ISO NEW ENGLAND

The people behind New England's power

2003

ANNUAL MARKETS REPORT

Table of Contents

1. Introduction

1.1. About ISO New England

Created in 1997, ISO New England Inc. (the ISO) is the not-for-profit corporation responsible for the day-to-day reliable operation of New England's bulk power generation and transmission system, oversight and fair administration of the region's wholesale electricity markets, and management of a comprehensive regional bulk power system planning process.

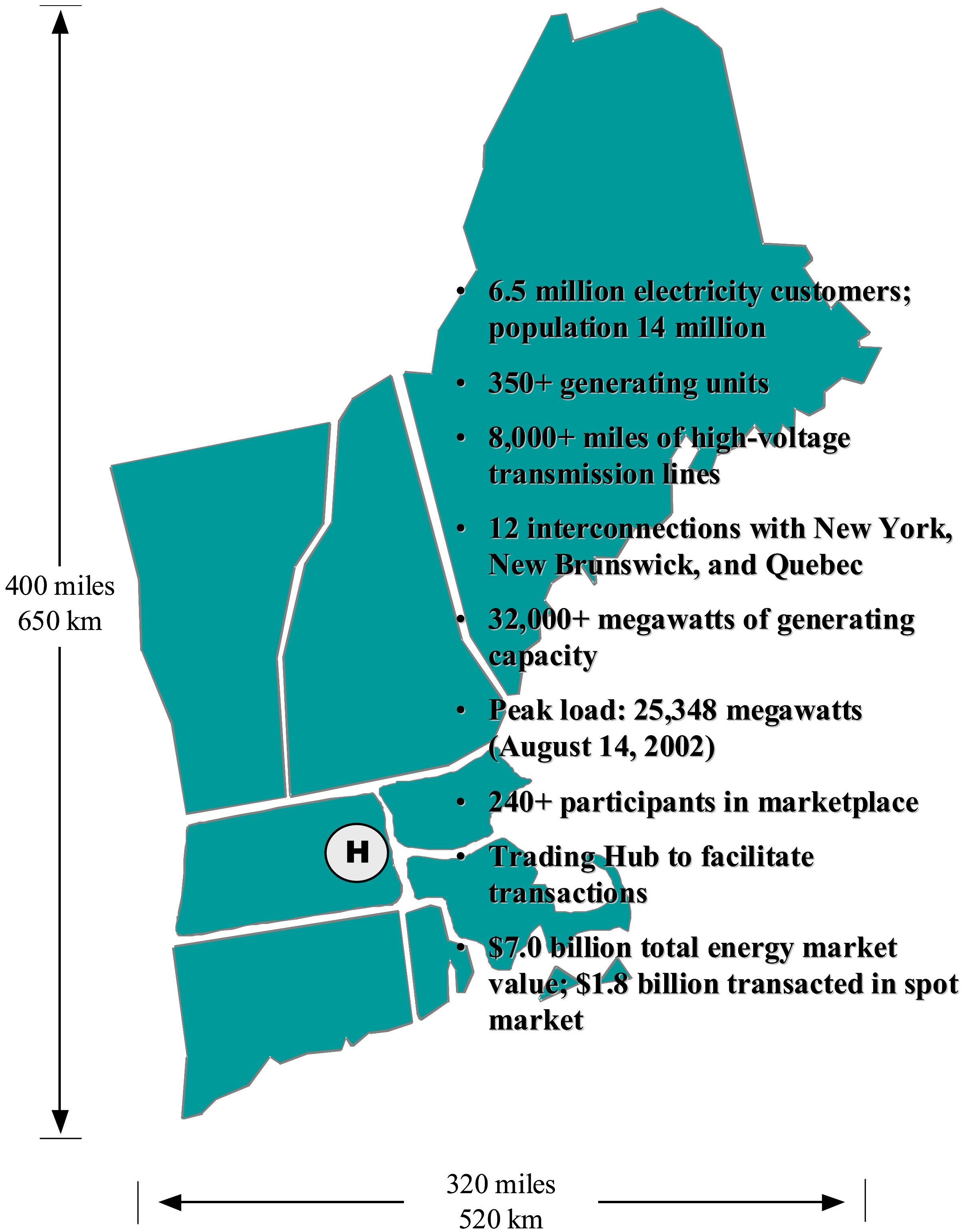
1.2. Market Analysis and Reporting

The ISO's responsibility in overseeing the region's wholesale electricity marketplace is to ensure that the markets are fair, transparent, efficient, and competitive. As part of this responsibility, the ISO monitors the markets, publishes market results, analyzes market efficiency, and addresses any impediments to efficiency or competition. Where design flaws are present, the ISO works with market participants, state regulators, the Federal Energy Regulatory Commission (FERC), and other agencies to correct those imperfections.

To assess the operation of the markets, provide transparency, and meet Federal reporting guidelines, the ISO issues periodic markets reports that describe the development and performance of New England's wholesale markets. The ISO seeks regular input from its Independent Market Advisor, David B. Patton, Ph.D., to provide an additional, independent review of significant market developments.

This 2003 Annual Markets Report, as required by New England Power Pool (NEPOOL) Market Rule 1, Appendix A, Section 11.3, is a comprehensive assessment of the competitiveness and efficiency of New England's wholesale electricity marketplace during its most recent operating year. Based on market data, performance criteria, and independent studies, the report describes the development, operation, and performance of the markets, and provides a retrospective analysis of market outcomes observed by the ISO.

Key Facts: New England's Power System and Wholesale Electricity Market



- 6.5 million electricity customers; population 14 million
- 350+ generating units
- 8,000+ miles of high-voltage transmission lines
- 12 interconnections with New York, New Brunswick, and Quebec
- 32,000+ megawatts of generating capacity
- Peak load: 25,348 megawatts (August 14, 2002)
- 240+ participants in marketplace
- Trading Hub to facilitate transactions
- $7.0 billion total energy market value; $1.8 billion transacted in spot market

2. Executive Summary

Each year, the ISO reports on the wholesale electricity markets that it administers. This report covers the period from January 1 to December 31, 2003. The markets operated under two distinctly different designs during the year. The Interim Markets, in place in New England since May 1999, were in effect during January and February. On March 1, a significantly enhanced wholesale market design, the Standard Market Design (SMD), was implemented. The report primarily summarizes market operations under SMD because the post-March 1 period represents the majority of the year and will provide the most useful basis of comparison for future market reports. Unlike the Interim Markets in New England in which there was only one electric energy clearing price, prices are calculated at three types of locations under SMD: the node, the load zone, and the Hub. Offers and bids are submitted, markets are settled, and locational marginal prices (LMPs) are calculated at these locations.

The report contains the ISO's analyses and summaries of market operations and builds on independent studies of market performance.

2.1. Standard Market Design (SMD)

On March 1, 2003, the ISO successfully implemented SMD, a major redesign of the wholesale electricity market which replaced the Interim Markets that became effective May 1999. A review of SMD's first six months of operation conducted by the ISO's Independent Market Advisor, David B. Patton, Ph.D. ("the Patton Report"), found that SMD operates as designed, substantially improves the efficiency of the marketplace, and increases participation in the markets for the six-state New England region.[1] The six-month review shows that the introduction of SMD in New England provides benefits, marks an important step in the evolution of wholesale electricity markets in the region, and lays the foundation for future market enhancements.

SMD is intended to:

- Provide the correct price signals to market participants and expand the options for electric energy transactions, making the market more liquid, more competitive, and more economically efficient;
- Provide clear economic signals indicating where investment in the bulk power system is needed, including the location of new generating units, expansion of transmission facilities, and participation in demand-side management programs. These elements are needed in a well-functioning market to alleviate constraints, increase competition, and improve the system's ability to meet power demand;
- Provide mechanisms to hedge against volatility and uncertainty of real-time prices, including variations in prices caused by congestion costs; and
- Reduce trading barriers across electricity markets in the Northeast to increase competition and trading choices offered to wholesale market participants.

The key features of SMD that accomplish these objectives are locational prices for electric energy in the Day-Ahead and Real-Time Markets, and Financial Transmission Rights (FTRs). These features provide a framework for trading electric energy in New England that is comparable to those in other Northeast electricity markets.

[1] Patton, David B., Ph.D., Pallas LeeVanSchaick, Robert A. Sinclair, Ph.D., *Six-Month Review of SMD Electricity Markets in New England,* February 2004.

2.2. 2003 Results

The ISO has analyzed the operation of the wholesale markets during 2003 and reports these significant results for the year:

1. **Price levels and fuel costs** – Energy prices were consistent with a competitive market. Electric energy market prices were high at SMD implementation (over $100/MWh) because of high natural gas spot market prices ($10 - $12/MMBtu) due, in part, to cold weather. By mid-March, gas prices fell to approximately $6/MMBtu, with electric energy prices decreasing to the $50-$60/MWh range. Average electric energy prices ranged between $40 and $50/MWh until December, when cold weather and higher fuel costs caused another rise in electricity prices. The average electric energy price, which rose over 40% relative to the 2002 level on a nominal basis, fell by over 6% when the effect of input fuel prices is accounted for. Fuel is the largest portion of generators' variable cost of operation, and gas and oil-fired units are generally the marginal units on the system.

2. **Day-Ahead and Real-Time Market clearing –** Consistently high amounts of actual real-time load cleared in the Day-Ahead Market in most load zones. On average, 96% of eventual real-time load obligation (the sum of metered load, exports, and load-shifting contracts) cleared in the Day-Ahead Market during the 10-month period. This indicates that market participants hedged market positions in advance of real-time operation, which translates into less demand susceptible to real-time price volatility during the first 10 months of SMD. The level of cleared day-ahead demand in New England is similar to the level of day-ahead cleared demand in the New York markets during 2003. The average cleared percentage for New England load zones ranged from a high of 99% in the Vermont load zone to a low of 79% in the Connecticut load zone.

3. **Day-ahead and real-time prices and relationship to demand** – Electric energy prices were positively correlated to the level of demand. As expected, off-peak prices were generally lower than on-peak prices. Summer prices, adjusted for fuel costs, were lower than prices in the prior two years. Ample available capacity coupled with the summer's cooler than normal weather pattern combined to produce relatively low prices during the peak demand season. Day-ahead prices averaged 0.8% higher than real-time prices at the Hub for the 10-month period ending December 31, 2003. Each load zone also demonstrated slight price premiums in the Day-Ahead Market over the Real-Time Market. This is consistent with outcomes in other Northeast markets.

4. **Demand Response -** Demand response (customers who reduce their electricity consumption) can help address short-run reliability problems by reducing supply needs. It is an integral part of a balanced and efficient wholesale market because it can reduce market price spikes, volatility, and provide a hedge against price risk. As of September 1, 2003, 443 assets were under contract under the ISO's demand response programs, representing over 380 MW of potential curtailment in any hour. During 2003, implementation of demand response programs by the ISO resulted in over 5,500 MWh of decreased electricity usage in New England. The only implementation of the reliability component of the ISO's Demand Response Programs occurred on August 15, when approximately 80 MW in each hour and a total of 1,100 MWh were curtailed in support of system restoration efforts in Connecticut following the Northeast Blackout that occurred on August 14.[2]

[2] On August 14, at approximately 4:10 PM EDT, a power surge occurred causing cascading outages in the Midwest, eastern PJM, NYISO, Ontario, and New England. As a result of this Northeast Blackout, New England experienced the interruption of approximately 2,500 MW of load, 2,000 MW of which was interrupted in southwestern Connecticut. System restoration efforts proceeded smoothly, with all but 100 MW of load back in service by 4:00 AM on Friday morning, August 15. The Northeast Blackout is not discussed within this report, however the reader is referred to ISO's February 2004 report *"Blackout 2003 - Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout."* This report is available on

5. **Transmission congestion –** Congestion on the system was generally low, driven by two factors. The first factor was lower-than-normal system peak demand during the summer months. The second factor was that fuel prices for gas units outside of load pockets increased relative to fuel prices for oil units within load pockets. This decreased the difference between the offer prices of the two types of generators on either side of constrained interfaces, thereby lessening the amount of financial congestion realized. When congestion occurred in the Day-Ahead Market, it was often due to levels and patterns of cleared day-ahead demand (fixed, price-sensitive, and virtual) and not due to constraints that would be expected during real-time operations. Congestion was also low in the Real-Time Market; however, Connecticut was the most congestion-prone area due to lack of import capability and weakness in its transmission infrastructure. The NEMA/Boston zone, historically a constrained area, experienced little real-time congestion in part due to recent infrastructure improvements, both transmission and generation.

6. **Congestion Hedging Through Financial Transmission Rights** – Under SMD, market participants are able to buy financial instruments that help them to hedge the price risk of day-ahead congestion caused by constraints on the transmission system. FTRs were offered to the marketplace in 10 ISO-administered monthly auctions and one three-month auction during 2003. Participation in the auctions was strong and market participants purchased FTRs consistent with expected patterns of congestion. Winning auction bids generated $28.5 million in revenue for auction rights holders, and the monthly and long-term FTRs awarded during the year provided over $84 million of day-ahead congestion cost offsets to their holders.

7. **Locational price signals and unit commitment –** A key feature of SMD, locational pricing, provided price signals reflective of the cost of production and delivery of electric energy to every location on the system during the year. However, the lack of flexible units in constrained areas of the system and local reliability requirements require the ISO to commit inflexible generators in those areas, muting locational price signals and creating notable out-of-market compensation to those generators. The resultant real-time LMPs are lower than they would be if it were not necessary to commit these resources because the units committed in this manner are not able to set price. This inefficiency in the marketplace, highlighted in the Patton Report, is being addressed by the ISO as part of its Wholesale Markets Plan.[3]

8. **Capacity Market –** The portion of the capacity market settled through the ISO had low prices in 2003, consistent with the system-wide surplus of installed capacity relative to reliability requirements. The current market does not recognize the locational value of capacity, thereby decreasing the ability of capacity-short areas to attract new supply needed to ensure reliability. Lack of a locational price signal for capacity also impairs the valuation of transmission expansion alternatives since the true value of the generation option cannot be discerned by the market. The FERC recently ordered a settlement process that will result in a final capacity market design for New England that sends price signals that attract and retain the resources necessary to ensure both short- and long-term reliability in all locations.

9. **Market Monitoring –** The ISO monitors the market to ensure efficient and competitive market results. During the year, congestion mitigation authority was utilized four times. There were two instances in which the ISO determined that a plant inspection was warranted as a result of

---

the ISO web site at: http://www.iso-ne.com/special_studies/August_2003_Blackout_Report/. Additionally, the U.S.-Canada Power System Outage Task Force Report can be found on the Department of Energy web site at: http://www.doe.gov/.

[3] Information concerning ISO's initiatives to improve wholesale markets is contained in "Wholesale Markets Plan, 2004-2005." This report, which will be updated in the fall of 2004, is available on the ISO web site at: http://www.iso-ne.com/about_the_iso/Annual_Reports/.

monitoring for the potential physical withholding of a resource. The inspections yielded no evidence that physical withholding took place.

10. **Competitiveness and Market Entry –** Overall, the concentration of generation ownership in New England's wholesale markets continued its downward trend during 2003. Large increases in available generating capacity over the last five years resulted in there being very few hours when suppliers were pivotal. Net revenue analysis shows that profit margins for gas-fired units in the marketplace were lower in 2003 than 2002 and also indicates that incentives for new generator entry, on a region-wide basis, are low. While the system has an overall surplus of capacity, certain locations remain in need of capacity additions. The ISO is working to enhance locational price signals. The locational capacity approach that will result from the FERC's settlement order and locational reserve requirements reflected in the market rules will also better value new demand and supply options in constrained areas. These improvements will enhance the efficiency of the market design as price discovery leads to more efficient investment decisions. The increased liquidity of the market afforded by virtual transactions and a market design consistent with that of neighboring areas have increased the options available to market participants. Continued effort by market operators on so-called "seams" issues between wholesale marketplaces will further enhance competition between and within these areas.

The findings noted above are materially consistent with those reported by Dr. Patton in his analysis.

The ISO's smooth transition to SMD was the culmination of a significant effort to improve wholesale markets in New England. The SMD markets substantially advance the efficiency of congestion management and associated electric energy pricing in New England. However, as noted, improvements to the market design and rules to ensure efficient and competitive outcomes are required. Improvements to the transmission infrastructure are critical to ensuring the reliability of the bulk power system. The ISO continues to work with its stakeholders and advisors to implement rules that increase the competitiveness of the system and reports on these initiatives in its Wholesale Markets Plan. Concurrently, the necessary infrastructure enhancements to increase reliability or decrease congestion are outlined in ISO's Regional Transmission Expansion Plan, or RTEP.[4] Taken together, these initiatives provide a blueprint for enhancing wholesale electricity markets and maintaining power system reliability in New England.

[4] The RTEP results from a yearlong regional planning effort that examines system needs throughout New England. It is published in the fall of each year, and is available on the ISO web site at: http://www.iso-ne.com/smd/transmission_planning/Regional_Transmission_Expansion_Plan/.

3. Electric Energy Markets

3.1. Overview of Electric Energy Markets Under SMD

The electric energy market under SMD consists of a Day-Ahead Market and a Real-Time Market for electricity, with each market producing its own separate financial settlement. This arrangement is known as a multi-settlement system. The Day-Ahead Market produces financially binding schedules for the production and consumption of electricity one day before the operating day. The Real-Time Market reconciles differences between the amounts of electric energy scheduled day-ahead and the actual real-time load requirements. Changes to supply or demand can occur for any number of reasons, including market participant re-offers, hourly self-schedules, self-curtailments, transmission or generation outages, and real-time system conditions, including weather. Participants with energy or generator megawatt-hour deviations from their day-ahead committed schedules are paid (or pay) the real-time LMP for the energy amount that is sold or purchased from the Real-Time Market.

Unlike the Interim Markets in New England in which there was only one electric energy clearing price, under SMD, prices are calculated at three types of locations: the node, the load zone, and the Hub. Offers and bids are submitted; LMPs are calculated; and markets settle at these locations. Generators are paid the price at their node, while demand pays a load-weighted average of the nodes located in that zone.

A small percentage increase in production of electricity is required from generators because transmission systems experience electrical losses. Nodal prices are adjusted to account for the marginal cost of losses.

If the system were entirely unconstrained and there were no losses, all LMPs would be equal and would reflect only the electric energy price. The lowest possible cost generation could flow to all nodes over the transmission system. If the transmission network is congested, the next increment of electric energy cannot be delivered from the least expensive unit on the system because it would violate transmission operating criteria, such as thermal or voltage limits. The congestion component of price at a node is calculated as the difference between the energy component of price and the cost of providing an additional, more expensive increment of electric energy to that location.

Under SMD, suppliers receive payments at their nodal point of delivery while consumers pay the price calculated for eight load zones or aggregations of nodes. New England has been divided into the following zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Massachusetts (WCMA), Northeastern Massachusetts/Boston (NEMA), and Southeastern Massachusetts (SEMA). These eight load zones were created under SMD to reflect the historical operating characteristics of, and the major transmission constraints on, the transmission system.

3.2. Underlying Drivers of Electric Energy Market Prices

The key factors that influence the market price for electric energy are supply and demand, and transmission constraints.

3.2.1. Supply and Demand

The key factor in determining electric energy price levels is electricity demand and the availability of supply to serve it. Under SMD, market clearing is accomplished by the interaction of supply with demand at various locations throughout the system in both the Day-Ahead Market and Real-Time Market.

In the Day-Ahead Market, any market participant may bid fixed, price-sensitive, or virtual demand at the Hub, load zone, or node. Generating units offer their output at their specific location, while any market participant may offer virtual supply at a location. The intersection of the supply and demand curves as offered and bid determines the Day-Ahead Market price at each location. This results in binding financial schedules and commitment orders to generators. In the Day-Ahead Market, supply offers from participants reflect their units' marginal costs of production which are heavily dependent on input fuels. They also incorporate the units' operating characteristics, operating costs, and bilateral contract requirements. Likewise, demand bids reflect participants' load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations surrounding congestion.

After the Day-Ahead Market clears, locational supply can be affected in several ways. First, as part of its Resource Adequacy Assessment (RAA)[5], the ISO may be required to commit additional generating resources to support local area reliability or to provide contingency coverage. Second, generators that were not committed in the Day-Ahead Market can request to self-schedule their units for real-time operation or, alternatively, request to be decommitted.

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

For many electricity generators, the largest variable cost of production is the cost of input fuels. If fuel costs rise, there is a corresponding increase in the offer price of generators in the marketplace. The additions to generating capacity in New England over the last five years have been almost entirely natural gas-fired. The ISO's analysis indicates that units burning primarily natural gas, or capable of burning natural gas and oil, constitute approximately 40% of electric generating capacity in the region, and these units are the marginal supply units over 50% of the time.

3.2.2. Transmission Constraints

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

In the Day-Ahead Market, RAA, and Real-Time Market time frames, units are committed in such a way as to ensure that the level of cleared, anticipated, and actual demand can be served reliably. The commitment takes into account limits on the transmission system, the need for reserves, and the need to provide contingency coverage. Higher demand in a given area may result in binding transmission constraints, requiring more expensive generation to be selected in import-constrained areas and leading to a higher market-clearing price. On the other hand, export-constrained areas will at times experience lower prices relative to unconstrained areas.

3.3. 2003 Demand and Availability of Supply

The total energy needed to serve demand including losses within the New England Control Area is referred to as Net Energy for Load (NEL). NEL supplied to the system increased by 2.1% compared to 2002. The cold weather at the beginning and end of the year and a humid summer were responsible for the increase.

---

[5] After the Day-Ahead Market clears, generators are able to reoffer uncommitted capacity to the market. The RAA is performed by the ISO after 6:00 PM on the day preceding dispatch to ensure that sufficient generation has been committed system-wide and in each sub-area to ensure reliable operation during the upcoming dispatch day.

After utilizing ISO's normalization methodology[6] to adjust for weather, the increase in NEL was 1.5% as shown in Table 1.

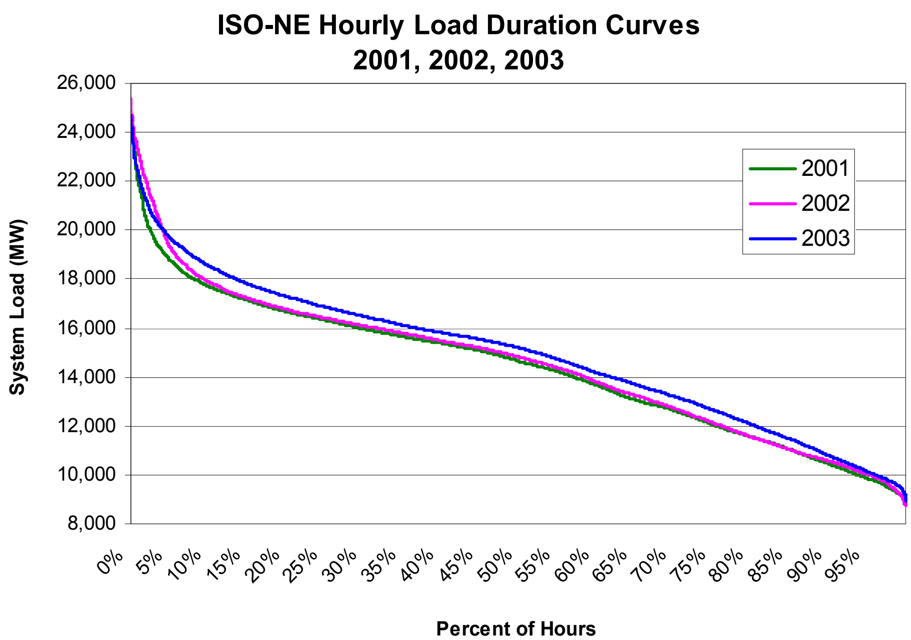
Recorded system summer peak demand (24,685 MW, August 22) was 2.6% below the 2002 peak, attributable to cooler than normal weather over the peak summer period. After weather normalization, peak demand grew 2.4% over the prior year.

Table 1 - Annual Electric Energy and Peak Statistics

Energy Concept	2002	2003	Change	% Chg.
Annual NEL (GWh)	128,029	130,777	2,748	2.1%
Normalized NEL (GWh)	126,903	128,848	1,945	1.5%
Recorded Peak Load (MW)	25,348	24,685	-663	-2.6%
Normalized Peak Load (MW)	24,590	25,170	580	2.4%

Figure 1 shows load levels over the past three years in duration curve format. This format shows the percentage of hours that system load was at or above the designated load level. The figure shows that, although the annual system peak load was lower in 2003, overall hourly load was consistently above each of the previous two years' levels.

Figure 1

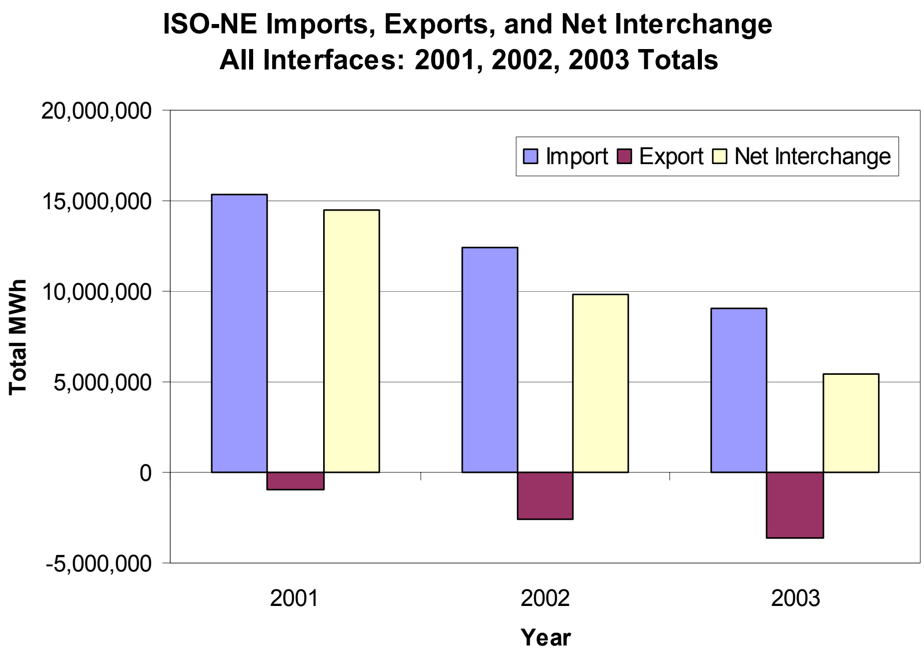


New England remained a net importer of power during 2003. Net imports from neighboring regions amounted to 5,441 GWh for the year, representing 4.2% of the annual NEL consumed in New England during 2003. New England was a net importer from its Canadian neighbors and a net exporter to New York. While the total net export to New York increased by 8% over 2002 (406 GWh in 2002 vs. 439 GWh in 2003), net imports from Canada dropped over 42% from 2002, reflecting low water conditions that

[6] To adjust for the effect of weather, the ISO uses statistically-derived factors to adjust energy consumption levels to reflect the departure of experienced weather during a period from 20-year average or "normal" levels. If temperatures are more severe than normal, consumption is adjusted downward; if milder than normal, an upward adjustment is made. Summer months also account for the effect of humidity on consumption levels.

affected hydro capacity availability in Canada during the year. Figure 2 shows net interregional power flows for 2001 through 2003.[7]

Figure 2



Overall, the supply available to meet demand was adequate on a regional basis. Unit availability statistics were comparable to 2002[8], and 2,600 MW of net new capacity (summer ratings) was added to the system – half of which was located in the NEMA/Boston load zone.

3.4. 2003 Electric Energy Prices

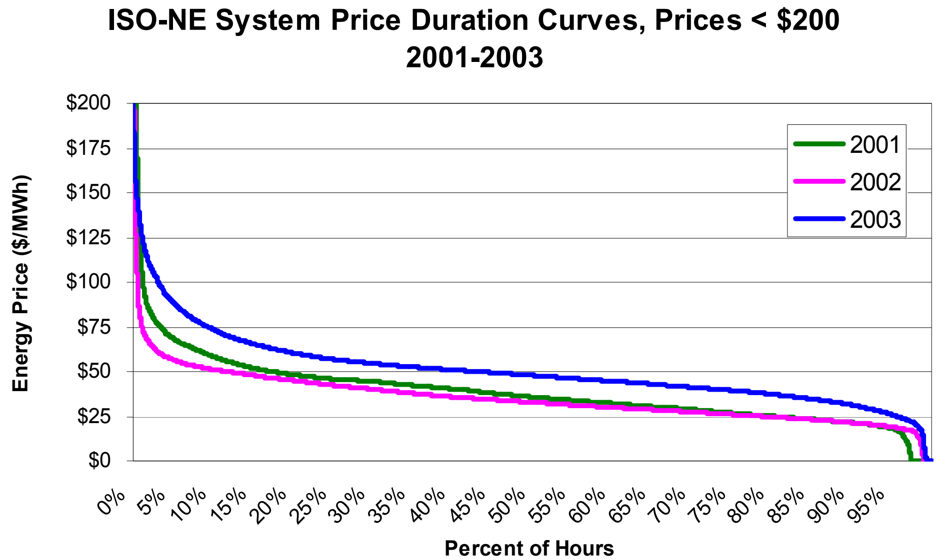
3.4.1. Annual Real-Time Electric Energy Prices

Figure 3 shows the real-time system electric energy price for New England over the last three years in duration-curve format. The duration curve shows, for each year, the percent of time that the system price was at or above the price levels shown. The figure shows that prices during 2003 were higher than in the previous two years. This was primarily due to input fuel prices as will be discussed in the next section.

[7] These statistics present the net flows on an annual basis. All control areas provide assistance to each other in emergency situations where flows are determined by reliability needs.

[8] See Section 13 of this report for additional discussion of unit availability.

Figure 3



System Price is single Energy Clearing Price for Interim Market Period ending Feb 28, 2003 and load-weighted Real Time Market LMPs for Mar-Dec 2003.

