

INVESTIGATION OF BULK POWER MARKETS

NORTHEAST REGION

November 1, 2000

The analyses and conclusions are those of the study team and do not necessarily reflect the views of other members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself.

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1. Overview

The Northeast is the only region of the country that is composed exclusively of highly organized markets or Independent System Operators (ISOs). As a consequence of the existence of the tight power pools of Pennsylvania-New Jersey-Maryland (PJM),¹ the New York Power Pool (NYPP) and the New England Power Pool (NEPOOL), the region was able to make the transition to an ISO structure relatively quickly.

Unlike other regions of the country that are partially organized around an ISO (the West), or are exclusively bilateral markets containing mostly vertically integrated utilities (the Midwest and Southeast), the Northeast is exclusively an “ISO market.” In spite of the fact that all three Northeast ISOs are essentially based on the same market design, which integrates the transmission entity (ISO) with the market function, they are each different. The markets provided in each ISO differ (e.g., energy, reserves, regulation services), as do the manner and times in which generation is dispatched and the rules governing them. The rules governing each are complex and provide the major focus of this report.

This report provides staff's observations of the market as it exists today in the Northeast as well as its major inefficiencies. Section 2 provides an overview of the supply and demand situation. Section 3 presents the prices in the ISO markets and some other indicators of market performance. Section 4 provides the regulatory framework under which this region operates and the organization of the ISOs, and section 5 discusses the major issues and inefficiencies. Finally, section 6 provides possible options available to address the inefficiencies identified.

Findings and Conclusions

Staff's overall findings and conclusions are as follows:

- Each Northeast ISO has completed a transition from a cost-based power pool to a market/bid-based ISO. This transition has ensured continuation of the benefits of pool cooperation for regional reliability, system integration and dispatch.
- To date, the success of the transition to a market environment has varied among the three pools. The PJM transition has been relatively smooth. The more ambitious designs in ISO-NE and the NYISO, which have attempted to begin their

¹Delaware and the District of Columbia are also included in the PJM territory as well as parts of Delmarva Virginia.

markets with a larger array of market-based services, have experienced a number of significant start-up problems, particularly in ancillary service markets.

- New York and New England ISOs continue to intervene significantly in their markets to correct prices. This reflects continued problems with market rules and procedures by which software calculates prices. The pace of change to rectify this situation, and the market uncertainty that this conveys, are cause for concern.
- The lack of a workable congestion management system in New England is a cause of significant cost to market participants without conveying a meaningful price signal to which the market can react. Further, the time line proposed for adoption of a new congestion management system is long.
- The New York ISO has proven to have a market structure, market rules, and software procedures that impede the ability to transfer power throughout the Northeast. This has implications not only for the broad wholesale market and prices, but also for consumers within New York State. It exacerbates already tight supplies in New York, and can affect New York's ability to meet its reliability criteria.
- Significant physical transmission constraints exist and are exacerbated in a wholesale market environment. This is especially the case in New York City and Long Island, but it affects the Boston area as well.
- There were few significant price events in the peak 2000 season, but the relatively low load conditions were due mostly to mild weather. Volatile prices may be experienced in the region until the arrival of significant levels of new generation in 2002. However, New York City experienced relatively high prices this summer that were largely due to increased natural gas and fuel oil prices, a large nuclear unit outage, and other unplanned outages, combined with limited transmission into the area. New England also suffered a significant price event in May caused by poor market rules.
- The ISOs generally are inwardly focused with little attention paid to the strategic goal of harmonizing their rules and procedures to allow the better integration of their systems. Their internal market reforms will take anywhere from several months to 2 years to be implemented. This will mean a transition period in which ISOs and market participants will be arguing over the need for price caps and further market interventions, which may further delay fully competitive markets.

2. Supply and Demand Conditions

Demand for electric energy in the Northeast has grown at a faster rate than anticipated in recent years and industry forecasts project continued growth. This summer, below-average temperatures served to keep this demand at a generally manageable level. Nonetheless, recent market events have raised questions regarding the short and long-term availability of supplies at a reasonable cost, and the ability of the transmission grid to keep the power flowing efficiently and without constraints. As the analysis below indicates, however, the supply outlook for the region, as a whole, appears to be relatively strong, after 2001.

A. Regional Overview

The bulk power system of the northeastern United States serves more than 23 million customers from Maine to the Delmarva Peninsula, including the major population centers of the eastern seaboard: Boston, New York, Philadelphia, Baltimore and Washington, DC. It is part of a larger electrical entity, the Eastern Interconnect. All U.S. bulk power transmission east of the Rocky Mountains (except Texas) is synchronously interconnected (that is, the frequency is the same everywhere, and power flowing in one part of the interconnection affects flows elsewhere). The Northeast's power system therefore reacts electrically to conditions throughout the Interconnect, and it imports from or exports to Canada (Ontario and Quebec), the Midwest (ECAR), and the South (SERC).

The blackout of 1965 spurred the development of power pools in the northeastern United States. By the early 1970s, the New England Power Pool (NEPOOL), serving the six New England states, and the New York Power Pool (NYPP), serving the state of New York, were created. They joined the Pennsylvania-New Jersey-Maryland Interconnection (PJM), formed in 1927 to serve New Jersey, Delaware, the District of Columbia, most of Pennsylvania and Maryland, and peninsular Virginia.

Each power pool centrally dispatched its combined generating resources to meet its combined loads, without regard to unit ownership. This improved reliability (through centralized control and sharing of reserves) and economy (by allowing economic dispatch of all generators). The savings thus realized were shared among pool members. Each pool also required its members to provide transmission access to other members without a direct charge for economy trades effected through central dispatch, as compensation for use of their facilities.

A large, interconnected transmission infrastructure evolved to support the pools. High voltage transmission lines, including many 345 kV and 500 kV lines, allowed internal sharing of economy power and improved reliability. They also enabled

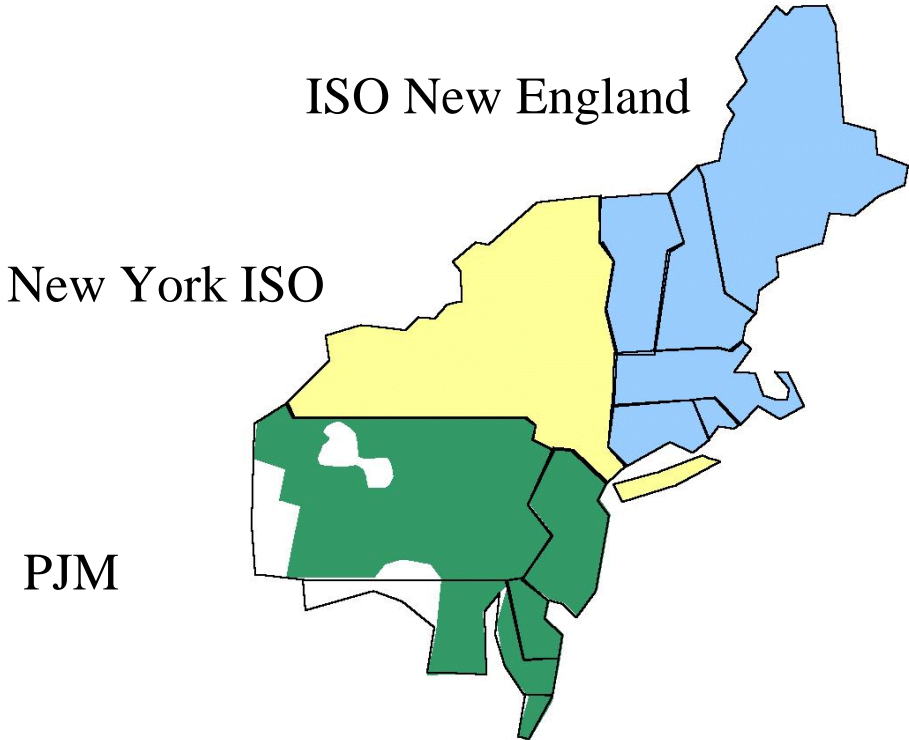
NEPOOL, NYPP, and PJM to transfer power from western coal-fired generators and northern hydropower generators to eastern load centers. Pursuant to Order No. 888, the Commission in 1997 and 1998 authorized the three power pools to become independent system operators.

The demand for electricity in the northeastern United States has grown steadily throughout the region, at an overall rate that has exceeded expectations. Between 1995-2000, the average annual growth rate was 1.3 percent, or 6.7 percent overall. Peak electrical demand for the region now stands at approximately 103,000 MW, and is expected to grow to over 105,000 MW by 2002. Of the three northeastern ISOs, PJM serves the largest total load (49,325 MW), followed by the NYISO (30,200 MW) and ISO New England (23,250 MW).

To meet the overall demand of the region, the northeastern ISOs are currently relying on a total supply portfolio (120,000 MW of installed generation capacity) that has remained relatively flat over the past 5 years. At the same time, the interconnected network of high voltage transmission lines operated by the northeastern ISOs has been susceptible to constraints, during peak periods, and has been able to rely on only limited intra-regional transfer capabilities.² Figure 1-1 shows the geographical extent of the northeastern ISOs.

²PJM has interconnection ties with ECAR, SERC and New York. The NYISO is directly interconnected to ISO New England, the Independent Electricity Operator of Ontario, Hydro Quebec, and PJM. ISO New England is interconnected with the NYISO, Hydro-Quebec, and New Brunswick.

Figure 1-1. Northeastern ISOs



B. Supply Capacity and Generation Entry

Table 1-1, below, summarizes the actual and forecasted peak summer demand and capacity of the Northeast region for the period 1998-2002.

Table 1-1. Peak Summer Generation Capacity and Demand (Megawatts)					
ISO	1998 actual	1999 actual	2000 forecast	2001 forecast	2002 forecast
ISO-NE Peak Demand ^a	21,406	22,544	23,250	23,700	24,046
Capacity ^b	22,263	23,210	26,950	30,732	40,991
Margin	4.0%	3.0%	15.9%	29.7%	70.5%
NYISO Peak Demand ^a	28,160	30,311	30,200	30,460	30,790
Capacity ^b	31,154	31,271	35,117 ^c	35,793	37,923
Margin	10.6%	3.2%	16.3%	17.5%	23.2%
PJM Peak Demand ^a	48,397	47,626	49,325	49,884	50,630
Capacity ^b	56,113	53,381	57,827	59,802	64,621
Margin	15.9%	12.1%	17.2%	19.9%	27.6%

^a Peak Demands are net of interruptible load and demand-side management.

^b 1998 and 1999 capacities are actual operable capacity + firm imports during the peak hour; other capacities are projections.

^c Reflects Indian Point 2 outage.

Sources: Northeastern ISOs and MAAC.

As Table 1-1 illustrates, installed capacity for the region, as a whole, was generally tight this year, and has been since 1998. This trend is likely to continue next summer. Over the short term, the region has not been able to meet its capacity reserve targets. This summer, for example, the capacity margins for each of the three ISOs fell slightly below the desired benchmarks. For 2000, the forecasted capacity reserve margin for PJM was 17.2 percent (below the 19 percent margin set by its reliability committee) and for the NYISO the reserve margin was 16.3 percent (below the required 18 percent margin set by the New York State Reliability Council).³

³ No target reserve margin is specified by ISO New England.

The availability of supplies in the Northeast region this year has also been affected by transmission and generation outages. For example, imports into New York City from PJM were reduced about 400 MW this summer by the failure of a large transformer in New Jersey. As a result, the total transmission capacity into the city was about 4,625 MW (4,175 MW from elsewhere in NYISO, and 550 MW from PJM). The same failure limited the ability of PJM or IMO to transfer power through New York to New England. Indian Point 2, a large nuclear generating station in New York, was unavailable this summer because of an unplanned outage.

As shown in Table 1-2, below, a significant portion of the existing generation capacity in the Northeast region relies on oil and natural gas as fuel sources. This dependency has exposed the region to higher fuel costs in this past summer, and proposed new generation in the region will largely be gas-fueled. See section 3 of this report for additional discussion of prices. Table 1-2 also shows that investor-owned utilities own the majority of generation in PJM, unlike NYISO and ISO-NE.

Table 1-2. Fuel Mix and Ownership of Installed Capacity				
	PJM	NYISO	ISO-NE	Northeast Region
Fuel Mix (%):				
Coal	26	3	11	17
Oil	20	20	31	22
Natural Gas	21	26	23	22
Nuclear	22	24	16	21
Hydro	10	27	14	15
Ownership (%):				
IOU	55	30	22	40
Non-utility	41	48	71	50
Public Power	1	20	4	8
(Not available)	3	1	3	2
Source: RDI; POWERdat.				

To meet the overall supply needs of the region, market participants are relying in some measure on imported power. Historically, PJM has imported approximately seven percent of its total annual energy requirements from outside of PJM, the majority being economy and other short-term purchases from ECAR. The NYISO is also dependent on imported power to meet its system demand. In 1999, for example, the NYISO imported

approximately 2.8 percent of its total energy requirements, mostly from PJM,⁴ and imports increased during the summer of 2000. The expected import level for the summer was 1,584 MW.⁵ ISO New England relies principally on the NYISO and Hydro-Quebec for its imported power requirements. The imported power from Canada is a typically cheaper source of power, but ISO New England's ability to rely on this power has been limited by the region's inability to maintain acceptable voltage levels across the interface.⁶ Since the transmission systems operated by the northeastern ISOs were designed for power pool operation, their intra-regional transfer capabilities are limited.

While the northeastern ISOs are currently relying on imports to help meet their overall demand needs, a significant supply of new generation is planned throughout the Northeast, as shown in Table 1-3, below. Each of the three ISOs have large interconnection queues, representing, in total, over 100,000 MW of proposed new generation capacity.

Only a fraction of this capacity is expected to come on line. Industry sources predict that perhaps only one-third of the PJM queue will actually be built.⁷ NYISO expects only one new plant to be built in the next 3 to 4 years, and is examining ways in which it can work with state government, environmental groups, and market participants to streamline the process.⁸

⁴ FERC Form 714 for 1999, p. 6; Load and Capacity Data, NYISO (July 2000) p. 11.

⁵ Summer 2000 Operating Study, New York Independent System Operator (May 2000), p. 10, A-2.

⁶ See "The Electric Transmission Network: A Multi-Region Analysis," Eynon, R. *et al.*, Energy Information Administration, Issues in Midterm Analysis and Forecasting 2000.

⁷ *Megawatt Daily*, September 29, 2000, p. 7.

⁸ "Market Protective Mechanisms"; policy statement of NYISO Board, October 19, 2000.

Table 1-3 . New Generation (Megawatts)				
Generation capacity expected to come online in each year	PJM^a	NYISO^b	ISO-NE^c	Northeast Region
2001	2,600	0	10,500	13,100
2002	3,800	1,080	5,300	10,180

^aPJM staff conservative estimate.
^bNYISO Board Policy Statement on “Market Protective Mechanisms,” October 19, 2000.
^cBased on queue. ISO-New England staff expects that limitations in natural gas supply will probably prevent this amount of capacity from being built.

In conclusion, the northeast region is experiencing a period of relatively tight supplies. The New York area is of particular concern because it expects only a 3.5 percent increase in new capacity in the next 3 to 4 years. In contrast, PJM and ISO New England should see significant amounts of new generation.

Growing demand, widespread heat events, and unplanned generation or transmission failures have all combined to stress the northeastern power system. Such events will continue to pose a threat in the short term. Beginning in 2002 the regional outlook will improve, but slowly in the New York area.

C. Transmission Capacity

Most load centers in the Northeast region are located along the eastern seaboard, causing a general west-to-east power flow. But load growth has overtaken the construction of new transmission and generation throughout the region, and the west-to-east flow today can overload the transmission systems operated by the northeastern ISOs, causing varying degrees of congestion. Congestion reduces the market's ability to supply power to loads economically.⁹ The problem can be expected to increase as market forces displace the old economic dispatch practices followed by the northeastern power pools and loads continue to increase.¹⁰ For example, PJM's 500 kV system experienced serious (and unexpected) voltage drops during peak demand in 1999, due in part to heavy power

⁹See generally “The Electric Transmission Network: A Multi-Region Analysis,” Energy Information Administration.

¹⁰Reliability Assessment 1999-2008: The Reliability of Bulk Power Systems in North America; NERC (May 2000), p. 34.

transfers across the system.¹¹

Power flows within each ISO can have significant effects on prices and the effective geographic reach of the market. Constraints in the transmission grid can create localized market areas within a region, or smaller areas known as “load pockets.” The existence of these constraints, and their economic implications, must be taken into account in designing markets and planning system expansions. Varying supply and demand conditions complicate the treatment of transmission constraints because most constraints only affect the system for limited periods, the occurrence and duration of which can be unpredictable.

Of the three northeastern ISOs, the issue of transmission constraints is of particular concern to the NYISO. For example, its Central-East interface (a set of transmission lines feeding power from north and west into the eastern part of the state) was at its capacity limit approximately 80 percent of the time in June of 2000.¹² In granting the member systems of the NYISO market-based rates authority in early 1999, the Commission relied on market studies that showed the existence of a significant west-to-east constraint that divides New York State into two separate markets.¹³ In the nearly 2 years since the Commission issued its order, the constraint at the Central-East interface remains significant, and the interface often is loaded heavily with west-to-east flows. Central-East congestion can also limit imports from Hydro Quebec into ISO New England. Congestion is also a problem for flows from north to south. A consequence of these constraints is that all of the 10-minute reserves must be located in the eastern part of the state.

In addition to the heavily congested Central-East interface, the NYISO has localized transmission constraints into New York City and Long Island. The capacity requirements for these load centers are treated separately from the rest of the service area operated by the NYISO, reflecting the concentration of load in, and the limited ability to import power into, these areas. During the installed capacity auctions for these areas this year, the load serving entities (LSEs) who participated in the auctions were unable to obtain all of the required capacity for these areas, and available capacity that could be acquired was expensive. Moreover, when thunderstorms threaten transmission lines to the north of New York City, reliability rules require operating changes that make this

¹¹Heat Wave 1999: July 1999 Low Voltage Condition Root Cause Analysis; PJM Root Cause Analysis Team, March 21, 2000 at 1.

¹²See Monthly Report, New York Independent System Operator (June 2000), p. 5.

¹³Central Hudson Gas & Electric Corporation, *et al.*, 86 FERC ¶ 61,062 at 61,233 (1999).

load pocket “deeper,” that is, reducing its ability to reach outside resources. This increases the market power of generators operating within the New York City load pocket.

Transmission capacity has also been a concern for PJM. Energy within the PJM control area flows from west to east across three internal interfaces: Western, Central and Eastern. Binding constraints have been infrequent at the three internal interfaces but there are still a significant number of hours where they are close to being constrained, especially over the Eastern interface. According to NERC, the Eastern region has a small deliverability margin and requires monitoring until future generation additions arrive.¹⁴ Also, at times when energy flows from ECAR into PJM are high, the ability of suppliers in SERC to send energy into PJM is sharply reduced. Consequently, the transmission lines between ECAR and PJM are relatively heavily utilized (but only reach the estimated limit for a few hours a year). PJM's transmission lines between SERC and NYISO (other than into New York City) have never reached their estimated limits and have large amounts of unused transfer capacity over the year.

Like PJM, NEPOOL planners initially assumed that congestion would remain minimal in the de-regulated generation market. In fact, however, congestion in the Northeastern Massachusetts/Boston area has grown steadily in recent years, particularly since the start of the markets in May 1999.¹⁵ This past summer, transmission constraints there and in Southwest Connecticut accounted for approximately 75 percent of ISO New England's transmission uplift.¹⁶

Some capacity additions are in the works in the Northeast region. In New York, for example, 240 MW of capacity (a 5-percent increase) is expected to be added to the congested Central-East interface by 2002. A private transmission line to serve Long Island from Connecticut with a capacity of 330 MW (with possible future expansion) is planned for 2002 (NYISO's capacity into Long Island at present is about 975 MW). For PJM, approximately 25 miles of 230kV bulk power transmission line additions and

¹⁴Reliability Assessment 1999 - 2008: The Reliability of Bulk Power Systems in North America; NERC, May 2000.

¹⁵ISO New England Web Site, “Summary of Transmission Congestion Uplift Activity During December 1999,” www.iso-ne.com/market_monitoring/congestion_summary/; *see also*, “Summary of Unit Transmission Areas,” www.iso-ne.com/market_monitoring/congestion_summary/Unit_Transmission_Area.xls

¹⁶Uplift is the socialized cost of uneconomic redispatch. Until ISO New England begins locational marginal pricing (in about 18 to 24 months), it will manage congestion by this method.

upgrades are scheduled within the next 2 years.¹⁷ In New England, 222 miles of new high-voltage lines are planned (to an existing 12,700 miles).¹⁸

Aside from the Long Island project, the planned transmission additions will probably not significantly relieve congestion within or between the Northeast ISOs. NERC finds that the proposed NYISO Central-East improvements will relieve “some” of its congestion; and cites three regions within PJM as requiring monitoring because of transmission adequacy concerns.¹⁹ Staff is aware of, but has not evaluated, planned transmission improvements for the Boston area in ISO-New England.

¹⁷MAAC Response to 2000 NERC Data Request (formerly the MAAC EIA 411), April 1, 2000.

¹⁸Reliability Assessment 1999 - 2008: The Reliability of Bulk Power Systems in North America; NERC, May 2000.

¹⁹*Id.*, pp. 68; 75.

3. Prices and Costs

Wholesale electricity prices in the northeastern region have increased under market-based pricing, introduced into each ISO market at different times in 1999. These price increases are partly but not totally attributable to increased demand and higher fuel costs. Other sources of the price increases include, most notably, a lack of market competitiveness under some system conditions (often limited to very few hours on peak demand days), market design flaws, many of which have been or will be corrected, and the lack of a price-responsive demand. Due to the moderate summer temperatures, only two significant price events stand out from the summer of 2000: the May 8-9, 2000, prices, particularly in New England, and the increase in wholesale prices over the summer as a factor in rising retail rates in New York City and Long Island. This section reviews the basic factual information, with further analysis in section 5.

Indicators of Market Performance

This section focuses on the following quantitative and qualitative indicators of ISO market performance:

- **Wholesale market prices.** Prices are the primary indicator of market performance, but may be difficult to interpret. Each ISO reports prices for several energy, ancillary service and capacity products, which may also be differentiated by location and time (day-ahead, real-time). These prices typically represent, depending on the ISO market, either the price of the next available MW of that product or the most expensive MW of the product currently in use. Depending on the congestion management system, energy prices may or may not reflect congestion redispatch costs.
- **Uplift costs.** Uplift costs are costs that are not priced in the ISO markets. In the energy markets, these can include different costs in different markets, depending on the market rules. For example, in PJM and New York, they may include start-up and no-load costs if the generation resource does not recover these costs through its energy spot market sales. In New England, uplift costs are created in starting up a unit to provide operating reserves, but not incremental energy. In addition, under the current New England congestion management method, the costs of re-dispatching the system in the presence of congestion are paid through uplift. In general, because uplift costs are paid by load on an averaged basis, they do not provide an accurate price signal for the underlying service. Increasing uplift costs are an indicator of market inefficiencies.

- **Price corrections (not related to market power).** Price corrections are ex post changes to posted market prices, undertaken by the ISOs for various reasons. The frequency of price corrections can be an indicator of problems in market rules and system operations; a large number of corrections undermines market confidence.
- **Market power mitigation actions.** Market power mitigation actions by the ISOs are undertaken in response to bidding behavior or physical withholding of generation capacity that are intended to increase the market clearing prices. Such actions can include mitigation of bids (e.g., by restricting them to marginal costs or some reference price), payment of liquidated damages and other types of penalties, and changes to market rules. Frequency of market power mitigation actions suggests market problems which may stem from market design and/or market structure. Because market power investigations take several months to conclude (and there are different public disclosure requirements among the ISOs), there is a lag in the availability of public data on mitigation actions.
- **Price and bid caps.** Price and bid caps have been used in several of the bid-based markets in the Northeastern region, reflecting both specific market design problems and concerns about market power, particularly during periods of capacity deficiency. In some installed capacity markets, a deficiency payment acts as an effective price cap (since it is the cost of not purchasing the product) and is indicated as such. The application of a price cap is thus a further indicator of underlying market problems.

Other indicators may also be used to assess the relative performance of the Northeastern region's bilateral and ISO markets:

- **Forward bilateral prices.** July to August forward contracts are the most actively traded summer contracts. In general, most forwards prices for the past few years suggest increasing expectations of higher prices and volatility in most regions and at most hubs. While some moderation in this trend may be seen for summer 2001, the expectation of average prices higher than marginal running costs and higher than actual prices during summer 2000 is clear.
- **Relative market shares.** Relative market shares, sometimes referred to as market liquidity, refer to the percentage of total electrical load served by the spot market, various types of bilateral transactions, and self-schedules. The ISOs do not report these data uniformly. Increasing liquidity in one or the other types of market transactions can be due to different factors (and also subject to interpretation).

A. Overview of Product Markets, Market Design and Pricing Rules

The three northeastern ISO markets share some common market design features. Reflecting their origins as tight power pools, the day-ahead schedule is determined with a centralized unit commitment model, which solves for a least-cost dispatch that meets transmission and reliability constraints (also called security-constrained dispatch).²⁰ Unlike the California market, this means that the ISO and Power Exchange (PX) functions are conducted jointly by the ISO. Like California, real-time prices are determined by energy management system software. Market rules in the Northeastern ISO markets also allow for development of separate bilateral power exchanges, although none are currently operational.

