	640	815	711	828	1,019
Jet fuel	611	471	485	481	478
Oil	198	192	234	184	235
Gas/oil	204	269	268	364	227
Wood/refuse	0	0	6	0	0
Total	1,876	1,963	1,863	1,972	2,185

[a] The market was initiated in January 2004.

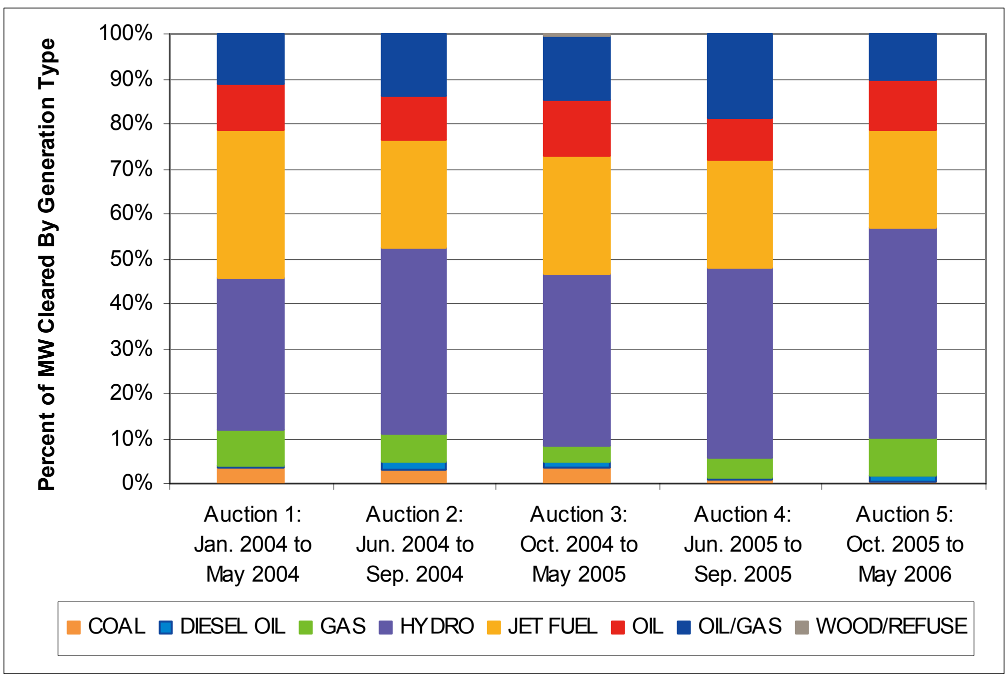

Figure 3-37: Percent of total forward-reserve capacity by fuel type.

3.2.2 Forward Reserve Market Operating Results

The only difference between FRM resources and other resources during market operations is that FRM units are obligated to offer their cleared capacity into the Day-Ahead Energy Market at a price greater than or equal to the strike price. Because of this, these FRM resources are more likely to remain unloaded and able to provide reserve when needed. When the LMP rises above the strike price, the resources are dispatched in merit order. As shown in Table 3-15, during the summer months and into the fall 2005, the real-time LMP was greater than the strike price in 10% to 25% of the on-peak hours and between 6% and 17% of all hours.[74] The target percentage used in setting the strike price is 2.5% of all hours. The higher actual percentage of hours that the real-time price exceeded the strike price is due to the record demand days experienced during summer 2005 and gas-price volatility.

Table 3-15
2005 Percentage of Hours Where the Real-Time Hub LMP Is Greater than the Monthly FRM Strike Price

Month	Strike Price	Percent of On-Peak Hours	Percent of All Hours
January	$112.83	7.1	5.5
February	$154.95	0.0	0.0
March	$106.94	3.8	2.2
April	$115.05	0.6	0.3
May	$114.89	0.3	0.3
June	$97.05	9.9	6.0
July	$112.26	14.1	6.3
August	$113.37	24.7	17.3
September	$144.29	14.6	9.2
October	$154.36	10.7	8.1
November	$179.25	1.2	0.6
December	$162.93	3.6	3.2

Table 3-16 summarizes total payments, penalties, and net dollars for all forward-reserve resources by month. Monthly payments are determined by allocating the $/MW-Month clearing price over all on-peak hours in the month. The penalty values are based on actual unit operations over the month. Generators incur penalties when they fail to reserve capacity or fail to respond to ISO dispatch instructions. The per-megawatt penalty for not reserving capacity is the forward-reserve payment plus the maximum of zero or the difference between the nodal day-ahead LMP and the strike price. The penalty for failing to activate or respond to a dispatch instruction within the specified time period is the forward-reserve payment plus the maximum of zero, or the difference between the nodal real-time LMP and the strike price.[75]

The total penalties for 2005 of $1.2 million are well below 2004's total of $3 million; however, almost $2.9 million of the 2004 total accrued during the January 2004 Cold Snap. Table 3-17 shows the total penalties for failing to reserve and failing to perform. Most of the penalties are for failing to reserve, charged to units that had a shortfall of available capacity. This can occur due to forced outages, self-scheduling for energy, or offering below the strike price.

[74] The real-time Hub LMP is used for comparison purposes in this analysis.

[75] If the day-ahead LMP does not exceed the strike price, the penalty for failing to reserve or failing to activate is limited to the revocation of the FRM payment.

Table 3-16
2005 Forward-Reserve Payments and Penalties

Month	Total Payments	Total Penalties	Net Dollars
January	$6,425,574	-$141,119	$6,284,455
February	$6,446,472	$0	$6,446,472
March	$6,303,537	-$6,159	$6,297,378
April	$6,204,117	-$16,317	$6,187,800
May	$6,438,292	-$2,056	$6,436,236
June	$4,467,607	-$35,184	$4,432,423
July	$4,514,451	-$154,549	$4,359,902
August	$4,444,744	-$182,635	$4,262,109
September	$4,358,543	-$458,434	$3,900,110
October	$3,593,530	-$114,026	$3,479,504
November	$3,955,790	-$7,532	$3,948,257
December	$4,055,460	-$53,823	$4,001,637
Total	$61,208,119	-$1,171,836	$60,036,283

Table 3-17
Breakdown of 2005 FRM Penalties in Dollars

Month	Reserve Penalties	Performance Penalties
January	$137,335	$3,785
February	$0	$0
March	$351	$5,808
April	$15,779	$538
May	$0	$2,056
June	$29,561	$5,623
July	$146,039	$8,510
August	$161,649	$20,986
September	$447,051	$11,383
October	$102,191	$11,836
November	$7,532	$0
December	$52,324	$1,499
Annual Total	**$1,099,811**	**$72,025**

3.2.3 Forward Reserve Market Conclusions

The level of participation in the Forward Reserve Market has continued to increase. In all the auctions, the 10-minute and 30-minute forward-reserve products had the same clearing price. The FRM is intended to provide a price signal to maintain existing peaking-capacity resources, attract new entry into the marketplace, and aid generator-owner decisions to modify or retire units. The strike-price feature targets high variable-cost flexible resources that have a low opportunity cost of providing reserves. The locational Forward Reserve Market being proposed for ASM II will provide an important improvement relative to the existing market design by correctly valuing reserve capability according to its location on the system.

3.3 Installed Capacity Market

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

New England's installed capacity requirements are calculated each year based on the Northeast Power Coordinating Council (NPCC) resource adequacy standard.[76] With input from participants, the ISO converts the capacity requirements into reliability requirements for the New England Control Area. A generating unit's installed capability rating is adjusted to reflect the probability that a resource will be unavailable to serve load due to forced outages. This adjusted value of a resource is referred to as unforced capacity, or 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. UCAP requirements are allocated to participants responsible for serving load based on their share of the prior 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.

The ISO conducts a supply auction at the middle of each month for the following month as one method for participants to transact UCAP. After a supply auction, the ISO conducts a deficiency auction to allow any load-serving participant that has not procured sufficient UCAP to cover its monthly UCAP requirement. Participants are required to offer in the deficiency auction any UCAP in excess of their UCAP requirement. Market Rule 1 requires 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 are not required to participate in these auctions (see Section 3.3.2).

A viable capacity market is required to ensure long-term resource adequacy. This need was first identified in 2003. On March 1, 2004, the ISO filed a proposal with FERC for a locational ICAP market for implementation on June 1, 2004.[77] On June 2, FERC set the matter for hearing and postponed the market's implementation until January 1, 2006. During early 2005, an extensive hearing was held before a FERC Administrative Law Judge (ALJ) to determine the appropriate parameters of the LICAP Market. The ALJ issued her initial decision on the litigation on June 15, 2005, and on August 10, 2005, FERC set the matter for oral argument, further delaying the implementation of the market until no earlier than October 1, 2006. On October 21, 2005, FERC provided an opportunity for the parties to settle the case by January 31, 2006. After extensive negotiations, on March 6, 2006, numerous parties, including the ISO, filed a settlement as a replacement to the existing ICAP market.

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

[77] 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. (FERC LICAP Explanatory Statement)

The settlement proposes a Forward Capacity Market (FCM) that will promote investment in new and existing power resources needed to meet growing consumer demand and maintain reliable service. The market will encourage new investment in all types of new resources, including new power plants, fast-start facilities, alternative energy sources, and demand response. As proposed for the FCM, the ISO will project the needs of the power system three years in advance and then hold an annual auction to purchase power resources to satisfy the region's future needs. The first forward-capacity auction is scheduled to take place no later than the first quarter of 2008, with the resources being paid roughly two and one-half years later, in 2010. If approved, a multi-year transition mechanism will be implemented to compensate new and existing resources in the interim period between December 2006 and May 2010. These dates are dependent on the outcome of the FERC order.

3.3.1 Installed Capacity Market Results

Most load-serving entities meet their ICAP Market requirements through self-supply or bilateral contracts with ICAP suppliers; relatively small amounts are traded through the supply and deficiency auctions, as shown in Figure 3-38. Over the January through December obligation months, approximately 90% of the system requirement (MW-Month) was met by participants that either owned entitlement to capacity or procured it bilaterally. Over the period, about 5% of the system requirement transacted in the supply auction; the remaining 5% was obtained in the deficiency auction.

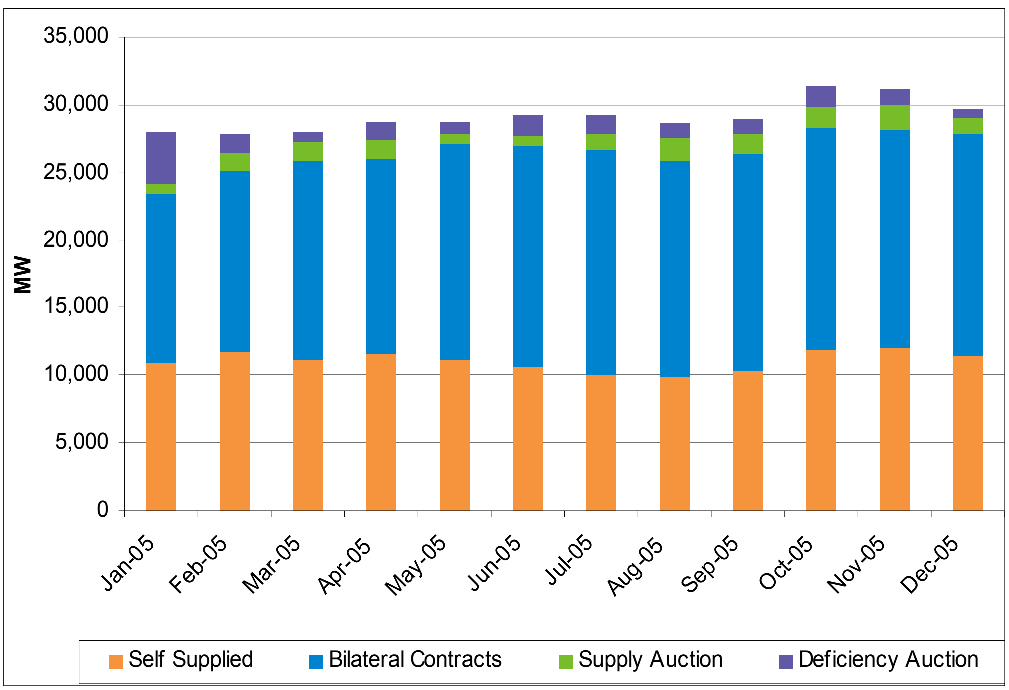

Figure 3-38: Sources of capacity (MW) in 2005 SMD ICAP Market.

Table 3-18 provides the clearing prices and cleared quantities for the ICAP Market auctions during 2005. Figure 3-39 shows clearing prices in the supply and deficiency auctions since April 2003. Deficiency-auction prices were $0.00/MW-Month from April 2003 through October 2004 before increasing to $40–$50/MW-Month in November and December 2004. In January 2005, the price spiked to $660/MW-Month, coinciding with the relatively high percentage of the capacity requirement met through the deficiency auction during this auction period. The prices for the supply auction exhibited more volatility during 2005 than in previous years and, in general, were higher than in 2004.

Table 3-18
ICAP Market Summary for 2005

Obligation Month	Supply Auction		Deficiency Auction	
	Cleared (MW)	Clearing Price ($/MW-Month)	Cleared (MW)	Clearing Price ($/MW-Month)
January	1,374	$120.00	3,717	$660.00
February	1,667	$700.00	1,309	$300.00
March	2,245	$400.00	747	$1.00
April	2,004	$175.00	1,294	$40.00
May	2,062	$50.00	809	$0.00
June	2,358	$100.00	1,582	$250.00
July	2,639	$260.00	1,399	$0.00
August	2,656	$225.00	1,052	$80.00
September	2,900	$210.00	1,027	$0.00
October	2,734	$110.00	1,429	$0.00
November	2,821	$110.00	1,150	$0.00
December	2,058	$0.00	697	$0.00

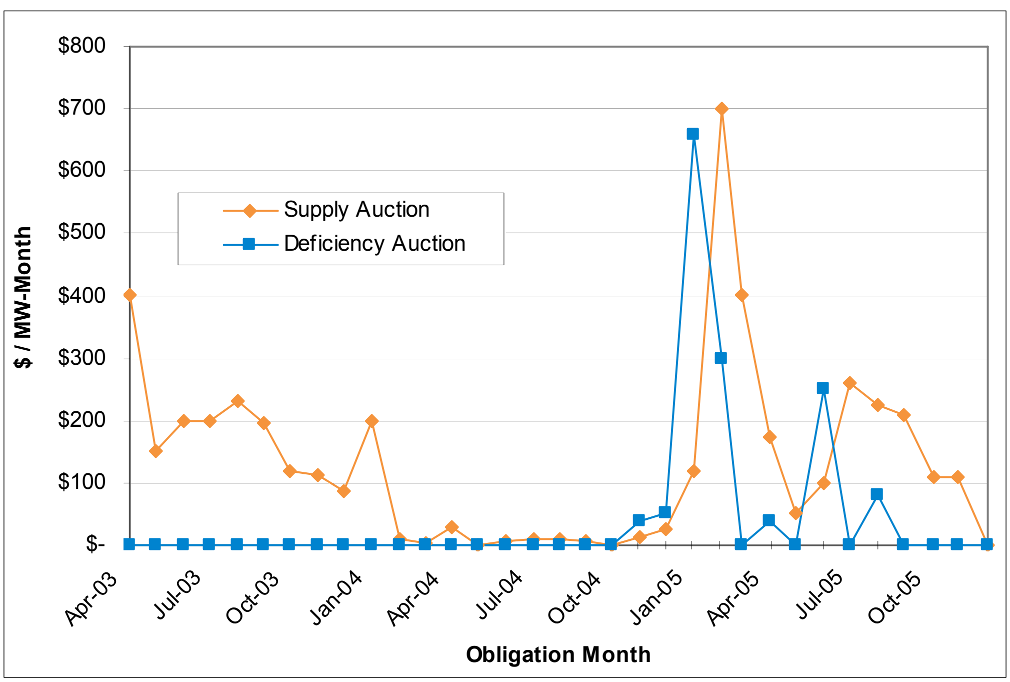

Figure 3-39: Auction clearing prices, April 2003 to December 2005.

Figure 3-40 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 3,717 MW in January to 697 MW in December.

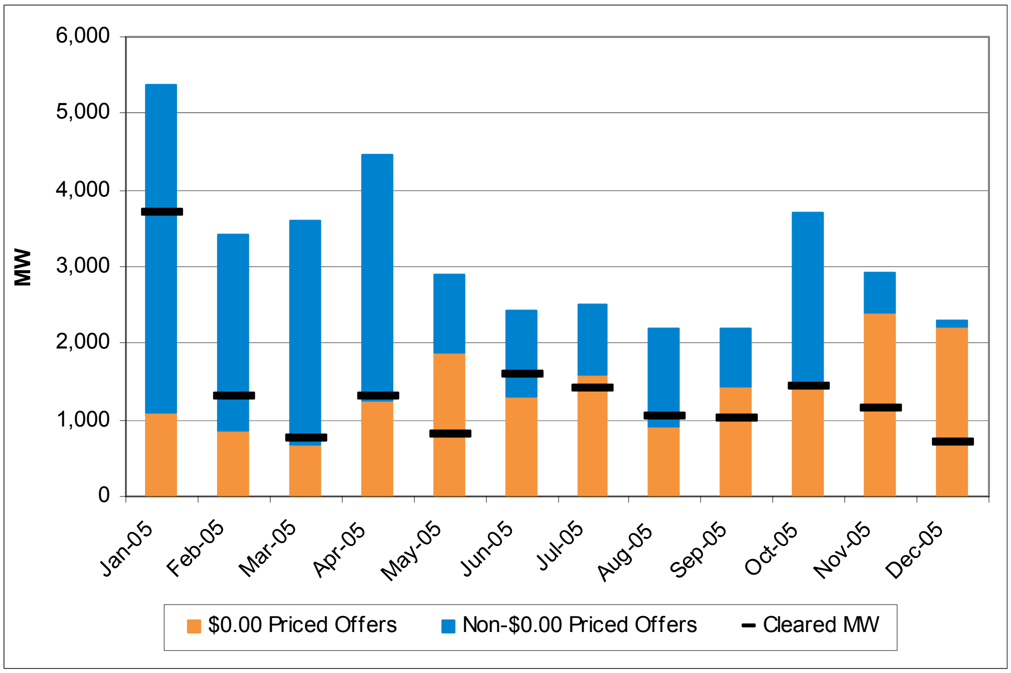

Figure 3-40: ICAP deficiency-auction quantities, 2005.

3.3.2 Delisted Capacity

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

On March 31, 2005, FERC accepted changes to Market Rule 1 that permit participants to delist a portion of a generator as a qualified ICAP resource. Previously, participants were only allowed to delist the entire capacity of a generator, not just a portion of its capacity. Manual M-20, *ISO New England Manual for Installed Capacity*, explains the steps a participant must take to delist a unit.[78] The new capability to partially delist was not greatly used during 2005; only one resource used this market feature during three months over the summer period. Figure 3-41 shows total delisted capacity by month, and Table 3-19 shows delisted capacity by month and load zone. After increasing during

[78] This manual can be accessed at http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

the first part of the year, the total delisted capacity showed a strong downward trend starting in June 2005. While the NEMA area experienced an increase in delisted capacity early in 2005, by October 2005, the delisted capacity in the area had fallen to zero.[79] As with the NEMA area, the Connecticut load zone also saw delisted capacity fall to zero in the second half of the year.

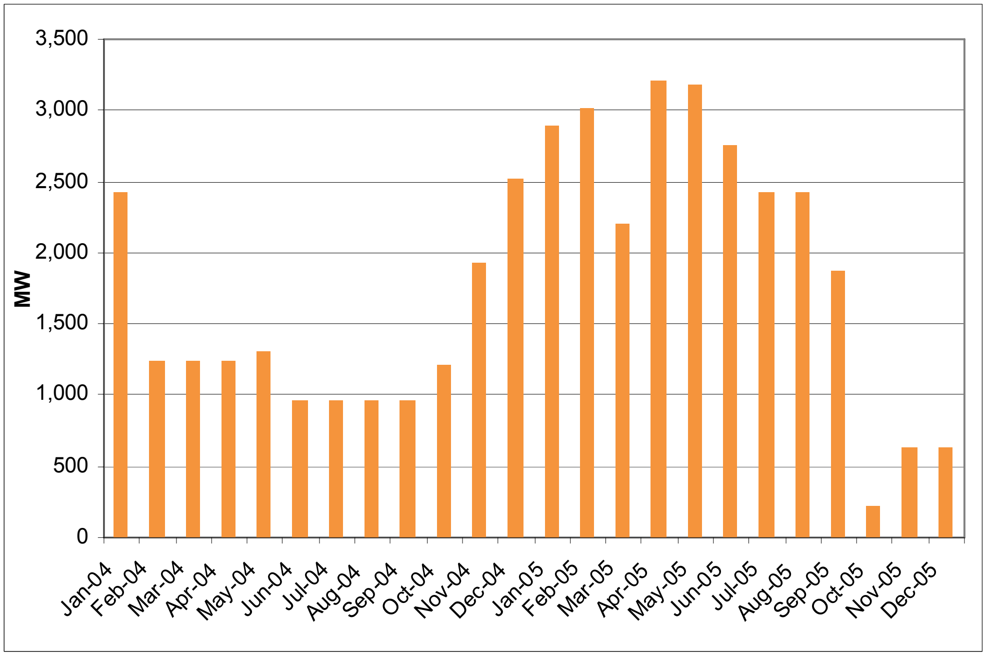

Figure 3-41: Total delisted capacity, January 2004–December 2005.

[79] While an increase in delisted capacity in the NEMA area occurred at the same time as the rule change allowing partial delisting, the increase is the result of resources delisting entirely, not partially.

Table 3-19
Delisted Capacity by Load Zone, January 2004–December 2005, MW

Month	Maine	NH	Vermont	CT	RI	NEMA	SEMA	WCMA	Total
2004									
January	0	535	0	1,551	0	225	109	0	2,419
February	0	535	0	484	0	225	0	0	1,244
March	0	535	0	484	0	225	0	0	1,244
April	0	535	0	484	0	225	0	0	1,244
May	0	535	0	445	0	225	0	0	1,305
June	0	535	0	336	0	0	0	0	971
July	0	535	0	336	0	0	0	0	971
August	0	535	0	336	0	0	0	0	971
September	0	535	0	336	0	0	0	0	971
October	0	522	0	465	0	0	132	0	1,219
November	0	522	0	613	0	560	132	0	1,926
December	0	522	0	706	0	560	632	0	2,521
2005									
January	184	522	0	1,027	0	560	501	100	2,893
February	184	522	0	1,153	0	560	501	100	3,020
March	0	522	0	1,027	0	560	0	100	2,209
April	0	522	0	1,188	0	1,397	0	100	3,207
May	0	522	0	447	0	2,217	0	0	3,187
June	0	522	0	0	0	2,217	14	0	2,753
July	0	201	0	0	0	2,217	14	0	2,432
August	0	201	0	0	0	2,217	14	0	2,432
September	0	201	0	0	0	1,658	14	0	1,872
October	0	201	0	0	0	0	14	0	215
November	0	522	0	0	0	0	14	94	630
December	0	522	0	0	0	0	14	94	630

3.3.3 Installed Capacity Market Conclusions

The capacity market experienced typical activity in 2005. 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. Increased purchases through the deficiency auction, coupled with increases in delisted capacity, raised prices in the deficiency auction. After an early increase in monthly delisted capacity in 2005, the second half of the year experienced a significant downward trend in the total delisted capacity. Consistent with this trend, the delisted capacity in the two historically import-constrained areas dropped to zero.

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 assist in maintaining the frequency of the entire Eastern Interconnection. This system balancing also maintains proper power flows into and out of the New England Control Area.