3.4.2. Fuel-Adjusted Electric Energy Price

Fuel is the largest variable expense for most electrical generating plants and therefore generators' energy offers are sensitive to variation in fuel prices. Electric energy market-clearing prices rise and fall commensurately with changes in fuel prices, particularly natural gas prices, for this reason.

The fuel-adjusted energy price normalizes electricity market-clearing prices for the variation in the prices of input fuels used by price-setting generating units. The analysis uses the year 2000 as a basis, and normalizes the price of the marginal unit in each five-minute interval for the change in its input fuel price.

Fuel-adjusted electric energy prices for the Interim Markets period were derived by adjusting each five-minute real-time marginal price (RTMP)[9] by a monthly index of spot market prices of the fuel used by the generator setting the RTMP. Fuel-adjusted energy prices for the SMD period were derived by adjusting five-minute Hub real-time LMPs by the same index of the fuel used by the marginal unit as determined by the unit dispatch software (UDS) run that was input to the five-minute LMP calculation.

Five-minute prices set by hydro plants were adjusted by a monthly index of average electric energy prices, reflecting changes in opportunity costs. Nuclear, wood, and other fuels without reliable prices were not adjusted. These unadjusted prices did not significantly affect the results because units using these fuels were seldom marginal.[10] The adjusted five-minute energy prices were then averaged to the hourly level and weighted by load before calculating yearly averages.

Table 2 shows yearly average actual and fuel-adjusted electric energy prices for New England. The fuel-adjusted energy price is the electricity market-clearing price normalized to year 2000 fuel-price levels. While 2003 had the highest real-time electricity prices on an actual basis, after adjusting for the price of fuels used to generate electricity, 2003's electric energy price was the lowest of the last four years. This

[9] The Energy Clearing Price (ECP) is the time-weighted average of the five-minute RTMPs in the hour.

[10] Units fueled with composite, nuclear, refuse, or wood were marginal less than 1% of the time during the four-year analysis period.

finding supports the hypothesis that the higher actual electric prices in 2003 were caused by higher input fuel prices. The low fuel-adjusted 2003 price is most likely due to the competitiveness of the energy market.

Table 2 – Actual and Fuel-Adjusted Average Real Time Electric Energy Prices

$/MWh	2000	2001	2002	2003
Actual Electric Energy Price	$45.95	$43.03	$37.52	$53.40
Electric Energy Price Normalized to Year 2000 Fuel Price Levels	$45.95	$48.60	$46.65	$43.51

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 after adjustment than actual prices; while energy prices in 2003, when gas prices were higher, were lower when adjusted.

To illustrate the movement of fuel prices that underlies the electric price movements over the last four years, Table 3 shows each of the last four years' average fuel prices for the indicated fuel indexed to its value in the year 2000. Natural gas prices during 2003 were 30% higher than those in 2000, and 73% higher than those in 2002.

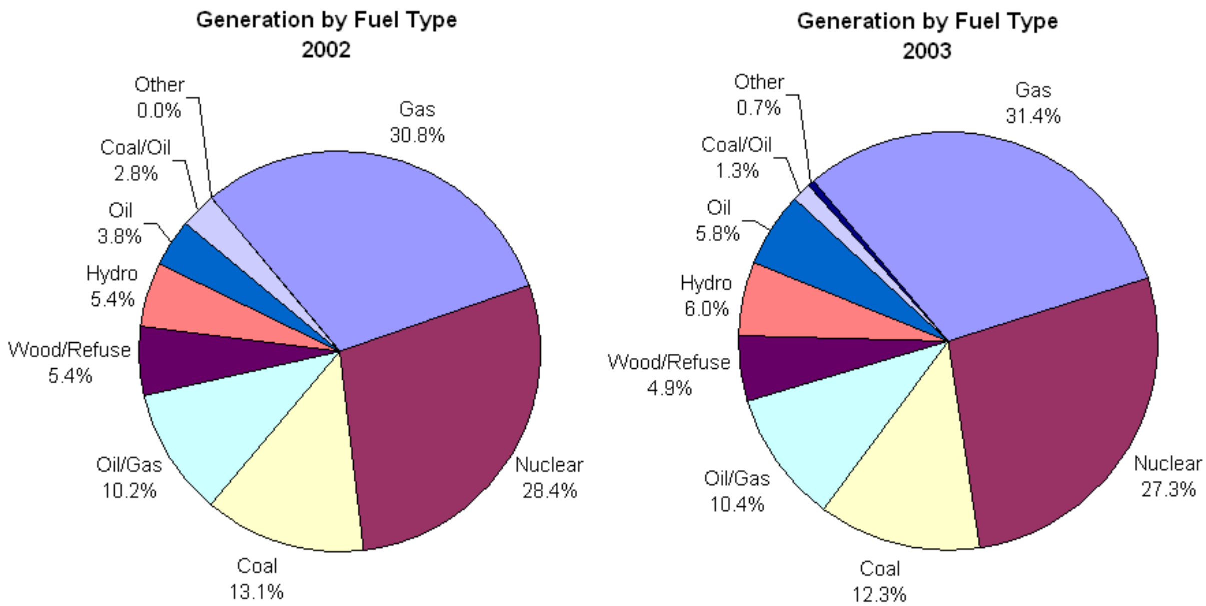
Table 3– Fuel Price Index, Year 2000 Basis

Fuel	2000	2001	2002	2003
Natural Gas	1.00	0.88	0.75	1.30
No. 6 Oil (1%)	1.00	0.83	0.90	1.09

There are certain limitations to the analysis presented here. The most significant is that if the relative prices of alternative fuels were different, the marginal units would also likely be different This analysis, however, assumes that the marginal units remained the same, while their fuel prices varied. This is not a major shortcoming, however, because there are limited hours where fuel price differences would alter the merit order of oil and gas-fired units. The analysis also does not make any adjustment for changes in offer rules or unit-commitment models that were in effect over the four-year period.

Figure 4 shows actual generation by fuel type for 2002 and 2003. The figures show the fuel mix of electric energy actually generated, which differs from the capacity fuel mix shown elsewhere in this report. While the percentages of generation by fuel type are relatively constant from 2002 to 2003, natural gas-fired units were very often the price setters in real time.

Figure 4



3.4.3. Wholesale Prices in Other Northeastern Pools

Comparing price levels across interconnected power pools provides a larger context for considering the reasonableness of price levels in New England. Many aspects of pricing can be analyzed, and the following represents one approach. Prices shown in Table 4 are system prices. System prices for New England and New York were calculated based on locational prices and locational loads, while prices for PJM are its published system prices.[11]

Table 4 - NE, PJM, and NY Average Electric Energy Prices, March – December 2003

Control Area	Day-Ahead			Real-Time		
	All	On-Peak	Off-Peak	All	On-Peak	Off-Peak
NE	**$48.72**	$55.31	$43.05	**$48.28**	$54.58	$42.88
NY	**$53.07**	$63.04	$44.45	**$51.86**	$61.56	$43.51
PJM	**$36.92**	$47.62	$27.74	**$36.46**	$47.24	$27.20

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 the differences in generator fuel mix. Significant coal and nuclear capacity in the PJM control area is a key driver of its lower average system price.[12] All three power pools exhibited higher Day-Ahead than Real-Time Market prices. New England prices were higher than PJM's and somewhat lower than New York's. The table shows that New England had the smallest gap between its peak and off-peak prices. This suggests that New England's need to commit base load and intermediate resources to meet peak demand levels, because of limited amounts of peaking units, contributes to the proximity of its on-peak and off-peak prices. Natural gas-fired units, which set price over 60% of all hours in New England, set price over 50% of the

[11] PJM web site at http://www.pjm.com. NYISO web site at http://www.nyiso.com.

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

time overnight, also contributing to the closeness of on-peak and off-peak prices. The cost impact of commitment requirements to support reliability is discussed in Section 7.4.

3.4.4. Electric Energy Prices Throughout the Year

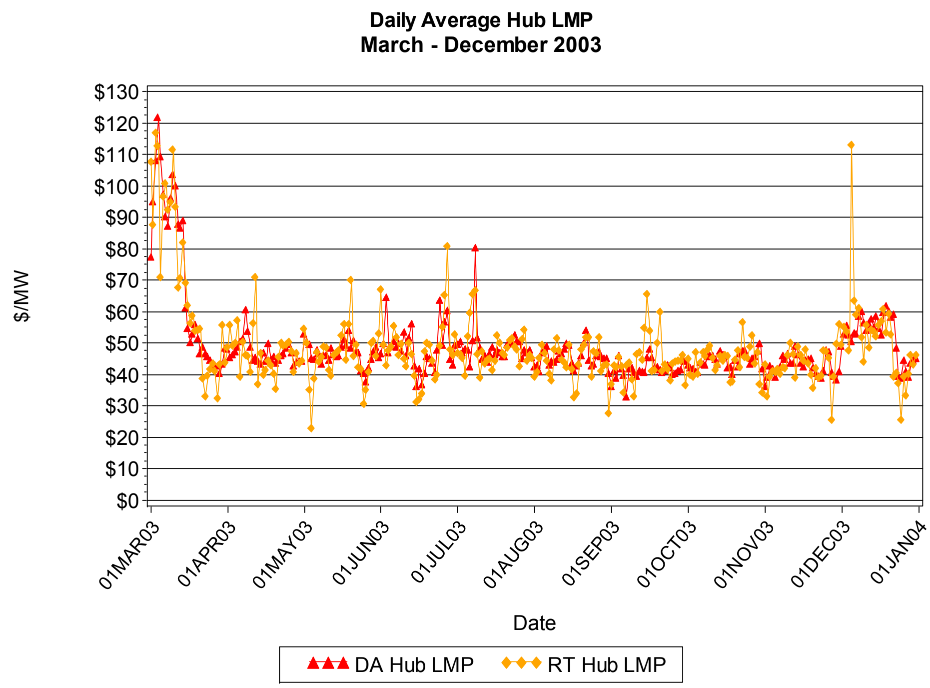
Natural gas prices were at historically high levels during the first quarter of 2003, and after falling, began to rise again in December, contributing to increases in wholesale electricity prices during those periods. The first quarter's average natural gas price was almost \$9.00/MMBtu, or two to two-and-a-half times historical averages. Over the summer period, gas prices fell to approximately \$5.50/MMBtu but began to climb again in December, approaching \$7.00/MMBtu.

Figure 5 illustrates the effect that high natural gas prices had on electricity prices at the time of SMD implementation and then again at the end of the year. The figure shows daily averages and therefore does not present hourly prices that, at times, were higher than these daily average values.

Over the 10-month period, price spikes occurred in both the Day-Ahead and Real-Time Markets. High price spikes in the Day-Ahead Market were generally caused by high levels of cleared day-ahead demand (fixed, price-sensitive, or virtual) or planned transmission outages that caused congestion. Real-Time Market price spikes were generally attributable to real-time unit or transmission outages or high loads, which caused the ISO to dispatch higher cost generation to maintain the balance between supply and demand and to adhere to reliability standards. As mentioned previously, cooler than normal weather during the summer peak demand season coupled with ample regional supply had a moderating effect on prices. Emergency operating procedures were employed only once during the summer of 2003,[13] and overall price levels during the summer did not reach the extremes of prior years. On December 5, several large generating units tripping off-line, necessitating the dispatch of very expensive generation for a two to three hour period, caused the unusually high average Real-Time Market price shown in Figure 5 for early December.

[13] Operating Procedure No. 4 (OP4) – Actions in a Capacity Deficiency – was invoked once on August 15 in Connecticut in support of system restoration efforts after the Northeast Blackout, not due to a region-wide capacity deficiency.

Figure 5

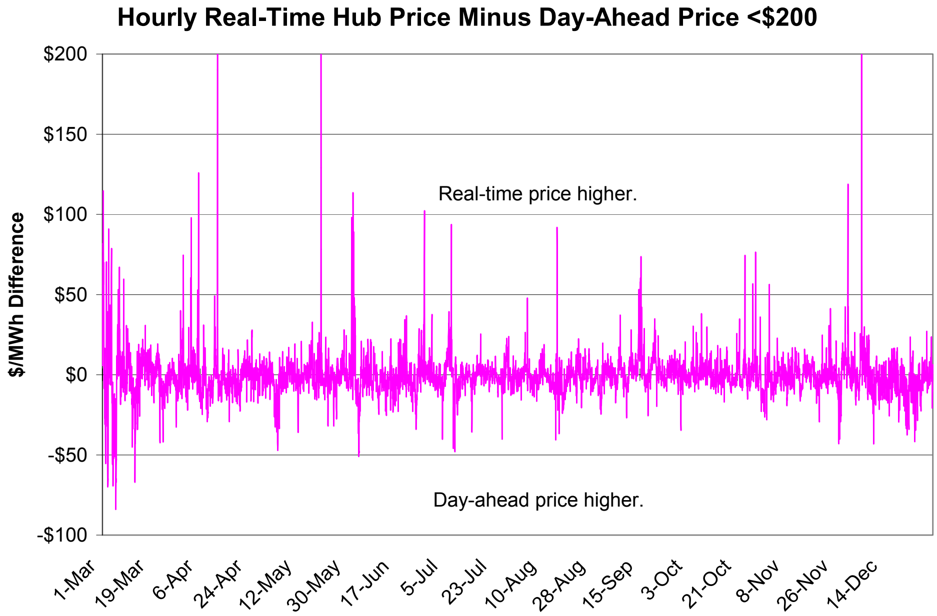


3.4.5. Hub and Load Zone Results Overview

During the first 10 months of SMD, average day-ahead and real-time prices were similar both at the Hub and in each of the eight load zones. Day-ahead LMPs were slightly higher than real-time LMPs, an outcome that reflects the slight premium associated with the Day-Ahead Market. The day-ahead Hub price averaged $48.97/MWh, while the corresponding real-time price averaged $48.59/MWh, a $0.38 or 0.8% difference. During the 10 months of SMD, over 90% of the day-ahead and real-time hours had average Hub LMPs at or below $75.00/MWh.

At the Hub, 55% of the 7,344 SMD hours had day-ahead prices that were higher than their real-time counterparts. The variability of the difference between the day-ahead and real-time prices was high, exhibiting a standard deviation of over $17.00/MWh. When real-time prices were high (generally due to real-time contingencies), they were very high, as shown in Figure 6.

Figure 6



Overall, the price effect of congestion in the Day-Ahead Market and Real-Time Market was low to moderate. At SMD implementation, very active virtual demand bidding by participants with so-called "seller's choice" contracts that settle in the Day-Ahead Market created large amounts of day-ahead congestion in the Maine load zone. Many of these contracts were reworked to settle in real time. When these contracts were modified to settle at real-time prices, the virtual trading activity and overscheduling in the Maine zone was substantially reduced.

During high demand periods in both the Day-Ahead Market and Real-Time Market, transmission interfaces between Maine/New Hampshire and the zones to the south became constrained as surplus generation located in Maine was exported to high demand areas of the system. Export constraints also occurred in the SEMA zone as surplus capacity attempted to reach other high demand areas. Because of high demand, relative lack of import capability, and internal transmission system weaknesses, the Connecticut zone was often constrained during the summer months, which created congestion and LMP price separation.

Recent transmission system improvements and recent additions of new generating capacity, and reliability commitment of generation by the ISO in the NEMA/Boston zone kept real-time import constraints to a minimum in that zone when compared to historical experience. This resulted in relatively little real-time congestion in that zone.

Varying levels of congestion and marginal loss effects resulted in the Maine zone, often an export-constrained area, having the lowest average prices over the period, while the often import-constrained Connecticut load zone experienced the highest. This result is consistent with the SMD design – local prices that are commensurate with the costs of producing and delivering power to local areas. Table 5 shows the 10-month average LMP as well as its minimum and maximum values at the Hub and the eight load zones in New England.

Table 5 - Summary LMP Statistics by Zone for 2003, All Hours

Location/Zone	LMP ($/MWh)					
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT
Internal Hub	$48.97	$48.59	$10.87	$0.00	$148.68	$998.41
Maine	$44.92	$44.19	$9.99	$0.00	$212.89	$510.43
New Hampshire	$47.87	$47.36	$10.61	$0.00	$146.17	$844.95
Vermont	$49.65	$48.75	$2.77	$0.00	$149.30	$946.70
Connecticut	$50.50	$50.22	$11.02	$0.00	$244.42	$988.68
Rhode Island	$48.11	$47.69	$10.78	$0.00	$351.00	$982.30
SEMA	$47.73	$47.54	$10.71	$0.00	$132.84	$967.01
WCMA	$48.99	$48.68	$10.89	$0.00	$148.52	$990.34
NEMA/Boston	$48.84	$48.09	$10.66	$0.00	$215.00	$991.82

Figure 7 and Figure 8 graphically compare the average LMP, congestion component of LMP, and marginal loss component of LMP for the Hub and load zones over the 10-month period for the Day-Ahead and Real-Time Markets. Average LMPs in each load zone reflect the cost to serve incremental energy, and that cost was generally higher in Connecticut (due to import constraints) and lower in Maine (due to export constraints). Export constraints in Maine also contributed to average negative congestion and marginal loss components of its LMP over the period.

Figure 7

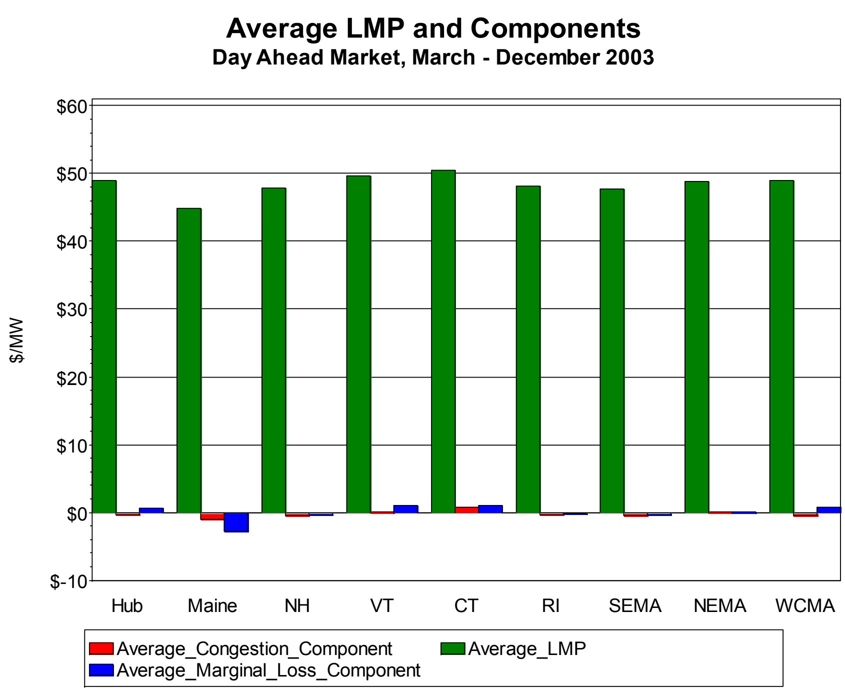
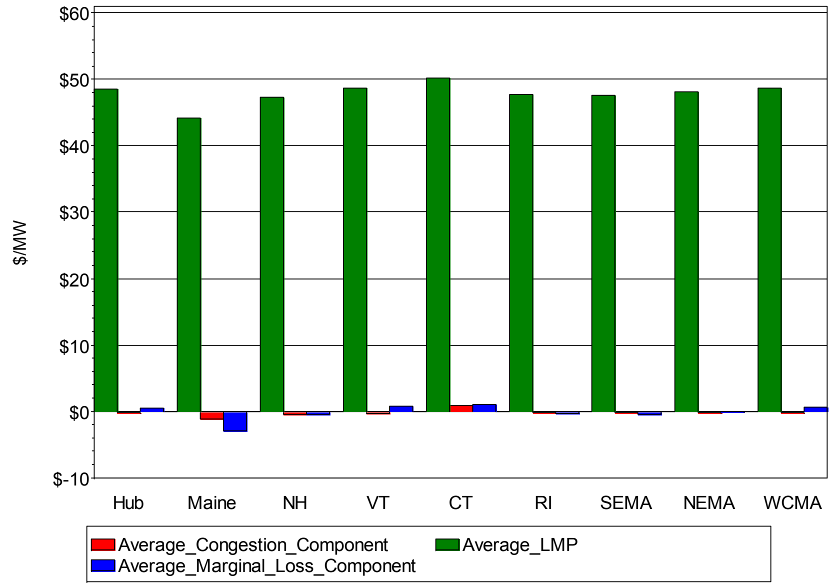


Figure 8

Average LMP and Components
Real Time Market, March - December 2003



3.4.6. Congestion

The congestion component of LMP reflects the effect that binding transmission constraints have on the marginal cost of electricity at a particular location. The Hub and all load zones except Connecticut, Vermont, and NEMA/Boston experienced, on average, negative day-ahead congestion component of LMP. This means that the Day-Ahead Market clearing process resulted in these zones (ME, NH, RI, SEMA, WCMA) being relatively unconstrained.

Connecticut, NEMA/Boston, and to a lesser extent, Vermont, all experienced a positive average day-ahead congestion component of LMP. Patterns of day-ahead demand led to constraints in those zones more often, with Connecticut's congestion component of LMP averaging around $0.80/MWh (0.8¢/kWh) over the 10 months.

The corresponding congestion components in the Real-Time Market were fewer and smaller. The greatest average negative real-time congestion component of LMP this year occurred in the Maine load zone, due to export constraints within the zone and to the south. The only positive average real-time congestion occurred in the Connecticut load zone due to both import constraints at the zonal interface and transmission constraints within the zone. The NEMA/Boston zone, which historically has experienced significant real-time congestion, did not experience it this year. The change was due primarily to recent transmission improvements, additions of generating capacity, a cooler than normal summer, and supplemental commitment of generating units in response to zonal reliability requirements. This effect is discussed in Section 7, Operating Reserve Credits (ORC).

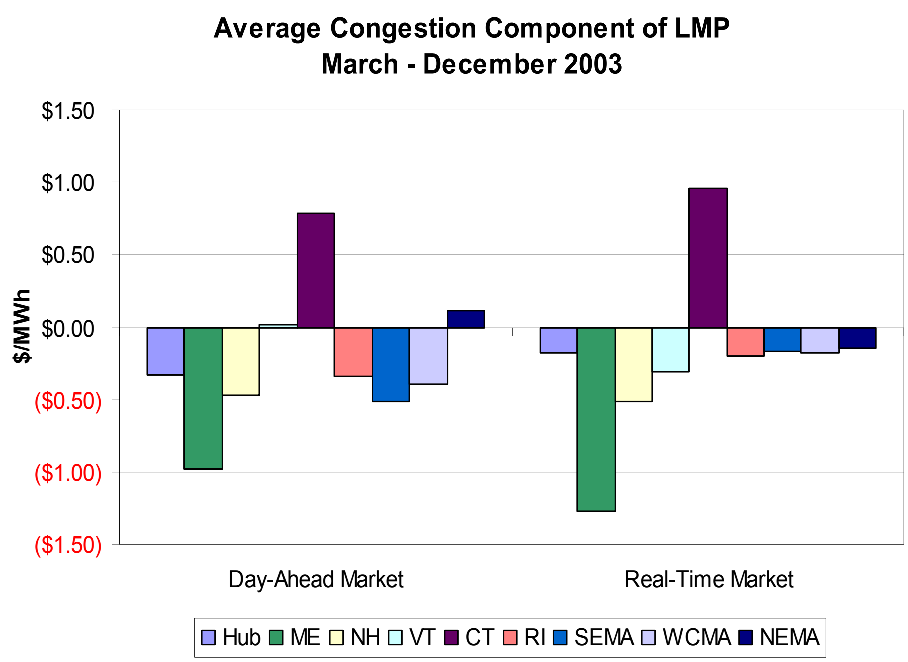
Table 6 provides the average congestion component of LMP for the Hub and load zones for the Day-Ahead and Real-Time Markets for the SMD period.

Table 6 - Average Congestion Component of LMP By Zone, 2003

Location	Day-Ahead Market	Real-Time Market
Hub	$(0.33)	$(0.18)
ME	$(0.98)	$(1.27)
NH	$(0.47)	$(0.51)
VT	$0.02	$(0.31)
CT	$0.78	$0.96
RI	$(0.34)	$(0.20)
SEMA	$(0.51)	$(0.17)
WCMA	$(0.40)	$(0.18)
NEMA	$0.11	$(0.15)

Figure 9 graphically portrays the average congestion component of LMP over the 10-month period for the Hub and each load zone. Notable in the figure is the positive average in the Connecticut load zone in both the Day-Ahead and Real-Time Markets.

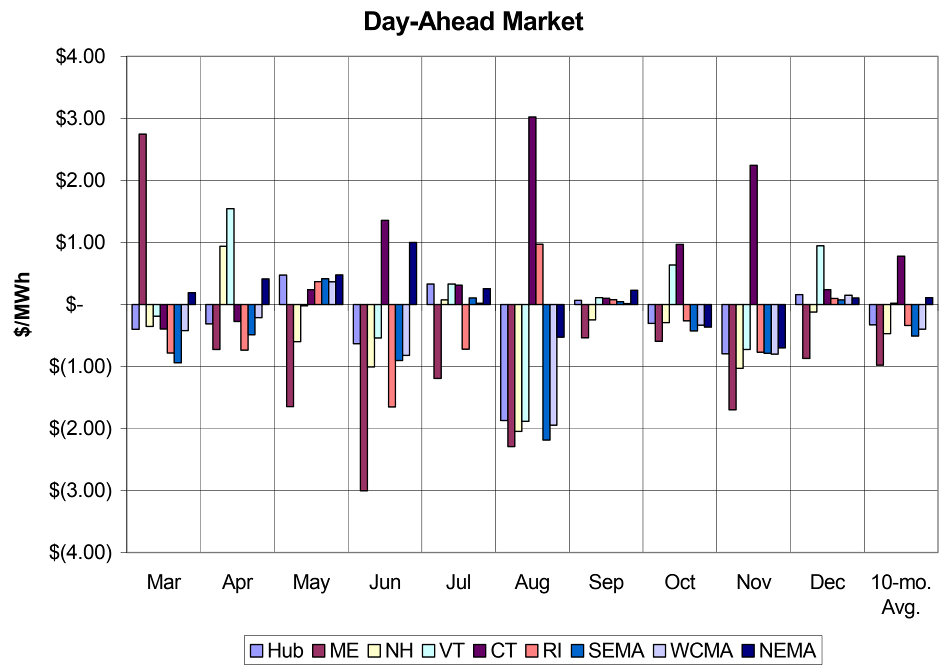
Figure 9

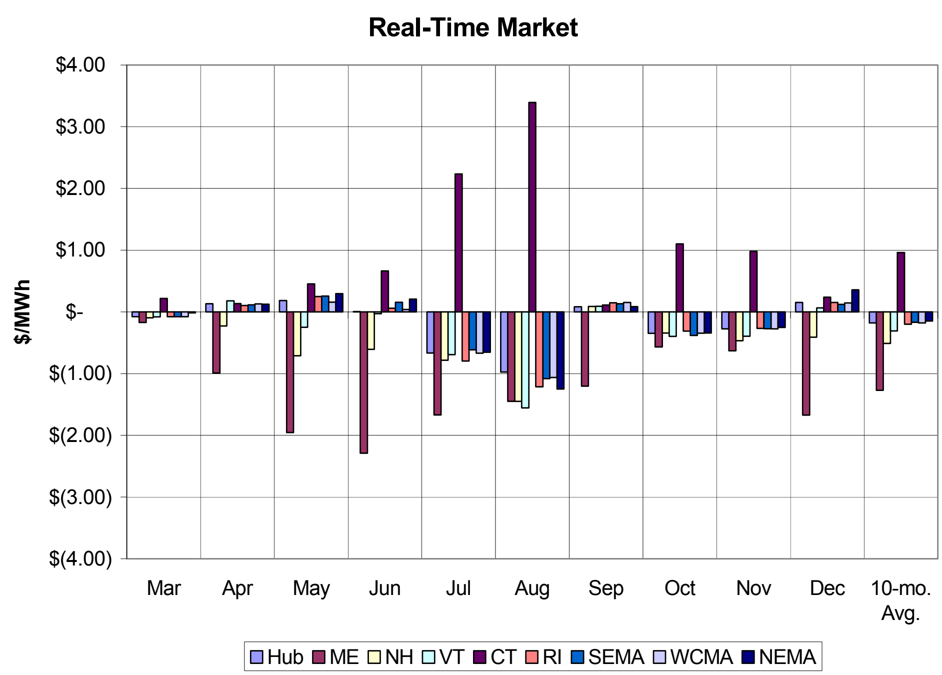


The two graphs in Figure 10 show the average congestion component of LMP by month for the Hub and for each load zone over the 10-month period. In the Day-Ahead Market, the congestion component varied from month to month, a reflection of patterns of cleared day-ahead bids and any resulting constraints on the system. While the congestion component for the NEMA/Boston zone was generally positive with some months slightly negative, the congestion portion of its LMP was small when compared to Connecticut, which experienced both import and intrazonal constraints. The Maine zone experienced consistently negative congestion components, except in March. The March results reflected virtual bids associated with "seller's choice" contracts between participants that initially settled in the Day-Ahead Market and were generally revised to settle in the Real-Time Market in subsequent months.

The real-time congestion component, shown in the second graph, shows that Connecticut experienced the most consistent and high levels of congestion over the 10-month period. Import constraints into the Connecticut zone also caused adjacent zones to experience negative congestion as less expensive electric energy became marginal in those zones. As was the case in the Day-Ahead Market, Maine experienced consistently negative congestion components in the Real-Time Market, indicative of large quantities of relatively inexpensive generation that was export constrained.

Figure 10 -Average Congestion Component of LMP by Location and Month





3.4.7. Losses

Calculating LMPs also involves calculating the marginal effect on system losses of serving an additional increment of load at each location. Marginal loss pricing constitutes an additional locational price signal in the marketplace. Losses are generally positively related to the distance between power source and power sink. If the marginal loss component of price is negative at a location, it means the lowest cost means of serving a load increment there will decrease overall system losses, while a positive marginal loss component means that serving a load increment at that location will increase losses.

