2002 State of the Market

PJM
Market Monitoring Unit
PJM Interconnection
March 5, 2003

PREFACE

The Market Monitoring Unit of the PJM Interconnection, L.L.C. publishes an annual State of the Market Report that assesses the level of competition in each of the markets operated by PJM, identifies specific market issues, and recommends potential enhancements to improve further the competitiveness and efficiency of the markets.

The PJM Interconnection State of the Market Report 2002 is the fifth annual report. This Report is made to the Board of Managers of the PJM Interconnection, L.L.C. following preparation by the PJM Market Monitoring Unit (MMU) pursuant to Attachment M to the PJM Open Access Transmission Tariff:

> "The Market Monitoring Unit shall prepare and submit to the PJM Board and, if appropriate, to the PJM Members Committee, periodic (and if required, ad hoc) reports on the state of competition within, and the efficiency of, the PJM Market."

The Market Monitoring Unit is providing the Report simultaneously to the Federal Energy Regulatory Commission per the Commission's Order in PJM Interconnection, L.L.C., 96 FERC 61, July (July 12, 2001):

> "The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of an RTO's market monitor at the same time they are submitted to the RTO."

© 2003 PJM

TABLE OF CONTENTS

Section	Title	Page
	Preface	i
	Table of Contents	ii
	List of Tables	iv
	List of Figures	vi
1	State of the PJM Market Report 2002	1
	Conclusions	
	Recommendations	
	Energy Market	
	Interface Transactions	
	Capacity Markets	
	Ancillary Service Markets	
	Congestion	
	Fixed Transmission Rights Auction Market	
2	Energy Market	18
	Overview	
	Market Structure	
	Market Performance	
3	Interchange Transactions	54
	Overview	
	Loop Flow	
	Interface Pricing Issues	
	Aggregate Imports and Exports	
	Interface Imports and Exports	
4	Capacity Markets	68
	Overview	
	Market Structure	
	Market Performance	
5	Ancillary Service Markets	86
	Overview	
	Regulation	
	Spinning Reserve Service	
6	Congestion	101
	Overview	
	Congestion Accounting	
	Congestion in PJM	
	Congested Facilities	

Section	Title	Page
7	FTRs and the FTR Auction Market	127
	Overview	
	FTR Auction Markets	
	Glossary	138
A	Appendix to Energy Market	146
	Frequency Distribution of LMP	
	Frequency Distribution of Load	
B	Appendix to Capacity Markets	167
	Capacity Market Background	
	Capacity Obligations	
	Capacity Resources	
	Market Dynamics	

LIST OF TABLES

Number	Title	Page
2-1	Record Peak Demand Days: 2001 and 2002	20
2-2	2002 PJM Hourly HHI	24
2-3	2002 Overall PJM Installed HHI	24
2-4	2002 PJM Hourly HHI by Segment	24
2-5	2002 PJM Installed HHI by Segment	24
2-6	Net Revenues in 2002 by Marginal Cost of Unit	34
2-7	PJM Average Hourly Locational Marginal Prices	39
2-8	PJM Load	42
2-9	PJM Load-Weighted, Average LMP	43
2-10	Load-Weighted, Fuel-Cost-Adjusted LMP	44
2-11	Comparison of Real-Time and Day-Ahead 2002 Market LMP	44
2-12	2002 Day-Ahead and Real-Time Generation	49
2-13	2002 Day-Ahead and Real-Time On-Peak and Off-Peak Generation	50
2-14	Average 2002 Difference Between Day-Ahead and Real-Time Markets	51
2-15	2002 Day-Ahead and Real-Time Load	51
2-16	2002 Day-Ahead and Real-Time Load During Off-Peak and On-Peak Hours	52
3-1	Interface LMP Differentials and Actual Schedule Differentials	60
4-1	PJM-East Region Member Capacity Summary	73
4-2	PJM-West Region Member Capacity Summary	78
4-3	PJM-East Region Capacity Credit Market	81
4-4	PJM-West Region Capacity Credit Market	84
5-1	Regulation Market HHI Values	87
6-1	Total Congestion	104
6-2	2002 PJM Congestion Accounting Summary	104
6-3	2002 Transmission Congestion Revenue Statistics	105
6-4	Constraint Duration Summary	108
6-5	Constraint Event Summary by Facility Type and Voltage Class	126
7-1a	Target Allocations by Path, 25 Largest Financial Benefit	129
7-1b	Target Allocations by Path, 25 Largest Financial Liability	129
7-2a	FTRs by Service Type	130
7-2b	Annual Mean FTRs by Service Type	131
A-1	Off-Peak and On-Peak Load – 1998, 1999, 2000, 2001, and 2002	157
A-2	Year-Over-Year Percent Change in Load	157
A-3	Off-Peak and On-Peak, Load-Weighted LMP for 2001 and 2002	158

Number	***Title***	***Page***
A-4	2001 and 2002 Load-Weighted Average LMP During Constrained Hours	159
A-5	2001 and 2002 Load-Weighted Average LMP During Constrained and Unconstrained Hours	159
A-6	2002 Off-Peak and On-Peak LMP	162
A-7	2002 LMP During Constrained and Unconstrained Hours	165

LIST OF FIGURES

Number	Title	Page
1-1	2002 PJM Average Hourly Load and Spot Market Volume	3
1-2	PJM Imports and Exports – 2002	8
1-3	The PJM-East Region's Daily and Monthly Capacity Credit Market Performance -2002	10
1-4	Daily Regulation Cost per MW: 1999 – 2002 (Includes PJM-West)	13
1-5	FTR Monthly Auction - FTR Cleared Volume and Net Revenue	17
2-1	Average PJM Region Aggregate Supply Curve (June - September)	21
2-2	Record Setting Peak Load Comparison - Wednesday 14-Aug-02/Thursday 9-Aug-01	22
2-3	2002 PJM Hourly Energy Market Minimum HHI	25
2-4	Marginal Unit Ownership	27
2-5	Average Monthly Load-Weighted Markup Indices	28
2-6	Average Markup Index by Type of Fuel	29
2-7	Type of Fuel Used by Marginal Units	30
2-8	Type of Marginal Unit	30
2-9	Average Markup Index by Type of Unit	31
2-10	PJM Energy Market Net Revenue - 1998, 1999, 2000, 2001, and 2002	32
2-11	Queued Capacity by In-Service Date	35
2-12	New Capacity in PJM-East Queues through 12/31/02	36
2-13	PJM Average Hourly LMP and System Load - 2002	37
2-14	PJM Price Duration Curves – Real-Time Market - 1998, 1999, 2000, 2001, and 2002	40
2-15	PJM Price Duration Curves – Real-Time Market - Hours Above the 95th Percentile	41
2-16	PJM Hourly Load Duration Curve – 1998, 1999, 2000, 2001, and 2002	42
2-17	PJM Price Duration Curves- Real-Time and Day-Ahead Markets - 2002	45
2-18	PJM Price Duration Curves - Real-Time and Day-Ahead Markets - 2002 – Hours Above the 95th Percentile	46
2-19	Hourly RT LMP Minus DA LMP - 2002	47
2-20	PJM Average Hourly System LMP - Day-Ahead and Real-Time Markets - 2002	48
2-21	Real-Time and Day-Ahead Generation - Average Hourly Values - 2002	50
2-22	Real-Time and Day-Ahead Load, Average Hourly Values - 2002	53
2-23	Real-Time and Day-Ahead Load and Generation - Average Hourly Values – 2002	53
3-1	Net Scheduled and Actual PJM Interface Flows—2002	56
3-2	PJM/AEP and PJM/VAP: Actual -Schedule Interface Differentials and LMP Differentials by Interface	61

Number	Title	Page
3-3	PJM/AEP and PJM/VAP: Actual - Schedule Tie Flows and Price Differentials	61
3-4	PJM Imports and Exports—2002	62
3-5	Total Day-Ahead Import and Export Volume - 2002	62
3-6	PJM Imports and Exports	63
3-7	Interface Net Imports	64
3-8	PJM/APS, PJM/AEP and PJM/DLCO Net Imports	65
3-9	Interface Gross Imports	66
3-10	Interface Gross Exports	66
3-11	Price Differential and NYIS Export Volume - Jan-Dec 2002	67
4-1	Percent of the PJM-East Region's Load Obligation Served in 2002	71
4-2	Load Obligation Served by the PJM-East Region Capacity Credit Market	72
4-3	The PJM-East Region's Capacity Obligations	74
4-4	The PJM-East Region's Daily CCM Clearing Price and Cinergy Spread versus Net PJM-East Region Exports	74
4-5	The PJM-East Region's External Transactions 2002	75
4-6	The PJM-East Region's Bilateral Transactions 2002	76
4-7	The PJM-West Region's Capacity Obligations	78
4-8	The PJM-West Region's CCM Clearing Price and Cinergy Spread versus Net PJM-West Region Exports	79
4-9	The PJM-East Region's Daily and Monthly Capacity Credit Market Performance 2002	80
4-10	The PJM-East Region's Equivalent Demand Forced Outage Rate (EFORd)	82
4-11	The PJM-East Region's Equivalent Outage and Availability Factors	83
4-12	The PJM-West Region's Daily and Monthly Capacity Credit Market Performance	85
5-1a	Regulation MW Offered versus MW Purchased - PJM	88
5-1b	Regulation MW Offered versus MW Purchased – PJM-West	89
5-2a	Hourly Regulation Cost per MW – PJM	90
5-2b	Hourly Regulation Cost per MW – PJM-West	91
5-3a	Daily Regulation MW Purchased Compared to Cost per Unit – PJM	92
5-3b	Monthly Regulation MW Purchased Compared to Cost per Unit – PJM –West	92
5-4	Daily Regulation Cost per MW – 1999 - 2002 (Includes PJM-West)	93
5-5	Percent of Hours Within Required PJM Regulation Limits	95
5-6	CPS1 and CPS2 Performance	96
5-7	Required Spin Provided by Condensing	98
5-8	Average Hourly Condensing MW	99
5-9	Total Condensing Credits per MW	99
5-10	December 2002 Spinning Payments: Tier 1 and Tier 2	100

Number	Title	Page
6-1	Annual Zonal LMP Differences - Reference to Western Hub	106
6-2	Regional Constraints - Congestion-Event Hours by Facility	109
6-3	Congestion-Event Hours by Facility – 500 kV System	110
6-4	2001-2002 Interface Congestion - Noncoincident Constraint Occurrences - BGE, PEPCO, PPL and PSEG	111
6-5	Constrained Hours by Facility Type	113
6-6	Constrained Hours by Facility Voltage	114
6-7	Constrained Hours by Zone	115
6-8	AECO Zone - Congestion-Event Hours by Facility	116
6-9	APS Zone - Congestion-Event Hours by Facility	116
6-10	BGE Zone - Congestion-Event Hours by Facility	117
6-11a	DPL Zone - Constrained Hours by Subarea	118
6-11b	DPL Zone (DPLS Subarea) - Congestion-Event Hours by Facility	119
6-11c	DPL Zone (DPLN and SEPJM Subarea) - Congestion-Event Hours by Facility	120
6-12	METED Zone - Congestion-Event Hours by Facility	121
6-13	PECO Zone - Congestion-Event Hours by Facility	122
6-14	PENELEC Zone -Congestion-Event Hours by Facility	123
6-15	PPL Zone - Congestion-Event Hours by Facility	124
6-16	PSEG Zone - Congestion-Event Hours by Facility	125
7-1	FTRs as a Percentage of Total by Service Type	131
7-2	FTR Monthly Auction - FTR Cleared Volume and Net Revenue	132
7-3	FTR Monthly Auction - Bid and Offer Volume and Average Buy Bid Clearing Price	133
7-4	FTR Monthly Auction - Percentage of Bid and Offer Volume Cleared	134
7-5	FTR Monthly Auction - Ten Highest Revenue Producing FTR Sinks Purchased – Revenue and Volume	135
7-6	FTR Monthly Auction - Ten Highest Revenue Producing FTR Sinks Sold – Revenue and Volume	136
7-7	FTR Monthly Auction - Ten Highest Revenue Producing FTR Sources Purchased – Revenue and Volume	136
7-8	FTR Monthly Auction - Ten Highest Revenue Producing FTR Sources Sold – Revenue and Volume	137
A-1	Frequency Distribution by Hours of PJM LMPs - 1998	147
A-2	Frequency Distribution by Hours of PJM LMPs – 1999	148
A-3	Frequency Distribution by Hours of PJM LMPs – 2000	149
A-4	Frequency Distribution by Hours of PJM LMPs – 2001	150
A-5	Frequency Distribution by Hours of PJM LMPs – 2002	151
A-6	Frequency Distribution of Hourly PJM Load – 1998	152
A-7	Frequency Distribution of Hourly PJM Load – 1999	153
A-8	Frequency Distribution of Hourly PJM Load – 2000	154
A-9	Frequency Distribution of Hourly PJM Load – 2001	155

Number	*Title*	*Page*
A-10	Frequency Distribution of Hourly PJM Load – 2002	156
A-11	PJM Constrained Hours—2001 and 2002	160
A-12	Frequency Distribution by Hours of Day-Ahead Market LMPs – 2002	161
A-13	Hourly Real-Time LMP Minus Day-Ahead LMP — Peak Hours 2002	163
A-14	Hourly Real-Time LMP Minus Day-Ahead LMP — Off-Peak Hours 2002	164
A-15	Real-Time and Day-Ahead Market Constrained Hours 2002	165

STATE OF THE MARKET 2002

The PJM Interconnection, L.L.C. operates the day-ahead energy market, the real-time energy market, the daily capacity market, the interval, monthly and multi-monthly capacity markets, the regulation market, the spinning market and the monthly fixed transmission rights auction market. The markets cover transactions within, out of, and into the PJM Region, a geographic area encompassing New Jersey, most of Pennsylvania, Maryland, Delaware, the District of Columbia and portions of Virginia, West Virginia and Ohio.

PJM introduced nodal energy pricing with market-clearing prices based on offers at cost on April 1, 1998, and nodal, market-clearing prices based on competitive offers on April 1, 1999. Capacity markets were introduced on January 1, 1999, [and were broadened to include monthly and multi-monthly markets in mid-1999]. PJM implemented a competitive, auction-based fixed transmission rights market on May 1, 1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserves on December 1, 2002.

This report assesses the competitiveness of the markets managed by the PJM Interconnection, L.L.C. during 2002, including both market results and market structure.

CONCLUSIONS

The MMU concludes that in 2002:

- The energy market results were competitive;
- The capacity market results in the PJM-East Region were competitive;
- The capacity market results in the PJM-West Region were consistent with a reasonably competitive outcome although there is not a functioning competitive market in the PJM-West Region;
- The regulation market results were competitive;
- The spinning market results were competitive; and
- The FTR auction market results were competitive.

The MMU also concludes:

- There are potential threats to competition in the energy, capacity, regulation and spinning markets that require ongoing scrutiny;
- The rule changes implemented by PJM have addressed the immediate causes of market power in the PJM-East capacity market, but market power remains a serious concern given the extreme inelasticity of demand and high levels of concentration in capacity credit markets. Market power is structurally endemic to PJM capacity markets and any redesign of capacity markets must address market power;
- The PJM-West capacity market is not competitive and should not be maintained as a separate market with separate rules;

- Market participants have the ability to exercise market power at the interfaces between PJM and external regions under some conditions;
- Market participants possess some ability to exercise market power in PJM energy markets under certain conditions; and
- Market participants possess some ability to exercise market power in PJM ancillary services markets under some conditions.

RECOMMENDATIONS

TThe MMU recommends the retention of key market rules and certain enhancements to those market rules that are required for continued, positive results in PJM markets and for continued improvements in the functioning of PJM markets. These include:

- Evaluation of additional actions to increase demand-side responsiveness to price in both energy and capacity markets and actions to address institutional issues which may inhibit the evolution of demand-side price response;
- Development of an approach to identify areas where transmission expansion investments would relieve congestion where that congestion may enhance generator market power and where such investments are needed to support competition;
- Continued enhancements to the capacity market to stimulate competition, adoption of a single capacity market design and incorporation of explicit market power mitigation rules to limit the ability to exercise market power in the capacity market;
- Continued development of more sophisticated methods for developing the appropriate prices for transactions between PJM and external control areas to provide incentives to competitive behavior;
- Continued development of appropriate credit protections for transactions in PJM markets that are consistent with those available to participants in bilateral transactions;
- Retention of the $1,000 per MWh offer cap in the PJM energy market and other rules that limit the incentives to exercise market power;
- Authority to require the provision of fuel-cost data in order to permit the enforcement of PJM's local market power mitigation rules; and
- Based on the experience of the MMU during its fourth year and its analysis of the PJM markets, the MMU does not recommend any additional changes to the Market Monitoring Unit or to the Market Monitoring Plan at this time.

ENERGY MARKET

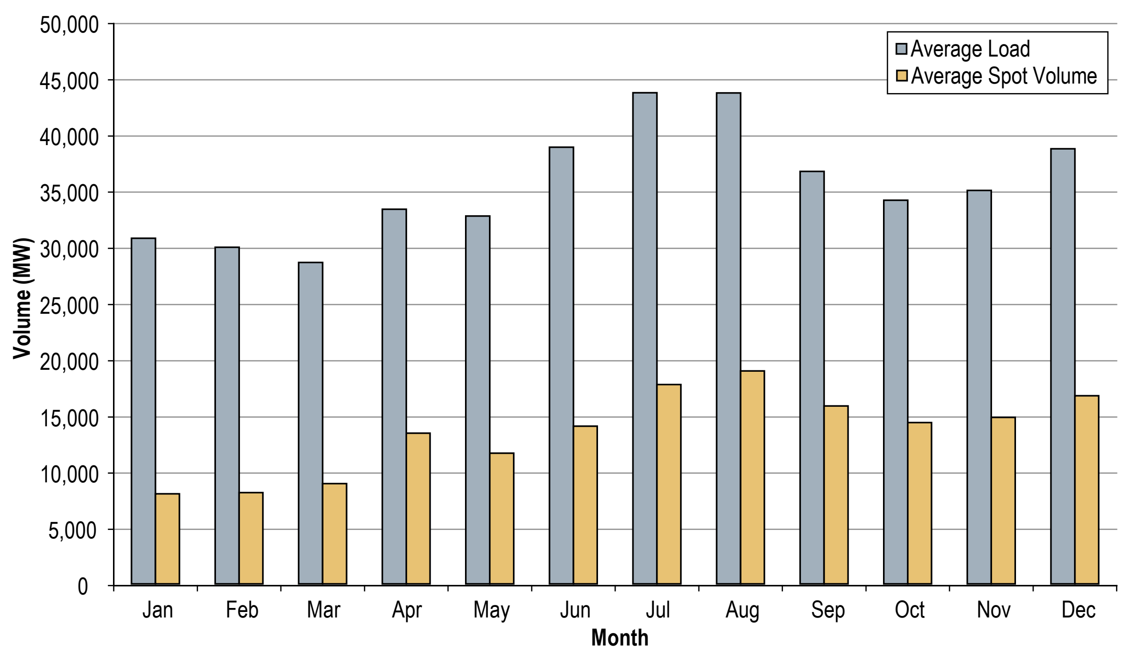
Energy Market Design

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in day-ahead and real-time balancing markets, bilateral and forward markets, and self-supply.

In PJM, market participants wishing to buy and sell energy have multiple options. Market participants decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the day-ahead market or the real-time balancing (i.e., spot) market. Energy purchases can be made over any time frame from instantaneous real-time balancing market purchases to long-term, multi-year bilateral contracts. Purchases may be made from generation located within or outside the PJM Region. Market participants also decide whether and how to sell the output of their generation assets. Generation owners can sell their output within the PJM Region or outside the Region and can use generation to meet their own loads, to sell into the spot market or to sell bilaterally. Generation owners can sell their output over any time frame from the real-time spot market to multi-year bilateral arrangements. Market participants can use increment and decrement bids in the day-ahead market to hedge positions or to arbitrage expected price differences between markets.

For the full year, real-time spot market activity averaged 15,094 MW during peak periods and 12,259 MW during off-peak periods, or 38 percent of average loads for all hours (Figure 1-1). In the day-ahead market, spot market activity averaged 12,868 MW on peak and 11,106 MW off peak, or 32 percent of average loads for all hours. Spot market activity as a proportion of loads increased in 2002. More participants relied on the spot market rather than self-supply or bilateral arrangements to clear their energy transactions. Such reliance on the spot market increases the importance of PJM implementing appropriate credit protections that are consistent with those available to participants in bilateral transactions.