The SMD Regulation Market used a clearing process to select a set of generators to provide regulation service. It also set hourly clearing prices based on regulation offers submitted by generators willing to supply this service. The hourly regulation clearing price (also called the regulation floor price) was set by the generating unit that had the highest combined regulation offer and ISO-estimated unit-specific opportunity cost of all selected generating units, based on the day-ahead market clearing prices.[80] The opportunity cost of this generator, calculated using the Day-Ahead Energy Market clearing price, was included in the regulation floor price. In the real-time Regulation Market, the ISO issued appropriate dispatch instructions to generators, which were compensated for any real-time opportunity costs in excess of the regulation floor price incurred while providing the service. At times, the generator that set the regulation clearing price during the regulation price-setting process completed prior to the beginning of the operating day might not provide regulation in real-time.

Significant changes were made to the Regulation Market as part of Phase I of the ASM project. These changes included adding a service payment and improving the calculation of opportunity costs. The regulation-selector software was also revised to incorporate estimates of opportunity costs and changes in production costs along with capacity and service costs. The Regulation Market clearing price is now calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Opportunity costs are paid separately and are not included as a component of the regulation-clearing price.

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 the North American Electric Reliability Council (NERC) Control Area Control Performance Criteria specified in NERC Standard BAL-001.[81] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[82]

> *The average Area Control Error (ACE) for at least 90% of the clock 10-minute periods (six nonoverlapping periods per hour) during a calendar month must be within a specific limit, referred to as L_{10}.*[83]

For the New England Control Area, the CPS 2 annual average compliance target is 92% to 97%. Figure 3-42 shows the CPS 2 compliance each month from June 2001 to December 2005 and the 90% lower monthly limit. The ISO has continually met its CPS 2 targets.

[80] Unit-opportunity cost is the estimated cost each generating unit would incur if it adjusted its output as necessary to provide its full amount of regulation. It is computed roughly as follows: [absolute difference between the day-ahead LMP at the generator's bus and the generator's energy offer associated with the regulation setpoint (in MW) the unit would have to maintain to provide its full amount of regulation] x [the deviation between economic dispatch and the regulation setpoint (in MW)].

[81] See http://www.nerc.com/~filez/standards/Reliability_Standards.html#Resource_and_Demand_Balancing.

[82] For more information of Control Performance Standard 2, see the NERC Web site at http://www.nerc.com/~filez/cpc.html.

[83] The ACE of the New England Control Area is the actual net interchange minus the scheduled net interchange.

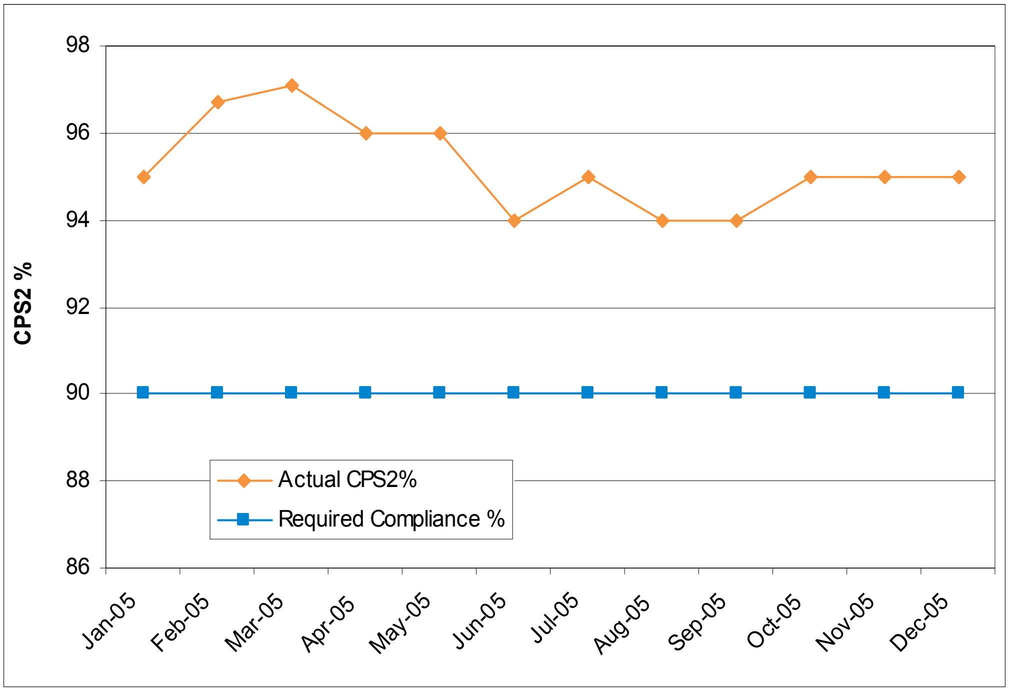

Figure 3-42: CPS 2 compliance.

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. Figure 3-43 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 3-43 shows a gradual downward trend of the average monthly requirements over the period. The ISO has been able to reduce the requirements, in part, due to the overall improvement in the response of the regulation resources to the regulation-control signals. Regulation requirements are lower in the spring and fall than in the summer and winter. This variation is reflected in Figure 3-43.

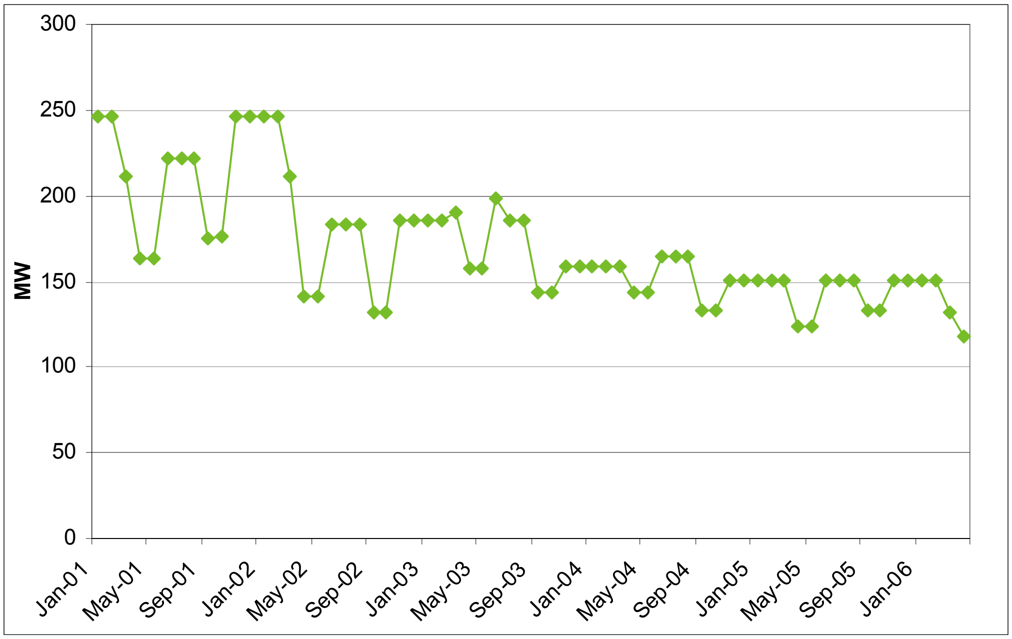

Figure 3-43: Monthly average regulation requirements.

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

New England has approximately 1,450 MW of installed regulation capacity. The pool 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 32%, or just over 460 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 $30.22/MWh (unweighted) over the year. Payments to generators for providing regulation totaled $69.5 million, including $15 million in real-time opportunity cost payments. Figure 3-44 shows total regulation payments by month from March 2003, when SMD was implemented, through March 2006. Costs increased after the implementation of ASM I 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.

As Figure 3-45 illustrates, average 2005 regulation prices were highest during the morning peak hours. The prices declined during the midday and the 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, with supply becoming tighter as units are decommitted overnight.

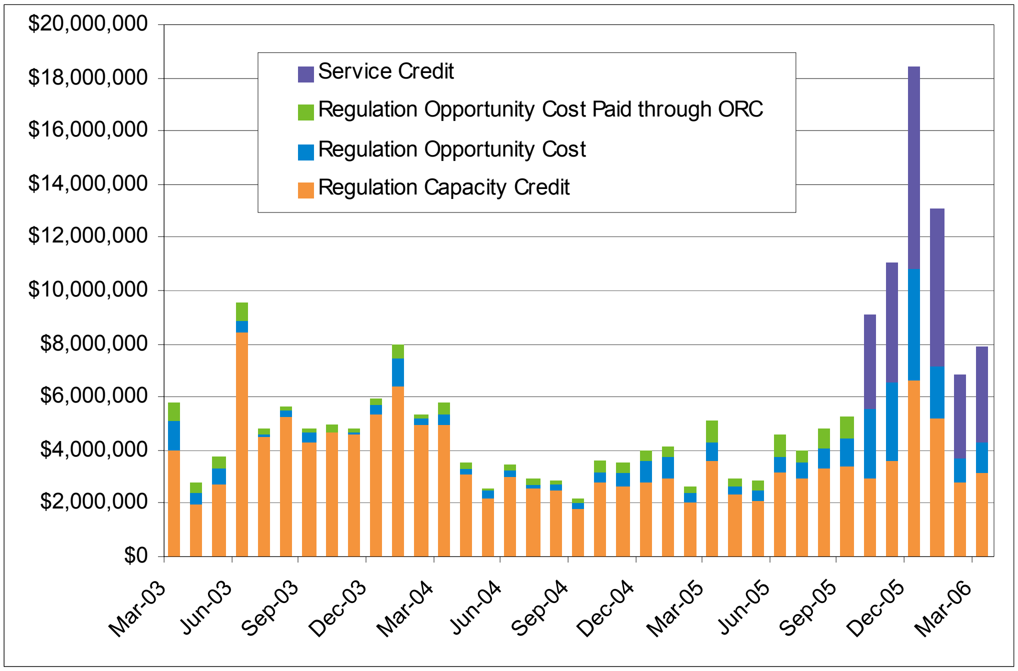

Figure 3-44: Total regulation payments by month.

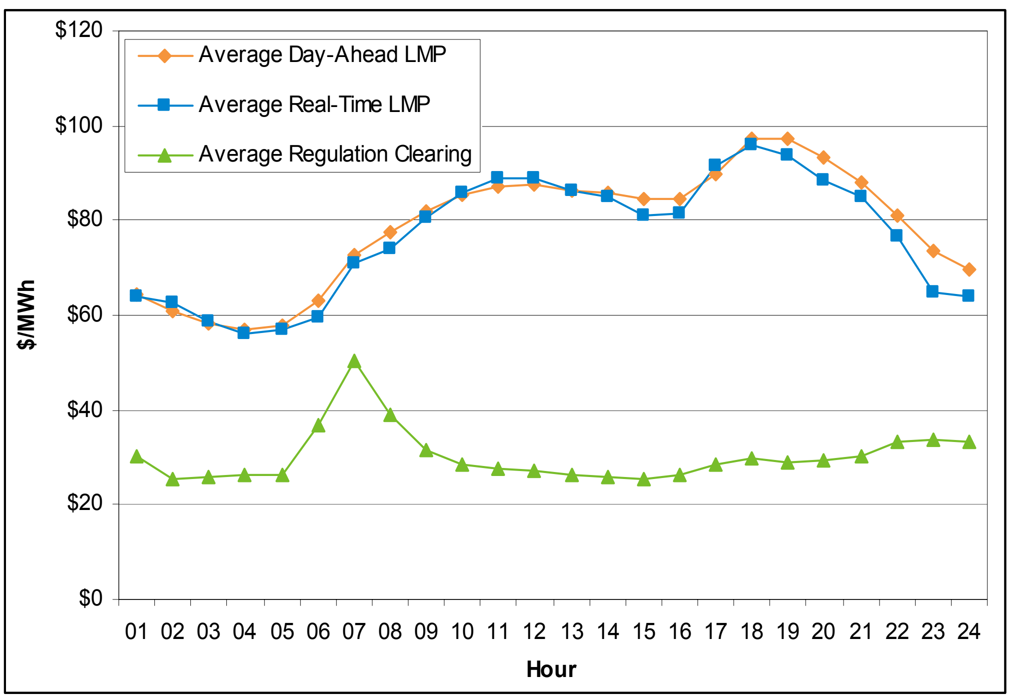

Figure 3-45: Average hourly regulation-clearing prices and Hub day-ahead and real-time LMPs, 2005.

Table 3-20 summarizes information about clearing prices in the Regulation Market during the year.

Table 3-20
2005 Regulation Market Clearing Prices, Summary Statistics, $/MWh

Month	($/MWh)			
	Average	Median	Minimum	Maximum
January	25.87	24.71	12.67	85.10
February	19.69	18.13	0.00	47.65
March	30.94	28.70	12.50	392.20
April	25.50	24.64	12.63	59.62
May	22.35	21.85	10.54	109.73
June	27.55	24.29	13.16	177.32
July	25.33	23.91	10.36	105.78
August	27.62	24.94	10.87	227.56
September	33.92	27.09	12.00	561.30
October	29.24	24.25	7.76	100.00
November	34.91	24.50	2.03	100.00
December	58.75	55.00	7.94	100.00
2005 Overall	30.22	24.60	0.00	561.30

3.4.3 Regulation Market Conclusions

The Regulation Market performed effectively in 2005 to provide sufficient amounts of regulation, and the New England Control Area fully complied with NERC reliability requirements for regulation.

As in the electric energy market, prices in the Regulation Market are influenced by fuel costs and other supply conditions. An increase in fuel costs will contribute to an increase in opportunity costs. Because generators experience a loss of thermal efficiency when providing regulation service, their costs are higher when regulating compared to when they are simply providing electricity. Fuel-contract provisions can also affect the cost of regulation, particularly for natural gas units.[84]

The early months of the ASM I Regulation Market in autumn 2005 coincided with a period of relatively high natural gas prices. Some generators exited the Regulation Market during this period for reasons unrelated to the market. The available regulation supply in November and December 2005 was further reduced, as fewer generators were on line and eligible to provide regulation, due to negative spark spreads created by the high gas prices.[85] These led to higher costs in the first months of the new market. However, regulation costs declined in early 2006. The ISO will continue to monitor the regulation market and evaluate opportunities for market enhancements.

[84] 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.

[85] *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) to produce the electricity. Also see Section 5.2.6 on implied heat rates.

Section 4
Reliability Costs, Congestion Management, and Demand Response

This section covers a number of additional programs and procedures administered by the ISO to provide system reliability, manage transmission congestion costs, and incorporate demand response. These include reliability commitments, Net Commitment-Period Compensation, tariff payments, Peaking Unit Safe Harbor activity, and Financial Transmission Rights. The section also discusses demand-response programs that reduce load and credits made to generators to reduce excess generation.

4.1 Reliability Commitment of Generation

The requirements for ensuring the reliability of New England's bulk power system reflect standards developed by NERC, NPCC, and ISO New England through open stakeholder processes. These requirements are codified in the NERC Standards, NPCC Criteria, and the ISO's operating procedures. To meet these requirements, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market.

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 process. The process is designed to maximize the opportunity for the market to respond and minimize supplemental commitments by the ISO to meet reliability criteria. The RAA begins after the re-offer period closes at 6:00 p.m. and is updated periodically throughout the day; commitments may be cancelled if reliability needs change during the operating day due to market response or other changed system conditions.

The RAA process begins with evaluating the set of generator schedules produced by the Day-Ahead Energy Market solution, any self-schedules that were submitted during the re-offer period, and the availability of resources for commitment near real time. If the Day-Ahead Energy Market generation schedule in combination with self-scheduled resources and off-line fast-start generation that can be committed does not meet the real-time forecasted demand and reserve requirements, the ISO will commit additional generation. When multiple generators are available to meet the RAA requirements, the ISO process minimizes the start-up, no-load, and cost 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. These distribution-support commitments [formerly called Special-Constraint Resource (SCR) commitments] are made at the request of the local transmission owner or distribution company.

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

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

7. Meet the systemwide operating-reserve requirement 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 Reserve Adequacy Analysis 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 also minimizing the capacity committed.

Figure 4-1 shows total generation, including self-scheduled generation (MW), economic pool-scheduled generation, and reliability commitments. Energy output from these commitments was 6.7% of total generation in 2005, ranging from a low of 2% in February to a high of 12% in April. Generators providing energy from reliability commitments are compensated through both energy-market revenues and daily reliability payments. The figures in this section include all megawatt-hours for the day from each unit with a reliability commitment, irrespective of its in-merit portion.

Figure 4-2 shows the energy output that resulted from reliability commitments in the Day-Ahead Energy Market, RAA process, and Real-Time Energy Market. Compared to 2004, reliability commitments were lower in the Day-Ahead Energy Market and higher in the RAA process and Real-Time Energy Market. The need for second-contingency coverage during high-load periods in the summer and the need for voltage control in Boston during low-load periods in the spring contributed to the increase in reliability commitments during 2005.

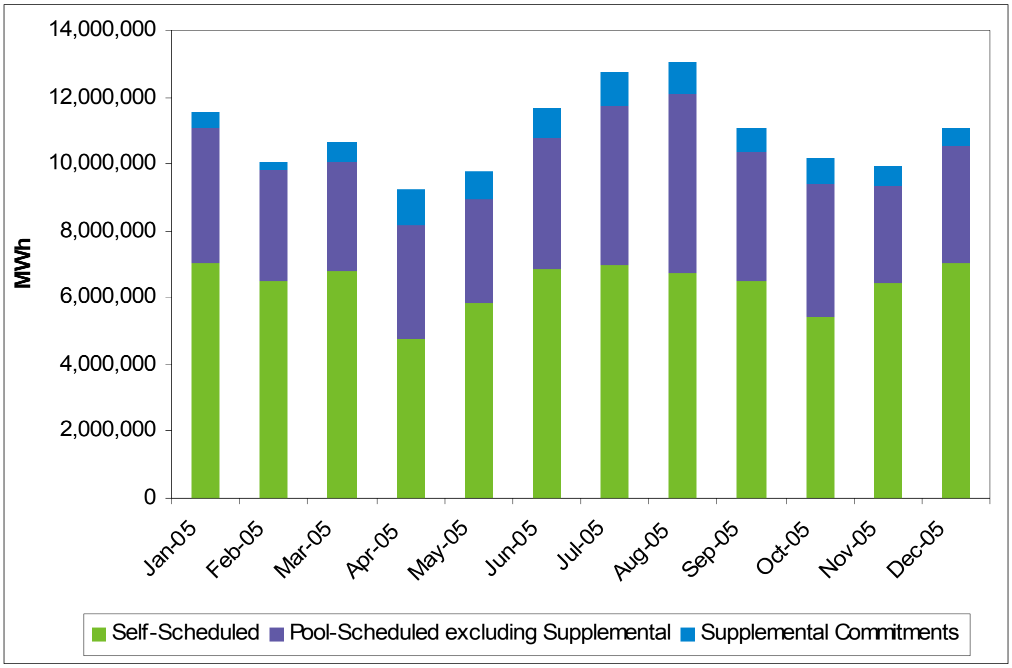

Figure 4-1: Electricity output from self-scheduled real-time, economic pool-scheduled real-time, and reliability commitments.

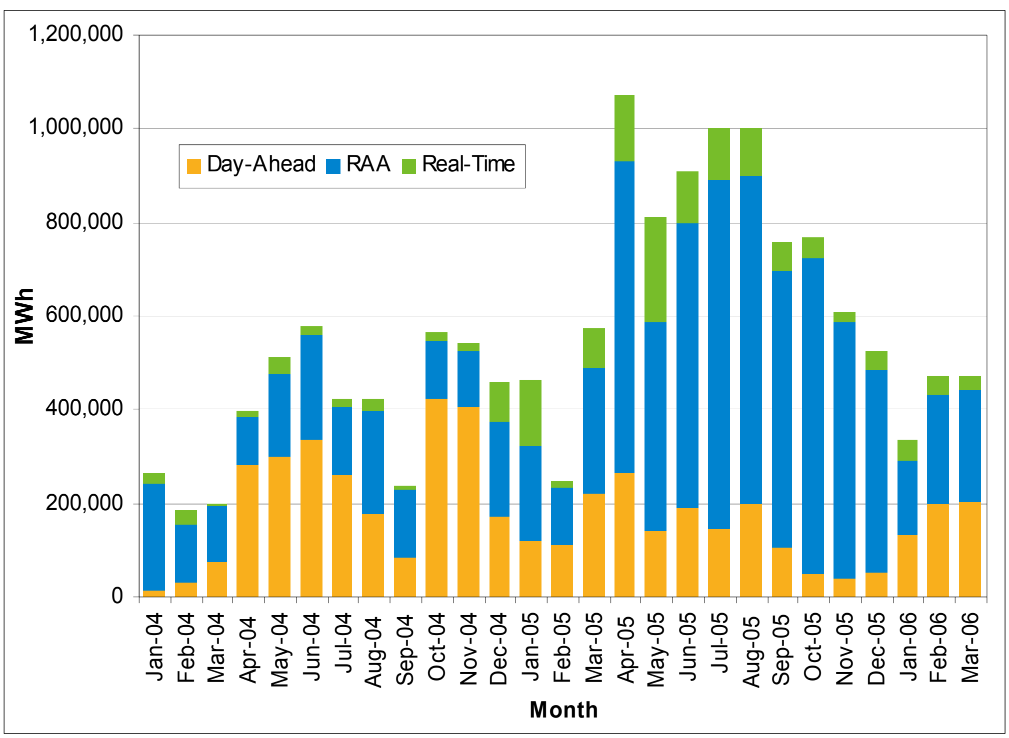

Figure 4-2: Total monthly electricity output from reliability commitments day-ahead, RAA, and real time.

Most of the increase in reliability commitments in late 2004 through 2005 was attributable to offer behavior of some Boston-area generation. This issue is discussed further in Section 5.1.4 on market monitoring in the Boston area.

Figure 4-3 shows total electricity output from commitments made to supply local second-contingency reserves by month and load zone. The majority of second-contingency commitments were made in NEMA and Connecticut. 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. During 2005, 61% of megawatt-hours for second-contingency commitments were in the NEMA load zone, and 39% were made in Connecticut.

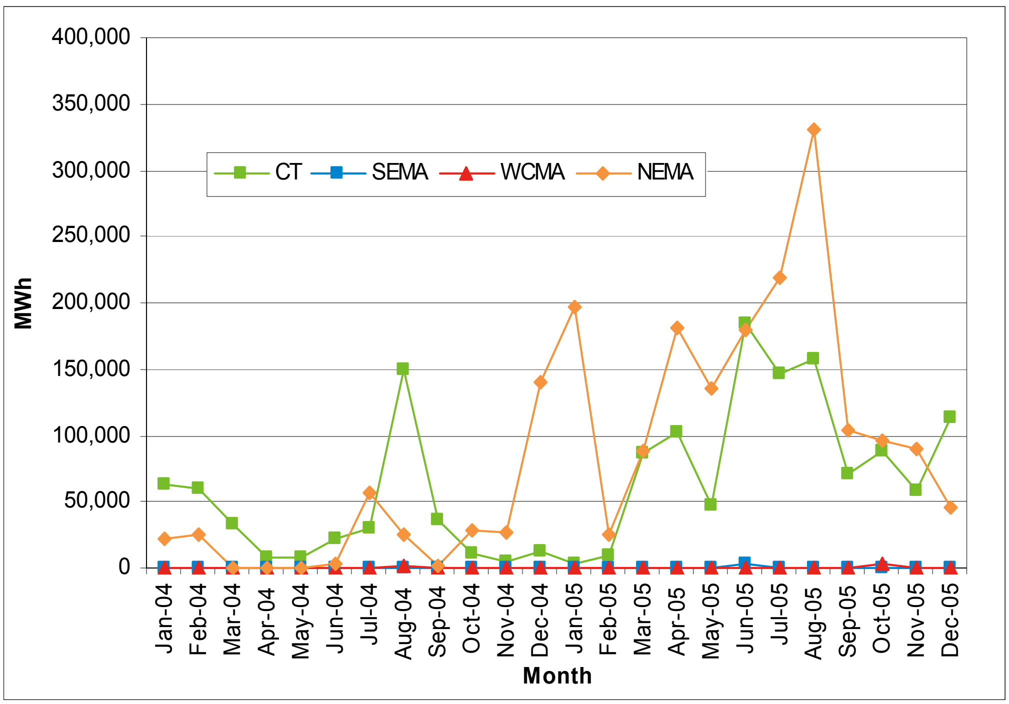

Figure 4-3: Total monthly electricity output from second-contingency commitments by load zone, 2005.