The Maine load zone has adequate supply resources in relation to demand and is at times export constrained. For most of the 10 months, serving an increment of load in the Maine zone would have decreased overall system losses. As a result, Maine experienced an average negative $2.73/MWh marginal loss factor in the Day-Ahead Market and a corresponding negative $2.94/MWh factor in the Real-Time Market.

During the 10-month period, Vermont, Connecticut, and the WCMA zones all experienced positive marginal loss components that averaged in the $0.60 - $1.00/MWh range, which indicated that at most times, serving an increment of demand in those zones would have increased system losses. The New Hampshire, Rhode Island, and SEMA zones experienced negative marginal loss components that averaged between $0.00 and minus $0.53/MWh in the Day-Ahead Market and Real-Time Markets. The NEMA/Boston zone had a slightly positive average marginal loss component in the Day-Ahead Market, while the real-time component was slightly negative. The loss component remains generally proportional to zonal loss factors, even though it varies with the overall level of prices because the marginal loss component of price is computed using a system that represents the physical transmission system (and its inherent loss sensitivities).

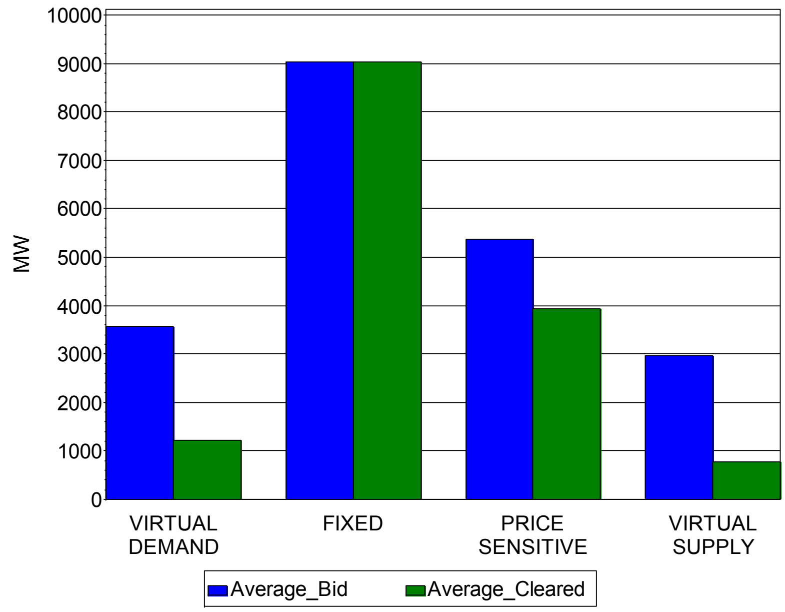
3.4.8. Day-Ahead Demand Bidding Patterns

An important enhancement to wholesale markets under SMD is the participation of the demand side in the Day-Ahead Market. All market participants with real-time load obligations can bid fixed or price-sensitive demand in the Day-Ahead Market and any participant can bid virtual demand. Demand bids that clear in the Day-Ahead Market create price certainty by locking in price and quantity in advance of the Real-Time Market.

The sum of the average hourly cleared fixed bids, price-sensitive bids, and decrement bids represents over 96% of average hourly system real-time load. For the 10 months, over 60% of cleared demand bids were fixed bids, insensitive to price, while slightly less than 30% were price sensitive. The balance of cleared day-ahead demand was composed of cleared decrement bids, or virtual demand, representing day-ahead locational purchases of electric energy. This is shown graphically in Figure 11.

Figure 11

Average Hourly Bid In and Cleared Demand, Virtual Demand, and Virtual Supply
Day Ahead Market, March - December 2003



Virtual trading enables market participants that are not generation owners or load-serving entities to participate in the Day-Ahead Market, establishing virtual (or financial) positions and helping to determine day-ahead LMPs. Virtual trading is important in a Day-Ahead Market/Real-Time Market design in that it allows more participants to take part in the day-ahead price-setting process and manage risk in a multi-settlement environment, provides arbitrage opportunities that promote price convergence, and mitigates market power in the Day-Ahead Market by reducing net day-ahead purchases when prices would otherwise rise.

Virtual supply (increment offers or “incs”) that clears in the Day-Ahead Market create a financial obligation for the participant to supply at a particular location in the Real-Time Market, while virtual demand (decrement bids or “decs”) creates a financial obligation to purchase at a particular location in the Real-Time Market. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which its offer or bid clears. Figure 12 shows the average daily submitted and cleared virtual transactions over the 10-month period.

Figure 12

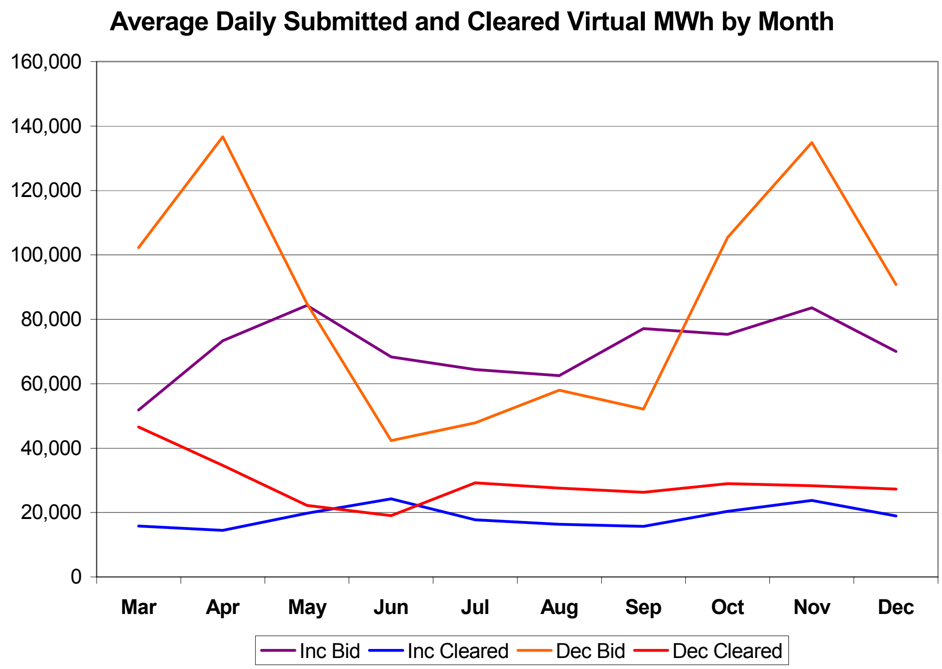


Figure 12 shows that the average daily submitted virtual demand bids varied widely over the 10 months, while increment offers were a bit more stable and exhibited a slight upward trend over the year. Interestingly, despite the variation in submitted quantities, cleared volumes of increment offers and decrement bids were reasonably stable over the year, with about 29,000 MWh per day of decrement bids clearing and about 19,000 MWh of increment offers per day clearing over the period.

For all hours during the 10-month period, day-ahead load obligation averaged almost 90% of real-time load obligation but varied across zones. Table 7 presents the statistics for the 10-month period by zone and overall.

Table 7 - Day-Ahead vs. Real-Time Load Obligation Statistics

Zone	Average	Maximum	Minimum	Std. Dev.
Overall	89.6%	104.1%	77.5%	3.8%
ME	96.4%	154.8%	82.4%	8.9%
NH	93.9%	134.4%	20.9%	7.5%
VT	99.2%	147.5%	59.4%	7.3%
CT	79.3%	109.9%	52.2%	8.4%
RI	94.8%	123.1%	64.1%	8.3%
SEMA	93.4%	124.3%	62.8%	9.1%
WCMA	85.5%	123.6%	53.2%	9.3%
NEMA	94.9%	113.6%	73.1%	4.9%

The Connecticut load zone experienced the lowest proportion of day-ahead load obligation to real-time load obligation – 10% below the overall percentage. This suggests that, all else equal, participants in Connecticut anticipated a lower real-time price and elected to underschedule day-ahead demand.

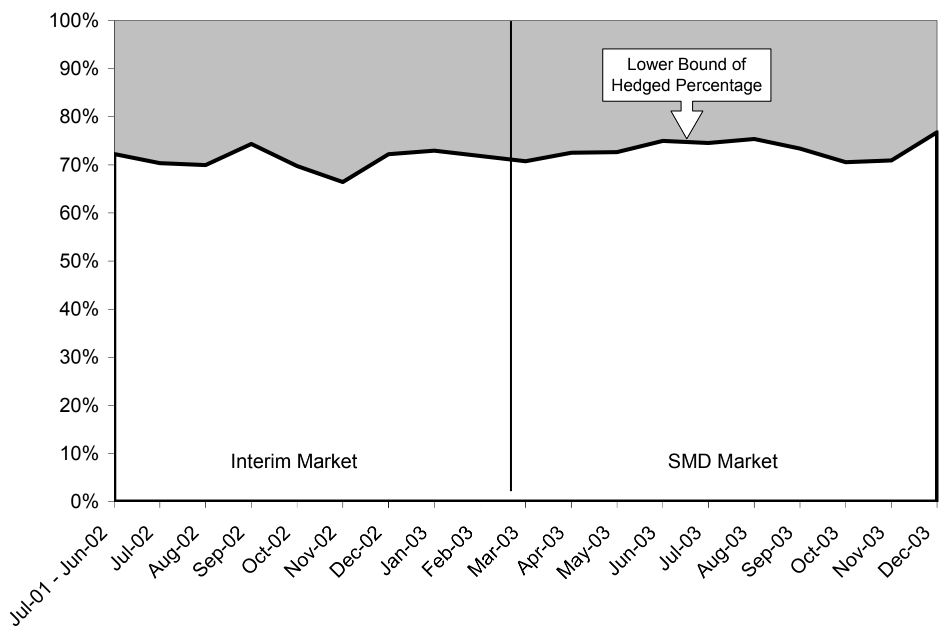
Supplemental commitment of generating units for reliability by the ISO after the Day-Ahead Market clears tends to suppress real-time prices and likely contributes to more Connecticut load opting for real-time prices.

3.4.9. Forward Contracting

Estimates of the level of forward contracting and generation self-supply in New England are important to any evaluation of how well New England's markets are working. These estimates also help in the assessment of market participant and consumer vulnerability to unanticipated events. Forward contracting not only insulates load from short-term price volatility but also serves as an incentive for generators to offer at marginal production costs.[14]

Calculations for March to December 2003 show that, on average, a little over 73% of total real-time load was ultimately either forward contracted or covered by a physical hedge. For each month of 2003, the degree of forward contracting was at least 70% of real-time load, as shown in Figure 13. This approach to the analysis tends to understate the true degree of forward contracting to the extent that bilateral contracts exist but are not settled through the ISO's centralized settlement system or to the extent that non-dispatched generators are available. Although the figure shows the lower bound of the amount of hedged load, it does illustrate that market participants have tended to cover their positions to at least the same extent that they did during the Interim Markets period.

Figure 13 - Lower Bound of Real-Time Load as Hedged Through ISO Settlement System



3.5. *Electric Energy Prices Under Interim Markets: January-February 2003*

January and February 2003 were both colder than normal in New England and energy usage was high. New England's January 2003 peak hourly load of 21,535 MW set a new winter record, surpassing the January 2000 record of 21,176 MW. February's peak load of 20,422 MW was the first-ever February peak over 20,000 MW. Both January and February's NEL were 8-9% higher than the corresponding months in 2002.

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

Fuel costs increased during the first two months of 2003 and power prices followed. Average Energy market clearing prices (ECP) in January were \$60.18/MWh, rising to \$69.42/MWh in February, both higher than the previous year.

3.6. All-In Total Price of Energy Analysis

Changes in fuel prices influenced wholesale electricity prices significantly during 2003. Analysis of the effect they had is complicated by fundamental differences in the calculation of locational prices under SMD and uniform system prices under the Interim Market. To facilitate comparison across both market designs an 'All-In Total Price of Energy' is calculated and presented here.[15]

The All-In Total Price of Energy accounts for amounts returned to load-servers as well as charges to them. The All-In Total Price of Energy incorporates energy, reserve, regulation, uplift or ORC costs, and the cost of Reliability Agreements. The price also accounts for revenues and charges related to the Marginal Loss Revenue Fund, Congestion Revenue Fund, and FTR and ARR allocations. The All-In Total Price of Energy is computed at the hourly level and is averaged for the day. The average daily All-In Total Price of Energy provides a measure of the trends in wholesale electricity prices over time.

For the Interim Markets period ending February 2003, the All-In Total Price was calculated as follows:

> *All-In Total Price of Energy =[(ECP * system load) + total reserve market payments + total AGC market payments + total Uplift or NCPC payments + Reliability Agreement payments]/system load.*

For the SMD market period beginning March 1, 2003, the hourly Total All-In Price of Energy is calculated as follows:

> *All-In Total Price of Energy =[sum(DA LMP * DA cleared locational demand) + DA ORC + sum(RT LMP * RT locational load deviation) + pro-rated RT ORC + total regulation payments+ Reliability Agreement payments + Net FTR auction dollars + FTR negative allocations – FTR positive allocations – marginal loss revenue fund – congestion revenue fund – ARR dollars allocation] / [sum(DA cleared demand) + sum(RT load deviation)].*

Figure 14 shows the average daily All-In Total Price of Energy plotted against the average variable production cost of hypothetical power plants burning either natural gas or oil. To show more detail, the graph excludes values above \$100/MWh. This convention excludes a handful of days, mostly during late February and March, when the variable production cost for a gas plant or the All-In Total Price of Energy was above the \$100/MWh threshold.

The proxy gas-plant production costs are based on a gas plant with a heat rate of approximately 7,000 Btu/kWh, while the proxy oil-plant production costs are based on a heat rate of approximately 10,000 Btu/kWh. Variable production costs reflect day-ahead spot market prices for fuel. The correlation coefficient of the All-In Price and variable cost of the proxy gas plant is 0.74. This is an indicator that movements in the All-In Total Price of Energy have been closely related to the movement in generating plants' fuel costs, which are generating units' largest variable cost.

---

[15] Composite Day-Ahead Market and Real-Time Market LMPs comprise over 96% of the All-In Total Price of Energy during the SMD period.

Figure 14

Daily Avg. All-In Total Price of Energy vs. Variable Production Costs < $100/MWh

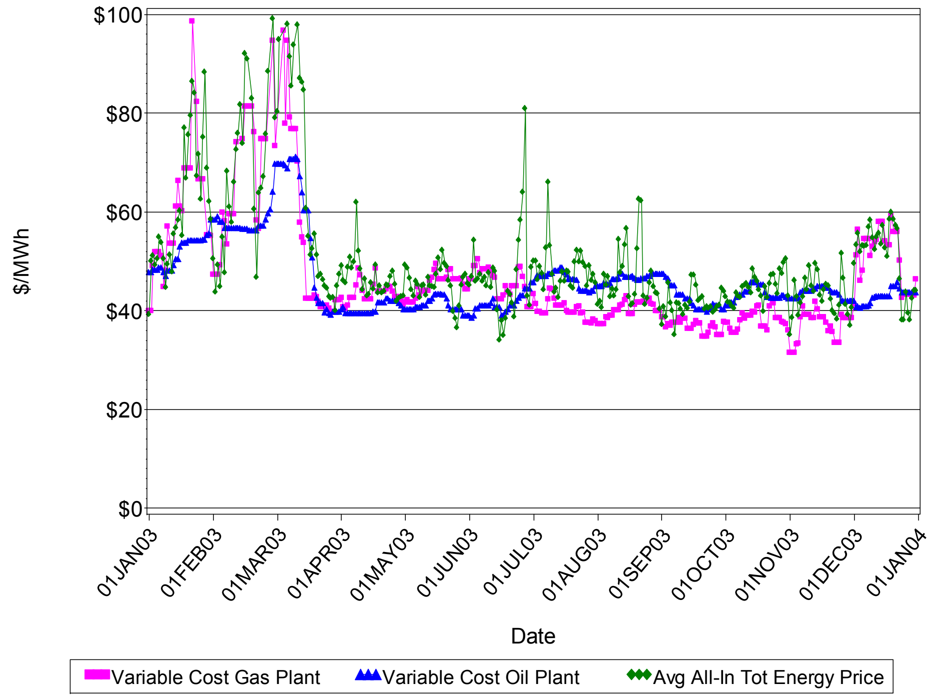


Figure 15 summarizes the marginal or price-setting units by fuel type during the 10-month period. Binding real-time transmission constraints can produce instances when there is more than one marginal unit on the system, and since each marginal unit is included in the analysis, the percentages in the figure sum to more than 100%. For simplicity, external transactions are not considered in this analysis. The figure shows that units burning natural gas were marginal 63% of the time (approximately 4,600 hours out of 7,344 hours[16]) during the period. These results show the extent to which the New England electrical system prices depend on gas-unit offers.

[16] The hourly calculations are the result of summing each five+ minute interval in which the fuel type was marginal.

Figure 15 – Marginal Unit(s) by Unit Type

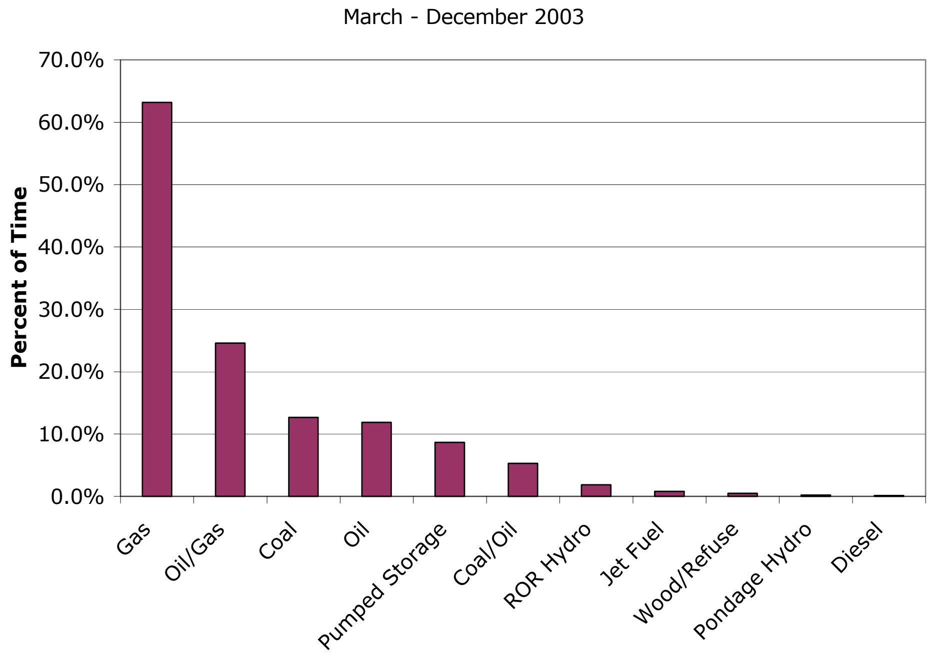
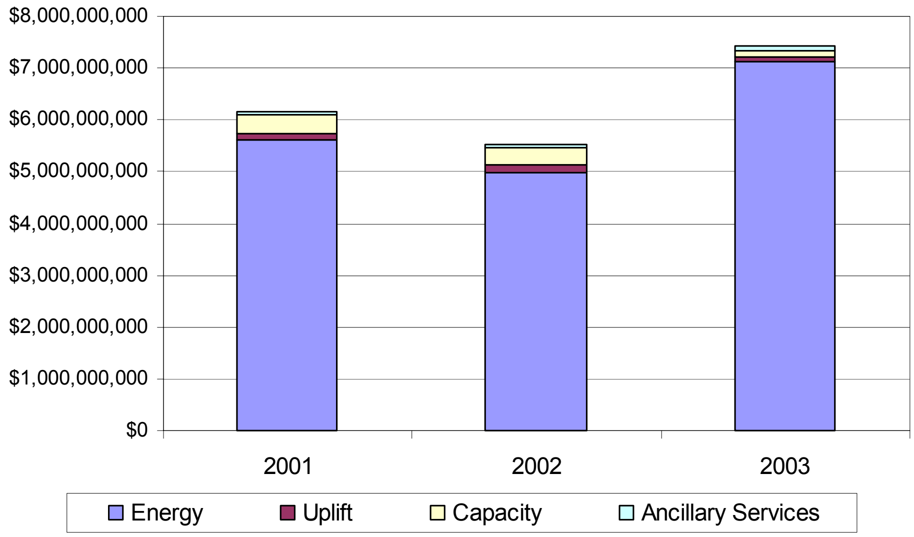


Figure 16 shows an annual total of the components (energy, uplift, capacity, and ancillary services) that comprise the All-In Price in New England over the last three years.[17] The figure illustrates that energy costs are the largest component of wholesale cost, accounting for 96% of wholesale charges to load in 2003. The 2003 value reflects the effect of high input fuel costs. Also notable in the figure is the decrease in capacity prices. Before 2003, participants who were deficient in their capacity obligations paid an administrative penalty, while from April 2003, deficiency amounts were purchased at auction – an auction that cleared at $0.00/MW-month in every month. A discussion of the deficiency auction may be found in Section 9.2 of this report.

[17] The 'All-In Price' shown in Figure 16 utilizes the FERC definition of energy cost in its calculation and, therefore, is different from the All-In Total Cost of Energy cost shown in Figure 14. The energy cost requested by FERC is the real-time load obligation of load-serving participants times the location-specific, real-time price. The All-In Total Cost of Energy shown in Figure 14 is the day-ahead load obligation times the location-specific, day-ahead price plus the real-time load obligation deviation from day-ahead times the location-specific real-time price. The two derivations, while not identical, are reasonable proxies for each other.

Figure 16

New England All-In Price Metric: Energy*, Uplift, Capacity, Ancillary Services Totals 2001, 2002 and 2003



*Energy: Interim Markets period = ECP * System Load, SMD period = RT Load Oblig * RT LMP.

3.7. Conclusions

Market participants took significant advantage of the Day-Ahead Market to insulate their positions from unexpected events in the Real-Time Market as they purchased significant percentages of real-time demand in the Day-Ahead Market. The Hub and most load zones saw comparable average prices in the Day-Ahead Market and Real-Time Market with a slight price premium for the Day-Ahead product.

The SMD market, with LMP as one of its central features, began to deliver locational signals on the marginal value of electric energy across the system, while explicitly quantifying the effect of transmission constraints through differences in prices. In general, export-constrained areas experienced lower prices, while import-constrained areas experienced higher prices.

Maintaining reliability in the SMD environment necessitates actions by the ISO when the resources committed by Day-Ahead Market clearing are not sufficient to support reliable real-time operation. Self-commitment decisions by participants and reliability commitments made by the ISO after day-ahead commitment influence real-time pricing. The cost and price impacts of these unit commitment actions are discussed in Sections 7 and 10 of this report concerning Operating Reserve Credits and Reliability Agreements.

4. Demand Response

4.1. Overview of Demand Response

Demand response in wholesale electricity markets refers to customers who reduce their electricity consumption in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale market prices. Demand response can help address short-run reliability problems by reducing supply needs. It also can reduce spot market price spikes and provide a hedge against price risks to wholesale purchasers. It is an important part of a balanced wholesale market, along with a solid market structure, ample supply, and robust transmission infrastructure.

The ISO administers the Load Response Program for the New England wholesale electricity market. During 2002, the ISO and NEPOOL filed new load response programs that, with the exception of the proposed Day-Ahead Demand Response Program, were activated concurrently with SMD. They are:

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

The Real-Time Demand Response Program offers two options relating to required response time – either within 30 minutes or two hours after receiving instruction to curtail from the ISO. Demand resources enrolled in this program are paid for an actual load interruption at the higher of the real-time zonal price or a floor price[18] for a minimum of two hours. All demand resources enrolled in this program qualify as Installed Capacity (ICAP) resources.

In the Real-Time Price Response Program, demand resources are paid real-time prices for voluntary reductions in electricity usage when the forecast hourly zonal price (based on the results of the Day-Ahead Market or on subsequent Resource Adequacy Analyses) is greater than or equal to $100/MWh. Meter readings are submitted either daily to the ISO on the same schedule as other meter data, or before the end of the 90-day resettlement period, depending on the program option chosen.

The Real-Time Profiled Response Program includes demand resources that are capable of being interrupted within two hours of an ISO instruction to do so. Each individual load participating in this program does not need to be interval-metered. Rather, the load response for the group of individual loads participating in this program can be estimated statistically provided that the aggregator ("Enrolling Participant") of such loads has an ISO-approved measurement and verification plan. Load participating in this program must be under the direct control of an Enrolling Participant. Examples include aggregated residential super-thermostat programs, hot water heaters, pool pumps, and distributed generation.

The transition from the pre-SMD program to the SMD Demand Response Program was accomplished by transferring assets that were active on February 28, 2003 to the corresponding SMD Demand Response Program. For instance, if an asset was active in the pre-SMD reliability-based program, it was transferred to the 30-minute Real-Time Demand Response Program. An asset in the pre-SMD voluntary program was transferred to the Price Response Program.

[18] The floor price is $500/MWh for the 30-Minute Real-Time Demand Response program, and $350/MWh for the 2-Hour Real-Time Demand Response Program.

4.2. *Demand Response Results*

As of August 31, 2003, 443 assets were enrolled in the program, comprising over 380 MW of potential demand interruption or curtailment. (This represents an increase of approximately 190 MW in potential demand relief over the summer-end 2002 value).

Elements of the Load Response Program were activated on a total of 65 days during the year. Assets in the Real-Time Demand Response Program (Two-Hour Demand, 30-Minute Demand with and without Emergency Generation, and Profiled Response programs – "reliability programs") were called on only one occasion during the year – August 15, 2003 – and only for the Connecticut zone for a total of 16 hours in support of system restoration procedures after the August 14 blackout.

The Real-Time Price Response Program, activated by real-time zonal price forecasts that exceed $100/MWh, was called on varying numbers of days across the region. The Connecticut load zone experienced program activation on 59 days, while the Maine load zone experienced only 26 days of program activation.

Overall, the programs produced slightly more than 5,800 MWh of demand reduction over the year. This relatively small amount of reduction is partially attributable to the eventual real-time prices realized after the Price Response programs were initiated. Frequently, the Day-Ahead Market price forecast of greater than $100/MWh in a zone ended up being much lower in real time, reducing the financial attractiveness of interrupting load.

4.3. *Conclusions*

During 2004, the ISO will continue to improve the current complement of demand response programs. More flexible hardware subsidies and more aggregation opportunities will be introduced, along with a shorter timeline to register and activate load response assets. Initiatives aimed at enhancing locational capacity markets may provide incentives to reliability resources to participate in the programs.

In the ISO's Wholesale Markets Plan, several areas of enhancement in the demand response area are discussed. Briefly, the ISO plans to:

- Work with market participants, state regulators, and state legislatures to improve the relationship between the wholesale and retail markets;
- Encourage and advocate increased participation in the ISO's Demand Response Programs;
- Continue to work toward implementation of a Day-Ahead Demand Response Program and to increase demand response's effectiveness in the markets; and
- Continue to work toward full integration of demand response into the Day-Ahead and Real-Time Markets.

5. Managing Congestion Risk – FTRs

5.1. Overview of Financial Transmission Rights

Transmission congestion in the Day-Ahead Market can cause prices to vary across the power grid. This causes more revenue to be collected from load in congested areas. To protect or "hedge" against the expense of higher LMPs, market participants may bid for the rights to receive a share of this congestion revenue. FTRs are financial instruments that entitle the holder to a share of congestion collections in the Day-Ahead Market.

In any hour, an FTR may result in either payments due or payments owed. 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 a liability. In this case, the FTR holder is obligated to *pay* the congestion cost.

FTRs can be acquired in three ways:

- FTR Auction – the ISO conducts periodic auctions to allow bidders to acquire and sell monthly and long-term FTRs. All FTRs are initially defined by the bidders in the FTR auction.
- Secondary Market – The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought or 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.

5.2. Monthly Auction Results

FTR auctions occur monthly. In the first seven of the 10 monthly FTR auctions in 2003, the entire transmission capacity of the New England Control Area was offered. The last three monthly auctions (where 50% of the system's transmission capacity was offered) were held subsequent to a long-term auction (where 50% of the system's transmission capacity was also offered) for the October to December period. This meant that any awarded FTR had to be acquired at auction each month. When a long-term auction is held, the long-term awarded FTRs are held aside in the ensuing monthly auctions, decreasing the volume of FTRs that can be awarded in those auctions. The first long-term FTR auction is discussed in the next section.

There were no implementation issues with the FTR auction, with significant activity and participation in each of the first 10 monthly auctions. The number of bidders in each monthly auction ranged from 24 to 40, and their bids to buy FTRs totaled $103.5 million for the period with almost $23 million awarded.

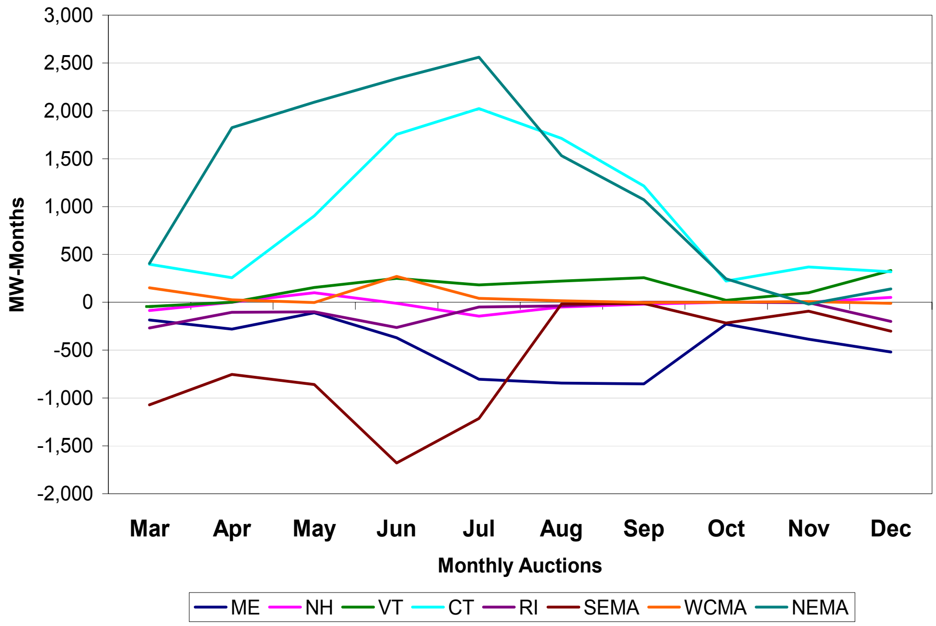
Analysis of the on-peak auction results (the hours when power flows are heaviest) indicates that market participants had expectations that were consistent with historical patterns of congestion on the New England system. Net FTR purchases were generally from the Hub to the NEMA/Boston, Connecticut, WCMA, and Vermont load zones (historically import-constrained) and to the Hub from the Maine, Rhode Island and SEMA zones (historically export-constrained).