Figure 1-1 **2002 PJM Average Hourly Load and Spot Market Volume**



Energy Market Results

The PJM day-ahead and real-time markets provide key benchmarks against which market participants may measure the results of other transaction types. The MMU analyzed measures of energy market structure and performance for 2002, including market size, concentration, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM energy market results were competitive in 2002.

Market Structure

- **Market Size.** On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as “PJM-West.” The addition of the PJM-West Region had significant impacts on the PJM energy market. Despite the fact that the combined PJM load reached record peaks in 2002, prices declined from 2001. Price levels in 2002 were a function of market fundamentals and, in particular, reflected changes to the aggregate energy market supply curve. For the PJM Region as a whole, there was a total addition of about 12,000 MW of generation, an addition of about 9,700 MW of load and thus an addition to net peak generation supply of about 2,300 MW. The shape of the aggregate supply curve changed with the incorporation of new generation and the fuel mix of that generation, producing an aggregate supply curve with an extended horizontal, base load, portion. The result was lower prices.

- **Concentration of Ownership.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios suggest larger numbers of sellers splitting market sales more equally. The MMU’s analysis of the PJM energy market indicates moderate market concentration overall, but high levels of concentration in the intermediate and peaking segments of the supply curve. Further, specific areas of the PJM Region exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence exists that market power was exercised in these areas during 2002, primarily because of generators’ obligations to serve load. If those obligations were to change, however, significant market-power-related risk would exist.

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price. Overall, the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive in 2002 although the evidence is not dispositive.
- **Net Revenue.** Net revenue is an indicator of generation investment profitability. It is thus a measure of incentives to add generation to serve PJM markets and a significant measure of overall market performance. Net revenue measures the contribution to capital cost generators receive from energy and capacity markets, ancillary service markets and operating reserve payments. In 2002, net revenue from these sources would not have covered fixed costs for a new peaking unit if it had run during all profitable hours. Market results vary from year to year; those for 2002 reflect lower energy and capacity market prices than those for 2001.
- **Demand-Side Management (DSM).** Markets require both a supply side and a demand side to function effectively. The demand side of the wholesale energy market is severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and other wholesale power markets. Total demand-side resources available in the PJM Region during 2002 averaged 1,569 MW of Active Load Management, 548 MW of Emergency DSM and 343 MW of Economic DSM. The 2,460 MW of total DSM resources were almost four percent of peak demand.
- **Energy Market Prices.** PJM's locational marginal prices reflect market structure and the conduct of individual participants. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. For example, overall average prices subsume congestion and price differences over time.

PJM average prices decreased from 2001 to 2002 for several reasons, including supply and demand fundamentals and decreased fuel costs. Prices declined despite the fact that three, new all-time peak loads were established in 2002. The simple, hourly average system-wide locational marginal price (LMP) was 12.6 percent lower in 2002 than in 2001, $28.30 per MWh versus $32.38 per MWh and approximately the same as in 2000 ($28.14) and 1999 ($28.32). When hourly load levels are reflected, the load-weighted LMP of $31.60 per MWh in 2002 was 13.8 percent lower than in 2001, 2.9 percent higher than in 2000 and 7.2 percent lower than in 1999. The load-weighted result reflects the fact that market participants typically purchase more energy during high-price periods and prices during the summer peak period were lower in 2002 than in 2001. When decreased fuel costs are accounted for, the average, fuel-cost-adjusted, load-weighted LMP was 2.0 percent lower in 2002 than in 2001, $35.93 per MWh compared to $36.65 per MWh.

PJM average real-time spot market prices decreased in 2002 over 2001 for several reasons, including decreased fuel costs, the inclusion of the PJM-West Region (Allegheny Power System or APS) in the PJM Region on April 1, and the addition of new generation capacity in PJM. These factors combined to flatten the supply curve of electricity and to shift the upward sloping portion of the supply curve to the right (Figure 2-1). As a result, although a new, all-time peak demand was established on three occasions during the summer of 2002, LMP never exceeded $800 per MWh and was greater than $700 per MWh for only one hour and greater than $150 per MWh for only 20 hours during all of

2002. By contrast, during the summer of 2001 when a then new all-time peak was established, LMP exceeded $900 per MWh for 10 hours, exceeded $700 per MWh for 13 hours and exceeded $150 per MWh for 60 hours.

The energy market results for 2002 reflected the addition of the PJM-West Region and the associated supply-demand fundamentals. While energy market results were competitive, analysis of the energy market has identified a number of concerns regarding market structure that could affect competitive market results when markets are tighter, including:

- The relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve;
- The relatively high levels of concentration in markets defined by transmission constraints; and
- The relatively high levels of concentration in the ownership of marginal units.

INTERCHANGE TRANSACTIONS

PJM has interfaces with five contiguous, external regions. These interfaces are the seams between PJM and other regions. PJM market participants import energy from and export energy to external regions on a continuous basis. These transactions may serve to fulfill long-term or short-term bilateral contracts or to take advantage of price differentials. Prior to the addition of the PJM-West Region on April 1, 2002, the PJM interfaces were PJM/New York ISO (PJM/NYIS), PJM/Allegheny Power System (PJM/APS), PJM/FirstEnergy (PJM/FE) and PJM/Dominion Virginia Power (PJM/VAP). With the addition of the PJM-West Region, the PJM/APS interface was internalized and two new external interfaces were added, PJM/American Electric Power (PJM/AEP) and PJM/Duquesne Light Company (PJM/DLCO).[1] About 410,000 MWh per month of imports at the PJM/APS interface were internalized as a result of market growth to incorporate the PJM-West Region. PJM was a net importer of energy on a monthly basis for every month in 2002 (Figure 1-2). On average, PJM imported 1,694 MW in each hour of 2002. Imports and exports respond to market prices. The level of interchange transaction activity illustrates that the PJM energy market exists in the context of a larger energy market. Import and export transactions are essential to maintaining a competitive PJM energy market.

Issues

- **Loop Flow.** Loop flow results when the transmission contract path for energy transactions does not match the actual path of energy flows on the transmission system. Loop flows can arise from transactions that are scheduled into, out of, or around the PJM system. Outside of PJM's LMP-based energy market, energy is scheduled and paid for based on contract path while the actual associated energy deliveries flow on the path of least resistance. Loop flows can result when a transaction is scheduled between two external control areas and some or all of the actual flows occur at PJM interfaces. Loop flows can also result when transactions are scheduled into PJM on one interface and actually flow on another. Although total PJM scheduled and actual flows were approximately equal in 2002, such was not the case for each individual interface.

- **Interface Pricing Issue.** PJM experienced a significant loop flow issue during the summer of 2002 when transactions scheduled at the PJM/VAP interface actually flowed at the PJM/AEP interface. The issue resulted from actions designed to exploit differences between the way in which PJM locational marginal prices (LMPs) are determined and the artificial contract paths existing in the areas to the west and south of PJM. In particular, there was a large and growing discrepancy between contract and actual power flows at the PJM/AEP interface and at the PJM/VAP interface. To address this issue, on July 19, 2002, the PJM Market Monitoring Unit (MMU) notified market participants of a rule change governing interface pricing for transactions, scheduled at the PJM/VAP interface, but delivered at the PJM/AEP interface, if they include an ECAR, MAIN, MAPP, or SPP control area, or the AECI control area as the source.[2] Since then, such transactions have been priced at the PJM/AEP interface price regardless of contract path.[3]

1 Interfaces are named after the adjacent control areas. This naming convention does not imply anything about the companies that operate the adjacent control areas.

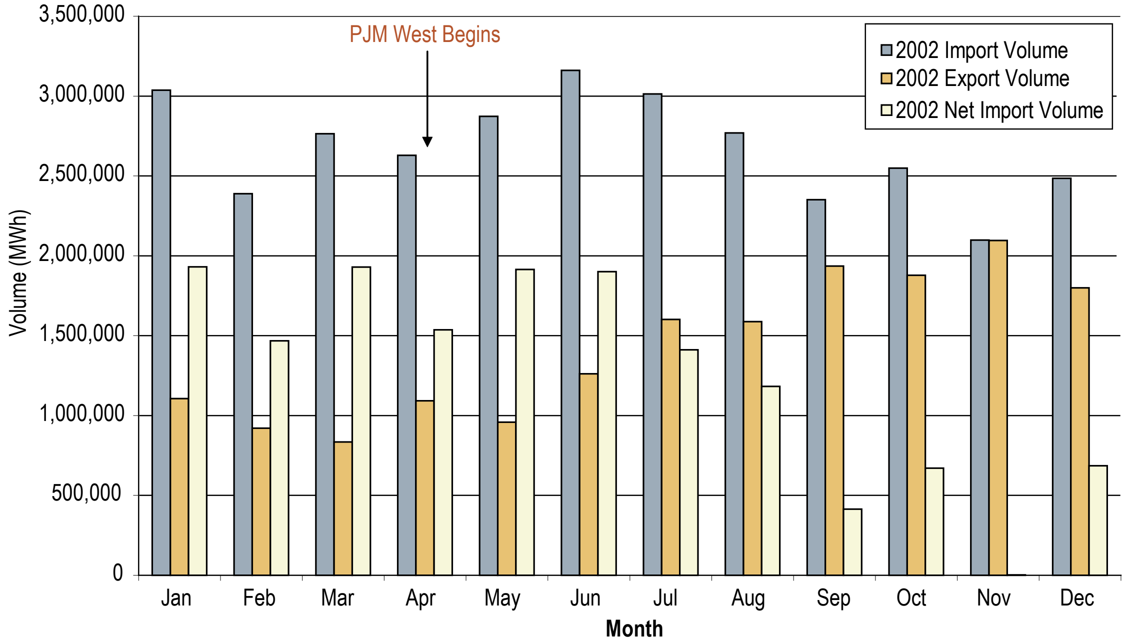
2 The four North American Electric Reliability (NERC) control areas involved are the East Central Area Reliability Coordination Agreement (ECAR), the Mid-American Interconnected Network (MAIN), the Mid-Continent Area Power Pool (MAPP) and the Southwest Power Pool (SPP). The other control area is that of the Associated Electric Cooperative, Inc (AECI) based in Springfield, Missouri.

3 The language is from the current rule which was updated most recently on January 9, 2003.

Performance

- **Aggregate Imports and Exports.** For each month of 2002, PJM was a net importer. Exports have increased since the addition of the PJM-West Region.
- **Interface Imports and Exports.** For 2002, the PJM/FE interface accounted for approximately 53 percent of net imports. The PJM/NYIS interface account for approximately 98 percent of net exports.

Figure 1-2 **PJM Imports and Exports - 2002**



CAPACITY MARKETS

Capacity Market Design

Each organization serving PJM load must own or acquire capacity resources to meet its respective capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements or by participating in the PJM-operated capacity credit markets. Collectively, all arrangements by which LSEs acquire capacity are known as the capacity market.

The PJM capacity credit markets provide a mechanism to balance the supply and demand of capacity that is not met via the bilateral market or self-supply. The PJM capacity credit market consists of the daily, interval, monthly and multi-monthly capacity credit markets. The capacity credit market is intended to provide a transparent, market-based mechanism for new, competitive retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The PJM daily capacity credit market permits LSEs to match capacity resources with short-term shifts in retail load while interval, monthly and multi-monthly capacity credit markets provide a mechanism to match longer-term obligations with capacity resources.

While designed to meet the same reliability objectives, the PJM-West Region's capacity obligations are structured differently than those in the PJM-East Region. The overall capacity obligation associated with load in the PJM-East Region is defined for an annual period. The overall capacity obligation associated with load in the PJM-West Region is defined daily.

Capacity Market Results

The MMU analyzed key measures of capacity market structure and performance for 2002, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2002. The PJM-East Region's capacity market results were competitive during 2002. The PJM-West Region's capacity market results were consistent with a reasonably competitive outcome although there is not a functioning competitive market in the PJM-West Region. Market power remains a serious concern in both capacity markets.

Market Structure – The PJM-East Region

- **Supply.** The structural analysis of the PJM-East Region's capacity credit markets found that short-term and long-term markets exhibited high concentration levels in 2002.
- **Demand.** During 2002, the original PJM-East Region electric utilities and their affiliates accounted for 92 percent of the PJM-East Region's load obligations.
- **Supply and Demand.** During 2002, installed capacity, unforced capacity and obligations grew in the PJM-East Region. Average installed capacity increased by 3,522 MW, or 6.0 percent, to 62,380 MW, while average unforced capacity rose by 6.4 percent to 59,363 MW. Average load obligations climbed by 3,070 MW, or 5.6 percent, to 57,557 MW, or 1,806 MW less than average, unforced capacity. Overall capacity credit market transactions increased by nearly 73 percent. Daily capacity credit market volume declined by 46 percent, while monthly and multi-monthly capacity credit market volume increased by 28 percent and 311 percent, respectively.

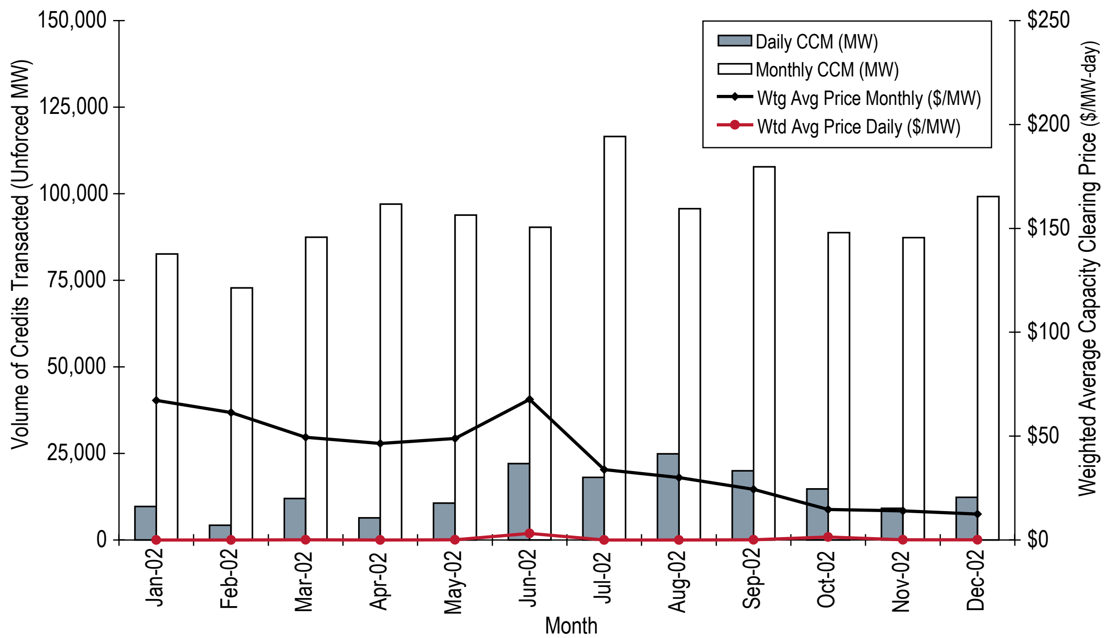
Market Structure – The PJM-West Region

- **Supply.** The structural analysis of the PJM-West Region's capacity credit markets found that capacity credit markets exhibited extremely high concentration levels in 2002.
- **Demand.** During 2002, the original PJM-West Region's electric utility accounted for 99.9 percent of the PJM-West Region's load obligations.
- **Supply and Demand.** In 2002, the PJM-West Region's average installed capacity was 10,014 MW and the average available capacity was 8,467 MW. The average capacity obligation was 6,823 MW while the maximum capacity obligation was 8,987. The capacity credit market was effectively not operating after June.

Market Performance – The PJM-East Region

- **Prices.** Daily capacity credit market prices were quite low during 2002, averaging $0.59 per MW-day. Prices in the interval, monthly and multi-monthly markets declined over the year from $67.20 per MW-day in January to $12.50 per MW-day in December, averaging $38.21 per MW-day. In both cases, prices reflected supply-demand fundamentals and were nearer competitive levels than during 2001.

Figure 1-3 **PJM-East Daily and Monthly Capacity Credit Market Performance 2002**



Market Performance – The PJM-West Region

- **Prices.** Daily capacity market prices averaged $84.03 per MW-day. Prices in the interval, monthly and multi-monthly markets averaged $10.31 per MW-day. Prices spiked in the daily markets on several occasions.
- **Volumes.** There was very little activity in the capacity credit markets, particularly after June.

Given the basic features of the capacity market structure in both PJM-East and PJM-West including high levels of concentration, the relatively small number of non-affiliated LSEs, the capacity deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure, and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the likelihood of the exercise of market power is high. Market power is structurally endemic to PJM capacity markets. Supply and demand fundamentals offset these market structure issues in the PJM-East capacity market in 2002, producing competitive results. In the PJM-West capacity market, the dominance of a single supplier and the extremely small load levels served by independent LSEs meant that there was not a functioning competitive market. After June, the small number of LSEs entered into bilateral contracts, resulting in a non-existent market. The price spikes in the PJM-West daily capacity market in the pre-June period were addressed directly with the relevant market participants by the MMU. The actual results in the PJM-West capacity market were consistent with a reasonably competitive outcome despite the absence of a functioning competitive market.

The MMU is also concerned about the existence of two interacting capacity markets within PJM with different rules and different incentives and the associated potential for gaming. The MMU recommends that PJM implement a single capacity market design across all parts of PJM.

ANCILLARY SERVICES

Regulation Market Design

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888.[4] Of these, PJM currently provides both regulation and spinning through market-based mechanisms.

Regulation matches generation with very short-term increases and decreases in load by moving the output of selected generators up and down via an automatic control signal. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Market participants can acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally. Spinning reserves are a form of primary reserves and must be synchronized to the system and capable of providing output within 10 minutes.

The regulation market design was modified by PJM effective December 1, 2002, in conjunction with the implementation of the spinning market. The regulation and spinning markets are cleared simultaneously and co-optimized in order to reduce the total cost of both ancillary products combined. In contrast to the previous regulation market design, the current regulation market is cleared in real-time instead of day-ahead and regulation prices are posted hourly throughout the operating day. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of $100 per MW. These offers plus opportunity costs determine the clearing price.

Regulation Market Results

The MMU reviewed structure and performance indicators for the regulation market and concludes that the regulation market functioned effectively and produced competitive results in 2002 (Figure 1-4).

Regulation Market Structure

- In 2002, the PJM regulation market was characterized by moderate concentration levels, but concerns about market concentration levels were offset by the level of available regulation supply from PJM resources relative to the demand for regulation.

Regulation Market Performance

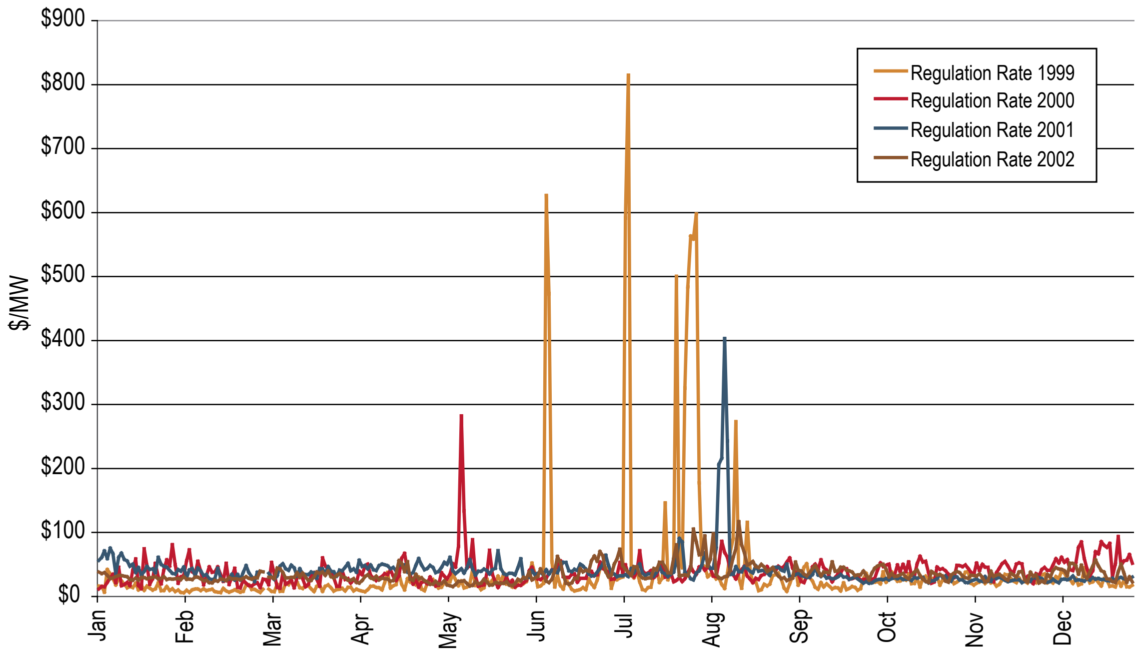
- **Price.** The market price of regulation was approximately equal to the price under the administrative, cost-based system, and the price exhibited the expected relationship to changes in demand (Figure 1-4).