Second-contingency commitments are a function of local reserve requirements and the availability of fast-start units to meet these requirements. These commitments follow a seasonal pattern, with higher commitments in high-load summer and winter months. Areas with local reserve requirements greater than available fast-start generation and without sufficient in-merit generation require second-contingency commitments. Local reserve requirements are determined by local contingencies, including the possibility of a transmission line or generator failure, and load-shedding assumptions for the area, which transmission owners supply to the ISO. Limited transmission capacity into an area reduces the amount of reserves that can be supplied from outside the area, and this lack of supply increases local reserve requirements.

The ISO is working with NSTAR (an investor-owned utility located in Massachusetts) to improve transmission into the Boston area. This will alleviate import constraints and lessen the need to make supplemental commitments for reliability. The NSTAR 345 kV Reliability Project will increase import transmission capacity to the Boston area by about 1,100 MW and reduce the need for out-of-merit commitments. Phase 1 of this project will add 850 MW and is scheduled for completion in June 2006, while Phase 2 is tentatively scheduled for completion in January 2007.

The Southwest Connecticut 345 kV Reliability Project will lessen the need for reliability commitments within Connecticut. Phase 1 of the project is scheduled for completion in December 2006 and will improve transmission between the Norwalk/Stamford Subarea and the rest of Southwest Connecticut. Phase 2 of the project, which will improve transmission between Southwest Connecticut and the rest of Connecticut, is expected to be in service in December 2009.

Although both the NSTAR Boston project and the Southwest Connecticut project will lessen the need for reliability commitments for second-contingency reliability support, they will not eliminate it. During periods of high load, reliability commitments may still be needed. And as load continues to grow and generators retire, the need for reliability commitments may increase absent further investment in efficient new resources.

Figure 4-4 shows, by month and by load zone, the total 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 load levels are low, while the commitments for voltage support are needed during high-load periods.

The ISO, together with the transmission owners, have taken several steps to reduce the need to commit generators to provide reactive power. In fall 2005, a 160 MVAR reactor was added in the Cambridge area that reduced the need for voltage commitments in the Boston area. Another reactor is scheduled for installation in spring 2006. In addition, the ISO, along with NSTAR and the Rhode Island, Eastern Massachusetts, and Vermont local control center (REMVEC), revised the Boston-area operating guide to capture recent reactive-limit improvements in the area and trained operations staff to implement the revised guide. While these improvements will lessen the need for commitment for reactive power, they will not eliminate it. The ISO is evaluating the need for additional reactive power resources (leading and lagging) as part of its system planning process.

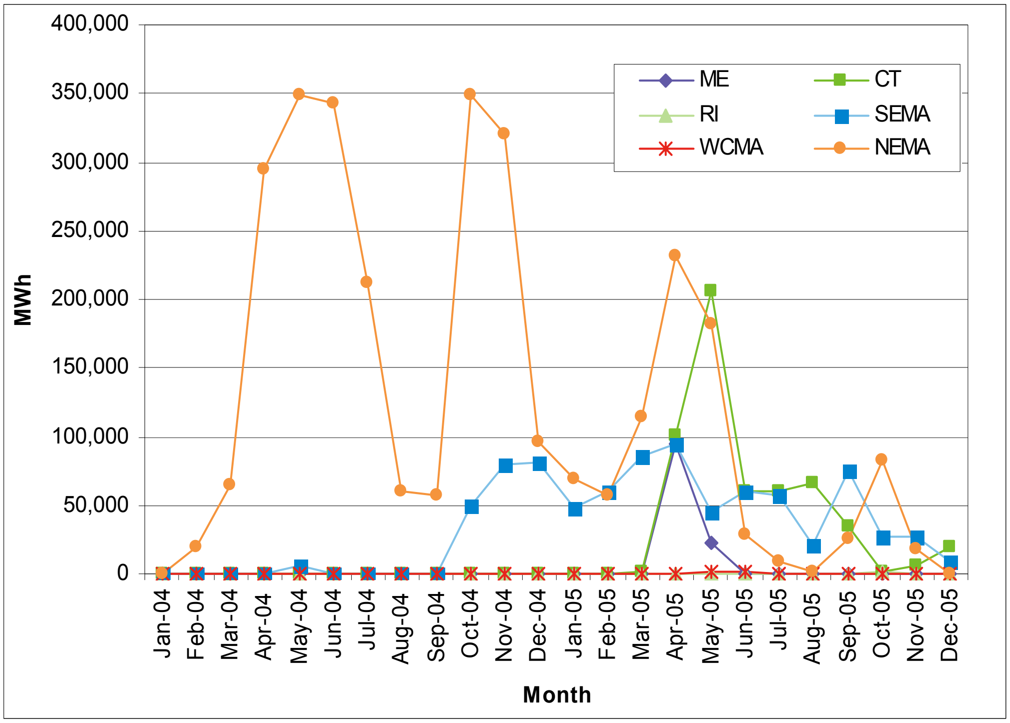

Figure 4-4: Total monthly electricity output from voltage commitments by load zone, 2005.

4.2 Reliability Cost Payments

Offers accepted by the ISO but not covered by energy-market revenues are paid through first-contingency and second-contingency Net Commitment-Period Compensation (also referred to as first and second-contingency reliability payments), voltage reliability costs payments, and distribution reliability cost payments.[86] These 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 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 (i.e., insufficient revenue) 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 energy market, unless the energy revenues are insufficient to cover its daily costs.

[86] 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 (subject to limitations). 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. First-contingency reliability costs were formerly called Economic ORCs. Second-contingency reliability costs were formerly called daily RMR ORCs. Voltage reliability costs were formerly called Voltage Ampere Reactive Transmission Tariff payments. Distribution reliability costs were formerly called Special-Constraint Resource Transmission Tariff payments. 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.

Table 4-1 illustrates the relationship between reliability cost payments and financial settlements. The following sections discuss first- and second-contingency reliability arrangements and payments for voltage and distribution reliability services in greater detail.

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 (Boston, CT, SW CT, NRST CT)		X		
Reactive power for voltage control or voltage support			X	
Local transmission support				X

4.2.1 First- and Second-Contingency Reliability Payments

Owners of eligible resources may receive reliability payments if the ISO commits them for first- or second-contingency coverage. 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. These 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 that reliability. First-contingency reliability payments are made to several types of generators. These include generators committed to providing systemwide stability or thermal support and generators supplying systemwide energy in peak hours that must stay on during later hours to satisfy minimum run-time requirements. While generators committed to providing energy may have been in-merit during peak hours, they may be out-of-merit in other hours and receive reliability payments. Or, energy market revenues may have been insufficient to cover start-up costs.

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 the day-ahead schedule and participants whose generators deviate from day-ahead schedules or that do not follow real-time dispatch instructions are charged in proportion to these deviations.

Second-contingency reliability payments are made to generating units required for reliability within a particular reliability region on a particular day. Second-contingency reliability costs in the Day-Ahead and Real-Time Energy Markets are currently charged to participants in proportion to their load obligations in the respective markets.

4.2.1.1 First- and Second-Contingency Reliability Payment Results

In 2005, the sum of first-contingency and second-contingency reliability payments totaled approximately $206 million. The majority of this is from second-contingency reliability payments. In 2004, the comparable payments were approximately $91 million. This year-to-year increase is driven by the increase in commitments discussed in Section 4.1. Figure 4-5 compares 2004 monthly totals for first- and second-contingency reliability payments with 2005 totals.

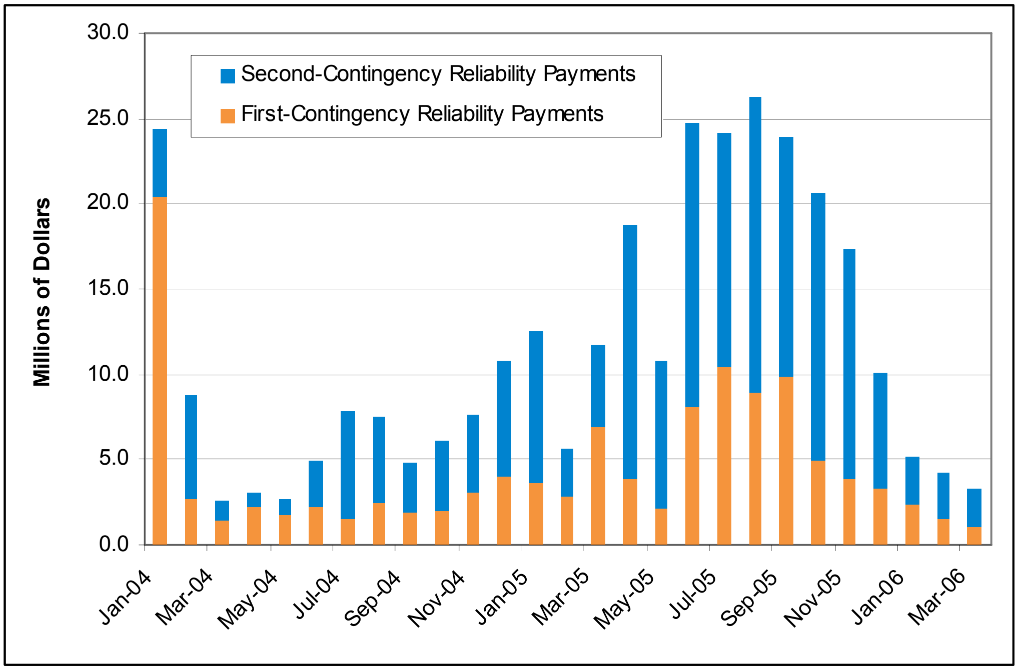

Figure 4-5: Monthly first- and second-contingency reliability payments, January 2004–March 2006.

Table 4-2 shows first- and second-contingency reliability payments for 2005. Generators in the NEMA and Connecticut load zones received almost all of the second-contingency reliability payments. Generating units in the NEMA load zone received the largest amount of second-contingency payments at $91.8 million (69%), while units in the Connecticut load zone received $41.5 million (31%). Generating units in the Rhode Island, SEMA, and WCMA load zones received $0.2 million.

Table 4-3 shows the breakdown of second-contingency reliability payments for each subarea that had a resource receiving a second-contingency payment in 2004 and 2005. Payments to generators in the Norwalk/Stamford area accounted for 87% of the daily reliability payments made to units in the Connecticut load zone. Generators in the Norwalk/Stamford area received 27% of the total systemwide second-contingency reliability payments. Due to import constraints into the Norwalk/Stamford area, generators committed in the rest of Connecticut cannot satisfy all of Norwalk/Stamford's reserve requirements. The Boston area experienced a large increase in second-contingency payments, from about $16 million in 2004 to almost $92 million in 2005, an increase from about 35% of the systemwide total in 2004 to almost 69% in 2005. This change was driven by the increase in commitments needed in the Boston area, as discussed in Section 4.1.

Table 4-2
Total First- and Second-Contingency Reliability Payments in Millions, 2005

Payment Type	Day-Ahead	Real-Time	Total
First-contingency reliability payments	$7.7	$61.0	$68.7
Second-contingency reliability payments	$6.5	$127.2	$133.5
Total	$14.2	$188.3	$202.3

Table 4-3
Second-Contingency Reliability Payments by Subarea in Millions, 2005

Subarea	2004			2005		
	Day Ahead	Real Time	Total	Day Ahead	Real Time	Total
BOSTON	$7.3	$8.8	$16.1	$3.4	$88.4	$91.8
CT	$0.0	$5.1	$5.1	$0.6	$4.6	$5.2
SWCT	$0.3	$1.3	$1.6	$0.1	$1.0	$1.1
NOR	$6.0	$16.6	$22.5	$2.4	$32.8	$35.2
SEMA	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
WCMA	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
Total	$13.6	$31.8	$45.4	$6.5	$127.0	$133.5

On April 1, 2005, the ISO made a filing with FERC to change Market Rule 1 to modify the eligibility of generators for offer-based reference levels. The rule change, which FERC approved on May 6, 2005, was needed because some generators in load pockets that usually ran out of economic-merit order for reliability had offer-based reference levels based on the few hours they ran in merit.[87] These reference levels were significantly above marginal costs. Generators with these elevated reference levels were able to offer energy above their costs, be committed out-of-merit for reliability, and collect reliability payments based on their offers. Reference levels for these generators are now based on marginal costs rather than accepted offers. Absent this rule change, the increase in Boston area second-contingency reliability payments would have been even higher.

Table 4-4 shows the average allocation of first- and second-contingency reliability charges by month for 2005. These averages are calculated based on days with charges. Allocations shown for Connecticut are for the entire state and are not subarea specific. Average charges for days with charges were as high as $25/MWh in the NEMA area.

Effective March 1, 2005, the basis for the allocation of real-time second-contingency reliability charges was changed.[88] The old method used real-time deviations from day-ahead schedules within a

[87] See the FERC's *Order Accepting Tariff Amendments* at http://www.iso-ne.com/regulatory/ferc/orders/2005/may/er05-767_5-6-05.doc.

[88] See FERC Docket No. ER05-439-000, March 7, 2005, *Order Accepting Tariff Revisions for Filing*, p. 12, available at http://www.iso-ne.com/regulatory/ferc/orders/2005/mar/er05_439_03_07_05.doc.

reliability region as the basis for the allocation. This change more closely aligns cost causation with cost allocation. The new method uses real-time load obligations within a reliability region as the basis for allocating real-time second-contingency reliability charges. This results in increasing the pool of megawatt-hours charged, therefore reducing the per-megawatt-hour allocation. The new allocation method more closely allocates costs to the participants that cause the costs, decreases the volatility of these charges, and encourages virtual trading. The decrease in real-time allocation costs per megawatt-hour is most significant in the NEMA load zone.

Table 4-4
CT and NEMA First- and Second-Contingency Daily Reliability Allocations for Days with Charges, $/MWh

Month	Day-Ahead First Contingency	Real-Time First Contingency	CT Day-Ahead Second Contingency	CT Real-Time Second Contingency	NEMA Day-Ahead Second Contingency	NEMA Real-Time Second Contingency
January	$0.04	$1.02	$0.57	$1.87	$0.00	$25.10
February	$0.04	$1.15	$0.61	$5.07	$0.00	$19.83
March	$0.05	$2.57	$0.06	$0.69	$0.01	$4.29
April	$0.08	$1.18	$0.93	$1.49	$0.02	$8.18
May	$0.03	$1.00	$0.00	$1.45	$2.63	$6.03
June	$0.04	$2.64	$0.38	$2.82	$1.33	$4.89
July	$0.07	$2.86	$0.32	$2.03	$0.88	$3.48
August	$0.05	$2.66	$0.44	$1.92	$1.27	$4.47
September	$0.13	$2.84	$0.33	$1.67	$1.07	$4.79
October	$0.06	$1.35	$0.13	$1.85	$0.00	$5.60
November	$0.07	$1.09	$0.11	$1.49	$0.00	$5.12
December	$0.03	$1.27	$0.15	$2.23	$0.00	$1.45
Annual Average	$0.06	$1.80	$0.37	$2.05	$0.90	$7.77

4.2.1.2 First- and Second-Contingency Reliability Payment Conclusions

The ISO and the transmission-owning utilities have taken a number of steps to reduce the need for out-of-market payments, while ensuring that generators are compensated for their costs. Transmission projects underway in Connecticut and Boston will reduce the need for reliability commitments. To prevent unwarranted increases in out-of-market payments, the ISO made a market-rule change affecting the calculation of reference levels.

These payments are assigned to load-serving entities in the Day-Ahead and Real-Time Energy Markets. The payments reflect out-of-merit operation that dampens price signals emanating from constrained areas on the system and decreases the incentive for flexible, fast-start capacity to locate and operate in those areas. The ISO will continue to refine the market rules to ensure that generating units following dispatch instructions are fairly compensated and to send appropriate price signals to local resources. This will provide proper incentives to maintain reliability and promote economic efficiency.

4.2.2 Voltage and Distribution Reliability Costs

Generators committed for voltage control and support and distribution support are compensated for shortfalls between their energy revenues and energy offers the same way as generators receiving first-contingency or second-contingency daily reliability payments. Figure 4-6 shows monthly voltage and distribution payments for 2004 and 2005. Table 4-5 shows 2005 voltage and distribution payments broken out by Day-Ahead or Real-Time Energy Market.

Most of the voltage payments made in 2005 ($57.8 million) went to generation required to control high-voltage levels during low-load periods in the Boston area. Significant voltage payments ($11.6 million) were also made to units in the SEMA load zone. In 2004, voltage payments totaled $66.5 million. The first half of 2005 saw the continuation of high monthly voltage payments first experienced in 2004, while the last half of 2005 saw a significant decrease. As described in the supplemental commitment section (Section 4.1), the decrease during the last half of the year is attributable to improvements to the transmission infrastructure in the Boston area. All New England transmission owners share voltage payments based on network load; distribution payments are assigned directly to the transmission owner requesting the generator commitment.

Appendix C describes other ISO tariff charges.

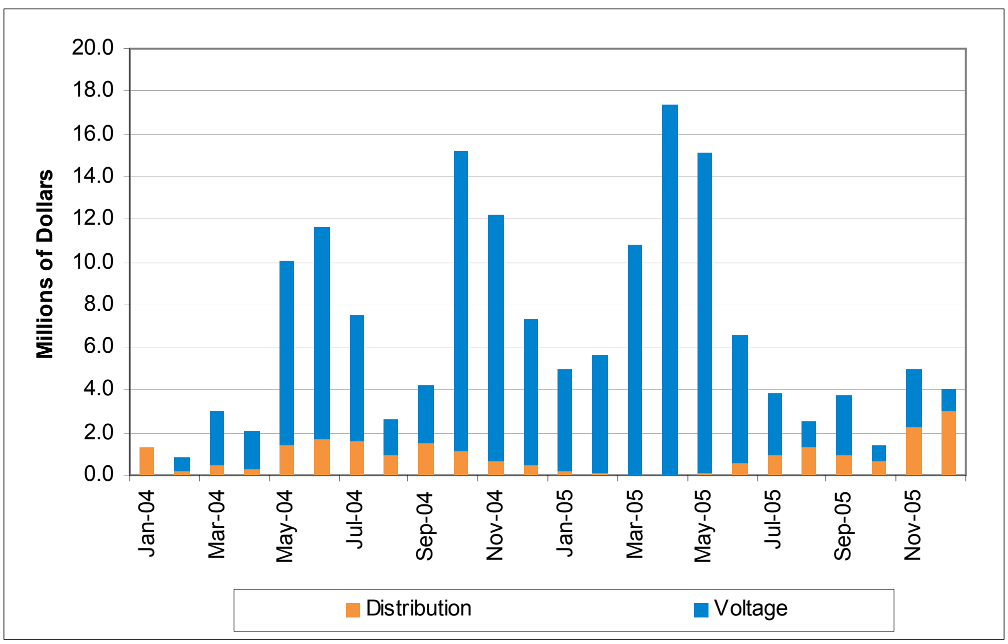

Figure 4-6: Distribution and voltage reliability payments by month, 2004–2005.

Table 4-5
Distribution and Voltage Reliability Payments in Millions, 2005

Payment Type	Day Ahead	Real Time	Total
Distribution	$0.0	$10.0	$10.0
Voltage	$20.7	$54.6	$75.3
Total	$20.7	$64.6	$85.3

4.3 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.[89] During times when a Minimum Generation Emergency has been declared, prices are set to zero. On September 16, 2005, FERC approved a change to Market Rule 1 that created special credits for generators dispatched above their economic minimum levels during minimum generation emergencies.[90]

The credits are separate from reliability credits, and related charges are allocated to participants with real-time generation obligations. The change was effective April 27, 2005. In 2005, generators received a total of $82,797 in minimum-generation emergency credits.

4.4 Reliability Agreements

Reliability Agreements provide eligible generators with monthly fixed-cost payments for providing reliability service. 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 that a specific participant pays. The need for these agreements suggests that the current market structure does not signal the need for new infrastructure or adequately compensate generators providing reliability service.

Most Reliability Agreements are for full cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through 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. Thus, the generator recovers no more than its fixed and variable costs. Other agreements, known as reliability trackers, provide for the payment of actual costs to cover minor and major maintenance materials and services. A single generating station may be covered by both types of agreements.

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

[90] See http://www.iso-ne.com/regulatory/ferc/orders/2005/sep/er05-870-0009-16-05.doc.

During 2004, FERC rulings effectively expanded eligibility for cost-of-service Reliability Agreements.[91] 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. A total of six applications for Reliability Agreements with generators outside the import-constrained areas of Southwest Connecticut and Boston were made. Three generating stations in the WCMA load zone have Reliability Agreements in effect, and a fourth has filed with FERC. Two units in the SEMA load zone are awaiting FERC approval with requested effective dates in the first half of 2006. If approved by FERC, these Reliability Agreements could be effective as of their original filing date.

4.4.1 Reliability Agreement Results

As of December 31, 2005, Reliability Agreements were in effect for 14 generating stations, comprising 4,719 MW of capacity.[92] This represents 15% of the total systemwide capacity. As of the end of the first quarter of 2006, Reliability Agreements were in effect or pending at FERC for 18 generating stations comprising 6,936 MW.[93] This represents 22% of the total systemwide capacity. As shown in Table 4-6, the percentage of capacity with Reliability Agreements is considerably higher in the NEMA and Connecticut reliability regions, 32% and 41% respectively for 2005, than in other areas. Figure 4-7 shows the increase in generating capacity with Reliability Agreements over time. The increase between 2005 and 2006 is primarily the result of Reliability Agreements with the Mystic Units 8 and 9 in the NEMA load zone that went into effect in January 2006 and the Fore River Station in the SEMA load zone that has a requested effective date of April 1, 2006. The addition of the Mystic Units 8 and 9 brings the total capacity under Reliability Agreements in the NEMA area to 71% of the total NEMA capacity.[94]

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

[92] These 14 stations include New Boston, Kendall Steam Units and Jet, West Springfield 3, 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 shut-down of the units before October 1, 2008, with guaranteed payment of $6.75 million distributed over a two year period..

[93] These stations include the 14 previously mentioned stations plus Mystic Units 8 and 9, Potter 2, West Springfield GTs, and Fore River. Additional information about Reliability Agreements is posted at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/index.html.

[94] The completion of transmission infrastructure projects could mitigate the need for Reliability Agreements resulting in the revaluation of a limited number of agreements.