Table 1-4 summarizes the types of products currently offered in each market. In addition, New England offered two additional bid-based products which have been terminated, operable capability and installed capability.

Table 1-4. Bid-Based Products in the Northeastern ISO Markets, October 2000

Product	PJM	New York	New England
Day-Ahead Energy	✓	✓	
Real-Time Energy	✓	✓	✓
Regulation (or Automatic Generation Control)	✓	✓	✓
Ten-Minute Spinning Reserve		✓	✓
Ten-Minute Non-Spinning Reserve		✓	✓
Thirty Minute Operating Reserve		✓	✓
Installed Capacity	✓	✓	

²⁰A unit commitment model is an optimization model, typically a linear program, which solves for the least cost provision of the various energy, ancillary service and transmission services traded in the daily ISO markets. Although a highly technical and mathematical topic, the unit commitment model is the means by which the day-ahead supply and demand bids of market participants are jointly solved. In New York and PJM, the unit commitment model is used to establish the day-ahead financial settlement; in the future it will serve this function also in the New England market, where it is currently used to provide a day-ahead advisory schedule. In the California market, there is no unit commitment model underlying the market solution; rather, the California Power Exchange (PX) and other scheduling coordinators provide day-ahead energy schedules based on bids to the California ISO, which evaluates the impact of these schedules on congestion through an iterative process until a market (but not least cost) solution is found.

1. Energy Markets

Each northeastern ISO market design allows three types of energy market transaction: a bid into the ISO spot markets, a self-schedule, and a bilateral schedule.²¹ Currently, both the PJM and New York ISOs operate both day-ahead and real-time energy markets. The day-ahead price is posted as an hourly price. Real-time prices are typically posted at intervals of about 4 to 5 minutes in New York (but sometimes as long as almost half an hour) and every 5 minutes in PJM. ISO New England currently only operates a real-time energy market and posts an hourly energy price which is the average of the price in each five minute period. As noted below, where relevant the average prices are load-weighted, by zone or period of the day.²²

2. Ancillary Service and Installed Capacity Markets

All three ISOs have bid-based markets for regulation and frequency control (called automatic generation control in New England). New York and New England have bid-based markets for operating reserves; PJM is still planning its own such markets. While New York and PJM have bid-based markets for installed capacity, New England has recently terminated its own capacity product markets (however, the definition and function of the capacity products differs between ISOs, as will be discussed further in Section 5, below). In each ISO, prices for these products are hourly system prices (that is, they are not locational prices).

²¹A bid into the spot market is represented by a bid function which provides prices and quantities from generators at specific locations. A self-schedule is a request to dispatch generation at a particular location regardless of price. Typically, it means that a vertically integrated utility is meeting its demand with its own generation. Bilateral transactions within the ISO markets are power delivery contracts of various periods in length (from several hours to months) that utilities undertake with independent power producers, merchant generators, power marketers and between utilities. Information required by the ISO for a bilateral schedule includes, variously, a point of delivery and point of receipt, a quantity, and, for some types of bilateral transactions, a price and a transmission bid.

²²For example, in New York, zonal prices and loads are reported for the 11 zones within the control area boundaries (as well as prices for interfaces at the boundary). The load-weighted hourly price requires that each hourly zonal price be multiplied by the hourly load and then the product divided by the total hourly system load.

3. Congestion Management and Transmission Rights

Currently, PJM and New York calculate locational marginal pricing of energy and base congestion pricing on the differences in locational prices at points of delivery and points of withdrawal. The locational price includes a congestion component (as well as losses). In addition, both PJM and New York offer financial congestion rights specified from points of delivery and points of withdrawal. These rights are offered through a centralized auction and also on a secondary bilateral market. Prices and quantities of these rights transacted through the auctions are reported regularly. New England is currently scheduled to implement this type of congestion management system in late 2001. Until then, New England does congestion management through redispatch, with the costs allocated on a pro-rata basis to all electrical load as uplift.

B. Fuel Prices

Fuel costs are normally the main factor in short-term marginal costs of producing electricity. This section will review trends in the prices of major fuels. Unlike California, moderate temperatures throughout the Northeast region in 2000 have limited the use of more expensive oil- and gas-fired generation. The price spikes in the region this year have tended to result as much from market design problems as from increases in input costs. Nevertheless, in selected cases in the summer of 2000, notably electricity prices in New York City, fuel costs played a significant role in increasing wholesale and retail electricity prices. In addition, tight markets for natural gas and fuel oil in the winter of 2000 may result in high electricity prices in the event of high demand.

Natural gas and fuel oil were much more expensive in summer 2000 than in 1999. The Northeast is more dependent on these fuels than some other regions: about 72 percent of installed generating capacity is fossil-fueled.²³

Natural gas prices rose sharply during 2000. Prices during 1999 had averaged \$3.11 per MMBtu.²⁴ By May 2000, they had increased to \$3.88; in mid-October they were above \$5.50.²⁵

²³ EIA database. Some Northeast capacity is coal-fired; coal prices were essentially unchanged.

²⁴ Citygate prices, EIA, *Monthly Energy Review*; September 2000.

²⁵ New York citygate prices, EIA, *Natural Gas Update*, October 12, 2000.

Prices of residual fuel (oil) also increased. Summer 1999 prices ranged from \$0.34 to \$0.46 per gallon, but prices in the summer of 2000 ranged from \$0.58 to \$0.69.²⁶

C. Significant Wholesale Price Events

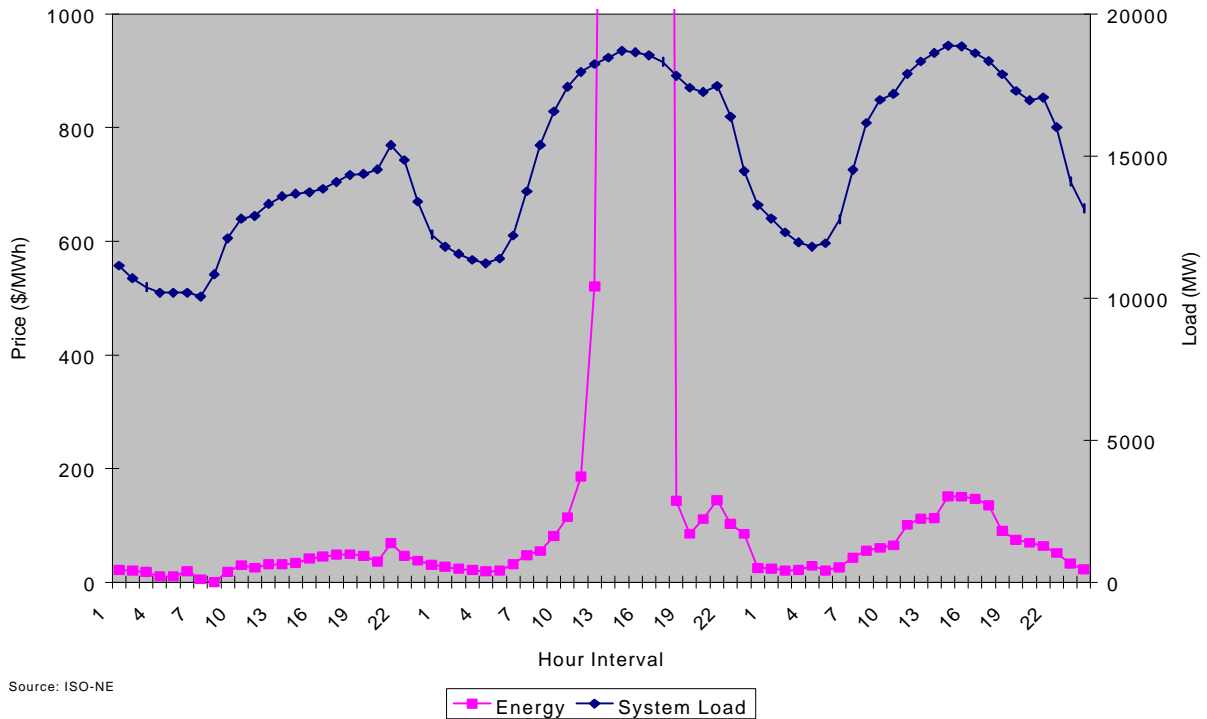
1. Prices in New England, May 8, 2000

On May 8, 2000, the New England markets experienced their highest hourly energy and 10-minute spinning reserve prices since the start of market operations. An external energy sale into New England set a \$2870.91/MWh price for hour 13 and a \$6000.00/MWh price for hours 14 to 17. The system load during that period ranged from just above 18,300 MW to a maximum daily peak load of 18,696 MW, of which upwards of 40 percent was energy purchased in the spot market. A 10-minute spinning reserve price of \$3479.71/MW was set in hour 14.

Section 5 discusses the causes of the price spike on May 8, but its scope was caused by a conjunction of unexpectedly high temperatures at a time when units were still out for Spring maintenance along with high unplanned outages, arbitrary bidding behavior selling installed capacity into New England, the interaction of energy and reserve market designs, and ISO New England judgments about New York energy prices in the coming hours. As shown in Figure 1-1 below, prices in surrounding hours and both the prior and subsequent day were substantially lower. The load-weighted average energy price on May 7 was \$32.15/MWh, on May 8 it was \$1409.12/MWh, while on May 9 it had subsided again to \$76.21/MWh. Figure 1-1 shows that the peak load on May 9 was actually higher (18,882.56 MW) than the peak load on May 8, but the associated hourly price (\$151.36/MWh) was much lower.

²⁶ New York harbor prices, EIA, *Weekly Petroleum Status Report*.

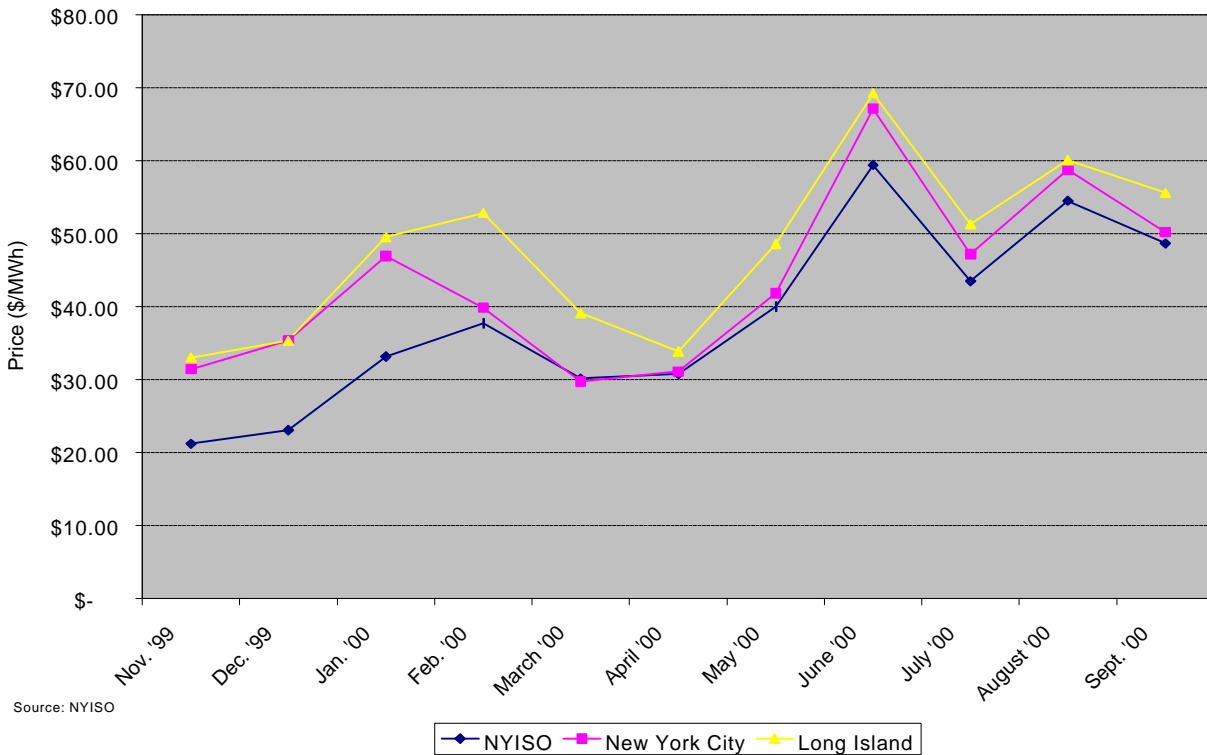
Figure 1-1. New England Energy Prices and Load, May 7-9, 2000



2. Energy Prices in New York City

Despite lower summer temperatures in 2000 as compared with 1999, prices in New York City were on average higher in the summer of 2000 than in 1999. Moreover, prices in the New York City and Long Island zones of the New York ISO were higher than the average prices in system (See Figure 1-2). The retail rates in these zones have been the subject of consumer concern and New York Public Service Commission intervention, as discussed in Section 5.

Figure 1-2. Average Monthly Day-Ahead Energy Prices, New York City and Long Island



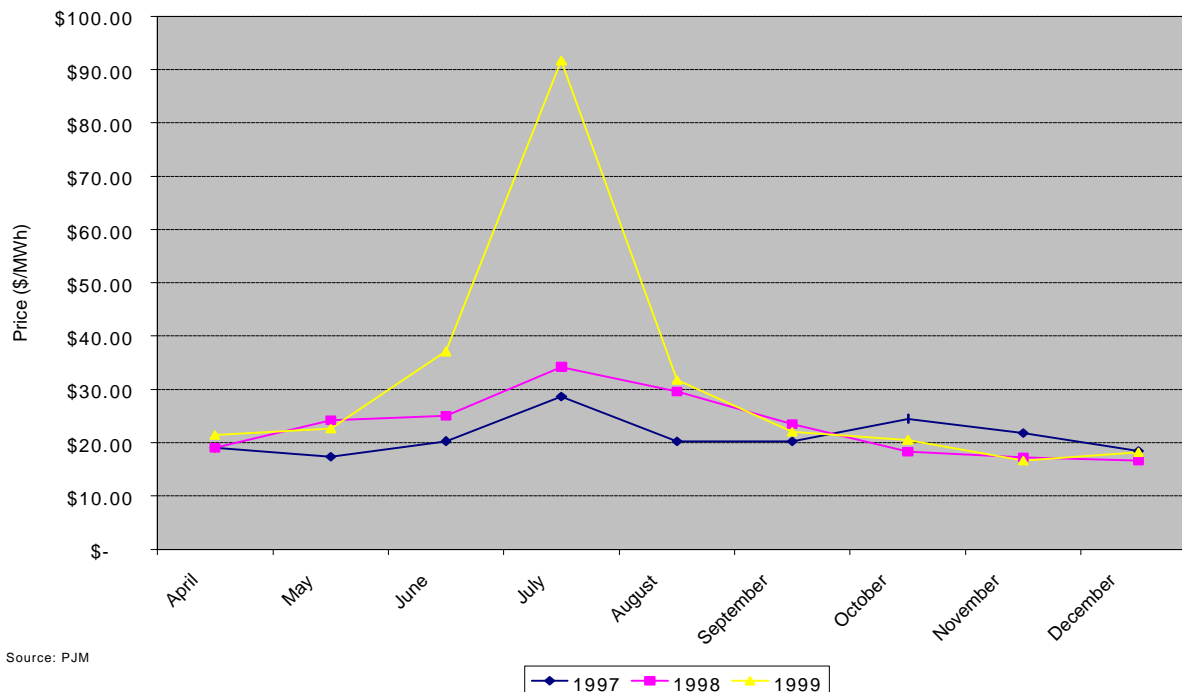
D. General Price Trends and Other Indicators of Market Performance

1. PJM

The way in which wholesale energy prices are calculated in PJM has undergone several changes since the ISO began operations. From April 1997 to April 1999, PJM operated its energy market with cost-based bids and financial settlement at real-time prices. A uniform system-wide energy price was calculated until April 1998, when locational marginal prices were established. On May 1, 1999, market-based bidding began. Finally, on June 1, 2000, the energy market was divided into a day-ahead and real-time market (two-settlement system). Since the beginning of market operations, PJM has imposed a bid cap on the energy market of \$1,000/MWh.

The change in wholesale prices between the cost-based bidding and market-based bidding rules provides some indication of price mark-ups, but has to be evaluated against

Figure 1-3. PJM Monthly Average Energy Prices, Comparison of Cost-Based and Bid-Based Markets, April to December, 1997 to 1999



changes in demand, fuel costs, planned and unplanned outages, and other factors. Figure 1-3 shows the monthly average energy price for April to December, 1997 to 1999. Table 1-5 shows PJM's calculation of daily average energy prices and the percentage increases in prices during the summer months, June to August, 1997 to 1999. PJM attributes the price increases from 1997 to 1998, under cost-based pricing, to, among other factors, increased demand in 1998 (although a lower peak demand) and higher fuel costs.²⁷ With the advent of market-based bidding in 1999 and record summer peak demand, prices in PJM increased significantly. Wholesale prices increased 81.08 percent between summer of 1998 and summer of 1999 (and 132.63 percent between summer of 1997 and summer of 1999). The PJM market monitor attributes some of the high prices on peak days in 1999 to exercise of market power.²⁸ These conclusions and their market design implications for PJM are discussed in Section 5.

²⁷ *PJM Interconnection State of the Market Report 1998*, PJM Market Monitoring Unit, May 1999, p. 22.

²⁸ *PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000.

Table 1-5. Comparison of PJM Summer Energy Prices, 1997 to 1999

	Summer 1997	Summer 1998	Summer 1999
Average Price	23.08	29.65	53.69
<i>Percentage increase from previous year</i>		28.47%	81.08%
Standard Deviation	17.89	58.99	140.33

Source: *PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000, p. 9.

Figure 1-4 shows the monthly average energy price from April 1999 to May 2000. The prices for the day-ahead and real-time markets, from June to September 2000, are shown in Figure 1-5 . With the moderate temperatures in summer 2000, and some market design changes undertaken to inhibit exercise of market power, energy prices have been lower in summer 2000 than summer 1999.

Figure 1-4. Wholesale Market Prices, PJM Monthly Average Single Settlement Energy Prices, April 1999 to May 2000

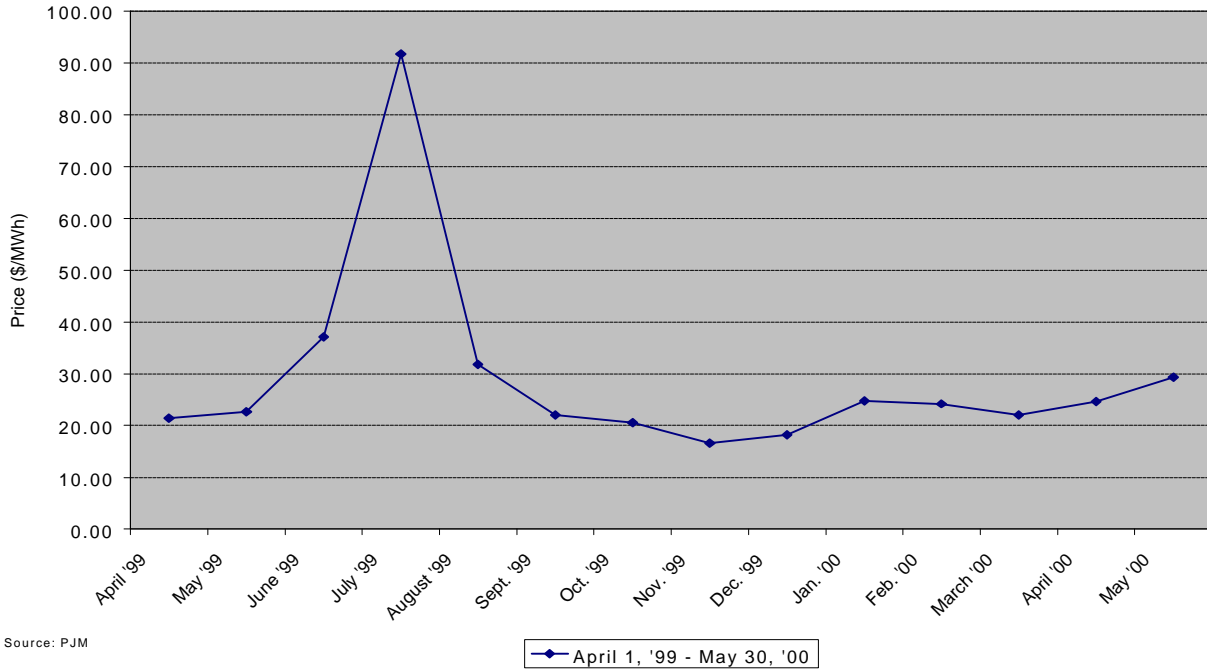
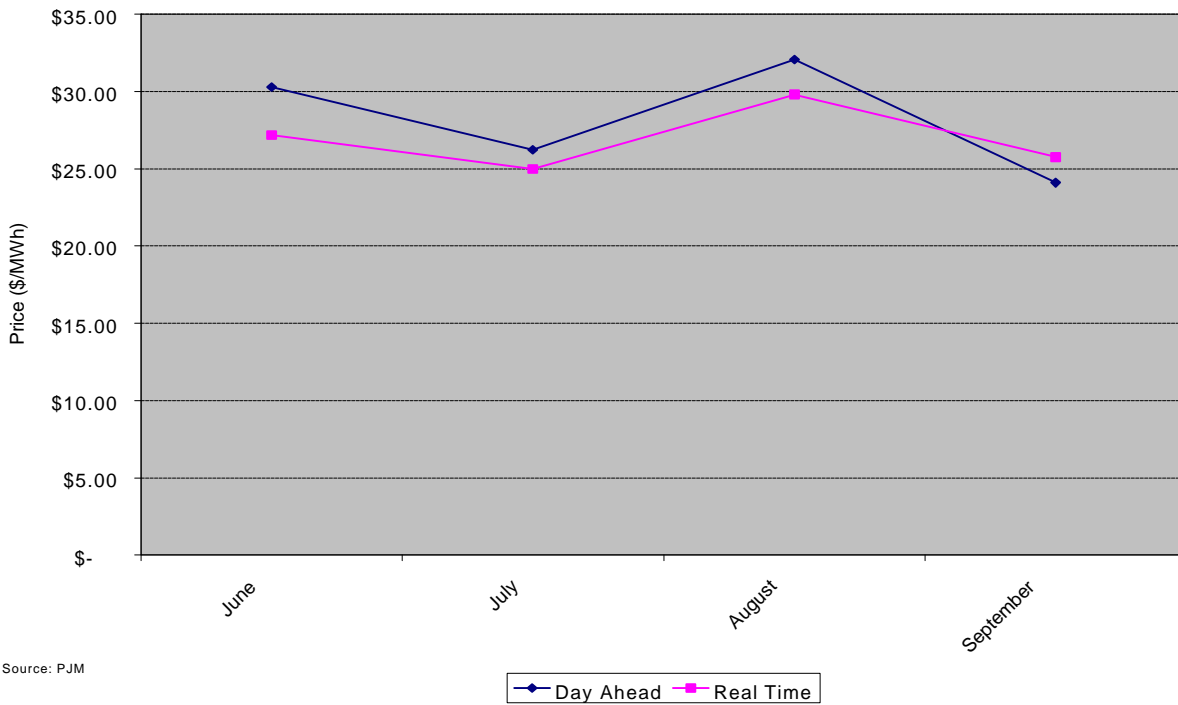


Figure 1-5. Wholesale Market Prices, PJM Monthly Average Day-Ahead and Real-Time Energy Prices, June 2000 to September 2000



Frequency of Price Corrections and Market Power Mitigation Actions

Unlike New York and New England, PJM does not appear to publish public data on the frequency of price corrections. In general, from discussion with PJM staff, it appears that prices have only been corrected as a result of sudden transmission outage.

PJM publishes its market power monitoring and mitigation activities in an annual report. In assessing prices in 1999, the market monitor concluded that firms exercised market power during high demand hours.²⁹ In 1999, the market monitor detected firms changing the minimum run times in their bid parameters as a means to run for longer periods at high prices. As discussed in Section 5, market rule changes were implemented to limit such behavior. In addition, also discussed further in Section 5, PJM has delayed implementation of a bid-based spinning reserve market on the basis that the small number of eligible generators will confer market power.