- **Service Availability.** Introduction of a market in regulation resulted in significant improvement in system regulation performance during 2001 and the first part of 2002. System regulation performance declined after the addition of the PJM-West Region.

4 See FERC “Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,” April 24, 1996.

Figure 1-4 **Daily Regulation Cost Per MW**

1999 - 2002 (Includes PJM West)



Spinning Reserve Market Design

Spinning reserve is an ancillary service defined to be generation which is synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can be provided by a number of sources including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines and combustion turbines running at minimum generation. PJM introduced a market in spinning reserves on December 1, 2002.

Spinning Reserve Market Results

The MMU reviewed structure and performance indicators for the new spinning reserve market and concludes that, based on the very limited evidence, the spinning market functioned effectively and produced competitive results in 2002.

Spinning Reserve Market Structure

- In 2002, concentration levels were high in the Tier 2 spinning reserve market during the opening month of December.

Spinning Market Performance

- **Price.** The average cost per MW associated with meeting PJM's demand for spinning reserves increased $1 per MW, or about five percent, in 2002 over 2001. The introduction of the new market in December, however, brought a month-to-month decrease of about 16 percent.

CONGESTION

Congestion occurs when available, low-cost energy cannot be delivered to all loads as a result of limited transmission facilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in that area must be dispatched to meet the load.[5] The result is that the price of energy in the constrained area is higher than elsewhere and congestion exists. Locational Marginal Prices (LMPs) reflect the cost of the lowest cost resources available to meet loads, taking into account the actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way of pricing energy supply when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion Results

- **Total Congestion Costs.** Congestion costs were approximately $430 million in 2002, a 58 percent increase from $271 million in 2001. This increase in measured congestion was, in significant part, the result of adding PJM-West facilities to the market, permitting the more efficient redispatch of local generation and making explicit the price differentials that result from that redispatch. The increase in congestion costs was one part of a mosaic of impacts associated with the addition of PJM-West. Inclusion of PJM-West generation facilities in the market and the use of locational pricing to target redispatch to the appropriate constrained transmission facilities simultaneously contributed to lower overall average PJM prices, reductions in LMP differentials in some zones and increases in LMP differentials in other zones.
- **PJM-West Region Facilities.** Most of the measured aggregate congestion cost increase is attributable to the redispatch of generating units to control constraints on PJM-West Region transmission facilities. The inclusion of these facilities in the PJM market did not change the underlying physical transfer capabilities of the transmission system. The physical limitations on the ability of the transmission system to transfer lower cost western power to the PJM-East Region existed prior to the addition of the PJM-West Region. However, the inclusion of the PJM-West Region constrained facilities in the market did mean that these transmission system limitations were priced explicitly and efficiently in 2002 and were thus defined as congestion in an LMP-based system.
- **Congestion Geography.** The addition of PJM-West Region transmission facilities to the market resulted in the redispatch of those PJM units required to relieve congestion on specific transmission constraints rather than the simple restriction of all power transfers that had been the pre-market method of controlling congestion for transfers of power from west to east across the Allegheny Power System (APS) and across PJM. The result of this market-based redispatch was the explicit pricing of congestion via LMP which in turn produced a decrease in LMP differentials for some PJM transmission zones and an increase in LMP differentials for other PJM zones after April 1, 2002.

5 This is referred to as dispatching units out of merit order. Merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

- **Congested Facilities.** Both interface and transformer facilities experienced increases in congested hours during 2002, while congested hours on lines decreased. There were increases in constrained hours on 500 kV, 345 kV, 138 kV and 115kV lines and decreases in constrained hours on 230 kV and 69 kV lines.
- **Monthly Congestion Charges.** Monthly swings in congestion continue to be substantial. In 2002, these swings were driven by different patterns of generation, energy imports, weather-induced demand spikes and increased congestion frequency on constraints affecting large portions of PJM load.
- **Local congestion.** Local congestion in the DPL zone decreased as the result of ongoing transmission reinforcement projects and rose in other zones, including PENELEC.

Increases in congestion resulting from the addition of PJM-West and the persistent congestion that exists in areas within PJM suggest the importance of PJM continuing to develop the sophistication of its congestion analysis and, based on that analysis, implementing the Order issued by the United States Federal Energy Regulatory Commission (FERC) to develop an approach to identify areas where investments in transmission expansion would relieve congestion where that congestion may enhance generator market power and where such investments are needed to support competition.

FTRs AND THE FTR AUCTION MARKET

Fixed Transmission Rights Auction Market Design

In PJM, Fixed Transmission Rights (FTRs) are available to firm point-to-point and network transmission service customers as a hedge against congestion charges. These firm transmission customers have access to FTRs because they pay the costs of the transmission system. Such customers receive FTRs to the extent that they are consistent both with the physical capability of the transmission system and with the other requests for FTRs.

An FTR is a financial instrument that entitles the holder to receive revenues (or to pay charges) based on the hourly LMP differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basis risk associated with delivering energy from one bus or aggregate to another bus or aggregate. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

The basic mechanics of the FTR auction have worked as intended, since their approval by the United States Federal Energy Regulatory Commission (FERC) on April 13, 1999.[6]

FTR Auction Market Results

The MMU reviewed structure and performance indicators for the FTR auction market and concludes that the FTR auction market was competitive in 2002 and has increased access to FTRs.

Market Structure

- **Supply and Demand.** Over the life of the FTR auction, bid volume has exceeded offer volume by nearly a 10:1 ratio, 45,000 versus 5,500 MW per month on average. Average bid and offer volume was 52,000 and 7,000 MW per month in 2002. Cleared bid volume ranged between 3,900 and 6,400 MW per month during the 2000 to 2002 period, while cleared offer volume ranged between 2,200 and 5,200 MW per month during the same period. Cleared bids exceeded cleared offers by 1,300 MW per month on average. Approximately two-thirds of cleared bids were supplied from cleared offers while one-third drew on residual system capacity.

Market Performance

- **Price.** Prices in the FTR auction rose from $356 per MW-month to $369.
- **Volume.** Auction FTRs increased from an average of three percent of all FTRs in 1999 to 11 percent on average in 2000 and 2001, to 20 percent in 2002. Auction FTRs peaked in November 2002 when 11,263 MW of on-peak FTRs cleared, representing 29 percent of all FTRs for the month.

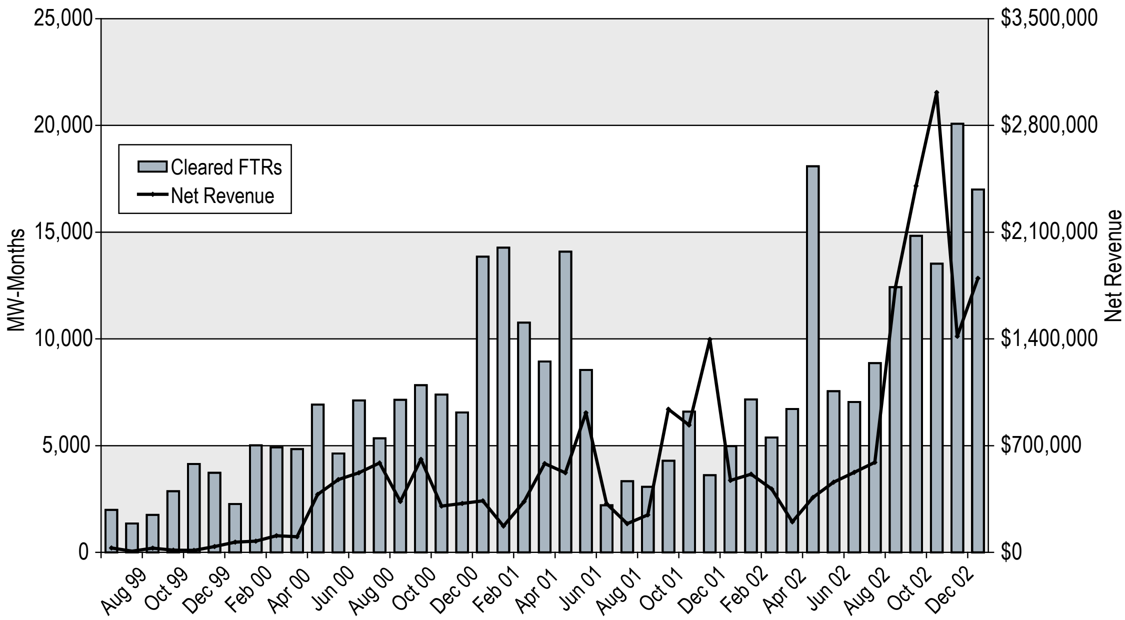
6 87 FERC ¶61,054 (1999).

- **Revenue.** Average monthly auction revenue grew from $30,000 per month in 1999 to over $350,000 in 2000. Revenue has doubled in each of the subsequent years, increasing to just over $600,000 and $1.2 million per month in 2001 and 2002, respectively.

- **Congestion Hedge.** In 2002, FTRs paid 95 percent of the FTR target allocation.

Figure 1-5 **FTR Monthly Auction**

FTR Cleared Volume and Net Revenue



SECTION 2—ENERGY MARKET

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in day-ahead and real-time balancing markets, bilateral and forward markets, and self-supply. Energy transactions analyzed in this report include those in the PJM day-ahead and real-time spot markets. These markets provide a key benchmark against which market participants may measure the results of other transaction types. The Market Monitoring Unit (MMU) analyzed measures of energy market structure and performance for 2002, including market size, concentration, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM energy market results were competitive in 2002.

OVERVIEW

Market Structure

- **Market Size.** On April 1, 2002, the PJM-East Region expanded with the addition of the Allegheny Power System (APS) under a set of agreements known as “PJM-West.” The addition of the PJM-West Region had significant impacts on the PJM energy market. Despite the fact that the combined PJM load reached record peaks in 2002, prices declined from 2001. Price levels in 2002 were a function of market fundamentals and, in particular, reflected changes to the aggregate energy market supply curve. For the PJM Region as a whole, there was a total addition of about 12,000 MW of generation, an addition of about 9,700 MW of load and thus an addition to net peak generation supply of about 2,300 MW. The shape of the aggregate supply curve changed with the incorporation of new generation and the fuel mix of that generation, producing an aggregate supply curve with an extended horizontal, base-load portion. The result was lower prices.

- **Concentration of Ownership.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios suggest larger numbers of sellers splitting market sales more equally. The MMU’s analysis of the PJM energy market indicates moderate market concentration overall, but high levels of concentration in the intermediate and peaking segments of the supply curve. Further, specific areas of the PJM Region exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence exists that market power was exercised in these areas during 2002, primarily because of generators’ obligations to serve load. If those obligations were to change, however, significant market-power-related risk would exist.

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price. Overall, the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive in 2002 although the evidence is not dispositive.

- **Net Revenue.** Net revenue is an indicator of generation investment profitability. It is thus a measure of incentives to add generation to serve PJM markets and a significant measure of overall market performance. Net revenue measures the contribution to capital cost generators receive from energy and capacity markets, ancillary service markets and operating reserve payments. In 2002, net revenue from these sources would not have covered fixed costs for a peaking unit with variable operating costs of between $40 and $45 per MWh[1] if it had run during all profitable hours. Market results vary from year to year; those for 2002 reflect lower energy and capacity market prices than those for 2001.

- **Demand-Side Management (DSM).** Markets require both a supply side and a demand side to function effectively. The demand side of the wholesale energy market is severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and other wholesale power markets. Total demand-side resources available in the PJM Region during 2002 were 1,569 MW of Active Load Management, 548 MW of Emergency DSM and 343 MW of Economic DSM. The 2,460 MW total DSM resources were almost four percent of peak demand.

- **Energy Market Prices.** PJM's locational marginal prices reflect market structure and the conduct of individual participants. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. For example, overall average prices subsume congestion and price differences over time.

  PJM average prices decreased from 2001 to 2002 for several reasons, including supply and demand fundamentals and decreased fuel costs. Prices declined despite the fact that three, new all-time peak loads were established in 2002. The simple, hourly average system-wide locational marginal price (LMP) was 12.6 percent lower in 2002 than in 2001, $28.30 per MWh versus $32.38 per MWh and approximately the same as in 2000 ($28.14) and 1999 ($28.32). When hourly load levels are reflected, the load-weighted LMP of $31.60 per MWh in 2002 was 13.8 percent lower than in 2001, 2.9 percent higher than in 2000 and 7.2 percent lower than in 1999. The load-weighted result reflects the fact that market participants typically purchase more energy during high-price periods and prices during the summer peak period were lower in 2002 than in 2001. When decreased fuel costs are accounted for, the average, fuel-cost-adjusted, load-weighted LMP was 2.0 percent lower in 2002 than in 2001, $35.93 per MWh compared to $36.65 per MWh.

  PJM average real-time spot market prices decreased in 2002 over 2001 for several reasons, including decreased fuel costs, the inclusion of the PJM-West Region (Allegheny Power System or APS) in the PJM Region on April 1, and the addition of new generation capacity in PJM. These factors combined to flatten the supply curve of electricity and to shift the upward sloping portion of the supply curve to the right (Figure 2-1). As a result, although a new, all-time peak demand was established on three occasions during the summer of 2002, LMP never exceeded $800 per MWh and was greater than $700 per MWh for only one hour and greater than $150 per MWh for only 20 hours during all of 2002. By contrast, during the summer of 2001 when a then new all-time peak was established, LMP exceeded $900 per MWh for 10 hours, exceeded $700 per MWh for 13 hours and exceeded $150 per MWh for 60 hours.

1 The $40 to $45 per MWh variable operating cost reflects 2002 average natural gas costs and the heat rate of a new peaking unit.

The energy market results for 2002 reflected the addition of the PJM-West Region and the associated supply-demand fundamentals. While energy market results were competitive, analysis of the energy market has identified a number of concerns regarding market structure that could affect competitive market results when markets are tighter, including:

- The relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve;
- The relatively high levels of concentration in markets defined by transmission constraints; and
- The relatively high levels of concentration in the ownership of marginal units.

MARKET STRUCTURE

Market Size

On April 1, 2002, the PJM Region expanded with the addition of the Allegheny Power System (APS) under a set of agreements known as "PJM-West." The PJM-West Region is currently comprised of the service territories of three operating companies: Monongahela Power Company, the Potomac Edison Company, and West Penn Power Company, collectively doing business as Allegheny Power. Allegheny Power's service territory is located in the states of Maryland, Ohio, Pennsylvania, Virginia, and West Virginia. Allegheny is a member of the East Central Area Reliability Coordination Agreement (ECAR). The Allegheny Power zone includes independent load-serving entities with 137 MW of load. The PJM-West Region is fully integrated into the regional PJM energy market, but maintains a separate capacity market and remains a separate control zone for purposes of capacity, regulation and operating reserves.

PJM experienced three, new record peak demand levels in the summer of 2002 (Table 2-1). The first was set at 62,304 MW on July 23, 2002, for the hour ending 1600. The second peak was set at 63,540 MW on July 29, 2002, for the hour ending 1700. The latest, all-time PJM Region peak was set at 63,762 MW on August 14, 2002, for the hour ending 1600. The previous peak demand had been set at 62,232 MW on August 9, 2001, for the hour ending 1500.[2] A summary of peak loads and associated real-time LMPs for each of these four days is presented in Table 2-1 below.

Table 2-1—Record Peak Demand Days: 2001 and 2002

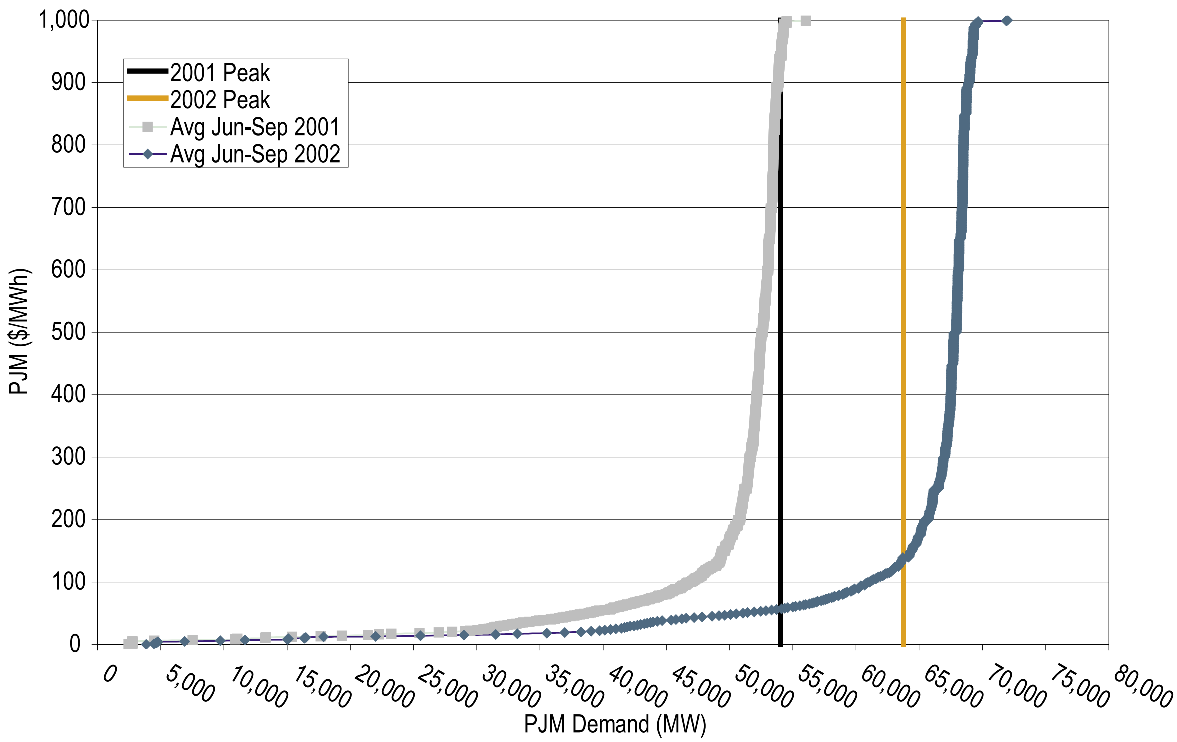
	09-Aug-01	23-Jul-02	29-Jul-02	14-Aug-02
Peak Demand (MW)	62,232	62,304	63,540	63,762
Maximum Daily LMP	$932.3	$584.9	$790.9	$445.3
Average PJM LMP ($/MWh)	$387.7	$85.4	$107.5	$88.0
Average Peak PJM LMP ($/MWh)	$559.4	$114.7	$149.4	$122.3
Average Off-Peak PJM LMP ($/MWh)	$44.2	$26.9	$23.6	$19.2

2 The peak demand for August 9, 2001, occurred prior to the addition of the PJM-West Region. For comparability, the 2001 Allegheny hourly load was added to the 2001 PJM hourly load in order to identify the time of the overall record peak demand for the combined energy markets in 2001.

Despite the higher load levels in 2002, prices fell in PJM compared to 2001. Price levels in 2002 were a function of market fundamentals and, in particular, reflected changes to the aggregate energy market supply curve. New generation additions and upgrades to existing units in the PJM-East Region resulted in a net addition of 2,941 MW of generation, after retirements and reductions in capacity. After accounting for the increased peak load in 2002 over 2001, there was a net increase in supply of about 1,500 MW in the PJM-East Region. The incorporation of the PJM-West Region resulted in the addition of 9,100 MW of new generating capability and of 8,300 MW in peak load, for a net increase in supply of 800 MW. For the PJM Region as a whole, there was a total addition of about 12,000 MW of generation, an addition of about 9,700 MW of load and thus an addition to net peak generation supply of about 2,300 MW.

The shape of the aggregate supply curve also changed with the incorporation of new generation and the fuel mix of that generation. The result was that the horizontal, base load, portion of the aggregate supply curve was extended (Figure 2-1). Of the total new generation added, approximately 70 percent was coal-fired and approximately 30 percent was gas-fired.