Figure 17 presents the overall pattern of interzonal FTR purchases (in MW-months) for each of the on-peak auctions during the 10-month period. Zone-to-zone FTR purchases were decomposed into their zone-to-Hub and Hub-to-zone components so that the analysis could be presented in relationship to the Hub. In the figure, negative values indicate that the net of all FTRs purchased between the Hub and the particular zone was toward the Hub (e.g., Maine and SEMA – export-constrained areas), while positive values indicate net purchases from the Hub to the zone (e.g., NEMA, Connecticut, and Vermont – import-constrained areas).

The reduction in cleared volume during the October to December period is notable. Lower than expected loads (and congestion) during the fall period and the first long-term auction (which offered 50% of the transmission capacity of the system) are responsible for the decrease in awarded FTRs observed in these three monthly auctions.

Figure 17

Net On-Peak FTR Purchases By Month and Zone Relative to Hub



5.3. *Long-Term Auction Results*

The first long-term auction was held in September, covering the October to December 2003 period. In that auction, 50 percent of the capacity of the New England transmission system was available, with the remaining system capacity made available in each of the October to December monthly FTR auctions. Also, winners of long-term FTRs could offer them for sale in each of the monthly auctions. The 21 bidders in the long-term auction, slightly less than the average monthly auction to date, made bids that resulted in $5.6 million of auction-cleared revenue.

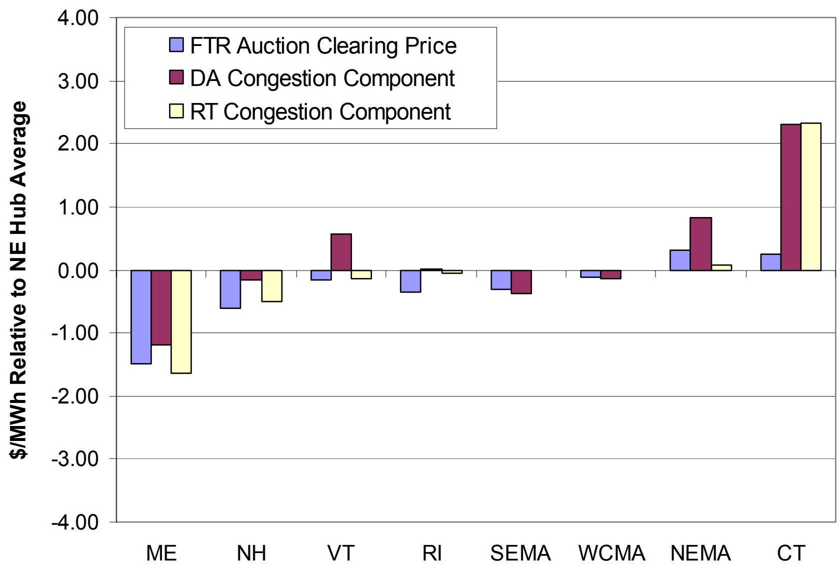
Analysis of the on-peak auction results for the long-term auction indicates similarities between it and the monthly auctions. The only notable net FTR purchase was from the Hub to the NEMA/Boston zone, where approximately half of the monthly average amount was purchased. Net purchases to the Hub from the Maine zone were roughly equivalent to the monthly average to date, while net purchases from the Rhode Island zone were about 30% of the monthly average to date. The remainder of the load zones exhibited no discernible pattern in the long-term auction.

5.4. *Conclusions*

The effectiveness of FTRs as a congestion hedge by participants was mixed. In general, FTR auction prices should correlate with Day-Ahead Market congestion, which in turn should be a reflection of real-time congestion expectations on the system. Zones that historically have experienced more congestion (Connecticut and NEMA/Boston) showed this positive correlation. As shown in Figure 18 (representing the 10 monthly on-peak auctions together), a Hub-to-NEMA/Boston FTR cost 38% of the eventual day-ahead congestion realized over the period (on a $/MWh basis), while a Hub-to-Connecticut FTR cost 11% of the day-ahead congestion cost incurred over the period.

Figure 18

FTR Auction Prices vs. DA and RT Congestion
March - December 2003



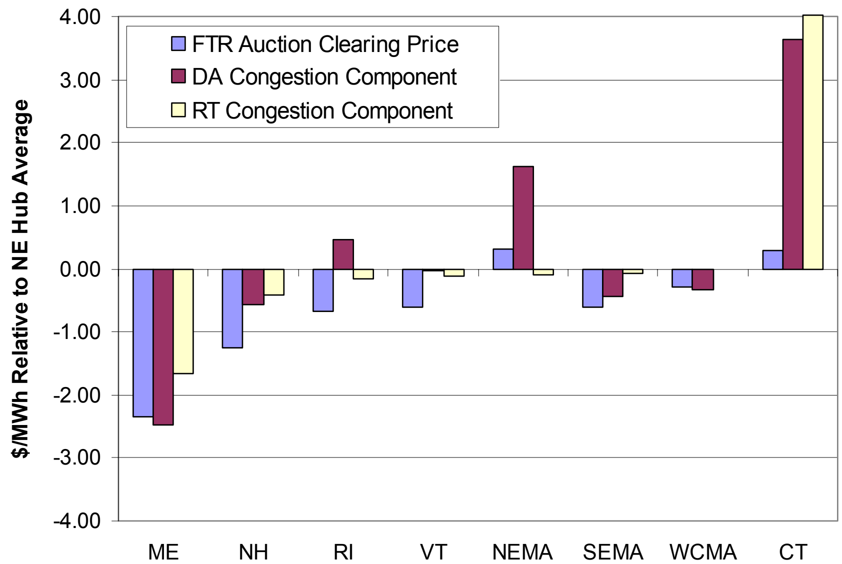
A combination of recent changes to the transmission system, generation infrastructure, the ISO's need to commit units for real-time reliability, and participant market strategies, including risk management approaches, all affect the patterns of congestion on the system, and therefore the FTR auctions. Briefly:

- FTRs awarded in the auctions appeared undervalued, exhibiting a low cost to procure when compared to the eventual day-ahead congestion that materialized, especially in the Connecticut and NEMA/Boston load zones. Analysis of trends near the end of 2003 and into 2004 indicates that FTR prices in these constrained areas more closely match actual congestion costs. This, coupled with increasing auction participation over the 2003-04 period, supports the conclusion that participants are becoming more efficient in valuing FTRs as a day-ahead congestion hedge. The ISO will continue to monitor the FTR auctions and report on them in subsequent reports.
- The Connecticut and NEMA/Boston zones continue to experience the most real-time congestion in New England. Connecticut is the most congested region. NEMA/Boston experienced less congestion than anticipated due to additions of generating capacity and several important transmission system improvements that have occurred in that zone recently. As real-time congestion patterns change, they will affect Day-Ahead Market congestion and participant strategies.
- Directional consistency between day-ahead congestion and real-time congestion and between day-ahead congestion and FTR auction clearing prices was somewhat better during the summer peak period. Auction clearing prices reflected the value that participants placed upon FTRs as a hedge instrument over the summer months when day-ahead (and real-time) congestion was anticipated to be highest. Figure 19 shows that average positive day-ahead congestion materialized in the Rhode Island, NEMA, and Connecticut zones. In Rhode Island, the modeling of a physical transmission system constraint in the Day-Ahead Market led to 10 hours with congestion components

approximating \$250/MWh (2.5¢/kWh) on August 11. With that day excluded, the four-month average day-ahead congestion component of LMP in Rhode Island was negative \$1.03/MWh.

Figure 19

FTR Auction Prices vs. DA and RT Congestion
June - September 2003



- Day-Ahead congestion costs and FTR auction prices were directionally consistent in the Maine and New Hampshire zones (export-constrained and negative), the Connecticut zone (import constrained and positive), and NEMA/Boston zone (import-constrained and positive).

- Day-ahead and real-time congestion added between \$3.50 and \$4.00/MWh of expense to every day-ahead and real-time MWh in the Connecticut zone over the 10 months. FTR clearing prices did not appear commensurate with the hedge they would have provided against day-ahead congestion. The ISO will continue to monitor and assess the performance of the FTR market.

6. Regulation Market

6.1. Overview of the Regulation Market

Regulation, or Automatic Generation Control (AGC), is necessary to balance supply levels against second-to-second variations in demand. The optimal frequency or the number of cycles the alternating electrical (AC) current moves through each second on the system is 60 Hertz (Hz). When an imbalance between supply and demand occurs for a sustained period of time, this frequency can shift either below or above 60 Hz. To respond to these slight changes on the system, specially equipped generators are sent signals to increase or decrease generation output. This helps balance the system, maintaining the 60 Hz frequency, and proper power flows into and out of the New England Control Area.

The ISO designates a set of generators to provide regulation and sets hourly clearing prices based on submitted day-ahead offers by generators that are willing to supply the service. The regulation clearing price is set by the resource with the highest combined regulation offer plus ISO-estimated, unit-specific opportunity costs based upon Day-Ahead Market clearing.[19] In the Real-Time Market, the ISO issues appropriate dispatch instructions to selected generators who are compensated for any real-time lost opportunity costs incurred while providing the service. Load-serving entities then pay for Regulation service based on real-time load obligation. Market participants may satisfy regulation requirements by providing the service from their own units, by internal bilateral transactions for regulation, or by purchasing regulation from the market.

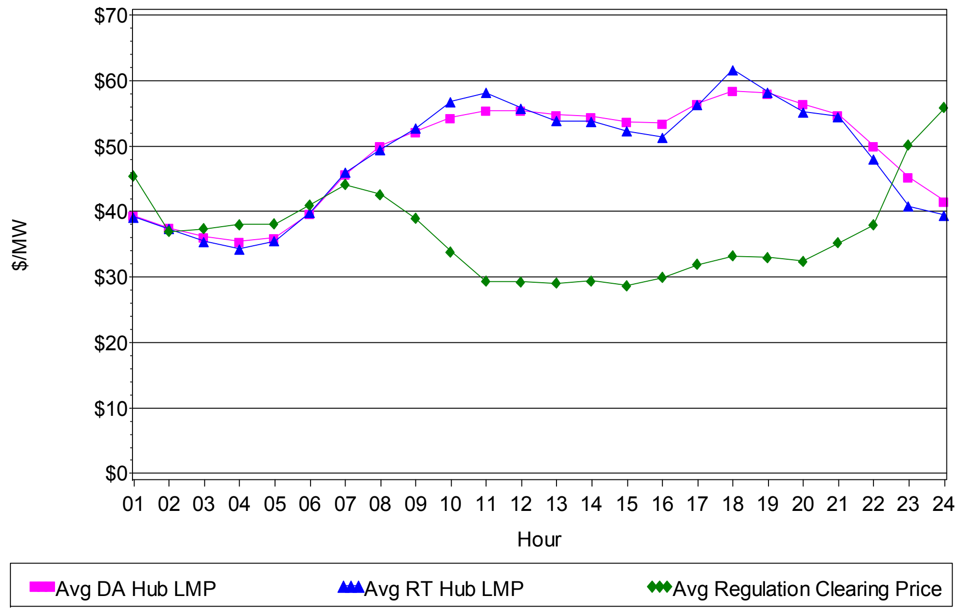
6.2. Regulation Market Results

The hourly regulation market clearing price averaged $36.75/MWh over the 10-month period. Regulation price patterns were lower during the on-peak hours and higher in the late evening and early morning as Figure 20 illustrates. This is consistent with the availability of regulation units, many of which are available during the day, with supply becoming tighter as units are decommitted overnight, The Regulation Market clearing process minimizes the total daily cost of procuring regulation service despite producing relatively high regulation prices during the overnight hours.

[19] Unit opportunity cost is the estimated cost each unit would incur if it adjusted its output as necessary to provide its full amount of regulation, and is roughly computed as the absolute difference between the day-ahead LMP at the generator's bus minus the price associated with the setpoint the unit would have to maintain to provide its full amount of regulation multiplied by the MW deviation between economic dispatch and the regulation setpoint.

Figure 20

Average Hourly Regulation Clearing Prices and Hub DA & RT LMPs
March - December 2003



Note: Average Regulation Clearing Price includes day-ahead lost opportunity costs, but excludes real-time lost opportunity costs.

6.3. Conclusions

The Regulation Market under SMD has performed effectively to reliably provide sufficient amounts of AGC. During the 10-month period, there were ample units available to supply regulation to the New England markets, and the New England Control Area's compliance with North American Reliability Council (NERC) reliability requirements for regulation was excellent.[20] The inverse relationship between the average energy and regulation prices seen in Figure 20 reflect the impact of supply and demand, with higher energy prices at peak demand times, and higher regulation prices when supply is lower.

The ISO's Market Monitoring Department and David Patton, Ph.D., the Independent Market Advisor to the ISO's Board of Directors, identified two issues facing the Regulation Market. The first relates to the ability of participants to self-schedule the regulation service. During 2003, the regulation clearing price was determined as part of the RAA process and not subject to change in real time. Owners of regulation resources were able to self-schedule regulation in real time without reducing the clearing price. This decreased the incentive for certain participants to offer the service in advance, resulting in potentially inefficient selection of resources and higher prices. This issue was addressed through a February 2004 change to operating procedures that limits the ability of participants to self-schedule regulation after the close of the Regulation Market and determination of regulation clearing prices.

A second issue in the Regulation Market design relates to the current optimization method used to select resources to provide the service. The current market rules require acceptance of the full offered amount from a unit. The ability to accept a portion of the offered amount would promote more efficient selection of resources and increase the number of regulation providers selected. Meeting the Control Area's regulation requirement by carrying regulation on more resources also might improve the system's ability to recover from contingencies involving regulation units. The ISO will be addressing further Regulation Market changes as more fully described in the Wholesale Markets Plan.

[20] CPS1 and CPS2 compliance reports are on the NERC web site at: http://www.nerc.com/~filez/cpc.html

7. Operating Reserve Credits – Uplift

7.1. Overview of Operating Reserves

Operating reserves can be viewed as the bulk power system's insurance policy. They provide a margin of additional supply above and beyond what is otherwise needed to meet real-time system demand. Operating reserves allow the ISO to respond to significant, unexpected imbalances between supply and demand without interrupting load.

The Interim Markets had separate, auction-based markets for procuring and compensating operating reserves (i.e., Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, Thirty-Minute Operating Reserve, and replacement reserves). SMD approaches the compensation of these reliability services differently. Generators whose output is constrained by the ISO up or down from (i.e., above or below) the economic level determined by the LMP in relation to their offer are eligible for compensation. This compensation is based on the generator's submitted costs for providing energy, including start-up and no-load costs. This operating reserve compensation ensures that generators providing reserves who experience lost opportunity costs or overall revenue shortfalls are made whole for any expenses not recovered through the sum of daily energy payments. These payments are called Operating Reserve Credits (ORC).

The ISO schedules adequate resources in the Day-Ahead Market to meet the cleared demand plus forecasted regional reserve requirements. After the Day-Ahead Market closes, the ISO conducts a reserve adequacy analysis to ensure that operating reserve requirements are met based on the forecast demand for the following operating day. Additional resources are then scheduled as necessary.

Operating reserves charges in the Day-Ahead Market are charged to participants in proportion to their day-ahead load obligations. In the Real-Time Market, participants whose real-time load deviates from the day-ahead schedule and participants whose generators deviate from day-ahead schedules or who do not follow real-time dispatch instructions, are charged in proportion to these deviations.

7.2. Types of Operating Reserve Credits

Operating Reserve Credits are calculated in both the Day-Ahead Market and Real-Time Market. There are four types of ORC: (i) Economic ORC[21] paid to eligible units that provide operating reserves and that are not flagged for another type of ORC; (ii) Reliability Must Run (RMR) ORC paid to units that are required for reliability within a particular reliability region on that particular day; (iii) Voltage Amperes Reactive (VAR) paid to units providing VAR support to the transmission system[22]; and (iv) Special Constraint Resources (SCR) ORC paid to units that provide SCR Service for local reliability under Schedule 19 of the NEPOOL Tariff.

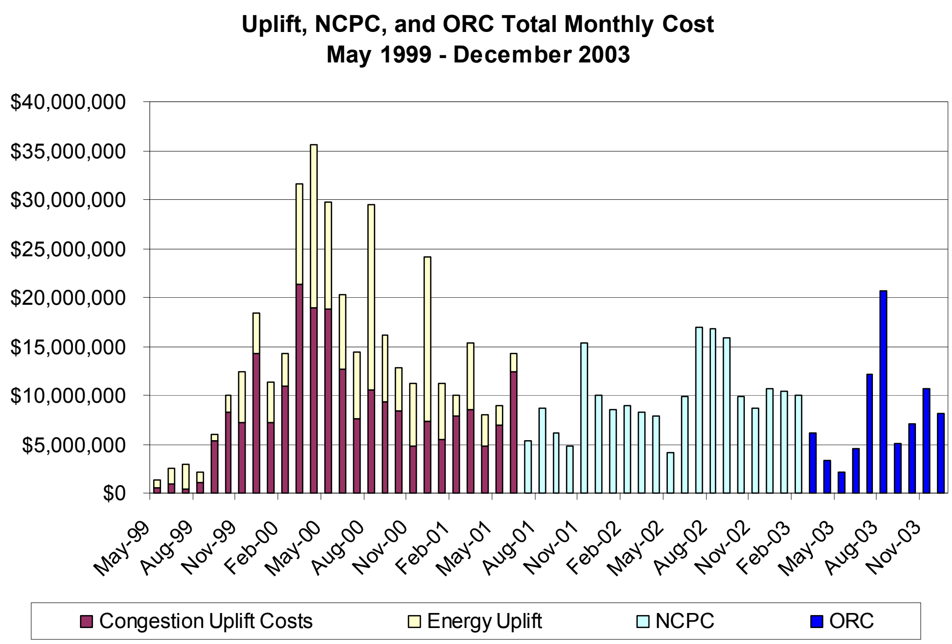
ORC payments are made to eligible pool-scheduled generators and participants with external dispatchable transactions that have a shortfall between their revenue (based on clearing prices in the energy and regulation markets), and their offer price (based on their energy offer, start-up fee, and no-load fee). If a generator operates "in-merit," most of its compensation will be from the energy market unless the energy revenues are insufficient to cover its costs. On a daily basis, eligible resources may receive ORC payments if the ISO commits them for economic, VAR support, or daily RMR.

[21] Economic ORC payments are made to generating units committed by ISO to ensure pool reliability (e.g., to supply replacement reserves) whose decommitment would pose a threat to that reliability. Economic ORC is not incurred for "economic" reasons.

[22] VAR support from generators is required to regulate system voltage within reliability criteria. Units that provide VAR support may incur a shortfall between their total daily supply offers and market revenues because, in providing the service, they may be dispatched out of merit order. ORC costs for VAR service are billed to market participants through the Regional Transmission Tariff.

From the beginning of the Interim Markets in May 1999 through June 2001, participants were eligible to receive uplift payments for hourly shortfalls between energy costs represented by their bids, and electric energy market compensation. Uplift payments were made to units required to run in order to maintain system reliability when transmission congestion occurred and for non-transmission reasons such as maintaining proper voltage limits. During the July 2001 through February 2003 period of the Interim Markets, participants received Net Commitment Period Compensation (NCPC) payments. NCPC was calculated on a daily basis in a manner similar to the ORC calculation. Although the eligibility criteria and calculation methods for uplift payments, NCPC payments, and ORC payments differ, all three represent payments for generation outside of those based on the energy clearing price. Figure 21 compares monthly totals for Uplift, NCPC, and ORC since the beginning of markets. The Northeast Blackout and so-called PUSH Offer Rules (discussed in the following section) contributed to the higher levels of ORC seen in the summer months.

Figure 21



7.3. *Operating Reserve Credit Results*

In 2003, ORC (composed of Economic, VAR, RMR, SCR) totaled approximately $86 million, and NCPC (composed of comparable concepts) totaled approximately $20 million for a grand total of approximately $106 million in uplift. ORC was affected by PUSH[23] offer rules implemented by the ISO in constrained areas of the system at the beginning of the summer. Under the PUSH offer rules, units in constrained areas were allowed to raise their offers in order to recover a portion of their fixed costs without risk of mitigation. These units set the LMP only 3% of their on-line hours because they were committed primarily for reliability. By being run out-of-merit or at low operating limit, they were recipients of increased ORC payments rather than impacting the LMP. ORC rose approximately $10 million over the June-July time frame.

[23] On June 1, 2003, ISO implemented Peaking Unit Safe Harbor (PUSH) offer rules, allowing owners of low capacity-factor units (less than 10% annual capacity factor) in Designated Congestion Areas (DCAs) to include levelized fixed costs in their energy offers without risk of mitigation. Please see Section 11.3 of this report for further discussion. Also see the ISO report on PUSH implementation in "Review of PUSH Implementation and Results, FERC Docket No. ER03-563-002, et al.," December 4 2003.

The ORC total in 2003 is approximately $26.5 million or 37% lower than the total paid in NCPC during 2002. If the ORC payments associated with the Northeast Blackout are removed, uplift decreased by almost $33 million on a year-over-year basis. This result is at least partially attributable to the LMP feature of the SMD market design in which costs associated with transmission congestion are incorporated directly into the locational price rather than making "make whole" payments to generators run out of economic merit to address transmission congestion.

The Northeast Blackout contributed to the higher than usual real-time ORC levels in August. System operators manually dispatched generating units for several hours because of a combination of reliability concerns and the need to restore the system following the Blackout. Many of those units operated at their low limits for extended periods. Units operating at their low limit that are not eligible to set LMP and have a net revenue shortfall when compared to offers are eligible to receive ORC payments.

All VAR ORC payments in 2003 ($14.3 million) were made to generation that was required to control possible high voltage levels during low load periods in the Boston area. Units in the Connecticut load zone received the largest amount of RMR ORC ($28.7 million), followed by units in the NEMA/Boston region ($7.8 million). Table 8 shows total 2003 ORC payments by category and market.

Table 8 - Total ORC Payments, March – December 2003

ORC TYPE	DA Market	RT Market	Total
Economic	$3,355,930	$24,698,746	$28,054,676
RMR	$1,701,290	$34,892,094	$36,593,384
SCR	$0	$6,945,798	$6,945,798
VAR	$13,496,309	$846,269	$14,342,578
Total	$18,553,529	$67,382,906	$85,936,435

7.4. Supplemental Commitment and Out-of-Merit Dispatch

Levels of real-time congestion in chronically constrained areas of the New England system (NEMA/Boston and parts of Connecticut) were somewhat less than expected. To ensure reliability, the ISO operates the system with what are essentially locational capacity requirements, a feature not yet reflected in the SMD design. These requirements cause the ISO to make supplemental commitment of generators and, at times, to operate generation out of merit order to ensure that constrained areas maintain their reliability after the Day-Ahead Market commitments are made. These commitments are necessary, in part, because these areas do not have significant quantities of quick-start, off-line resources to respond to real-time contingencies. The Patton Report found that this supplemental capacity commitment averaged approximately 500 MW in the NEMA/Boston zone and 600 MW in the Connecticut zone over the peak hours during the March through August period.[24]

Supplemental commitments serve to increase the available supply in the constrained areas, thereby lessening imports and associated congestion. These units, once committed, tend to increase the amount of ORC paid because they are either ineligible to set price while operating at their economic minimum, or operating out-of-merit order (i.e., their offers are higher than the prevailing market price). The effect of the supplemental commitment is to lower prices in the constrained area, and sometimes system-wide, because these units sometimes displace the marginal unit. The ISO is currently assessing the effect of including these supplemental commitment requirements in the Day-Ahead Market.

[24] Patton, David B., et. al., p. 6.

7.5. Changes to Eligibility for ORC

A specific rule change related to ORC was approved by FERC on May 7, 2004. The changes to Appendix F to Market Rule 1 replace the current eligibility criteria for ORC. The market rules permitted ORC only to generating resources that were pool-scheduled with no self-scheduled hours during their minimum run time before the change. Under the new eligibility criteria ordered in the change, generating resources with self-scheduled hours during their minimum run time may receive ORC in certain circumstances. A March 1, 2004 effective date was requested and approved by FERC.

7.6. Conclusions

In the SMD market, as under the Interim Market, ORC reflects an "out-of-market" expense that participants cannot hedge. ORC is indicative of out-of-merit operation that dampens price signals emanating from constrained areas on the system, decreasing the incentive for flexible, quick-start capacity to locate and operate in those areas. The ISO will continue to refine the market rules to ensure that units following dispatch instructions are fairly compensated and send appropriate price signals to local resources. This will ensure proper incentives to maintain both reliability and economic efficiency.

8. Forward Reserve Markets

8.1. Overview of the Forward Reserve Market

In December 2003, the ISO implemented a Forward Reserve Market (FRM). The FRM is designed to provide a market-based method for procuring operating reserve services in advance through a reservation payment that represents a "call option" on energy. The call-option premium provides a revenue stream to resources that can provide reserves during peak demand periods. As SMD was initially implemented in March 2003, resources received revenues primarily for electric energy provided, with lost opportunity payments for electric energy production foregone to provide operating reserve, and compensation for shortfalls between their supply offers and their energy market revenue if committed by the ISO for reliability. The rules did not initially contain a separate market-based approach for compensating generating units that provide operating reserves – capacity (either on-line or off-line) available to the system operator in real time to recover from operating contingencies. In particular, resources that are designed to provide off-line, quick-start reserves rarely received energy payments, relying on the ICAP Market for much of their revenues The ICAP Market, which is discussed in Section 9 of this report, provided insufficient economic incentive to those resources.

The FRM process begins by establishing an Operating Reserve Purchase requirement for the region – the amount of reserves needed in accordance with established reliability standards. Once the requirement is established, the ISO seeks to satisfy these requirements through an auction in which qualifying resources submit competitive bids. Both off-line and on-line resources can compete to provide this reserve service.

Forward reserve resources with winning bids are contractually obligated to submit offers into the energy market at or above a predetermined minimum "strike-price." This strike price is calculated by the ISO using a fuel index and an implied system heat rate, and set at a level that corresponds to a generator that would be expected to operate only about 2% of the time. This is consistent with the expected operating profile of a peaking resource.

The selected forward reserve resources are required to provide energy upon request within either 10 minutes (ten-minute non-spinning reserves) or 30 minutes (thirty-minute operating reserves). If a forward reserve resource is not able to supply energy when needed, it must pay a penalty. The size of the penalty is directly related to the degree of reserve shortage that exists at the time when delivery failure occurs (the greater the shortage, the greater the penalty). All costs related to compensating resources in the FRM are allocated to load based on real-time load obligations (RTLO).

The FRM is intended to provide a price signal to attract new entry to the marketplace and to aid in generator-owner decisions to modify or retire units. The strike-price feature targets flexible resources with high variable costs – the units that can provide reserves most economically.

8.2. Forward Reserve Market Auction Results

The ISO cleared the first FRM auction on December 8, for the reservation period January to May 2004. The auction results (which apply to the January to May 2004 period) are in Table 9:

Table 9 - Results Summary For First Forward Reserve Auction

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)
1,908.039	1,623.896	4,495.00	1,565.5	252.0	4,495.00

The clearing price of $4,495/MW-month is approximately 70% of the estimated carrying cost of a new combustion turbine in New England[25] and may be adequate to finance some marginal improvements at individual plants if the results are sustained over time. Prices for both products were the same because the auction received many 10-minute forward reserve offers that were cheaper than 30-minute forward reserve offers Therefore, 10-minute forward reserve resources substituted for 30-minute forward reserve. Even though the underlying 30-minute requirement was 150% of the 10-minute requirement, the auction cleared 30-minute megawatts that were only 15.5% of the 10-minute megawatts cleared.

8.3. Conclusions

The level of participation in the initial auction was adequate. Participation by internal combustion units (ICUs) was nearly universal. Hydro units participated but only if they had significant storage. The level of participation by available peaking capacity on thermal units was modest. Because the first auction of a new product is often perceived as more risky than subsequent auctions, no conclusions concerning participation can be drawn. The ISO will continue to report on the Forward Reserve Market in its market reports and in its Wholesale Markets Plan as ancillary service markets evolve under SMD.

[25] A study of the levelized annual cost of constructing a new peaking resource in New England was performed by e-Acumen Advisory Services (e-Acumen) in 2001. That study, which is available on the ISO web site at: http://www.iso-ne.com/special_studies/2001/, estimated that cost to be $6,150/MW-month.

9. Capacity Market

9.1. Overview of the Capacity Market

In the Capacity, or ICAP, Market, generators receive compensation for their investment in generating capacity in New England. Load-serving entities, the market participants responsible for serving demand, make ICAP payments to generators across New England as an incentive to generators to ensure sufficient capacity is available for reliable operation of the bulk power grid.