Prices in Bilateral Forward Market

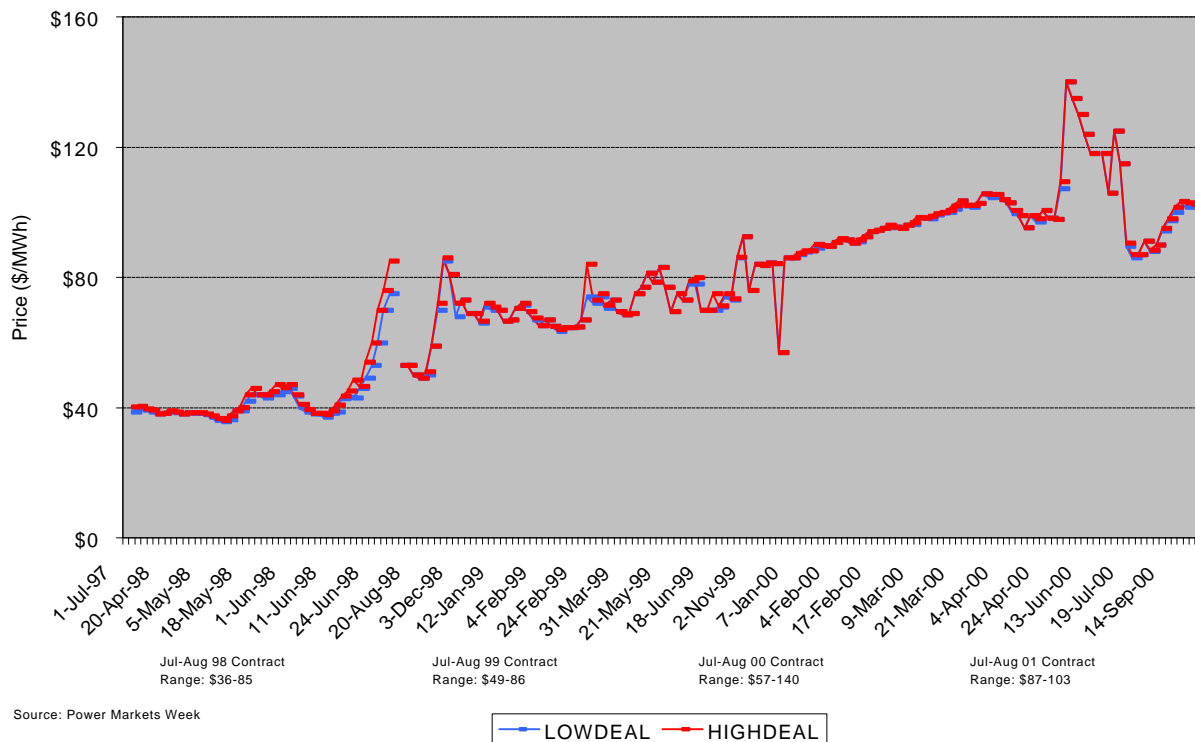
The PJM West hub is the highest volume electricity trading hub in the United States, with volume rising steadily since the introduction of market-based pricing. Figure 1-6 shows that forward prices in PJM increased substantially in the early months of summer 2000, but then subsided. A similar pattern is observed in the other northeastern markets. The overall trend has been an increase in the forward price since 1999.

Relative Shares of Transactions in Energy Market

Unlike New York and New England, the PJM ISO does not report daily and monthly shares of transactions in the spot and bilateral markets. Table 1-6 shows the shares in 1999. Reflecting the continued vertical integration of PJM utilities, it is not surprising that the majority of load is served through self-scheduled transactions. The

²⁹ *PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000, p. 9.

Figure 1-6. PJM West On-Peak Forwards: July to August Contracts



spot market accounts for around 15 percent of total load served, a percentage now substantially lower than New York and New England.

Table 1-6. Relative Shares of Transactions in PJM Energy Market

Year	Energy Spot Market	Self-Schedule	Bilateral Transactions	Imports
1999	15	53	30	2

2. New York

The New York ISO began market-based pricing in its day-ahead and real-time energy and ancillary service markets on November 18, 1999. The markets experienced a high number of price corrections in the initial months. By mid-January, exercise of market power was apparent in the operating reserve markets, which was addressed through market rule changes and price caps. In the energy market, market problems included poor functioning of advisory prices and, as discussed above, concern focused on

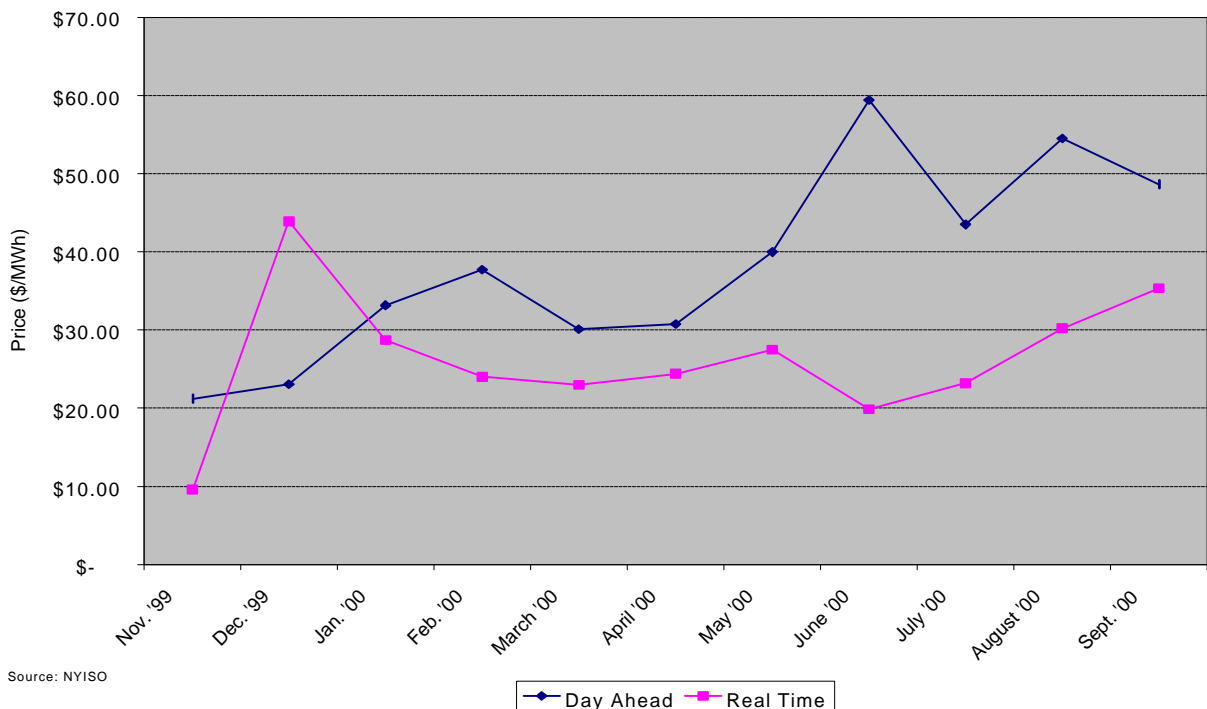
energy prices in transmission constrained zones in Eastern New York, notably New York City and Long Island.

Over 95 percent of total energy is scheduled in the day-ahead, rather than real-time market. As shown in Figure 1-7, in 2000, the monthly average system price for day-ahead energy has ranged between \$29.24/MWh (March) and \$57.96/MWh (June). As noted above, the system price is the price of the next available MW of energy in New York; if the day ahead energy price is calculated as a zonal-load weighted average price, then the price will be higher, typically by \$1 to \$3.

The monthly average system price for real-time energy in 2000 has ranged between \$27.40/MWh (March) and \$50.12/MWh (September). The thinness of the real-time market results in significant volatility, as shown in the graph of hourly average prices in Figure 1-8.

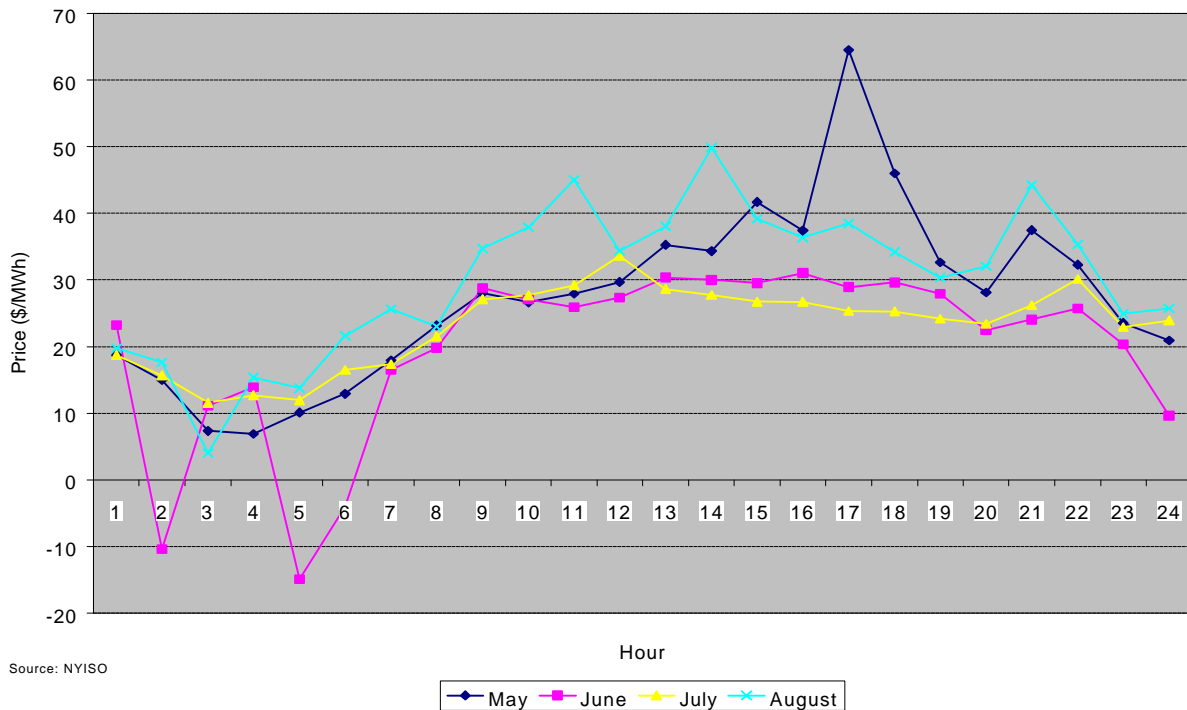
The New York ISO has experienced major problems with its operating reserve markets. Prices remained reasonable from the start of the market until mid-January 2000, when prices for both 10-minute operating reserves climbed dramatically. The ISO suspended both markets in late March and applied a price cap.

Figure 1-7. New York ISO Monthly Average System Price for Day-Ahead and Real-Time Energy, November 1999-September 2000



Source: NYISO

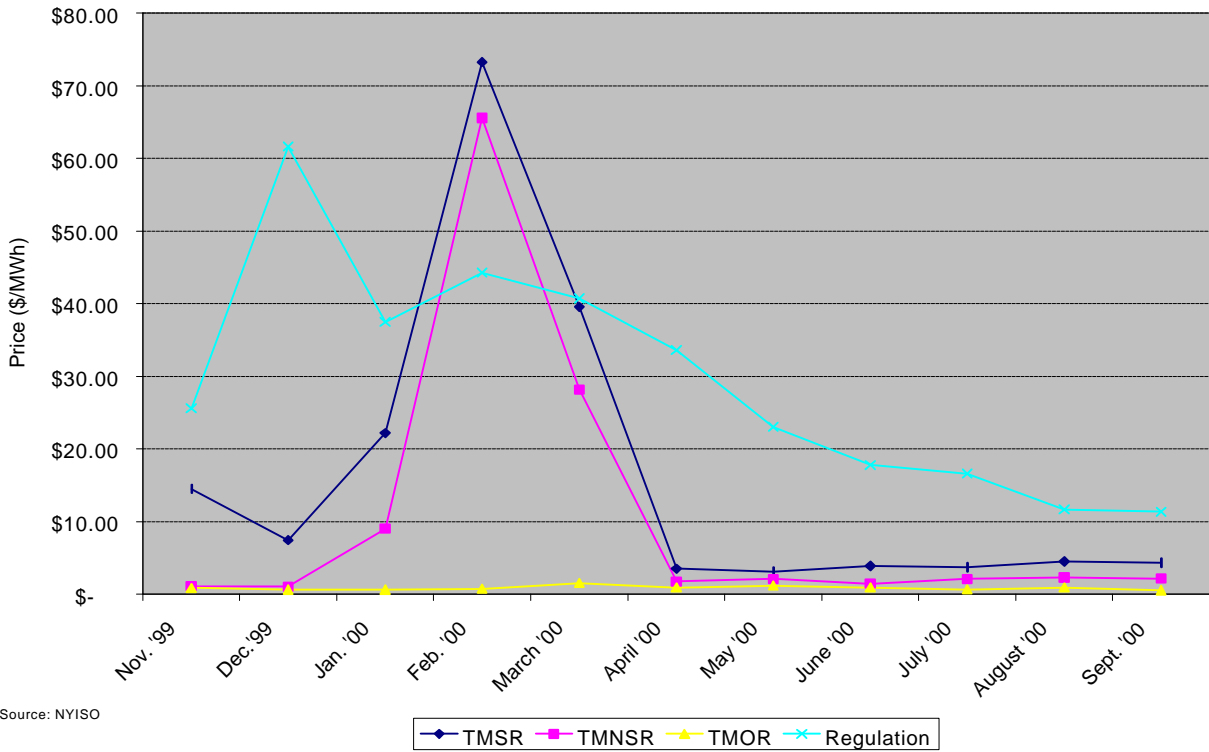
Figure 1-8. New York ISO Average Real-Time Energy Prices by Hour of the Day, May through August, 2000



As shown in Figure 1-9, the monthly average price for 10-minute spinning reserve prices hit a peak of \$73.27/MW in February 2000. Following the application of a price cap of \$6.68/MW, prices declined substantially in April 2000, to a monthly average price of \$3.51/MW. That price cap was later rejected by the Commission and removed. The monthly average price has ranged between \$3.10/MW and \$4.45/MW from April to September 2000.

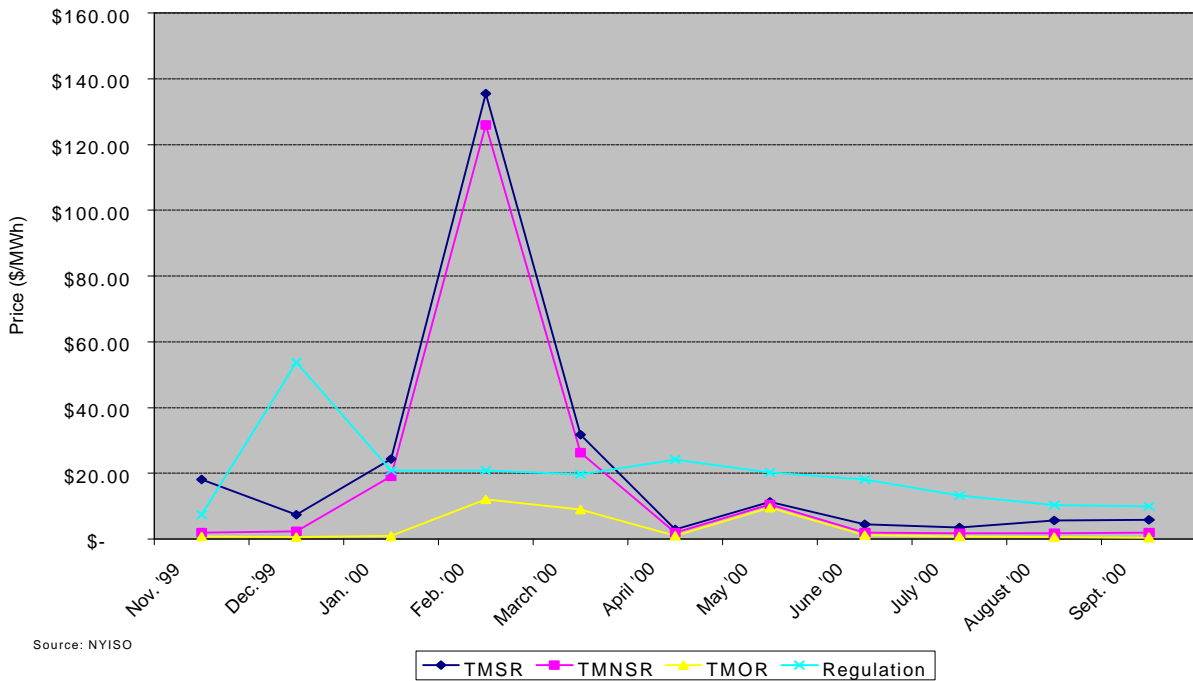
A similar pattern holds for 10-minute non-synchronous, or non-spinning, reserves. The average monthly price hit a peak of \$65.58/MW in February 2000. Following application of a price cap of \$2.52/MW in April, average prices declined substantially in this market as well, to \$1.75/MW in April 2000. The monthly average price has ranged between \$1.47/MW and \$2.30/MW from April to September 2000.

Figure 1-9. New York ISO Monthly Average Day-Ahead System Price for Ancillary Services, November 1999-September 2000



Source: NYISO

Figure 1-10. New York ISO Monthly Average Hour-Ahead System Price for Ancillary Services, November 1999-September 2000



Source: NYISO

Until summer 2000, the average regulation price was higher than the average energy price. This reflects a market inefficiency. However, regulation prices have dropped over the course of summer 2000.

Frequency of Price Corrections and Market Power Mitigation Actions

The New York ISO has undertaken numerous price corrections in its real-time markets since beginning operations (note that these prices are calculated every few minutes).³⁰ Within weeks of the New York ISO's start-up, the percentage of real-time intervals needing correction was over 50 percent at a given time; that is, more than half of the 5-minute prices in real time were in error. While this level of corrections has decreased, reflecting improvements in system operations, both in May and June 2000 the percentage of price corrections were high during certain periods: 40 percent of real-time prices in early May, 50 percent in mid-May, and around 40 percent near the end of June.³¹ Overall, the frequency of real time 5-minute interval price corrections has declined, and the New York ISO expects them to continue to decline.³²

On a monthly average basis, the frequency of real-time price corrections has fluctuated, but since May has declined. In May, there were twelve issues that caused the need for price corrections including several instances where inputs to price calculations were incorrect, e.g., incorrect setting of security constrained dispatch (SCD) limits on steam turbines, incorrect limit setting for units ordered to operate out-of-merit, incorrect treatment of limited energy resources in price calculations. In addition there were instances of missing and invalid data, e.g., binding transmission constraint not modeled, invalid prices during maximum generation pick-up. Since May, the number of problems that have caused pricing errors has declined, but some problems still persist. For example, in June and July SCD limits were still a problem³³; and posted prices were

³⁰ New York ISO has authority to undertake Extraordinary Corrective Actions under its Temporary Extraordinary Procedures. Authority is granted until October 31, 2000. See New York Independent System Operator, Inc., 92 FERC ¶ 61,051 (2000).

³¹ Approximately 95 percent of the NYISO's administered transactions take place in the day-head market; the NYISO has had to correct day-ahead prices only once since inception, September Report, transmittal letter, p. 32.

³² September 1, 2000, Compliance Report (September Report). Docket No. ER00-3591-000, transmittal letter, pp. 31-33.

³³ NYISO reports, September Report, that the problem which had caused SCD to assign incorrect upper operating limits to steam units was eliminated by a software change introduced on July 25.

inconsistent with the bids of marginal units in June through September, as experienced as early as January. So, while some problems appear to have been remedied, others continue and new ones develop.

Table 1-7. Price Corrections by New York ISO, November 1999-August 2000

Month	Average Percentage of 5-Minute Real-Time Price Corrections	Number of Days In a Month Having Correction(s)
November	5.9	NA
December	1.3	NA
January	6.7	26
February	5.5	23
March	1.2	12
April	1.8	12
May	13.72	21
June	4.72	18
July	1.87	12
August	0.52	19

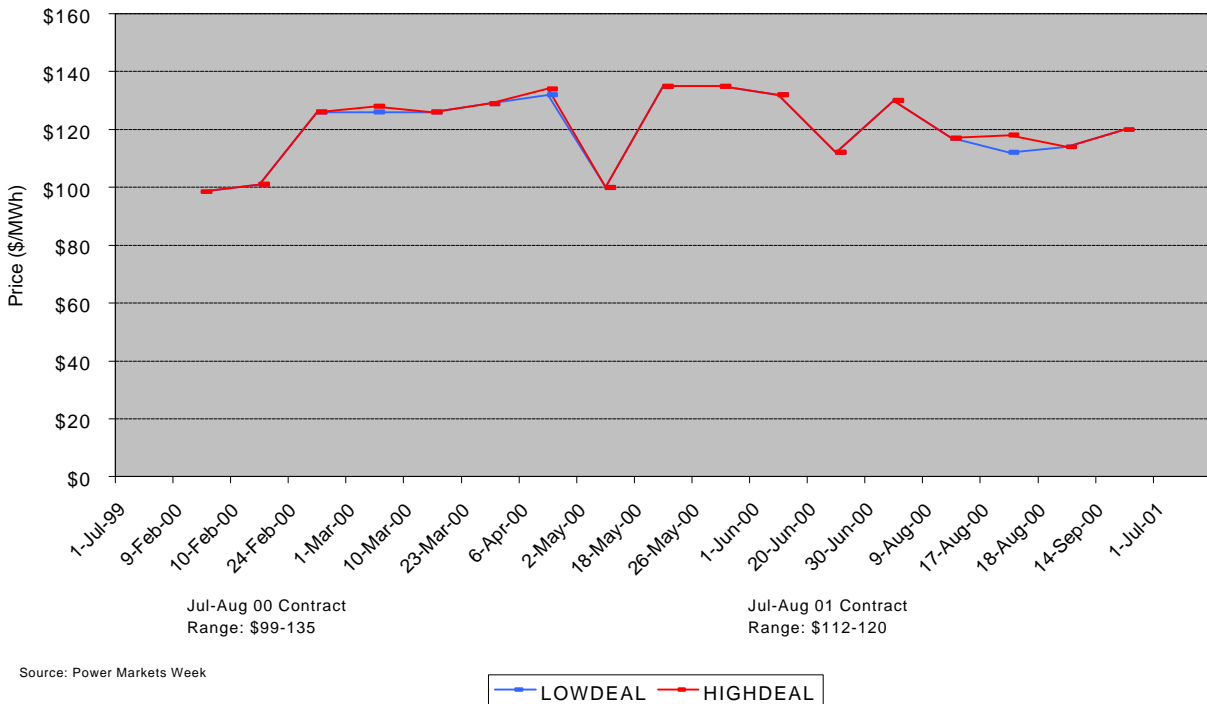
Note: On some days there were more than 15 price corrections.
Source: New York ISO

The New York market monitor has not yet published results of its mitigation actions. However, in cases before the Commission, the ISO has based requests for price caps in its operating reserve and energy markets on the existence of market power.

Prices in Bilateral Forward Market

Figure 1-11 shows prices in the New York bilateral forward market. The range of the July-August 2000 contracts shown in Figure 1-11, \$99 to \$135, proved to be higher than the NYISO price for New York City and Long Island. The June day-ahead, NYISO prices of \$94 and \$93 in New York City and Long Island, respectively, came near the range of forward prices for July and August. However, the New York City and Long Island prices for July averaged only \$64, and the August price averaged \$79. NYISO prices at other locations in eastern New York were near these prices. *Megawatt Daily* prices for on peak, bilateral sales in New York East were even lower than the NYISO

Figure 1-11. East New York On-Peak Forwards: July to August Contracts



day-ahead prices: \$48 in July and \$55 in August.

Relative Shares of Transactions in Energy Market

Table 1-8 shows that the relative shares of transactions in the energy market in New York has shifted markedly over 2000 from bilateral transactions to the spot market (import and export bilaterals and wheels through make up between 4 to 6 percent of the market).

Table 1-8. Relative Shares in New York Energy Markets
(Percentage of Total Electrical Load)

Month	Energy Spot Market	Internal Bilaterals	Import plus Export Bilaterals	Wheels Through
January 2000	30	64	3	2
February 2000	31	63	3	3
March 2000	35	60	3	1
April 2000	37	58	3	1
May 2000	42	52	2	4
June 2000	44	51	2	3
July 2000	45	50	3	3
August 2000	45	51	2	2
September 2000	50	45	3	2

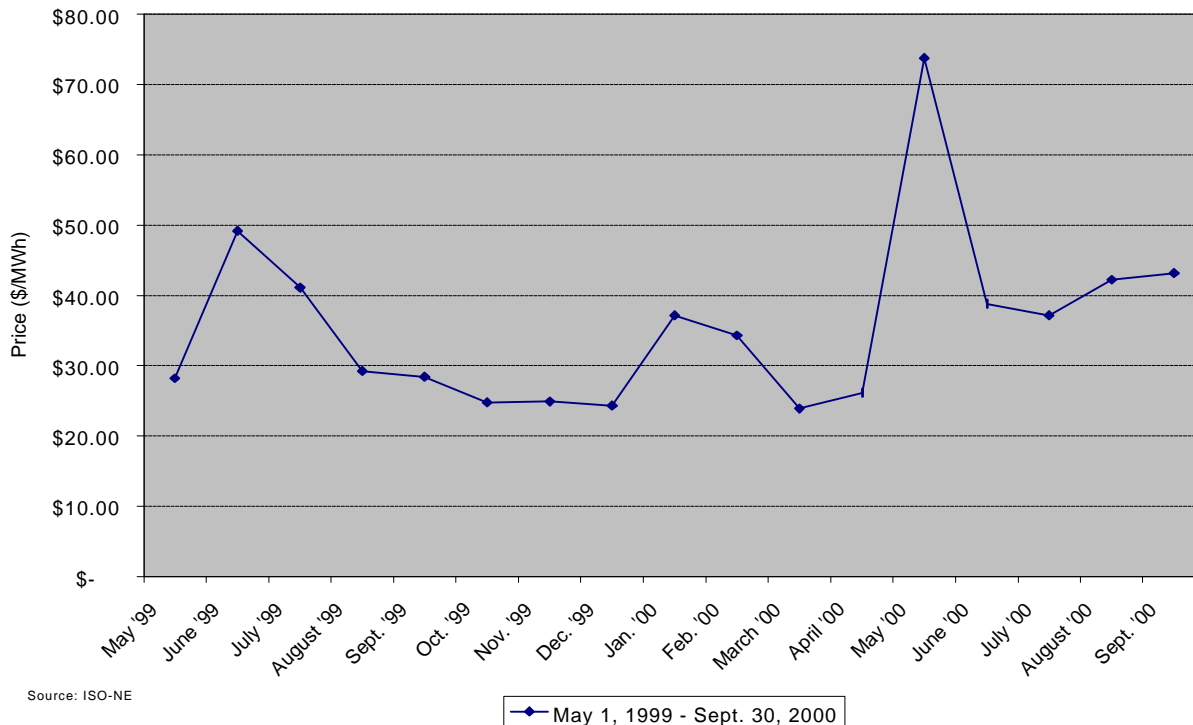
Source: New York ISO. Note that numbers may not add to 100 percent.