Figure 2-1 Average PJM Region Aggregate Supply Curve (June - September)

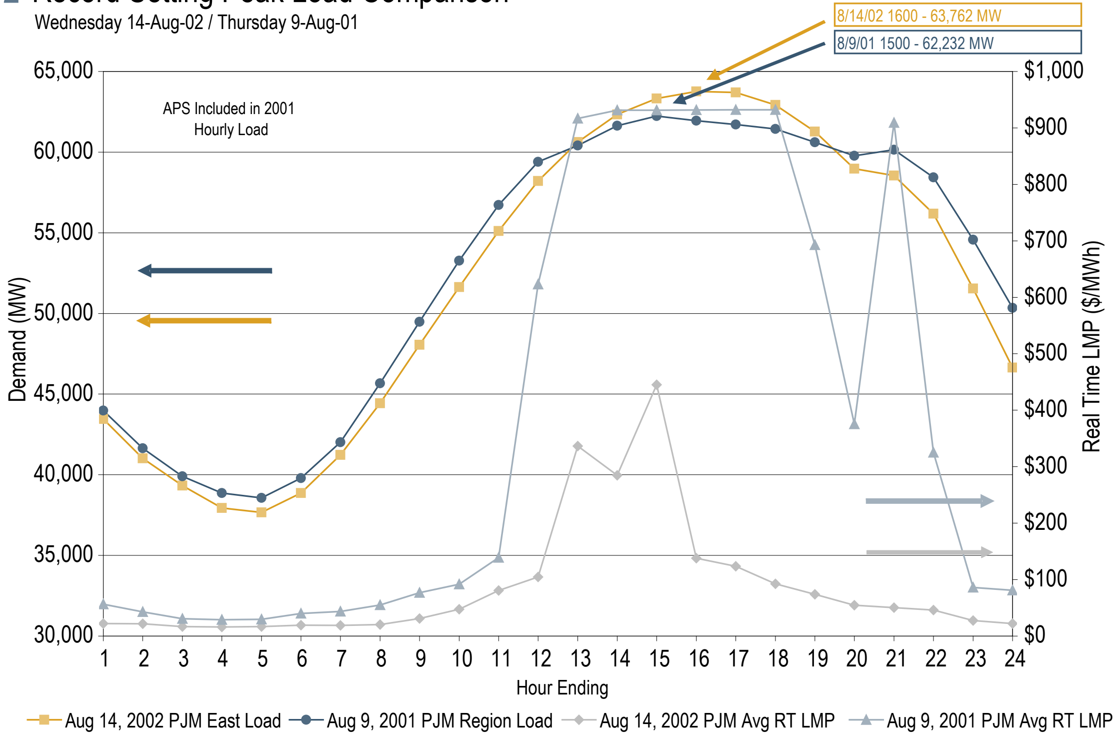


During the summer of 2002, the demand curve intersected the supply curve at a lower price level than would have occurred if there had been less additional generation or if there had been a different mix of additional generation.

The generation fuel mix on August 14, 2002, and August 9, 2001, further illustrates the impact of changes in the supply curve. Of the increased generation output on August 14, 2002, approximately two-thirds was supplied by coal-fired generation while the remaining one-third was supplied by natural gas (about 20 percent) and oil-fired generation.

The price performance in 2001 illustrates the impact of the changes to the aggregate supply curve. Figure 2-1 compares the hourly load and prices for the peak load day in 2002 and the peak load day in 2001. Despite the fact that loads were higher on August 14, 2002, prices were much lower throughout the day than they had been on August 9, 2001. On August 14, 2002, prices only exceeded $200 for three hours, while prices had exceeded $200 for 11 hours on August 9, 2001, including seven hours at levels in excess of $900.

Figure 2-2 Record Setting Peak Load Comparison



Market Concentration

Concentration in the PJM energy market during 2002 was moderate overall, but high in the intermediate and peaking segments of the supply curve. High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. A pivotal supplier's output is required in order to meet load. Further, specific areas of the PJM Region exhibit moderate to high concentration ratios that may be problematic when transmission constraints exist. No evidence exists that market power was exercised in these areas during 2002 primarily because of generator load obligations. If those obligations were to change, however, significant market-power-related risk would exist.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct and performance of individual participants and their impact on price. The price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. Low aggregate-market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly energy market HHIs were calculated based on the real-time energy output of generators located in the PJM Region, adjusted for hourly imports (Table 2-2). The installed HHIs were calculated based on the installed capacity of PJM generating resources, adjusted for aggregate import capability (Table 2-3).

Imports and import capability were incorporated in the HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The overall maximum hourly HHI was calculated by assigning all actual positive net tie flows in each hour to the market participant with the largest market share, while the overall minimum hourly HHI was determined by assigning hourly net tie flows to five non-affiliated market participants. Similarly, the overall maximum installed HHI was calculated by assigning all import capability to the market participant with the largest market share; the overall minimum installed HHI was determined by assigning import capability to five non-affiliated market participants and the overall average is the average of the two.

For both hourly and installed HHIs, generators were aggregated by ownership and, in the case of affiliated companies, by parent organization. Hourly and installed HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. The hourly HHIs by supply curve segment were calculated based on hourly market shares, unadjusted for imports, while the installed HHIs by segment were calculated on an installed capacity basis, also unadjusted for import capability.

In addition to the aggregate PJM calculations, HHIs were calculated for various areas of PJM to provide an indication of the level of concentration that exists when specific areas within PJM are isolated from the larger PJM market by transmission constraints.

The "Merger Policy Statement" of the United States Federal Energy Regulatory Commission (FERC) [3] states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000 - equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800 - equivalent to between five and six firms with equal market shares.

3 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement," Order No. 592, pages 64-70.

Results

Calculations for installed and hourly HHI indicate that by FERC standards the PJM energy market is moderately concentrated (Table 2-2). Overall market concentration varies from 843 to 2247 based on the hourly measure and from 993 to 1152 based on the installed measure.[4]

Table 2-2—2002 PJM Hourly HHI

	Overall Minimum	Overall Maximum
Maximum	1823	2247
Average	1194	1417
Minimum	843	1016

Table 2-3—2002 Overall PJM Installed HHI

	Minimum	Average	Maximum
Overall	993	1072	1152

Tables 2-4 and 2-5 include HHI values for capacity and energy measures by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the installed measure indicates that, on average, all segments are moderately concentrated. For both hourly and installed measures, HHIs are calculated for facilities located in PJM; imports are not accounted for.

Table 2-4—2002 PJM Hourly HHI by Segment

	Base	Intermediate	Peak
Maximum	2118	4709	10000
Average	1402	2000	4744
Minimum	1175	849	1029

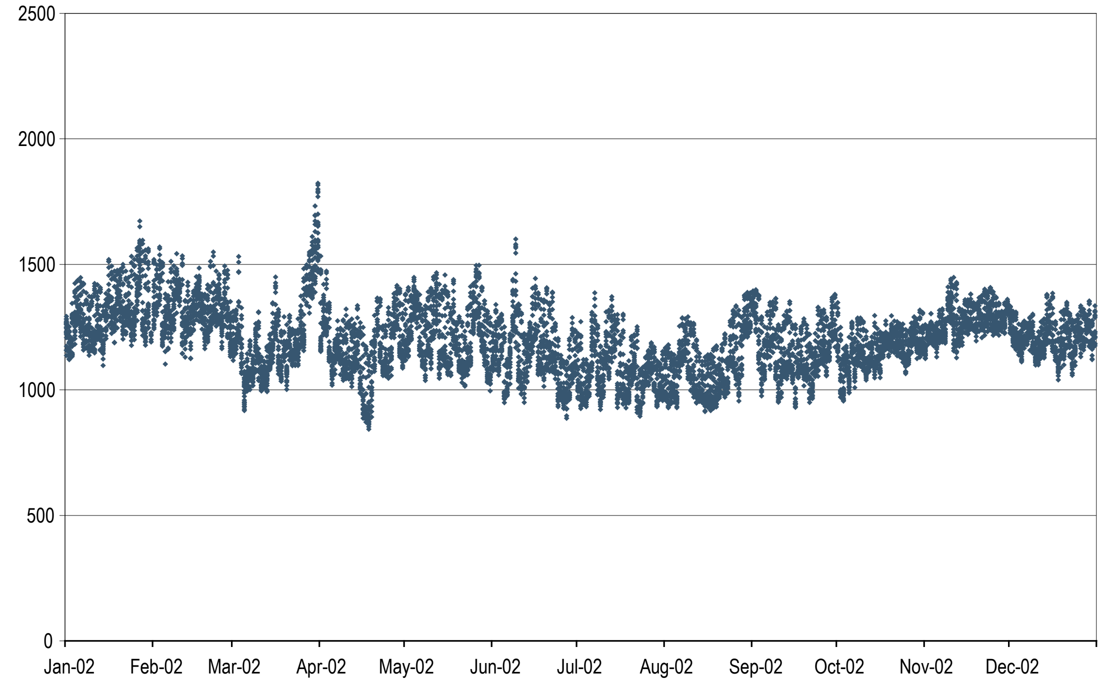
Table 2-5—2002 PJM Installed HHI by Segment

	Base	Intermediate	Peak
HHI	1317	1050	1438

4 The maximum HHI level for the overall maximum hourly measure assumes that the market participant with the largest share controls all imports. While this is an important sensitivity, there is no evidence that this has occurred or is likely to occur.

Figure 2-3 presents hourly HHI results for the "Overall Minimum" measure shown in Table 2-2.

Figure 2-3 2002 PJM Hourly Energy Market Minimum HHI



High Market Concentration and Frequent Congestion

Seven sub-regions within the PJM Region showed high local market concentration and frequent congestion in 2001 or 2002: Northern Public Service, Northcentral Public Service, Eastern PJM, Delmarva Peninsula, Atlantic Conectiv, Erie and Towanda.

- **Northern Public Service:** During 2002, constraints in this subarea became less significant, decreasing from 550 hours on average in 2000 to 2001 to 250 hours in 2002. The Roseland-Cedar Grove 230 line contributed to 30 percent of congestion in 2002 compared to 65 percent in 2001. New generation added in the subarea during 2002 appears to have contributed to the decrease in congestion. Although congestion decreased, market concentration remained high for the local market, with an average HHI of 7400; minimum and maximum HHIs were 5000 and 9800.

- **Northcentral Public Service:** During 2002, this subarea continued to exhibit high market concentration and continued to experience local congestion about 425 hours per year. Energy transfers into the area are still restricted by limitations on the Brunswick-Edison-Meadow Road 138 kV circuit, which was constrained 356 hours. Ninety-five percent of the congested hours were during on-peak periods. When this subarea is constrained, about 375 to 575 MW of load is isolated and market concentration varies from a minimum of 4500 to a maximum of 10000. Average HHI was 7200 during 2002.

- **Eastern PJM**: Transfer limitations into Eastern PJM became less significant in 2002 as new generating stations came on line, providing additional voltage support and reducing the occurrence of the East Interface constraint. This constraint was in effect only 54 hours in

2002, down from an average of 300 hours per year over the previous two years. The addition of new generation in this region also reduced market concentration to a minimum of 1800 and a maximum of 2450.

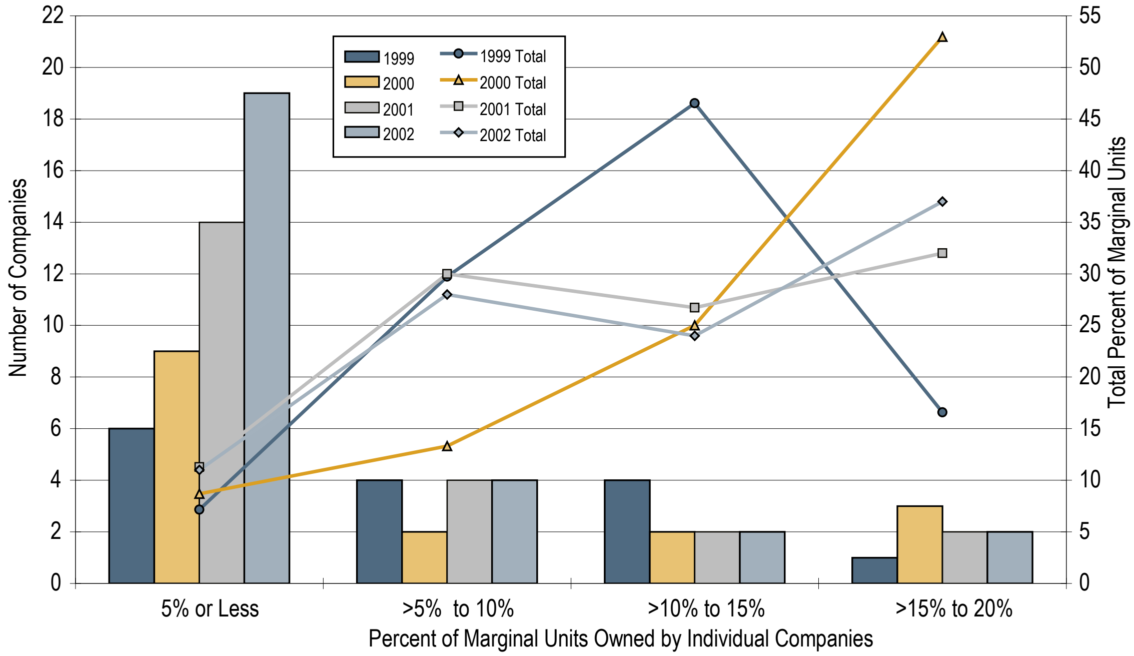
- **Delmarva Peninsula.** Additional investment in transmission reinforcements on the Delmarva Peninsula continued to reduce the occurrence of congestion on the peninsula, from 2,800 constrained hours in 2001 to 792 constrained hours in 2002. Four facilities were constrained for more than 100 hours in 2002 and accounted for 79 percent of all facility event-hours: Hallwood-Oak Hall 138, 286 hours, Cheswold 138/69, 263 hours, Church 230/69, 130 hours, and Indian River 230/138, 113 hours. Nearly 70 percent of all congested hours occurred during on-peak periods. Average HHIs range from 4600 to 7200 for the load pockets cutoff by these four constraints, while minimum and maximum HHIs varied from 2400 to 4400 and from 6300 to 10000, respectively.
- **Cedar Subarea.** The Cedar Subarea in the AECO Zone, which has less than 100 MW of load and an average HHI of 6000, continued to be frequently constrained. Constraint occurrence nearly doubled, from 400 hours during 2000 to 2001 to 790 hours in 2002. The primary cause of congestion was Cedar-Motts 69, which was constrained 537 hours, 378 hours during on-peak periods. Minimum and maximum HHIs were 2000 and 10000.
- **The Erie Subarea.** The Erie Subarea of the PENELEC Zone was constrained 900 hours by the Erie West 345/115 transformer, with approximately 50 percent of congested hours occurring during on-peak periods. Some 800 MW of load was isolated by this constraint, and HHI averaged over 5000. Minimum and maximum HHIs were 1100 and 9800, respectively.
- **The Towanda Subarea.** The Towanda Subarea, with approximately 500 MW of load and also located in the PENELEC Zone, was constrained 538 hours during 2002 and had an HHI with a minimum of 1000 and a maximum of 10000. Average HHI was 5400.

Ownership of Marginal Units

Figure 2-4 shows the ownership distribution for marginal units. The bars for 2002 show all units that were on the margin for one or more five-minute intervals during the specified year. In 2002, two companies each owned 15 to 20 percent of the marginal units, while two other companies each owned 10 to 15 percent of the marginal units. The Figure's "2002 Total" line shows that the two companies that each separately owned from 15 to 20 percent of the marginal units, together owned the marginal unit in more than 35 percent of the five-minute intervals. Similarly, the two companies that each separately owned from 10 to 15 percent of the marginal units, together owned the marginal unit in about 25 percent of the intervals. Thus the four companies that owned the marginal unit in more than 10 percent of the intervals, together owned the marginal unit in about 60 percent of the intervals. The top eight companies owned the marginal unit in about 90 percent of the intervals. In 2001, the top four companies owned about 60 percent of the marginal units; in 2000, the top five companies owned about 80 percent of the marginal units; in 1999, the top five companies owned more than 60 percent of the marginal units.

Together with the data on HHIs by supply curve segment, distribution of ownership of marginal units causes further concern about the structure of the energy market.

Figure 2-4 Marginal Unit Ownership



MARKET PERFORMANCE

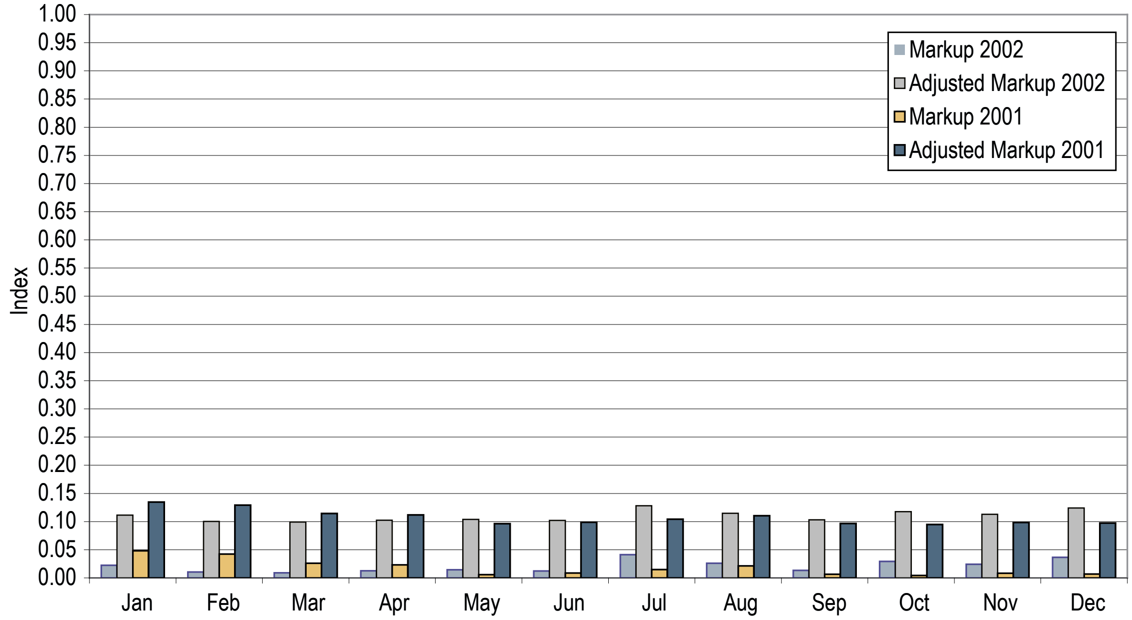
Price-Cost Markup Index

The price-cost markup index is a measure of market power. The goal of the markup analysis is to estimate the difference between the observed market price and the competitive market price.

The price-cost markup index is defined here as the difference between price (P) and marginal cost (MC), divided by price, where price is determined by the offer of the marginal unit and marginal cost is from the highest marginal cost unit operating (The markup index = (P – MC)/P). This markup index measure can vary from -1.00, when price is less than marginal cost to 1.00 when price is higher than marginal cost[5] (Figure 2-5).

5 The value of the index can be less than zero if a unit offers its output at less than marginal cost. This is not implausible because units in PJM may provide a cost curve equal to cost plus 10 percent. Thus the index can be negative if the marginal unit's offer price is between cost and cost plus 10 percent.

Figure 2-5 Average Monthly Load Weighted Markup Indices



PJM has price and cost offer data for every unit in the PJM system for which construction commenced prior to July 9, 1996. The markup can thus be calculated directly for any time period. The markup is calculated for the marginal unit or units in every five-minute period. The marginal unit is the unit that sets LMP in the five-minute interval. There are multiple marginal units when congestion exists. Congestion is accounted for by weighting the markup for each of the multiple marginal units, in a five-minute interval with congestion, by the load that pays the price determined by that marginal unit.[6] The resultant markups are adjusted so that the markup index compares the price offer for the marginal unit to the cost corresponding to the output of the highest marginal cost unit operating, rather than to the marginal cost of the marginal unit.