Table 4-6
Percent of Capacity Under Reliability Agreements Effective and Pending, March 2006

Zone	2005 CELT Summer SCC (MW)	2005 Reliability Agreements (MW)	Capacity Under Reliability Agreement as Percent of 2005 CELT	2006 Reliability Agreements (MW)	Capacity Under Reliability Agreement as Percent of 2005 CELT
Maine	3,259	0	0%	0	0%
New Hampshire	4,050	0	0%	0	0%
Vermont	820	0	0%	0	0%
Connecticut	7,505	3,082	41%	3,082	41%
Rhode Island	1,813	0	0%	0	0%
SEMA	5,984	0	0%	743	12%
WCMA	3,858	472	12%	548	14%
NEMA	3,605	1,165	32%	2,563	71%
New England Total	30,895	4,719	15%	6,936	22%

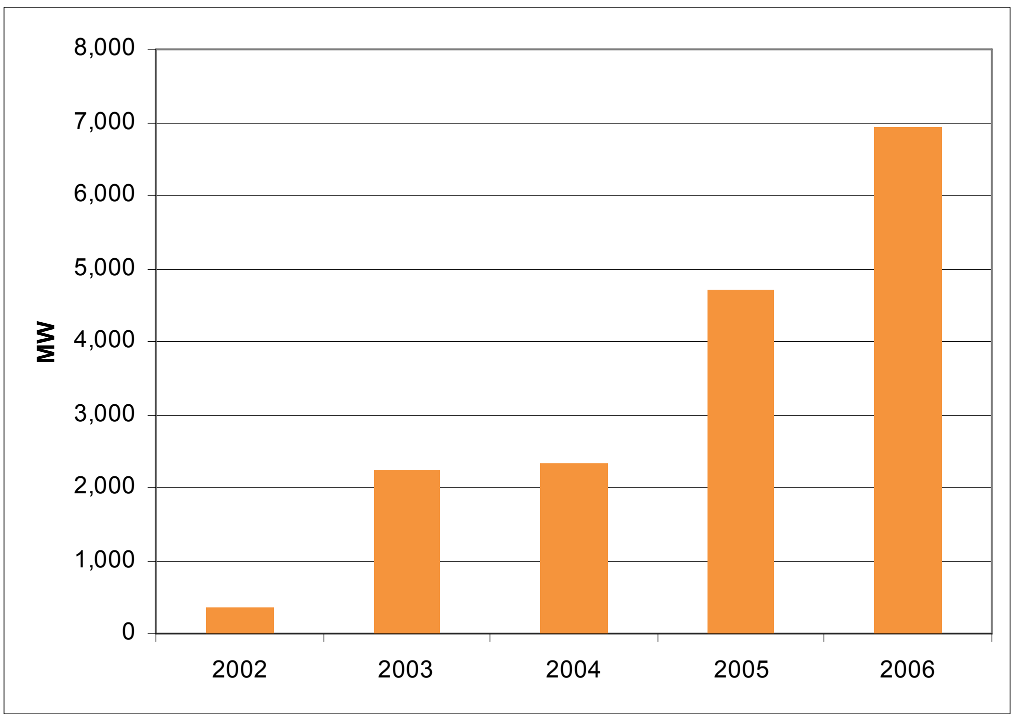

Figure 4-7: Generating capacity with FERC-approved Reliability Agreements.

Note: The 2006 value assumes the Potter unit receives final FERC approval.

The total annualized fixed-cost requirement for all resources with Reliability Agreements effective as of December 31, 2005, is $450.8 million.[95] The actual Reliability Agreement payments made to a generating unit with a Reliability Agreement is reduced by the market revenues that exceed its offers. This will result in Reliability Agreement payments plus market revenues that are equal to FERC-approved fixed and variable costs. Table 4-7 shows the annual sum of monthly net payments for 2003, 2004, and 2005. Consistent with the increase in capacity under Reliability Agreements, the nonmarket payments made to generators operating under Reliability Agreements has also increased over time.

Table 4-7
Net Reliability Agreement Payments in Millions, System Total

2003	2004	2005
$83.4	$177.9	$240.5

4.4.2 Reliability Agreement Conclusions

An increasing number of units have sought Reliability Agreements, and the associated costs have increased rapidly. 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.

4.5 Peaking Unit Safe Harbor Implementation

On April 25, 2003, FERC issued its *Order Accepting, in Part, Requests for Reliability Must-Run Contracts and Directing Temporary Bidding Rules* (Devon Order).[96] The Devon Order directed the ISO to replace the existing rules for mitigation in chronically congested areas, referred to as the Proxy CT or Designated Congestion Area (DCA) rules, with new rules applying special mitigation formulae to units in DCAs with low capacity factors (i.e., an annual capacity factor of less than 10%).

On June 1, 2003, the ISO implemented Peaking Unit Safe Harbor (PUSH) offer rules, which allow owners of low-capacity-factor generating units in DCAs to include levelized fixed costs in their energy offers without risk of mitigation. The rule was intended to increase opportunities for fixed-cost recovery and to produce signals for investment through higher LMPs in these areas during periods of energy scarcity.[97]

As of the end of 2005, 42 generating units in the congested areas of NEMA and Connecticut met the low-capacity-factor and DCA-location criteria for PUSH treatment. This total includes multiple units at the same station. Of these 42 generating units, 20 were offering their generation under PUSH rules with positive fixed-cost adders. Ten had Reliability Agreements and offered their generation under the terms of those agreements and not as PUSH units.

[95] A full year of annualized fixed costs are included in this total for resources with Reliability Agreements effective as of December 31, 2005, regardless of when the agreement became effective during the year.

[96] 103 FERC ¶ 61,082 (Apr. 25, 2003)

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

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 energy-market revenues. In 2005, PUSH units received approximately $35.7 million in second-contingency reliability payments and $6.2 million in first-contingency reliability payments. PUSH units also received about $100,000 in distribution support payments.

4.6 Financial Transmission Rights

Financial Transmission Rights are financial instruments that entitle the holder to a share of the 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. While FTRs were designed to provide load-serving participants with a financial hedge against differences in LMPs due to transmission congestion, they 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.

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.

As approved by FERC on March 3, 2005, and beginning with the May 2005 FTR auction, which was held in April 2005, participants were allowed to submit negatively-priced bids for counterflow FTRs. Previously, only bids of zero dollars and higher were allowed. Allowing negative bids encourages the purchase of counterflow FTRs and allows for an increase in FTR capacity 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 of the ISO-administered process. However, the ISO compensates only FTR holders of record and does not recognize business done in this manner for day-ahead congestion-settlement purposes.

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 exists 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. For example, if congestion occurs during a period when a transmission interface is derated, fewer megawatts of congestion revenue will be collected than were sold at auction.

If 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 if congestion on the path of a specific FTR were adequate to meet the entitlements for that FTR's holder, if the revenues for all FTRs were to fall short, the holder would receive a prorated share of the entitlement.

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 shortfalls that occurred during the year. Any funds remaining after paying all positive allocation shortfalls are allocated to entities that paid transmission congestion costs during the year.

4.6.1 Auction Results

The first long-term auction covering an entire year was held in December 2004 for all of 2005. The long-term auction offered 50% of the system's transmission capacity. In addition, FTR auctions were held for each month in 2005. 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 26 participants, in the January through December 2005 auction, to 40 participants, in the December 2005 monthly auction. Auction revenues for the 12 monthly auctions and one 12-month auction covering 2005 totaled $107 million.

Market Rule 1 specifies that auction revenues must first be allocated to entities in the form of Qualified Upgrade Awards (QUAs). By paying for transmission upgrades, the entities have increased the transfer capability of the New England transmission system and enabled more FTRs to be available in the FTR auction. Auction revenues are then allocated to entities through the Auction Revenue Rights process. During the ARR process, auction revenues are awarded primarily to congestion-paying load-serving entities. In 2005, 84% of the revenue generated by the FTR auctions was returned to congestion-paying entities in the NEMA and Connecticut load zones. Table 4-8 shows total distribution of auction revenue for 2003, 2004, and 2005, and Figure 4-8 shows the distribution by load zone.

Table 4-8
Total Auction Revenue Distribution, 2003, 2004, and 2005

Year	QUA Dollars	ARR Dollars	Total Auction Allocation
2003	$384,186	$28,162,540	$28,546,726
2004	$3,080,554	$88,620,763	$91,701,316
2005	$1,624,929	$105,566,046	$107,190,972

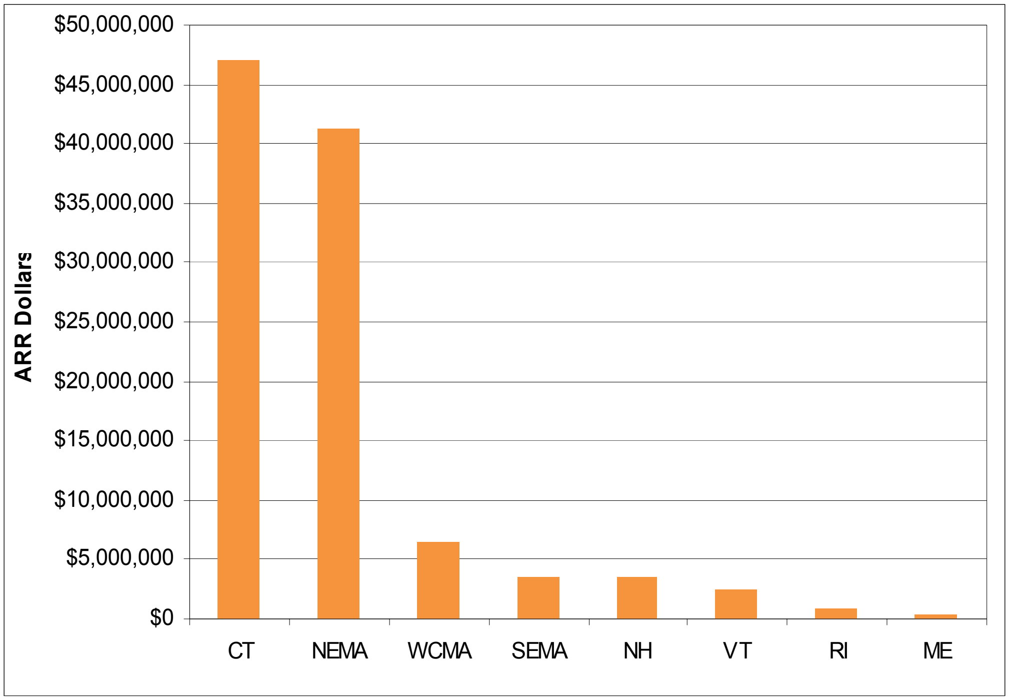

Figure 4-8: ARR distribution by zone, January–December 2005.

The ARR process further allocates ARR dollars to the three categories listed below and as shown in Table 4-9:

- **Excepted transactions**—special grandfathered transactions (listed in Attachment G of the ISO Open Access Transmission Tariff)[98]

- **NEMA contracts**—other long-term contracts with 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

The largest portion of auction revenue was returned to those entities that paid for congestion on the system.

[98] 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-1 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 upon request for the earlier of 10 years following the SMD effective date or termination of the Excepted Transaction.

Table 4-9
Auction Revenue Distribution by Category, 2005

ARR Allocation	Amount
Excepted-transaction dollars	$260,935
NEMA contract dollars	$4,592,240
Load-share dollars	$100,712,871
Total	$105,566,046

Figure 4-9 shows the total auction-cleared megawatts and revenues by month, while Figure 4-10 shows the long-term totals for auction-cleared megawatts and revenues. Revenues in 2005 showed a markedly different pattern than those in 2003 and 2004. Revenues in the earlier years were highest for auctions held to cover the summer months, when the likelihood of congestion is highest, and lower during shoulder-season months, when congestion is likely to be lower. In 2005, revenues had a second peak for auctions held to cover the autumn months, when fuel costs were unusually high.

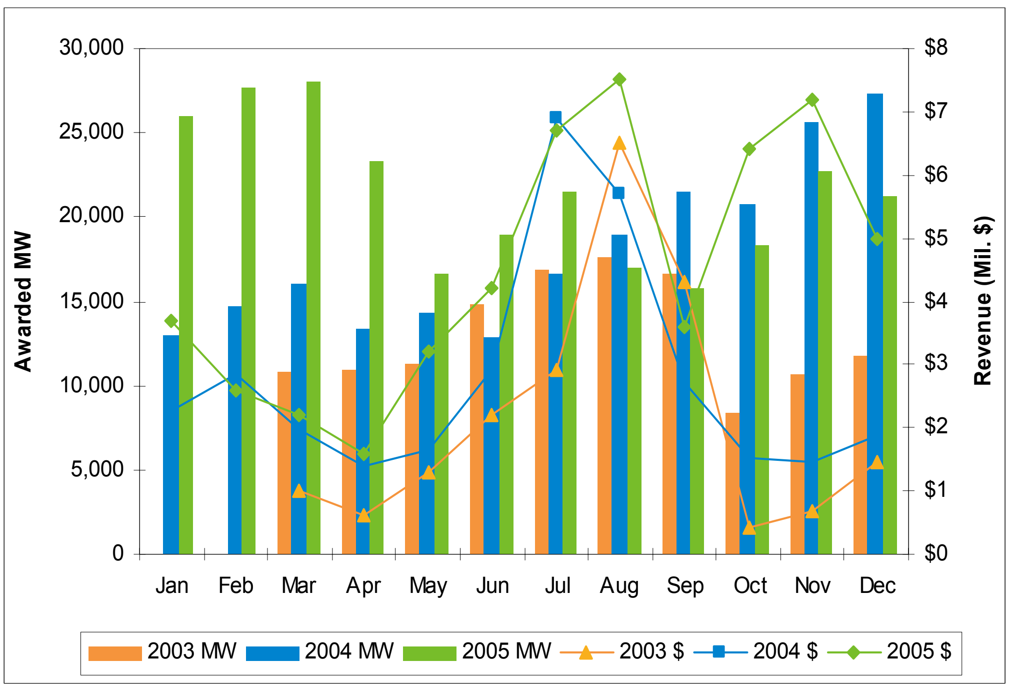

Figure 4-9: Monthly on-peak FTR auction results.

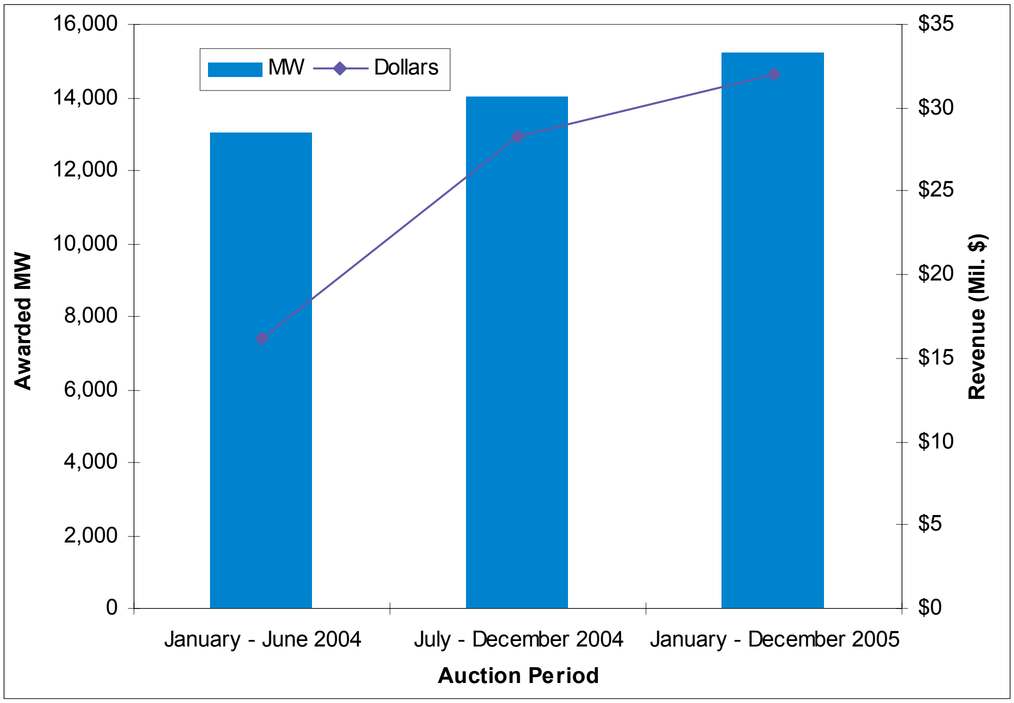

Figure 4-10: Long-term on-peak FTR auction results.

Total FTR volumes shown in Figure 4-9 and Figure 4-10 exceeded system capacity in some months. While the physical line or interface limit applies to the net FTRs sold over a particular line or interface, FTRs flowing in one direction may counterbalance FTRs flowing in the opposite direction. FTRs issued in the direction opposite of expected congestion patterns allow a greater number of FTR megawatts to be sold in the prevailing direction than would be available without the counterbalancing FTR megawatts. This is similar to the way that simultaneous imports and exports over the same external interface can allow total transactions to exceed the import or export 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 4-11 and Figure 4-12 compare LMP congestion components in the Day-Ahead and Real-Time Energy Markets with FTR auction prices. In on-peak hours, the FTR auction prices were directionally consistent with actual day-ahead congestion in seven of the eight load zones, and FTR costs were less than congestion costs. FTR prices and congestion levels were relatively small in the Vermont load zone where they were not directionally consistent. In general, off-peak results also were directionally consistent, or the actual FTR costs were small. These results suggest that the auction process is functioning as designed.

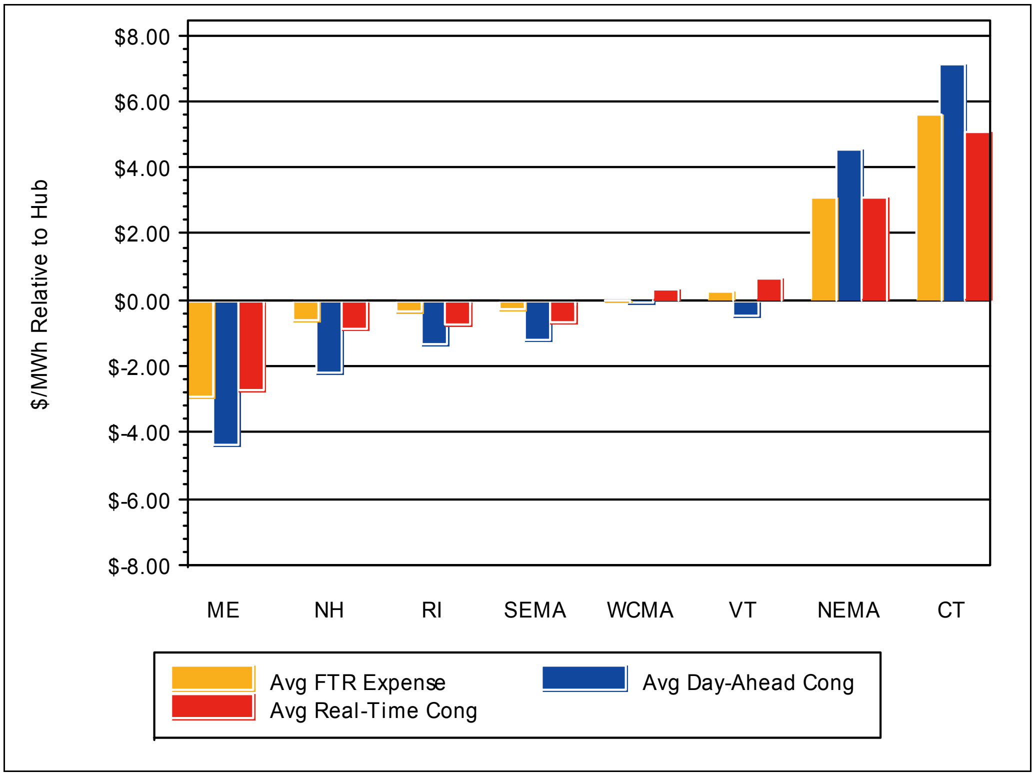

Figure 4-11: 2005 FTR auction prices compared with day-ahead and real-time congestion, on-peak hours.

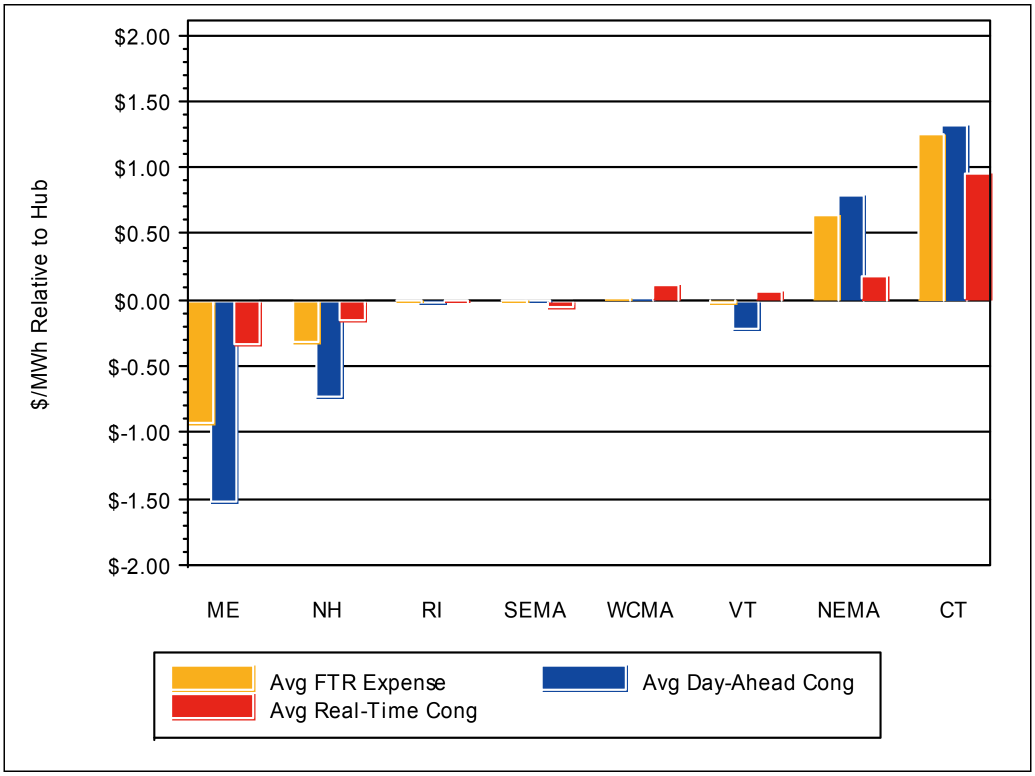

Figure 4-12: 2005 FTR auction prices compared with day-ahead and real-time congestion, off-peak hours.

4.6.2 Financial Transmission Rights Payment Results

FTR holders were paid 100% of their positive FTR allocations in 2005. Overall, the congestion revenue fund had a surplus of $56 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 2005. Payments due to FTR holders with positive target allocations totaled $268.8 million, while available funds, from congestion revenue and negative FTR allocations, totaled $324 million. Table 4-10 shows monthly revenues, allocations, and allocations paid.

Table 4-10
2005 Transmission Congestion Revenue Fund ($)

Month	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation (paid in by participants)	Positive Target Allocation (held by participants)	Amount Paid Out to Positive Target Allocations	Percent Positive Allocation Paid
Jan	9,348,838	(370,161)	970,440	10,226,569	(9,954,990)	97%
Feb	3,092,354	(242,617)	620,823	3,431,396	(3,431,396)	100%
Mar	5,153,875	(2,807,202)	1,935,407	6,924,207	(4,331,888)	63%
Apr	24,934,158	(237,954)	10,755,180	32,112,913	(32,112,913)	100%
May	9,680,905	128,864	2,764,837	12,547,149	(12,547,148)	100%
Jun	38,949,011	244,828	8,497,068	34,793,451	(34,793,451)	100%
Jul	47,318,573	(1,215,160)	7,069,177	41,056,370	(41,056,370)	100%
Aug	57,363,090	(1,596,871)	8,513,940	46,621,067	(46,621,067)	100%
Sep	33,087,358	(1,182,083)	4,591,610	27,974,113	(27,974,113)	100%
Oct	21,523,962	(125,658)	5,554,703	28,127,462	(26,952,445)	96%
Nov	7,875,360	(248,122)	1,434,447	8,485,460	(8,485,460)	100%
Dec	15,122,387	437,240	5,093,627	16,558,999	(16,558,999)	100%

Monthly congestion revenues were inadequate to pay all positive target allocations in three months in 2005; however, surpluses in later months were available to pay these shortfalls. The shortfalls were paid, with interest, in January 2006.