3. New England

New England ISO began market-based pricing for energy, ancillary service and capacity products on May 1, 1999. Following a quiet start in May 1999, the New England markets encountered their first problems in June and July 1999, when summer heat waves tested the efficiency of the market design. The maximum energy prices in June and July 1999 were \$1003.21/MWh and \$572.54/MWh, respectively, and the average prices were \$49.18/MWh and \$41.14/MWh. Ten minute spinning reserve prices in June and July 1999 reached \$807.34/MW and \$986.07/MW, respectively, while average prices were \$11.48/MW and \$17.26/MW. During the summer and into the fall of 1999, ISO New England corrected hundreds of hourly market prices, generally reducing them, on the basis of market design flaws. The maximum and average prices cited here reflect the corrected prices. The price correction authority was controversial among market participants and was substantially limited by the Commission.

Following the price events of the summer of 1999, a combination of continuing market design changes, price caps in certain markets, and moderate temperatures restrained market prices until the price spike of May 2000. As shown in Figure 1-12, the average energy prices from August 1999 until April 2000 ranged between \$23.90/MWh (March) and \$37.15/MWh (January). The maximum energy price in this period was

Figure 1-12. Monthly Average Energy Price, May 1999 to September 2000



\$188.07/MWh (October). Ancillary service prices also subsided dramatically in this period (Figure 1-13).

The \$6000 energy price on May 8, 2000, created substantial concern among purchasers of wholesale electricity in New England. Because of the price spike, the average energy price in May 2000 was \$73.76/MWh, the highest monthly average experienced in the New England markets to date. Bilateral forward prices also increased dramatically, anticipating capacity shortages and continuing market operations problems (as shown in Figure 1-15). However, prices in the New England markets in the summer of 2000 were generally lower than the previous summer, reflecting both the cooler weather and the elimination of some market design problems that may have inflated prices previously. The average energy prices for June-September, 2000, were \$38.81/MWh, \$37.14/MWh, \$42.23/MWh, and \$43.15/MWh, respectively. The energy market prices, however, do not capture the rising uplift charges due to congestion and the placing of generation on replacement reserve. Also, the use of generation for replacement reserve may dampen the energy price

Uplift Costs

There are two major sources of uplift costs in the New England markets: energy and transmission congestion. Energy market uplift stems from several sources, including the averaging of the hourly price from the 5-minute real-time prices and payments to generators that are being operated at their low operating levels to provide reserves. This latter reason has become prominent in 2000. Transmission uplift is due largely to generators' output being increased due to congestion. The rapid increase in both types of uplift in New England, as shown in Figure 1-14, suggests the importance of implementing a more efficient market design. Note that the transmission congestion in this figure represents the initial "unmitigated" estimate published monthly by the ISO. Subsequently, the ISO reports on the mitigation of bids in transmission constrained areas, which typically reduces the total transmission congestion uplift by half or more.

Figure 1-13. Monthly Average Ancillary Service Prices, May 1999 to September 2000

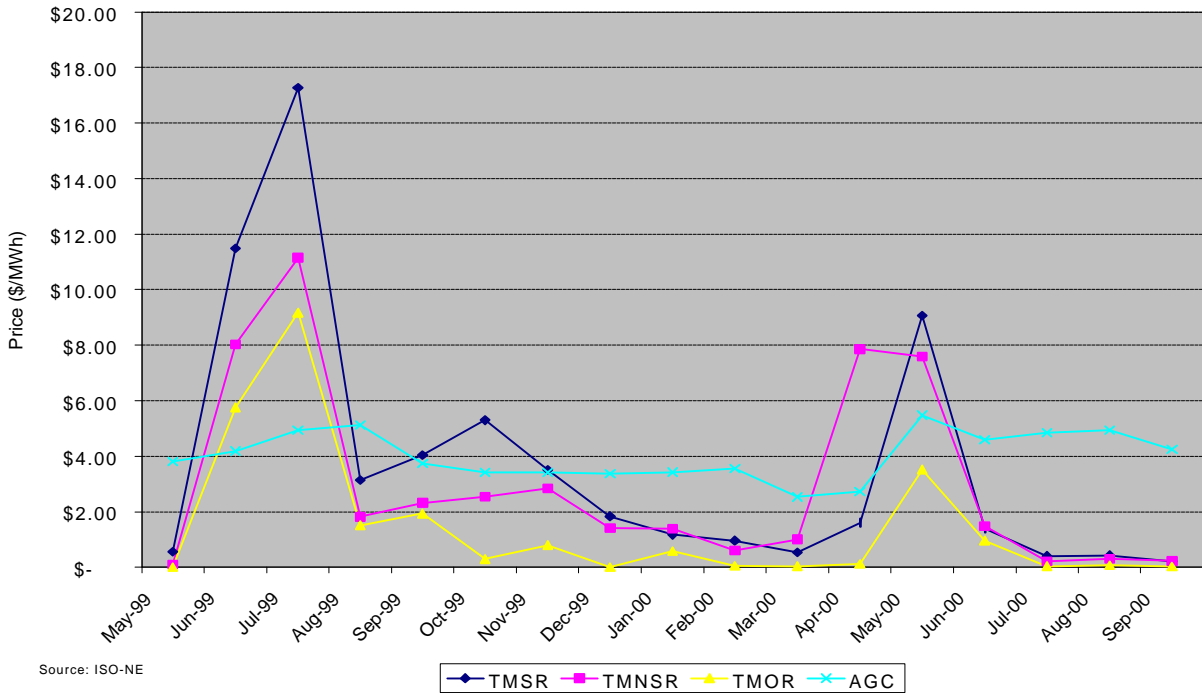
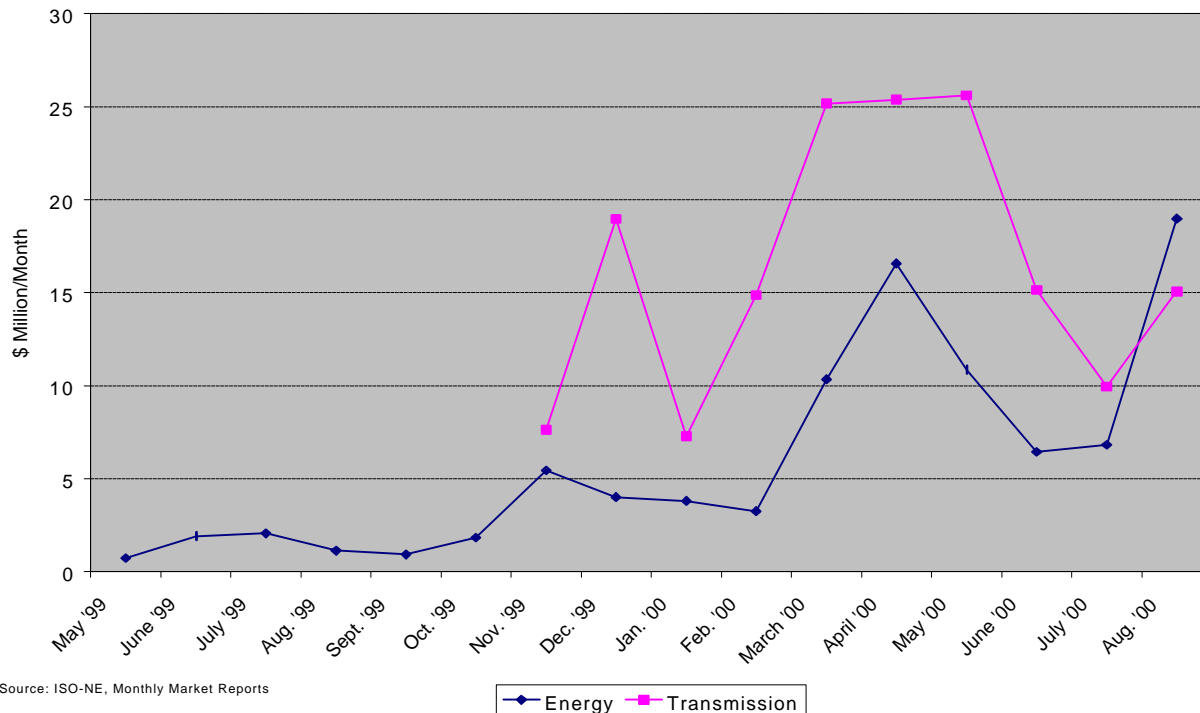


Figure 1-14. Uplift Costs in New England, May 1999-August 2000



Overall, since May 1999, New England's transmission system has experienced increasing congestion. This may be attributable to the fact that, because of divestiture, the major generators in New England are no longer in the transmission business and, because of ISO New England's uplift procedures, do not have an incentive to minimize congestion. In June 28, 2000, the Commission approved a new congestion management system for ISO New England, embodied in a market redesign proposal submitted by the ISO.³⁴ Accordingly, the ISO will also establish locational marginal pricing of energy, with a zonal/nodal system similar to New York ISO. Currently, congestion in the Northeastern Massachusetts/Boston area accounts for much of the transmission uplift (cost of uneconomic dispatch) in ISO-NE: for example, about \$4.7 million of a total \$10 million in July 2000. The southwest Connecticut and Connecticut areas also accumulate significant uplift.

Frequency of Price Corrections and Market Power Mitigation Actions

ISO New England's authority to correct prices is embodied in Market Rule 15. The first version of this rule, approved in anticipation of market start-up and following review of potential design flaws, gave the ISO fairly broad but temporary authority to

³⁴ISO New England, Inc., 91 FERC ¶ 61,311 (2000), rehearing pending.

correct prices that were deemed incorrect due to a market design flaw. This authority was used extensively in 1999, but was not approved by the Commission for subsequent extensions.³⁵ A more restrictive version of the rule was subsequently approved which allowed the ISO to take corrective steps to remedy technical implementation errors and emergency system conditions, but not to adjust clearing prices to account for market design flaws.

Table 1-9 shows that the frequency of price corrections under the less restrictive price correction authority was much greater than under the subsequent rule. From May through September 1999, nearly 10 percent of the hourly prices were corrected. In July 1999 nearly 35 percent of the hourly prices were corrected due mainly to a market design flaw in the operating reserves market. Since December 1999, under the more restrictive rule, the average number of monthly price corrections have fluctuated from as low as 1 percent in February 2000 to as high as 9.7 percent in April 2000. In the period March through July 2000 nearly half of the days experienced price corrections. The ISO has amended its internal procedures to correct the major problems which lead to these corrections and plans to file a market rules change with the Commission in the near future.

The New England ISO market monitor provides quarterly reports of market mitigation actions to the Commission.³⁶ In 1999, the market monitor reported numerous mitigation activities in each market, ranging from mitigation of bids to ex post price corrections. A large amount of the mitigation activity in New England has taken place with respect to bids from generators in transmission congested areas. The congestion costs associated with these generators are typically substantially lowered following mitigation.

In addition, the market monitor took major actions in the installed capability market in January and February 2000. These actions and subsequent changes in the installed capability market are discussed in Section 5.

³⁵ The initial Market Rule 15 expired on September 30, 1999, 89 FERC 61,209 (1999).

³⁶ ISO New England, Market Report, Quarters 1 & 2, May - July 1999, August - October 1999, October 26, 2000.

Table 1-9. Price Corrections by ISO New England, May 1999 to August 2000

Month	Hours with Real-Time Price Corrections (%)	Number of Days In a Month Having Correction(s)
May 1999	11.4	N/A
June	8.6	"
July	34.8	"
August	15.6	"
September	8.6	"
October	0 ^a	"
November	0	"
December	1.7	"
January 2000	2.0	9
February	0.7	3
March	5.9	12
April	9.7	16
May	5.1	15
June	6.9	14
July	4.8	12
August	1.5	5

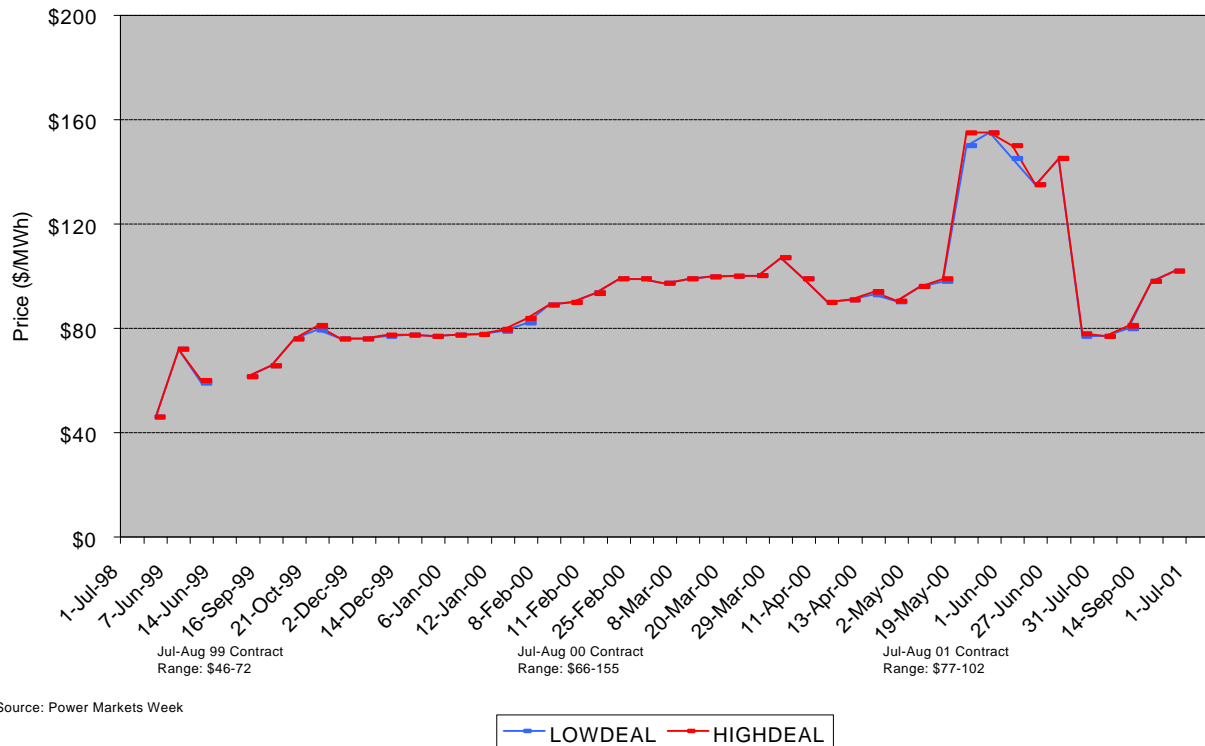
^aISO-New England stated that it was without Commission authority to change prices pursuant to Market Rule 15 and consequently made no price corrections for the month.

Source: ISO New England Monthly Market Reports May 1999 to August 2000; ISO New England Price Corrections Reports January to August 2000.

Prices in Bilateral Forward Market

Figure 1-15 shows the dramatic increase in the bilateral forward contact price following the May 8, 2000, price spike in the energy spot market. However, forward prices decreased substantially on recognition that the price spike was largely anomalous and with the subsequent moderate temperatures and eventual application of a bid cap in the energy market.

Figure 1-15. NEPOOL On-Peak Forwards: July to August Contracts



Relative Shares of Transactions in Energy Market

From May to December 1999, the ISO energy market averaged between 10.65 percent (July) and 14.09 percent (May) of electrical load, with a maximum of 20.37 percent (August) and a minimum of 6.56 percent (August). In January 2000, the size of this market doubled. As shown in Table 1-10, in 2000 the market has averaged between 21.62 percent and 25.02 percent, with a maximum of 47.43 percent.³⁷

³⁷ ISO New England, *Monthly Market Reports*, May 1999 to August 2000.

Table 1-10. Share of ISO New England Energy Market
(Percentage of Total Electrical Load)

Month	Average	Maximum	Minimum
January 2000	24.50	32.73	19.13
February 2000	22.32	32.43	14.52
March 2000	21.61	29.55	15.87
April 2000	22.36	32.32	16.34
May 2000	22.39	33.15	13.90
June 2000	24.37	42.63	13.37
July 2000	25.02	40.54	17.14
August 2000	24.38	47.43	15.43

Source: ISO New England, Monthly Market Reports.

4. Price and Bid Caps

Table 1-11 summarizes the various price and bid caps in the northeastern ISO markets. The existence of price and bid caps is an indication of market performance problems. In general, the price and bid caps in the energy markets have been no less than \$1000, and have been intended as a means to screen out exceptionally high bids. Ancillary service markets have experienced lower bid and price caps, to address markets that were fundamentally flawed (e.g., the New England operable capability market) or where the bid cap is intended to protect against market power associated with specific generators (as in the New York 10-minute non-synchronous reserve market). All the price and bid caps, except for the PJM energy market bid cap, were required to have justification prior to Commission approval and are of a temporary nature pending market design changes.

Table 1-11. Application of Price Caps, Bid Caps and Deficiency Charges in the Northeastern ISO Markets

Market		Type and Scope	Duration
PJM	Energy	Bid cap, \$1000, all hours	No duration specified
	Regulation	none	none
	Installed Capacity	Deficiency charge	No duration specified
New York	Energy	Bid cap, \$1000, all hours	July 27, 2000 to October 28, 2000. Request for extension pending.
	Regulation	none	none
	10-minute Synchronized Reserves	Temporary application of \$6.68 cap, March 27 2000.	Not approved by Commission and subsequently removed
	10-minute Non-Synchronized Reserves	Bid cap of \$2.52/MW.	March 28, 2000 to unspecified termination date.
	30-minute Operating Reserve	none	none
	Installed Capacity	none	none
New England	Energy	Bid cap, \$1000, OP 4 conditions	July 26, 2000 to October 31, 2000
	Regulation	Bid cap, \$1000, OP 4 conditions	July 26, 2000 to October 31, 2000
	10-minute Spinning Reserves	Price cap, Energy Clearing Price, OP 4 conditions	November 1999, Extension request pending
	10-minute Non-Spinning Reserves	Price cap, Energy Clearing Price, OP 4 conditions	November 1999, Extension request pending
	30-minute Operating Reserve	Price cap, Energy Clearing Price, OP 4 conditions	November 1999, Extension request pending
	Operable Capability	Price cap, five times average price in previous month, OP 4 conditions	September 1999 to February 2000 (market terminated)
	Installed Capability	none	(market terminated)

5. Summary

- With the exception of May 2000 in New England when temperatures were significantly above normal, and the constrained sub-markets in New York, prices in the summer of 2000 were lower than the summer of 1999 due to more moderate temperatures.
- Although prices were generally lower in 2000 than in 1999, high hourly prices still occurred during capacity deficiency periods, in certain constrained sub-markets, and under some designs for specific product markets. These factors contributed to conditions of scarcity or limited competition, conditions conducive to price increases and increased potential for market power exercise. Measures to mitigate market power and correction of market design problems can limit the price effects during these periods.
- The existing bid and price caps set a limit on the hourly price of energy in the ISO-administered markets. However, bid and price caps are, at best, transition controls that can limit the extent and speed of development of competitive markets, and price caps of \$1000/MWh may restrict, but will not prevent, exercises of market power.
- Price corrections by the ISO are a continuing concern in New York and New England. Recent statistics suggest some improvement; however, for the period May through August, some form of price correction occurred on 57 percent of the days in New York, and 37 percent of the days in New England.
- In New England, the increasing uplift costs associated with replacement reserves and transmission congestion highlights some of the inefficiency in the interim market design. Although some of these costs should be addressed by the new market design, their rapid increase raises concerns about how quickly the new market designs can be implemented.
- The share of the overall energy market traded in the ISO day-ahead and real-time energy markets in New York and New England has grown significantly, to around 45 to 50 percent, raising concerns that too much energy is exposed to potentially volatile short-term prices. These concerns could become heightened if high load conditions occur this winter or next summer creating conditions for greater volatility and higher prices than were seen this past summer.

4. Regulatory and Institutional Environment

The wholesale bulk power market in the Northeast, as in other regions of the country, is the product of the underlying structural changes set in place since 1996 both by the Commission and by the industry itself. As discussed below, these initiatives have been designed to remove impediments to competition in the wholesale bulk power market and to give consumers access to a reliable supply of electricity at the lowest reasonable cost. In compliance with these initiatives, the three tight power pools formerly in place in the Northeast have reconstituted themselves as ISOs. It has been an ambitious undertaking that is still unfolding. Federal policies promoting competition in the bulk power markets have also been an important impetus for fostering competition at the state level. As discussed below, each of the northeastern states has now adopted or is considering plans to extend competition from the wholesale level to the retail level. The retail open-access market, however, remains a work in progress.

A. Federal Regulatory Responsibilities

The northeastern ISOs are subject to the Commission's jurisdiction under the Federal Power Act (FPA). Specifically, under sections 205 and 206 of the FPA, the Commission is responsible for ensuring that the ISOs' rates, terms and conditions of service are just and reasonable, and not unduly discriminatory or preferential.³⁸ In addition, FPA section 203 gives the Commission jurisdiction to review any proposed merger or other asset transfer involving the ISOs or other public utilities.³⁹

In 1996, the Commission set in place the foundation necessary for a competitive wholesale power market by requiring that all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce, including each of the three tight power pools then being operated by NEPOOL, PJM, and the NYPP, file open access, non-discriminatory transmission tariffs with the Commission.⁴⁰

In compliance with Order No. 888, the three northeastern power pools filed comprehensive restructuring proposals with the Commission in which they sought to transfer the control of their respective transmission facilities and operations to an ISO. In

³⁸16 U.S.C. §§ 824d and 824e (1994).

³⁹*Id.* at § 824b.

⁴⁰Order No. 888, FERC Stats. & Regs. at pp. 31,036. Order No. 888 also required the three tight power pools to amend their power pooling agreements to include open, non-discriminatory membership provisions. *Id.* at 31,727.

a series of orders issued on these filings, the Commission authorized the creation of ISO New England,⁴¹ the PJM ISO,⁴² and the NYISO.⁴³

B. Organization, Governance and Operating Authority of the ISOs

Consistent with the Commission's policies, the northeastern ISOs have been charged with the responsibility of operating their respective systems under a Commission-approved open access tariff, and overseeing the efficient and competitive functioning of their regional power markets. Based on these mandates, ISO New England commenced operations on July 1, 1997, followed by PJM on January 1, 1998, and the NYISO on December 1, 1999. While similar in their overall organizational structure, the northeastern ISOs vary significantly in their governing framework and operational authority, as discussed below.

1. Governance

The Commission has consistently encouraged stakeholder participation in the formation and revision of ISO rules and practices. This has been accomplished, in large part, through a system of checks and balances in which the interests of all industry segments are meant to be represented. It has been a policy that is intended to promote the principle of self-governance, to the extent feasible, while balancing the interests of all interested parties.

The governing structures utilized by the northeastern ISOs share these common goals. As approved by the Commission, each ISO is governed by a board of directors.⁴⁴

⁴¹New England Power Pool, 79 FERC ¶ 61,374 (1997), order on reh'g, 85 FERC ¶ 61,242 (1998) (order conditionally authorizing ISO New England); New England Power Pool, 83 FERC ¶ 61,045 (1998), reh'g pending (order on NEPOOL tariff and restructuring).

⁴²Pennsylvania-New Jersey-Maryland Interconnection, et al., 81 FERC ¶ 61,257 (1997), order on reh'g, 92 FERC ¶ 61,282 (2000).

⁴³Central Hudson Gas & Electric Corporation, et al., 83 FERC ¶ 61,352 (1998), order on reh'g, 87 FERC ¶ 61,135 (1999) (order conditionally authorizing the NYISO); Central Hudson Gas & Electric Corp., et al., 86 FERC ¶ 61,062 (1999), reh'g pending (order on NYISO tariff and pricing issues).

⁴⁴The NYISO and ISO New England have 10-member boards, while PJM has a seven-member board plus a non-voting president.

In the case of the NYISO and PJM, the board oversees various stakeholder committees that have been given voting rights divided into five sectors. For example, PJM's Members Committee is composed of voting sectors that consist of (1) generation owners; (2) other suppliers; (3) transmission owners; (4) electric distributors; and (5) end-use customers.

The Interim ISO Agreement giving rise to ISO New England provides that NEPOOL and ISO New England shall have joint responsibility to develop new or changed rules. These obligations are to be carried out through NEPOOL committees, in which ISO New England will be represented. Like PJM and the NYISO, NEPOOL has various industry sectors represented in its committees. However, it has yet to activate its end-use sector, because this sector currently lacks representation within NEPOOL. To approve an action, PJM and NEPOOL require a two-thirds majority sector vote. The NYISO requires only a 58-percent majority. NEPOOL also has an appeals process which permits those on the losing side of a vote to appeal the decision before a review board comprised of five members independent from the market participants.

