SECTION 7—FTRS AND THE FTR AUCTION MARKET

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 Locational Marginal Price (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.[1]

OVERVIEW

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.

1 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.

A review of the operation of the FTR auction process in 2002 indicates that the FTR auction was competitive and succeeded in its purpose of increasing FTR access. There has been a steady increase in the MW of cleared FTRs. Trends in the number of bids, the number of offers and MW of bids have also been upward. The increases in the FTR auction clearing prices reflect the prices bid to purchase FTRs which were supplied from PJM residual capacity and tendered offers.

A significant change to the method of allocating FTRs was approved during 2002 and will be implemented for the planning year commencing June 1, 2003. The Network FTR Allocation Process will be discontinued and replaced with an Annual FTR Auction that will be used to allocate all FTRs. This change in the way FTRs are allocated will provide a market evaluation of FTR value and permit all participants who value FTRs to bid a corresponding price to purchase them. Network customers will be allocated FTR Auction Revenue Rights (ARRs), which are the right to collect the revenues from the FTR auction, based on the fact that network customers pay for the transmission system.

FTR AUCTION MARKETS

FTR Values

Tables 7-1a and 7-1b include FTR target allocations from the auctions for January through December 2002. The data cover the highest value transmission paths as measured by target allocations. FTR target allocations represent the amount of revenue needed to hedge FTR holders fully against the congestion on the purchased FTR paths. During this period, FTR target allocations totaled $452 million on approximately 3,100 different transmission paths.

- **Largest Financial Benefits.** Table 7-1a lists the 25 FTRs with the largest financial benefits for the period. These FTRs accounted for over $192 million, or approximately 42 percent, of the total target allocations. Most of them were from the westernmost part of the PJM Region to points east and many spanned the PJM-West Region 500, Bedington-Black Oak, and AP South Interfaces. Seven of these maintained their top 25 ranking from last year, and seven were from newly incorporated Allegheny Power System (APS) locations.

- **Largest Financial Liabilities.** Table 7-1b lists the 25 FTR paths with the largest financial liabilities for the period. These FTRs accounted for about $26 million, or 35 percent, of the $75 million negative target allocations. There was no clear directional pattern for these FTRs. Some were east-to-west, others were west-to-east; still others were local. None were FTRs that maintained their top 25 ranking from last year.

Results of the FTR Monthly Auction

PJM designed its FTR Monthly Auction to increase FTR availability. The auction has achieved that goal and done so in a competitive manner. As Tables 7-2a and 7-2b and the following figures demonstrate, auction activity has increased steadily since the inception of the FTR Monthly Auction.

Table 7-1—Target Allocations by Path

Table 7-1a	
25 Largest Financial Benefit	
Path	**Target Allocations**
Harrison Tap - APS Zone	$17,552,910
Hatfield - APS Zone	$16,046,035
Pleasants - APS Zone	$11,866,178
First Energy - PEPCO Zone	$10,996,082
Hatfield - PEPCO Zone	$10,284,163
Peach Bottom - PSEG Zone	$9,551,994
Handsome Lake - PENELEC Zone	$9,296,574
Fort Martin - PEPCO Zone	$9,206,308
Homer City - PSEG Zone	$8,973,324
Conemaugh - PSEG Zone	$7,624,013
Keystone - BGE Zone	$6,736,714
Fort Martin - APS Zone	$6,599,214
Susquehanna - PENELEC Zone	$6,476,313
Keystone - PSEG Zone	$6,431,005
Montour - PPL Zone	$6,109,690
Mitchell - PEPCO Zone	$6,011,975
Crane - PENELEC Zone	$5,546,154
Edgemoor - DPL Zone	$5,249,691
AEP - Western Hub	$5,119,345
AEP - APS Zone	$5,059,319
Burlington - PSEG Zone	$4,544,746
Mercer - PSEG Zone	$4,428,330
Keystone - PECO Zone	$4,383,433
Conemaugh - PECO Zone	$4,368,708
Warrior Run - PEPCO Zone	$4,088,924
Total – Above Paths	**$192,551,143**
Total – All Paths	**$451,880,796**