The shortfall in congestion revenues was greatest in March 2005, when only 63% of the $6.9 million in positive allocations was paid. While day-ahead congestion revenues totaling $5.1 million were paid into the fund, real-time congestion revenues of −$2.8 million had to be paid out of the fund before FTR allocations were paid.

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 adjustment)

The first three columns of Table 4-10 show the amount each component (including FTRs with negative allocations) contributed to the Transmission Congestion Revenue Fund for each month of 2005. 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. Table D-1 in Appendix D shows more details about Congestion Revenue Fund Accounting. The method for managing monthly surpluses changed on July 1, 2005. Prior to that date, the surplus rolled from month to month. After July 1, surpluses were retained for settlement at the end of the year. In months with shortfalls, FTR holders are paid a reduced percentage of their monthly entitlement, which reduces the usefulness of the congestion hedge for the month. In months with surplus funds, FTR holders are paid their full allocation. The last column shows the percentage of positive allocations that FTR holders received in each month.

Figure 4-13 compares net auction revenues with payments made to FTR holders for 2003, 2004, and 2005. FTR holders in 2003 and 2005 had positive allocations far in excess of the costs they paid to procure the FTRs.

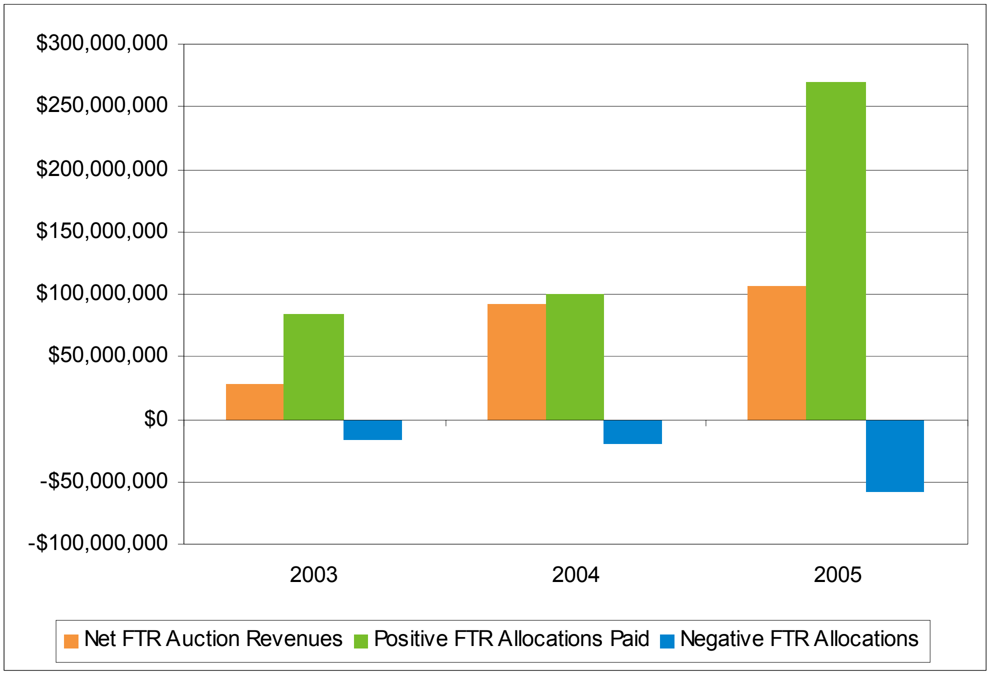

Figure 4-13: FTR auction costs by year compared with benefit payments to FTR holders.

Any participant, regardless of whether it needs to hedge congestion costs, can purchase FTRs. FTR holders that do not pay congestion costs are most concerned with the ratio of the cost to purchase an FTR to the FTR's return. However, FTR holders that do pay congestion costs will be more concerned with the effectiveness of the cost and return of an FTR as a part of their entire congestion-cost picture than with this cost/return ratio. Table 4-11 compares energy-market congestion costs and FTR procurement costs with revenues that offset congestion costs, including ARRs, FTR revenues, and excess congestion-revenue funds returned to load-serving entities. The data in Table 4-11 are limited to participants with load obligations. In 2003 and 2005, revenues were equal to 88% and 86% of congestion and FTR-procurement costs, respectively. In 2004, when congestion costs were relatively low, revenues were equal to 105% of costs.

Table 4-11
Congestion and FTR Procurement Costs Compared with Auction Revenue Rights, FTR Revenues, and Payments from Excess Congestion Revenue Funds, Participants with Load Obligations Only[(a)]

	Millions of Dollars		
	2003	2004	2005
Energy-market congestion costs	$87.3	$79.6	$266.2
FTR Auction Revenue Rights (load-share dollars only)	$26.6	$85.6	$100.7
Congestion Revenue Fund excess (paid to load-serving participants)	$19.1	$0.0	$55.2
FTR procurement cost—positive (paid by FTR purchaser) *Participants with load obligations only*	$19.0	$60.9	$78.7
FTR procurement cost—negative (paid to FTR purchaser) *Participants with load obligations only*	$0.0	-$2.8	-$22.9
FTR positive allocations (paid to FTR holders) *Participants with load obligations only*	$56.9	$66.8	$148.5
FTR negative allocations (paid by FTR holders) *Participants with load obligations only*	-$10.0	-$7.2	-$33.8
Total paid by participants with load obligations (congestion costs, positive procurement costs, negative allocations)	$116.3	$147.7	$378.7
Total received by participants with load obligations (Auction Revenue Rights, Congestion Revenue Fund excess, negative procurement costs, positive allocations)	$102.6	$155.2	$327.3
ARR, FTR, and excess congestion revenues as a percentage of FTR procurement and congestion costs *Participants with load obligations only*	88%	105%	86%

[(a)] Participants with 1% or greater of total real-time load obligation during the year are included. FTR positive allocations are the amounts actually paid, not owed. A shortfall occurred in 2004, when the total was $110.8. Data for both monthly and long-term FTRs are included.

4.6.3 Financial Transmission Rights Conclusions

Net FTR auction revenues totaled $107.2 million in 2005. Auction revenues from positively priced FTRs were approximately $143.8 million, while payments to participants that "bought" negatively priced counterbalancing FTRs were approximately $32 million. In the auctions, small payments also were made to owners of FTRs that had bought the FTRs in earlier, long-term auctions but then sold back all or a portion of their FTRs for the month into the monthly auctions.

FTR holders had positive target allocations totaling $268.8 million, all of which were paid. Negative target allocations, which are liabilities for FTR holders, totaled $57.8 million. The net FTR revenue of $211 million was nearly double the $107.2 million cost to procure FTRs.

Participants that serve load can use FTRs to hedge against congestion costs, but several FTR holders participate in the market purely as financial players. Approximately 23% of FTR payouts went to entities that did not own generation or transmission or have significant load obligations in New England. Some of these may be affiliated with companies that do own generation or transmission or have load obligations.

4.7 Demand Response

Demand response in wholesale electricity markets refers to resources that reduce their electricity consumption in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale market prices.[99] Demand response can help improve grid reliability by quickly reducing demand during emergency conditions. It 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 is an important part of a wholesale market.

4.7.1 Demand-Response Programs

The ISO administers the demand-response programs for the New England wholesale electricity market. During 2005, the ISO administered the following programs:

- Day-Ahead Load-Response Program
- Real-Time Demand-Response Program (30-minute and two-hour response)
- Real-Time Price-Response Program
- Real-Time Profiled-Response Program

On April 18, 2005, FERC issued an order approving revisions to Market Rule 1, Appendix E, to create a Day-Ahead Load-Response Program (DALRP).[100] Implementing the DALRP, which went into effect on June 1, 2005, required reconfiguring the existing software and coordinating the new DALRP with the existing real-time programs. An enrolling participant that wants to participate in the day-ahead program must first register a resource in one of the Real-Time Demand-Response Programs. It may then register the resource in the DALRP and can make offers to reduce its load based on 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 enrolling participants with offers that clear will be paid the day-ahead LMP. Day-ahead cleared resources that show demand-response deviations in real time will be settled with the enrolling participant at the real-time LMP.

The Real-Time Demand-Response Program provides participants and the resources they enroll with two options for curtailing consumption. Resources must respond within either 30 minutes or two hours after receiving notice from the ISO to curtail consumption, and the ISO guarantees a minimum curtailment period of two hours for each event. Participants with resources enrolled in this program are paid the greater of either the real-time LMP applicable to their resource's load zone, or the floor price, which is $500/MWh in the 30-minute program and $350/MWh in the two-hour program. Enrolling participants are also eligible to receive ICAP payments. Failure to perform during a curtailment event results in the forfeiture of the ICAP payment accumulated for the month. It also

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

[100] See http://www.iso-ne.com/regulatory/ferc/orders/2005/apr/er04_1255_001.doc.

results in the derating of the resource's future curtailment capability accordingly. Participation in the Real-Time Demand-Response Program requires the resource to be able to record its electricity usage in five-minute intervals, as well as have Internet-based communication capability.

In the Real-Time Price-Response Program, enrolling participants are paid real-time prices for their resources' voluntary reductions in electricity usage when the forecast hourly zonal price (based on the results of the Day-Ahead Energy Market or subsequent Reserve Adequacy Analyses) is greater than or equal to $100/MWh. Enrolling participants either submit their meter readings to the ISO each day, on the same schedule as other meter data, or before the end of the 90-day resettlement period. Activation may be zone-specific or regionwide.

The Real-Time Profiled-Response Program includes demand-response resources capable of being interrupted within two hours of an ISO instruction to do so. Participants in this program are not required to install five-minute metering on their resources. Rather, the load response for the individual or group of individual resources is estimated using an ISO-approved measurement and verification plan. For example, statistical sampling can be used to estimate load reductions for projects, such as aggregated residential super-thermostat programs, hot-water heaters, pool pumps, and distributed generation (DG).[101]

Demand-response program costs are allocated based on network load.

4.7.2 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.[102] The stated goal was to improve the reliability of the electric system in Southwest Connecticut through summer 2007, at which time a 345 kV transmission-loop expansion is expected to come into service.[103] The majority of the resources selected under this RFP are participating in one of the standard ISO's Real-Time Demand-Response Programs. These resources receive supplemental capacity payments expected to total $128 million over the four-year term of the RFP. The ISO contracted with seven companies that provided the resource types eligible to respond to the RFP, as follows:

- New fast-start generation
- 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 later, with approximately 260 MW to be available by June 2007.

[101] Distributed generation is generation provided by relatively small installations, including those powered by renewable energy resources, directly connected to distribution facilities or retail-customer facilities. DG can alleviate or avoid transmission or distribution constraints or the installation of new transmission or distribution facilities.

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

[103] Phase 1 of Southwest Connecticut Reliability Project is now scheduled for completion in December 2006, with Phase 2 currently scheduled for completion in December 2009.

4.7.3 Winter Supplemental Program

ISO New England developed the Winter Supplemental Program (WSP) to improve the reliability of power system operations during winter 2005/2006. The program was developed as one of several initiatives in response to uncertainties in fuel supply and delivery due to the impacts of Hurricanes Katrina and Rita. A total of 330 MW of additional demand-response and small-supply resources were enrolled in the program. Had an OP 4 condition occurred during December 2005 to March 2006, these resources would have reduced load within 30 minutes of ISO New England's request to do so.

4.7.4 Demand-Response Program Participation

As of September 1, 2005, 781 assets were enrolled in the real-time programs, comprising 472 MW of potential demand interruption or curtailment. Of that total, 290 MW or 61% is in the Connecticut load zone, with another 10% in the NEMA and Maine load zones. Figure 4-14 shows demand-response program enrollments by month for 2004 and 2005. Overall enrollment in 2005 has increased by 25% from a monthly average of 345 MW in 2004 to 430 MW in 2005. The increased participation comes largely from resources contracted as part of the Southwest Connecticut RFP. The average 2005 summer period (June through September) enrollment under the RFP was 213 MW, up from 113 MW in 2004. With this additional enrollment, the RFP accounts for over 70% of Connecticut's total 290 MW of demand-response enrollments and approximately 45% of the regionwide total.

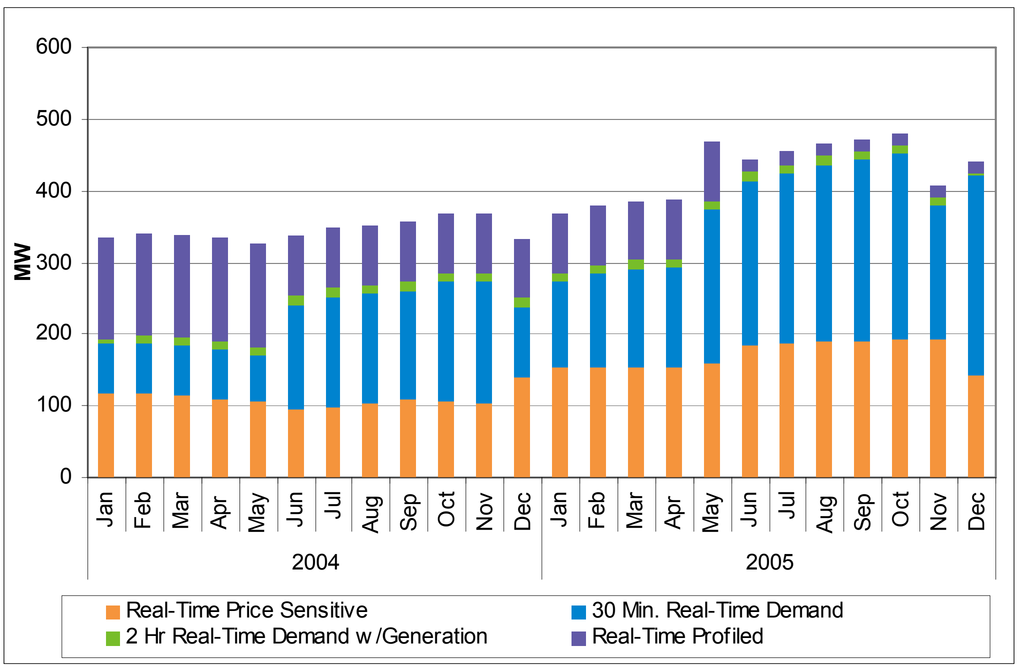

Figure 4-14: Monthly enrollments in demand-response programs, 2004 and 2005.

During 2005, enrollments in the Real-Time Profiled-Response Program dropped off, while enrollments in the Real-Time Price-Response Program and 30-Minute Real-Time Demand-Response Program increased. Table 4-12 shows the results of all demand-response programs combined. In total, $8.1 million in payments were made to enrolling participants for curtailing a total of 66,251 MWh during the year. This is in addition to $35.9 million in supplemental payments made to participants selected under the Southwest Connecticut RFP.

Table 4-12
Summary of 2005 Results for All Load-Response Programs

Month	Number of Days Activated	MWh Interrupted	Payment
January	16	9,061	938,757
February	7	3,206	320,563
March	12	2,628	268,845
April	18	2,607	263,955
May	15	1,553	159,104
June	21	4,706	494,911
July	19	8,403	1,506,384
August	23	9,981	1,345,470
September	21	5,940	736,212
October	21	6,731	797,877
November	20	7,168	798,477
December	21	4,267	489,487
Total	214	66,251	8,120,042

Table 4-13 presents the monthly breakdown by demand-response program for resources that participated in the DALRP in addition to the Real-Time Demand-Response Programs. Resources activated in the DALRP receive a day-ahead payment, based on the number of cleared megawatts, and a real-time payment, based on the difference between their actual number of interrupted megawatts and the amount cleared day ahead. The program started in June 2005, and participation from June 1 to December 31, 2005, was limited. Experience with the DALRP in 2005 showed that the real-time reduction in network load was greater than the quantity cleared day ahead.

Table 4-13
Day-Ahead Interruptions and Payments by Program Type[a]

Month	Demand					
	Day-Ahead Cleared (MW)	Real-Time Deviations (MWh)	Actual Interruptions (MWh)	Day-Ahead Payments	Real-Time Deviation Payments	Total Day-Ahead Payments
January	0	0	0	$0	$0	$0
February	0	0	0	$0	$0	$0
March	0	0	0	$0	$0	$0
April	0	0	0	$0	$0	$0
May	0	0	0	$0	$0	$0
June	10	123	133	$1,168	$10,241	$11,409
July	8	93	101	$844	$7,856	$8,701
August	5	151	156	$1,022	$21,748	$22,771
September	0	0	0	$0	$0	$0
October	0	0	0	$0	$0	$0
November	0	0	0	$0	$0	$0
December	97	417	514	$8,363	$33,817	$42,180
Total	120	783	903	$11,398	$73,662	$85,060

[a] The day-ahead programs began in June 2005.

Table 4-14 shows the real-time interruptions and payments for resources participating in only the Real-Time Demand-Response Programs. The Real-Time Price-Response Program was activated on 214 days during 2005. Although resources are called on to curtail consumption when prices are forecast to exceed $100/MWh, and participation in the price-response events is voluntary, actual participation in this program depends on the business condition for each individual customer and price levels. The Real-Time Price-Response Program resulted in 64,063 MWh of load curtailments in 2005. The number of resources that curtailed load and the total load curtailed varied from event to event. The Real-Time Demand-Response Programs were activated twice during the period. The event in Connecticut on July 27, 2006, was in response to an OP 4 event, while the events in August and September were for test and audit purposes of the Real-Time Demand and Profiled-Response Programs.

Table 4-14
Real-Time Interruptions and Payments by Program Type

Month	Demand		Price		Profiled	
	Real-Time Interruptions (MWh)	Payments ($)	Real-Time Interruptions (MWh)	Payments ($)	Real-Time Interruptions (MWh)	Payments ($)
January	0	$ 0	9,061	$938,757	0	$ 0
February	0	$ 0	3,206	$320,563	0	$ 0
March	0	$ 0	2,628	$268,845	0	$ 0
April	0	$ 0	2,607	$263,955	0	$ 0
May	0	$ 0	1,553	$159,104	0	$ 0
June	0	$ 0	4,573	$483,502	0	$ 0
July	1,158	$ 578,570	7,144	$919,114	0	$ 0
August	34	$ 12,852	9,730	$1,300,173	61	$ 9,674
September	31	$ 15,597	5,908	$720,615	0	$ 0
October	0	$ 0	6,731	$797,877	0	$ 0
November	0	$ 0	7,168	$798,477	0	$ 0
December	0	$ 0	3,752	$447,307	0	$ 0
Total	1,224	$ 607,018	64,063	$7,418,288	61	$ 9,674

4.7.5 Demand-Response Improvements

The major enhancement made to the ISO's demand-response programs during 2005 was the introduction of the DALRP. Since overall participation in the new program has been limited, conclusions about the program cannot be made at this point.

In March 2005, the number of hours a Real-Time Price-Response Program event remains activated was modified from an 11-hour period all year to a 6-hour period in the winter and an 8-hour period during the summer. This change more closely matches the program interruptions to system needs.

On November 29, 2005, FERC approved the ISO's implementation of the Demand-Response Reserve Pilot Project. The project is evaluating the ability of smaller (i.e., less than 5 MW) demand-response and *settlement-only* generating resources to deliver reserve products functionally equivalent to larger resources.[104]

The objectives of the pilot are as follows:

- Based on analysis of actual response data, demonstrate whether customer loads can reliably provide reserve products, specifically 30-minute operating-reserve and 10-minute nonsynchronized-reserve services
- Determine the requirements for the level and type of control-room communications, dispatch, metering, and telemetry sufficient for these smaller resources providing reserve services

[104] Settlement-only generators have a capacity of less than 5 MW. They are not modeled in the energy-management system and are therefore exempt from submitting day-ahead and real-time supply offers. These units are typically connected to the distribution system of the host utilities and run as price-takers in the Real-Time Energy Market. They provide energy to the market when available. For further information, see http://www.iso-ne.com/rules_proceds/isone_mnls/m_20_installed_capacity_(revision_12)_01_01_06.doc.

- Identify and evaluate lower-cost communications and telemetry solutions that meet the requirements and are more suitable for demand-response resources to provide reserves

To meet these objectives, the pilot project will focus on two distinct subprojects, as follows, with concurrent timelines to address two specific issues:

1) Determine the ability of demand-response resources to respond to reserve-activation events compared with off-line and on-line generation resources
2) Evaluate lower-cost, two-way communication alternatives to the current combination of Supervisory Control and Data Acquisition (SCADA) and Remote Intelligent Gateway (RIG) technology presently required to connect dispatchable resources to the ISO

The experience gained in the Demand-Response Reserves Pilot will help the ISO achieve the following long-term goals:

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

The ISO will solicit a maximum of 50 MW of demand-response and settlement-only generation resources to participate in the pilot. Pilot resources will be recruited from among various resource types (generation and demand response) and selected to represent the mix of resources that would likely participate in a competitive reserve-product market. For example, resource types may include but not be limited to weather-sensitive loads, nonweather-sensitive loads, small generation, and load-reduction resources.

4.7.6 Demand-Response Conclusions

The total value of payments made to enrolling participants in 2005 was about $44 million, $8.1 million in demand-response program payments and $35.9 million in supplemental capacity payments associated with the Southwest Connecticut RFP.[105] Capacity enrolled in the programs has increased by about 100 MW, primarily as part of the Southwest Connecticut RFP. Program payments have increased relative to last year due to the increase in days with interruptions from 59 days in 2004 to 214 days in 2005. Focusing on the most active program, the Real-Time Price-Response Program, the total curtailment increased from 17,639 MWh of curtailment in 2004 to 64,063 MWh in 2005. Initial participation in the DALRP has been limited, but participation is expected to increase as market participants become more familiar with the program.

[105] The annual supplemental payments associated with the SWCT Gap RFP translate to $14.04/kW-Month based on the average capacity provided from June to September 2005.

Demand response is an important component of the wholesale electricity market, without which the wholesale electricity markets would be incomplete and produce less-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.

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, exceed 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 2005.

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 it 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 Market Monitoring and Mitigation Results

Congestion mitigation was triggered 16 times during 2005, as shown in Figure 5-1. Eight mitigation events were attributable to the bidding strategy of one participant to maximize uplift revenue, while an additional five events were small-dollar threshold violations due to fuel volatility. In addition to taking these specific actions, the Internal Market Monitoring Unit had nearly daily discussions with individual participants concerning specific market behavior. The systemwide thresholds did not trigger mitigation of energy suppliers that were pivotal in 2005.