Figure 2-5 shows the monthly average markup index. The average markup was 0.02 in 2002, with a maximum markup of 0.04 in July and a minimum markup of 0.01 in several other months. Generators in PJM are permitted to provide cost-based offers that include a 10 percent markup over marginal cost. Since a significant number of generators have increased their cost bids by this 10 percent, the calculated markup index is likely to be low. The adjusted markup index in Figure 2-5 assumes that all units' costs include a 10 percent markup over cost. Given this assumption, the average 2002 markup index was 0.11, with a maximum index of 0.13 in July and a minimum index of 0.10 in several other months. [7]

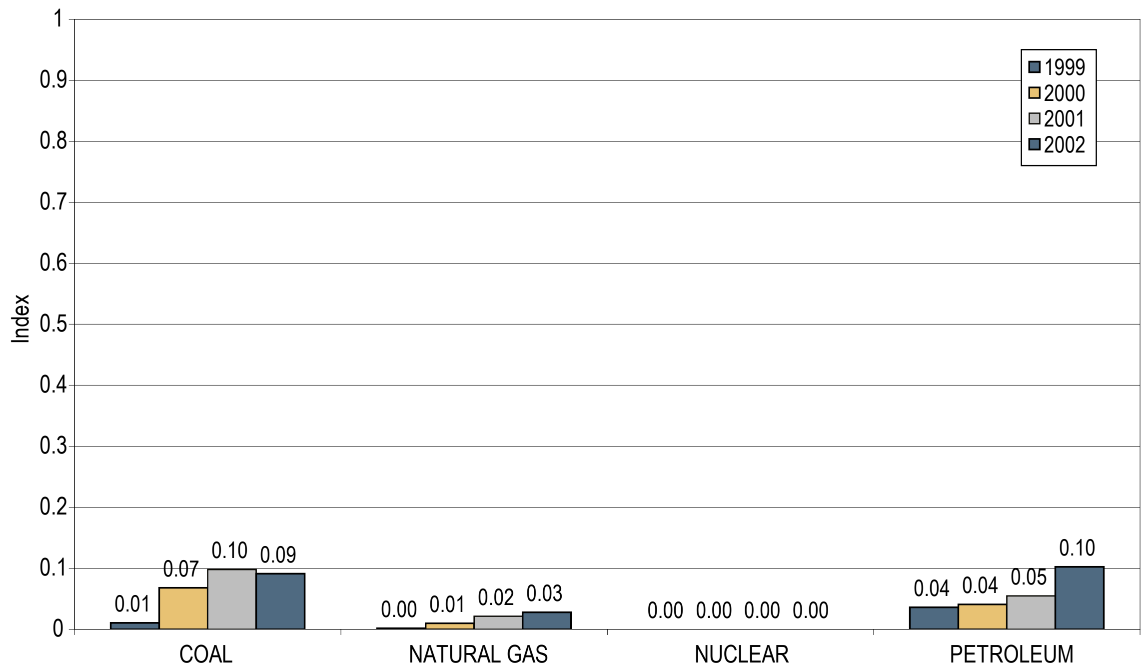
6 For example, if a marginal unit with a markup index of 0.50 set the LMP for 3,000 MW of load in an interval and a second marginal unit with a markup index of 0.01 set the LMP for 27,000 MW of load, the weighted average markup index for the interval would be 0.06.

7 The 10 percent mark up is permitted, in part, to account for inaccuracies in marginal cost calculations. Thus, the correct markup index lies between the adjusted and unadjusted index values.

The markup index calculation is based on the marginal production cost of the highest marginal cost operating unit and does not include the marginal cost of the next most expensive unit, an appropriate scarcity rent, if any, or opportunity cost, if any, as a cost component. Thus, if the marginal unit is a combustion turbine (CT) with a price offer equal to $500 per MWh and the highest marginal cost of an operating unit is $130 per MWh, the observed price-cost markup index would be 0.74 [(500-130)/500]. If, however, the unit can export power and the real-time price in the external control area is $500 per MWh, then the appropriately calculated markup index would actually be zero.

To understand the dynamics underlying observed markups, the MMU analyzed the marginal units in more detail, including fuel type, plant type and ownership. Figure 2-6 shows the average, unit-specific markup by fuel type. The markup [(P-MC)/P] is calculated using price and marginal cost for the specific unit of the identified fuel type that is marginal during any five-minute interval. Units using coal and petroleum showed the highest levels of markup index. Coal and petroleum units had average markup indices between 0.09 and 0.10 during 2002.[8]

Figure 2-6 Average Markup Index by Type of Fuel



8 The primary fuel types contained in the miscellaneous category include methane, petroleum coke, refuse, refinery gas, waste coal, wood and wood waste.

Figure 2-7 shows the "Type of Fuel Used by Marginal Units." In 2002, coal-fired units were on the margin 55 percent of the time, gas-fired units 23 percent of the time, petroleum-fired units 21 percent of the time and nuclear units less than one percent. The share of coal increased from 49 percent in 2001 to 55 percent in 2002; natural gas units' share increased from 18 to 23 percent; nuclear units' share decreased and petroleum-fired units' share of marginal usage decreased from 32 percent to 21 percent.

Figure 2-7 Type of Fuel Used by Marginal Units

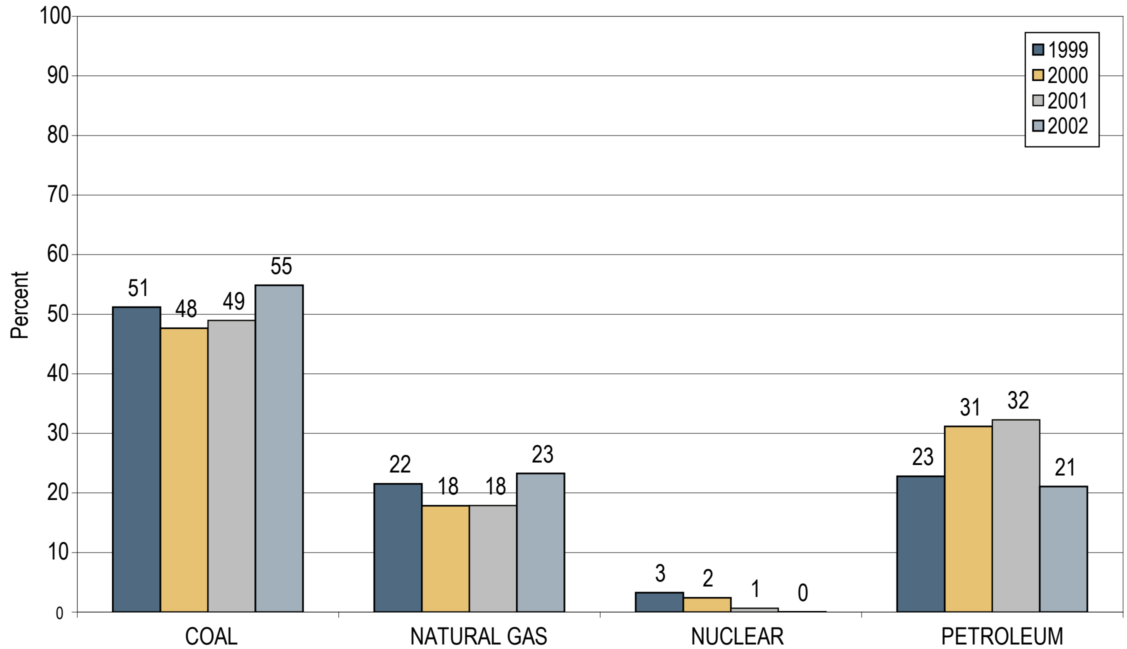


Figure 2-8 shows the type of units on the margin from 1999 to 2002. During 2002, the marginal unit was a CT 26 percent of the time and a steam unit 74 percent of the time.

Figure 2-8 Type of Marginal Unit

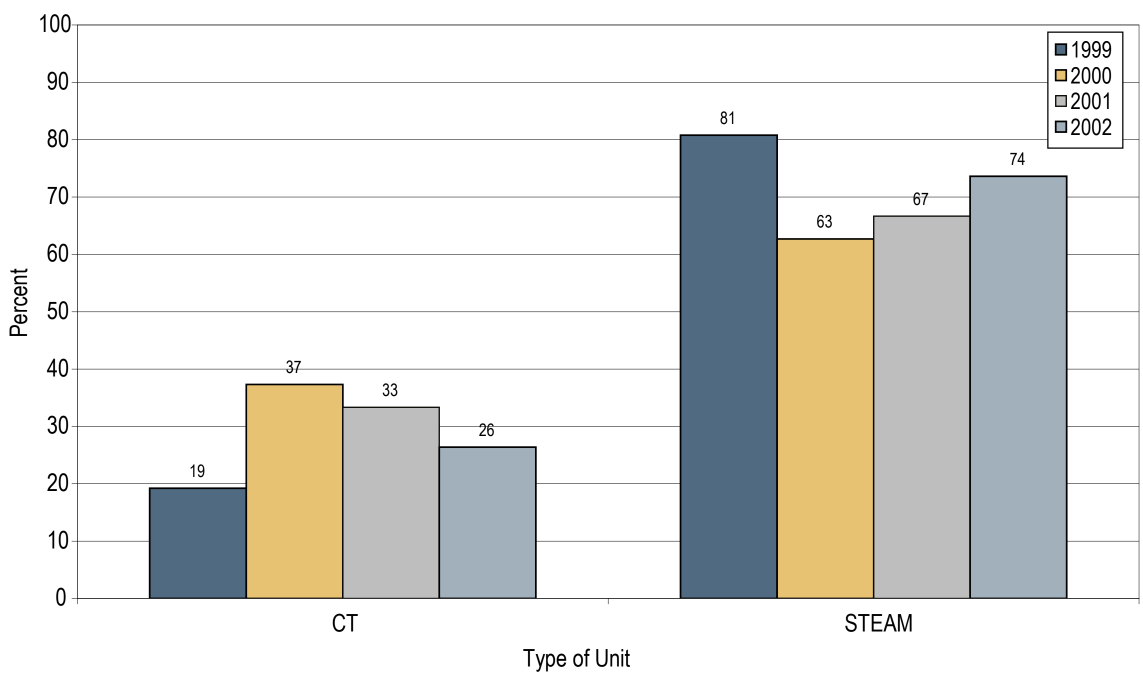
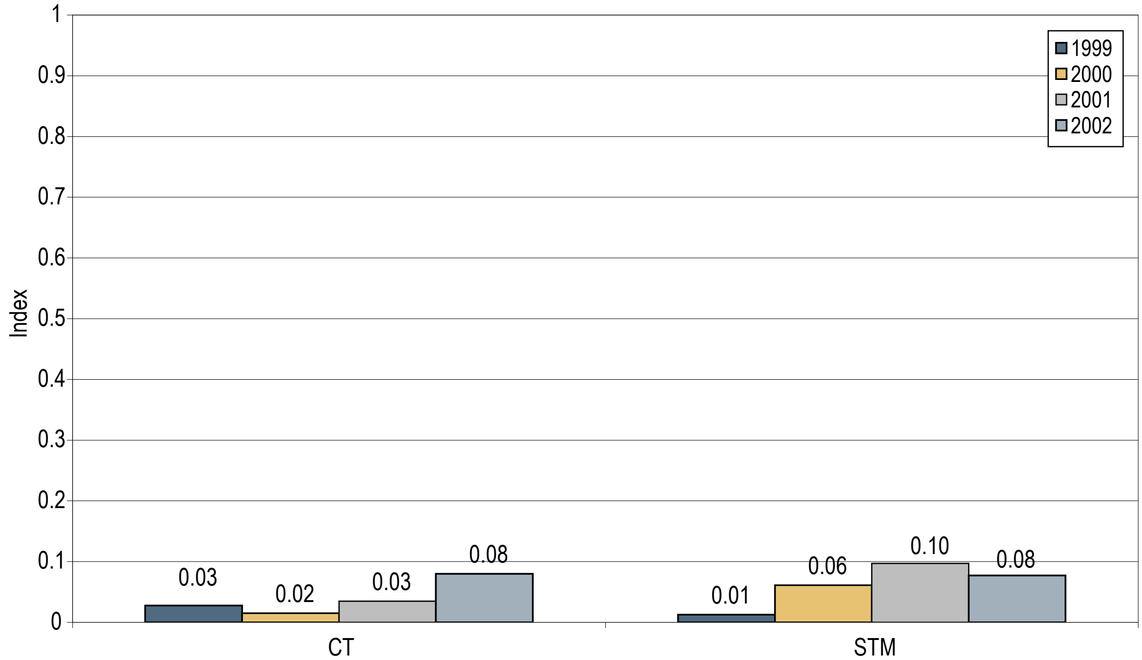


Figure 2-9 shows average markup index by unit type. The average annual markup index was approximately the same for steam units and CTs. The average annual index increased for CTs in 2002 and decreased for steam units.

Figure 2-9 Average Markup Index by Type of Unit



Overall, the index results presented here are consistent with the conclusion that the energy market results were competitive in 2002.

Net Revenue

Net revenue is an indicator of generation investment profitability and is thus a measure of incentives to add generation to serve PJM markets and a measure of overall market performance. Net revenue measures the contribution to capital cost received by generators from energy and capacity markets, from ancillary service markets and from operating reserve payments. Gross energy market revenue is the product of market price and generation output. Gross revenue less variable cost equals net revenue, and the net revenue curve illustrates the relationship between net revenue and generation variable cost (Figure 2-10).

In other words, net revenue is the amount that remains from gross sales revenue, after variable costs, to cover fixed costs, including a return on investment, depreciation, taxes and fixed operating and maintenance expenses.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue would be expected to equal the total of all these fixed costs for the marginal unit, including a competitive return on investment. The PJM capacity, energy and ancillary service markets and operating reserve payments are all sources of revenue to cover the fixed costs of generators. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity, ancillary service and operating reserve payments, the net revenue from all sources would equal the fixed costs of generation, for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and whether market prices are high enough to encourage the entry of new capacity.

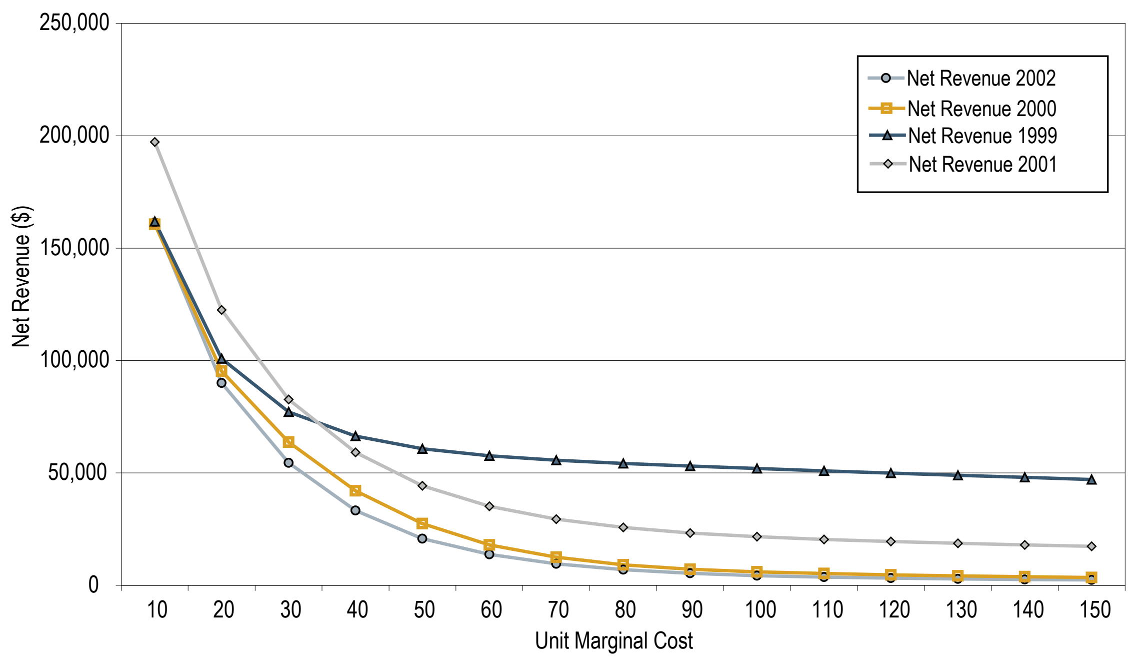
Energy Market Net Revenue

Net revenue curves presented in Figure 2-10 reflect net revenues from energy markets only. Additional sources of net revenue are presented in Table 2-6.

The vertical axis of Figure 2-10 shows the dollars per MW-year received by a unit in PJM which operated whenever system price exceeded the variable cost levels shown in dollars per MWh on the horizontal axis. For example, a unit with marginal costs equal to $30 per MWh had an incentive to operate whenever LMP exceeded $30 per MWh. If this unit had operated during all profitable hours, it would have received about $55,000 per MW in net revenue during 2002 from the energy market alone. The Figure 2-10 net revenue curves are approximate measures, representing an upper bound, of the energy markets' contribution to generator fixed costs. The net revenue curve does not take account of forced outages or operating constraints. For example, a 12-hour start-up time could prevent a unit from running during two profitable hours in the morning and two more profitable hours in the evening, separated by eight non-profitable hours. As another example, ramp limitations might prevent a unit from starting and ramping up to full output in time to operate for all profitable hours.

As Figure 2-10 illustrates, the energy market net revenue curve was consistently lower in 2002 than in the years 1999 to 2001. If a unit with marginal costs of $30 per MWh had operated during all hours when the LMP exceeded $30 per MWh, it would have received about $77,000 per MW in net energy revenue in 1999, about $64,000 in 2000, about $83,000 in 2001 and about $55,000 in 2002. In 1999, if a unit with marginal costs of $50 per MWh had operated in all hours when LMP exceeded $50 per MWh, it would have received about $61,000 per MW in net energy revenue versus about $27,000 in 2000, about $44,000 in 2001 and about $21,000 in 2002.

Figure 2-10 PJM Energy Market Net Revenue - 1999, 2000, 2001, and 2002



Differences in the shape and position of net energy revenue curves for the three years result from different distributions of energy market prices. These differences illustrate the significance of a relatively small number of high-price hours to the profitability of high marginal cost units. Although average prices in 2000 were approximately equal to average prices in 1999, hourly average prices in 2000 were actually higher than hourly average prices in 1999 for all intervals except hours 1200 through 1800, when 1999 prices significantly exceeded those in 2000. These peak hours included intervals when 1999 prices spiked to more than $900 per MWh for a limited number of hours. The 91 hours in 1999 when prices exceeded $150 per MWh and the 43 hours when price exceeded $800 per MWh generally occurred during these peak intervals. These periods were responsible for the shape of the 1999 net revenue curve. In 2000, there were only 27 hours when price exceeded $150 per MWh and only one hour when the price exceeded $800 per MWh. The limited number of high-price hours in 2000 resulted in lower net revenue for units operating at marginal costs above $30 per MWh.

Simple average prices were lower in 2002 than in 2001 and approximately equal to prices in 2000 and 1999. Load-weighted average prices were lower in 2002 than in 2001 and 1999, and approximately equal to those in 2000. Overall price levels explain, in part, why the net revenue curve for 2002 was lower than for prior years. The frequency distribution of prices is also important in understanding the relative shapes of the net revenue curves. Figure 2-13 shows that 2002 experienced the lowest frequency of prices greater than $100 of any year in the comparison. Price spikes in 2002 were very limited in frequency, duration and level compared to earlier years.

Capacity Market Net Revenue

Generators also receive revenues for capacity in addition to energy-related revenue. In 2002, PJM capacity resources received a weighted-average payment from all capacity markets of $33.40 per MW-day, or $11,601 per MW of installed capacity for the year.

Ancillary Service and Operating Reserve Net Revenue

Generators also received ancillary service and operating reserve revenues. Aggregate ancillary service revenues from regulation and spinning reserves were about $2,800 per MW-year of installed capacity in 2002. Operating reserve payments were about $2,900 per MW-year of installed capacity.

Total Net Revenue

Including all revenue streams, a PJM capacity resource with a marginal cost of $30 per MWh would have received about $72,000 per MW-year in 2002 while a unit with a cost of $50 per MWh would have received about $38,000 per MW-year. Table 2-6 shows results for units with a range of marginal costs.