Table 7-1b	
25 Largest Financial Liability	
Path	**Target Allocations**
Peach Bottom - PSEG Zone	($2,945,303)
Crane - PENELEC Zone	($1,904,625)
Brunner Island - PPL Zone	($1,868,822)
Susquehanna - PENELEC Zone	($1,848,779)
Peach Bottom - PECO Zone	($1,373,070)
Burlington - PSEG Zone	($1,308,541)
Kent – DPL ODEC	($1,251,321)
Limerick – PECO Zone	($1,248,560)
Mercer - PSEG Zone	($1,240,523)
Calvert Cliffs - BGE Zone	($1,105,453)
Montour - PPL Zone	($1,036,629)
Harrison Tap - APS Zone	($1,026,664)
VAP - Western Hub	($888,120)
PEPCO Zone – Hatfield	($740,919)
Morgantown - PENELEC Zone	($723,467)
Perryman - PENELEC Zone	($713,320)
METED Zone – VAP	($623,704)
Muddy Run - PECO Zone	($603,676)
Chalk Point - METED Zone	($575,017)
Shawville – JCPL Zone	($534,107)
GPU – BGE Zone	($507,940)
PEPCO Zone - Fort Martin	($504,273)
Moser - PECO Zone	($478,655)
Morgantown - METED Zone	($443,914)
PENELEC Zone - Morgantown	($424,795)
Total – Above Paths	**($25,920,199)**
Total – All Paths	**($74,643,128)**

Table 7-2a—FTRs by Service Type

Period	FTRs (in MW)				Percent of Total			FTRs (in MW)	% Total
	Network	Pt. To Pt.	On-Peak Auction	Total (MW)	Network (%)	Pt. To Pt. (%)	On-peak Auction (%)	Secondary (MW)	Secondary (%)
May-99	30,684	607	357	31,648	97%	2%	1%	0	0%
Jun-99	29,808	1,107	184	31,099	96%	4%	1%	4,349	14%
Jul-99	28,058	1,107	708	29,873	94%	4%	2%	4,349	15%
Aug-99	32,144	1,107	873	34,124	94%	3%	3%	4,349	13%
Sep-99	32,144	1,107	1,721	34,972	92%	3%	5%	4,349	12%
Oct-99	31,550	1,107	1,729	34,386	92%	3%	5%	4,349	13%
Nov-99	31,178	1,107	1,874	34,159	91%	3%	5%	4,349	13%
Dec-99	31,178	1,107	1,332	33,617	93%	3%	4%	4,349	13%
Jan-00	30,936	750	2,817	34,503	90%	2%	8%	4,349	13%
Feb-00	30,936	750	2,567	34,253	90%	2%	7%	4,349	13%
Mar-00	30,936	750	2,585	34,271	90%	2%	8%	4,349	13%
Apr-00	30,936	750	3,565	35,251	88%	2%	10%	4,349	12%
May-00	30,981	750	2,396	34,127	91%	2%	7%	4,349	13%
Jun-00	30,213	750	3,752	34,715	87%	2%	11%	4,501	13%
Jul-00	29,916	750	2,718	33,384	90%	2%	8%	4,501	13%
Aug-00	30,053	750	3,838	34,641	87%	2%	11%	4,501	13%
Sep-00	30,038	250	4,026	34,314	88%	1%	12%	4,501	13%
Oct-00	30,038	250	3,966	34,254	88%	1%	12%	4,501	13%
Nov-00	29,655	250	3,017	32,922	90%	1%	9%	4,501	14%
Dec-00	29,655	250	7,311	37,216	80%	1%	20%	4,501	12%
Jan-01	24,620	150	8,396	33,166	74%	0%	25%	4,501	14%
Feb-01	28,986	150	4,950	34,086	85%	0%	15%	4,501	13%
Mar-01	29,062	150	3,021	32,233	90%	0%	9%	4,501	14%
Apr-01	29,019	150	6,464	35,633	81%	0%	18%	4,501	13%
May-01	29,018	150	3,528	32,696	89%	0%	11%	4,501	14%
Jun-01	23,497	150	1,131	24,778	95%	1%	5%	2,499	10%
Jul-01	23,497	150	2,083	25,730	91%	1%	8%	2,499	10%
Aug-01	23,497	150	2,097	25,744	91%	1%	8%	2,499	10%
Sep-01	23,497	150	2,788	26,435	89%	1%	11%	2,499	9%
Oct-01	22,341	150	3,776	26,267	85%	1%	14%	2,499	10%
Nov-01	22,197	150	2,233	24,580	90%	1%	9%	2,499	10%
Dec-01	22,234	150	2,923	25,307	88%	1%	12%	2,499	10%
Jan-02	21,648	290	4,634	26,572	81%	1%	17%	5,045	19%
Feb-02	22,079	290	3,520	25,889	85%	1%	14%	4,152	16%
Mar-02	21,740	290	3,471	25,501	85%	1%	14%	5,146	20%
Apr-02	29,283	384	9,713	39,380	74%	1%	25%	5,146	13%
May-02	29,283	302	3,961	33,546	87%	1%	12%	3,563	11%
Jun-02	27,491	302	3,866	31,659	87%	1%	12%	8,912	28%
Jul-02	28,224	302	5,011	33,537	84%	1%	15%	8,902	27%
Aug-02	27,242	602	8,678	36,522	75%	2%	24%	8,921	24%
Sep-02	27,239	300	10,613	38,152	71%	1%	28%	9,071	24%
Oct-02	27,662	300	8,230	36,192	76%	1%	23%	9,071	25%
Nov-02	27,810	215	11,263	39,288	71%	1%	29%	9,071	23%
Dec-02	28,259	216	8,701	37,176	76%	1%	23%	9,071	24%