In practice, the governing structures of the northeastern ISOs have produced a mixed record. PJM and the NYISO have generally been able to resolve issues and produce decisive sector votes. Commission filings have generally been made in a timely fashion. NEPOOL, however, has had difficulty building a consensus for its initiatives on such important matters as congestion management and other issues.⁴⁵ Part of the difficulty experienced by NEPOOL and ISO New England may be attributable to the NEPOOL requirement for a two-thirds sector vote. In practice, this rule translates into a 75-percent majority vote requirement, since there are only four sectors currently

⁴⁵On March 31, 1999, for example, NEPOOL stated that it would file complete design details for a congestion management system and multi-settlement system by no later than September 1, 1999. However, on August 11, 1999, NEPOOL stated that it would not be able to do so until December 30, 1999. *See* New England Power Pool, 91 FERC ¶ 61,023 (2000). The Commission placed NEPOOL under a deadline of March 31, 2000. By that date, however, NEPOOL was able to file only a status report. Moreover, while ISO New England did file a complete proposal, it had no clear mandate for doing so. Consequently, its filing was unable to stake out a fully supported position on the issues it addressed. The fact that the membership could not come to agreement and ISO New England did not have the authority to make a unilateral section 205 filing also led to two additional competing proposals being filed. Similar disarray has been evidenced on other issues, including market rule changes and price cap extensions. *See, e.g.*, ISO New England, Inc., *et al.*, 90 FERC ¶ 61,170 (2000) (revised Market Rules 6, 8 and 9, governing the NEPOOL markets for ten-minute spinning reserves); ISO New England, Inc., *et al.*, 89 FERC ¶ 61,209 (1999) (order rejecting emergency rule to extend ISO New England's authority, under Market Rule 15, to implement corrective actions in the NEPOOL operating reserves market).

represented within NEPOOL. In addition, the division of interests between NEPOOL's generation sector and its transmission sector have become clearly drawn in recent years, following the significant divestment of generation assets throughout the ISO New England control area.⁴⁶ Finally, NEPOOL's appeals process has hindered timely action by NEPOOL, while extending a protection to market participants that may be redundant.⁴⁷

2. Market Design and Market Monitoring Responsibilities

As noted above, the Commission has jurisdiction under the FPA over the northeastern ISO's rates, terms and conditions of service. In exercising this jurisdiction, the Commission has attempted to avoid a one-size-fits-all approach to the region by giving the northeastern ISOs flexibility in meeting their regional needs. As experience with market performance grows, however, it may be appropriate, and perhaps even necessary, to apply the lessons learned in one ISO on a broader, region-wide basis.

PJM

In its restructuring proposal submitted to the Commission, PJM included an Amended and Restated Operating Agreement (PJM Operating Agreement), a Transmission Owners Agreement (Owners Agreement), the PJM Open Access Tariff (PJM OATT), and a Reliability Assurance Agreement Among Load Serving Entities in the PJM Control Area (Reliability Agreement). The PJM Operating Agreement establishes PJM as an independent body to operate the ISO, administer the PJM OATT, operate the pool spot energy market, approve a regional transmission expansion plan, and administer certain aspects of the Owners Agreement and Reliability Agreement. The Owners Agreement requires the owners of transmission facilities in the PJM control area to offer regional transmission service under non-pancaked rates, and to transfer to PJM the responsibility for administration of the PJM OATT and regional transmission planning and operations. The Reliability Agreement governs installed capacity reserve sharing obligations within the PJM control area.

PJM has been authorized by the Commission to operate a bid-based market for

⁴⁶By contrast, the traditional utilities within PJM are, for the most part, still functioning as integrated utilities. As a consequence, traditional utilities and merchant generators have shared interests in PJM, even though these traditional utilities continue to be represented in the transmission sector for voting purposes.

⁴⁷For example, the Commission could serve the same role played by NEPOOL's appeals process, while acting on the merits of the filing in a more expeditious manner.

energy, energy imbalances, and regulation and frequency response. PJM has also been authorized to provide an operating reserves service (including spinning and supplemental reserves), reactive supply and voltage control. To calculate and recover the costs of transmission congestion, PJM proposed a locational marginal pricing model. This pricing, as noted in Section 3, is based on differences in the marginal price of generation at each location on PJM's transmission grid.

On June 29, 1998, PJM filed a market monitoring plan establishing a market monitoring unit (MMU), with responsibilities for monitoring: (1) the activities of participants in the PJM PX for the potential exercise of market power; (2) all bilateral and other electric power transactions; and (3) compliance with all applicable rules, standards, procedures and practices.⁴⁸ Within the MMU's ambit of monitoring responsibilities is the duty to monitor matters relating to transmission congestion pricing, structural problems in the PJM market, and design flaws in PJM's operating rules.

The MMU is also authorized to pursue corrective actions, including discussion with market participants; make recommendations to change the terms and conditions pursuant to which PJM is operated; issue demand letters to market participants requesting the discontinuance of violative actions; make reports and complaints to state and federal agencies; and pursue remedial measures with the approval of the PJM board. Unlike ISO New England or the NYISO, the MMU is not authorized to impose remedial measures.

New York

The member systems of the NYPP established the NYISO and set forth its governing authority in: (1) an ISO Agreement; (2) a New York Power Exchange Agreement (NYPE); (3) a New York State Reliability Council (NYSRC) Agreement; (4) an ISO-NYSRC Agreement; (5) an ISO-Transmission Provider Agreement; (6) an NYISO OATT; and (7) a NYPE OATT.

The ISO employs: (1) locational marginal pricing; (2) a two-settlement process for establishing schedules and energy prices for the day-ahead and real-time markets; and (3) the ability to optimize unit commitment and dispatch based on the bids of the market participants. In addition, the NYSRC establishes reliability standards for the bulk power system in the state.

The NYISO has been authorized by the Commission to operate day-ahead markets

⁴⁸In an order issued March 10, 1999, the Commission accepted PJM's plan, as modified. PJM Interconnection, L.L.C., 86 FERC ¶ 61,886 (1999).

and real-time markets for energy and four ancillary services: regulation and frequency response, 10-minute spinning reserves, 10-minute non-spinning reserves, and 30-minute non-spinning reserves. In its order approving the NYISO, the Commission also accepted the NYISO's proposed Temporary Extraordinary Procedures (TEP) to permit the ISO to address, in its first 90 days of operation, market design flaws, transitional abnormalities and severe operational difficulties, as required.⁴⁹ Subsequently, the NYISO sought and was granted a 90-day extension for its TEP, with some revisions, because of continuing limitations of its software and its inability to calculate prices accurately.⁵⁰ On July 25, 2000, the Commission again extended the NYISO's TEP authority, through October 31, 2000, because of the continued need to correct for pricing problems.⁵¹

The Commission has also given the NYISO authority to impose mitigation measures where market power has been exercised, e.g., in the case of physical or economic withholding, or uneconomic production. On December 23, 1999, the NYISO filed a revised market mitigation plan, as required by the Commission in *Central Hudson Gas & Electric Corp., et al.*⁵² The revised plan sets forth specific threshold values for identifying generators or transmission facilities that are found to exercise market power. In an order issued March 29, 2000, the Commission accepted the NYISO's revised plan.⁵³

The revised plan sets forth specific thresholds values for identifying generators or transmission facilities that engage in proscribed conduct, and gives the NYISO authority to impose a financial penalty on the party engaging in this behavior if it caused a material increase in price or in one or more “guarantee payments.”⁵⁴

New England

To establish the ISO New England, NEPOOL submitted a comprehensive

⁴⁹88 FERC at 61,752-53.

⁵⁰New York Independent System Operator, Inc., 90 FERC ¶ 61,320 (2000).

⁵¹New York Independent System Operator, Inc., 92 FERC ¶ 61,051 (2000).

⁵²89 FERC ¶ 61,196 (1999).

⁵³New York Independent System Operator, Inc., *et al.* 90 FERC ¶ 61,317 (2000).

⁵⁴*Id.* at 62,052. A guarantee payment assures a generator that is committed that it will receive all its bid costs, including payments for start-up and no-load costs. If the revenues from selling in the ISO's markets fail to cover all these costs, a guarantee payment equal to the difference will be made through up-lift charges.

restructuring proposal to the Commission, which consisted of: (1) a Thirty Third Amendment to the NEPOOL Agreement (33rd Amendment); (2) a restated NEPOOL Agreement; (3) a pool-wide OATT; and (4) an Interim ISO Agreement.

Under the Interim ISO Agreement, as approved by the Commission, ISO New England was given the authority to independently conduct system assessment and planning as it may deem necessary or as requested by NEPOOL. ISO New England was also given the authority to adopt or propose new system rules and procedures as it may deem necessary or desirable to implement its recommendations. ISO New England was also given authority to direct any market participant to take any action necessary to preserve the reliable operation of the NEPOOL control area, and the authority to procure emergency power on behalf of NEPOOL.

The Commission has authorized ISO New England to operate markets for six products: energy, automatic generation control, 10-minute spinning reserve (TMSR), 10-minute non-spinning reserve, 30-minute operating reserve, and installed capability (ICAP).⁵⁵ A seventh product, operable capability, was traded from the inception of the market until March 2000.

NEPOOL's market rules outline the manner in which ISO New England is required to operate these markets.⁵⁶ Among these market rules, Market Rule 15 gives ISO New England authority to take corrective steps to remedy technical implementation errors and emergency system conditions. In addition, Market Rule 17 authorizes ISO New England to monitor and mitigate behavior that interferes with competition in the NEPOOL markets. Specifically, Market Rule 17 establishes two monitoring and mitigation procedures: one, for when transmission capacity constraints require generators to be dispatched out of merit order, and the other for general circumstances whether or not

⁵⁵The ICAP requirement was instituted originally by NEPOOL as a reliability measure. If a utility had an ICAP deficiency, it could either obtain its requirements from an entity having a surplus or be subject to a deficiency charge from the pool. ISO New England sought to eliminate the ICAP market, based on its position that it needed time to study possible replacement alternatives, including forward purchases of reserves. The Commission, however, rejected this proposal, due to the hardship this termination would impose on current holders of contracts with ICAP provisions. The Commission stated that the proper time to consider the elimination of the ICAP requirement would be after an alternative mechanism is proposed. *See* ISO New England, Inc., *et al.*, 91 FERC ¶ 61,311 at 62,080-81 (2000). In a July 28, 2000 compliance filing, which remains pending at this time, NEPOOL proposed a new charge as a replacement for its existing ICAP mechanism.

⁵⁶*See* New England Power Pool, 85 FERC ¶ 61,379 (1998); New England Power Pool, 87 FERC ¶ 61,045 (1999).

transmission is constrained. The mitigation plan for a situation of capacity constraints calls for a two-tiered screening procedure (i.e., structural and price) to determine whether mitigation will be imposed, and specifies the method for calculating any screen prices which may apply. The mitigation plan for addressing general circumstances includes a range of remedies.⁵⁷

On June 13, 2000, ISO New England proposed two amendments to Market Rule 17 to expand its mitigation authority. First, ISO New England sought authority to preclude any mitigated bid from setting the clearing price. Second, ISO New England sought to establish mitigation triggers and measures dealing with certain energy imports contracts that are coupled with ICAP. In an order issued July 26, 2000, the Commission accepted the proposed amendments, subject to revisions conforming Market Rule 17 to the comparable rule administered by the NYISO.⁵⁸

C. State Regulatory Activities and Retail Competition

While the Commission has jurisdiction under the FPA over the rates, terms and conditions of service of the northeastern ISOs, retail sales and the local distribution of electric energy remain subject to state jurisdiction. In addition, states continue to exercise jurisdiction over the siting and construction of new power plants and transmission lines. These state functions, taken as a whole, can have an important effect on the overall performance of the bulk power market, due to the impact that state planning decisions can have on regional supply and demand conditions. As noted in section 2, above, for example, the tightness of supplies in the Northeast, in recent years, has been attributable, in part, to the long lead time that is required for new capacity to come on line.⁵⁹ In many cases, proposed capacity additions are being delayed and risk being rejected altogether.⁶⁰

⁵⁷These options include (1) reducing bid flexibility to limit bid increases; (2) increasing a market participant's reserve obligation; (3) substituting a default bid equal to defined reference prices; and (4) substituting a default bid equal to actual marginal costs of the resource being used to effect the anomalous behavior.

⁵⁸*NSTAR Services Company v. New England Power Pool, et al.*, 92 FERC ¶ 61,065 at 61,204 (2000), *reh'g pending* (order requiring ISO New England to revise Market Rule 17 to reduce the level of ISO discretion in determining when to apply mitigation measures).

⁵⁹In Londonderry, N.H., for example, a 720 MW, \$300 million gas-fired power plant proposed by AES in early 1999, became the subject of a protracted battle that went all the way to the state's highest court. Construction on the plant was delayed until this August.

⁶⁰For example, plans recently developed by KeySpan and Con Edison Development to build a 500 MW merchant plant on the East River in Brooklyn, N.Y. had to be scrapped after the

The State of New York has attempted to streamline the siting process, by adopting new guidelines for applications to construct and operate electric generating facilities with a capacity of 80 MW or more.⁶¹ All certification and review processes, however, allow for the consideration of a broad range of interests, including the review of all reasonable alternatives to a proposed facility. In addition to a traditional public necessity analysis, meteorological, hydrological, and environmental studies must also be considered. Article X vests authority over siting matters in a state siting board, which includes (on a case-by-case basis) the appointment of a resident from the judicial district in which a facility is proposed to be located and a resident from that county. Article X also requires the applicant to establish communications with the public during the pre-application process and before any written agreements have been entered into by the applicant with any state agency or interested stakeholder. Following a state agency approval for a new facility, judicial appeals can be filed by aggrieved parties.⁶²

State retail access programs are also having an important impact on the wholesale bulk power market. Even before the Commission issued Order No. 888, several of the northeastern states, including New York and Delaware, were already considering open access initiatives. In New York, for example, the New York Public Service Commission (New York Commission) solicited comments on retail competition as early as 1994.⁶³ In doing so, the New York Commission noted that the high rates being paid for electricity in New York could be expected to have a long-term, negative impact on the state's economy, if reform measures at the state level were not taken.⁶⁴

While most of the northeastern states have been at the forefront of the retail competition movement (among them Maine, Massachusetts, New Hampshire, New York, Pennsylvania, and Rhode Island) other states in the region have pursued a more cautious course. Vermont, for example, has yet to adopt a restructuring law, and while its state

issuance of new state environmental requirements. The new rules, which address the use of river water for cooling capacity, rendered the project uneconomical.

⁶¹See N.Y. Public Service Law Ch. 48, Art. X (McKinney 1997).

⁶²

⁶³Notice Inviting Comments on Proposed Principles to Guide the Transition to Competition, N.Y.P.S.C. Case No. 94-E-0952 (issued Dec. 22, 1994).

⁶⁴In fact, high rates were being experienced at that time throughout the region. By 1996, for example, while the average revenue from electricity sales to retail consumers for the nation as a whole was 6.9 cents per kWh, rates throughout most of the northeastern states exceeded the national average. In New York, the rate was 11.0 cents per kWh, while in New Hampshire the rate was 11.6 per kWh.

commission has issued guidelines on restructuring, those guidelines have yet to be implemented. Similarly, Virginia will not begin even the phase-in of retail competition until January 1, 2002.

Even for those states who have been relatively quick to act, actual implementation of retail competition has been slowed in many instances.⁶⁵ To date, then, the growth of the retail open access market continues to be a work in progress. In Maine and Pennsylvania, where the customer switch rates have been among the highest in the region, 20 to 25 percent of the states' loads now rely on alternative suppliers. But in Massachusetts, the figure is only 8.5 percent, and in New Jersey and New York the figures are 3 percent and 2.5 percent, respectively. For those retail customers who are currently using alternative suppliers, most are commercial and industrial users.

⁶⁵ While New Hampshire was the first state in the country to adopt a retail restructuring law, on May 21, 1996, for example, federal court litigation and related proceedings have delayed the implementation of retail access in the state. In New York, individual restructuring plans for each utility were approved, with implementation dates that have varied for each. The largest utility in the state, Consolidated Edison of New York, Inc., is scheduled to offer full retail access November 1, 2000. Central Hudson Gas & Electric Corporation will not offer full retail access until July 1, 2001.

5. Prices, Market Design and System Operations

A. Overview: Key Events

The Northeast region is unique among the Eastern Interconnection regions investigated, in that it is composed of recently restructured, organized markets administered by three ISOs. These markets are extremely complex and are in varying states of completeness. The ISOs have made impressive progress in developing markets; however, these efforts have maintained the central dispatch assumptions underlying their roots as tight power pools. The market rules that each ISO developed were a product of those assumptions. The markets in the Northeast also suffer from a lack of demand-responsiveness and, currently, tight supplies in some areas. In this respect there are similarities to the market in California. However, since many of the problems in the Northeast markets are a result of poor market design and faulty, inflexible software which produces anomalous outcomes, market design issues are the primary focus of this report. Although there is a substantial degree of convergence, continuing differences in market design, implementation, and products among the ISOs contribute to problems unique to the Northeast by preventing power from moving through the region in the most efficient ways. These differences divide what many view as an emerging regional market into three separately administered markets. This section concludes that problems in the region may require a more strategic approach than the three similar but divergent approaches taken by the individual ISOs.

In evaluating the Northeast region, staff's primary focus has been on market design. In the time available for this investigation, staff was not able to evaluate the effects of market power on this market. The market monitors in each of the ISOs were established as the Commission's first line of defense against market power abuses. From the reports of the market monitors, as well as the Commission's prior assessments of the Northeast markets, it appears that market power exists in some markets but we have not been able to analyze it in any detail for this report. Staff received the bid data from the ISOs and will be evaluating them, but that analysis could not be completed in the time available. Additionally, the mild weather during the summer peak season this year produced conditions such that any underlying market power was not a prominent issue in most parts of the Northeast.

With respect to the market design in the Northeast, two events from the summer of 2000, though perhaps anomalous, serve to illustrate the types of problems faced by the region: (1) May 8, 2000, in New England, when prices cleared at \$6,000/MWh, primarily as a result of software errors and market rules which allowed an out-of-market bid to set the clearing price, and (2) consistently higher prices in New York City during a cooler than normal summer. These events are discussed below, followed by a discussion of

issues in each of the three northeastern ISOs, and the intraregional issues that constitute some of the major inefficiencies in this region.

1. May 8, 2000

On May 8, 2000, New England, as well as the other Northeast ISO control areas, experienced record-breaking temperatures that resulted in unanticipated, extremely high loads. This was problematic since spring months are typically relatively low load periods for the Northeast and are typically the time scheduled maintenance is performed. This was the case in May 2000 in New England when there were unanticipated generator outages and reduced operating levels which totaled 8,485 MW, or approximately 45 percent of the peak load.⁶⁶ This resulted in ISO-New England's capacity analysis for the peak hour for May 8 showing a shortfall in available resources of 736 MW, leaving ISO-NE with insufficient available capacity to meet consumer demand plus required reserves.

Under NEPOOL Operating Procedure 4 (OP4), ISO-NE has the authority to take specific actions to maintain reliable operations.⁶⁷ Operating procedures, market rules and NERC guidelines state that external resources are not eligible to provide operating reserves, which are insurance against the loss of the largest contingency on the system, because they are not under the dispatch control of the ISO. When there are capacity deficiencies, the ISO must select external dispatchable resources, if available, to provide energy while holding internal resources for reserves. When scheduled, these external contracts set a floor for the market clearing price (as determined in the 5-minute, real-time marginal price). Hence, during reserve shortages, all external contracts must be dispatched (even if out-of-merit) for reliability reasons. Thus, the requirement to maintain full reserves means that there is no effective market constraint on the level of the external bids. However, these external bids are eligible to set the clearing price.

The contract that set the \$6,000/MWh clearing price was an external contract for the purchase of energy and was bundled with an ICAP contract. In anticipation of initiating OP4, ISO-New England reviewed the forecasted prices posted on the NYISO's web site, which showed advisory prices as high as \$3,387/MWh. Based on these prices and an estimation of the cost of purchasing emergency power from NYISO, ISO-NE concluded that a \$6,000/MWh bid price submitted by a NEPOOL participant to provide 300 MW was reasonable. ISO-NE was advised by the NEPOOL participant who

⁶⁶This was roughly the same as the level of outages in 1999 (52 percent of peak load), but was considerably higher than 1998 (31 percent of peak load).

⁶⁷These actions include: voluntary demand reduction, purchase of emergency capacity and energy from neighboring Control Areas, operation of the bulk power system with diminished thirty minute reserves, and voltage reductions.

submitted the contract that its cost was the price in New York, which the participant was unable to estimate. ISO-NE's dispatch of the external purchase resulted in an energy clearing price of \$6,000/MWh for four hours. The \$3,387/MWh price was revised by NYISO a week later to \$331/MWh, and it was determined that the forecasted clearing price in New York was the result of flaws in the NYISO market.

The requirement to maintain full reserves means that there is no effective market constraint on the level of the external bids, but they are eligible to set the clearing price. The result is to transfer the effect of the reserve shortage to the energy market where the same per MWh price increase has a much greater effect on load serving participants because of the volumes in the spot market and the long-term impact on forward energy purchases. The \$6,000/MWh clearing price created sufficient concern in the markets to prompt revisions to market rules by ISO-New England, requests by market participants for a \$1,000/MWh cap, and requests that the clearing prices be recalculated to exclude the \$6,000/MWh bid price for energy purchased from a supplier under an ICAP and associated energy bilateral contract.

ISO-New England recognized the market flaw in allowing the use of external ICAP resources, which typically do not bid energy into the market, to set the clearing price. ISO-New England has now received Commission approval to mitigate external energy bids coupled with ICAP during OP4 conditions. Additionally, the Commission approved the use of a \$1,000/MWh cap for use in OP4 conditions through October 31, 2000.⁶⁸

While the \$6,000/MWh bid set the clearing price for only 4 hours, it had a direct and significant effect on several market participants and also had after-shock effects on the market. Bangor Hydro incurred costs of approximately \$2.6 million for energy purchases during the critical hours of May 8 that have been passed on to its retail customers. The \$6,000/MWh bid resulted in the highest monthly average energy price since the market began.⁶⁹ (See Figure 1-12.) It also had a significant effect on the forward markets as forward prices jumped significantly from April and did not come down quickly, as shown in Figure 1-15. The \$6,000/MWh bid translated into a premium

⁶⁸NSTAR Service Co. v. New England Power Pool, et al., 92 FERC ¶ 61,065 (2000), *reh'g pending*.

⁶⁹If the \$6,000/MWh bid had been limited by a \$1,000/MWh bid cap (as was later established during the summer months), the monthly average energy price for May would have been \$43.39/MWh. If the market monitor had rejected the \$6,000 bid on the basis of its arbitrarily high price (the bid actually was *not* intended to be used for energy but rather for installed capability) and used the next cheapest available MW within the New England control area, the monthly average likely would have been substantially lower.

attributable to the uncertainty of the ISO-New England's actions.

The \$6,000/MWh price highlights the inter-relationship of the ISOs and the complications that result from flawed market operations and rules. The NYISO's software problems spilled over into the ISO-New England markets, which of their own design provided the vehicle for the \$6,000/MWh bid to set the clearing price. The impact was widespread and long-standing in its effect on the market.

2. Prices in New York City

Despite lower summer temperatures in 2000 as compared with 1999, prices in New York City were on average higher in summer 2000 than in 1999.⁷⁰ Moreover, prices in New York City and Long Island were higher than the average prices in NYISO (see Figure 1-2). Several factors contributed to this price increase: load pockets exacerbated by outages which could have led to the exercise of market power in some instances, difficulty siting new plants, transmission constraints, increased fuel costs, onerous reliability rules, and software and design problems which make it difficult to import power from ISO-NE and PJM.

In April of this year, a number of IOUs in New York filed complaints with the Commission expressing alarm at the run-up of reserve power prices in the NYISO markets. Most of these problems were the subject of Commission orders and resultant compliance filings to fix software problems and revise flawed market rules. But these early perceptions about a flawed market set the stage for perceptions about prices later in the summer.

ConEd was the target of much criticism within New York City because of its passthrough to retail customers of increasing electric supply costs. As discussed in Section 2, NYISO's transmission system faces some severe constraints, particularly with respect to getting power into New York City, forcing in-city consumers to rely heavily on in-city generation rather than more economic resources located in western New York or other states. ConEd, which had owned most of the generation located in New York City, has divested most of its generating units, and instead procures supply through the spot market to serve its remaining retail customers. The fact that ConEd merely passes through its costs to its retail customers has left these customers vulnerable to the 20 to 30 percent increases in spot market prices. Local politicians demanded rate cuts in the face

⁷⁰Prices as summer approached were up sharply. For the 5 months ending May 1999, Con Edison's total energy cost was approximately \$456 million, whereas for the 5 months ending May 2000, Con Edison's total energy cost was approximately \$1.002 billion. ConEd attributed the majority of the difference (an increase of \$546 million) to higher fossil fuel costs.

of ConEd failing to shoulder some of the risk of competitive markets through purchases of long-term power or other means, while consumers had no ability to avoid the cost increases in the absence of demand side management programs.