New England installed capacity requirements are calculated each year based on the Northeast Power Coordinating Council (NPCC) resource adequacy standard and, with input from participants, are converted by the ISO into reliability requirements for the New England Control Area. The market commodity for suppliers offering to provide this service adjusts the unit's installed capability rating to reflect the probability that a resource will be unavailable to serve load due to forced outages. The adjusted value of a resource is referred to as unforced capacity or UCAP. Two resources may have the same installed capacity rating, however the resource with a low forced outage rate will have more of the UCAP commodity to sell. The UCAP requirements are then allocated to participants who are responsible for serving load based upon 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 Quebec Interconnection Capability Credits, or purchase of UCAP in either of the supply or deficiency auctions administered by the ISO.

The ISO conducts a supply auction at the middle of each month as one method for participants to transact UCAP for the succeeding month. If, after the supply auction, the ISO determines that any load-serving participant has failed to procure sufficient UCAP to cover its monthly requirement, the ISO will conduct a deficiency auction. Participants are required to offer any UCAP in excess of their UCAP requirement in the deficiency auction. If a participant is still deficient after the deficiency auction, the participant must pay a deficiency charge.

9.2. Capacity Market Results

Table 10 shows the clearing prices for the ICAP Market auctions during the April-December period, along with deficiency quantities during the January-March period.

Table 10 – ICAP Market Summary for 2003

Obligation Month	Supply Auction Cleared (MW)	Supply Auction Clearing Price ($/MW-Month)	Deficiency Auction Cleared (MW)	Deficiency Auction Clearing Price ($/MW-Month)
January-03	n/a	n/a	62.550	$4,870.00[26]
February-03	n/a	n/a	12.800	$4,870.00
March-03	n/a	n/a	44.210	$4,870.00
April-03	310.310	$400.00	204.271	$0.00
May-03	1,125.497	$150.00	15.448	$0.00
June-03	780.545	$200.00	1,206.563	$0.00
July-03	558.526	$200.00	666.859	$0.00
August-03	676.491	$230.00	351.435	$0.00
September-03	1,203.753	$195.00	291.945	$0.00
October-03	684.081	$120.00	731.827	$0.00
November-03	906.892	$111.00	479.816	$0.00
December-03	959.743	$87.00	937.758	$0.00

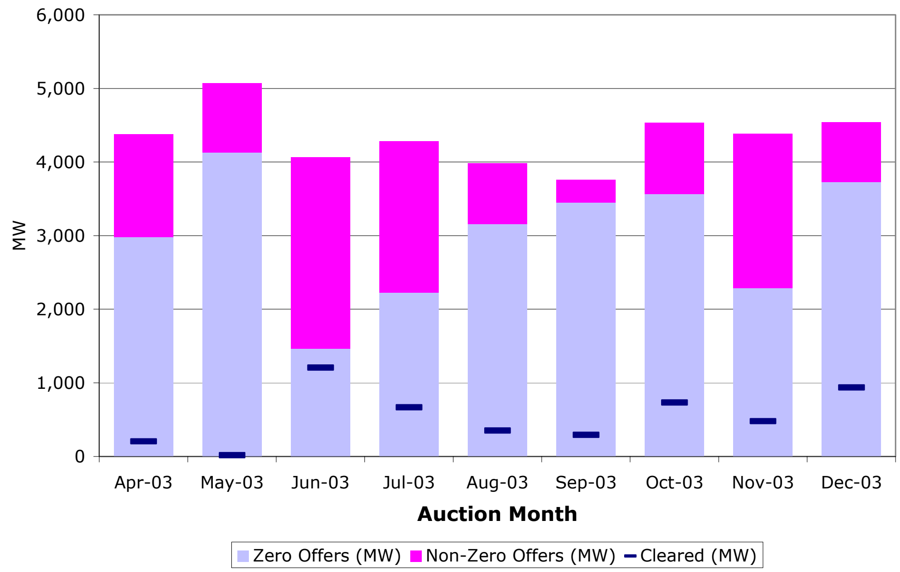
Most ICAP Market requirements are met through self-supply or bilateral contracts, and small amounts are traded through the supply and deficiency auctions. Over the April through December obligation months, approximately 95% of the Pool Capability was met by participants who owned entitlement to capacity or procured it bilaterally. Over the period, a MW-month quantity equivalent to about 3% of the Pool Capability transacted in the supply auction, with the remaining 2% obtained in the deficiency auction.

Analysis of the deficiency auction is aided by Figure 22. Participants who have excess capacity at the time of the deficiency auction but do not submit an offer price with it have their excess offered for them at a value of $0.00/MW-month. An average of over 4,300 MW of surplus ICAP was offered into the deficiency auctions during the period, with an average of close to 3,000 MW being offered at $0.00. A zero offer is a strategy employed by an auction participant to collect the auction clearing price for the commodity. The risk of this strategy is illustrated in the figure. If the sum of capacity offered at $0.00 is more than the sum of participant deficiencies, the auction clears at $0.00/MW-month. The June deficiency auction came within 260 MW of producing a non-zero clearing price, but the system-wide surplus of capacity, coupled with the zero-price offers, prevented any deficiency auction held during 2003 from producing a non-zero result.

[26] Before the March 2003 Obligation Month, participants that were deficient in their ICAP obligation paid an administrative penalty of $4,870/MW-month.

Figure 22

ICAP Deficiency Auction Quantities, 2003



9.3. Conclusions

The New England electric markets, which currently lack markets for reserves and include mandated energy offer caps, need a system capacity requirement to ensure reliable power system operations. The New England system as a whole currently enjoys a surplus of generating capacity and, in a market environment, this translates into low prices for capacity. As such, capacity market revenue currently provides very little contribution to fixed costs for generator owners and sends a signal that investment is not needed. The ISO has analyzed incentives for market entry, and its supporting analysis is presented in Section 12.6 of this report.

While aggregate supplies are ample and the system-wide investment signal is appropriate, certain constrained areas of the system are barely reliable and are dependent on generators that have applied to deactivate or retire. This results in the use of Reliability Agreements and dramatically mutes the investment signal both to repower older, environmentally-challenged units and to attract investment in new, cleaner units and peaking capacity. Incentives for the development of new capacity in constrained areas are weak because the current ICAP Market does not reflect the locational reliability value of capacity to provide either energy or reserves where needed.

After extensive stakeholder efforts to develop a proposal, on March 1, 2004, the ISO filed its Locational ICAP Proposal as directed by the Commission. The proposal addresses two of the Commission's primary concerns in the Devon Order; namely, the lack of a locational component in the capacity market and the over-reliance on Reliability Agreements. The proposal includes a locational element intended to value capacity appropriately by area and to provide incentives for new entrants to invest where needed. Also, a downward-sloping demand curve was included to address the binary pricing issues associated with the current vertical demand curve.

On June 2, 2004, FERC issued an order deferring implementation of the ISO's locational capacity proposal until January 1, 2006. In the order, FERC agreed with two broad concepts in the ISO's proposal. First, FERC accepted the ISO's concept of a demand curve approach but set the matter for hearing to obtain further information. Second, FERC found it appropriate to establish ICAP regions but was concerned that the specific regions proposed by the ISO do not adequately reflect where infrastructure investment is needed, especially with regard to the constrained area of Southwest Connecticut (SWCT).

The ISO will participate in the FERC settlement process for LICAP to improve the capacity market design. The ISO will work toward a final market design that sends price signals that attract and retain the resources necessary to ensure both short and long-term reliability in all locations in New England.

10. Reliability Agreements

10.1. Overview of Reliability Agreements

Under defined circumstances, certain generating units are eligible to enter into contracts with the ISO, referred to in the market rules as Reliability Must-Run or Reliability Agreements. These Reliability Agreements reflect a determination by the ISO that these generating units are needed to maintain system reliability within the areas in which they are located and will be required to run out-of-economic merit order during transmission constraints and for voltage support, operational reserves, or other reliability reasons. These contractual arrangements, which are subject to FERC approval, provide financial support to ensure that such units will be available. Under SMD, Reliability Agreements are paid for by load in the zone in which the generating units are located.

In a series of orders during 2003 and early 2004, the FERC rejected the widespread use of Reliability Agreements as a tool to provide cost recovery to generating facilities that must run to ensure reliability because the unit's fixed costs are recovered through payments outside of the market. As a short-term measure, FERC directed the ISO to establish the PUSH bidding mechanisms and then, as a long-term measure, to work toward a locational capacity or similar market mechanism. While the FERC's settlement order of June 3, 2004 in the locational capacity docket provides for the limited continuation of reliability agreements, their goal remains to limit the use of Reliability Agreements to unique, special circumstances, not to compensate for the lack of a locational component in capacity markets. The extent of the phase out of the use of special contracts to ensure reliability depends on the manner in which locational markets for capacity and reserves are implemented and with actual experience after implementation.

10.2. Previous Reliability Agreements

During 2002, the ISO entered into a Reliability Agreement with the New Boston station (Units 1 and 2) in the NEMA/Boston load zone and another with the Devon station (Units 7, 8 and 10) in the Connecticut load zone. Both of these contracts were in the cost-of-service form, whereby the generator recovers its fixed costs in a fixed monthly payment and its variable costs through energy offers made at short-run marginal cost. All revenues received in excess of variable cost, including capacity revenues, serve to reduce the monthly fixed cost payment. Thus, the generator recovers no more than its fixed and variable costs.

As provided for in the agreement with the New Boston station's owner, one unit at New Boston station (Unit 1) was allowed to retire on July 1, 2002. However, because Unit 2 was disabled by fire, the No. 1 Unit replaced the disabled unit and remained under contract during all of 2003. The New Boston Unit 1 Agreement has been extended to December 31, 2006, unless terminated earlier by the ISO. Unit 1 is required for reliability until the projected completion of certain transmission projects during 2006.

Under the terms of the agreement with the Devon station's owner, Unit 10 was allowed to deactivate on October 1, 2002. Units 7 and 8 were under contract for all of 2003. In October 2003, the Agreement covering both units was extended. The ISO terminated Unit 8's portion of the Agreement effective April 27, 2004, because one of the two units was no longer needed for reliability due to the availability of new generation in the local area. It is expected that the Agreement will terminate completely on October 1, 2004, when additional new generation is anticipated to be in service in the local area.

10.3. Reliability Agreement Activity During 2003

In early 2003, certain affiliates of NRG and PPL filed cost-of-service Reliability Agreements for FERC approval. With respect to NRG, FERC approved only the Reliability Cost Tracker portion of NRG's proposal so that seasonal maintenance outages, including projects that had been deferred in previous years, could be undertaken for all units at Middletown, Montville and Norwalk Harbor Stations and for Devon 11 - 14.[27] By means of this cost tracker, NRG has been reimbursed the actual cost of materials and services procured from third parties for minor and major operations and maintenance items. The initial term of the cost tracker was February 27, 2003 through March 31, 2004. NRG filed to extend this arrangement for an additional year, but FERC extended it only until the effective date of a Locational ICAP (LICAP) market. There are rehearing requests pending.

As an alternative to continued reliance on Reliability Agreements, FERC established the Peaking Unit Safe Harbor (PUSH) supply offer mechanism, to be effective from June 1, 2003, until the implementation of a "locational capacity or similar market." The PUSH mechanism was implemented to allow peaking units in Designated Congestion Areas with capacity factors of 10 percent or less during 2002 to increase their bids above variable cost to allow them the opportunity to recover their fixed costs through a market mechanism. The results of PUSH implementation are discussed in Section 11.3 of this report.

10.4. Reliability Agreement Costs

The cost of Reliability Agreements to load for the year 2003 is presented in Table 11. For New Boston and Devon 7 and 8, these payments are net of revenues in excess of variable costs. On April 7, 2004, NRG filed its required true-up of the cost tracker for 2003, indicating an over-recovery of almost $11.3 million. This over-recovery was never actually paid to NRG as those funds were held in escrow by the ISO in accordance with FERC orders. The over-recovery will be refunded to load in the Connecticut zone subject to the provisions of the escrow agreements and FERC orders.

Table 11 – 2003 Reliability Agreements, Net Cost

New Boston	Devon 7 & 8	NRG Reliability Cost Tracker	CT Total	All Reliability Agreements
$29,755,747.94	$11,540,830.36	$42,952,713.00	$54,493,543.36	$84,249,291.30

10.5. Conclusions

FERC has ordered that Reliability Agreements should terminate immediately upon the implementation of a locational capacity mechanism or regional deliverability requirement. While FERC has accepted Reliability Agreements, they remain committed to the implementation of a market-based mechanism to appropriately compensate generators providing reliability services. The agreements are intended to ensure that generators needed for reliability are adequately recovering revenues until a permanent market-based solution is in place and that the generation covered by these contracts will be part of the functioning locational capacity market that will develop in New England.

[27] On January 16, 2004, NRG again filed cost-of-service Reliability Agreements for approval at FERC for Middletown, Montville and Devon 11-14. ISO agreed to enter into these as a stop-gap measure, with the contracts to expire 90 days after LICAP implementation. FERC accepted the Agreements, subject to refund, but set them to expire upon LICAP implementation. Rehearing requests are pending.

11. Market Monitoring and Mitigation

11.1. Overview of Monitoring and Mitigation Activities

Market Rule 1, Appendix A, *Market Monitoring, Reporting and Market Power Mitigation,* provides for the monitoring and, in specifically defined circumstances, the mitigating of behavior that interferes with the competitiveness and efficiency of the Energy, Regulation, and Operating Reserve markets. As specified in the rule, the ISO monitors offers for the market impacts of specific bidding behavior. Whenever one or more of a participant's offers or declared unit characteristics (1) exceed specified offer thresholds, (2) exceed market impact thresholds, and (3) are not explained by the participant as consistent with competitive offer behavior, the ISO substitutes a Default Offer in place of the offer submitted by the participant.

The ISO's intervention in the market was limited in 2003. During the 10-month period of March-December, there was generally limited congestion in the Day-Ahead Market and Real-Time Market. Congestion mitigation was triggered four times during the period – once in April, twice in May, and once in June. Under Market Rule 1, Appendix A, Section 8.2.2, on December 4, 2003, the ISO (in conjunction with its Independent Market Advisor), suspended a participant's authority to submit virtual bids at a particular node. The suspension was in response to a pattern of bidding behavior by the participant that contributed to a persistent deviation between day-ahead and real-time LMPs, which the ISO determined would not be expected under a workably competitive market. In addition to these specific actions, the Market Monitoring Department has daily discussions with individual participants concerning specific market behavior.

11.2. Resource Audits

Under Market Rule 1, Appendix A, Section 4.2.2, the ISO is authorized to verify forced (unplanned[28]) outages. This allows additional monitoring for physical withholding of a resource.

The ISO uses all available data to determine if a plant inspection is warranted. If the determination is made that a plant inspection is appropriate, the ISO contacts both the plant management and the lead participant to coordinate access to the plant to visually inspect the reported cause of the forced outage.

If the plant inspection results in findings that suggest physical withholding of the resource has taken place, further contact is made to obtain any additional information that may be appropriate. Once the review is completed, if physical withholding has taken place, sanctions may be imposed as outlined in Appendix B of Market Rule 1.

During the year, there were two instances in which the ISO determined that a plant inspection was warranted as a result of monitoring for potential physical withholding of a resource. The inspections yielded the conclusion that no physical withholding had taken place.

11.3. Peaking Unit Safe Harbor (PUSH) Bidding

On June 1, 2003, the ISO implemented the PUSH offer rules, allowing owners of low capacity-factor units (less than 10% annual capacity factor) in Designated Congestion Areas (DCAs) to include levelized fixed costs in their electric energy offers without risk of mitigation. The rules are intended to increase opportunities for fixed cost recovery and to produce signals for investment through higher LMPs in these areas during periods of scarcity.

[28] Defined by OP-5 as an unplanned/unexpected outage or derating that cannot be delayed and interrupts operation of the machine.

On December 4, 2003, the ISO filed with FERC a report entitled *A Review of PUSH Implementation and Results,* prepared by the ISO's Market Monitoring Department, along with the ISO's management response to the recommendations contained in the report.[29] The PUSH Report finds that while PUSH units ran frequently during the summer of 2003, they set LMPs for only 3% of their on-line hours despite being relatively expensive resources. PUSH units are often dispatched out of merit to provide local reserves and not as part of the system-wide economic dispatch.

The PUSH Report recommends that the ISO continue its efforts to reduce out-of-merit dispatch, and replace the PUSH rules as soon as practicable with a mechanism that signals the need for investment in areas of capacity shortage. In this regard, the ISO continues to participate with FERC toward the implementation of a locational capacity approach and the design of an ancillary services (reserves) market. The report also recommends a review of the allocation of real-time ORC payments that are currently in the stakeholder review process.

[29] *See* Review of PUSH Implementation and Results, FERC Docket No. ER03-563-002 (filed December 4, 2003).

12. Analysis of Competitive Market Conditions

This section presents analyses of competitive market conditions during 2003. It includes analyses of market share, outages, pricing efficiency, and market entry.

12.1. Herfindahl-Hirschman Index – System and Areas

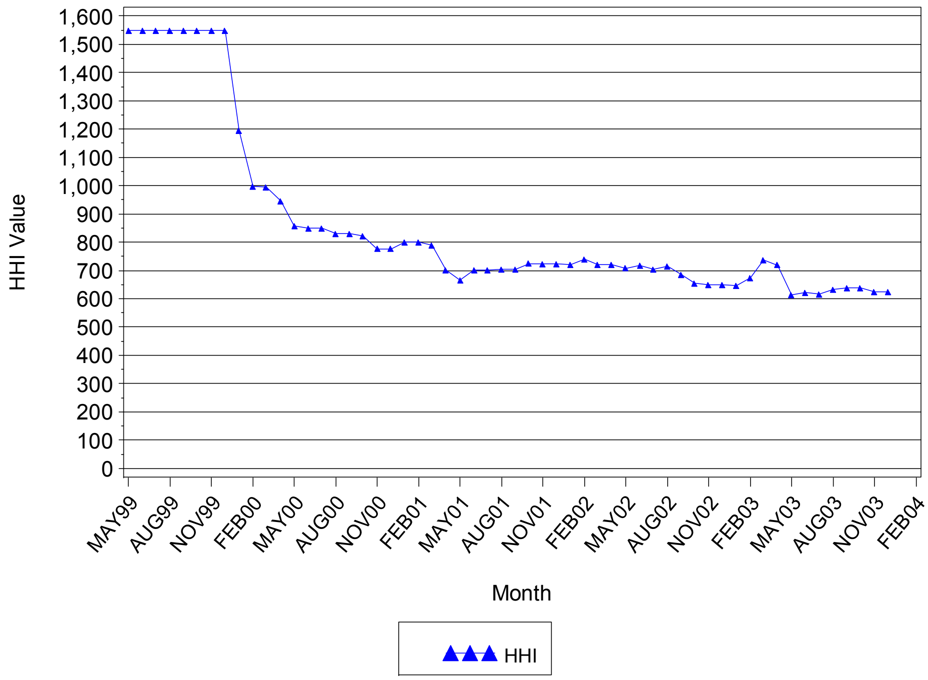
Market concentration is a function of the number of firms in a market and their respective market shares. One measure of market concentration is the Herfindahl-Hirschman Index ("HHI"). The HHI is calculated by summing the squares of the individual market shares of all market participants. The HHI reflects 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.

HHI is not a sufficient indicator of market concentration in wholesale electricity markets. No measure of the overall supply/demand balance is captured in the calculation. Contractual entitlements to generator output are not reflected in the HHI calculation, which may tend to overstate concentration. Also, HHIs ignore the effect that transmission constraints can have on the market. Load pockets that result from these constraints may be less competitive than the system-wide HHI would suggest.

Market concentration measured by HHI may be divided into three regions that can be broadly characterized as unconcentrated (HHI below 1000), moderately concentrated (HHI between 1000 and 1800), and highly concentrated (HHI above 1800). Although the resulting classifications provide a framework for market concentration analysis, they are imprecise. Although a low concentration index does not guarantee that a market is competitive, higher values are indicative of greater potential for the exercise of market power by participants.

Figure 23 shows the HHI for New England internal resources based on summer capabilities and lead participant responsibilities (for offering the unit to the market). The values shown were developed from participant information collected by the ISO Market Monitoring Department. The market-wide HHI shows a steady decline from the opening of wholesale electricity markets in New England, with a slight up-tick in the winter of 2002/2003 (due to the assignment to a participant of certain generators that were previously unclassified), and a slight upward movement during the third quarter of 2003 due to the commencement of commercial operation of a large generating facility owned by an existing participant.

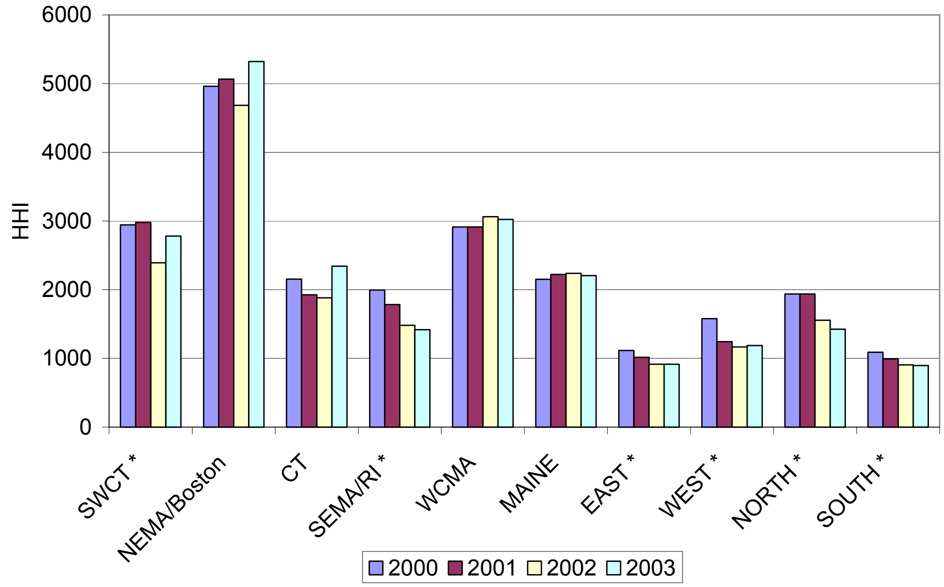
Figure 23
Herfindahl-Hirschman Indices (HHI)
May 1999-December 2003



The ISO analyzes HHIs for both SMD load zones and transmission areas as part of its market assessment and reliability functions. Figure 24 shows the HHI for selected load zones and transmission areas within New England. While several areas show decreases in the area-specific HHI over the four years, the NEMA/Boston and WCMA load zones, along with the Southwest Connecticut transmission area, have the highest HHIs, indicating the highest potential for market power concerns.

Figure 24

HHI for Selected Load Zones and Transmission Areas



* Denotes transmission area.[30]

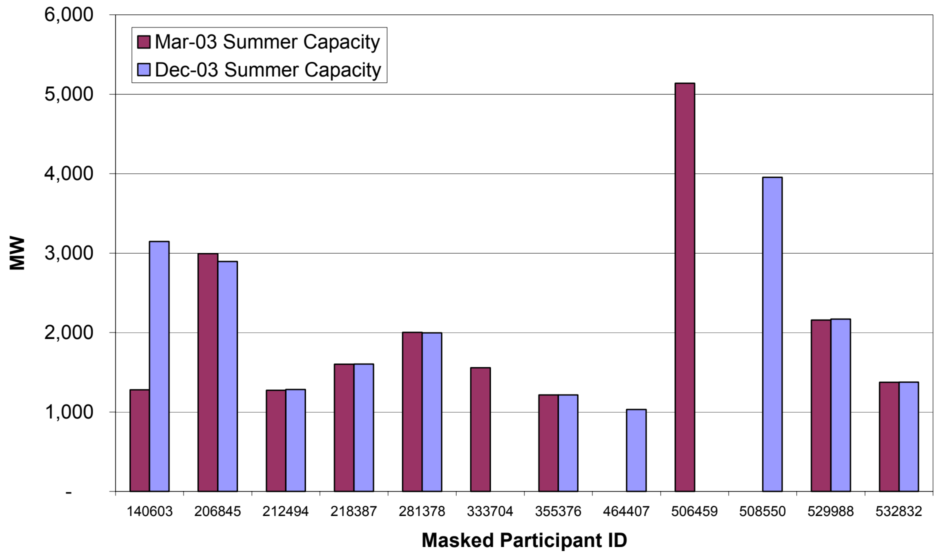
12.2. *Market Share by Participant Bidder*

Figure 25 shows generation capability for the 10 lead participants with the largest portfolios on March 1, 2003, and December 31, 2003. At year's end, the size of the largest generation portfolio was 1,100 MW smaller than it was on March 1. This indicates slightly more dispersion in the ownership of generation in the marketplace and is consistent with the trend observed in the overall HHI analysis.

[30] Areas in the figure shown with an asterisk (*) are transmission areas (defined by major transmission interfaces) rather than load zones. The southwest Connecticut interface separates that area from the remainder of Connecticut and New England. The SEMA/RI transmission interface separates those two load zones from the remainder of the system. The North/South transmission interface separates the majority of Vermont, New Hampshire, and Maine from Massachusetts, Rhode Island, and Connecticut. The East/West interface separates Vermont, Western Massachusetts and Connecticut from the remaining areas to the east.

Figure 25

Generation Capability by Lead Participant

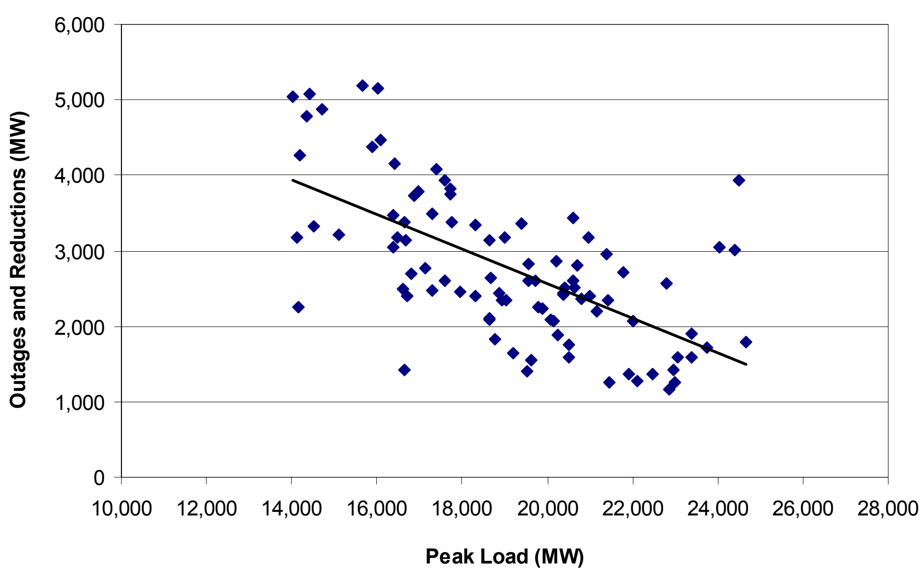


12.3. Outages and Reductions vs. Demand Levels

Figure 26 shows total generating unit capability reductions and outages at the time of the peak hour compared to actual peak demand during June through August 2003. This time frame represents the summer peak demand period. Importantly, there are generally few planned outages during the summer months so the data represent primarily forced and unplanned outages. The figure includes a simple regression line showing a least-squares fit to the data.

Figure 26

Outages and Reductions vs Daily Peak Load
June - August 2003



The scatter plot illustrates that as demand levels increase, reductions and outages tend to decrease. This suggests that the markets are providing the proper incentives to make units available when they are most needed and that the ISO is scheduling short-term outages appropriately.

12.4. Residual Supply Index

The Residual Supply Index (RSI) measures the percentage of load that can be met without the largest supplier and is computed as RSI = (total supply minus largest seller's supply)/(total demand). The RSI measures the potential for individual bidders to influence the market-clearing price. 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, however, the RSI exceeds 100%, then alternative suppliers have sufficient capacity to meet demand.

A pivotal supplier can 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 (i.e., non-pivotal) suppliers is price-elastic. The RSI, like the HHI, is an indicator of market competitiveness. However, the RSI is regarded as a more robust indicator for electricity markets which are characterized by rapidly changing market conditions with continuous balancing of essentially non-storable supply and inelastic demand. Studies conducted by the California ISO[31] suggest an inverse relationship between the RSI and the price-cost mark-up, which is the market metric developed in the competitive benchmark analysis (described later in this report).

On July 9, 2003, in Docket No. ER03-849-000, FERC accepted the ISO's request to implement a pivotal supplier trigger that would provide for the evaluation of pivotal suppliers' energy supply offers for mitigation. [32] 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. The calculation of RSI, which is consistent with the requirements outlined in the Order, is presented below.

Table 12 shows the number of hours in each month in 2003 during which the RSI was below 100% and below 110% .[33] RSIs are generally lowest during high demand periods. This analysis shows that pivotal suppliers existed during a limited number of hours in 2003. The number of hours with low RSIs is somewhat lower than observed in previous years. This is due to a relatively mild summer and new capacity additions. Only 18 hours had values below 100, and these hours occurred in a total of only three days when New England was experiencing high demands due to warm weather. This is consistent with other analyses that show relatively good market performance. The RSI analysis presented here is somewhat conservative and may overstate the number of hours with one or more pivotal suppliers. The analysis does not take into

[31] 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 (Accessed May 28, 2004).

[32] 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, no matter how high the offer price, to maintain reliability. 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. FERC directed the ISO to include in its market reports (per Market Rule 1, Appendix A, Section 11.2.2), for one year following implementation of the pivotal supplier trigger, information regarding all instances of mitigation of pivotal suppliers, as discussed in the order.

[33] For the RSI analysis, total supply was defined as the month's seasonal claimed capability derated by 8% + net imports. Total demand before SMD was defined as: [Electrical Load – under 5 MW generation + AGC + requirements for operating reserves]. Total demand under SMD is defined differently. Since each participant has a market position at each location on the system, adjusted real-time load obligation forms the basis of the calculation. Adjusted real-time load obligation is the sum of metered load at a location plus any scheduled exports, plus the net effect of any transactional quantities at a location. Thus, the equation for total demand for the RSI analysis under SMD is expressed as [adjusted real-time load obligation + AGC + requirement for operating reserves].