Tables 7-2a and 7-2b present FTR data by type. The data show that 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, which was 29 percent of all FTRs for the month. About 15 percent of FTRs were traded on the secondary FTR market on average. These tables and Figure 7-1 show that network FTRs have decreased from 94 percent of all FTRs in 1999 to 79 percent in 2002. Point-to-point FTRs have represented overall only about one percent of all FTRs.

Table 7-2b—Annual Mean FTRs by Service Type

Period	FTRS				Percent of Total			FTRs	% Total
	Network	Pt. To Pt.	On-Peak Auction	Total (MW)	Network (%)	Pt. To Pt. (%)	On-Peak Auction (%)	Secondary (MW)	Secondary (%)
1999	30,843	1,045	1,097	32,985	94%	3%	3%	3,805	12%
2000	30,358	583	3,547	34,488	88%	2%	10%	4,438	13%
2001	25,122	150	3,616	28,888	87%	1%	12%	3,333	11%
2002	26,497	316	6,805	33,618	79%	1%	20%	7,173	21%
Total	27,965	476	4,009	32,450	87%	1%	12%	4,767	15%

It is usually assumed that a cleared FTR buy bid reduces available FTRs and that a cleared FTR sell offer increases available FTRs. Neither is always correct. For example, when an interface is constrained west-to-east, both a west-to-east FTR sell offer and an east-to-west buy bid would make more FTRs available in the direction of congestion.

In previous reports, all buy bids were categorized as purchases regardless of whether the buy bid was in the same or the opposite direction as the congested flow. Data in Tables 7-2a and 7-2b reflect this convention. This report's figures, however, categorize bids and offers as buys or sells based on whether they are in the same or the opposite direction as the congested flow.