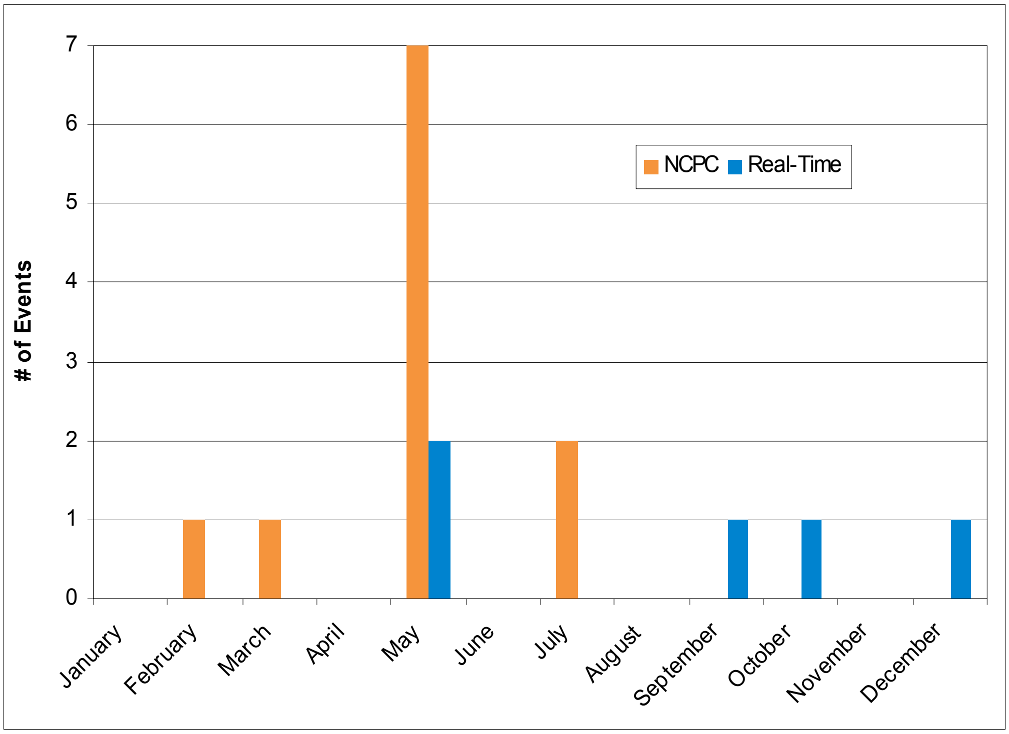

Figure 5-1: Mitigation events in 2005.

5.1.3 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.[106] 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.[107]

During 2005, 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.

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[106] This section can be accessed at http://www.iso-ne.com/regulatory/tariff/sect_3/appendix_a_mkt_monitoring_redone_1-18-06.doc.

[107] This appendix can be accessed at http://www.iso-ne.com/regulatory/tariff/sect_3/Market_Rule_1_Appendix_B_06-01-05.DOC.

5.1.4 Reliability Costs in the Boston Area

While the ISO is committed to developing market means for paying costs related to reliability requirements, at present, some of these costs are paid outside of the market through daily reliability payments (See Section 4.2). Although at times necessary, committing generation outside of the market can have a negative impact. It may depress electricity prices and dampen price signals for investment in constrained areas.

In 2005, daily reliability payments, comprised of first and second contingency, voltage, and distribution, totaled $287 million. Approximately 28% of this total was paid to two generators in Boston. The Boston area has requirements for voltage control and local second-contingency coverage that require generation to be committed for reliability. The area is import constrained, and only a limited number of generators are able to meet these requirements. Beginning in late 2004, issues emerged related to the offer behavior of this generation. The generation was offered in a manner that avoided in-merit, market-based economic dispatch, causing the ISO to dispatch the generation through the RAA process. These actions had the effect of increasing the opportunity for the generator to receive daily reliability payments.

Market Rule 1 specifies that the ISO must monitor generators' energy offers by comparing daily offers with offer thresholds called reference levels. For most generators, the threshold is the average of accepted supply offers for the previous 90 days adjusted for changes in fuel prices. However, the specific generators discussed here were usually committed for voltage control or second-contingency coverage at offer levels above LMPs and rarely ran in merit. Because the generators were required for reliability and did not face significant competition, the participant was able to submit offers above the generators' marginal costs and still be committed. This caused the generators' reference levels, which were based on the few instances when their offers were accepted in merit, to be significantly above marginal costs. As a result, the participant avoided potential mitigation of its energy offers, and the opportunity for the participant to receive daily reliability payments based on those offers increased.

The lead participant for the generators in Boston also offered its generation in a manner that maximized the opportunity to receive reliability cost payments, rather than relying on economic dispatch. When the generators were not dispatched for reliability reasons, the participant self-scheduled its units. This caused higher than necessary reliability costs by duplicating functions of other resources the ISO had already scheduled for reliability reasons. For example, the participant frequently self-scheduled the generators for a contiguous block of time in real-time (e.g., four hours). If at the end of the period, the ISO had not committed the units for second-contingency protection or voltage control, the participant again self-scheduled the units for another four-hour contiguous block. This self-scheduling was done with little notice. When the ISO did commit the units for reliability, the participant received reliability cost payments. The short notice self-scheduling of the units contributed to excess commitments in the day-ahead and RAA process, as the ISO was unable to rely on the generators to be available in real-time because of the short duration and short lead-time of their self-schedule.

In its *2004 Assessment of the Electricity Markets in New England*, the IMMU noted the following about reliability commitments:[108]

[108] The *2004 Assessment of the Electricity Markets in New England* is available on the ISO's Web site at http://www.iso-ne.com/pubs/spcl_rpts/2005/immu/index.html.

> [Reliability commitments] can create incentives for generators frequently committed for reliability to avoid market-based commitment when they would be economic at the day-ahead LMP. This frequently induces the ISO to commit the resource in the Resource Adequacy Assessment . . . process for local reliability where the generator is paid its bid price in the form of uplift. When the generator is not committed in the RAA, but expects to be economic at the real-time LMP, it simply commits itself after the RAA.

The report also found that in late 2004, "two generators in the NEMA area did this with regularity." This behavior continued in 2005 and was the primary reason for the increase in reliability commitments during the year.

The ISO took several actions to address the offer behavior. On February 9, 2005, the ISO presented the issue to the NEPOOL Markets Committee, and on March 11, 2005, the NEPOOL Participants Committee voted to support a rule change. On April 1, 2005, the ISO made a filing with FERC to change Market Rule 1 to modify the criteria used to determine when a generator is eligible for a market-based reference level rather than a marginal-cost-based reference level. The rule change was approved by FERC on May 6, 2005.[109] Under the revised criteria, the generators in question have marginal-cost-based reference levels.

In addition to the rule change, infrastructure improvements are underway in the Boston area, including NSTAR's transmission system improvements and the installation of two new MVAR reactors. As discussed in Section 4.1, when complete, these improvements will lessen the need for generation commitments for reliability. The installation of one of the two new MVAR reactors was completed in fall 2005 and has reduced the need for commitments for voltage control. However, some generation commitments in Boston may still be required for reliability even after these upgrades are completed.

In late 2005, the two Boston generators filed for Reliability Agreements. The filing cited revenues that were inadequate to cover costs, due in part to the rule change that caused the generators' reference levels to be based on their marginal costs.[110] Following an ISO determination that two of the generators were required for reliability, FERC accepted the agreement for these two generators with an effective date of January 1, 2006. Under this agreement, the participant is required to offer its generation into the Day-Ahead Energy Market at marginal cost. Because of this, costs related to daily reliability commitments declined significantly in early 2006 compared with 2005 levels. The agreements remove negative impacts on the market by eliminating the behavior that led to excess reliability commitments and potentially distorted price signals.

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[109] For more information on this FERC order, *Order Accepting Tariff Amendments*, see http://www.iso-ne.com/regulatory/ferc/orders/2005/may/er05-767_5-6-05.doc.

[110] For more information on this filing, see http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20050811-0105

5.2 Analysis of Competitive Market Conditions

This section presents analyses of competitive market conditions during 2005. 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.

However, the HHI is not a sufficient indicator of market concentration in wholesale electricity markets. For example, the calculation does not include any measure of the overall supply/demand balance. 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)

Although these classifications are imprecise in that a low-concentration index does not guarantee 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.

Despite the modest increase from 2004, the HHI for 2005 of about 700 is well below the U.S. Department of Justice benchmark for an unconcentrated market.

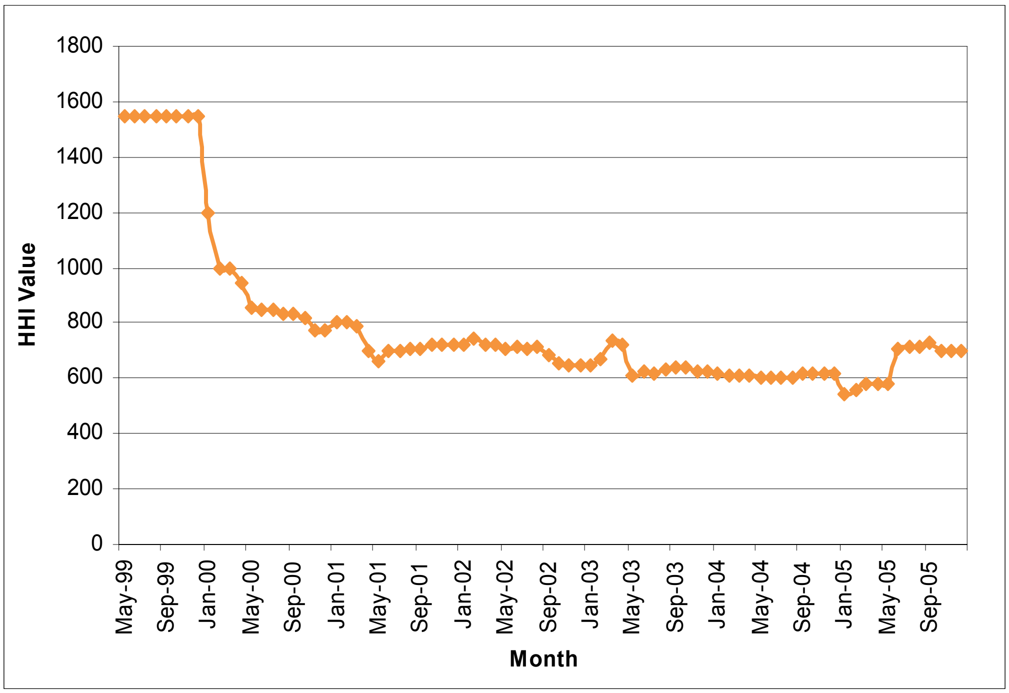

Figure 5-2: Herfindahl-Hirschman indices for New England, May 1999–December 2005.

As part of its market assessment function, the ISO also develops an HHI for each load zone. These are shown in Figure 5-3. 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, as 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, it declined significantly in 2005.

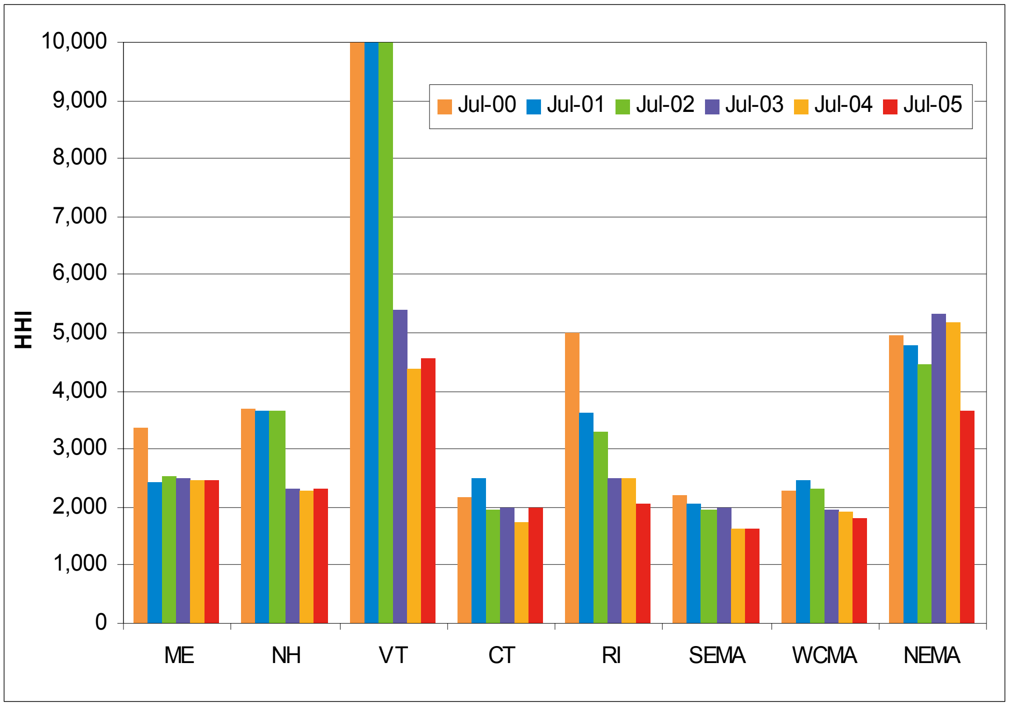

Figure 5-3: Herfindahl-Hirschman indices by load zone.

5.2.2 Market Share by Participant Bidder

Figure 5-4 shows generation capability for the 12 lead participants with the largest portfolios during 2005. The largest portfolio at the beginning of the year was 4,000 MW, while the largest portfolio at the end of the year was 4,800 MW, owned by a different participant.

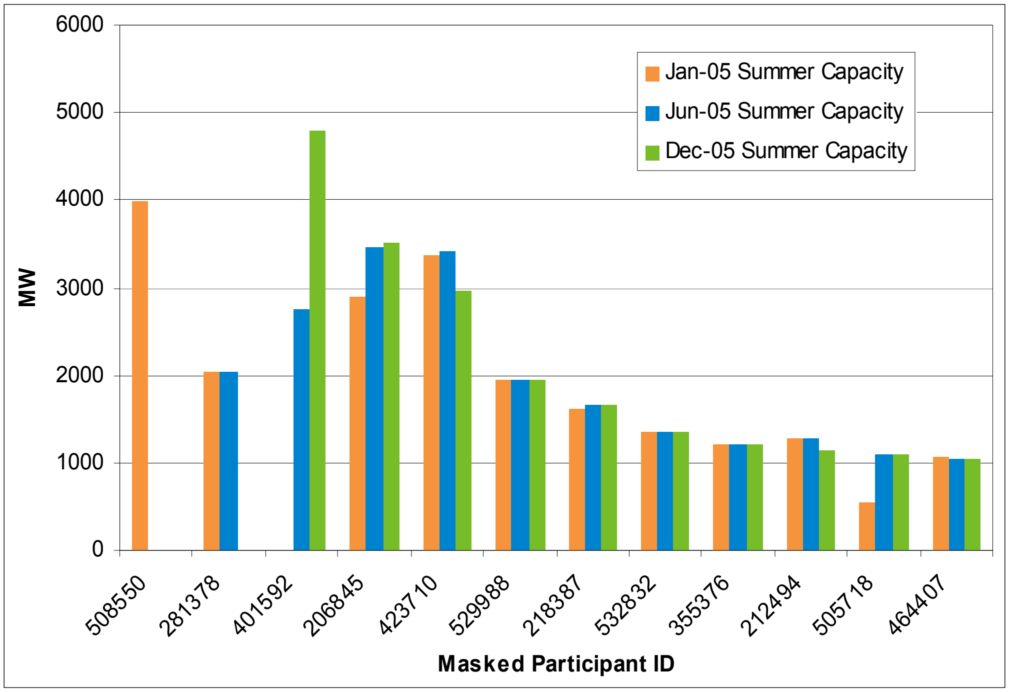

Figure 5-4: 2005 generation capacity by lead participant.

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.[111]

Calculations for January through December 2005 show that, on average, at least 63% 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 2005, as shown in Figure 5-5, the degree of forward contracting was at least 57% of real-time load obligation. In 2004, the average was 73%. 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. They also understate the physically hedged load to the extent that nondispatched generators are available. Conversations between the INTMMU and market participants suggest that the drop in hedging through the settlements system during 2005 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.

[111] Newbery, David, 1995, "Power Markets and Market Power," *The Energy Journal*, Vol. 16, No. 3.

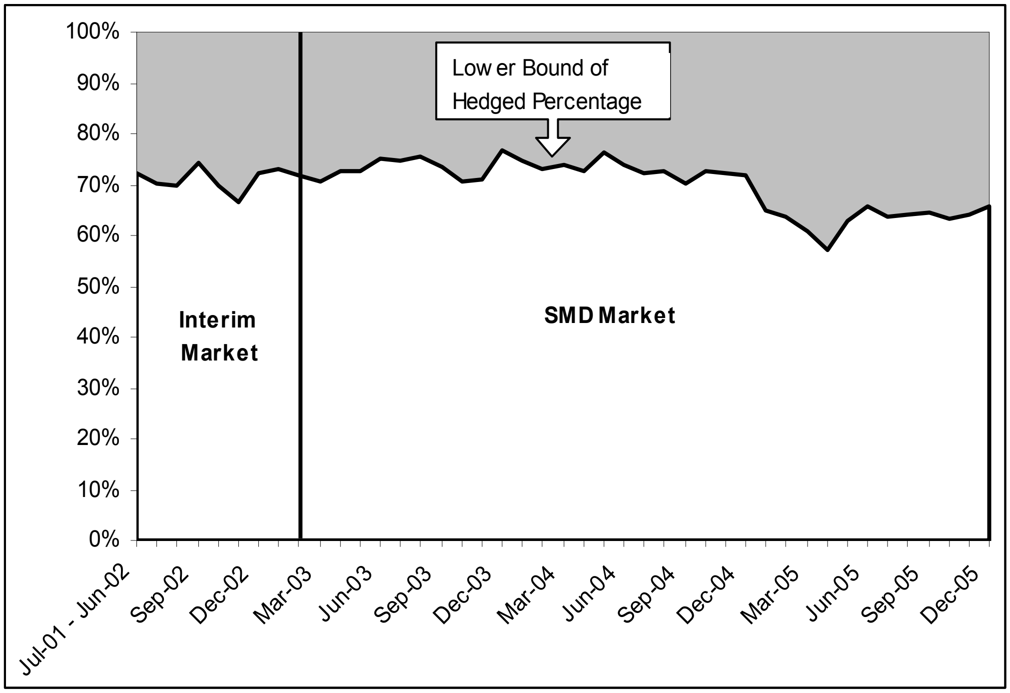

Figure 5-5: Lower bound of real-time load as hedged through ISO settlement system.

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:[112]

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

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.[113]

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

[113] Sheffrin, Anjali, 2001, *Preliminary Study of Reserve Margin Requirements Necessary to Promote Workable Competition*, California ISO, November 19, 2001, Revision; http://www.caiso.com/docs/2001/11/20/200111201556082796.pdf.

On July 9, 2003, in Docket No. ER03-849-000, FERC accepted the ISO's request to implement a pivotal-supplier trigger for evaluating a pivotal supplier's energy-supply offers for possible mitigation.[114] 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.[115] The calculation of the RSI, described above, is consistent with the requirements outlined in the docket.

Table 5-1 shows the number of hours in each month of 2005 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 2005; the RSI was below 100% during 311 hours of 2005, most of which were on high-demand summer days. As Table 5-2 shows, 2005 had many more hours with pivotal suppliers than 2004. This is due to the higher loads during summer 2005, as well as the modest increase in market concentration (shown in Sections 5.2.1 and 5.2.2).

The RSI analysis conforms with other analyses that show relatively good market performance in New England, as it shows that there were pivotal suppliers in only 3.6% hours during 2005. 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.[116] The ISO will continue to monitor and assess the existence of pivotal suppliers and their influence on the market.

[114] 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.

[115] 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).

[116] Green, Richard, 1999, "The Electricity Contract Market in England and Wales," *Journal of Industrial Economics*, Vol. XLVII, No. 1, pp 107–124.

Table 5-1
Residual Supply Index, 2005

Month	Number of Hours RSI <100%	Number of Hours RSI <110%	Average Monthly RSI	Maximum RSI	Minimum RSI
January	0	6	146	203	108
February	0	0	153	194	122
March	0	8	138	177	105
April	0	17	136	180	104
May	0	0	145	209	114
June	16	120	140	209	92
July	114	182	128	196	82
August	127	225	124	181	86
September	46	153	131	185	90
October	8	127	128	330	93
November	0	11	143	196	105
December	0	16	141	203	101
Total	**311**	**865**	**138**	**330**	**82**

Table 5-2
Residual Supply Index, 2004 and 2005

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

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 (2002).[117] 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 each market participant acted as a price-taker and the market operated with perfect efficiency

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

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: 1) the ISO's real-time LMP at the Hub; and 2) 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 (i.e., the bid intercept). 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 below).[118] This metric is more appropriate than using a simple arithmetic average of hourly Lerner Indices.

Table 5-3 shows that the QWLI for 2005 increased from 2004 for both the real-time Hub price and the aggregate bid-intercept price. The 2005 results are consistent with outcomes expected in a competitive market, with small markups by either measure. While the QWLI is a useful and intuitive measure of market competitiveness, it is subject to an uncertain amount of modeling error due to the necessary simplified assumptions and the need to rely on estimates of generator-input cost and efficiency (e.g., environmentally limited units not explicitly considered, hydroelectric units 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 2005.

118 $$QWLI_1 = \frac{\sum(LMP * Load) - \sum(benchmark\_price * Load)}{\sum(LMP * Load)}$$

$$QWLI_2 = \frac{\sum(bid\_intercept\_price * Load) - \sum(benchmark\_price * Load)}{\sum(bid\_intercept\_price * Load)}$$

Table 5-3
ISO Model Market Price Measures

Price Measure	2005 Price ($/MWh)	Quantity-Weighted Lerner Index		
		2003	2004	2005
Competitive benchmark price	$75.39			
Real-time Hub price	$79.96	9%	3%	6%
Aggregate bid-intercept price	$76.18	-4%	-6%	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 a high thermal efficiency may be unable to break even or earn a profit 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	13,600	13,300
Kerosene	13,400	11,000
Natural gas	8,200	7,100
No. 2 fuel oil	16,200	11,000
Diesel	12,500	11,000
No. 6 fuel oil	10,500	9,000

The implied heat rate is the ratio of the day-ahead Hub LMP and the next-day price for the applicable fuel in each hour. This rate approximates the thermal efficiency that would be required to break even 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/million British thermal units (MMBtu), the implied heat rate would be 10 MMBtu/MWh, or 10,000 Btu/kWh.[119] Generators with actual heat rates lower than the implied heat rate at least break even on their conversion of fuel to electricity, ignoring fixed and other variable operating and maintenance costs.

Figure 5-6 reports the monthly average implied heat rates for price points on two major interstate natural gas pipelines in New England. During January and December 2005, when gas prices were high, the implied heat rate was especially low. The data suggest that gas-fired generators with a thermal heat rate less than 8.2 MMBtu/MWh, the average in New England, were typically 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.

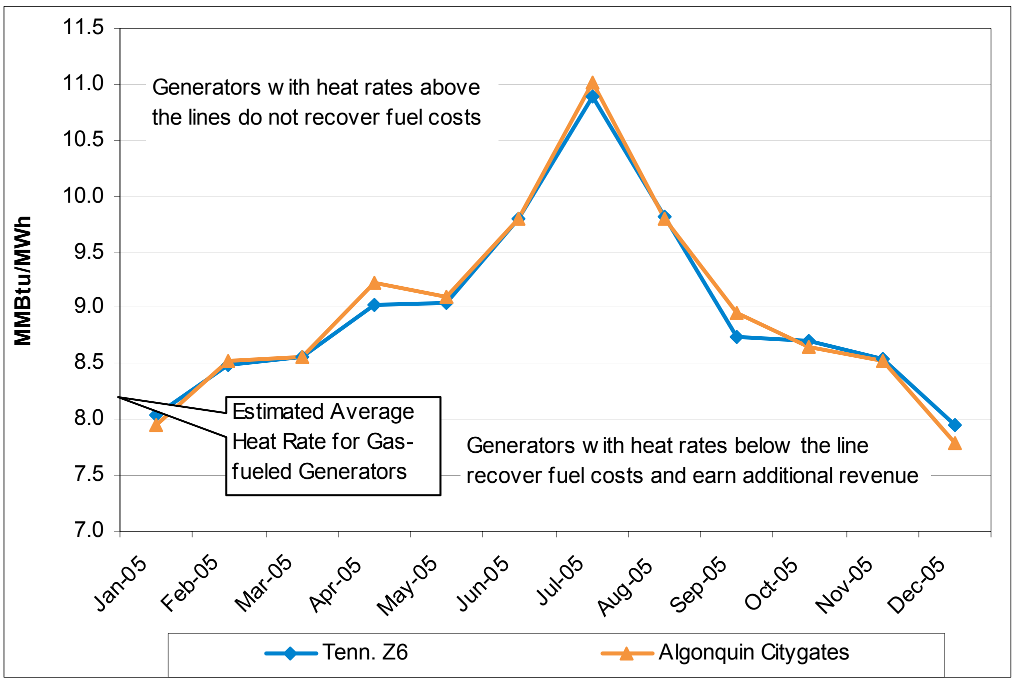

Figure 5-6: Monthly average implied heat rates in New England, natural gas and electricity.