The price increases in New York City this past summer are largely attributable to tight supplies resulting from outages and the difficulty importing power into the city, which has a load that can exceed 10,000 MW but in-city supplies of only 7,900 MW. Further, it is difficult to site new generation or transmission facilities in or near the city. This difficulty, combined with the existing Central-East constraint that limits otherwise economic power flows to the East, and increasing demand has turned New York City into a load pocket which is heavily dependent on in-city generation, making it susceptible to the exercise of market power. The Commission recognized this in its order granting market-based rates to the NYISO market participants and so required price mitigation measures, including price caps, for sales of installed capacity and energy into New York City.⁷¹

The situation was exacerbated this summer with the loss of the 940 MW Consolidated Edison of New York, Inc. (ConEd) Indian Point Unit 2 nuclear plant for the entire summer. This had a tremendous impact on prices within New York City. While Indian Point is not located within the city, it provides a substantial resource to the city at a low cost. ConEd estimated that the loss of Indian Point Unit 2 alone added at least \$600,000 per day in additional replacement supply costs to ConEd's customers.⁷² In addition, as noted in section 2.B., imports into New York City were further reduced by

⁷¹Currently, NYISO markets have a \$105/kW/year cap on installed capacity within New York City, and in-City energy bids capped at the amount that these same generators had bid during unconstrained periods in the previous 90 days when the bid prices become 5 percent greater than the price at the Indian Point 2 bus. Consolidated Edison Company of New York, Inc., 84 FERC ¶ 61,287 (1998). The NYISO markets also have a cap of \$2.52/MWh plus opportunity costs for non-spinning reserves east of the Central-East constraint and a temporary \$1,000/MWh cap on energy and ancillary services through the summer capability period.

⁷²The Governor of New York signed an order which prohibited ConEd's recovery of replacement power costs for loss of Indian Point 2 on the basis that ConEd was liable for the failure, given that it had replacement steam generators on site for 12 years stemming from a lawsuit against Westinghouse regarding premature tube cracking, the problem that ultimately shut the unit down, and never replaced the potentially faulty units prior to the failure. The New York Commission was to then draw up an order and direct ConEd to make refunds for replacement power costs (\$600,000-\$800,000 per day). However, the U.S. District Court in New York rejected the refund plan, declaring that ConEd never had a chance to make its case and that the company was singled out for a punitive attack by New York in response to the high electricity charges in New York City. *Electric Utility Week*, August 14, 2000, pp. 4-5 and October 16, 2000 pp. 1-3.

400 MW (8 percent) this past summer by the failure of a large transformer in New Jersey.

Inaccurate forecasts of supply and demand may have contributed to the scarcity of supply available for New York City. The New York Public Service Commission has recognized that, as recently as 1995, state planners expected a glut of power to come online because of an abundance of independent power projects in New York. However, demand has grown beyond all expectations, such that the state hit a peak (30,311 MW) in 1999 that it did not expect to reach until 2003.⁷³ The first merchant plant in New York is not expected for an additional 2 years⁷⁴ and is not located within New York City. With the difficulty in siting new generation and transmission facilities in New York, these conditions will likely continue until demand side management or other measures, such as distributed generation, are put in place.

The increase in natural gas and fuel oil prices nationwide drove up fuel costs for generators located in New York City as much as \$9/MWh from the summer of 1999 to the summer of 2000.⁷⁵ As much of the generation east of the Central-East constraint is fueled by natural gas or oil, the increase in fuel costs contributed greatly to the overall increase in energy prices.

As will be discussed further in section 5.C, difficulties with transfers of power across the NYISO interfaces occasionally contributed to cuts of economic power into New York which would have an impact on prices in New York City. For instance, on one occasion, 1,700 MW scheduled to be imported from a resource in PJM in the day-ahead market was cut 15 minutes before the hour flow was scheduled to begin because of problems with NYISO's hourly bid evaluation software. Cuts such as these force loads to purchase power from less economic sources, driving up overall market prices.

The New York State Reliability Council's local reliability rules can also contribute to higher prices. The rules require that New York City and Long Island have substantial amounts of generation capacity installed locally. For example, New York City is required to have generation equal to 80 percent of its forecasted peak load installed within the City. New York City's forecasted peak load this summer exceeded 10,000

⁷³“Politicians Blast ConEd 20% Hikes; PSC, NYISO Say More Plants Crucial,” *Id.*, July 17, 2000 at 1, 7-8.

⁷⁴PG&E's 1,080 MW gas-fired, combined cycle Athens plant took two years to get siting authority and will take an additional 29 months to be constructed. *Id.*, June 19, 2000 at 17-19.

⁷⁵ The cost increase is from \$32/MWh in the summer of 1999 to \$41/MWh in the summer of 2000. Staff's estimate is based on fuel mix of New York City generators, average fuel costs in summer 1999 and 2000, and typical heat rates.

MW, so the requirement amounts to more than 8,000 MW and exceeds the actual in-city generation by a few hundred megawatts. A similar requirement applies to Long Island.

The intent of these “locational requirements” is to enhance reliability: New York City and Long Island have limited capacity to import power, so they are vulnerable to blackouts if transmission is interrupted. Having a large amount of local generation reduces the risk. Other locational capacity restrictions go into effect for New York City when thunderstorms threaten transmission lines that supply the city from the Hudson River valley.

Locational requirements can create temporary or seasonal supply scarcity that can be exploited by local generators. Hotter summers will exacerbate the problem; increased transmission and generation capacity, and relaxed locational requirements if advisable, would reduce it.

Ultimately, concerns about high prices faced by ConEd's retail customers may be muted in part through a settlement reached as part of ConEd's merger with Northeast Utilities, as it would reduce electric rates for New York consumers by \$1.465 billion over four years. The settlement would have no effect on market clearing prices, but only on ConEd's ability to pass through the costs it incurs to procure power for its customers. Similarly, the addition of new generation such as PG&E's 1,080 MW Athens unit and Long Island's access to New England through the TransEnergie line will help drive down prices in New York beginning in 2002.

In sum, higher prices faced by New York City in particular this summer were largely driven by the outage of Indian Point 2 as well as several in-city outages, increased fuel costs, and the inability to import power. More important, this example demonstrates some of the major problems faced by New York and other portions of the Northeast: difficulties importing power into New York, difficulties siting generation near major load centers such as New York City and Long Island, and the need for demand responsiveness, including proper price signals to encourage distributed generation in such regions where generation siting is difficult. These issues will be more fully addressed below.

B. PJM

The PJM markets have functioned with fewer market design and operational problems than the other northeastern markets. This is due to a number of factors in the evolution of the PJM market design and in systems operations, some of which have been noted above. First, PJM operated its energy market with cost-based bids for 24 months before requesting market-based rates.⁷⁶ This was a much longer market “trial” than attempted by the other northeastern ISOs. Second, still under the cost-based regime, PJM was the first ISO to implement locational marginal pricing of energy with associated financial transmission rights. As such, it has provided important experience with the functioning of this market design, in particular demonstrating that with additional design features, such as price hubs and transmission bidding, liquid bilateral forward markets can be established and transmission price uncertainty can be reduced. These lessons were transferred to New York and New England, which have either implemented or plan to implement these features. Third, PJM has phased in bid-based ancillary service markets more slowly than the other northeastern ISO markets (and California). In doing so, it has had the opportunity to observe and take into account a number of ancillary service market problems in the other ISO markets. Finally, PJM has accumulated a better record of system operations, including the development and modification of market and power system software, than the other northeastern ISOs.

The remainder of this section will examine current issues relating to market design and market power in PJM. The section focuses on the exercise of market power in the energy market, and the question of the continuation of the bid cap in that market. In addition, the section describes PJM's decision to delay implementation of spinning reserve markets due to concern about market power, the interaction between the capacity market and energy market during high demand days, and some forthcoming changes in the allocation of fixed transmission rights (FTRs).

1. Energy Market

As shown in section 3, PJM energy prices under market-based pricing have been comparable to prices under cost-based pricing for most days of the year. However, the energy market is clearly not competitive during capacity deficiencies. In particular, the PJM market monitor found that a large portion of the observed increase in prices could be attributed to 15 days in the summer of 1999 when hot weather contributed to unusually

⁷⁶This phase did experience market design problems, most notably with congestion management, but these problems were corrected with the introduction of locational marginal pricing.

high demands.⁷⁷ The market monitor estimates that about 69 percent of the average price increase from 1998-1999 to 1999-2000 is accounted for by prices that occurred during 96 hours on these 15 high demand days. Moreover, after adjusting 1999-2000 prices for fuel cost increases, the prices in the 96 high demand hours account for about 84 percent of the overall increase.

The market monitor believes that the observed higher prices in 1999 were the result of the interaction of high demand levels with supply curves that exhibited steep slopes over very narrow ranges of output. Some firms appear to have withheld capacity and changed bid parameters during peak hours as a means to drive up prices.⁷⁸ However, these prices also appear to have attracted imports into PJM. The market monitor thus concludes that the high prices were due both to scarcity and to the exercise of market power, but that the relative importance of the two factors cannot be determined.

PJM has operated with a \$1,000 bid cap in the energy market since market operations began. The PJM market monitor recommends, based on its findings, that the \$1,000/MWh bid cap be retained in the PJM energy market, but that consideration be given to other (unspecified) rule changes that might reduce the incentives to exercise market power.⁷⁹ The bid cap was approved by the Commission. However, it was not subject to the scrutiny and termination schedule applied to the price and bid caps in New England and New York. As such, it should be evaluated in concert with the bid caps in the neighboring ISO markets. To the extent that similar market conditions exist in each regional market, there should be continued uniformity of administrative price restraints.

⁷⁷ *PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000, pp. 15-19.

⁷⁸ PJM found that under emergency conditions in the summer of 1999, some generators would specify minimum run times of as much as 24 hours when they submitted their energy bids. This had the effect of ensuring that the generator received, at a minimum, its full bid price (up to \$1,000/MWh) for the full minimum run time even though, absent the minimum run time, the bid would have been selected by PJM as an economic bid for perhaps only a few hours. PJM concluded that this was an abusive practice that was specifically designed to circumvent the bid cap. In response, PJM implemented a revised procedure that ensures that generators that specify minimum run times will not earn in the aggregate more than the maximum \$1,000/Mwh. *See*, PJM Interconnection, L.L.C., Docket Nos. ER00-2445 and EL00-74.

⁷⁹ Other measures recommended by the market monitor include investigating market mechanisms that would permit prices in the real-time market to be bid to a level sufficient to attract imports on days of high demand and evaluation of possible actions to increase demand side responsiveness to price. *PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000, p. 8.

2. Ancillary Service Markets

Unlike New England and New York, PJM did not begin operation with separate markets for ancillary services. PJM now operates bid-based markets for energy imbalance service⁸⁰ and regulation and frequency response service⁸¹, but it has yet to introduce competitive markets for the provision of operating reserves (i.e., spinning and supplemental reserves). Examining the PJM approach is instructive because both New York and New England have experienced market power problems in operating reserve markets.

In PJM, each load serving entity has the responsibility to obtain, through ownership or purchase, sufficient generating capacity to meet its load plus a reserve margin. It is primarily through this requirement that PJM ensures its ability to meet reliably the energy and ancillary services needs of all loads in its control area. PJM provides simultaneously for energy and operating reserves (spinning and supplemental) through a centralized process of unit commitment and dispatch.⁸² Each unit started and operated by PJM is guaranteed sufficient revenue to cover its three-part bid, whether the unit is operated for reserves or energy.

PJM states that it is considering the feasibility of implementing a bid-based market for spinning reserves.⁸³ However, PJM indicates that the implementation of such markets is problematic because the ownership of synchronous condensing combustion turbines, which are particularly well suited for providing spinning reserves, is highly concentrated. PJM also notes that the demand for spinning reserves, which is based on reliability requirements, is completely inelastic. Therefore, PJM concludes that a bid-based

⁸⁰Since April 1, 1999, energy imbalance service, whether the result of excess supply or excess demand, has been priced at the locational marginal price for energy.

⁸¹On June 1, 2000, PJM introduced a bid-based market for regulation service. In this market, owners of resources that are capable of providing regulation services may submit market-based offers to provide this service.

⁸²LSEs are required to make their capacity resources available to PJM either by bidding them into the PJM energy market, self-scheduling the units, or entering into bilateral transactions. Capacity resources as well as other units that are bid into the energy market commit to providing not only energy but also the ability to provide reserves. The bids may include separate components for start-up, no-load, and incremental energy. Based on the bids received, PJM schedules the necessary resources to meet load and reserve requirements on a least cost basis; that is, energy and reserves costs are optimized jointly, not separately.

⁸³*Report to the Federal Energy Regulatory Commission: Ancillary Services Markets*, PJM Market Monitoring Unit, April 1, 2000.

spinning reserve market will not be viable until the market is broadened. In this regard, PJM states that it has taken steps to encourage new entry in the spinning reserves market in an effort to broaden the market and reduce or eliminate market power.

3. Capacity Markets

The interaction of energy markets and installed capacity markets are important during the peak demand days when regional prices outside PJM are also likely to be high. PJM's experience with this market interaction has been assessed and provides some lessons for future capacity market design in both PJM and elsewhere.

Each load serving entity (LSE) in PJM incurs an obligation to own or purchase capacity resources sufficient to meet its load plus a reserve margin.⁸⁴ Capacity obligations are updated annually based on peak loads for the prior 12 months. To qualify as a capacity resource, a generating unit must pass tests regarding overall capability and the ability to deliver energy to PJM load, which requires adequate transmission capability. LSEs can use their capacity resources to produce energy for export from the PJM control area, but such transactions are subject to recall by PJM in emergencies.

In order to avoid having an export transaction recalled by PJM, current rules allow an LSE to delist some or all of its capacity resources up to 36 hours prior to the day of the transaction. If the LSE sells itself short of its capacity obligation, the LSE is automatically bid into the daily capacity credit market and pays the market clearing price for the relevant day up to a penalty amount to \$160/MW-day, which is 1/365th of the annual value of capacity. If the PJM system is short of capacity, the penalty is doubled, or \$320/MW-day. The PJM market monitor notes that the latter amount equates to \$20/MWh for a 16-hour forward contract.⁸⁵ Thus, with a net price spread between internal and external markets of \$20/MWh or more, an LSE would have an incentive to delist capacity resources and sell energy externally. Given that the delisted capacity is not subject to recall by PJM, this behavior can be detrimental to the reliability of the PJM

⁸⁴LSEs can purchase capacity either by purchasing all or part of a specific generating unit or by purchasing a capacity credit, which is a unit of unforced capacity measured in MWs of unforced capacity per day. Capacity credits can be purchased bilaterally or through PJM's capacity credit markets, which allow for the buying and selling of capacity credits for terms of a day, a month or multiple months. PJM created these markets partly in response to retail restructuring, which created the opportunity for new entrants to compete to serve retail loads in the PJM area.

⁸⁵*PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000, p. 57.

system. Also, PJM notes that the recall rules provide an incentive for owners of capacity resources to exercise market power in the PJM energy market. When a capacity resource (that has not been delisted) is engaged in an export transaction and is subsequently recalled, it receives the internal PJM price for the energy it provides. The market monitor claims that this creates an incentive for the owner of the capacity resource to bid up the internal price prior to the recall of its external sales.

PJM's market monitor notes that PJM members in the future may want to consider alternatives to the use of capacity requirements to ensure system reliability.⁸⁶ In the meantime, the market monitor recommends certain rule changes for the PJM capacity markets. First, some form of market based mechanism could be implemented to give LSEs an incentive to deliver energy from capacity resources to loads at a level consistent with the claimed capacity of the units. Second, all LSEs should be required to meet their capacity obligations on an annual or semiannual basis, and all capacity resources should be offered on an annual or semiannual basis with a bid cap. The market monitor notes that, with longer-term capacity markets, the likelihood that a net external price differential will exceed the annual value of capacity will be lower, reducing incentives to sell the system short.

4. Congestion Management and Transmission Rights

As the first ISO market to undertake locational marginal pricing with financial congestion contracts called fixed transmission rights (FTRs), PJM is a test case for this approach to transmission markets. Market participants, especially those engaged in frequent bilateral transactions, have raised concerns that the bilateral market is adversely affected by this congestion management system (as compared, ostensibly, to alternative congestion pricing mechanisms such as zonal pricing and physical or flow-based transmission rights). In particular, shorter term bilateral transactions must either pay ex post congestion costs, resulting in transmission price uncertainty, or must seek FTRs in a limited secondary market. Some transmission price uncertainty can be mitigated through the use of a trading hub, which in this context refers to a reference node (not an actual delivery point) whose price is the average of a set of surrounding nodes and hence is less volatile. In addition, the day-ahead market allows financial settlement of some congestion charges before real-time. Finally, transmission bidding, in which a bilateral transaction includes a ceiling on the congestion cost, can also be implemented. PJM has implemented each of these market design features, which appear to have improved the functioning of the bilateral market if not solved all the pricing uncertainties. Each of

⁸⁶*PJM Interconnection State of the Market Report 1999*, PJM Market Monitoring Unit, June 2000, p. 58.

these features have been subsequently adopted by the New York market design and the future New England market re-design.

PJM in June 2001 plans to implement a change to the method by which it allocates FTRs to network transmission customers.⁸⁷ Under current procedures, network customers are entitled to FTRs in an amount equal to their peak load responsibility. However, the quantity of FTRs held by most network customers currently falls well below this level. Therefore, most network customers are not required to surrender any FTRs when they lose load. PJM notes that this greatly limits the availability of network service FTRs to customers that change suppliers. To remedy the situation, PJM plans to implement a new annual procedure whereby all network FTRs that are requested in an open enrollment period will be allocated, using a simultaneous feasibility analysis, in proportion to requested MW amounts and in inverse proportion to the impact of the request on transmission constraints. This will eliminate the “grandfathering” that is inherent in the present allocation procedure.

⁸⁷See, Answer of PJM Interconnection, L.L.C., in *Old Dominion Electric Cooperative v. PJM Interconnection, L.L.C., and Connectiv*, Docket No. EL00-96-000.

C. New York

Since rolling out a largely untested and highly complex (though theoretically sound) market design last year, the NYISO has spent the following months making numerous adjustments and corrections, including hundreds of price corrections. These difficulties have been well-chronicled in a number of complaints filed with the Commission by market participants and related filings submitted by the NYISO.

Following a 2-week trial operating period, the NYISO assumed control of the electric power grid in the State of New York on November 17, 1999, operating both day-ahead and real-time spot markets, and an energy market that relies on a locational marginal pricing model for congestion management. From the beginning, energy and ancillary services markets were cleared simultaneously in the day-ahead market to prevent strategic bidding. In addition, the NYISO put in place a congestion management system which permitted participants to hedge against congestion by purchasing financial rights, similar to PJM's FTRs, which NYISO called transmission congestion contracts (TCCs). The basic NYISO market design went beyond PJM's by including a bid-based operating reserves markets.

Within weeks of the NYISO's start up, a number of market flaws and system operations issues arose, prompting the filing of numerous complaints. For example, in a complaint filed on March 8, 2000 by NRG Power Marketing, Inc., it was alleged that the NYISO reduced energy clearing prices for certain hours on December 11 and 12, 1999, in violation of the NYISO's market rules.⁸⁸ Complaints were also filed with the Commission regarding the competitiveness of the NYISO's ancillary services markets and the NYISO's operation of these markets.⁸⁹ In another complaint filed by Strategic Power

⁸⁸In its answer, the NYISO explained that it was a series of previously undetected software flaws that caused the NYISO's Security Constrained Dispatch (SCD) program to miscalculate real-time prices over the periods at issue. The NYISO also asserted that its SCD program, in some instances, had incorrectly ignored a number of low-cost generators in the price calculation step, causing the NYISO to post erroneous market clearing prices. In an order issued June 30, 2000, the Commission clarified that, under the circumstances presented, the NYISO would be permitted to correct prices to match those which would have been properly determined by application of the NYISO's market rules. 91 FERC ¶ 61,346 at 62,165 (2000).

⁸⁹On March 24, 2000, Niagara Mohawk Power Corporation (NIMO) filed a complaint in Docket No. EL00-57-0000, alleging that the NYISO had refused to permit NIMO to self-supply operating reserves without having to participate in the NYISO's market for operating reserves. On March 31, 2000, Orion Power New York GP, Inc. (Orion) filed a complaint in Docket No. EL00-60-000, requesting fast track processing and an emergency order requiring the NYISO to cease and desist from implementing its market mitigation measures for 10-minute reserves. On

Management, Inc. (SPM) on April 10, 2000, the NYISO's operations of its ancillary services markets were again challenged. Specifically, SPM alleged that there was evidence of market failure or manipulation in the operating reserves markets beginning in mid-January 2000, that the NYISO had failed to monitor these markets appropriately, and that an order requiring the NYISO to reinstate cost-based rates for ancillary services was therefore justified.⁹⁰ In another complaint, filed by NYSEG on April 24, 2000, in Docket No. EL00-70-000, an order was requested suspending market-based pricing in the NYISO's energy and ancillary service markets.⁹¹

Other operational and design flaws in its markets were discovered by NYISO itself, prompting a number of filings with the Commission. On December 23, 1999, the NYISO submitted a revised market mitigation plan which would more clearly identify thresholds over which mitigation would occur.⁹² On February 1, 2000, the NYISO submitted a transitional installed capacity (ICAP) market design to increase ICAP availability.⁹³ On March 27, 2000, the NYISO requested authority to: (1) suspend the use

that same date, New York State Electric & Gas Corporation (NYSEG) filed a complaint, in Docket No. EL00-63-000, alleging that, in addition to highly concentrated markets, there were market design flaws that were also responsible for the market inefficiencies attributable to the NYISO's operating reserves market.

⁹⁰In an order issued June 30, 2000, the Commission determined that the NYISO operating reserve markets were not workably competitive, as of late January 2000, and that there were features of the NYISO market operation and design that had exacerbated these market failures. 91 FERC ¶ 61,218 at 61,798-9 (2000).

⁹¹On May 10, 2000, NYSEG filed an amended complaint asking the Commission to (1) adopt a "price screening" procedure recommended by the Members of the Transmission Owners Committee of the Energy Association of New York State; and (2) extend the NYISO's TEP authority through October 31, 2000.

⁹²The revised plan was submitted in compliance with the Commission's order in *Central Hudson Gas & Electric Corp., et al.*, 89 FERC ¶ 61,196 (1999), in which the Commission found that the NYISO's original plan gave the NYISO too much discretion in using specific mitigation measures, namely reducing bid flexibility, imposing financial obligations to pay for operating reserves, and imposing default bids. In accepting the revised plan, as modified and clarified, the Commission noted that it more narrowly defined descriptions of behavior that could significantly affect market prices and that would justify specific mitigation measures. The revised plan, for example, included specific threshold values for identifying generators or transmission facilities that engage in proscribed conduct. *See New York Independent System Operator, Inc., et al.*, 90 FERC ¶ 61,317 (2000).

⁹³In an order issued March 29, 2000, the Commission accepted the proposed transitional market design, subject to conditions. The Commission found that the proposed design opened the

of market-based bids for operating reserves; and (2) impose bid caps for eastern 10-minute non-spinning reserve suppliers and for eastern suppliers of 10-minute spinning reserves.⁹⁴ On May 26, 2000, the NYISO requested an order extending the NYISO's Temporary Extraordinary Procedure (TEP) authority,⁹⁵ and on June 30, 2000, requested a temporary bid cap of \$1,300 per MWh on its energy markets through October 28, 2000.⁹⁶ The net effect of these filings was a Commission finding of a variety of market flaws and software errors which produced the ability for gaming the markets and, thus, required price caps on the energy and spinning reserves markets and various mitigation measures.

Specifically, flaws in the New York markets and their implementation have required the Commission in these proceedings to conclude, among other things: (1) the NYISO's 10-minute spinning reserve market is not workably competitive; (2) NYISO's Schedule 1 charges were volatile and unpredictable since market participants had little access to cost information underlying the charge; (3) NYISO required the continued use of its Temporary Extraordinary Procedure (TEP) authority since faulty software required repeated recalculation of energy prices; (4) numerous market flaws required the imposition of a bid caps on several of the NYISO-administered markets; and (5) software flaws effectively prevented economic export transactions from occurring.

In response to the above conclusions, NYISO made a compliance filing on September 8, 2000, in Docket No. ER00-3591-001, in which the NYISO reported that it has made considerable progress towards eliminating the market design and system

auction to additional non-LSE participants and would increase the supply of resources available to provide ICAP. The Commission further found that opportunities for gaming under the proposed transitional market design would be small, but required revisions to the NYISO's recall provisions. New York Independent System Operator, Inc., 90 FERC ¶ 61,319 (2000).

⁹⁴In an order issued May 31, 2000, the Commission suspended market-based pricing in the non-spinning reserve market and instead limited bids to \$2.52 per MW plus opportunity costs. New York Independent System Operator, Inc., et al. 91 FERC ¶ 61,218 at 61,801-2 (2000).

⁹⁵In an order issued July 25, 2000, the Commission authorized the requested extension through the summer peak period in light of the continued use of the procedures to correct for pricing problems such as those resulting from the dispatch of fixed block generation. The Commission also recognized that the TEP procedures would be necessary to aid the NYISO in monitoring and correcting errant prices attributable to system software errors. New York Independent System Operator, Inc., 92 FERC ¶ 61,051 (2000).

⁹⁶In an order issued July 26, 2000, the Commission determined that there were numerous market flaws in NYISO's energy markets and required a temporary bid cap of \$1,000 per MWh for the Summer 2000. New York Independent System Operator, Inc., et al., 92 FERC ¶ 61,073 (2000), order clarifying prior order, 92 FERC ¶ 61,181 (2000).

operations flaws that have plagued its system. The NYISO also claimed that its fundamental market design remains sound. The NYISO stated, for example, that the performance of its system software has improved in recent months, while the need for price corrections in its markets has declined. However, market participants in that proceeding continue to challenge these assessments and cast doubts about the market performance of the NYISO going forward.