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.[34] The ISO will continue to monitor and assess the existence and influence of pivotal suppliers on the market.

Table 12 - Residual Supply Index, May 1999 and All Months in 2003

	Number of hours RSI < 110	Number of hours RSI < 100	Average monthly RSI	Maximum RSI	Minimum RSI
Beginning of Markets: May 1999	248	18	121%	169%	95%
January 2003	10	0	141%	188%	105%
February 2003	0	0	155%	204%	115%
March 2003	11	0	138%	180%	105%
April 2003	25	0	134%	175%	106%
May 2003	2	0	145%	186%	109%
June 2003	30	7	155%	205%	95%
July 2003	27	11	137%	179%	96%
August 2003	22	0	139%	198%	101%
September 2003	18	0	144%	204%	102%
October 2003	9	0	135%	179%	108%
November 2003	1	0	137%	178%	110%
December 2003	6	0	143%	189%	101%
Total – 2003	**161**	**18**	**142%**	**205%**	**95%**

[34] See Newbery.

12.5. *Competitive Benchmark Analysis*

12.5.1. Introduction

In 2002, the ISO's Market Monitoring Department developed a tool ("the ISO model") for conducting competitive benchmark analyses. The ISO model is designed to evaluate the competitive performance of New England's wholesale electricity markets as Bushnell and Saravia did in 2002.[35] This tool is used 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 efficiently. The benchmark price accounts for production costs (including environmental costs and variable O&M), unit availability, and net imports. It thus represents the estimated incremental costs associated with the least expensive unit that is not needed to serve demand in a given hour.

The ISO model for this Report ("the 2003 ISO model") compares the benchmark price to two other measures of the wholesale market price: (a) the ISO's reported ECP prior to March 1, 2003 and the real-time LMP at the Hub ("RT Hub LMP") from March 1, 2003 onward (together "the system-wide Energy Clearing Price"), and (b) the price at which market demand intersects the aggregate supply curve from all generating units' price bids ("bid-intercept").

12.5.2. Methodology

The 2003 ISO model closely follows the methodology used by Bushnell & Saravia, with the exception of the modeling of unit availability. The model derates each unit's high operating limit (HOL) by its historical forced outage rate while Bushnell & Saravia modeled unit availability using Monte Carlo simulation techniques. Due to the convexity of the supply curve, the 2003 ISO model will systematically understate the benchmark price, thereby producing a more conservative result.

The 2003 ISO model features several updates to the model used in the 2002 Annual Markets Report. These improvements include:

- More reliable information regarding transportation costs for various fuels;
- Recognition of lower unit availability during a generator's first and second years of commercial operation;
- Improved modeling of generation asset additions and retirements during the year; and
- Using the real-time Hub LMP as a proxy for a system-wide energy clearing price for the energy market, beginning on March 1, 2003.

12.5.3. ISO Competitive Benchmark Model Results

The metric used to compare these market price measures is the Quantity-Weighted Lerner Index ("QWLI"). The conventional Lerner index, defined as the price-cost margin in percentage terms,[36] is widely used to assess the competitiveness of market outcomes. The QWLI weights each hour's Lerner index by total system-wide load. The QWLI is more appropriate than a simple arithmetic average of the hourly Lerner Index because load varies hourly.

Table 13 compares the competitive benchmark price estimates for 2002 and 2003 with the system-wide Energy Clearing Price in 2002 and 2003, as well as the aggregate bid-intercept prices for 2002 and 2003.

---

[35] James Bushnell and Celeste Saravia, *An Empirical Analysis of the Competitiveness of the New England Electricity Market*, University of California Energy Institute, January 2002. The study report can be found at http://www.iso-ne.com/special_studies/Other_Special_Studies/.

[36] Lerner Index = (P- MC)/P, where: P = Price and MC = Cost of Marginal Resource.

Table 13 – ISO Model Market Price Measures, 2002 and 2003

Price Measure	2003 Price ($/MWh)	Quantity-Weighted Lerner Index	
		2002	2003
Competitive Benchmark Price	48.10		
Energy Clearing Price (Real-Time Hub Price as of March 1,2003; ECP prior to March 1, 2003)	52.91	11%	9%
Aggregate Bid-Intercept Price	46.03	6%	-4%

The model results suggest that the market continued to behave competitively through 2003. The QWLIs are somewhat lower than those estimated for 2002. This result could be due to a number of factors, including the introduction of SMD, the dispatch of PUSH units out-of-merit at their Economic Minimums to provide local reserves[37], and additional large gas-fired units placed into service during 2003 that created a larger number of hours during which minimum generation conditions prevailed.[38] These QWLIs indicate that the New England markets continue to be workably competitive.

Benchmark analysis will continue to play an important role in diagnosing the potential for the exercise of market power in the SMD environment. In its role as market monitor, the ISO intends to update this benchmark assessment over time to maintain its usefulness in providing timely diagnostic information.

12.5.4. Conclusion

The analyses conducted show that New England's wholesale power market has been workably competitive since the beginning of the markets and continued to be competitive in 2003. The continued competitiveness is consistent with the increase in generation capacity during 2003 and with the analysis of net revenues and market entry that follows in Section 12.6.

12.6. Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit entering the market. In the long run, the revenues from the energy, capacity, and ancillary services markets must cover the costs of a 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 non-variable 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 estimates of capacity and ancillary services revenue.

---

[37] Units dispatched at economic minimum are generally ineligible to set nodal LMPs, so the LMPs are lower than they would be if these units were part of the system-wide price-setting. See ISO New England Market Monitoring Department (2003) *A Review of Peaking Unit Safe Harbor (PUSH) Implementation and Results.*

[38] Bushnell, Mansur and Saravia (2004) find in a study of the California, PJM and New England markets that another explanation for the negative QWLIs is the presence of suppliers who are also large load aggregators who exercise monopsony power. While out-of-merit operation may be one driver of the New England outcome observed, the authors failed to reject the hypothesis that vertical integration of generation owners and retail suppliers who are overall "net buyers" also contributes to negative QWLIs in New England. This study covers the May 1999-September 2001 period; The Market Monitoring Department is investigating the extent to which this continues to be true. See Bushnell, Mansur and Saravia "Market Structure and Competition: A Cross-Market Analysis of U.S. Electricity Deregulation", UCEM Working Paper WP126. http://www.ucei.berkeley.edu/PDF/csemwp126.pdf (Accessed April 1, 2004).

Figure 27 shows the net revenue from electric energy for a hypothetical generator bidding one (1) MW into the energy market at various price points. Net revenue was calculated using the ECP for hours in the Interim Markets period and the real-time Hub LMP for hours in the SMD period. It was assumed that the generator ran in every hour in which the electric energy price was equal to or greater than its bid. Net revenue was calculated by subtracting the bid from the electric energy price for each hour, and this value was summed over the year.[39] This calculation was performed for each bid point shown in the graph.

Figure 27

Net Revenue from Energy at Various Bid Points
Calendar Years 2000, 2001, 2002, 2003

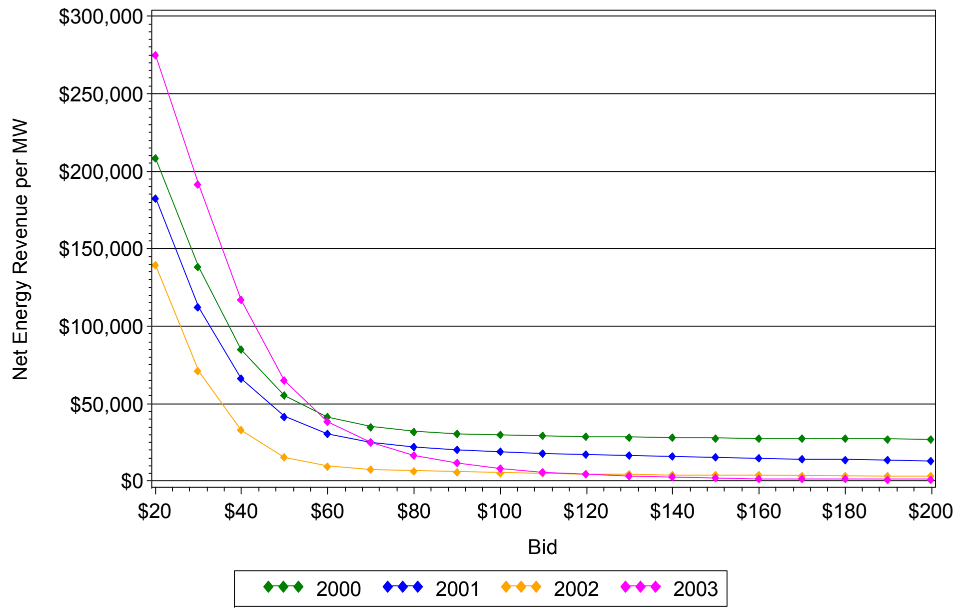


Figure 27 shows that a unit with variable costs of $40/MWh that ran whenever prices exceeded that level would have received approximately $120,000/MW in net revenue from New England's electric energy market in 2003. A New England generator with variable costs of $30/MWh (approximating a coal unit in New England) would have earned approximately $190,000/MW in net energy revenues in 2003. Note that it is only appropriate to calculate net revenues using this methodology for units or contracts with stable costs over time such as nuclear, hydro, and coal generators.

Table 14 presents an estimate of net revenues for hypothetical generators in New England during 2003. Daily marginal costs are calculated using spot fuel prices, the assumed heat rates, and other production costs, for each hour for a representative combined-cycle, natural gas-fired plant with a heat rate of 6,800 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 that the price was above its marginal cost. Under these assumptions, the combined-cycle plant would have earned about $74,000/MW during 2003, while the combustion-turbine plant would have earned approximately $12,000/MW. For purposes of this analysis, unit outages and physical operating parameters are ignored.

The anticipated annual non-variable costs of a new combined-cycle plant in New England, which include fixed O&M, taxes, depreciation, debt repayment, and a competitive return on investment, are in the range of $100,000/MW to $125,000/MW. The corresponding values for a combustion-turbine plant are in the

[39] This assumes that the generator is a price-taker, bidding its marginal cost.

range of $60,000/MW to $80,000/MW.[40] These calculations, therefore, suggest that neither of the plants burning natural gas at the delivered spot price in 2003 would have recovered its annual fixed costs plus a return on investment from energy market revenues alone. In fact, the net revenue curve tends to overestimate the contribution toward generators' fixed costs and investment return since it ignores plant outages and other operational constraints that may prevent a plant from running in every profitable hour. On the other hand, this calculation underestimates revenues by excluding revenue sources such as ancillary services and capacity payments. Though ancillary market opportunities in 2003 were modest, capacity payments are estimated to be in the range of $2,000/MW, while ancillary service revenues are negligible. Table 14 summarizes these findings.

Long-run equilibrium analysis is not applicable to a single year in isolation since market outcomes will vary over time. Nevertheless, it appears that at 2003 electric energy prices and fuel costs, the hypothetical generators' net revenues were lower than the amount needed to cover a new entrant's fixed costs and competitive rate of return on investment. This observation is consistent with relatively robust reserve margins, the lack of announcements of new projects, few units in the early stages of construction, and the cancellation of some new generation projects.

Table 14 - Net Revenue for Hypothetical Generators

Generator	Marginal Cost	Heat Rate	2003 net revenue ($/MW-Year)	Annual Non-Variable Costs – New Unit
Generator X	$30/MWh		$190,000	
Generator Y	$40/MWh		$120,000	
Representative CC/Gas fired	Daily fuel cost times heat rate	6,800 Btu/KWh	$ 74,000	$100,000 – 125,000/MWh
Representative CT/Gas fired	Daily fuel cost times heat rate	10,500 Btu/KWh	$ 12,000	$60,000 – 80,000/MWh
Approximate revenue from capacity sales	$2,000 /MW			
Approx. ancillary services revenue	$0/MW			

In recent studies of the New England electricity markets, Dr. Paul Joskow of MIT also used a form of net revenue benchmark analysis to demonstrate that the energy markets do not provide sufficient scarcity rents to recover the annualized fixed costs (defined as amortized capital costs + fixed O&M) of a unit operating only during periods of scarcity. He concludes that, without enhancements, the existing New England electric energy and reserves markets are unlikely to provide the necessary incentives for investment in new generating capacity to maintain existing reliability levels. Although raising the offer cap could encourage this level of investment, Dr. Joskow cautions that this may simply increase incentives for the exercise of market power. Rather, he states, the proper policy is to develop market rules that facilitate prices rising to the existing offer cap during reserve-deficiency hours.[41]

[40] These estimates are intended to be the relevant annual returns required for an entity contemplating new generation investment.

[41] "*The Difficult Transition To Competitive Electricity Markets In The U.S.*", Joskow, Paul L., Ph.D., Prepared for the conference "Electricity Deregulation: Where From Here?" at the Bush Presidential Conference Center. Texas A&M University, April 4, 2003. http://econ-www.mit.edu/faculty/download_pdf.php?id=537 (Accessed June 2, 2004).

12.7. Summary of Analyses

Overall, the concentration of generation ownership in New England's wholesale markets continued its downward trend during 2003. Certain areas of the system, defined by transmission interfaces, continue to have somewhat high concentrations of unit ownership. Overall generation portfolio sizes decreased during the year as asset ownership changed. While this is generally favorable, there remain areas of the system where the lack of diversity in unit ownership necessitates continued oversight.

Large increases in available generating capacity over the last five years resulted in there being very few hours in which suppliers were pivotal. Outages and reductions in overall generating capacity decrease as demand increases, indicating that the market is generally delivering the proper price signal for availability. There still remain times, especially during high maintenance periods in the spring and fall, when unexpectedly high load levels or unit outages can create pivotal suppliers. Over time, as electricity demand plus reserves grow into the current surplus, there may be an increase in the instances of a pivotal supplier, indicating the need for continued vigilance.

While the system has an overall surplus of capacity, certain locations remain in need of capacity additions. Locational operating requirements (first and second contingency coverage, transmission stability) require post Day-Ahead Market commitment of generators by the ISO. These supplemental commitments suppress real-time prices in constrained areas, namely parts of Connecticut and NEMA/Boston. The muting of price signals in these areas encourages day-ahead underscheduling of load (Connecticut), masks the local area shortages, and delays or eliminates incentives for building capacity to address the shortages in these areas.

The current surplus, coupled with the general lack of high peak loads, kept pricing levels relatively moderate during 2003 (after adjusting for increases in input fuels). The competitive benchmark analysis indicates that the hypothetical "profit margin" for spot-market-only generators, which was modest last year, was lower still this year. This manifested itself in the Net Revenue and Market Entry analysis which shows that incentives for new entry, on a region-wide basis, are low.

The ISO is working to enhance locational price signals. FERC's settlement process for locational capacity markets in which the ISO is participating will result in a market design that provides better investment signals in all areas. A locational reserve requirement reflected in the market rules would also better value new demand and supply options in constrained areas. That, in turn, would enhance the efficiency of the market design as price discovery would lead to more efficient investment decisions.

13. Generating Unit Availability

In its continuing effort to monitor and analyze the availability of New England's generating units, the ISO's System Planning department routinely analyzes generating unit performance statistics on a periodic basis. Analysis of unit availability is important in assessing whether the market is providing the proper incentives for availability, a key factor in maintaining both reliability and market competitiveness. Historical generator availability is presented through 2003 to provide a more encompassing view of trends in unit performance.

Table 15 shows the annual Weighted Equivalent Availability Factors[42] (WEAF) of New England generating units for 1995 - 2003. As shown, availability decreased from 1995 to 1997 and then began increasing again to just above 1995 levels in 1999. The decrease during 1996-1998 can be attributed to the outages of two large nuclear units during this period. After the beginning of the wholesale markets in May 1999, the New England system WEAF increased to a high of 89% in 2002 and then fell slightly to 88% in 2003.

Table 15 - New England Annual WEAF[43]

New England System Weighted Equivalent Availability Factors (%)									
Year	**1995**	**1996**	**1997**	**1998**	**1999***	**2000**	**2001**	**2002**	**2003**
System Avg.	79	78	75	78	81	81	87	89	88

* 1999 represents May - December data only

Figure 28 illustrates how both the spring and fall months continue to have the largest number of outages, while the summer period has the smallest number. This figure shows total outages in megawatts for 2003 and the amount of capacity on outages as a percentage of total available capacity (summer claimed capability).

[42] The term "Weighted" means that averaging is proportional to unit size, so that a 100 MW unit counts ten times more than a 10 MW unit. "Equivalent" means that both deratings (partial outages) and full unit outages are counted, proportional to the megawatts that are unavailable.

[43] The statistics for 1995 through April 1999 were calculated from the NEPOOL Automated Billing System (NABS). NABS data are representative of conventional, cost-based system dispatch. The system captured actual run-time MW/hour information and outage information as defined in the billing rules. The data were used primarily by the NEPOOL Settlements Department for payment to the generators. Based on statistical analysis approved by the NEPOOL Power Supply Planning Committee, generators were allotted a certain number of maintenance outage weeks per year to perform "scheduled maintenance." If an outage ran over this amount, or was out-of-service any other time, it was considered "unplanned" or "forced." Statistics for May 1999 - 2003 were based on competitive, bid-based dispatch and calculated from a Short Term Outage Database. This database is populated by the ISO Forecast and System Planning Departments based on information received from generators, and records scheduled and unplanned outages as they occur in real time.

Figure 28

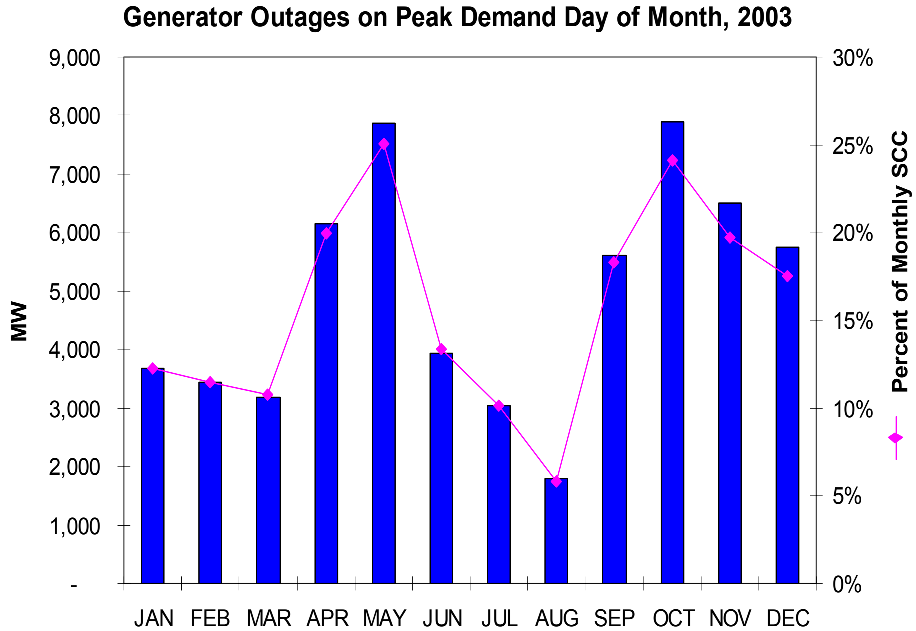


Figure 29 illustrates how the availability of the New England generating units tracks the monthly demand. Specifically, Figure 29 illustrates the monthly WEAF compared to the monthly peak demand. Similar to the information portrayed in Figure 28, the average availability for the New England generating units is lowest during the months that have the lowest demand. In contrast, when New England experiences the highest demand, the average availability of New England generators is the greatest.

Figure 29

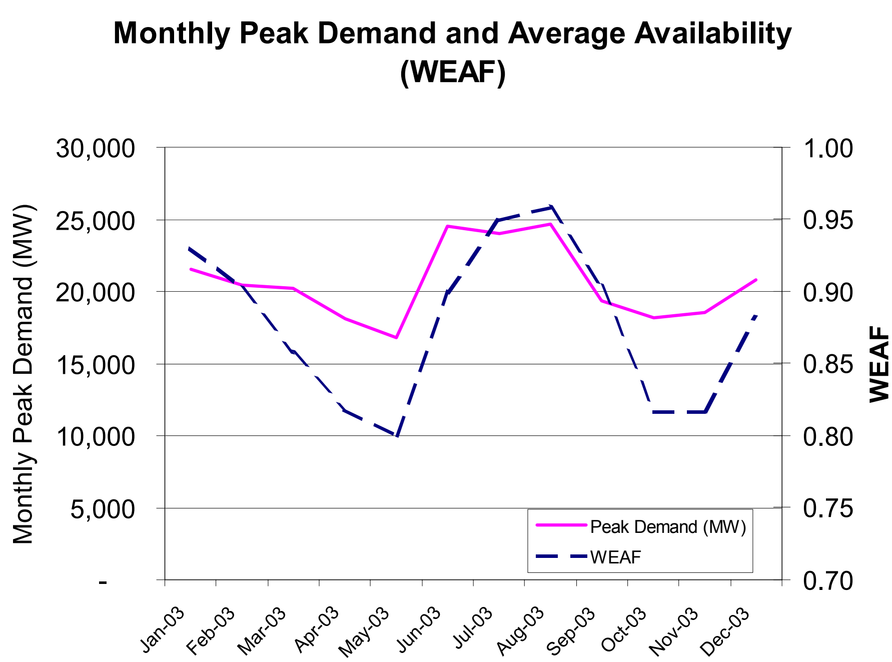
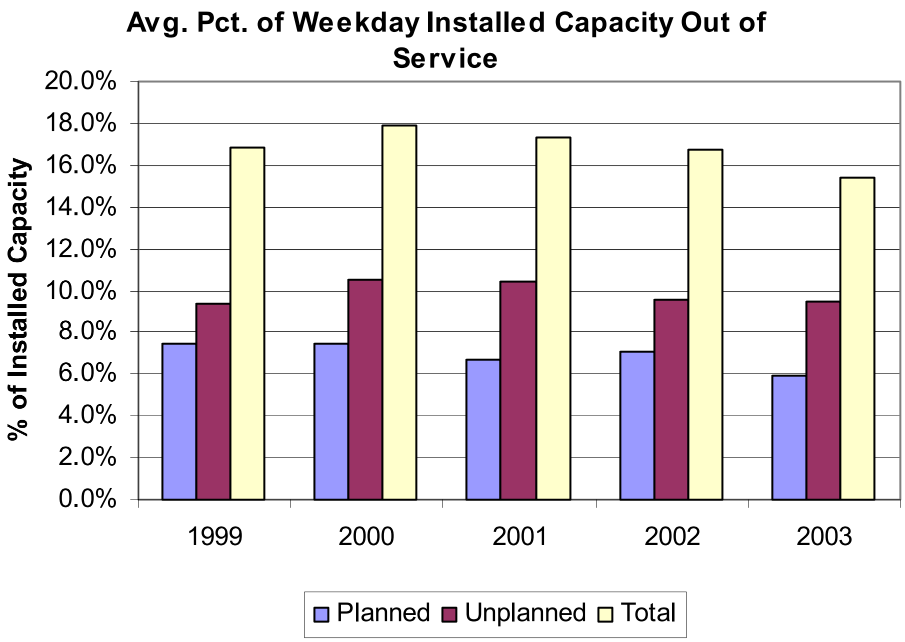


Figure 30 shows the percentage of installed generating capacity that was out-of-service over the peak hour on weekdays during the past 5 years. Overall, the average percentage of capacity out-of-service over all weekdays declined from 16.7% in 2002 to 15.4% in 2003. The percentage of capacity out-of-service due to unplanned outages was roughly the same in 2003 as in 2002. However, the percentage of capacity out-of-service in 2003 due to planned outages fell from 7.1% in 2002 to 6.0% in 2003.

Figure 30



Generator availability remains good, although on an overall basis the system-wide WEAF dropped by one percentage point from 2002 to 2003. Unit availability increases during seasonal peak periods and declines during off-peak months, indicating that the market is providing appropriate price signals for availability. As a percentage of installed capacity, the amount of capacity out-of-service on weekdays declined for the third straight year. The ISO will continue to closely monitor and report generator availability statistics, especially the relationship between planned and unplanned outages.

14. Administrative Price Corrections

The ISO continually monitors the processes associated with the calculation of LMPs. In the event of a data input failure, hardware or software failure or outage, program failure, or binding constraint errors, corrective actions may be taken to ensure that the resulting LMPs are as accurate as is reasonably obtainable.

Hourly real-time LMP values are derived by integrating 12 five-minute interval values. Table 16 details the number of five-minute interval real-time LMP corrections made during the SMD period.

Table 16 - Price Corrections, March - December 2003

	No. Intervals	% of Intervals
March	32	0.4%
April	46	0.5%
May	83	0.9%
June	52	0.6%
July	51	0.6%
August	112	1.3%
September	52	0.6%
October	189	2.1%
November	39	0.5%
December	105	1.2%
Total	761	0.9%

The Patton Report noted that the overall rate of administrative price correction in the New England markets was very low when compared to analogous start-up phase of New York's multi-settlement wholesale electricity markets.[44] The correction of prices in fewer than 1% of the five-minute intervals is indicative of a competent transition to SMD.

[44] Patton, David B., et. al., p. 33.

Appendix A: Statistical Appendix

The statistical appendix presents information about the New England electrical energy markets in more detail than in the body of the report. The appendix includes sections on electric energy prices; system loads; capacity, net interchange, and fuel mix; FTRs, ARRs, the congestion revenue fund, and the marginal loss revenue fund; operating reserve credit (ORC) payments; regulation market prices; and market volumes.

Contents

A1.1. Electric Energy Prices

The exhibits in this section show zonal average LMP and LMP component data for the SMD period, compare year-to-year energy price trends, and show information about load levels and electric energy prices. Except where specifically noted, prices are not load-weighted.

Table 17 shows LMP summaries for the 10-month period comprising SMD during 2003. Generally, day-ahead prices exhibited a slight premium over their real-time counterparts, with zonal prices exhibiting variation from the Hub reflective of their zonal supply/demand balance and existence of congestion. Day-ahead standard deviations are lower than real time, reflecting the higher variability of price in the Real-Time Market due to unexpected events such as generator and transmission contingencies, or variations in demand from forecast.

Table 17

LMP Summary Statistics, March - December 2003

Location	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA as % of Hub	RT as % of Hub	RT as % of DA	DA Std Dev	RT Std Dev	RT Std/DA Std
Internal Hub	$48.97	$48.59	$10.87	$0.00	$148.68	$998.41	100%	100%	99%	$14.91	$22.54	1.51
Maine Load Zone	$44.92	$44.19	$9.99	$0.00	$212.89	$510.43	92%	91%	98%	$15.44	$18.11	1.17
New Hampshire Load Zone	$47.87	$47.36	$10.61	$0.00	$146.17	$844.95	98%	97%	99%	$14.77	$20.96	1.42
Vermont Load Zone	$49.65	$48.75	$2.77	$0.00	$149.30	$946.70	101%	100%	98%	$15.43	$22.02	1.43
Connecticut Load Zone	$50.50	$50.22	$11.02	$0.00	$244.42	$988.68	103%	103%	99%	$17.78	$25.03	1.41
Rhode Island Load Zone	$48.11	$47.69	$10.78	$0.00	$351.00	$982.30	98%	98%	99%	$17.07	$22.04	1.29
SEMA Load Zone	$47.73	$47.54	$10.71	$0.00	$132.84	$967.01	97%	98%	100%	$14.23	$22.04	1.55
WCMA Load Zone	$48.99	$48.68	$10.89	$0.00	$148.52	$990.34	100%	100%	99%	$14.75	$22.46	1.52
NEMA/Boston Load Zone	$48.84	$48.09	$10.66	$0.00	$215.00	$991.82	100%	99%	98%	$16.30	$22.62	1.39
NB-NE External Node	$42.82	$41.95	$5.00	$-0.03	$154.01	$472.21	87%	86%	98%	$13.88	$17.41	1.26
NY-NE AC External Node	$48.80	$48.55	$10.83	$-4.87	$146.47	$963.95	100%	100%	99%	$14.42	$22.08	1.53
HQ Phase I/II External Node	$47.53	$47.22	$10.65	$0.00	$144.05	$954.92	97%	97%	99%	$14.14	$21.67	1.53
Highgate External Node	$46.76	$45.96	$0.00	$0.00	$140.23	$872.13	95%	95%	98%	$14.81	$20.23	1.37
Cross Sound Cable Ext. Node	$49.56	$49.81	$2.58	$0.00	$219.14	$970.25	101%	102%	101%	$16.80	$24.06	1.43

Table 18 and Table 19 shows LMP summaries for the on and off-peak hours during SMD in 2003. Bilateral contracts utilize the hours between 7:00 a.m. and 11:00 p.m. on non-holiday weekdays as “on-peak” hours in the New England Control Area. Conversely, from 11:00 p.m. to 7:00 a.m. on weekdays, and all day on Saturdays, Sundays, and holidays represent the “off-peak” period. Demand for electricity is generally higher during the on-peak periods and lower in the off-peak periods, driven primarily by commercial and industrial sector use.

On-peak pricing averaged 12-13% higher than the overall average for the period in most load zones, with Connecticut averaging 15% higher. Off-peak pricing averaged approximately 11% lower than the overall price in all load zones. Finally, off-peak pricing was approximately 20% lower than on-peak pricing during the period.