Table 2-6—Net Revenues in 2002 by Marginal Cost of Unit
(Energy, capacity, ancillary service, operating reserve and total net revenues in $/MW-year)

Unit Marginal Cost ($/MWh)	Net Revenue Sources ($/MW-year)		Ancillary Services	Operating Reserves	Total Net Revenues: 2002
	Energy	Capacity			
$10	$161,427	$11,601	$2,822	$2,875	$178,726
$20	$90,015	$11,601	$2,822	$2,875	$107,314
$30	$54,536	$11,601	$2,822	$2,875	$71,834
$40	$33,258	$11,601	$2,822	$2,875	$50,557
$50	$20,781	$11,601	$2,822	$2,875	$38,080
$60	$13,767	$11,601	$2,822	$2,875	$31,066
$80	$6,959	$11,601	$2,822	$2,875	$24,258
$100	$4,318	$11,601	$2,822	$2,875	$21,616
$120	$3,219	$11,601	$2,822	$2,875	$20,518
$140	$2,628	$11,601	$2,822	$2,875	$19,927

The difference in net revenues for a unit with a marginal cost of $50 per MWh between 2002 and 2001 was a reduction of about $50,000. This difference resulted from the $24,000 difference in energy market revenues and $25,000 difference in capacity market revenues, with the balance made of up of differences in ancillary service and operating reserve revenues.

To put the net revenue results in perspective, the average gas cost in PJM in 2002 was about $3.80 per MMBtu and the corresponding variable cost for a new CT was between $40 and $45 per MWh. The corresponding variable cost for a combined cycle was between $26 per MWh and $31 per MWh.[9] The PJM Capacity Deficiency Rate (CDR) is $58,400 per MW-year. The CDR was designed to reflect the annual fixed costs of a CT in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense. The CDR also includes, as an offset, an energy credit of about $4,500 per MW-year designed to reflect the difference between the PJM dispatch rate and CT costs during the hours when the CTs ran. [10] Thus the annual fixed cost of a CT in PJM, per the CDR calculations, is about $63,000 per MW-year. The capacity costs of intermediate and base load units are higher while their variable costs are lower than those of a CT. The capacity costs of a new CT constructed in New England was recently estimated to be $73,800 per MW-year.[11]

In 2002, the net revenues from the energy market, the capacity market, ancillary services and operating reserves of between $43,431 and $50,557 would not have covered the fixed costs of peaking units with operating costs between $40 and $45 per MWh which ran during all profitable hours.

9 The key variables are fuel cost and heat rate.
10 The CDR was calculated in 1997 and has not been updated.
11 e-Acumen, "Final Report to ISO New England," December 10, 2001.

Although it can be expected that in the long run, in a competitive market, net revenues from all sources should cover the fixed costs of investing in new generating resources including a return on investment, actual results will vary from year to year. Revenues from the capacity market, ancillary services and operating reserves clearly will vary from unit to unit depending on particular capacity market transactions, the provision of specific ancillary services and the receipt of specific operating reserves. The MMU's analysis of 2002 net revenues suggests that the fixed costs of a marginal unit were not fully covered. The data suggest that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower capacity market prices, and lower, less volatile energy market prices.

Net revenues provide an incentive to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in the PJM Region reflects the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets plus operating reserve payments. At the end of 2002, about 28,000 MW of capacity were in generation request queues for construction through 2007, compared to an average installed capacity of 62,380 MW in 2002 (Figure 2-11). Although it is clear that not all of this generation will be completed, PJM is steadily adding capacity. Figure 2-12 shows the level of capacity from the queues that is in-service and the level that has been withdrawn.

Figure 2-11 Queued Capacity By In-Service Date

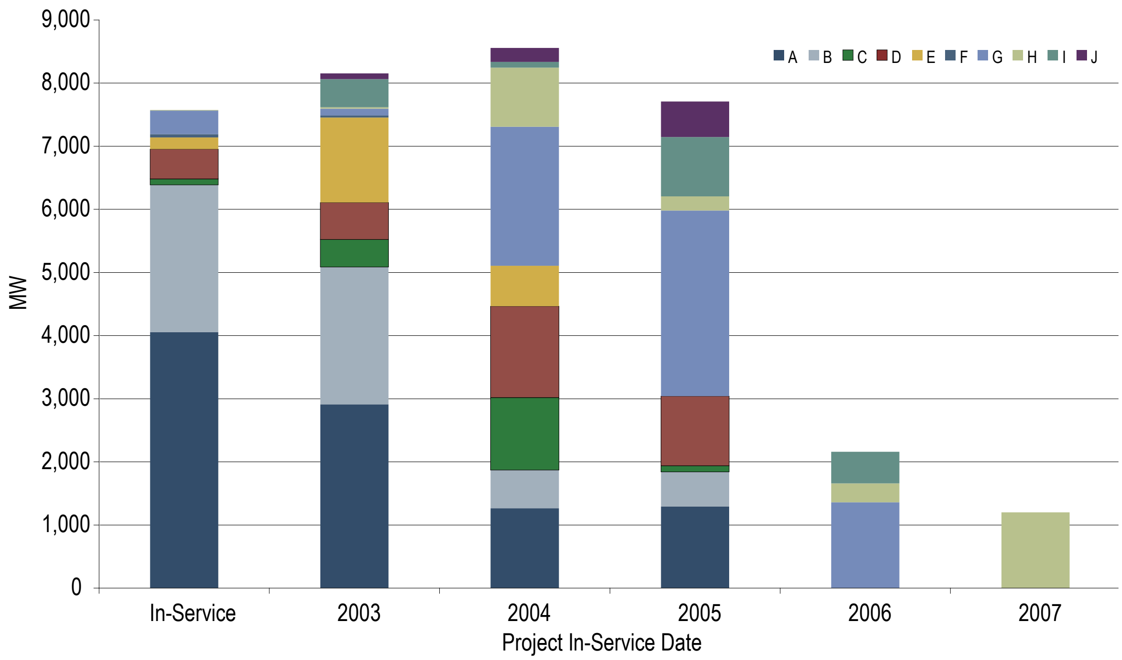
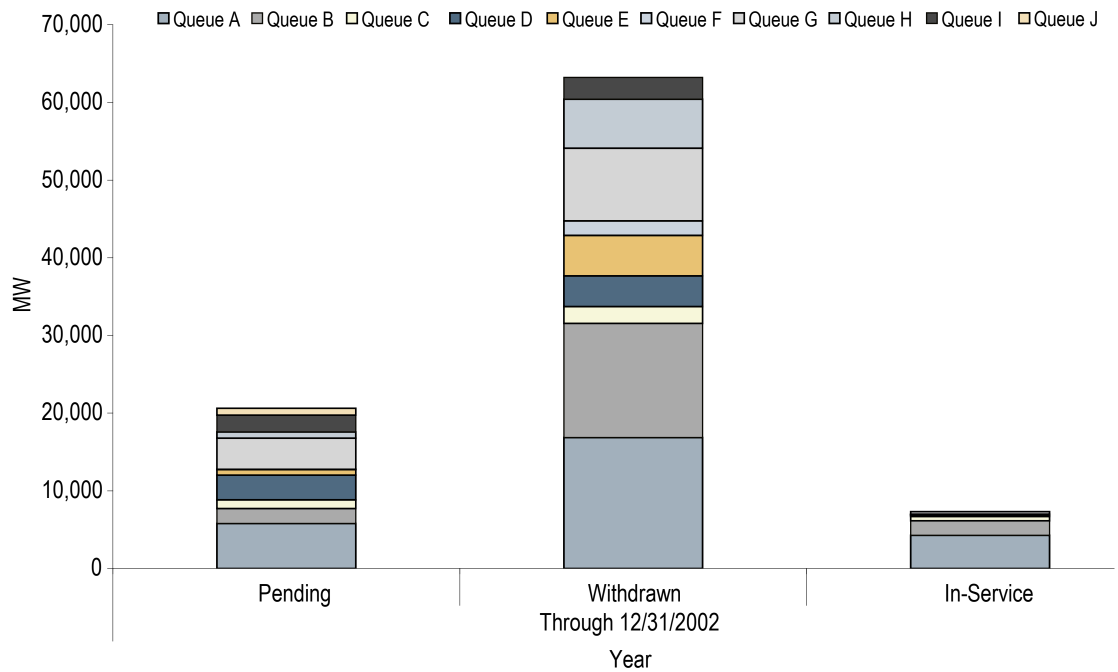


Figure 2-12 New Capacity in PJM East Queues Through 12/31/2002



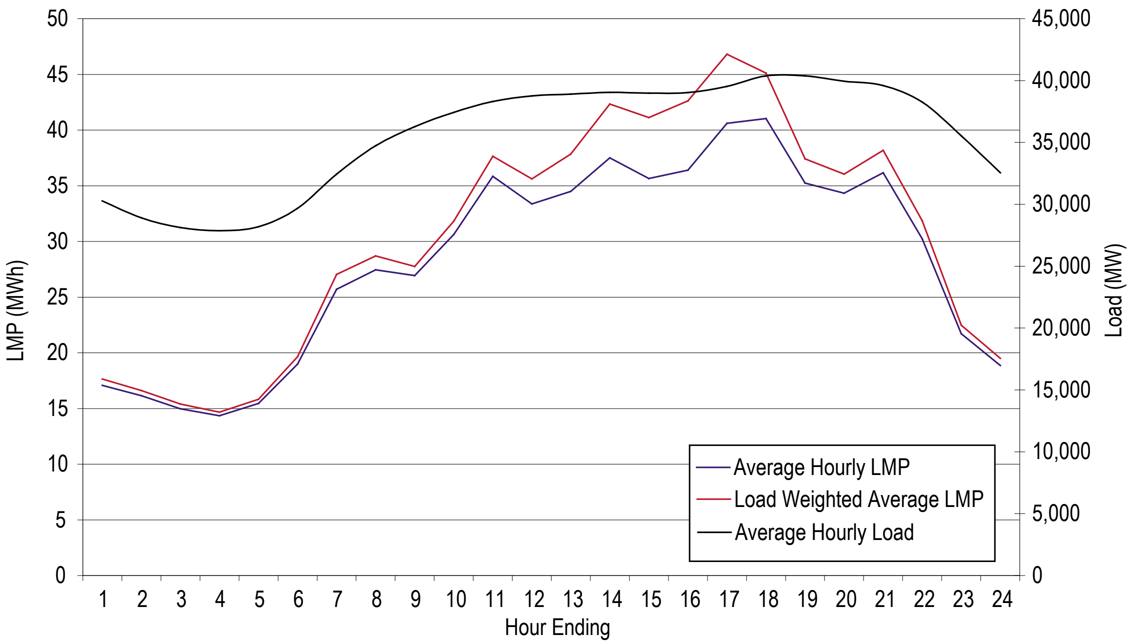
Demand-Side Management

Markets require both a supply side and a demand side to function effectively. The demand side of the wholesale energy market is severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and other wholesale power markets. It is widely recognized that wholesale energy markets will work better when a significant level of potential demand-side response is available in the market. In order to develop such demand-side response it is necessary to increase the level of load which can see, react to and benefit from reacting to prices in real time. The issue is a complex one that includes a variety of institutional barriers ranging from jurisdictional to fundamental incentive matters.

It is difficult to measure the reaction of loads to prices if loads do not have meters that record use by time period. As a result, it is difficult for loads to benefit from reacting to prices in real time. It is not clear what market entity currently has an incentive to invest in the widespread installation of the meters necessary for effective demand-side participation. While retail price caps apparently limit the degree to which price signals from the wholesale market are transmitted to the retail market, retail price caps do not remove the incentive to reduce load at times when wholesale market prices are high. The incentive to reduce load is shifted to the generator or the load-serving entity which has an obligation to deliver energy to load at a fixed price, but which incurs much higher costs to serve that load when prices are high. These costs include the direct costs incurred by a load-serving entity purchasing on the spot market to serve load and the opportunity costs incurred by a generator selling a fixed-price product to a load-serving entity at times of high spot prices.

The pattern of prices within days and across months illustrates that prices are directly related to demand. The fact that price is a direct function of load (Figure 2-13) illustrates the potential significance of price elasticity of demand in affecting price. The potential for load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale energy market.

Figure 2-13 PJM Average Hourly LMP and System Load - 2002



While PJM's Demand-Side Management (DSM) program in 2002 was limited in enrollment, it demonstrated the potential impact of effective demand-side participation in the market. The maximum hourly reduction in load that resulted from PJM programs was 1,833 MWh during 2002.

In 2002, the total resources in the Economic Program were 343 MW; the total resources in the Emergency Program were 548 MW, and the total resources in the ALM program were 1,569 MW. The maximum hourly Economic reduction was 101 MW; the maximum hourly Emergency reduction was 76 MW, and the maximum hourly ALM reduction was 1,775 MW. The maximum total daily Economic reduction was 935 MWh; the maximum total daily Emergency reduction was 341 MW, and the maximum total daily ALM reduction was 10,803 MW. The maximum Economic hourly reduction occurred on August 14 at hour ending 1500. The total DSM reduction for that hour was 515 MW. The impact of this load reduction was to lower average hourly LMP by about $16 per MWh to $110. [12]

12 These load reductions include both the ALM program and the Customer Load Reduction Pilot Program.

Energy Market Prices

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[13]

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market, although individual prices are not always easy to interpret. In a competitive market in long-run equilibrium, prices are directly related to the cost of the marginal unit required to serve load. The markup index is a direct measure of that relationship. LMPs are a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration, and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus illustrates the potential significance of price elasticity of demand in affecting price.

Real-Time Spot Market Prices

PJM real-time spot market prices declined in 2002. The simple hourly average system-wide LMP[14] was 12.6 percent lower in 2002 than in 2001, $28.30 per MWh versus $32.38 per MWh. The average LMP in 2002 was approximately the same as in 2000 and 1999 (Table 2-7). When hourly load levels are reflected, the load-weighted LMP of $31.60 per MWh in 2002 was 13.8 percent lower than in 2001, 2.9 percent higher than in 2000 and 7.2 percent lower than in 1999 (Table 2-9). The load-weighted result reflects the fact that market participants typically purchase more energy during high price periods and that peak period prices were lower in 2002 than in prior years. When decreased fuel costs are accounted for, the average fuel-cost-adjusted, load-weighted LMP in 2002 was 2.0 percent lower than in 2001, $35.93 per MWh compared to $36.65 per MWh (Table 2-10). Thus, after accounting for both the actual pattern of loads and the decreased costs of fuel, average prices in PJM were 2.0 percent lower in 2002 than in 2001.

PJM average, real-time spot market prices decreased in 2002 over 2001 for several reasons, including decreased fuel costs, inclusion of the PJM-West Region (Allegheny Power Systems) in the PJM Region on April 1, 2002, and addition of new generation capacity in PJM. These factors combined to lower the supply curve of electricity and to shift the upward sloping portion of the supply curve to the right. As a result, although a new, all-time peak demand was established on three occasions during the summer of 2002, LMP never exceeded $800 per MWh and was greater than $700 per MWh for only one hour and greater than $150 per MWh for only 20 hours. By contrast, during the summer of 2001 when a then new all-time peak was established, LMP exceeded $900 per MWh for 10 hours and exceeded $150 per MWh for 60 hours.

Average Hourly System-Wide Unweighted LMP

At $28.30 per MWh, the average hourly system-wide unweighted LMP for 2002 was 12.6 percent lower than for 2001 and at about the same level as in 2000 and 1999 (Table 2-7).

13 See Appendix A, "Energy Market," for methodological background and detailed price data and comparisons.

14 The simple average system-wide LMP is the average of the hourly LMP in each hour without any weighting.

Table 2-7—PJM Average Hourly Locational Marginal Prices[15] (in $/MWh)

	Locational Marginal Prices (LMP)			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2002	$28.30	$21.08	$22.40	-12.6%	-8.27%	-50.3%
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2000	$28.14	$19.11	$25.69	-0.6%	6.9%	-64.5%
1999	$28.32	$17.88	$72.41	30.4%	7.7%	130.2%
1998	$21.72	$16.60	$31.45			

Price Duration

New all-time peak demands were set on July 23, July 29, and August 14. On these days the three highest prices of 2002 also occurred for a duration of one hour each: $791 per MWh on July 29, $585 per MWh on July 23, and $445 per MWh on August 14. For the year, prices were above $150 per MWh for only 20 hours.

While prices during most hours generally reflect the interaction of demand and lower-price energy offers, prices on high load days may reflect a combination of market power and scarcity. The additional capacity provided by the PJM-West Region and new capacity built in PJM, however, caused a downward shift in the supply curve and a shifting to the right of the upward sloping portion of the supply curve. Thus in 2002, the shape of the supply curve meant that there were relatively few hours when scarcity existed or when there was an opportunity to exercise market power.

Figure 2-14 compares the PJM system-wide price duration curves for 1998, 1999, 2000, 2001 and 2002. A price duration curve shows the percent of hours that LMP was at or below a given price for the year. Figure 2-14 shows relatively little difference in LMPs for 60 percent of the hours in each of the five years, for 96 percent of the hours in 2000, 2001, and 2002, and for more than 96 percent of the hours in 1998 and 1999. Figure 2-15 compares price duration curves for hours above the 95th percentile. Figure 2-15 shows that, with the exception of 1999, prices generally exceeded $100 per MWh for about one percent or less of the hours.

Figures 2-14 and 2-15 show that LMP exceeded $900 per MWh in 1998, 1999 and 2001, but not in 2002. For 1998 and 1999, prices were greater than $900 per MWh for a total of 35 hours during the hot summer months. In 2001, prices rose to more than $900 per MWh for 10 hours during the week of August 6 when a new peak demand was set for that year. New all-time peak demand levels were set three separate times during the summer of 2002: on July 23, hour ending 1600; on July 29, hour ending 1700; and on August 14, hour ending 1600. Despite these demand spikes, however, prices in 2002 never exceeded $800 per MWh, exceeded $700 per MWh for only one hour, and exceeded $150 per MWh for 20 hours.

15 The hourly statistics were calculated from hourly-integrated PJM system-wide LMPs and MCPs for January to March 1998. MCP is the single market-clearing price calculated by PJM prior to implementation of LMP.