Below-average temperatures this summer, and an increasing dependence on imports,⁹⁷ helped the NYISO avoid major market or reliability problems. However, market inefficiencies continue to threaten the overall competitiveness of the NYISO's markets. It is clear that the NYISO needs to develop and implement better demand-side response mechanisms and, at a minimum, improve its Balancing Market Evaluation (BME) software, as well as develop new market rules and operating procedures to give market participants better and more flexible access to the NYISO's transmission grid. These issues are discussed in more detail below.

1. Software Problems

Although the NYISO markets are similar to the market design models implemented by PJM, it appears now that the NYISO did not adequately test the interaction of market design and system operations. Software errors have occurred frequently and with significant impacts on market prices.

A number of software flaws have been cited:

- On May 8, 2000, a mistaken NYISO advisory price which overestimated the actual real-time energy price by a factor of ten caused ISO-New England to purchase an external energy sale at \$6,000/MWh. Similar problems with respect to imports of energy have also occurred.
- Software shortcomings have been attributed, in part, to the market failures

⁹⁷NYISO reports a significant increase in imported energy compared to operations under the New York Power Pool. The New York Control Area was historically a net exporter of energy between January and July, but in 2000 it was a net importer, importing energy about 97 percent of the time. By contrast, in 1998 and 1999, the NYCA was a net importer of energy about 25 percent of the time. From January 1 through July 31, 2000, import energy schedules from neighboring control areas exceeded 1000 MW nearly 85 percent of the time, and exceeded 2000 MW about 34 percent of the time. In 1998 and 1999 net imports exceeding 1000 MW and 2000 MW were scheduled only 10 percent and 1 percent of the time, respectively. See Affidavit of Ricardo T. Gonzales, September Report.

experienced in the NYISO's 10-Minute Reserves Markets. Specifically, the NYISO's original software modeled the Blenheim-Gilboa Pumped Storage Project (Blenheim-Gilboa) as a single unit and scheduled it either for generation or pumping (but not both), contrary to the practice formerly followed by the NYPP.⁹⁸ As a consequence, the NYISO was unable to rely on Blenheim-Gilboa as a source of reserves.⁹⁹

- In an order issued July 26, 2000, the Commission found errors in the NYISO's System Constrained Unit Commitment software that effectively prevented economic export transactions from occurring.¹⁰⁰
- In a September 22, 2000, filing made by the NYISO in Docket No. ER00-3740-000, the NYISO has acknowledged that its system software is currently unable to perform ICAP recalls. In its filing, the NYISO is seeking authority to manually determine the least cost unit to recall.
- The NYISO's system software incorrectly predicts less expensive supplies, only to force purchases at much higher prices. As a result, prices have often fluctuated substantially over short periods.¹⁰¹
- Large numbers of incorrect prices, up to 50 percent of the real-time prices (see section 3) have led to inefficient decision making in both the real-time and bilateral markets.

In its compliance filing report filed in Docket No. ER00-3591-001, the NYISO states that in the future it hopes to institute software design changes permitting it to dispatch loads with real-time metering and time of use pricing to bid into the day-ahead market and supply 10-minute or 30-minute reserves, depending on how quickly they can be dispatched. However, many of the necessary fixes noted in the compliance filing are still in the discussion stage and, therefore, are not near term solutions. The rigidity of the NYISO software makes it difficult to schedule transactions into, through, and out of New

⁹⁸Blenheim-Gilboa consists of four 250 MW units that can be used either to operate the project's pumps or for external sales. It is located east of the Central-East constraint.

⁹⁹In Docket Nos. ER00-1969-000, *et al.*, the Commission required the NYISO to modify its software to permit Blenheim-Gilboa to be utilized for 10-minute spinning and 10-minute NSR bids. 91 FERC ¶ 61,218 at 61,800 (2000).

¹⁰⁰New York Independent System Operator, Inc., 92 FERC ¶ 61,060 (2000).

¹⁰¹92 FERC ¶ 61,060 at 61,154 (2000).

York, preventing the most efficient flows of power through the region from one ISO to another. More significant changes to the software than have been proposed to date should be considered. Greater efficiencies could be gained by standardizing the software among the Northeast ISOs, for example, by adopting the PJM method of linking power system operations and market functions or by adopting the actual PJM software..

2. Transmission Scheduling Issues

Differences in scheduling and confirming energy transactions between those used by NYISO and those used by both PJM and ISO New England have led to major inefficiencies in the northeastern regional markets. PJM and New England permit bilateral schedules apart from price, whereas New York evaluates all transactions, including bilateral, on an economic basis, i.e., only transactions reducing the overall market economics are permitted to flow. This results in day-ahead bilateral transactions being cut in real-time. In addition, this evaluation process is done on an hourly basis, so that any export transaction, even those confirmed in the day-ahead market, to PJM or to ISO New England must be rebid on the hour. The BME schedules flows based on price and not whether the transaction is firm. Exports can be cut by the NYISO as late as 10 minutes before the hour. Neither PJM nor ISO New England have procedures that create the same difficulties for exports.

A number of market participants have objected to these procedures. NYSEG, among others, has alleged that energy imports to New York have been unworkable. PJM indicated to staff that severe cuts to inter-control area transactions at one point led it to consider discontinuing day-ahead transactions with the NYISO.¹⁰² Market participants have also expressed concern regarding the inability to secure transmission in and out of the NYISO, alleging that the NYISO is an impediment to through transmission because it protects internal load by favoring network service over point-to-point service. Others have charged that the NYISO is reluctant to release information supporting its curtailments. The Commission's Enforcement Hotline has fielded complaints about the lack of information provided by NYISO about curtailments, and staff has arranged for market participants to receive more information on an ad hoc basis. PECO Energy Company claims that it has lost \$13 million in cuts by the NYISO.

The NYISO has put in place a temporary fix to the problem by automatically subtracting \$20,000 from the decremental bids of such transactions. The BME then gives these bids a priority over all other transactions. But even the temporary fix is

¹⁰²PJM reports that it has had up to 1,700 MW of supply from New York cut only 15 minutes before a scheduled flow.

problematic—all transactions in New York are limited to submitting decremental bids of no lower than negative \$9,999.99. Due to the rigidity of its software design, the NYISO recognizes that this fix causes other problems by driving down the evaluator's hour-ahead price forecasts and causing the evaluator to reject some economic transactions and instead call on more expensive units which ultimately raises real-time energy prices.¹⁰³ The patchwork fix is representative of the troubles faced by the NYISO and its market participants, and is indicative of how New York's market implementation (lack of robust software) slows the further development of trade in the Northeast markets.

3. Transmission Constraints Affecting New York City and Long Island

As previously discussed, NYISO's markets are effectively divided in two by the frequently congested Central-East interface. This is especially problematic because the eastern region, and New York City and Long Island in particular, are NYISO's major load centers, where the exercise of market power is likely due to high market concentration.¹⁰⁴ Despite Commission directives requiring NYISO to propose solutions to maximize access to western supplies, particularly with respect to reserves (e.g., allowing reliance on western suppliers for 10-minute reserves during times when there is no congestion or expanding the supply markets for 10-minute reserves to include western suppliers),¹⁰⁵ NYISO has yet to devise a solution to the Central-East constraint. This affects prices not only for energy within the New York City and Long Island load pockets, but also for reserves west of the constraint that would otherwise be economic. These conditions result in tight supplies in the major load centers, leading to higher prices and the potential for the exercise of market power. For instance, while there are mitigation measures applied to the generation units divested by ConEd, these measures do not apply to other sellers into New York City who, because of the load pocket and tight supply conditions, could set the market clearing price.

New York City's load, which can exceed 10,000 MW, is served by in-city generators and by power imported through transmission lines from the north (running along the Hudson River) and east (from New Jersey). Each of these sources is

¹⁰³NYISO compliance filing in Docket No. ER00-3591-000, transmittal letter at pp. 36-37.

¹⁰⁴ConEd historically owned the majority of in-city generation. When it was sold off as part of a state restructuring proceeding, the total was divided into three packages and auctioned off to three separate entities. However, even with three, rather than one, generation owner in the city, the market remains highly concentrated.

¹⁰⁵ 91 FERC ¶ 61,218 at 61,800 (2000).

constrained, creating a load pocket in the city. In-city generation totals about 7,900 MW (summer capacity), all of it oil or natural-gas fueled. Little if any of the proposed 4,700 MW of new generation in the city is expected to be operable even by summer 2002; the NYISO expects none of it to be online in within “three or four years.”¹⁰⁶ Thus the outlook for new supply within the city is poor.

Transmission of power into New York City is limited by the capacity of the existing lines. Several lines run north to the Dunwoodie and Sprainbrook substations in the Hudson River valley. Their capacity is about 4,175 MW. Lines from New Jersey (part of the PJM system) normally have about 1,000 MW capacity, but they were limited in summer 2000 to 550 MW because a large transformer failed and could not be replaced before summer.

Total transmission capacity into the city is therefore 5,175 MW when fully functional. Because the Hudson River lines comprise a large portion of the city's supply, they are important for reliability. During thunderstorms that could knock those lines out of service, reliability rules require 80 percent of New York City's energy to be generated within the city. This protects the city from blackouts caused by transmission outages, but it also increases the market power of the in-city generators. If demand in the city is 10,000 MW, there is insufficient installed capacity to meet the reliability requirement.

Long Island is also constrained by transmission and generation. About 4,400 MW of generation (summer capacity) is now installed on Long Island. As in New York City, no new generation is expected for 3 or 4 years. Transmission capacity to Long Island is about 975 MW, primarily in lines across Long Island Sound from Dunwoodie and Sprainbrook. An additional 330 MW should be available in 2002 as a private transmission line from Connecticut is completed.

Ongoing difficulties importing power into Eastern New York because of transmission constraints and market design (BME) issues, combined with the difficulty of siting new transmission or generation facilities, create formidable challenges to the markets and to reliability.

4. Difficulty Siting Generation

New York has evolved in recent years to be a market that is dependent on imports, primarily from PJM, to meet demand in its control area because total demand plus reserve

¹⁰⁶ The New York State Board on Electric Generation Siting and the Environment; NYISO Board Policy Statement on “Market Protective Mechanisms,” October 19, 2000.

requirements exceeds its internal generation. As noted above, the New York Public Service Commission has recognized that demand has grown beyond all expectations such that the state hit a peak in 1999 that it did not expect to reach until 2003.

As noted in section 2, a recent NYISO study indicated there were approximately 74 projects proposed to be built in New York State. However, the report further pointed out that only one of these projects is like to be built during the next 3-4 years.¹⁰⁷ The New York City and Long Island areas are among the most challenging in which to build new generation or transmission facilities. Both are very heavily urbanized. Statewide, the state's Article X approval process has been criticized by market participants as slow and uncertain. Environmental concerns (most recently, water use restrictions) have figured in plant cancellations, and the New York State Department of Environmental Conservation was criticized in June by the State Supreme Court for failing to clear a two-year backlog of air quality permits. Clearly, there are constraints on the ability to site new plants in New York that could further harm the state's reliability, push prices in an upward direction, and delay the entry of new suppliers into the market to mitigate the market power of current suppliers. As has been the case with California, New York state may need to review its transmission siting procedures, including provisions for a streamlined appeal process and environmental rules.

However, in the near term, the state must continue to rely on imports. Thus, until software changes are made to the BME to facilitate imports, new supply, demand side management or other measures, such as distributed generation, are put in place prices are likely to rise and market power could become more of a problem.

5. Price Caps

The Commission has approved various price caps and mitigation measures for New York markets in three orders, beginning with the initial grant of market-based rates to the members of the then-forming NYISO. The Commission granted market-based rates for energy and ancillary services throughout New York; however, ConEd chose not to seek approval to sell at market-based rates within New York City.¹⁰⁸ Instead, ConEd carried forward restrictions on its sales price within New York City which arose out of its

¹⁰⁷ The New York State Board on Electric Generation Siting and the Environment; NYISO Board Policy Statement on “Market Protective Mechanisms,” October 19, 2000.

¹⁰⁸ Central Hudson Gas & Electric Corporation, *et al.*, 86 FERC ¶ 61,062 at 61,233 (1999).

state restructuring proceeding.¹⁰⁹ The Commission cited localized market power as the reason which necessitated the use of mitigation measures.¹¹⁰ It noted that this localized market power was the result of “well-documented” constraints into New York City, local reliability rules which require in-city loads to be supported by installed generation and spinning reserves from generators located in the city, and in-city generation supply that is not adequate to support competition among the three or four generation-owning entities within the city.

In addition, the Commission approved a cap of \$2.52/MWh plus opportunity costs for non-spinning reserves east of the Central-East constraint.¹¹¹ The Commission reasoned that conditions under which market-based rates were initially granted had changed. The markets are more concentrated than indicated in the original analysis and the prime mitigating factor relied on—the presence of multiple suppliers with the ability to fully satisfy the ISO's ancillary service requirements—does not exist. The Commission also cited to problems with the NYISO design and operating protocols, including the requirement to procure all of the 1,200 MW of 10-minute reserves east of the Central-East constraint based on the historical power pool practice even when there is no congestion or, if there is a constraint, if the overall cost of energy and ancillary services would be lower.

Most recently, the Commission approved a temporary \$1,000/MWh cap on energy and ancillary services through the summer capability period.¹¹² The Commission cited several factors as the basis for the cap: market design flaws that are in various states of repair, some short-term fixes and other long-term fixes that may not be implemented for

¹⁰⁹Consolidated Edison Company of New York, Inc., 84 FERC ¶ 61,287 (1998).

¹¹⁰The mitigation measures include the use of bid prices for in-city generators to be used by NYISO to compute the in-city clearing price unless the bid prices become 5 percent greater than the price at the Indian Point 2 bus, which is located outside the city and considered to be representative of the broader Southeast New York markets. When mitigation measures are invoked, the actual in-city bids will be capped at the amount that these same generators had bid during unconstrained periods in the previous 90 days. Further, installed capacity prices within the city are capped at \$105/kW/year.

¹¹¹New York Independent System Operator, Inc., *et al.*, 91 FERC ¶ 61,217 at 61,798-799 (2000).

¹¹²New York Independent System Operator, Inc., *et al.*, 92 FERC ¶ 61,073 at 61,302-303 (2000).

some time; lack of demand-side responsiveness and tight supplies,¹¹³ specifically installed capacity and operating reserve supply shortages in New York City, which force the NYISO to accept any and all bids when supply is tight which magnifies price spikes.

All of these mitigation measures were approved to address, primarily, the tightness of supply in New York City and, secondarily, market design flaws. As the report notes in several places, these conditions remain largely unchanged since new generation plants and transmission lines are not being built and demand has continued to grow without demand reduction in the forms of distributed generation, increases in end-use efficiency, or an increase in price-responsive demand bidding.

6. Conclusions

While many of the problems with prices in New York this past summer stem from fuel costs, outages, and import difficulties, many of the above rules and software corrections remain incomplete. While some solutions are before the Commission in a compliance filing in Docket Nos. ER00-3591-000 and -001, in most instances, the filing notes that NYISO and stakeholders are still considering solutions. All of these are examples of how the New York market is slowly evolving and, perhaps, too slowly correcting itself. New supply will not be available for years and many design changes will take months if not longer to effect, during which time prices will rise, market confidence will continue to be adversely affected, and opportunities to exercise market power will increase. This could have unfortunate consequences for the entire region. For example, during the transition, the continued need for market intervention could have adverse consequences. Market participants may then have an incentive to use bidding strategies in which they increase their bids for one product to recover perceived lost opportunity costs because their bids for another product are capped or mitigated in some form. In the absence of new generation or relief for transmission constraints, incentives for either reducing demand or encouraging distributed generation should be employed.

The need for so many software corrections and the length of time necessary to effect the required changes begs the question as to whether one existing market protocol and software package ought to be applied to New York as part of a greater northeastern market restructuring or, at least, whether NYISO should limit its markets to energy until

¹¹³The Commission pointed to NERC's *2000 Summer Assessment* (at 36) which states that, based on historical demand data and generator forced outage performance when NYISO demand exceeds 29,025 MW (a peak of 30,200 was predicted), the area will not be able to satisfy its operating reserve requirements without invoking emergency relief measures. The Commission approved the cap, adding that it was "not confident that energy prices will not dramatically increase in New York this summer as a result of these problems."

that market functions efficiently, at which time it could add other products.

D. New England

The New England markets have experienced design problems and complaints about system operator procedures almost since their inception.¹¹⁴ In addition to the major energy and reserve market price spikes on May 8, 2000, market problems have included numerous price corrections, market power mitigation actions (in certain markets) and general design flaws. This section examines the major issues.

The underlying market design in New England has been a source of most of the market problems. Along with numerous market rule changes since the start of the markets, the Commission has approved a complete market re-design, including a congestion management system based on locational marginal pricing and multi-settlement system.¹¹⁵ This market re-design will bring the New England market more closely in line with the PJM and New York market designs. A key issue is the schedule for implementation of the market re-design and the choice of available software for future market and system operations. Until the market re-design is accomplished, ongoing problems stemming from the current market design (and resulting in increasing transmission and energy related uplift costs) will continue.

1. Energy Market

Market power and the effect of interactions between the energy, reserve and capacity markets (as evidenced in the May 8, 2000, price spike) have been the major problems in the energy market. Like PJM, New England reports some degree of strategic bidding in its energy market during the summer and fall of 1999.¹¹⁶ Actions taken in winter 1999 and through 2000 have not yet been reported to the Commission. The bulk of actual bid mitigation, since market operations began, has taken place with respect to bids

¹¹⁴ The preliminary New England market design was developed by NEPOOL committees over the course of 1998. Problems with this design were suggested by independent experts under contract to the ISO (See Peter Cramton and Robert Wilson, "A Review of ISO New England's Proposed Market Rules," Report to ISO New England, Market Design Inc., September 1998). However, these experts, the ISO and NEPOOL supported beginning market operations and addressing market design problems with the markets in progress. NEPOOL proposed a phased implementation which was approved by the Commission. Market trials were run in January 1999 and the markets were started on May 1, 1999.

¹¹⁵ ISO New England, Inc. et al. 91 FERC ¶ 61,311 (June 28, 2000).

¹¹⁶ ISO New England, Market Report, Quarters 1 & 2, May - July 1999, August - October 1999, October 26, 2000.

from generators in transmission congested areas. These bids are subject to mitigation relative to a reference price.

Apart from the May 2000 price spike, prices in the New England energy market have remained moderate since summer 1999. However, the price spike showed that reserve requirements can render the energy market un-competitive, a result which can be generalized to all periods of capacity deficiency (as was found in PJM). This consideration lead to the establishment by the Commission of a \$1000/MWh bid cap in the energy market during periods of capacity deficiency. The bid cap was limited to the summer and fall of 2000 (terminating on October 31, 2000).¹¹⁷ Unless market conditions change over the coming year, the energy market will continue to be vulnerable during capacity deficiencies.

In addition, over the period of operation there have been several other complaints about the energy market, including the impact on energy market prices of generators being used to provide operating reserves (particularly replacement reserves) and rules governing energy transactions after the day-ahead bidding deadline (short-notice bilateral transactions).

Some of these problems stem from the single-settlement system that is to be replaced and thus are interim in nature. Under the single-settlement system, generators submit their final bids by a day-ahead bidding deadline, but prices are only settled financially at real-time. This means that generators with day-ahead bids submitted cannot respond to changes in the market (greater demand, higher prices) closer to real-time. When New England begins its day-ahead market with a financial settlement, all desired changes in output will be settled at real-time prices, allowing generators to change their position in response to real-time market information.

Other aspects of the interim problems in the energy market may be resolved with changes in the market bidding rules. Under current New England market rules, any generator set at its low operating level is not eligible to set the clearing price but is paid its bid price for the output it provides. Generators are often set at their low operating levels to provide operating reserves. The ISO does this to provide replacement reserves (which are not priced in the operating reserve markets), but it has two effects on the energy market. First, the energy provided by generators turned on to provide reserves may be more expensive than the system clearing price but is not allowed to set the price. Second, the energy provided by such generators also dampens the energy price by being de facto bid at zero. These problems will be solved in part by the introduction of three-part bids, which include start-up and no-load bids. However, only incremental energy

¹¹⁷NSTAR Services Company, 92 FERC ¶ 61,065.

bids will set the clearing price, so a more permanent solution will require entry of additional generation which can provide high quality reserves (particularly the capability to quick start).

Like the other ISO markets, New England has little price-responsive demand. In recent Orders, the Commission has begun to address the issue of demand-side responsiveness and establish schedules for implementation.¹¹⁸

2. Ancillary Service Markets

There have been numerous problems with the ancillary service markets under their current design. New England began operations with four daily ancillary service markets: ten-minute spinning reserve, ten-minute non-spinning reserve, thirty minute operating reserve, and automatic generation control. New England also has several ancillary service products which are not priced through markets, including replacement reserves, voltage support and blackstart capability. The definitions and interim market rules for these products were idiosyncratic, complex, and in some cases simply did not reflect standard economic assumptions.¹¹⁹ These rules have undergone several subsequent changes which have removed some inefficiencies. In addition, there is a price cap on operating reserves during capacity deficiencies.

A fundamental problem in the ancillary services markets is the method of clearing the markets. Each eligible generator submits a bid into one or more of these markets, which have a daily bidding deadline of 2 p.m. the prior day (or month in the case of installed capability). In the reserves markets, each bid is then subject to an often complex bid evaluation which determines a ranking on the basis of expected costs, including opportunity costs and, in the case of automatic generation control, penalties for shifts upward along the bid curve during dispatch. The daily markets are then cleared during real-time dispatch in the following order: energy, automatic generation control, 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve. This order reflects both technical requirements and the expectation that higher value uses of

¹¹⁸ In *NSTAR Services Company*, 92 FERC ¶ 61,065, ISO New England is required to file a report discussing opportunities for and barriers to implementation to enhanced demand-side measures by February 28, 2001. Specific options that can be formulated and/or implemented earlier should be filed in advance of this date; all feasible options should be filed no later than April 1, 2001.

¹¹⁹ *New England Power Pool*, 85 FERC ¶ 61,379, 1998; Peter Cramton and Robert Wilson, "A Review of ISO New England's Proposed Market Rules," Report to ISO New England, Market Design Inc., September 1998.

generation capacity will clear at higher prices.

As was experienced in the California ISO, clearing each ancillary service market in sequence without recognizing substitution possibilities among the services is an invitation to strategic bidding behavior. As an interim measure, the ISO enforces the expected valuation of the operating reserves with a price cap set at the energy clearing price, but limited to capacity deficiency conditions. Since September 1999, a substitution rule allows prices in one market to cascade into subsequent markets, thus limiting opportunities for bidding up prices for low valued reserves. Nevertheless, price inversions between the operating reserves and energy markets still do occur on occasion.

Another ongoing problem in the operating reserve markets stems from New England's particular generation mix, which has fewer quick start generation resources than, for example, PJM. This characteristic of the resource mix has resulted in market interventions and market rule changes to provide both the amount and quality of operating reserves required by NPCC and NERC guidelines and particular system conditions. For example, the system operator may manually place certain large hydro units on reserve during capacity deficiencies. These units are then paid according to a pricing formula which includes the opportunity costs of not providing energy. In addition, as discussed above, the ISO uses generators at their low operating levels to provide replacement reserves. While the generation mix in New England will only change over years, some of the inefficiencies caused by the current market design can be remedied by features of the market re-design, such as demand curves for ancillary services, option contracts for forward reserves, and dynamic scheduling with neighboring control areas.

3. Capacity Markets

The two capability markets proved to be the most poorly designed markets in New England and both were terminated in 2000. Under the prior power pool rules, load-serving entities had to demonstrate that they had sufficient installed capability to meet peak load and a reserve requirement on a seasonal basis. The power pool also provided an incentive program for generation owners to keep that capability operable on a short-term basis. Under NEPOOL, two markets were designed to meet these objectives: the monthly installed capability market and the daily operable capability market. Both were residual markets and both products were available also on a bilateral basis.

There is general consensus that the operable capability market was misconceived

and that there is no need to provide its services with a different product.¹²⁰ However, as noted above, both PJM and New York have installed capacity markets; whether New England recreates an installed capacity market or provides the service of this market in a different way (such as through forward reserve markets) has implications for northeastern regional coordination. Moreover, although the installed capability market has been terminated, the experience with it is instructive with respect to market design for capacity products.

The installed capability auction market operated smoothly until 2000, but, like the operable capability market, was cleared at an ex post settlement rather than during dispatch (hence there was no opportunity cost to providing the product). The market was thus vulnerable to strategic bidding behavior. During 1999, there were typically about 1,000 megawatts sold each month in the auction market, with the remainder of load-serving entities meeting their installed capability requirements in a robust bilateral market (installed capability is often bundled with bilateral energy contracts). For most of 1999, at least double that amount of installed capability was offered at zero or low prices and for most months the market-clearing price was \$0 per megawatt.

Beginning in January 2000, the amount sold in the auction market greatly increased, ranging between 2,798 and 4,021 MW in the January through July period. Also, bid prices increased, reaching as high as \$105,000/MW through March. The ISO determined that bids for a significant amount of installed capability in the January to March period represented a pattern of behavior consistent with an intentional or systematic effort to raise the market clearing price. The ISO mitigated a number of bids to zero pursuant to the market rule that allows the ISO to mitigate anomalous bids to their actual marginal costs. The ISO concluded that in those instances the marginal costs for supplying installed capability was zero. After the mitigation, the market cleared at zero for those months.