Table 18

LMP Summary Statistics, On-Peak Hours, March - December 2003

Location	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)
Internal Hub	$55.31	$54.74	$34.33	$19.29	$148.68	$998.41
Maine Load Zone	$50.24	$48.77	$30.00	$18.06	$212.89	$510.43
New Hampshire Load Zone	$54.06	$53.21	$33.19	$19.06	$146.17	$844.95
Vermont Load Zone	$56.26	$54.79	$33.41	$19.49	$149.30	$946.70
Connecticut Load Zone	$58.10	$57.78	$33.74	$19.48	$244.42	$988.68
Rhode Island Load Zone	$54.34	$53.55	$33.80	$18.92	$351.00	$982.30
SEMA Load Zone	$53.73	$53.45	$33.44	$18.97	$132.84	$967.01
WCMA Load Zone	$55.27	$54.88	$34.15	$19.38	$148.52	$990.34
NEMA/Boston Load Zone	$55.49	$54.12	$33.81	$19.26	$215.00	$991.82
NB-NE External Node	$47.67	$45.50	$5.00	$14.62	$154.01	$472.21
NY-NE AC External Node	$54.98	$54.73	$33.44	$-4.87	$146.47	$963.95
HQ Phase I/II External Node	$53.48	$52.87	$33.30	$18.73	$144.05	$954.92
Highgate External Node	$52.47	$50.22	$0.00	$15.51	$140.23	$872.13
Cross Sound Cable External Node	$56.55	$56.98	$2.58	$19.22	$219.14	$970.25

Table 19

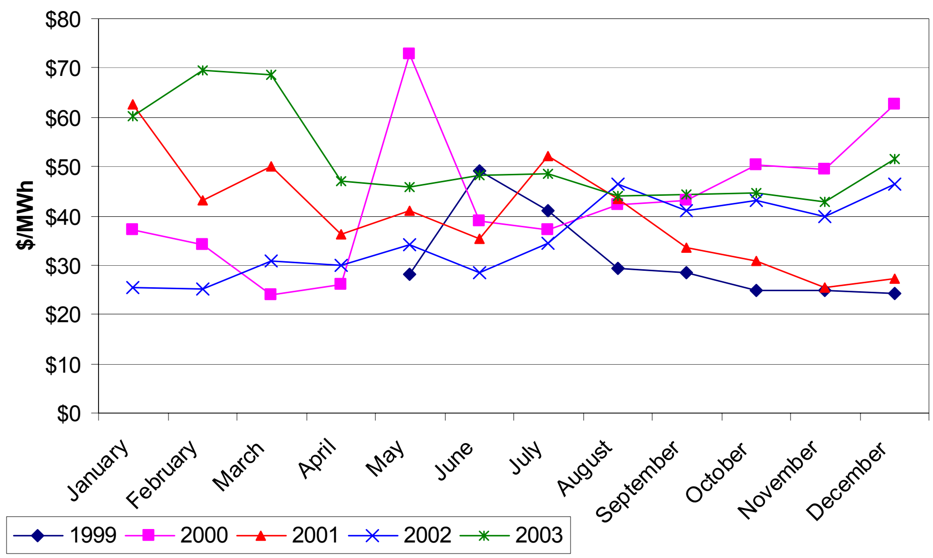
LMP Summary Statistics, Off-Peak Hours, March - December 2003

Location	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)
Internal Hub	$43.54	$43.31	$10.87	$0.00	$124.38	$398.60
Maine Load Zone	$40.35	$40.27	$9.99	$0.00	$160.21	$367.81
New Hampshire Load Zone	$42.56	$42.33	$10.61	$0.00	$122.27	$389.02
Vermont Load Zone	$43.98	$43.56	$2.77	$0.00	$124.89	$388.90
Connecticut Load Zone	$43.98	$43.72	$11.02	$0.00	$122.97	$393.44
Rhode Island Load Zone	$42.76	$42.66	$10.78	$0.00	$119.70	$394.85
SEMA Load Zone	$42.58	$42.47	$10.71	$0.00	$117.44	$392.85
WCMA Load Zone	$43.59	$43.35	$10.89	$0.00	$124.25	$397.53
NEMA/Boston Load Zone	$43.14	$42.91	$10.66	$0.00	$147.62	$397.63
NB-NE External Node	$38.66	$38.90	$9.31	$-0.03	$128.09	$345.16
NY-NE AC External Node	$43.50	$43.25	$10.83	$0.00	$122.53	$391.95
HQ Phase I/II External Node	$42.43	$42.38	$10.65	$0.00	$120.50	$379.77
Highgate External Node	$41.86	$42.31	$2.57	$0.00	$118.63	$368.19
Cross Sound Cable External Node	$43.56	$43.65	$10.94	$0.00	$122.47	$392.96

Figure 31 shows the monthly average system real-time energy price for the last five years. Although price concepts are slightly different, the figure illustrates the effect that input fuel prices have had on electric energy prices over the period. Note the increase in prices at the end of 2000, their decrease over the course of 2001, and the steady rise over the course of 2002 into 2003.

Figure 31

Monthly Average Real Time Energy Prices*, 1999 - 2003



*Energy price is ECP for May 1999-February 2003, and Real Time Hub LMP for March-December 2003.

Figure 32 illustrates the daily average energy component of LMP over the 10-month period. Because it excludes congestion and marginal losses, the energy component is reflective of system-wide price at the margin in each hour. The figure shows the effect that high fuel prices had on electric energy prices both at the beginning and end of the period. High demand driven by warm weather was responsible for the price elevation near the end of June, while several large unit trips caused the real-time spike in average price shown at the beginning of December.

Figure 32
Daily Average Energy Component
March - December 2003

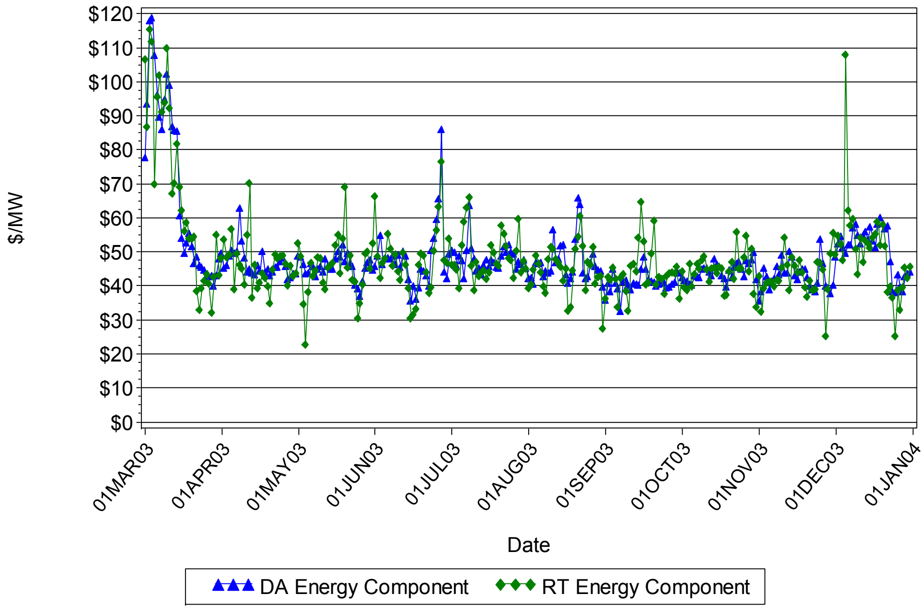
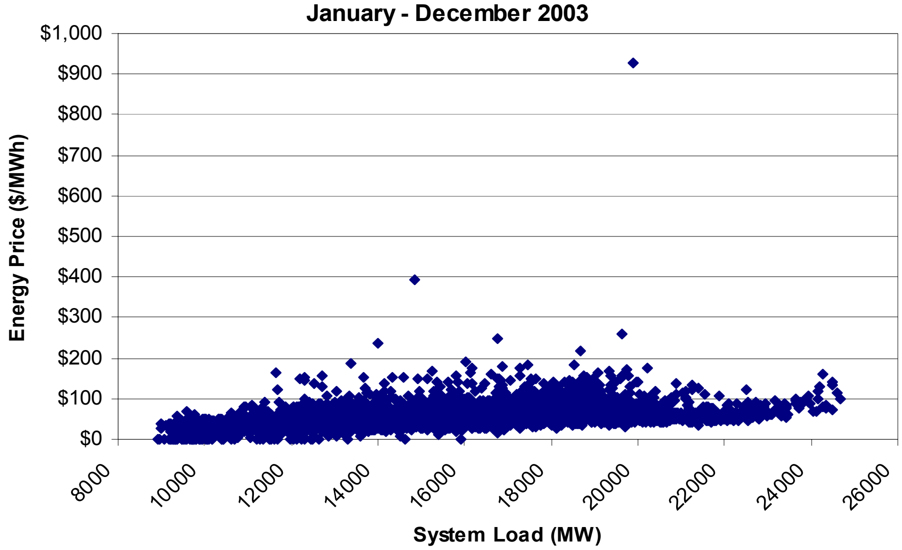


Figure 33 shows the relationship between demand levels on the system and the corresponding system-wide energy price. A distinctly positive correlation can be seen. The extremely high price ($900+/MWh) was a result of a capacity deficiency in early December, caused by almost simultaneous trips of three large generating units.

Figure 33

New England Energy Price* vs. System Load
January - December 2003

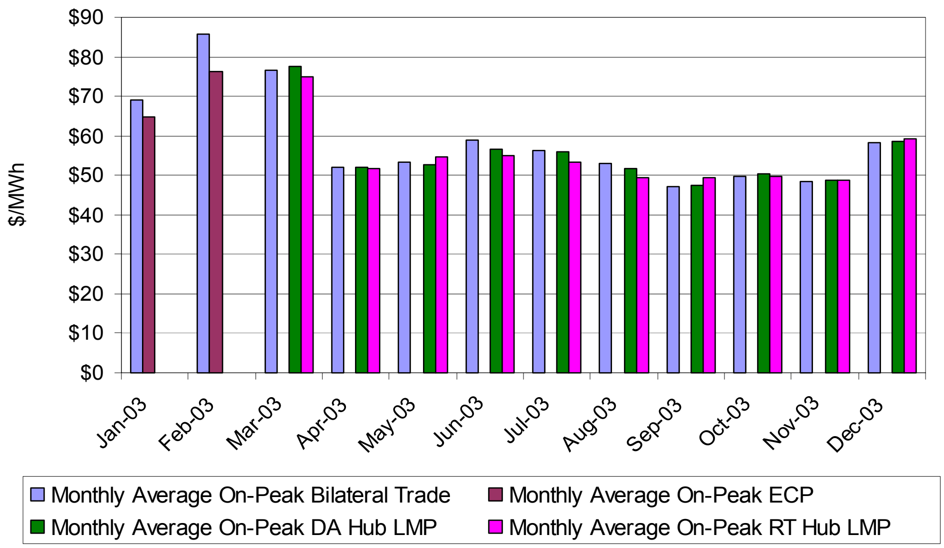


*Energy Price is single Energy Clearing Price for Interim Market Period ending Feb 28, 2003 and System price (calculated by load-weighting RTM LMPs) for

Figure 34 shows the monthly average on-peak spot market electric energy price in New England compared to the average before-the-month quotes for on-peak bilateral energy transactions reported by a third party vendor, Energy Argus. The spot market price for January and February is the average Energy Clearing Price, while after March 1, the average on-peak Hub LMP is shown for both the Day-Ahead and Real-Time Markets. The figure shows that the bilateral market quotes were higher than the eventual spot market price, while post-SMD implementation, the bilateral market quotes were fairly accurate predictors of the eventual Day-Ahead and Real-Time Market prices.

Figure 34

New England Monthly Average On-Peak Bilateral Trades vs Spot Market Energy Prices



Source: Bilateral Trade Data from Energy Argus

A1.2. System Electrical Loads

The exhibits in this section present information about hourly, monthly, and yearly system electrical load levels.

Table 20 shows summary statistics for hourly system load for the last three years. 2003 showed the highest average hourly load and highest average minimum load over the period, indicative of growth in demand on the system. Cooler than expected summer peak weather is responsible for the lower maximum value in 2003.

Table 20

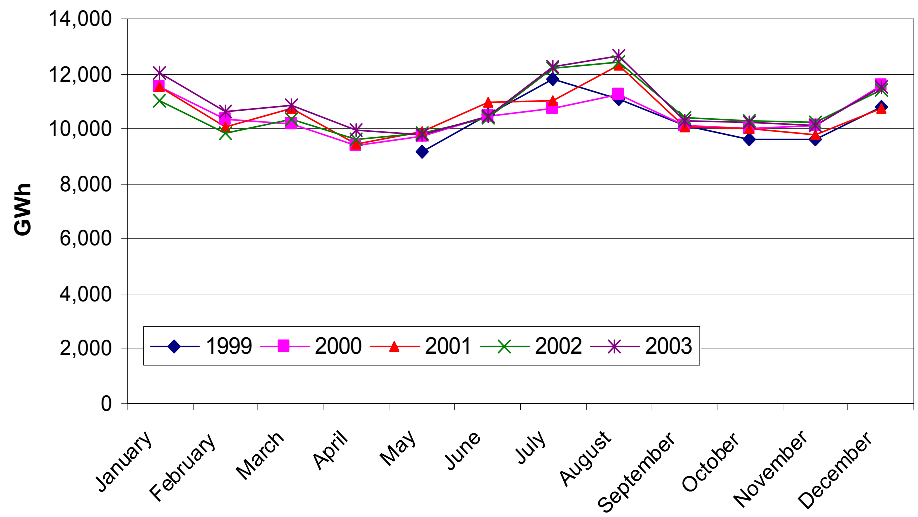
Hourly Load Statistics, 2001 - 2003

MW	2001	2002	2003
Mean	14,381	14,550	14,921
Maximum	24,967	25,348	24,685
Minimum	8,765	8,748	8,934
Std. Deviation	2,840	2,975	2,928

Figure 35 shows system monthly energy consumption since May of 1999. The figure shows the effects of both weather and underlying demand growth on monthly energy levels. Many months during 2003 had NEL values that were the highest over the period shown.

Figure 35

Monthly Total Load*, 1999 - 2003



*NEPOOL Net Energy for Load (NEL) is the total net energy used to serve load for the month in GWh. NEL is calculated as: Load = Generation - pumping + net interchange.

A1.3. Capacity, Net Interchange, and Fuel Mix

The exhibits in this section present information about generating capacity and generation by fuel type, net interchange over all interfaces, and imports and exports with New York.

Figure 36 shows summer capacity MW by year input fuel type. In 2003, dual-fueled generators, capable of burning both oil and gas, made up 23% of installed capacity; while natural gas fired generators were 21%. In 2002, only 13% of capacity was gas fired. Detailed information about generating capacity is available in the NEPOOL Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) report.[45]

[45] http://www.iso-ne.com/Historical_Data/CELT_Report/

Figure 36

System Summer Capacity by Generator Type, Summarized from NEPOOL CELT Report

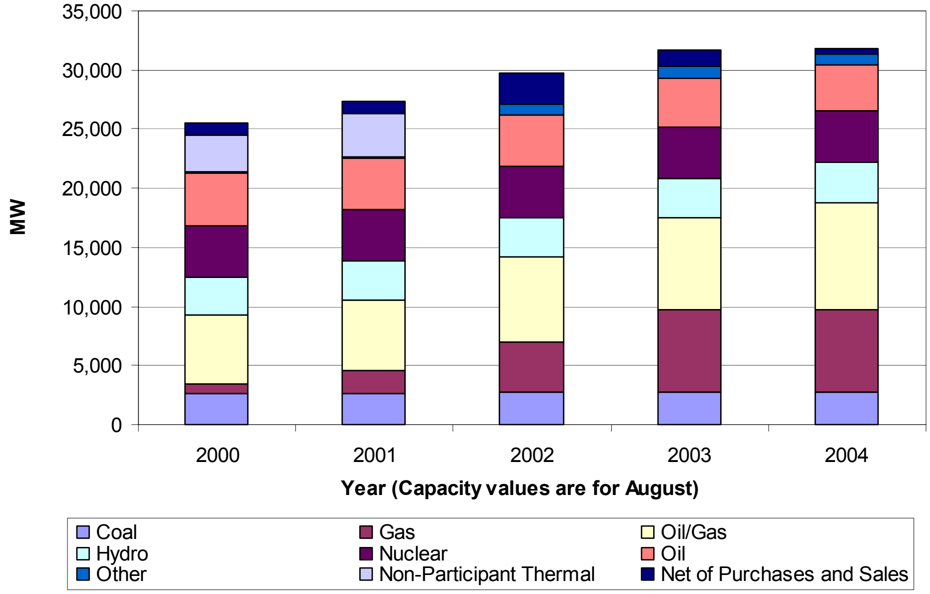


Figure 37 shows average hourly imports from and exports to New York, and the average net interchange by day for the same three-year period. The pattern of decreasing imports and increasing exports is evident on a daily basis, even though there is significant variability between days.

Figure 37

Imports from and Exports to New York, Hourly Average by Day, 2001-2003

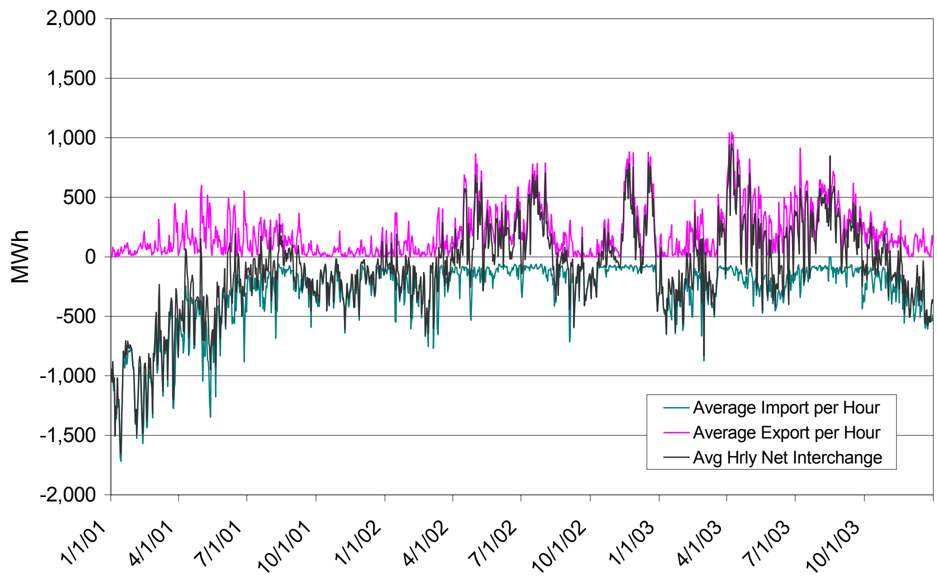
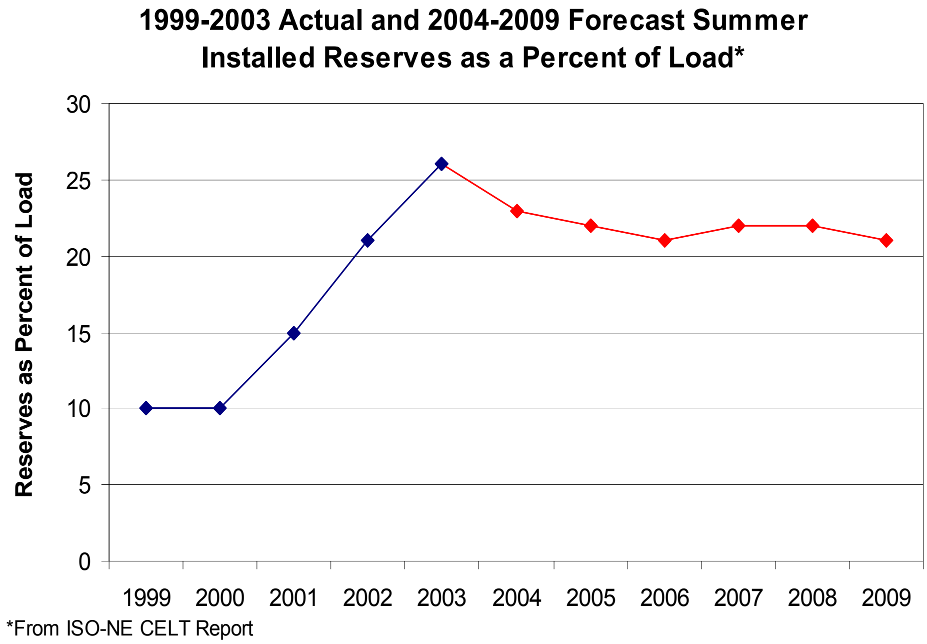


Figure 38 shows installed reserves as a percent of actual and forecast peak load as reported in the CELT report. Installed reserves are defined as excess of total capacity over the reference load level. Installed reserves increased from 2000 to 2003, but are forecast to decline slightly over the next four years as generating capacity retires.

Figure 38



A1.4. FTRs, ARRs, Congestion Revenue Fund, and Marginal Loss Revenue Fund

Table 21 provides summary information for the long-term and monthly FTR auctions for 2003. The subsequent five figures show trends in buying and selling activity within these auctions. Information for 2004 has been included in the graphical analysis for the long-term auction in order to provide perspective. Selling activity did not occur until October when long-term auction FTRs that were awarded for October to December were available for re-sale.

Table 21 shows that while only 15% of the auction-year's available network capacity was awarded in the long-term auction[46], that auction accounted for 25% of monthly equivalent awarded MW and 20% of awarded auction revenue for the year. The long-term auction yielded a higher volume and dollar yield per unit of available network capacity than did the monthly auctions. This is consistent with an observed trend of increasing participation and competition for FTRs as the year progressed. Figure 39 shows a continuance of this trend into the following year.

Table 21 – FTR Auction Statistics

Auction Type	#of Auctions	Avg. # Bidders	% of 2003 FTR capacity	Awarded Bids	Awarded MW	Total Awarded $
Monthly	10	30	85%	11,209	129,867.5	$22,894,021.9
Long-Term	1	21	15%	1,351	13,936.8	$5,645,358.0
Total			*100%*	*12,560*	*143,804.3*	*$28,539,379.9*

Figure 39 shows that, on an equivalent monthly basis, long-term FTR auction revenues increased significantly in the January to June 2004 auction over the October to December 2003 auction.

[46] Each of the first seven monthly auctions offered 100% of the system's transmission capacity, while the last three monthly auctions offered 50% of the system's capacity. The long-term auction offered 50% of the system's capacity for a three-month period, or 15% of the total capacity offered to the auction market during 2003.

Figure 39

Long-Term On-Peak Auction Bid and Cleared Volumes
Oct-Dec, 2003 & Jan-Jun, 2004

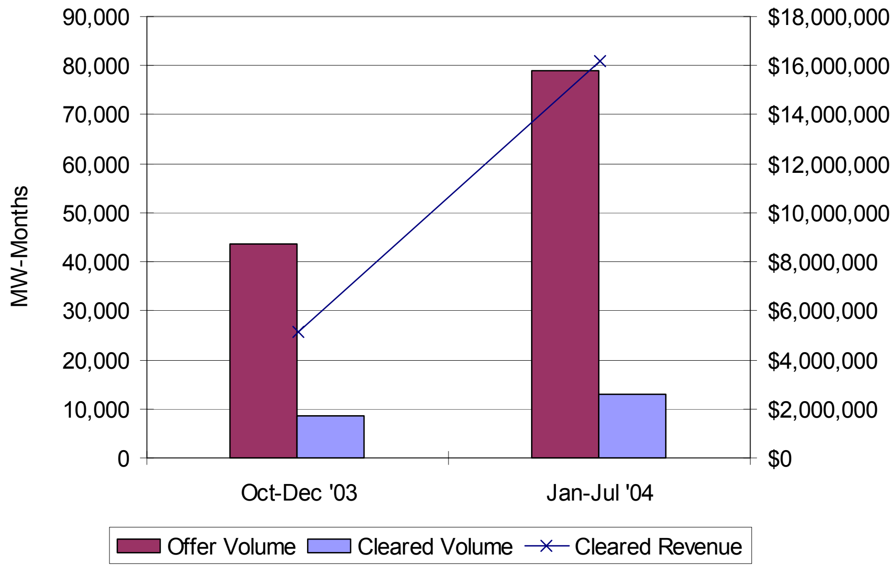
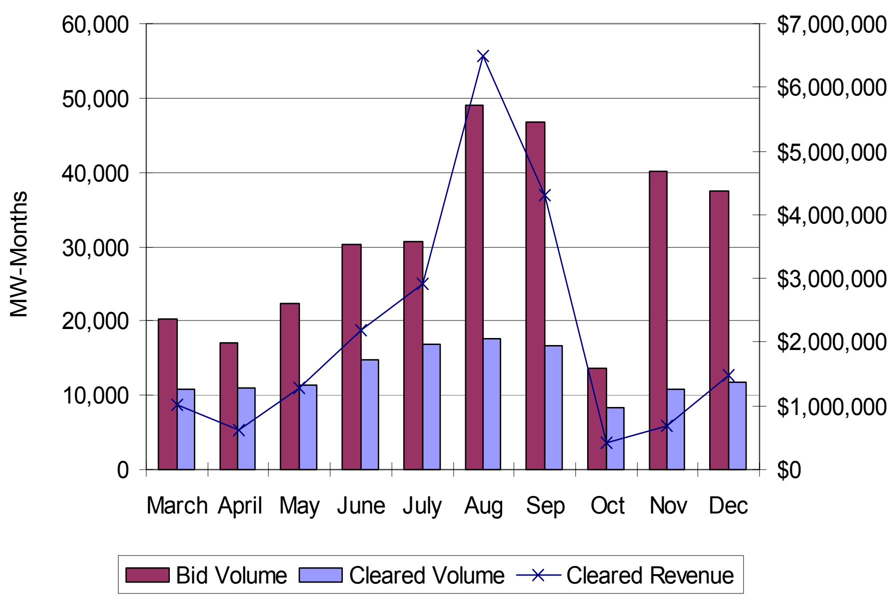


Figure 40 shows that monthly auction volumes follow overall electricity demand patterns on the system. Monthly volume decreased in October due to lower expected demand levels and the October to December long-term auction. In the aggregate, the monthly and long-term auction results indicate higher bidding activity and more FTRs awarded during the fall months than during the spring months.

Figure 40

2003 Monthly On-Peak Auction Bid and Cleared Volumes



On-Peak FTRs offered for resale in the October, November, and December auctions, subsequent to the long-term auction, averaged approximately 1,500 MW-months per month. Cleared resale volume averaged only 30 MW-months in each of the monthly auctions, and cleared FTRs generated slightly less than $12,000 as shown in Figure 41. The ISO will continue to report on the amounts of long-term purchased FTRs that are re-sold in the monthly auctions.

Figure 41

2003 Monthly On-Peak FTR Auction Resale Volumes

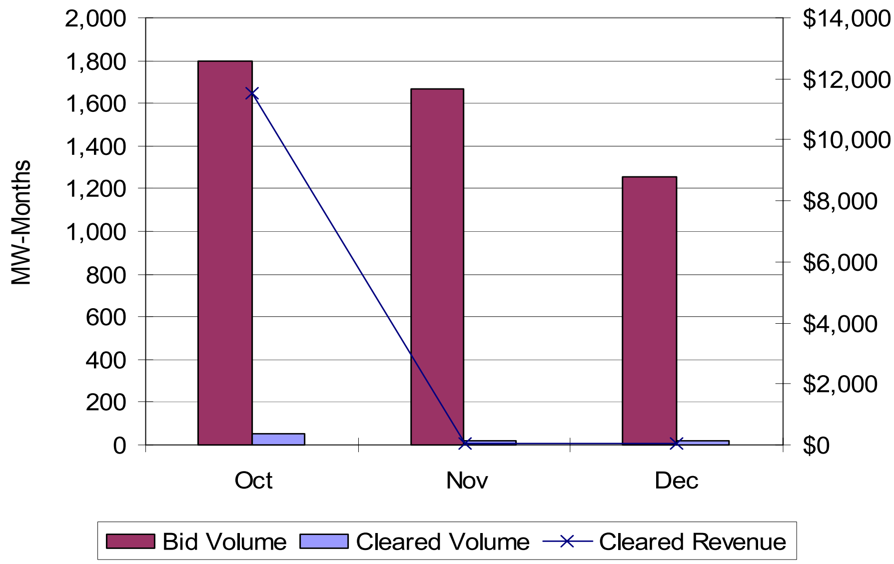


Figure 42 and Figure 43 illustrate the ten highest total revenue-producing sinks and sources (along with the respective MW amounts) as purchased in the Monthly On-Peak auctions during 2003. Both figures show that the Hub was a very popular sink and source. This reflects the popularity of the Hub as a trading point between generation and load areas. In general, the two graphs reflect the use of FTRs as a congestion hedge between generation rich areas, such as Maine, and the most constrained areas on the system, such the Connecticut and NEMA/Boston zones. Seven of the ten highest revenue-producing sources were nodes.

Figure 42

Top Ten Purchased FTR Sinks By Revenue Including MW

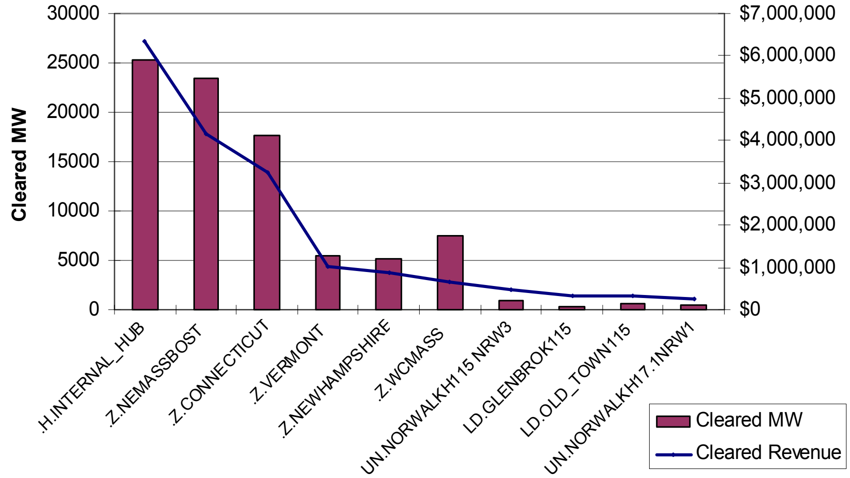
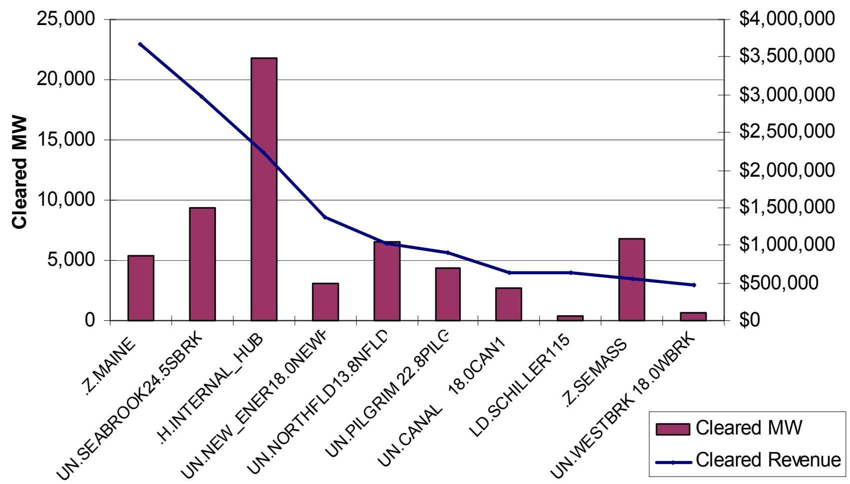


Figure 43

Top Ten Purchased FTR Sources By Revenue Including MW



Market Rule 1 specifies that auction revenues are allocated first in the form of Qualified Upgrade Awards (QUAs) to entities, who, by paying for transmission upgrades, have increased the transfer capability of the New England transmission system and have enabled more FTRs to be available in the FTR auction, and second, through the Auction Revenue Rights (ARR) process, where they are primarily awarded to congestion paying load-serving entities (LSEs). QUA awards were very small, as shown in Table 22.