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 and 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 oil-fueled generator was not recovering fuel costs based on average monthly prices, and diesel and jet fuel generators only recovered fuel costs in September. This is consistent with ISO

[119] Heat rates are traditionally reported in Btu/kWh, which is a multiple of 1,000 times the MMBtu/MWh values.

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.

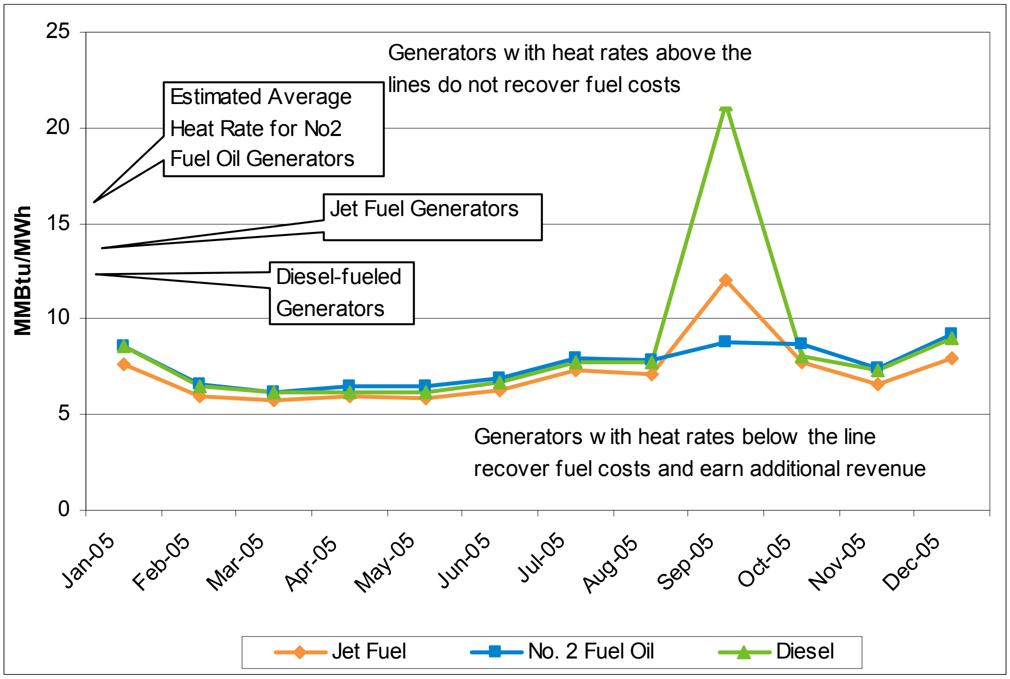

Figure 5-7: Monthly average implied heat rates in New England, petroleum-based fuels and electricity.

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 and the fuel price. For each month, an average of all days in the month was calculated.

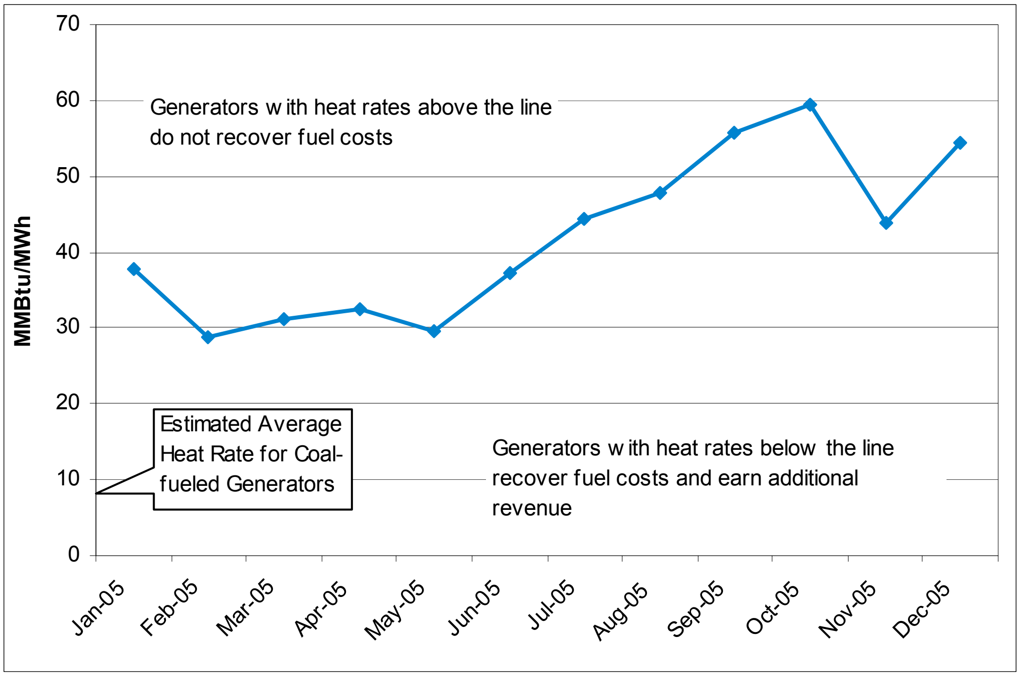

Figure 5-8: Monthly average implied heat rates in New England, coal and electricity.

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 and 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, and ancillary services 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 2005. 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
2005 Yearly Theoretical Maximum Revenue, Net of Variable Costs, per MW, for Hypothetical Generators

Generator	Marginal Cost Formula	Heat Rate (Btu/kWh)	($/MW-Year)			
			2005 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	$111,635	$200	$2,208	$114,043
Representative combustion-turbine/ gas-fired	(Daily fuel cost x heat rate) + (VOM of $3/MWh)	10,500	$20,877	$200	$32,225	$53,302

[a] The revenue from capacity sales is based on ICAP supply auction-clearing prices.
[b] The revenue from ancillary services is based on the Regulation Market for combined-cycle units, and the Regulation and Forward Reserve Markets for combustion-turbine units. Forward-reserve revenues equal auction revenues minus average penalties.
[c] Variable operations and maintenance costs.

Under these assumptions, the combined-cycle plant would have earned a theoretical maximum of about $114,000/MW in the electric-energy markets and Ancillary Services Markets during 2005, net of variable costs. The combustion-turbine plant would have earned a theoretical maximum of approximately $21,000/MW in the electric-energy market, and if it participated in the Forward Reserve Market, it could have earned an additional $30,000/MW. Capacity-market revenues were negligible for the year. For this analysis, unit outages were represented by reducing energy revenues by 5%.

This 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 and reserve revenues were the same throughout the system.

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.

The above analysis is hypothetical. The ISO also conducted an analysis of revenues and costs of real generators. This analysis included eight relatively efficient natural-gas-fired combined-cycle generators throughout New England. The analysis included revenues based on each generator's megawatts cleared in the Day-Ahead and Real-Time Energy Markets and the corresponding LMPs at each generator's node. Revenues from daily reliability payments and the Regulation Market were also included.[120] The analysis did not account for revenues from bilateral contracts.

Costs were calculated based on each unit's generation and marginal cost per megawatt-hour, including VOM, fuel costs, fuel-transport adders, and emission costs. Start-up and no-load costs, based on generators' offers, were also included. However, because some participants waive start-up and no-load costs, these were zero for some of the generators included in this analysis.

While specific costs and revenues are confidential and cannot be reported here, the analysis showed that, accounting for variable costs, estimated net revenues were significantly lower than indicated by Table 5-5. Net revenues ranged from $15,000/MW-Year to $80,000/MW-Year, and averaged $47,000/MW-Year. Net revenues were lower for generators in the Maine and New Hampshire load zones, where LMPs are lower than those at the Hub; they were highest for generators in the Connecticut and NEMA load zones, where LMPs are higher.

Revenues net of variable costs contribute to covering fixed costs. Several of the generators included in this analysis have Reliability Agreements, which provide monthly fixed-cost payments. These payments were not included in the revenue analysis. The analysis shows that net market revenues for these generators were inadequate to cover their fixed costs, which is consistent with the determination that the generators required additional, out-of-market payments.

5.2.8 Analysis of Participant Credit Ratings

Due to the capital-intensive nature of the electricity industry, the creditworthiness of firms participating in a market can have an impact on operations and infrastructure development. This section evaluates changes in the credit ratings of the 10 largest participants, measured in terms of generating capacity ownership. Together, these 10 participants own approximately 73% of generation capacity in New England. Table 5-6 shows the distribution of credit rating scores Standard and Poor's has assigned these 10 firms for 2000 to 2005.[121] Relative to the year 2000, credit ratings have degraded slightly; however, over the past three years, the number of firms in each category has remained constant.

[120] Daily reliability payments include first- and second-contingency NCPC payments, and voltage and distribution payments (see Section 4.2).

[121] Standard and Poor's credit rating scores are available for registered members at http://www2.standardandpoors.com.

Table 5-6
Credit Ratings, Top 10 Generation-Owning Participants

Year	AA	A	BBB	BB	B	CCC and Lower
2000	1	3	5	1	0	0
2001	0	4	5	1	0	0
2002	0	3	4	2	0	1
2003	0	2	5	0	2	1
2004	0	2	5	0	2	1
2005	0	2	5	0	2	1

Source: Standard and Poor's, McGraw Hill Companies, Inc.

In the wake of the Enron Corporation's bankruptcy at the end of 2001, nationwide, the electricity industry experienced a downturn, which is consistent with the pattern shown in Table 5-6. In addition to Enron, four other firms with operations in New England declared bankruptcy during the downturn—PG&E Energy Trading-Power L.P., Mirant Corporation, NRG Energy Inc., and USGen New England, Inc. By the end of 2005, the latter four had either emerged from bankruptcy, had an approved liquidation plan, or were on the verge of having an approved reorganization plan.[122] In late 2005, Calpine Corporation filed for bankruptcy.

5.2.9 Summary of Analyses

Overall, the concentration of generation ownership in New England's wholesale markets continued at low levels during 2005, although it increased slightly from 2004. Generation portfolio sizes increased slightly during the year as generation ownership changed. Certain areas of the system, such as NEMA and Vermont, defined by transmission interfaces, continue to have high concentrations of generator ownership.

High loads 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 10% of the hours during the year had an RSI of less than 110%. Over time, the growing demand for electricity plus reserves may cause an increase in the instances of pivotal suppliers. The INTMMU monitors for the existence of pivotal suppliers on a daily basis and is prepared to intervene if a pivotal supplier is judged to be exercising market power.

5.3 Generating-Unit Availability

Table 5-7 illustrates the annual Weighted Equivalent Availability Factors (WEAF) of the New England generating units for 1995 to 2005.[123] 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. After the beginning of the wholesale electricity markets in May 1999, the New England system WEAF increased to a high of 89% in 2002 and has remained at 88% since 2003.

[122] Mirant emerged from bankruptcy protection in January 2006.

[123] 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 5-7
New England System Weighted Equivalent Availability Factors (%)[a]

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

[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. Based on 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 calculated from a Short-Term Outage Database. This database is populated by the ISO System Planning Department based on information received 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, 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 how both 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-load days in 2005 and the amount of capacity on outages as a percentage of total available seasonal claimed capacity. The figure shows how the system reacts to electrical peak demands. Less capacity is on outage during periods of high loads (summer- and winter-peak periods) than during the spring and fall low-load periods.

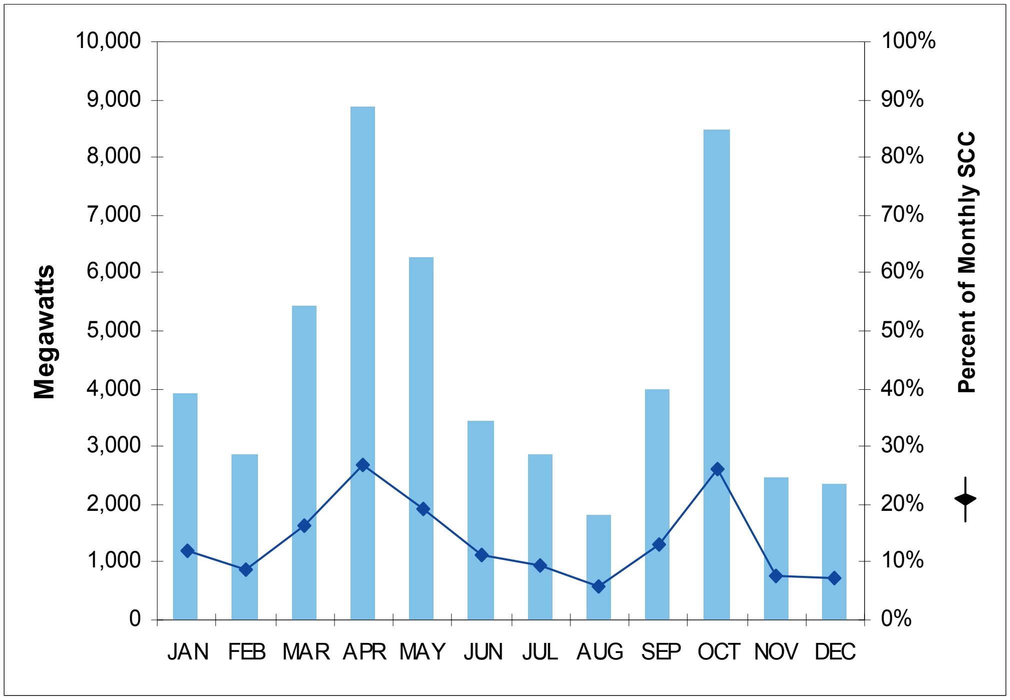

Figure 5-9: Generator unit total outages during peak-load days, January–December 2005.

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 load. 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.

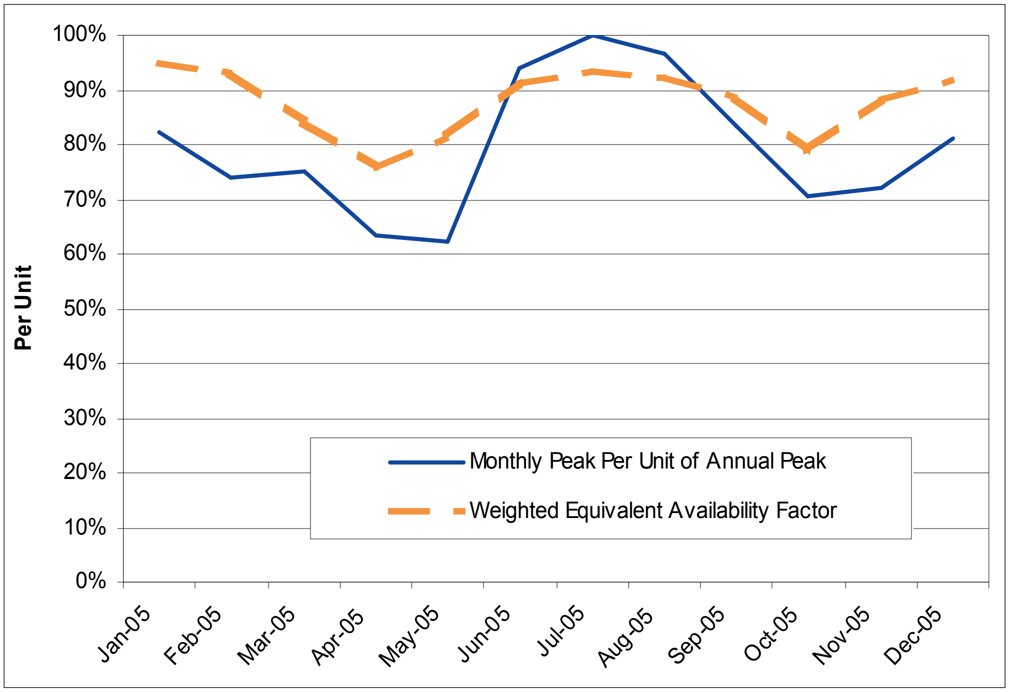

Figure 5-10: Monthly peak demand and monthly average availability (WEAF).

Figure 5-11 shows the average generation capacity on outage during each weekday peak for 1996 to 2005. The total amount of capacity on outages has remained fairly constant over the past few years, even with the addition of a large amount of generation to the system.

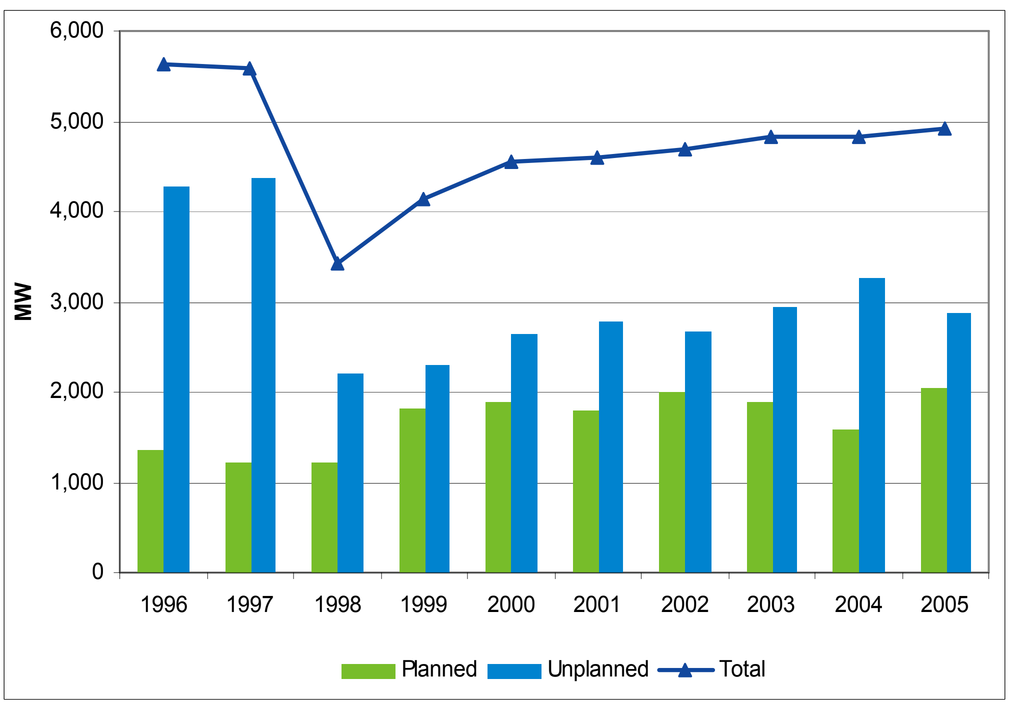

Figure 5-11: Average megawatts of outage each weekday.

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 load, 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 made in the Day-Ahead Energy Market at 4:00 p.m. and the Reserve Adequacy Analysis period at 10:00 p.m. 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.

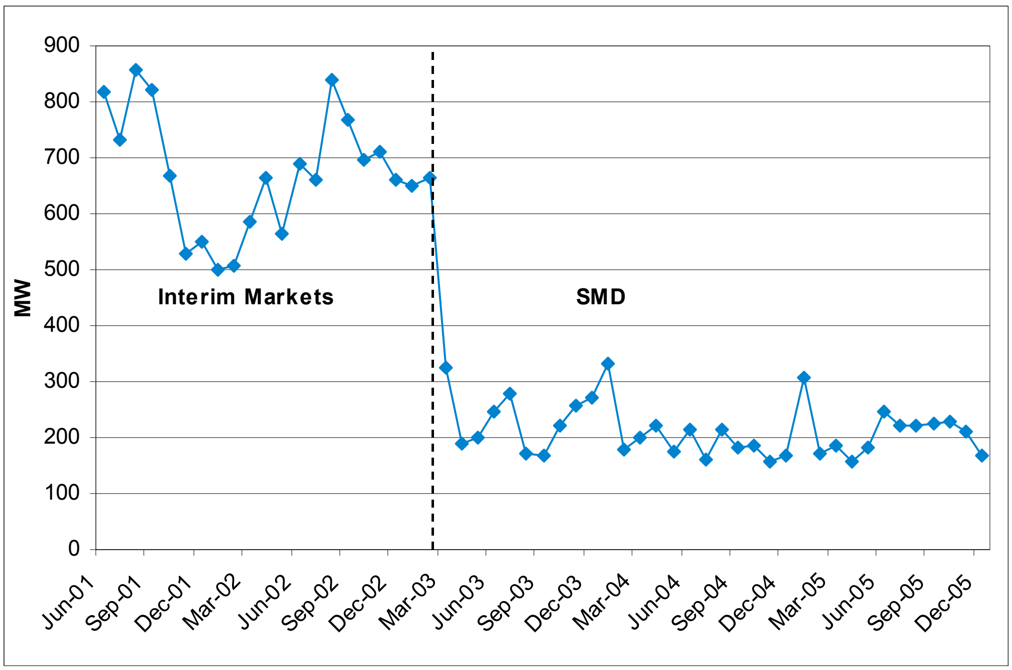

Figure 5-12: Average monthly overnight capacity loss.

Section 6
ISO Operations

This section reports on enhancements to the markets and ISO operations, audit activity during 2005, the Quality Management System (QMS), and administrative price revisions.

6.1 Audits

The ISO participated in several audits during 2005. These audits, as follows, 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 2005, the ISO successfully passed a SAS 70 Type 2 Audit, which resulted in a positive opinion about the design of its controls and operating effectiveness. Developed by the American Institute of Certified Public Accountants (AICPA), the SAS 70 Audit is used by service organizations, such as RTOs, to provide assurance regarding the validity and integrity of controls and systems used in the "bid-to-bill" business processes that govern wholesale electricity markets.

  The 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, transmission, capacity, and reserves. Conducted by the auditing firm PricewaterhouseCoopers LLP, the Type 2 Audit covered an eleven-month period, from November 1, 2004, through September 30, 2005. A SAS 70 Type 2 Audit is a more thorough review of the design and procedures for controls (including testing) compared with a Type 1 Audit, which is a high-level review of controls design and procedures. The ISO plans to conduct a SAS 70 Type 2 Audit annually.

  The SAS 70 Type 2 Audit report has been made available to participants upon request through the ISO external Web site.

- **Internal Settlements Market-System Audits—**The ISO elected to conduct internal audits in the Settlement Market System (SMS) area as a compliment to the SAS 70 Type 2 Audit. These audits included testing the security of access to these systems and the change/configuration-management processes. The results of these audits showed that controls were working as designed.

- **Operations Reviews—**Based on the ISO's audit-coverage strategy and input from the NEPOOL Operations Audit Steering Committee (OASC), the ISO's Internal Audit Department planned and performed detailed testing of the control room and day-ahead operations. NEPOOL's representative from Gestalt (formerly Barker, Dunne and Rossi) monitored the work. The *Control Room Operations Audit Report* was issued on April 27, 2005, and the *Day-Ahead Operations Audit Report* was issued on July 14, 2005. A third area, Forecast Operations, was audited during 2005 and the final report was issued on August 30, 2005.