Figure 2-14

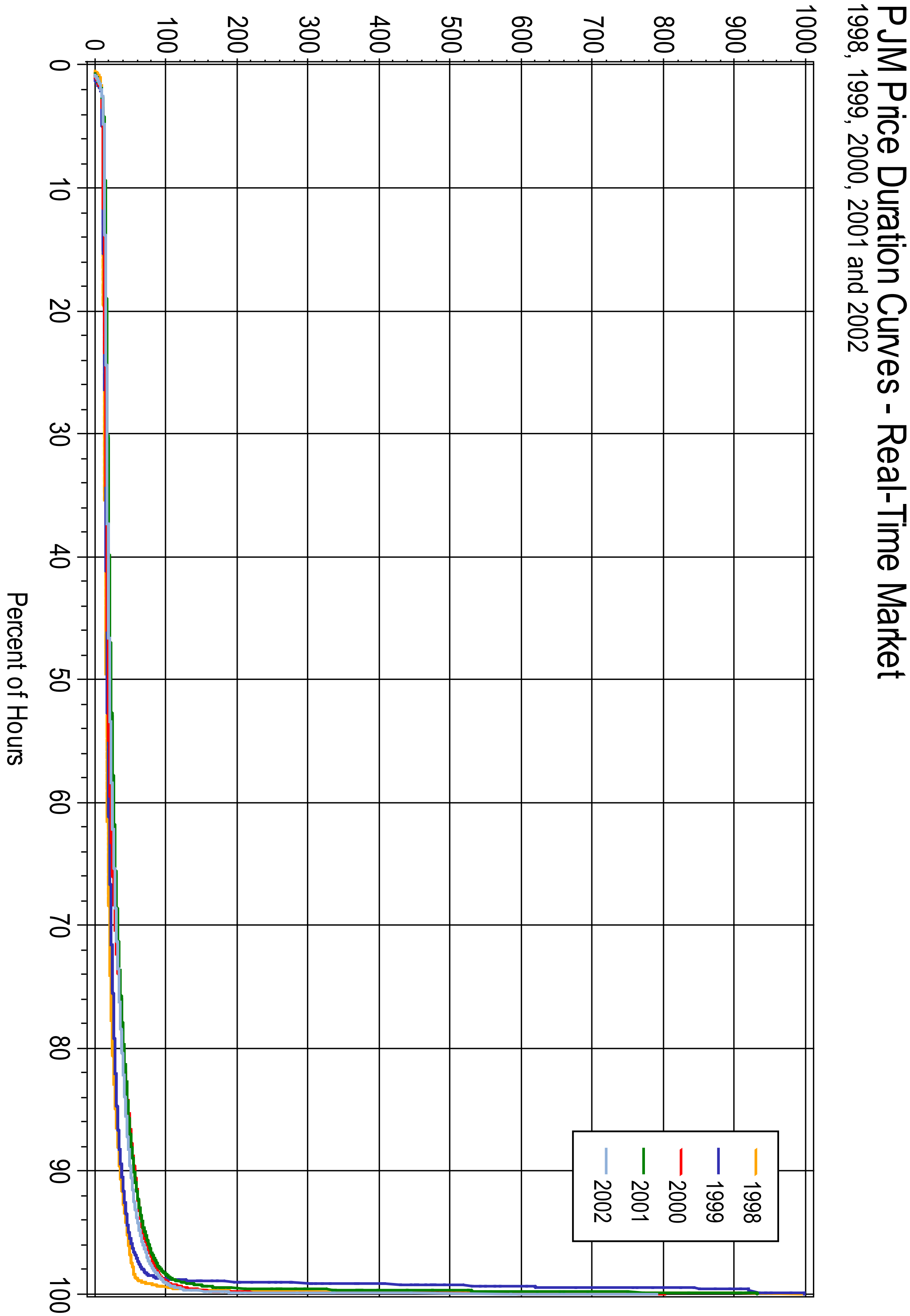
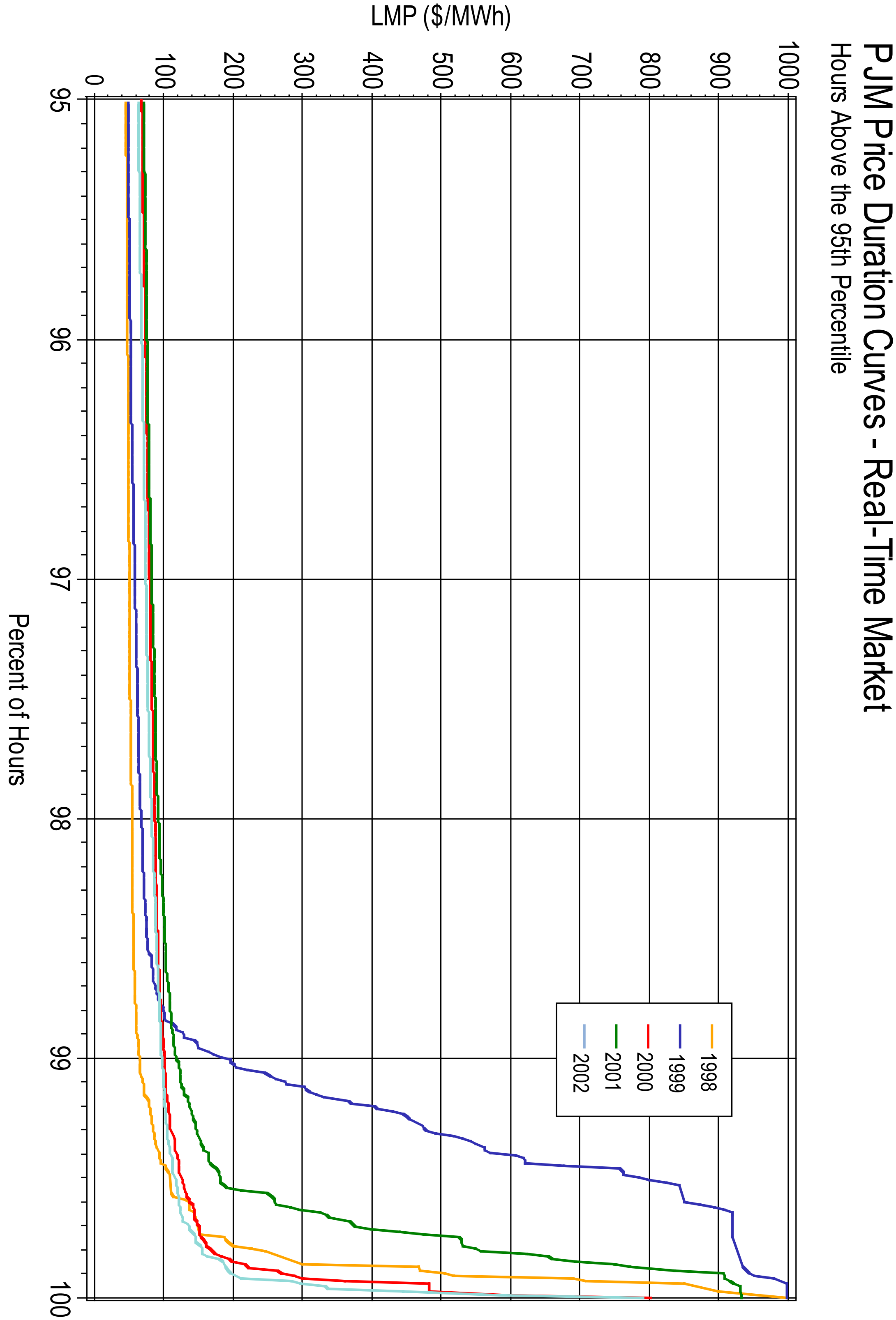

PJM Price Duration Curves - Real-Time Market
1998, 1999, 2000, 2001 and 2002
LMP ($/MWh)
Percent of Hours
1998
1999
2000
2001
2002

Figure 2-15


PJM Price Duration Curves - Real-Time Market
Hours Above the 95th Percentile
LMP ($/MWh)
0
100
200
300
400
500
600
700
800
900
1000
95
96
97
98
99
100
Percent of Hours
1998
1999
2000
2001
2002

Load

Table 2-8 presents summary load statistics for the five-year period 1998 to 2002. The average load of 35,551 MW in 2002 was 17 percent higher than in 2001, reflecting both growth in the traditional PJM Region and the addition of APS to the PJM Region. The variability of load, indicated by the standard deviation, was greater in 2002 than in 2001, although the significance of the 2002 standard deviation is questionable given that it reflects the addition of the PJM-West Region load.[16]

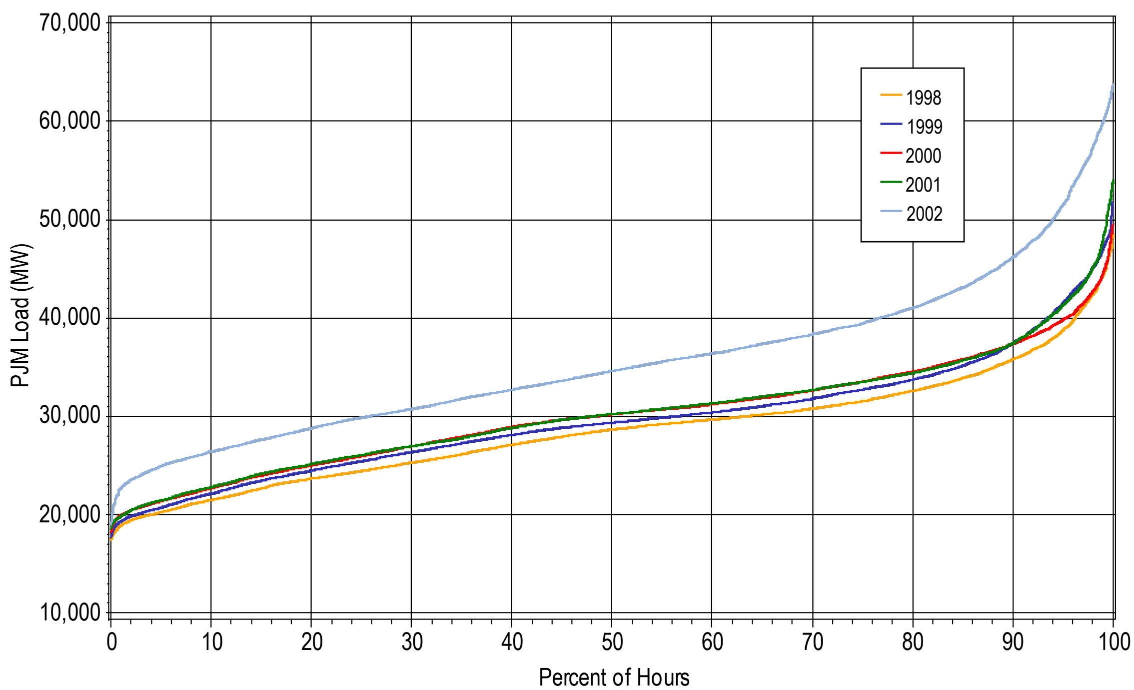
Table 2-8—PJM Load (in MW)

	PJM Load			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average Load	Median Load	Standard Deviation
2002	35,551	34,596	7,942	17.3%	14.5%	35.2%
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2000	30,113	30,170	5,529	1.6%	2.8%	-7.2%
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
1998	28,577	28,653	5,512			

Load Duration

Figure 2-16 shows load-duration curves for 1998, 1999, 2000, 2001 and 2002. A load duration curve shows the percent of hours that load was at or below a given level for the year. The graph shows the increase in both the average and peak loads.

Figure 2-16 PJM Hourly Load Duration Curve
1998, 1999, 2000, 2001 and 2002



16 See Appendix A, "Energy Market," for additional load frequency details, including on-peak and off-peak loads.

Load-Weighted LMP

Market participants typically purchase more energy during high-price periods as higher demand results in higher prices. As a result, when hourly load levels are reflected, the 2002 average hourly load-weighted LMP was about 12 percent higher than the simple average LMP.

Load-weighted LMP reflects the average LMP paid for actual MWh generated and consumed during a year. Hourly LMP is weighted by the total MW of load in each hour to derive load-weighted LMP.

Table 2-9 shows "PJM Load-Weighted, Average LMP" for 1998 to 2002. In 2002, load-weighted LMP fell to $31.60 per MWh, 14 percent lower than in 2001, three percent higher than in 2000, and seven percent lower than in 1999. [17]

Table 2-9—PJM Load-Weighted Average LMP (in $/MWh)

	Locational Marginal Price (LMP)			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2002	$31.60	$23.41	26.74	-13.8%	-6.7%	-53.3%
2001	$36.65	$25.08	57.26	19.3%	22.3%	101.8%
2000	$30.72	$20.51	28.38	-9.8%	7.8%	-69.0%
1999	$34.06	$19.02	91.49	41.0%	8.1%	132.9%
1998	$24.16	$17.60	39.29			

Fuel Cost and Price

Changes in prices can result from changes in unit costs. Fuel costs comprise the bulk of marginal costs for most generating units. To control for differences in fuel cost between 2001 and 2002, the 2002 load-weighted LMP was adjusted to reflect the price change of fuels used by the marginal units and for the change in marginal MW generated by each fuel type.[18]

Table 2-10 compares 2002 load-weighted, fuel-cost-adjusted, average LMP to 2001 load-weighted, average LMP. After adjustment for fuel price changes, average, load-weighted LMP in 2002 was 2.0 percent lower than in 2001. If fuel prices for both years had been the same, the 2002 load-weighted LMP would have been $35.93 per MWh instead of $31.60 per MWh.[19] This means that a significant portion of the 13.8 percent decrease in load-weighted LMP between 2001 and 2002 resulted from decreased fuel cost. The fact that lower fuel prices were reflected in lower energy market prices is consistent with the functioning of a competitive market.

17 See Appendix A, "Energy Market," for peak and off-peak load-weighted LMP details.

18 See Appendix A, "Energy Market," for fuel cost adjustment method.

19 See Appendix A, "Energy Market," for details on LMPs during constrained hours.

Table 2-10—Load-Weighted, Fuel-Cost-Adjusted LMP (in $/MWh)

	2002	2001	Percent Change
Average LMP	$35.93	$36.65	-2.00%
Median LMP	$28.31	$25.08	12.9%
Standard Deviation	$29.07	$57.26	-49.2%

Day-Ahead Market LMP

When the PJM day-ahead market was introduced on June 1, 2000, it was expected that competition would cause prices in the day-ahead and real-time markets to converge. As the following tables and graphs show, day-ahead prices were slightly greater than real-time prices ($0.16/MWh) on average during 2002.

Figure 2-17 shows 2002 price duration curves for the two markets, while Figure 2-18 shows 2002 price duration curves for hours above the 95th percentile. The two figures show that real-time and day-ahead prices were almost coincident for the lowest priced 80 percent of the hours, with some alteration in the pattern over the course of the hours. Real-time prices were slightly higher for most of the remaining 20 percent of the hours while the difference increased in the highest priced one percent of the hours.

Figure 2-19 compares average hourly day-ahead and real-time LMP for 2002. Although the average difference between the day-ahead and real-time markets was only $0.16 per MWh for the entire year, Figure 2-19 shows that there was considerable variation, both positive and negative, between day-ahead and real-time prices, especially during some peak season hours. Figure 2-20 shows the average hourly levels of real-time and day-ahead LMP.[20]

Table 2-11 presents summary statistics for the two markets. Average LMP in the day-ahead market was $0.16 per MWh or 0.6 percent higher than average LMP in the real-time market. The day-ahead median LMP was 10.4 percent higher than real-time LMP, reflecting an average difference of $2.19 per MWh. Consistent with the price duration curve, price dispersion in the real-time market was 26.7 percent greater than in the day-ahead market, with an average difference in standard deviation between the two markets of $4.72 per MWh.[21]

Table 2-11—Comparison of Real-Time and Day-Ahead 2002 Market LMP (in $/MWh)

	Day-Ahead	Real-Time	Difference	Difference as Percent Real-Time
Average LMP	$28.46	$28.30	-$0.16	0.6%
Median LMP	$23.27	$21.08	-$2.19	10.4%
Standard Deviation	$17.68	$22.40	$4.72	-21.1%

20 See Appendix A, "Energy Market," for more details on the frequency distribution of prices.

21 See Appendix A, "Energy Market," for more details relative to LMP on-peak and off-peak as well as during constrained hours.

Figure 2-17

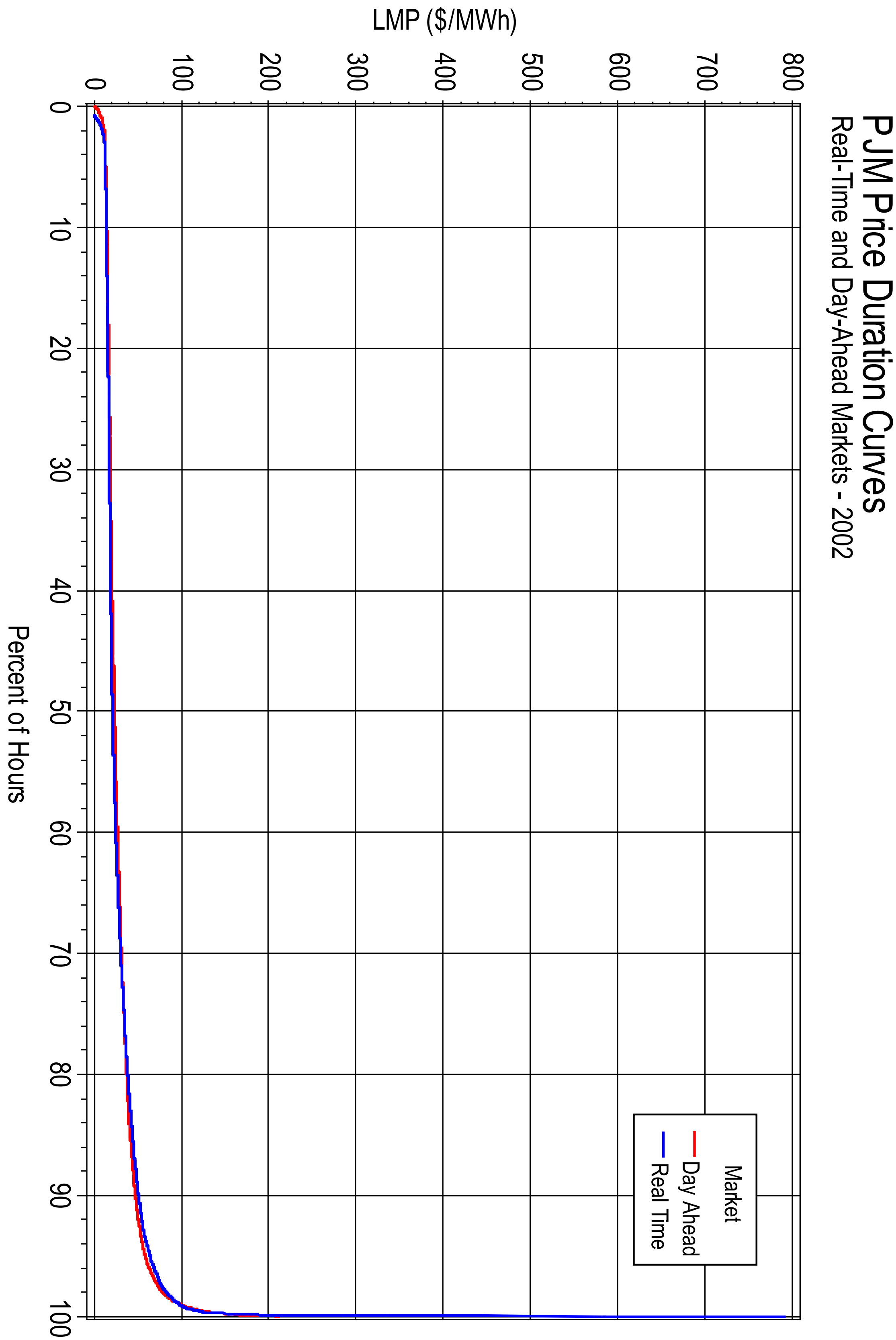

PJM Price Duration Curves
Real-Time and Day-Ahead Markets - 2002
LMP ($/MWh)
0
100
200
300
400
500
600
700
800
Percent of Hours
0
10
20
30
40
50
60
70
80
90
100
Market
Day Ahead
Real Time

Figure 2-18

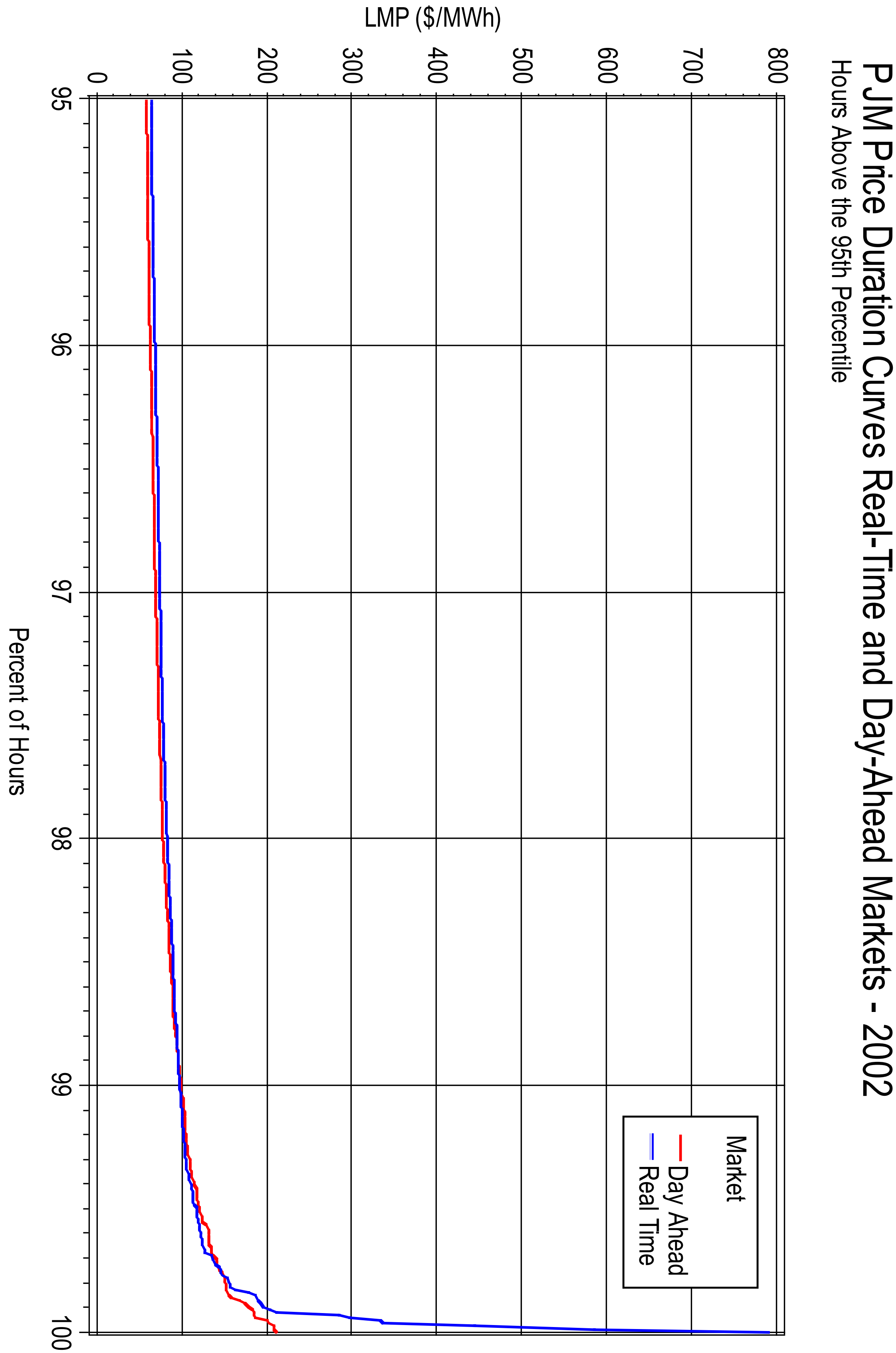

PJM Price Duration Curves Real-Time and Day-Ahead Markets - 2002
Hours Above the 95th Percentile
LMP ($/MWh)
0
100
200
300
400
500
600
700
800
95
96
97
98
99
100
Percent of Hours
Market
Day Ahead
Real Time