Figure 7-1 FTRs as a Percentage of Total by Service Type

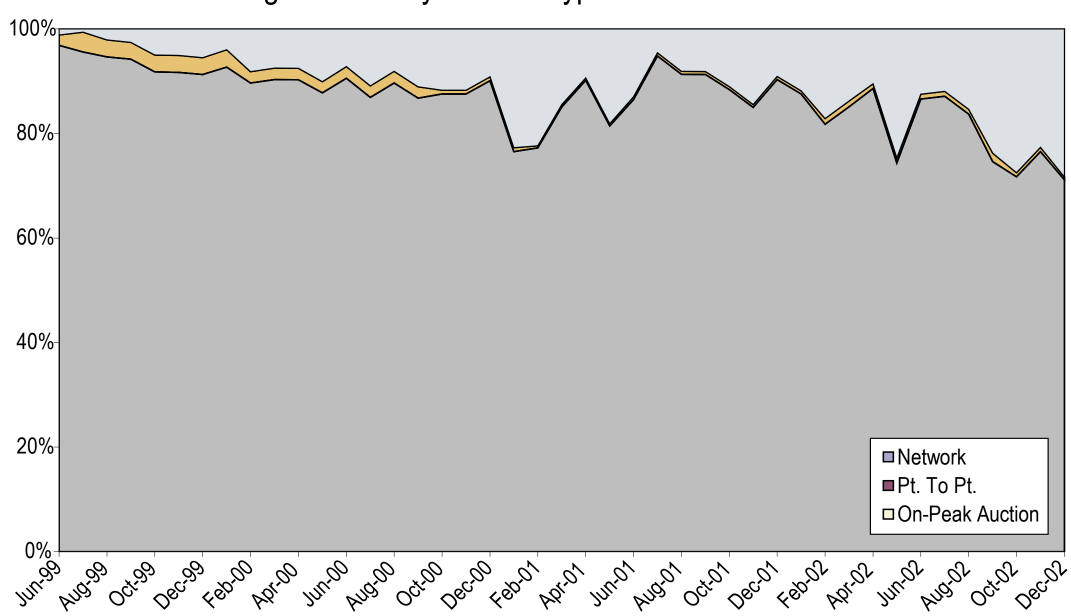


Figure 7-2, "FTR Monthly Auction, FTR Cleared Volume and Net Revenue," depicts the total cleared bid and offer volume in MW-months together with the total auction revenue generated each month. Average monthly auction revenue grew from $30,000 per month in 1999 to over $350,000 in 2000. Revenue doubled in each of the subsequent years, increasing to just over $600,000 and $1.2 million per month in 2001 and 2002, respectively. Total cleared bid and offer volume increased from 2,300 MW-months in 1999 to 6,700 MW-months in 2000, and 7,000 MW-months in 2001. 2002 saw a significant increase in volume to 11,500 MW-months. The $18 million of auction revenue produced in 2002 was more than the $12 million than had been produced in all three previous years combined. As of December 31, 2002, $30 million of net revenue had been produced by the FTR Monthly Auction and distributed to transmission owners and customers.

Figure 7-2 FTR Monthly Auction
FTR Cleared Volume and Net Revenue

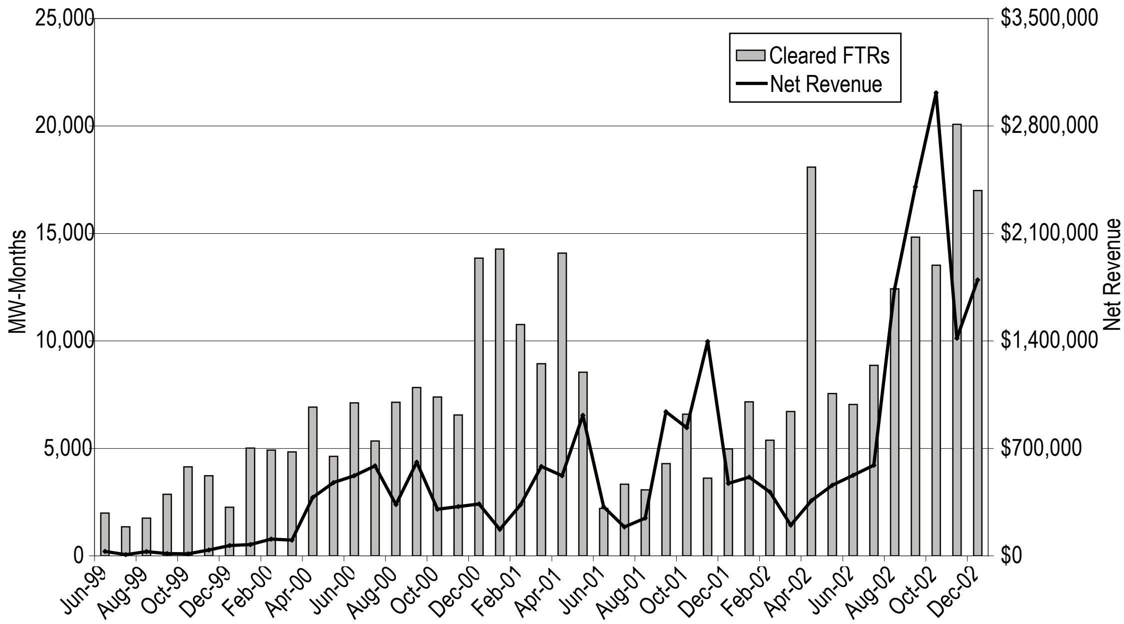


Figure 7-3, “FTR Monthly Auction, Bid and Offer Volume and Average Buy Bid Clearing Price,” presents the MW volume of the submitted and cleared bids and offers. It shows that over the life of the auction, bid volume has far exceeded offer volume by nearly a 10:1 ratio, 45,000 versus 5,500 MW per month on average. Bid volume increased from nearly 6,000 MW in 1999 to 35,000 MW in 2000, and 78,000 MW in 2001, dropping somewhat to 52,000 MW in 2002. Offer volume averaged about 3,900 MW in 2000 and 2001 and increased to 7,000 MW 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 during the same period, with cleared bids exceeding cleared offers by 1,300 MW per month on average. Based on these comparative volumes, it can be concluded that approximately two-thirds of cleared bids were supplied from cleared offers while one-third were drawing on residual system capacity.