For the month of April 2000, there was no pattern of bidding that the ISO felt justified it treating as an indication of economic or physical withholding or other

¹²⁰The operable capability market was presumably intended as a small additional payment to generators for their available capacity—essentially available energy and operating reserve. In this sense, operable capability duplicated the existing energy and operating reserve markets. The operable capability “product” was not used during system dispatch; it was basically an accounting device with associated payments or charges. Hence, there was no opportunity cost to participating in the market. The bidding incentives were to either bid zero or very low or to set the clearing price at an arbitrary level. Following attempts by bidders to set very high clearing prices for this low or zero value product, and the failure of consensus on how to reform the market rules, the operable capability market was terminated on March 1, 2000. See New England Power Pool, 90 FERC ¶61,168 (February 23, 2000).

anomalous conduct by a bidder. The ISO did not mitigate any April bids and the market was allowed to clear at \$3,426/MW. The ISO has not settled the installed capability market for the months of May, June and July. It has indicated that the bidding pattern in those months is consistent with a disturbed market that has not settled into a competitive pattern and which pattern may be inconsistent with a competitive market. The ISO has requested guidance from the Commission on possible mitigation actions for those months. A number of protests have been filed concerning the installed capability market mitigation undertaken by the ISO. The Commission presently has under consideration the appropriateness of the market mitigation undertaken or proposed by the ISO during 2000. In addition, there is a pending Department of Justice investigation of the market.

In its June 28, 2000, order, the Commission agreed with the ISO that the existing installed capability auction market was not useful and that it could produce inflated prices unrelated to the actual harm created by installed capability deficiencies.¹²¹ Among other things, buyers could not see the prices in advance of the month in order to weigh various alternatives for supplying needed installed capability. Thus, they were forced to pay whatever price was determined after the fact. In this situation, there was a lack of competitive influence on bid prices. The Commission permitted the elimination of the auction market effective August 1, 2000, and required the ISO to revert to administratively-determined deficiency charge for failure to meet installed capability requirements (a Commission Order setting the amount of the deficiency charge is pending).

4. Congestion Management and Transmission Rights

Since beginning operations, ISO New England has conducted congestion management by redispatching the system and paying generators whose output is increased additional payments, as required by their energy bid curve (there is no compensation for generation whose output is decreased). As noted in Section 3, these payments are then included in uplift charges to transmission users. Because this system does not explicitly price congestion, there are no transmission rights. Rather, there is a system of physical priorities detailed in the energy markets rules. For example, in the event of congestion, resources dispatched through the spot market are redispatched, while self-schedules and firm bilateral transactions are respected to the extent possible. Non-firm bilateral transactions have least priority.

As shown in Section 3 (Figure 1-14), since market operations began, congestion costs have increased substantially, from about approximately \$0.5 million in May 1999 to

¹²¹ISO New England, Inc. et al. 91 FERC ¶ 61,311 (June 28, 2000).

several months with congestion costs between \$10 million and \$25 million in 2000. Currently, all electrical load is charged pro rata for congestion, meaning that in essence low congestion areas are subsidizing high congestion areas. New England is examining options for interim congestion management, which may allocate congestion costs on the basis of regional load zones within the control area. However, the solution to this mis-allocation of costs lies with the implementation of locational marginal pricing of congestion, as discussed below.

5. Planned Market Design and System Operations Changes

In June 2000, the Commission approved a revised congestion management system and multi-settlement system for New England, along with many changes to specific market rules.¹²² This proposal changes the New England market fundamentally, moving to a design that is quite similar to New York and PJM but still has some differences. The redesigned market will be a multi-settlement system with simultaneously cleared energy and ancillary service markets. Congestion management will be based on locational marginal pricing with financial congestion rights. There will be a day ahead market accepting both supply and demand bids. In addition, New England will implement some new market design features, including demand curves for ancillary services and four hour reserves.

Given the problems with the current market design in New England and the system operations problems in New York, two important issues in the market re-design are the schedule for implementation and the choice of available software for market and system operations. In response to an ISO estimate for full implementation of the market re-design of 16 to 24 months, the Commission requested, in the June 2000 Order, an enhanced schedule for implementation. The ISO's current projection, pending with the Commission, is that full implementation is possible by fourth quarter 2001. In addition, the Commission has sought to improve operational success by requiring ISO New England to seek best available software rather than build on its existing capabilities.¹²³ Delays will result in the continuation of the current inefficiencies in the markets.

The current transitional period in the New England market design makes it difficult to predict market performance in the coming one and a half to two years. Some

¹²²ISO New England, Inc. et al. 91 FERC ¶ 61,311 (June 28, 2000).

¹²³ISO New England, Inc. et al. 91 FERC ¶ 61,311 (June 28, 2000) states that "ISO New England should consider acquiring existing congestion management software that has been shown to successfully operate locational pricing, as an alternative to designing its own software from scratch."

improvements in market performance in the near term could result from the termination of the worst performing product markets (operable capability and installed capability), improvement in system operations, including forthcoming implementation of electronic dispatch, expectations of new entry of generation capacity, increased demand-side price responsiveness, and enhanced market monitoring and mitigation. However, the experience of the New England markets to date suggests that continued close oversight by the Commission is warranted and that, in the absence of sufficient market power mitigation capabilities and a developed demand-side response, continued measures to limit high prices may be required at least through the summer of 2001.

E. Northeastern Regional Coordination

The three northeastern ISOs share a number of similar features. They all rose from tight power pools that used, and still use, economic dispatch. They have other operational features that are similar as well as similar market designs. Given the similarities, there are many efficiencies that could be gained by greater coordination between the ISOs. Centralized, region-wide system dispatch and common reliability criteria, along with standardized products and rules would improve trade across the region. To date, the primary focus of each of the ISOs has been to make their own markets and systems functional. It may be appropriate to take a more strategic approach to the Northeast region, so that efficiencies that could be achieved from coordination and standardization across ISOs are not lost, or too long delayed, in the process of remedying the separate problems of each ISO.

The ISOs have common market participants, and operate from the same general market design, i.e., each ISO is centrally dispatched, its energy and ancillary service markets are cleared with uniform price auctions, and has some similar market elements (financial transmission rights and locational marginal pricing). However, while the ISOs have similar basic market designs, the products currently offered are different, the basic implementation software is different leading to different dispatch decisions, and the market rules and business processes are different. While each ISO began with the same basic market design, each proceeded at a different pace, offering different products under different rules, and implemented by different software. These differences were not highlighted during the ISO's market formation but have become significant and may continue to diverge as the ISOs continue on separate tracks. The lack of “universal” products in the Northeast as well as the lack of harmonized or standardized procedures for buying and selling power across the region is a loss to the efficient functioning of the market.

To address this, the three ISOs entered into a Memorandum of Understanding (MOU) to explore ways in which the ISOs can work together cooperatively to resolve present and future northeastern regional issues. The objectives of the agreement are to: (1) enhance northeastern regional reliability through coordinated operations and planning; (2) facilitate broader competitive markets; and (3) improve the flow of information to market participants and the public. However, this process began over one year ago and has yet to make significant progress.

As part of the MOU process, market participants have identified a number of issues that present obstacles or allow for inefficiencies to inter-ISO trade that broadly fall into the categories of transaction flexibility, consistent practices, information, and planning. Specific issues raised by market participants are highlighted below followed by a discussion of their inter-related nature and effects on coordination and standardization.

The issues identified by the market participants are:

- **Information exchange.** More frequent and better information exchange with the ISOs. Conflicting information on tags required by NERC and the different ISOs, the limited amount of time to perform investigation or confirmation of schedules, and differences in notification process among ISOs all act to create confusion and market uncertainty at times resulting in transactions being cut with participants having little opportunity to resurrect the transaction.
- **Increased Flexibility.** Greater flexibility with the scheduling of interchange transactions—market participants want the ISOs to respond to schedule changes more frequently than at the top of the hour, e.g., respond every 15 minutes (PJM) instead of just the 10 minutes across the top of the hour (NYISO). A restriction on the flexibility to change schedules may limit the amount of economic transactions within the hour.¹²⁴
- **Information transparency.** More timely release of bid data¹²⁵ and better notification to market participant when changes, such as curtailments, are made in their transactions. ISOs have made some progress on keeping participants informed with regard to the status of their transactions. For curtailments PJM posts, in real time via its web site, when a constraint develops that may call for curtailment and why it is occurring, and also notifies participants by telephone of the curtailment. NYISO, on the other hand, currently offers terse emails indicating a transaction will be cut and then requires that the customer make a phone call to get further information.¹²⁶
- **Common implementation of criterion.** Increased coordination among the ISOs of the implementation of resource adequacy criterion. The goal would be to coordinate resource planning to achieve more robust regional markets so that

¹²⁴This problem may be alleviated if there were common scheduling and posting times between ISOs.

¹²⁵In NSTAR the Commission required ISO-NE to disclose individual bid data with a 6-month lag in a way that permits analysts to track each individual bidder's bids over time without revealing the names of individual bidders. The issue is whether the bid data should be released with a shorter time lag.

¹²⁶Market participants allege that even the phone call results in neither a timely or satisfactory explanation as to the reason for the curtailment. NYISO is working to add real-time transaction curtailment notices on its website and is working to add greater detail to this notification.

energy delivered can serve load anywhere in the Northeast region.

- ***Awareness of capacity market differences.*** The installed capability (ICAP) requirements, how load serving entities meet these requirements, and the rules for recall and payment vary among the ISOs. These differences act to fragment the Northeastern region rather than bring it together, and may also drive resources from one control area to the next¹²⁷ potentially exacerbating market power in situations of limited ICAP.
- ***Consistent interconnection policies.*** Market participants want one-stop shopping for generation interconnection procedures, practices, and approval. Currently, they must deal with three ISOs, plus any requirements of IOUs, and multiple state agencies to gain interconnection to the grid creating inefficiencies in process and outcome.¹²⁸ Standardization of procedures would also be an objective.
- ***Congestion Management.*** Lack of coordinated LMP models (LMP markets not tied by one set of rules or software) and differing rights to transmission may result in foregone transactions because they appear uneconomical.¹²⁹
- ***Consistent Transmission Scheduling.*** Power does not flow across ISOs as easily as it could or should. This is in large part due to physical characteristics, but also due to the differing market designs of adjacent ISOs. This latter point is especially true for scheduling into and out of the NYISO where transactions are evaluated on the basis of the economics of the energy bid.

The above specific concerns identified by market participants serve to highlight

¹²⁷Because ICAP is associated with reliability, differences in ICAP across regions may result in resource inadequacy. It has been alleged by market participants that ISOs do not necessarily know which energy transactions are at risk of being curtailed due to a recall of ICAP by another ISO; and whether they know which generation belongs to whom and which are at risk for curtailment.

¹²⁸While the ISOs each have interconnection procedures, they are not consistent across ISOs.

¹²⁹Hypothetically, assume that the price at point A within PJM is \$40 and the price at the export node (B) is \$70. Assume also that the price at the NYISO import node (C) (essentially the PJM export node) is \$60 and the price at delivery at point D within NYISO is \$70. The transmission congestion charges from A to D would be priced as the difference between (A) and (B) plus the difference between (C) and (D) for a total price of \$40. If there was one LMP, the price from (A) to (D), assuming all other things equal, would be \$30.

the broader issue—that the three northeastern ISOs have similar features but are not structured to enhance Northeast regional coordination and may, in fact, be deterring trade across the Northeast. Some of the concerns raised are business practices that, in market participants' views, if implemented would aid in their ability to buy and sell power in multiple regions. For example, increasing the flexibility of interchange schedules from a period more frequent than just across the top of the hour would enable more transactions. Increased information to the market would go a long way toward enabling buyers and sellers to be able to rely on transactions, e.g., knowing not only that a transaction has been curtailed but also knowing why increases predictability. Simply operating under one tariff, with one-stop shopping would create greater efficiency.

Other issues (some raised by market participants and others not) however, are more significant, require greater effort on the part of ISOs, and will likely have greater impact on regional market maturity. These entail more structural changes or enhancements. Eliminating institutional boundaries for determining locational marginal prices, offering firm transmission rights, and creating universal procedures for generation interconnection, reserve requirements, and transmission expansion would allow pricing and planning to be done on a macro-regional basis. This would serve to unite the three ISO markets over time. For example, there is underway a northeastern reserve sharing procedure to take advantage of regional economies of scale to improve regional reliability while reducing individual reserve requirements of ISOs (which are met by market participants). If effectively implemented, this procedure has the potential to increase the economic utilization of inter-regional ties (i.e., allow more Hydro Quebec transfers while eliminating the requirement for NYISO to carry added reserves—the reserves would be carried by the reserve sharing group), and reduce the amount of reserves individually required.¹³⁰ It may also increase supply options east of NYISO's Central-East constraint.¹³¹

Pricing without regard to boundaries coupled with intra-regional transmission expansion planning would help to focus the addition of resources where most valued, internalizing such issues as limited transfer capability. If there was one LMP market, the price would be based on the cheapest MW to supply a location. Coordinated LMP models would offer consistent rights to transmission (as opposed to incremental rights from three different systems) and could improve intra-regional reliability. A Northeast

¹³⁰For example, if Hydro Quebec's DC line trips, to NYISO it appears like a loss of generation to NYISO and NYISO must carry reserves sufficient to cover this contingency, even if the supply was not destined to serve New York markets. Under shared reserves, if a portion of the load carried over the DC line was destined for PJM, PJM would be responsible to cover a share of the reserves.

¹³¹September 1, 2000, filing letter, Docket No. ER00-3519-000.

regional market could decrease costs as additional resources are available to buyers and decrease periods when market power can be exercised. Common implementation of the markets via software and rules would reduce transaction costs to market participants.

NYISO's market implementation (software) has created significant market uncertainty as evidenced by the impact on forward contracts following May 8. NYISO's software has also contributed to transactions erroneously being cut. NYISO performs an hour ahead market assessment wherein schedules that were confirmed in the day ahead market might be curtailed due to the NYISO's unique BME re-evaluation of the economics of the hour ahead market superceding the financially binding day ahead schedules. The participant whose schedule is cut is left to buy back the transaction at the NYISO's real time price, which has not been accurate. Such implementation problems unnecessarily add transaction costs to the market and negatively affect operations.

Conclusion

The northeastern ISOs are in various stages of development. PJM has yet to implement market pricing for several ancillary services, NYISO upon implementation undertook a complete market design, and ISO-NE is undergoing a significant market re-design and enhancement. While ISO-NE's redesign may, in the end, be very similar to NYISO's, the governing market rules and procedures and implementation of the markets via software are expected to be different. The differences in the rules, procedures, and implementation software that now exist, even before expansive redesign of ISO-NE and before PJM embarks on offering additional market-based ancillary services, present barriers to trade and create inefficiencies. Greater coordination and standardization among the ISOs would add efficiencies to the market

To date the ISOs have been focused on improving the markets they each administer. This is demonstrated by the numerous incremental changes to market design and rules that have been filed with and approved by the Commission since inception of the ISOs. For ISO-NE and NYISO, the pace of these changes have been frequent. Thus, ISOs are still revising and incrementally improving their basic market platforms. ISO-NE must continue such incremental revisions as it moves forward with its significant re-design that will take 18 to 24 months. Implementation of the re-design will no doubt generate years of additional refinements. These changes require considerable investments of time, money, and human resources by all segments of the market and regulators.

It might be more effective to devote the resources of all market segments and regulators to the potential for northeastern regional solutions to issues such as transmission planning or congestion management than to perfect separate ISO-administered markets. Synergies that will further the Commission's goal of broader

regional coordination may be lost, at a minimum, in the near term and quite possibly longer term once NYISO and ISO-New England have made considerable investments in fixing or enhancing their separate markets. To prevent the possibility of continued internal changes by ISOs that do not also enhance, and may hinder, further trade across the Northeast, the Commission may want to take a more active role in the coordination and standardization process begun with the MOU.

6. Policy Options

The operation of competitive wholesale electricity markets in the northeastern region has a record to date of general success mixed with the revelation of some significant problems in market structure, market design and system operations. PJM, the first ISO to operate markets in the region, corrected some initial design problems, particularly with congestion management, and has accumulated a generally good record of market operations. However, PJM has also restrained possible market power during capacity shortages with a \$1,000/MWh bid cap. ISO-New England and NYISO, on the other hand, have experienced numerous problems with market design and implementation flaws, software problems, market rule changes, and non-competitive supply conditions. These flaws have undermined market functioning and performance to the detriment of some market participants. While the price events in the spring of 2000 exposed some market flaws, the moderate temperatures in the summer of 2000 mitigated the price impacts of market problems.

As indicated earlier in this Report, the Northeast markets are in various stages of transition in market rules and structure. While there are many positive developments in the markets, there are several issues that continue to prove problematic. General capacity deficiencies, locational market power and market design flaws may require continued consideration of the need to impose price or bid caps. 's transition to its comprehensive market re-design will be complex and difficult. NYISO's implementation and software problems will continue to be an issue. This section discusses some of the options available to the Commission to correct the conditions that are creating market uncertainty, hindering the development of commonly defined market products and business practices, and sustaining other barriers to trade in the Northeast.

A. Prevent the Exercise of Market Power in the Near-Term

- ***Allow the continuation of caps based on clear criteria for termination.*** Allow the continuation of price or bid caps until market design flaws are corrected and market rules that contribute to market power (e.g., requirement to procure 1,200 MW of reserves east of central-east, 600 MW of which has to be 10-minute spinning reserves) are revised. However, without a date certain for termination, ISOs have less incentive to quickly resolve market design flaws. In addition, the Commission should establish criteria for when these caps would be removed based on entry of sufficient additional generation or increased demand response.
- ***Institute consistent caps.*** Institute consistent price caps across all three ISOs, e.g., \$1,000 per MWh regardless of system conditions (similar to PJM's energy price

cap).

- ***Remove the price caps.*** Remove price caps and let market operators decide on alternative means to address market power problems. This would provide a clear incentive for quick resolution of market design flaws and would likely hasten the introduction of new generation. However, such an option may increase the likelihood that ISOs would intervene in other ways to restrain market power in times of tight supply.
- ***Establish new reporting requirements and refund option for high bids.*** Require reporting of bids in excess of a threshold to the Commission. Bids in excess would be subject to review and refund. This would lift the stigma of caps, would isolate the effect of caps, but would, on its face, undermine some of the authority vested with ISOs.
- ***Return to traditional cost of service regulation for generators that have locational market power.*** Re-institute cost-based rates for generation that exhibits locational market power, and require such entities to supply the market. The divestiture of plants and the premiums paid make this option problematic.
- ***Promote more aggressive market power monitoring and mitigation.*** The Commission has required the consideration of new methods of market power monitoring and mitigation that could improve the ISO's capability to address generators with potential market power. In New England, this has included requiring the ISO to evaluate a structural screen for market wide market power in New England and its possible uses in market power monitoring and mitigation. Such a screen (which could take on several forms) would seek to automatically mitigate certain units if their market shares exceeded a target percentage during particular hours. If such methods can be implemented, they may eliminate the need for blanket price caps. However, this would represent a significant step toward increased market intervention.
- ***Direct market monitors to monitor the ISO as well as the markets to assure that operational procedures for dispatch are consistent and transparent.*** The transition from a cost-based model to a market model with centralized dispatch is not without its difficulties. In order to respond to the fast pace of an electric environment system operators may sometimes revert to command and control approaches that seem to be arbitrary decisions to market participants. Market monitors may need to provide some review of ISO operations to assist in development of procedures that are transparent and consistent.
- ***Demand-Side Responsiveness.*** The Commission should encourage the

development of demand-side measures as it did in NSTAR Service Company, 92 FERC ¶ 61,065 (2000). The Commission should require PJM and NYISO to file a report discussing opportunities for and barriers to implementation to enhanced demand responsiveness by February 28, 2001 (the date is to file). The three ISOs should be directed to explore additional opportunities as a region.

- Encourage state Commissions to implement policies to increase retail demand responsiveness to price. Encourage load bidding.
- Direct each ISO to file a quarterly report with the Commission on demand-side measures to improve price responsiveness.

B. Address Barriers to Increased Intra-Regional Trade in the Near-Term (i.e., Encourage Consistency in Rules, Practices, Products, and Implementation Across ISOs)

- ***Common practices.*** To further economic trade and universal products, the ISOs should be directed to identify specific and significant ISO practices that should be common and coordinated among ISOs and be required to file a plan with the Commission (by date certain) detailing the new processes for ensuring that the ISOs approach and resolve the issue from a regional perspective. The ISOs should be directed to make these filings no later than June 1, 2001, or explain why it cannot (operationally) be accomplished. This effort would effectively replace the ISO MOU process.

To facilitate this effort, the Commission could assign FERC technical staff to work with the ISOs at identifying the issues and to act as facilitators and arbiters. The intent would be to increase the pace of implementation where possible and assist in overcoming jurisdictional barriers to cooperation in some areas.

C. Address Adoption of Best Available Software

Much of the uncertainty in the Northeast surround the NYISO's implementation of its market design. The software design has resulted in market operational problems, as compared to PJM's, and lacks the robustness needed to make changes in a reasonable amount of time. A similar situation could occur in New England in its market re-design over 2001 if the issue of best available software is not considered.

- ***Require wholesale software review.*** Direct ISOs to contract with an outside

consultant to assess the best common software platform for the three ISOs. The ISOs would issue an RFP that would be reviewed by FERC. Common software would eliminate some of the price corrections, and reliance on incorrect prices that have resulted from NYISO's software.

- ***Require surgical software revisions.*** Direct the NYISO to hire an outside entity to perform a cost-effectiveness analysis of continuing the piecemeal approach to software and market fixes as opposed to adopting PJM's software, i.e., the amount of money (dollars and human capital) it will take to revise all known software problems as compared to implementing PJM's software design (i.e., a design where the operations and market rules are not inextricably linked).
- ***Direct adoption of best practices.*** Direct ISO-New England and NYISO to implement PJM market rules, protocols, and software by May 1, 2001, i.e., effectively requiring ISO-New England and NYISO to offer only energy and regulation as markets.

D. Keep Informed on Generation Additions and Activities and Investigation of Generator Behavior

- ***Reporting.*** Require the reporting of generation outages to the Commission on a quarterly basis.

Direct each ISO to file a quarterly report detailing the status of its generation queue, type of generation, targeted in-service date.

Direct an investigation of generators with abnormally high unplanned outage rates.

- ***Pricing Policies.*** Reconsider cost responsibility rules for generation interconnection, including rolling-in upgrade costs instead of directly assigning these costs to generators.

Adopt wholesale policies that encourage and facilitate the investment in new generation.

E. Other Options to Address ISO and Market Participant Concerns

- ***Restrict NEPOOL's role to an advisory status to the Board.*** Since the beginning of operations in the Spring of 1999, complaints from market participants of nearly every sector have been heard regarding the governance of ISO-New England. One

significant difference between ISO-New England governance and PJM and NYISO, is the continued role of NEPOOL as an additional governance structure, seemingly in parallel with the ISO-New England Board. Eliminating NEPOOL's ability to intervene in ISO-New England decisions or serve as an appeal process may significantly improve the decision making process of ISO-New England.

- ***Eliminate single price auction and institute “pay as bid.”*** Under this option, each seller would be paid its bid rather than the market clearing price and buyers would pay a price reflecting the average of the accepted sellers' bids. This might have the effect of reducing the total paid by buyers during high demand periods because some sellers would be paid less than the highest bid accepted. However, “pay as bid” might also change seller bidding behavior to increase bids because the seller no longer receives the clearing price (even when its bid is less than the clearing price) but receives only its bid. The motivation is to bid to receive the highest profits.
- ***Timing and Release of Bid Data.*** Reconsider the ruling on the timing of the release of bid data from the current 6-month lag to 3 months. The lack of meaningful data about markets contributes to the lack of confidence. Forward premiums can be reduced or eliminated if participants have better information.

F. Address Market Power and Barriers to Increased Intra-Regional Trade in the Longer Term

- ***Require a single northeastern RTO.*** A single RTO is best equipped to deal with the narrow, business process type issues such as scheduling and interchange flexibility as well as the more significant issues such as regional transmission expansion. A single RTO would be required to use one set of software, operate as one control area (offering seamless transmission expansion), and administer one tariff. Thus, differences in terminology and business practices could be eliminated and a universal approach to managing the Northeast system would be undertaken by a single, independent entity. (Note that this approach may mean that some markets that have not been working from a competitive standpoint may be eliminated, i.e., return to just an energy market and build from there.) This would help strengthen inter-ties, possibly reduce market power (lessen incentives to flee from one ISO to another), and would result in a harmonized market without competing ISO interests or goals. The likely benefit of this approach is that market enhancements would be made more readily than if the ISOs were to remain as separate RTOs with seams agreements to address coordination issues. Thus far, the ISOs have made little significant progress on inter-ISO issues; there is really no motivation for the ISOs to do so.

- ***Allow the three ISOs as separate RTOs and mandate specific fixes to seams issues.*** This is an alternative to the option discussed above. A seams agreement will likely produce incremental benefits over time, but will not provide for the wholesale changes to the markets that a single RTO would provide. This approach will likely codify the existing designs of the ISOs and effectively result in ISO coordination. The downside of this is that it results in less gain of market efficiency that would result from one set of rules, procedures, tariffs, etc. In addition, incremental changes would likely continue that may or may not impact adjacent ISOs. Moreover, the institutional barriers remain and ISOs will remain entrenched in their own designs.