Table 22

Total Auction Revenue Distribution March-December 2003			
Year	QUA Dollars	ARR Dollars	Total Auction Allocation
2003	$384,186	$28,162,540	$28,546,726
% of Total	1.3%	98.7%	100.0%

The ARR process further allocates ARR Dollars to the four categories shown in Table 23. The ARR process allocates dollars to:

- Long-Term Firm Through or Out Service;
- Excepted Transactions - special grand fathered transactions (listed in Attachment G of the NEPOOL Tariff);
- NEMA Contracts - other long-term contracts with delivery in Northeastern Massachusetts; and
- Load Share - paid in proportion to Real-Time Load Obligation at the time of the pool's coincident peak for the month, to the so-called "congestion paying entities."

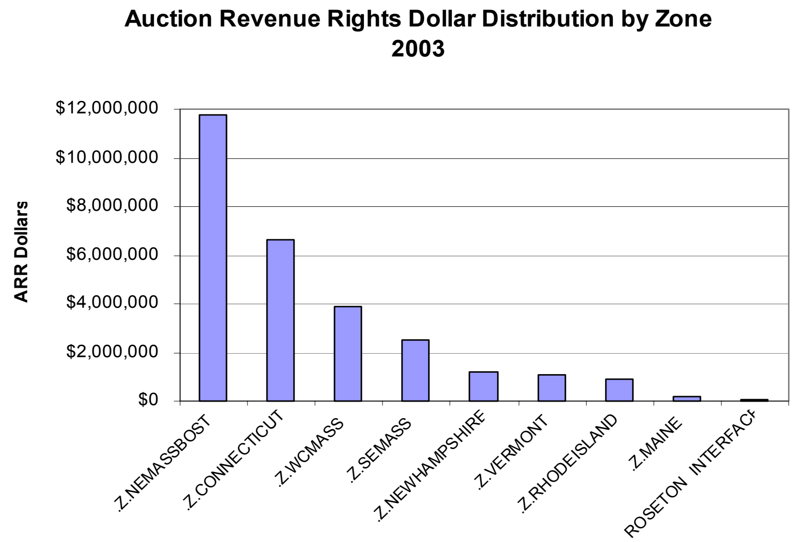
The largest portion of auction revenue was returned to those who pay for congestion on the system, as shown in the Load Share Dollars item below.

Table 23

ARR Allocation	Amount
Long-Term Firm Trans. Svc. Dollars	$65,285
Excepted Transaction Dollars	$188,435
NEMA Contract Dollars	$1,335,539
Load Share Dollars	$26,573,280
Total	$28,162,540

Figure 44 shows that 65% of the revenue generated by the FTR auction was returned to congestion paying entities in the NEMA/Boston and Connecticut load zones.

Figure 44



The Transmission Congestion Revenue Fund is the vehicle that manages congestion-related revenues. First, it is used to pay Positive Target Allocations to FTR holders. If they hold an FTR in the correct direction, they are entitled to a share of day-ahead congestion revenues during each hour of the month in which there was congestion in the Day-Ahead Market along the FTR path.

Once Positive Target Allocations are paid, the fund balance rolls forward each month and, at year's end, any excess collection is allocated back to congestion paying entities. Table 24 summarizes the annual activity in the fund. The positive ending balance indicates that overall day-ahead congestion revenue was greater than the funds owed to FTR holders for congestion revenue entitlements in 2003.

Table 24

Transmission Congestion Revenue Fund Item	Amount
Annual Beginning Balance	$0
Annual Fund Adjustment	$101,836
Annual DA Congestion Revenue	$85,964,589
Annual RT Congestion Revenue	$1,392,648
Negative Target Allocations	$16,082,699
Positive Target Allocations	($84,436,744)
Annual Ending Balance	$19,105,028

The Marginal Loss Revenue Fund collects hourly market settlement imbalances that occur in the form of energy and marginal losses and allocates these amounts, generally in the form of credits, to participants according to their monthly share of real-time load obligation, net of bilateral trades. Table 25 shows the contribution of each component to the Marginal Loss Revenue Fund and the fund total for the months of

March through December. A negative fund value denotes a credit allocation, meaning that, in total, $80 million was returned to load.

Table 25

2003 Marginal Loss Revenue Fund Item	Totals
Energy Market Total Collections	$82,938,765
DA Loss Revenue	($128,786,343)
RT Loss Revenue	($19,836,639)
Loss Revenue Total	($148,622,981)
RT Inadvertent Energy Revenue	($12,720,652)
RT Emergency Dollars	($1,752,545)
MLRF Fund Total	($80,157,413)

A1.5. Operating Reserve Credit (ORC) Payments

The exhibits in this section present ORC payment data for the Day-Ahead and Real-Time Markets by type of ORC on an overall and monthly basis.

Table 26

Total ORC Payments, March – December 2003

ORC TYPE	Day Ahead Market ORC Payments	Real Time Market ORC Payments	Total
ECONOMIC	$3,355,930	$24,698,746	$28,054,676
RMR	$1,701,290	$34,892,094	$36,593,384
SCR	$0	$6,945,798	$6,945,798
VAR	$13,496,309	$846,269	$14,342,578
Total	$18,553,529	$67,382,906	$85,936,435

Table 27 shows economic ORC payments by month. Economic ORC is the default ORC category for generators that are eligible for uplift but not flagged as RMR, VAR, or SCR. August real-time economic ORC was unusually high due to payments made to generators that were manually dispatched during the Northeastern Blackout.

Table 27

2003 ORC Economic Payments by Month

	Day Ahead	Real Time
March 2003	$580,060	$3,253,420
April 2003	$81,561	$590,245
May 2003	$109,588	$1,042,187
June 2003	$859,388	$1,706,805
July 2003	$173,778	$2,570,550
August 2003	$177,894	$7,251,148
September 2003	$62,882	$1,145,905
October 2003	$69,987	$1,479,999
November 2003	$356,168	$2,389,265
December 2003	$884,626	$3,269,222

Table 28 shows VAR ORC payments by month. All VAR ORC payments made during 2003 were to generation that was required to control voltage levels during low load level periods in the NEMA/Boston load zone. VAR ORC payments were highest in the spring and fall months.

Table 28

2003 ORC Volt-Amperes Reactive (VAR) Payments by Month

	Day Ahead	Real Time
March 2003	$609,297	$101,104
April 2003	$2,040,331	$290,769
May 2003	$626,776	$91,077
June 2003	$82,328	$88,920
August 2003	$90,653	$125,497
September 2003	$2,730,395	$111,991
October 2003	$3,080,833	$9,181
November 2003	$3,346,956	$24,036
December 2003	$888,740	$3,694

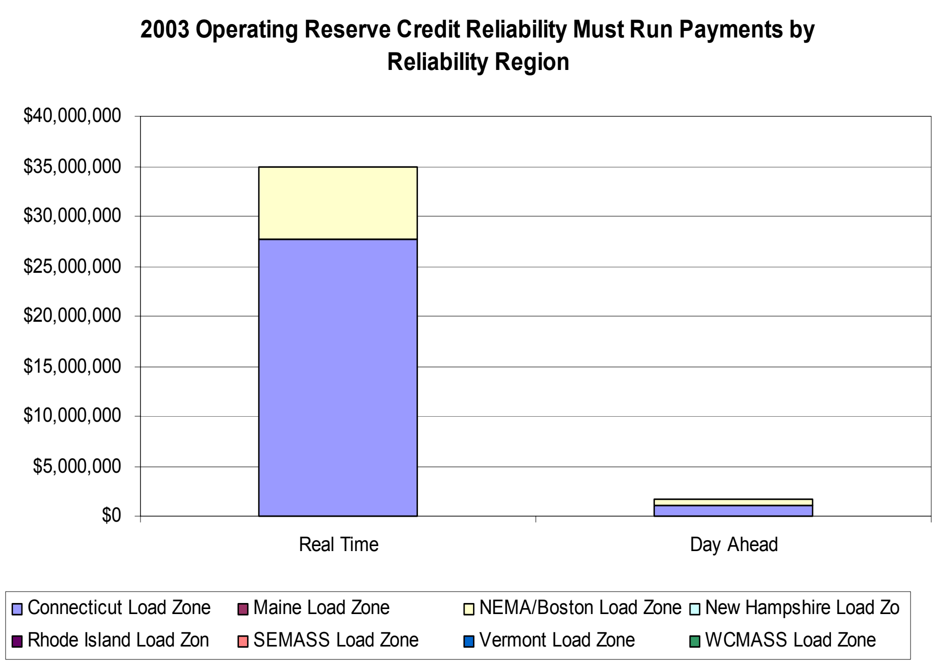
Table 29 shows RMR ORC payments by month. RMR ORC payments are made to generators that are flagged as such and are generating out-of-economic-merit order in transmission-constrained areas. Figure 45 shows that generators in the Connecticut reliability region were paid the most RMR ORC.

Table 29

2003 ORC Daily Reliability Must Run (RMR) Payments by Month

	Day Ahead	Real Time
March 2003	$54,694	$1,502,022
April 2003	$46,657	$331,349
May 2003	$23,718	$299,139
June 2003	$0	$1,851,096
July 2003	$23,825	$9,500,830
August 2003	$7,913	$11,740,106
September 2003	$0	$1,004,251
October 2003	$140,188	$2,342,860
November 2003	$581,857	$4,013,367
December 2003	$822,438	$2,307,074

Figure 45



A1.6. Regulation and AGC

The tables below show summary information about clearing prices in the AGC and Regulation Markets during the year. In the Interim Market, regulation was called AGC, and the unit of measure for the commodity was $/reg-hr. This concept is not directly comparable to the price for regulation under SMD, which is expressed as $/MWh.

Table 30

AGC Market Clearing Prices Summary Statistics ($/Reg-Hr),January - February 2003

$/Reg-Hr	Average	Median	Minimum	Maximum
January 2003	$5.17	$5.06	$2.50	$10.26
February 2003	$5.38	$5.56	$2.96	$10.47

Table 31

Regulation Market Clearing Prices Summary Statistics ($/MWh), March - December 2003

$/MWh	Average	Median	Minimum	Maximum
March 2003	$28.55	$21.28	$0.00	$137.11
April 2003	$17.09	$15.86	$7.16	$58.90
May 2003	$23.83	$19.76	$7.03	$182.77
June 2003	$58.70	$50.00	$15.01	$678.43
July 2003	$33.35	$33.10	$19.55	$88.51
August 2003	$38.80	$34.42	$10.40	$1,021.74
September 2003	$39.85	$39.54	$0.00	$136.16
October 2003	$41.42	$42.63	$16.00	$99.78
November 2003	$39.71	$40.14	$15.31	$70.36
December 2003	$46.43	$48.07	$15.31	$150.00

A1.7. Market Volumes

The exhibits in this section present information about electric energy traded through the ISO by category, and virtual demand and virtual supply by month for the Hub and load zones.

Table 32

MWh Quantities Traded in the Day-Ahead and Real-Time Markets by Transaction Type

Transaction Type by Market	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
Day-Ahead Market										
Load Obligation - DA LMP[47]	10,517,372	9,978,139	9,468,874	10,203,549	11,890,736	12,237,934	10,448,432	10,403,773	10,153,883	11,279,778
Bilateral - Export With Price[48]	*31,634*	*149,776*	*206,121*	*120,982*	*206,209*	*115,294*	*85,121*	*87,335*	*98,323*	*91,256*
Bilateral - Export Without Price	*24,100*	*144,897*	*63,909*	*32,831*	*105,569*	*178,503*	*152,567*	*183,800*	*143,969*	*88,377*
Bilateral - Export Up-To Congestion	*0*	*10,374*	*5,656*	*45,029*	*0*	*1,470*	*68,572*	*4,165*	*11,348*	*18,120*
Bilateral - Internal for Market DA	8,320,783	9,006,585	9,868,164	9,391,106	10,641,164	10,628,953	8,932,411	9,689,376	9,528,825	9,696,331
Bilateral - Import With Price	38,933	64,020	84,960	85,141	163,483	196,875	28,200	34,960	48,087	112,852
Bilateral - Import Without Price	697,049	530,790	519,819	492,878	490,977	533,048	186,646	193,083	182,119	328,493
Bilateral - Import Up-To Congestion	0	915	1,025	1,035	10,165	1,356	25,774	31,262	4,950	2,555
Total DA MWh	**19,574,137**	**19,580,449**	**19,942,842**	**20,173,709**	**23,196,525**	**23,598,166**	**19,621,463**	**20,352,454**	**19,917,864**	**21,420,009**
Real-Time Market										
Adjusted Load Obligation Deviation - RT LMP[49]	489,818	428,487	603,766	514,401	741,059	779,065	331,198	154,078	230,845	494,909
Adjusted Load Obligation Deviation - lower than DA	*-3,225,233*	*-3,047,463*	*-2,384,203*	*-2,228,031*	*-2,780,559*	*-2,740,879*	*-2,522,117*	*-2,501,758*	*-2,399,449*	*-2,458,158*
Adjusted Load Obligation Deviation - higher than DA	*3,715,051*	*3,475,950*	*2,987,969*	*2,742,431*	*3,521,618*	*3,519,945*	*2,853,315*	*2,655,836*	*2,630,294*	*2,953,067*
Bilateral - Export With Price	*0*	*399*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Bilateral - Export Without Price	*121,040*	*466,945*	*321,414*	*236,524*	*375,837*	*372,673*	*389,685*	*340,506*	*241,929*	*205,588*
Bilateral - Internal for Market - Additional to DA IBMs	1,938,098	2,124,623	1,766,552	1,486,437	2,000,019	2,096,492	1,855,736	1,865,503	1,708,847	1,851,439
Bilateral - Internal for Load RT	161,140	146,445	141,080	167,372	185,557	192,442	145,418	145,978	143,259	162,134
Bilateral - Import With Price	26,413	51,860	144,644	286,330	199,055	236,795	73,470	45,139	71,072	74,150
Bilateral - Import Without Price	908,412	741,251	770,969	674,044	662,127	686,963	245,792	256,851	365,027	536,626
Bilateral - Through	14,112	39,977	0	0	0	4,326	0	0	0	0
Total RT MWh	**3,537,993**	**3,532,643**	**3,427,011**	**3,128,584**	**3,787,817**	**3,996,083**	**2,651,614**	**2,467,549**	**2,519,050**	**3,119,258**
Net Energy for Load (GWh)[50]	*10,815*	*9,842*	*9,761*	*10,481*	*12,290*	*12,659*	*10,347*	*10,229*	*10,124*	*11,534*

[47] The day-ahead load obligation for energy is equal to the MWh of demand bids, decrement bids, and external transaction sales accepted by the ISO in the Day-Ahead Market. It is settled at the day-ahead LMP. The figure reported here is the pool 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.

[48] Exports are included in load obligation.

[49] 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 pool total of participants' locational adjusted load obligation deviations. Adjusted load obligation deviation may be negative (indicating that there is a lower load obligation than cleared day ahead) or positive (indicating that there is a higher load obligation than 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 DA at the participant level net to zero when the pool 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 Market.

[50] Net Energy for Load (NEL): NEL is calculated as *generation – pumping + net interchange*. It is shown here for reference.

March 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	**190,768**	**111,521**	**276,161**	**199,705**
Maine Load Zone	**120,780**	**47,314**	**185,618**	**85,176**
New Hampshire Load Zone	**119,037**	**31,614**	**29,981**	**19,196**
Vermont Load Zone	**7,950**	**7,050**	**72,617**	**59,190**
Connecticut Load Zone	**11,640**	**4,834**	**50,735**	**6,172**
Rhode Island Load Zone	**400**	**400**	**38,500**	**10,774**
SEMA Load Zone	**52,700**	**20,280**	**13,605**	**7,550**
WCMA Load Zone	**0**	**0**	**48,707**	**39,365**
NEMA/Boston Load Zone	**405**	**400**	**196,780**	**36,047**

April 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	198,381	135,726	182,983	124,071
Maine Load Zone	72,675	13,054	104,007	29,315
New Hampshire Load Zone	79,371	11,924	31,917	12,588
Vermont Load Zone	13,130	4,329	67,821	38,623
Connecticut Load Zone	16,819	4,720	131,655	8,120
Rhode Island Load Zone	0	0	17,667	1,899
SEMA Load Zone	0	0	18,827	2,207
WCMA Load Zone	0	0	42,615	3,899
NEMA/Boston Load Zone	34,800	29,367	256,300	13,064

May 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	113,105	94,599	269,500	217,261
Maine Load Zone	148,945	63,990	82,089	70,472
New Hampshire Load Zone	60,126	7,408	15,333	10,076
Vermont Load Zone	222	78	59,541	49,037
Connecticut Load Zone	44,983	31,393	121,288	42,768
Rhode Island Load Zone	145	52	7,394	889
SEMA Load Zone	145	49	7,394	718
WCMA Load Zone	145	50	10,061	859
NEMA/Boston Load Zone	145	55	177,383	11,388

June 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	295,892	250,412	246,912	152,601
Maine Load Zone	131,249	95,141	22,278	22,030
New Hampshire Load Zone	39,340	11,441	11,390	9,406
Vermont Load Zone	5,690	3,783	50,283	46,310
Connecticut Load Zone	51,253	35,758	109,296	17,440
Rhode Island Load Zone	279	58	8,688	8,443
SEMA Load Zone	282	62	45,261	16,155
WCMA Load Zone	294	68	5,453	664
NEMA/Boston Load Zone	2,646	2,007	166,359	72,381

July 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	222,406	146,086	184,254	91,006
Maine Load Zone	43,462	5,297	71,072	55,888
New Hampshire Load Zone	36,971	25,603	36,979	12,214
Vermont Load Zone	8,546	1,915	77,203	57,554
Connecticut Load Zone	61,803	10,083	126,339	55,293
Rhode Island Load Zone	4,100	2,406	2,490	940
SEMA Load Zone	61,565	40,383	32,770	8,020
WCMA Load Zone	5,875	1,365	20,541	2,577
NEMA/Boston Load Zone	4,642	1,772	48,146	12,057

August 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	249,981	139,141	287,169	155,140
Maine Load Zone	165,877	110,857	100,591	9,455
New Hampshire Load Zone	12,757	8,026	25,764	11,193
Vermont Load Zone	4,449	1,928	65,153	50,590
Connecticut Load Zone	38,148	4,831	106,687	34,624
Rhode Island Load Zone	8,512	794	2,349	303
SEMA Load Zone	6,583	3,118	11,399	2,149
WCMA Load Zone	2,468	782	20,048	6,194
NEMA/Boston Load Zone	3,861	196	19,849	915

September 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	96,815	52,912	298,448	186,821
Maine Load Zone	247,428	186,004	82,402	22,228
New Hampshire Load Zone	18,586	8,524	31,617	13,288
Vermont Load Zone	4,118	330	62,447	47,181
Connecticut Load Zone	43,699	2,581	59,304	28,408
Rhode Island Load Zone	1,128	35	4,137	2,338
SEMA Load Zone	6,678	1,478	13,671	4,397
WCMA Load Zone	2,628	510	19,180	3,241
NEMA/Boston Load Zone	2,951	40	2,697	887

October 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	129,290	38,292	363,471	199,449
Maine Load Zone	233,954	156,828	103,223	27,333
New Hampshire Load Zone	30,253	7,363	63,385	25,550
Vermont Load Zone	3,381	133	77,899	48,066
Connecticut Load Zone	36,159	5,239	73,425	40,731
Rhode Island Load Zone	4,617	2,031	14,685	3,923
SEMA Load Zone	10,729	3,530	72,910	55,363
WCMA Load Zone	7,479	2,584	30,588	3,078
NEMA/Boston Load Zone	929	54	6,367	4,592

November 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	238,325	91,137	263,996	153,016
Maine Load Zone	153,753	90,924	115,117	45,137
New Hampshire Load Zone	45,728	24,124	40,662	18,001
Vermont Load Zone	8,290	2,662	68,023	52,770
Connecticut Load Zone	20,549	8,964	21,289	7,089
Rhode Island Load Zone	12,990	3,761	5,366	1,741
SEMA Load Zone	10,220	3,896	17,234	5,755
WCMA Load Zone	13,920	5,309	20,712	3,659
NEMA/Boston Load Zone	2,020	303	2,494	1,022

December 2003

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply (MWh)	Submitted Virtual Demand (MWh)	Cleared Virtual Demand (MWh)
Internal Hub	103,558	53,158	319,216	213,650
Maine Load Zone	136,207	86,823	154,391	79,414
New Hampshire Load Zone	13,756	7,460	46,275	18,601
Vermont Load Zone	21,570	10,055	90,709	64,038
Connecticut Load Zone	4,330	743	15,826	3,781
Rhode Island Load Zone	2,926	563	7,003	1,272
SEMA Load Zone	3,569	718	15,299	2,905
WCMA Load Zone	2,926	643	19,005	4,018
NEMA/Boston Load Zone	3,226	901	4,374	1,656

A1.8. Demand Response Programs

Table 33 reports the assets that were both "ready to respond" and "pending" as of September 1, 2003. Over 380 MW were under contract at this time, with almost 200 MW of that total in the Connecticut load zone. Because enrollments in the program increase up to and through the summer peak demand season, and assets retire after the summer, September 1 is shown as it is representative of the activity over the summer.

Table 33 – Demand Response Program Enrollments, September 1, 2003

Zone	Active Assets (MW)						Pending Assets (MW)					
	No. of Assets	Demand Response 2 Hr	Demand Response 30 min.	Price Response	Profiled [51]	Total	No. of Assets	Demand Response 2 Hr	Demand Response 30 min.	Price Response	Profiled	Total
ME	3			0.4	65.0	**65.4**	1		14.7			**14.7**
NH	1		0.4			**0.4**						**-**
VT	16		1.3	7.1	5.9	**14.3**						**-**
CT	132	1.0	96.9	42.1	58.6	**198.6**	8		4.9			**4.9**
RI	11			1.6		**1.6**						**-**
SEMA	72		0.5	7.4		**7.9**						**-**
WCMA	96	2.0	6.0	9.6	6.9	**24.5**						**-**
NEMA	112	0.8	3.4	62.5	1.4	**68.1**	3	0.6	0.2			**0.8**
Total	**443**	**3.9**	**108.6**	**130.7**	**137.7**	**380.8**	**12**	**0.6**	**19.8**	**-**	**-**	**20.4**

Table 34 shows the MWh of credited curtailment for assets that interrupted or curtailed their usage by day throughout the March to December period. Almost 25% of the curtailed MWh during the 10-month period were attributable to implementation of the programs in Connecticut in support of system restoration efforts after the Northeastern blackout.

Table 34 – Demand Response Program Impacts by Date

Date	MWh Interrupted By Program Type					
	Demand Response 2 Hr	Demand Response 30 Min. w/EG	Demand Response 30 Min. w/o EG	Price Response	Profiled	Total
3/3/2003				12.048		12.048
3/4/2003				35.984		35.984
3/5/2003				25.822		25.822
3/6/2003				20.652		20.652
3/7/2003				39.121		39.121
3/10/2003				22.818		22.818
3/11/2003				50.566		50.566
3/12/2003				19.564		19.564
3/13/2003				72.700		72.700
3/14/2003				49.983		49.983
4/4/2003				0.000		0.000
4/8/2003				0.000		0.000
4/11/2003				54.614		54.614
4/14/2003				21.430		21.430
6/5/2003				95.496		95.496
6/25/2003				0.638		0.638

[51] Includes 130.9 MW of former Type 2 Interruptible Load.

Date	MWh Interrupted By Program Type					
	Demand Response 2 Hr	Demand Response 30 Min. w/EG	Demand Response 30 Min. w/o EG	Price Response	Profiled	Total
6/26/2003				130.958		130.958
6/27/2003				207.063		207.063
7/1/2003				107.055		107.055
7/8/2003				163.509		163.509
7/21/2003				1.312		1.312
7/23/2003				41.511		41.511
7/31/2003				19.236		19.236
8/11/2003				4.587		4.587
8/15/2003	280.888	378.788	458.210	32.694	193.371	1,343.951
8/20/2003				23.555		23.555
8/21/2003				36.464		36.464
8/22/2003				60.542		60.542
8/27/2003				104.727		104.727
9/15/2003				340.182		340.182
10/17/2003				63.742		63.742
10/27/2003				31.290		31.290
10/28/2003				82.742		82.742
10/29/2003				48.732		48.732
10/30/2003				57.504		57.504
10/31/2003				108.365		108.365
11/3/2003				46.625		46.625
11/4/2003				68.330		68.330
11/5/2003				40.165		40.165
11/6/2003				78.105		78.105
11/7/2003				51.030		51.030
11/10/2003				99.209		99.209
11/13/2003				60.668		60.668
11/14/2003				124.093		124.093
11/17/2003				69.595		69.595
11/18/2003				78.062		78.062
11/19/2003				50.827		50.827
11/20/2003				56.168		56.168
11/24/2003				110.405		110.405
11/25/2003				95.102		95.102
12/1/2003				247.490		247.490
12/18/2003				357.596		357.596
12/19/2003				402.317		402.317
Total	280.888	379.934	209.655	4,222.993	440.780	5,534.250
% of Total	5.1%	6.9%	3.8%	76.3%	8.0%	100.0%

Table 35 – Demand Response Program Impacts by Date and Load Zone

Date	MWh Interrupted By Load Zone								
	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Total
3/3/2003	1.900	0.014	0.206	2.090	3.744	1.019	2.849	0.226	12.048
3/4/2003	5.732	0.102	0.366	12.264	3.938	1.824	9.884	1.874	35.984
3/5/2003	3.584	0.035	0.122	8.489	3.405	1.932	7.843	0.412	25.822
3/6/2003	2.714	0.013	1.409	10.644	1.092	0.081	4.291	0.408	20.652
3/7/2003	7.834	0.442		9.784	1.020	2.061	16.013	1.967	39.121
3/10/2003	4.430	0.010		7.102	4.079	2.173	4.724	0.300	22.818
3/11/2003	6.680	0.106		10.715	3.469	1.976	27.389	0.231	50.566
3/12/2003	4.287	1.261		8.864	0.471	1.926	2.101	0.654	19.564
3/13/2003	4.646	0.056		61.197	0.964	0.000	5.603	0.234	72.700
3/14/2003	2.233	2.152		26.799	0.978	0.556	16.856	0.409	49.983
4/4/2003									0.000
4/8/2003									0.000
4/11/2003	9.572	0.150		20.585	2.420	2.511	17.745	1.631	54.614
4/14/2003	2.702	0.069		13.015	0.272	0.818	4.259	0.295	21.430
6/5/2003	17.864		1.337	46.165	2.632	0.752	23.351	3.395	95.496
6/25/2003			0.638						0.638
6/26/2003				54.538				76.420	130.958
6/27/2003			23.679	22.813	0.365	6.011	6.313	147.882	207.063
7/1/2003								107.055	107.055
7/8/2003			0.000	57.856	0.335	2.297	6.672	96.349	163.509
7/21/2003				1.312					1.312
7/23/2003				41.511					41.511
7/31/2003				19.236					19.236
8/11/2003					4.587				4.587
8/15/2003				1,343.951					1,343.951
8/20/2003				23.555					23.555
8/21/2003				36.464					36.464
8/22/2003				60.542					60.542
8/27/2003								104.727	104.727
9/15/2003			16.448	155.339	4.996	15.707	20.888	126.804	340.182
10/17/2003			63.742						63.742
10/27/2003				31.290					31.290
10/28/2003				82.742					82.742
10/29/2003				48.732					48.732
10/30/2003				57.504					57.504
10/31/2003				108.365					108.365
11/3/2003				46.625					46.625
11/4/2003				68.330					68.330
11/5/2003				40.165					40.165
11/6/2003				78.105					78.105
11/7/2003				51.030					51.030
11/10/2003				99.209					99.209
11/13/2003				60.668					60.668
11/14/2003				124.093					124.093
11/17/2003				69.595					69.595

Date	MWh Interrupted By Load Zone								
	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA	Total
11/18/2003				78.062					78.062
11/19/2003				50.827					50.827
11/20/2003				56.168					56.168
11/24/2003				110.405					110.405
11/25/2003				95.102					95.102
12/1/2003				51.759	4.771		20.870	170.090	247.490
12/18/2003				45.077	8.501		58.624	245.394	357.596
12/19/2003				76.972	12.087		67.448	245.810	402.317
Total	74.178	4.410	107.947	3,585.655	64.126	41.644	323.723	1,332.567	5,534.250
% of Total	1.3%	0.1%	2.0%	64.8%	1.2%	0.8%	5.8%	24.1%	100.0%