Figure 7-3 FTR Monthly Auction
Bid and Offer Volume and Average Buy Bid Clearing Price

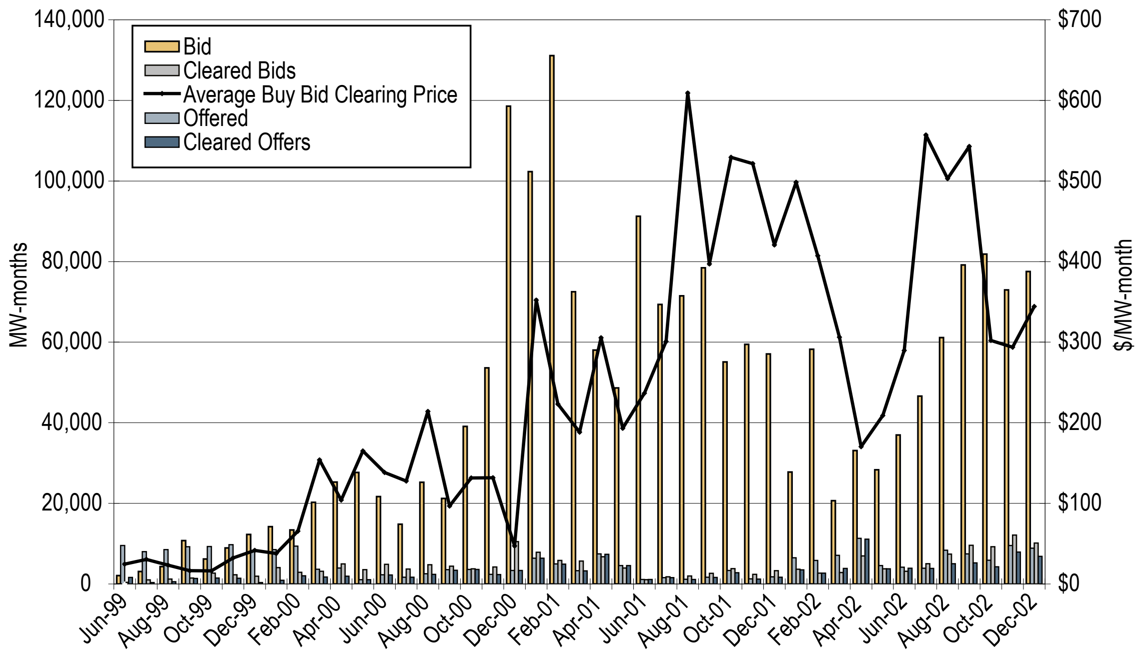
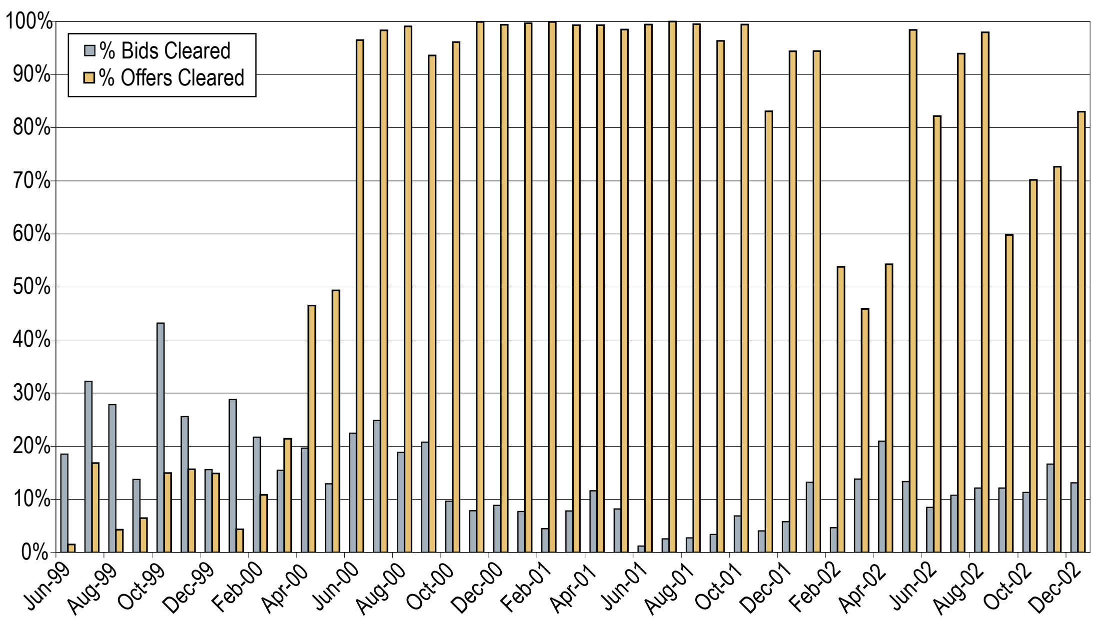