  All three operations reports have been made available to participants upon request through the ISO external Web site.

- **Market-System Software Recertification—**Prior to the implementation of SMD, all market-system clearing engines were certified by an outside consultant, PA Consulting. The ISO went through a similar certification in 2004 and early 2005. PA Consulting issues a compliance certificate for an SMD module after conducting detailed tests and analyses of the mathematical formulations. The certificate provides assurance that the software is operating as intended and is consistent with Market Rule 1 and associated manuals. In 2004 and 2005, the process included testing of the following software systems: real-time Unit Dispatch Software/Scheduling Pricing Dispatch (UDS SPD), the LMP Calculator, day-ahead SPD (DA SPD), Simultaneous Feasibility Testing (SFT) software, Financial Transmission Rights clearing software, and Auction Revenue Rights clearing software. PA Consulting issued final certificates for all of these modules in early 2005.

  In addition, several certificates were issued throughout 2005 to address changes in SMD modules. On April 25, 2005, a certificate was issued for FTR negative-bid functionality. On October 10, 2005, certificates were issued to address updates to the LMP Calculator. On October 14, 2005, a certificate was issued for the new Regulation Clearing-Price (RCP) Calculator, part of the Ancillary Services Market Phase I project. PA Consulting has also completed work on certifying the updated UDS-SPD module, also part of the ASM I project. The final certificate was issued in February 2006.

  Criterion Auctions performed similar testing on the Forward-Reserve Auction software in 2005, with a final certificate issued on December 30, 2005. Participants can request all final certificates through the ISO's Web site.

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.[124] 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 2005, the ISO completed the development of the QMS. It reached several project milestones during the year, including the development of a continual-improvement process called Operational Excellence, the implementation of a corrective action/preventative action program, and the implementation of an internal QMS-assessment process. The ISO also established document and record-control programs.

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

[124] International Organization for Standardization, Geneva, Switzerland. Information about the standard is available 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.

Corrections to prices at inactive buses, or "dead" buses, accounted for price changes in 170 hours in 2005. A dead bus results when a bus becomes islanded for a period of time, typically due to 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 impact 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, due to 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 zero dollars. 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 2005, corrections to five-minute LMPs were required in 105 hours due to data errors or software limitations. The LMP calculator runs every five minutes and requires information from an approved UDS case for the five-minute period in question. If the unit-dispatch software case is not approved prior to the scheduled execution of the LMP calculator, a mismatch of data can occur, resulting in an incorrect LMP. This problem typically occurs for one of two reasons. One reason is that the status of a constraint changes some time between when the UDS case accesses data to 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.

Corrections to hourly prices are also 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.

Scheduled system maintenance required price corrections in eight hours during 2005. Unplanned outages required price corrections in 10 hours during the year. In addition to the 293 hours for which corrections were made, as described above, four unique circumstances in 2005 led to price corrections, as described below:

- The ISO corrected day-ahead LMPs at the Highgate external node for January 29, 2005. The LMPs were incorrect because the resistance value for the Highgate facility in the external node loss-calculation database was not consistent with the value submitted by the transmission owner. The corrected day-ahead LMPs at this node were approximately 2% lower. Real-time LMPs on January 27 and 28 were also revised for the same reason as part of the normal LMP-finalization process. LMPs at other locations were not affected.

- Real-time zonal LMPs were corrected during most hours from March 7 through April 21, 2005, due to a software error involving the zonal load-weighting algorithm. Real-time nodal prices were unaffected. Most hours were revised to values within plus or minus \$0.05 of their preliminary values (less than 0.1 % change).

- The ISO corrected prices over several days in June due to a combination of outages and constraints that caused incorrect results at the Hydro-Québec Phase I & II external node. On those days, one of the two direct current (DC) lines was physically out of service. However, due to the way the software modeled these lines, combined with certain nearby transmission constraints, the software calculated an incorrect energy price at the external node. This required the ISO to manually calculate and post the corrected prices at this location until the software fix was implemented. A total of 50 hours were affected over a period of approximately two weeks. LMPs at other locations were not affected.

- Real-time LMPs were recalculated from October 1, 2005, through HE 6:00 p.m. on October 4 to correct for a problem in the ASM 1 project software that was implemented on October 1. The error in the software caused a pricing anomaly related to the way flexible generators were handled as opposed to nonflexible generators in setting LMPs. On average, the hourly LMPs were revised to values within $0.25/MWh of the preliminary values (less then a 0.2% change).

Section 7 Conclusions

During 2005, New England experienced high demand for electricity, a record peak hourly load, and stressed energy infrastructure. It also experienced high fuel costs throughout 2005, particularly in January and in the fall. The wholesale electricity markets met these challenges and continued to perform well during the year. Also in 2005, the ISO made a number of market improvements consistent with the goal of providing a reliable electric power system and competitive and efficient wholesale markets.

Electricity prices are driven by the interaction of supply and demand. Electricity prices in 2005 were 47% higher than those in 2004. ISO analyses, presented in Section 3.1.4.3, show that the increase in the cost of supply in 2005 due to the high cost of fuels, particularly natural gas, was responsible for most of the price increase. Transmission congestion caused more price separation during 2005 than in previous years. Zonal prices were highest in Connecticut and lowest in Maine. The remainder of the increase is attributable to the increase in demand.

The Forward Reserve Market, introduced in 2004, attracted more supply in 2005, and clearing prices fell significantly. The capacity market functioned normally, and Financial Transmission Rights provided an effective hedge for participants with load obligations and associated congestion costs. The demand-response programs also functioned as expected in 2005. The ISO's implementation of the demand-response programs during the year resulted in reduced energy consumption and improved system reliability. While the level of demand-response energy savings experienced in 2005 represents an improvement over last year, further enhancements are still necessary. For example, integrating demand into the markets rather than implementing them through separate programs will improve the long-run performance of the New England electricity markets.

7.1 Development and Implementation of Market Enhancements

In 2005, the ISO implemented ASM I, which included the introduction of a new Regulation Market. Transitioning to the new market design coincided with a period of relatively high gas prices, and, as in the energy market, costs in the Regulation Market are influenced by fuel costs and supply conditions. While the ISO observed both market entry and exit during this period, some generators exited the Regulation Market for reasons unrelated to the market, causing an increase in the cost of regulation service. Regulation costs have since declined during the first three months in 2006. The ISO will continue to closely monitor the Regulation Market.

The ISO worked with its stakeholders during 2005 to approve two market-rule changes. The first change was designed to prevent participants that own generators that do not often run in merit from inappropriately raising market-mitigation reference levels. This change corrected an offer behavior that led to a large increase in second-contingency payments in the Boston area. The second change revised the method for allocating costs associated with real-time second-contingency commitments to more closely assign costs to participants that cause those costs to be incurred. This change removed a disincentive for making virtual transactions that improve price convergence.

7.2 Support of Reliable Operations

The New England wholesale electricity market supported reliable operations throughout 2005, despite significant operational challenges during the year. In addition to tight system capacity due to the high summer loads, these challenges included uncertainty about the availability of nonfirm gas for generating electricity and fuel-price volatility during the winter months. In 2005, the ISO and its stakeholders applied lessons learned from previous cold snaps by improving operating procedures, increasing regional conservation and demand response, and increasing the amount of dual-fueled generating units in the region. These measures addressed the threat posed by potential severe winter weather combined with natural gas supply disruptions in the Gulf of Mexico due to Hurricanes Katrina and Rita.

The ISO is committed to finding market solutions to reliability issues. However, during 2005, as in earlier years, assuring the availability of adequate capacity continued to require some out-of-market compensation for generation in the form of Reliability Agreements and daily reliability payments. During 2005, the ISO and participants worked on implementing an action plan to reduce daily reliability costs, undertaking transmission-improvement projects and rule changes. These changes began to provide reductions in daily reliability costs in the fourth quarter of 2005, with the trend continuing into 2006.

Significant transmission investment activity occurred in 2005, with several important projects underway for maintaining reliability and reducing reliability costs. Total system generation capacity did not change significantly, with approximately equal amounts of new generation additions and retirements of existing generation. While this level of investment was not a cause for immediate concern, ISO analyses indicate that the continued growth in demand may necessitate emergency actions to meet peak demand in the 2007 to 2009 timeframe, absent the addition of new capacity to the system.

The ISO continues to work with participants to enhance the reliable and efficient operation of the region's electric power system. The majority of New England stakeholders have reached an agreement on a proposal for a forward-capacity market that should induce new entry in load pockets. This proposal is based on a forward auction the ISO will administer to procure resources for ensuring long-term resource adequacy and reliability and encouraging new investment in all types of new resources. In addition, the second phase of the ASM project, designed to induce investment in new generation and demand-response resources that can serve peak load, is scheduled for implementation in 2006. The market design includes a locational Forward Reserve Market and real-time reserve pricing. It also provides for demand-side participation in the electric energy and reserve markets.

7.3 Additional Issues Facing the Market

While the market continues to function well, a review of the 2005 results shows two areas of concern that are not likely to be addressed by wholesale market design alone. The first is the declining load factor and the resultant need to invest in generation and transmission infrastructure needed for only a few hours per year. The second is New England's continued dependence on oil and natural-gas-fired resources, which makes New England electricity costs especially vulnerable to price increases in these fuels. The wholesale electricity markets are sending strong signals about the costs of each of these issues, and the ASM project and proposed capacity market changes will strengthen these signals. However, impediments to responding to these signals remain.

The load data for 2005 show that peak demand continues to increase faster than average demand, even when loads are weather normalized. Because peak loads drive many capacity and transmission investment needs, a greater amount of capacity must be built to serve these loads. Because average demand is growing more slowly, these investments are needed to support fewer hours of operation. The energy market sends high price signals during these hours, and ASM II and the proposed capacity market revisions will better reveal these costs of consumption during peak-load periods. However, consumers generally do not pay retail prices that reflect hourly wholesale electricity prices, and they are unlikely to change their electricity usage without a more direct linkage between wholesale and retail prices. State retail rates should be adjusted to allow customers to see these costs and how they vary with the time of consumption.

The sharp rise in oil and natural gas prices has resulted in a large increase in electricity prices. This makes investment in generation power by other fuel sources much more attractive. However, building these resources in New England is proving difficult. For example, numerous wind projects have been proposed, but many have run into local siting problems. Until New England is willing to allow the construction of power plants fueled by resources other than natural gas, it will continue to be vulnerable both to price increases in oil and natural gas and to supply disruptions in the delivery of those two fuels.

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 2005, by zone and overall.

Table A-1
Percentage of Real-Time Load Obligation Cleared in the Day-Ahead Energy Market, 2005

Zone	Average	Minimum	Maximum	Std. Dev.
Overall	95%	83%	103%	4%
Maine	92%	75%	102%	5%
New Hampshire	97%	82%	109%	5%
Vermont	78%	21%	112%	20%
Connecticut	98%	63%	110%	4%
Rhode Island	92%	57%	128%	12%
SEMA	95%	78%	113%	6%
WCMA	97%	77%	119%	7%
NEMA	93%	72%	106%	7%

A.2 Electric Energy Prices

Table A-2 to Table A-5 show 2005 LMP summary statistics for on- and off-peak hours and the monthly average day-ahead and real-time LMPs by zone.

Table A-2
LMP Summary Statistics, On-Peak Hours, January–December 2005

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	$88.90	$86.19	$44.20	$23.00	$194.67	$856.06
Maine Load Zone	$78.93	$77.44	$35.89	$7.46	$183.89	$779.45
New Hampshire Load Zone	$84.60	$83.43	$43.00	$22.21	$189.91	$844.64
Vermont Load Zone	$89.12	$87.32	$44.09	$22.32	$195.65	$852.42
Connecticut Load Zone	$96.77	$92.45	$43.89	$23.27	$247.91	$865.94
Rhode Island Load Zone	$85.58	$83.10	$43.56	$22.29	$191.15	$827.72
SEMA Load Zone	$85.52	$83.19	$43.54	$22.35	$190.17	$838.73
WCMA Load Zone	$89.09	$86.81	$44.22	$23.03	$194.85	$857.52
NEMA Load Zone	$92.07	$87.82	$43.81	$22.56	$323.78	$1,078.48
NB–NE External Node	$74.92	$72.21	$33.84	$2.47	$182.04	$718.15
NY–NE AC External Node	$88.44	$86.84	$43.41	$22.13	$191.69	$843.32
HQ Phase I/II External Node	$85.10	$81.69	$43.22	$-26.83	$188.49	$834.41
Highgate External Node	$84.95	$80.85	$39.95	$20.43	$209.61	$772.48
Cross-Sound Cable External Node	$90.91	$89.07	$43.85	$23.21	$195.51	$865.31

Table A-3
LMP Summary Statistics, Off-Peak Hours, January–December 2005

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	$69.65	$68.44	$26.82	$0.00	$166.93	$303.36
Maine Load Zone	$63.85	$64.30	$12.85	$0.00	$151.26	$274.57
New Hampshire Load Zone	$67.31	$66.76	$26.12	$0.00	$159.70	$295.23
Vermont Load Zone	$69.92	$69.01	$6.74	$0.00	$163.15	$308.47
Connecticut Load Zone	$71.46	$69.61	$26.65	$0.00	$225.61	$366.10
Rhode Island Load Zone	$68.13	$67.20	$26.30	$0.00	$164.02	$302.67
SEMA Load Zone	$67.99	$66.92	$26.38	$0.00	$165.36	$297.00
WCMA Load Zone	$69.85	$68.69	$26.79	$0.00	$166.62	$304.22
NEMA Load Zone	$69.34	$67.67	$26.54	$0.00	$177.14	$295.99
NB–NE External Node	$60.97	$61.91	$10.49	$0.00	$149.74	$255.04
NY–NE AC External Node	$69.20	$68.16	$26.57	$0.00	$160.82	$302.56
HQ Phase I/II External Node	$67.62	$66.71	$26.20	$0.00	$171.18	$289.97
Highgate External Node	$66.69	$67.14	$0.00	$0.00	$225.89	$296.43
Cross-Sound Cable External Node	$70.52	$69.21	$26.66	$0.00	$226.95	$308.79

Table A-4
Monthly Average Day-Ahead LMPs by Zone, 2005[(a)]

Month	Hub	CT	Maine	NEMA	NH	RI	SEMA	VT	WCMA
Jan	$69.68	$69.13	$64.91	$71.81	$67.99	$68.34	$68.37	$69.53	$69.77
Feb	$56.39	$57.03	$52.07	$56.17	$54.88	$55.17	$55.07	$56.71	$56.46
Mar	$63.21	$64.57	$58.63	$63.55	$61.69	$62.00	$62.01	$63.58	$63.29
Apr	$64.12	$71.09	$57.48	$69.71	$61.91	$62.23	$62.52	$63.33	$64.27
May	$57.74	$58.57	$50.38	$58.34	$54.45	$56.46	$56.74	$56.40	$57.56
Jun	$68.10	$73.90	$57.67	$69.30	$62.42	$64.34	$64.31	$65.28	$67.35
Jul	$75.11	$81.25	$65.29	$80.61	$70.35	$71.14	$71.12	$76.48	$75.14
Aug	$89.57	$100.32	$78.07	$93.60	$85.23	$85.20	$84.78	$93.17	$89.85
Sep	$103.16	$110.39	$94.02	$103.86	$99.33	$99.06	$98.54	$106.29	$103.27
Oct	$112.33	$117.97	$100.20	$111.33	$107.97	$110.15	$109.88	$112.09	$113.49
Nov	$79.62	$82.17	$72.82	$78.53	$76.10	$78.49	$78.49	$78.45	$79.86
Dec	$101.35	$109.00	$96.40	$99.03	$99.19	$99.64	$99.17	$101.93	$102.34

Table A-5
Monthly Average Real-Time LMPs by Zone, 2005

Month	Hub	CT	Maine	NEMA	NH	RI	SEMA	VT	WCMA
Jan	$66.31	$65.82	$62.18	$65.57	$65.04	$64.99	$64.74	$66.33	$66.34
Feb	$53.71	$54.43	$50.13	$53.02	$52.43	$52.56	$52.47	$54.01	$53.78
Mar	$63.77	$66.51	$59.32	$63.12	$62.40	$62.49	$62.93	$64.43	$63.86
Apr	$60.65	$61.95	$55.68	$61.12	$59.06	$59.33	$59.46	$60.37	$60.82
May	$56.86	$57.14	$50.60	$58.42	$54.37	$55.68	$55.95	$56.34	$56.93
Jun	$63.43	$67.39	$56.40	$65.28	$60.89	$61.42	$61.44	$64.18	$64.66
Jul	$72.62	$81.61	$65.89	$73.58	$70.17	$69.26	$69.06	$75.29	$73.29
Aug	$91.80	$101.71	$81.22	$96.33	$89.29	$87.32	$86.83	$96.87	$92.69
Sep	$102.23	$106.93	$93.37	$102.65	$99.31	$98.98	$98.48	$104.54	$102.82
Oct	$111.64	$114.80	$103.29	$111.33	$108.34	$109.01	$109.08	$110.71	$112.06
Nov	$74.21	$76.68	$68.72	$73.04	$71.88	$73.13	$72.97	$73.63	$74.45
Dec	$100.02	$104.15	$95.43	$97.71	$97.97	$98.03	$97.54	$100.43	$100.56

A.3 Statistical Analysis of Year-to-Year Price Changes

The ISO conducted a regression analysis to estimate the relationship of average daily real-time prices at the Hub to natural gas and fuel-oil prices and system net energy for load. The model is estimated using data from the beginning of SMD in March 1, 2003, through December 31, 2005. Following are the results of the analysis.

AvgRTHubLMP =	-33.15049 +	3.87591*Pgas +	5.54472*Poil +	0.09599*SysNEL
Std Error	(2.595549)	(0.148587)	(0.32775)	(0.00787)
p-values	(<.0001)	(<.0001)	(<.0001)	(<.0001)
Confidence Intervals on Parameter Estimates				
Lower 95%	(-8.94994)	(3.58436)	(4.90159)	(0.08054)
Upper 95%	(-27.35103)	(4.16745)	(6.18784)	(0.11144)

R-square	.7665
F value	1130.44
p-value	<.0001

A.4 2005 Average Electric Energy Prices for the ISO New England, NYISO, and PJM

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, 2005, $/MWh

Control Area	Day-Ahead			Real-Time		
	All	On-Peak	Off-Peak	All	On-Peak	Off-Peak
ISO NE	$78.62	$89.78	$69.11	$76.66	$86.88	$67.94
NYISO	$83.09	$98.29	$70.11	$84.36	$99.12	$71.76
PJM	$57.90	$73.74	$44.39	$58.11	$74.19	$44.39

Appendix B
Net Commitment-Period Compensation and Reliability Payments

Table B-1 shows a summary of NCPC changes.

Table B-1
NCPC Change Summary

	Rule Change	Effective Date	Implemented
1	Pro-rated start-up costs	December 1, 2004	April 1, 2005
2	Partial self-schedule	December 1, 2004	April 1, 2005
3	Second-contingency RTLO allocation	March 1, 2005	March 1, 2005
4	Minimum generation emergency	April 27, 2005	September 16, 2005
5	Name change from ORC to NCPC	October 1, 2005	October 1, 2005
6	Re-offer eligibility for all resources	October 1, 2005	October 1, 2005
7	Regulation Market (ASM) changes	October 1, 2005	October 1, 2005
8	Ramping MW	October 1, 2005	October 1, 2005
9	Eligible start up	October 1, 2005	October 1, 2005
10	Eligible no load	October 2005	October 2005

1. The compensation is provided for the actual start-up time during continuous hours of operation. As an example, if the minimum run time is 15 hours and the unit trips after 10 hours, it will receive prorated start-up costs.
2. If the ISO requires a unit to run above its self-scheduled amount, the unit is eligible to receive NCPC for the amount above the self-scheduled amount.
3. NCPC for units providing second-contingency coverage are based on the RTLO of the respective regions and charged to loads.
4. Units dispatched above their economic minimum are compensated during the minimum generation emergency.
5. The name of this payment was changed from Operating Reserve Credit to Net Commitment-Period Compensation.
6. Participants are allowed to change their day-ahead offers during submission into RAA.
7. The Regulation Market price is computed in real time, given offers of available resources.
8. A unit must be on line with an output greater than or equal to 75% of its economic minimum to be eligible for NCPC. This is applicable for both ramp up and ramp down.

9. Resources eligible to receive a start-up fee in the Day-Ahead Energy Market will not be eligible for a corresponding start up in the real time.
10. A pool-scheduled resource will be eligible for a no-load fee for hours of operation beyond the number of hours that cleared in the day-ahead market.

Appendix C
Other Tariff Charges

In 2005, 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 C-1.

Table C-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
2005 Total	$19,285,092	$67,923,180	$27,568,571

Transmission services were paid for under the Open Access Transmission Tariff. 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)—**are transactions that go through the New England Control Area or originate on a pool transmission facility (PTF) and flow over the PTF prior to 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 allow 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 restoration of the New England Control Area following a blackout.

- **Schedule 19: Special-Constraint Resource Service of the Open Access Transmission Tariff—**are 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 C-2.

Table C-2
OATT Tariff Charges

Date	Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2005 Total	$20,386,209	$12,358,707	$75,264,253	$1,814,181	$407,407,181	$8,370,085	$10,006,212

Appendix D
Congestion Revenue Fund

Table D-1 shows details about the accounting for the Transmission Congestion Revenue Fund.

Table D-1

2005 Transmission Congestion Revenue Fund ($)

Month	Beginning Balance	Fund Adjustment	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 Target Allocations	Monthly Fund Surplus or Shortfall	Interest	Ending Balance	Cumulative Balance for Year End	Percent Positive Allocation Paid
Jan	0	5,873	9,348,838	(370,161)	970,440	(10,226,569)	(9,954,990)	(271,579)	0	0	N/A	97%
Feb	0	7,980	3,092,354	(242,617)	620,823	(3,431,396)	(3,431,396)	47,144	0	47,144	N/A	100%
Mar	47,144	2,664	5,153,875	(2,807,202)	1,935,407	(6,924,207)	(4,331,888)	(2,592,320)	0	0	N/A	63%
Apr	0	5,793	24,934,158	(237,954)	10,755,180	(32,112,913)	(32,112,913)	3,344,264	0	3,344,264	N/A	100%
May	3,344,264	23,620	9,680,905	128,864	2,764,837	(12,547,149)	(12,547,148)	3,395,342	0	3,395,342	N/A	100%
Jun	3,395,342	23,298	38,949,011	244,828	8,497,068	(34,793,451)	(34,793,451)	16,316,097	0	16,316,097	N/A	100%
Jul	16,316,097	(924)	47,318,573	(1,215,160)	7,069,177	(41,056,370)	(41,056,370)	28,431,392	62,078	28,493,471	28,493,471	100%
Aug	N/A	876	57,363,090	(1,596,871)	8,513,940	(46,621,067)	(46,621,067)	17,659,968	119,386	17,779,354	46,272,825	100%
Sep	N/A	1,617	33,087,358	(1,182,083)	4,591,610	(27,974,113)	(27,974,113)	8,524,390	185,007	8,709,398	54,982,222	100%
Oct	N/A	(563)	21,523,962	(125,658)	5,554,703	(28,127,462)	(26,952,445)	(1,175,017)	191,913	191,913	55,174,136	96%
Nov	N/A	(4,548)	7,875,360	(248,122)	1,434,447	(8,485,460)	(8,485,460)	571,678	208,450	780,128	55,954,264	100%
Dec	N/A	(23689)	15,122,387	437,240	5,093,627	(16,558,999)	(16,558,999)	4,070,566	190,994	4,261,560	60,215,823	100%