Figure 2-19

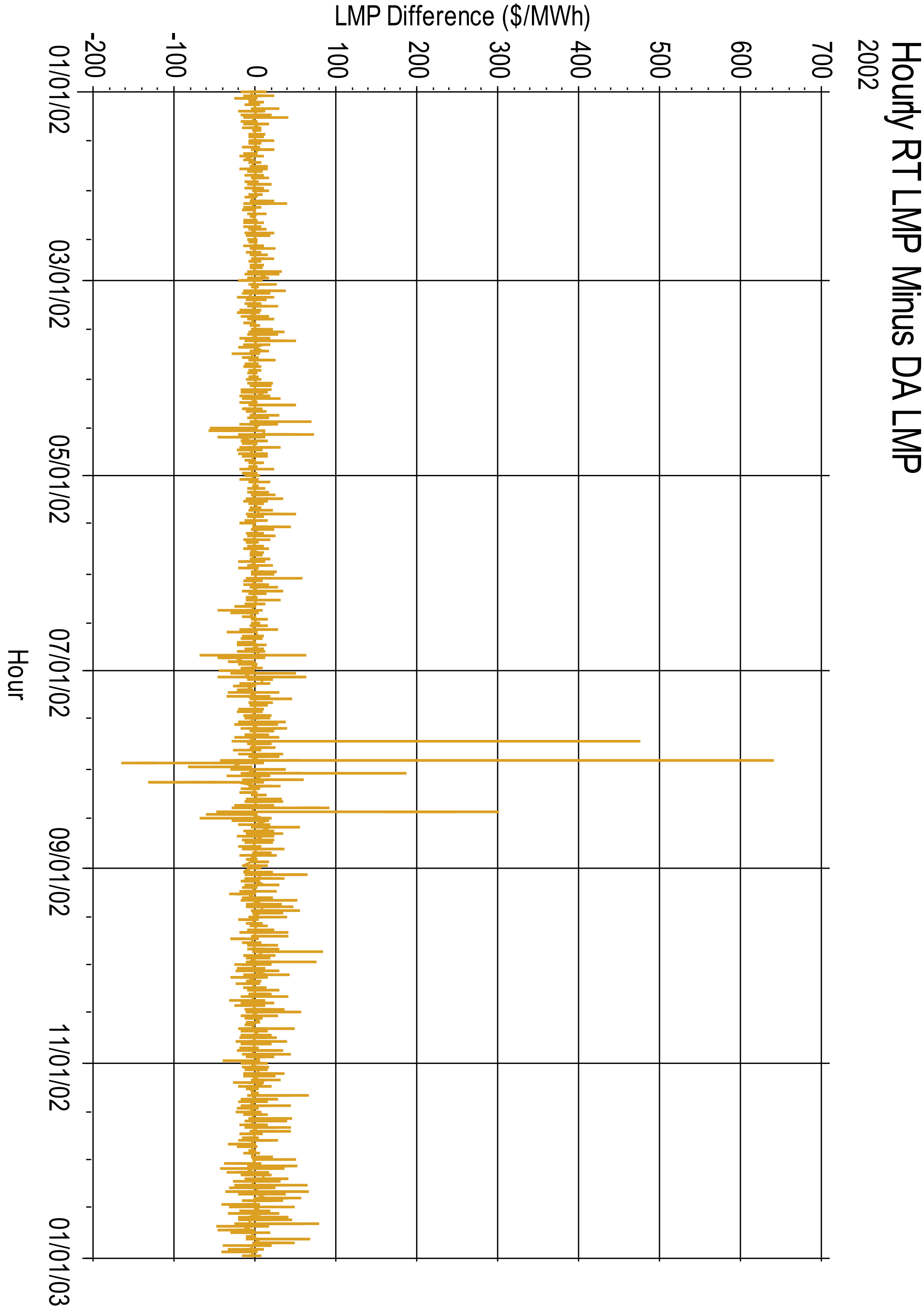
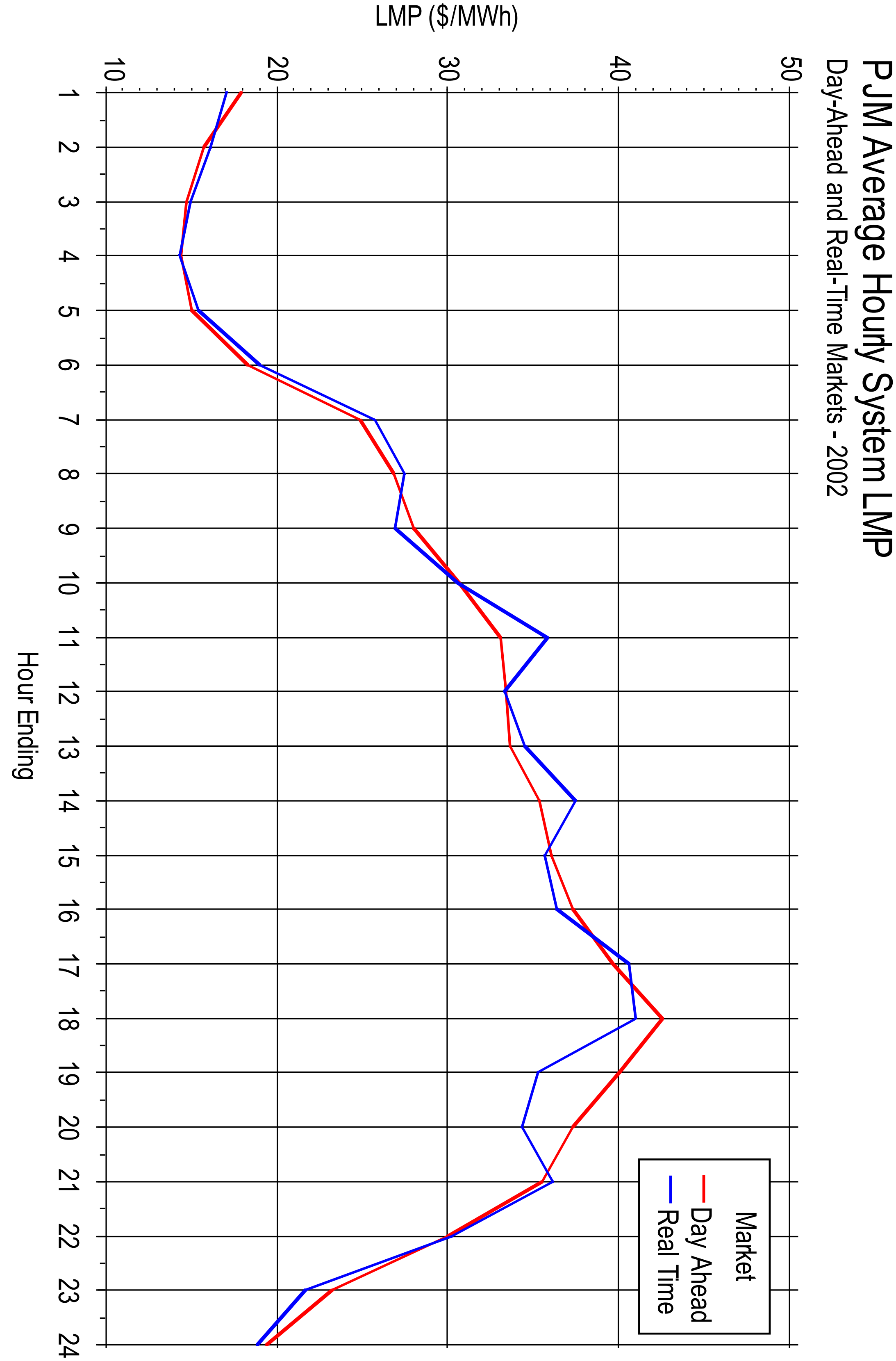

Hourly RT LMP Minus DA LMP
2002
LMP Difference ($/MWh)
-200
-100
0
100
200
300
400
500
600
700
Hour
01/01/02
03/01/02
05/01/02
07/01/02
09/01/02
11/01/02
01/01/03

Figure 2-20


PJM Average Hourly System LMP
Day-Ahead and Real-Time Markets - 2002
LMP ($/MWh)
10
20
30
40
50
Hour Ending
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Market
Day Ahead
Real Time

Day-Ahead and Real-Time Generation

Real-time generation is the actual production of electricity during the operating day.

In the day-ahead market, three types of financially binding commitments for generation are made and cleared:

- **Self-Scheduled.** Units submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
- **Generator Offers.** Schedules of MW offered and the corresponding offer price.
- **Increment Offers.** Financial offers to supply specified amounts of MW at or above a given price.

Figure 2-21 shows average hourly values of day-ahead generation, day-ahead generation plus increment offers, and real-time generation for 2002. Day-ahead generation is all generation cleared in the day-ahead market. During 2002, real-time generation was always higher than day-ahead generation. If, however, increment offers had been added to day-ahead generation, total day-ahead MW offers would have always exceeded real-time generation.

Table 2-12 presents summary statistics for the 2002 Day-Ahead and Real-Time Generation and the average differences between them. Day-ahead generation averaged 2,167 MW less than real-time generation. The sum of day-ahead generation offers and increment offers (financial day-ahead generation offers) was 7,587 MW higher than real-time generation.

Table 2-12—2002 Day-Ahead and Real-Time Generation (in MW)

	Day-Ahead		Real-Time	Average Difference	
	Generation	Increment Offers	Generation	Generation	Generation plus Increment Offers
Average MW	31,939	9,754	34,106	-2,167	7,587
Median MW	30,965	8,933	32,879	-1,914	7,019
Standard Deviation	7,620	3,187	8,657		

Figure 2-21 demonstrates that during 2002 differences between the two types of day-ahead generation offers and real-time generation were greatest during peak hours (i.e., hours ending 800 to 2300).

Figure 2-21 Real-Time and Day-Ahead Generation

Average Hourly Values - 2002

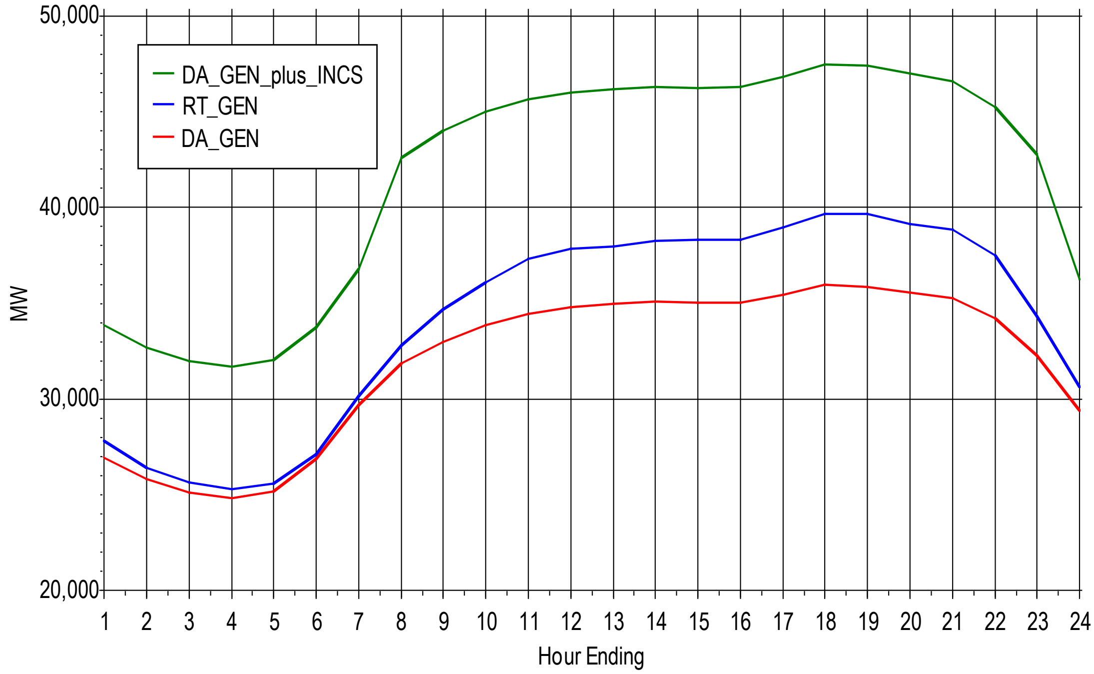


Table 2-13 shows the average MW values in the day-ahead and real-time markets during the off-peak and on-peak hours, while Table 2-14 shows the average differences during the two periods. Day-ahead generation was less than real-time generation in both periods. The average difference between day-ahead and real-time generation during off-peak hours was 1,074 MW, and the average difference during peak hours was 3,420 MW. The sum of day-ahead generation and increment offers (financial day-ahead generation offers) exceeded real-time generation during both periods. During off-peak hours, day-ahead generation plus increment offers averaged 6,319 MW more than real-time generation, and during peak hours, day-ahead generation plus increment offers averaged 9,402 MW more than real-time generation.

Table 2-13—2002 Day-Ahead and Real-Time On-Peak and Off-Peak Generation (in MW)

	Day-Ahead				Real-Time	
	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak
	Generation	Generation	Increment Offers	Increment Offers	Generation	Generation
Average MW	28,647	35,715	7,393	12,462	29,721	39,135
Median MW	27,685	35,823	7,088	11,897	28,295	38,039
Standard Deviation	6,153	7,387	1,376	2,431	6,630	7,946

Table 2-14—Average 2002 Difference Between Day-Ahead and Real-Time Markets (in MW)

	Off-Peak		On-Peak	
	Generation	Generation Plus Increment Offers	Generation	Generation Plus Increment Offers
Average MW Difference	-1,074	6,319	3,420	9,402
Median MW Difference	-610	6,478	2,216	9,681

Day-Ahead and Real-Time Load

Real-time load is the actual load on the system during the operating day. In the day-ahead market, three types of financially binding bids are made:

- **Fixed-Demand Bids.** Bids to purchase a defined MW level of energy, regardless of LMP.
- **Price-Sensitive Bids.** Bids to purchase a defined MW level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bids.** Financial bids to purchases a defined MW level of energy up to a specified LMP, above which the bid is zero. Decrement bids are financial bids that can be submitted by any market participant.

Figure 2-22 shows the average 2002 hourly values of day-ahead fixed demand, price-sensitive load, decrement bids, and total day-ahead and real-time load (total day-ahead load is the sum of the three demand components).

Table 2-15 presents summary statistics for the 2002 day-ahead load components, total day-ahead load, real-time load, and the average difference between total day-ahead load and total real-time load. As Figure 2-22 and Table 2-15 show, during 2002 total day-ahead load was higher than real-time load by an average of 6,580 MW. The table also shows that, at 74 percent, fixed demand was the largest component of day-ahead load. At seven percent, price-sensitive load was the smallest component, with decrement bids accounting for the remaining 19 percent of day-ahead load.

Table 2-15—2002 Day-Ahead and Real-Time Load (in MW)

	Day-Ahead				Real-Time	Average Difference
	Fixed Demand	Price Sensitive	Decrement Bids	Total Load	Total Load	
Average MW	31,310	2,943	7,878	42,131	35,551	6,580
Median MW	30,291	2,735	7,262	40,720	34,596	6,124
Standard Deviation	7,113	960	3,197	10,130	7,942	

As Figure 2-22 shows, except for price-sensitive demand, day-ahead load components increased during on-peak hours (hours ending 800 to 2300), as did real-time load. Table 2-16 shows the average load MW values in the day-ahead and real-time markets for 2002 during the off-peak and on-peak hours. Total day-ahead load was higher than real-time load during both off-peak and on-peak hours. The average difference during off-peak hours was 4,894 MW, while the average difference during on-peak hours was 8,512 MW. The percentage of day-ahead load comprised by each of the components was similar during the two periods. At 76 and 73 percent, fixed-demand accounted for the largest percentage of day-ahead load during off-peak and on-peak periods, respectively. Price-sensitive load, at eight and seven percent respectively, accounted for the smallest percentage during both periods while decrement bids accounted for 16 percent and 20 percent, respectively.

Table 2-16—2002 Day-Ahead and Real-Time Load During Off-Peak and On-Peak Hours (in MW)

	Day-Ahead								Real-Time	
	Off-Peak				On-Peak				Off-Peak	On-Peak
	Fixed_ Demand	Price Sensitive	Dec Bids	Total Load	Fixed Demand	Price Sensitive	Dec Bids	Total Load	Total Load	Total Load
Average	27,633	2,771	6,074	36,478	35,527	3,139	9,948	48,614	31,584	40,102
Median	26,566	2,494	5,827	35,386	33,534	2,975	10,515	47,856	30,457	38,243
Standard Deviation	5,241	1,012	2,047	6,961	6,622	856	3,021	9,277	6,044	7,400

Figure 2-23 shows day-ahead and real-time load and generation for 2002. For this analysis, increment offers were subtracted from total day-ahead load. Since increment offers look like generation, subtracting them from day-ahead load provided an estimate of day-ahead generation that had to be turned on to meet the load.

Figure 2-22 Real-Time and Day-Ahead Load

Average Hourly Values - 2002

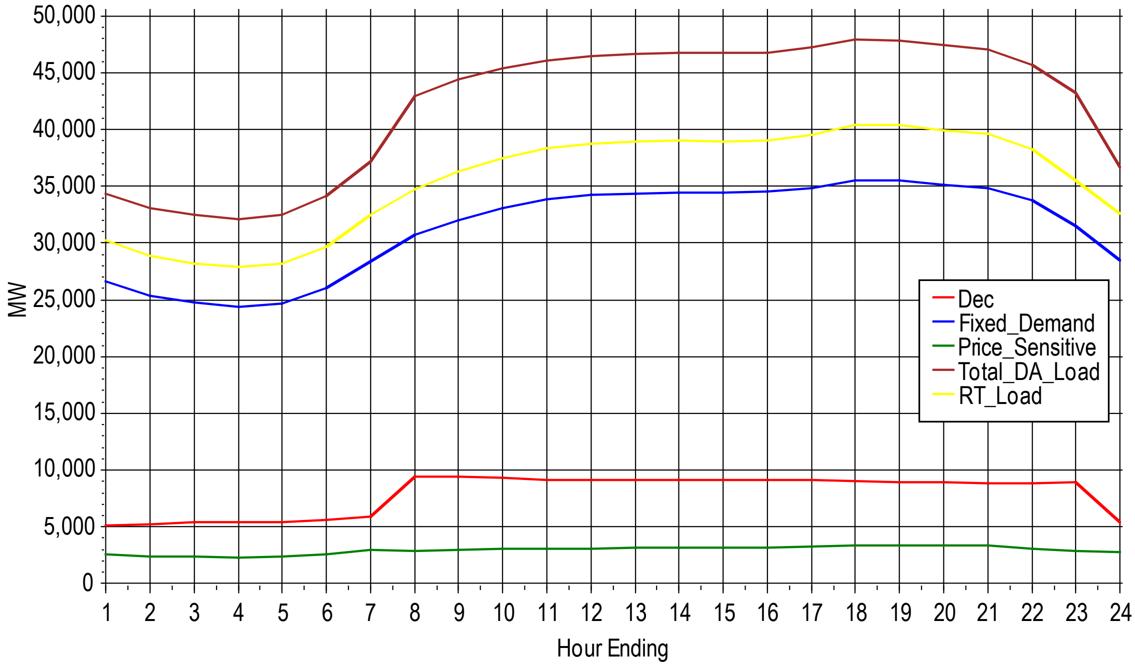


Figure 2-23 Real-Time and Day-Ahead Load and Generation

Average Hourly Values - 2002