Figure 7-4, "FTR Monthly Auction, Percentage of Bid and Offer Volume Cleared," presents the percentage of bids and offers that cleared. On average, 15 percent of bids and 69 percent of offers cleared. These statistics are based on the convention that classifies buy or sell auction transactions as bids or offers based on whether the transaction consumed or released transmission capability, with the former classified as buy bids and the latter as sell offers, regardless of market participant intent. This distinction is important because FTRs are directional and some market participants that "buy" FTRs in the wrong direction, i.e., counter to constrained flow, actually are releasing transmission capability, genuinely selling, in the constrained direction of flow across the constrained facility. Because they are releasing transmission capability, these bids always clear and these market participants receive actual auction revenue. When congestion occurs on the system, however, these wrong-way FTRs become a financial liability rather than a benefit and end up costing the buyer money. Based on this convention (which differs from previous versions) and after discounting the start-up year of 1999, the PJM Market Monitoring Unit (MMU) found that cleared buy bids averaged about 12 percent of all bids during the period from 2000 through 2002, while cleared offers constituted 82 percent of all offers during the same period. As shown, during 2001 nearly all offers cleared, 97 percent on average per month. This dropped to 74 percent in 2002. The decline in this measure might have occurred because market participants had stopped "buying" FTRs in the wrong direction, i.e., counter to congestion, as evidenced by the relative decrease in negative target allocations.

Figure 7-4 FTR Monthly Auction
Percentage of Bid and Offer Volume Cleared



Figures 7-5 through 7-8 examine the FTR sources and sinks bought and sold that had the greatest amounts of associated auction revenue. Figure 7-5, "Ten Highest Revenue Producing FTR Sinks Purchased," depicts the revenue and MW volume of the 10 FTR sinks purchased in the auction that produced the most revenue. Six of these 10 are located in Eastern PJM, and these 10 accounted for 51 percent of all FTR bid revenue produced. Also popular were the Western Hub, which was the most active trading hub for energy, the PJM/NYIS Interface, and PENELEC and PPL Zones.

Figure 7-5 FTR Monthly Auction
Ten Highest Revenue Producing FTR Sinks Purchased Revenue and Volume

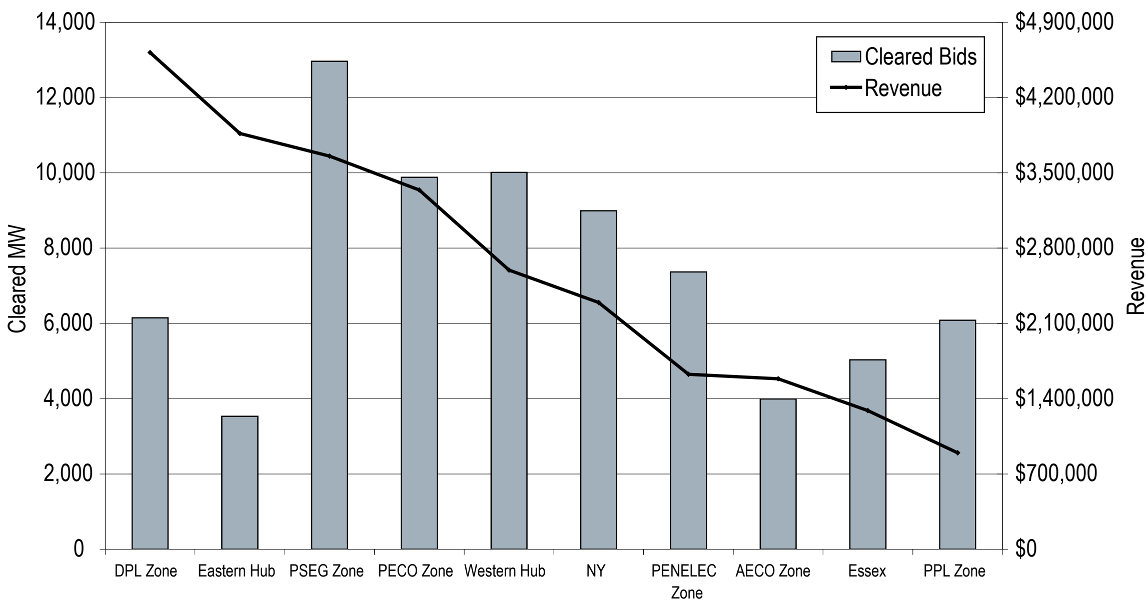


Figure 7-6, "FTR Monthly Auction, Ten Highest Revenue Producing FTR Sinks Sold," depicts the revenue and MW volume of the 10 FTR sinks sold in the auction that produced the most revenue. Six of these 10 are located in Western PJM, and these 10 accounted for 42 percent of all FTR offer revenue produced, with just the Western Hub, which was the most active trading hub for energy, accounting for eight percent of revenue. Also popular were the PSEG, PECO, JCPL, and DPL Zones in the PJM-East Region.

Figure 7-6 FTR Monthly Auction

Ten Highest Revenue Producing FTR Sinks Sold Revenue and Volume

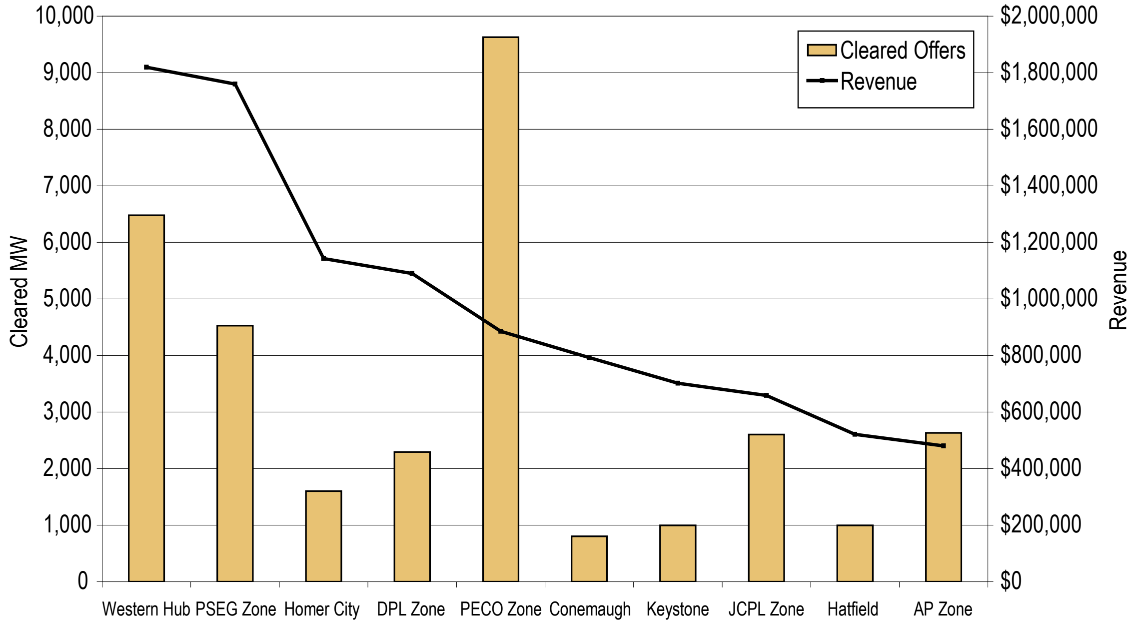


Figure 7-7, "FTR Monthly Auction, Ten Highest Revenue Producing FTR Sources Purchased," depicts the revenue and MW volume of the 10 FTR sources that produced the most revenue. Five of these 10 are located in Western PJM, and these 10 accounted for 46 percent of all FTR bid revenue produced, with the Western Hub alone accounting for 19 percent of revenue. Also popular were PECO, JCPL, and PEPCO Zones and the NYISO Interface.

Figure 7-7 FTR Monthly Auction

Ten Highest Revenue Producing FTR Sources Purchased Revenue and Volume

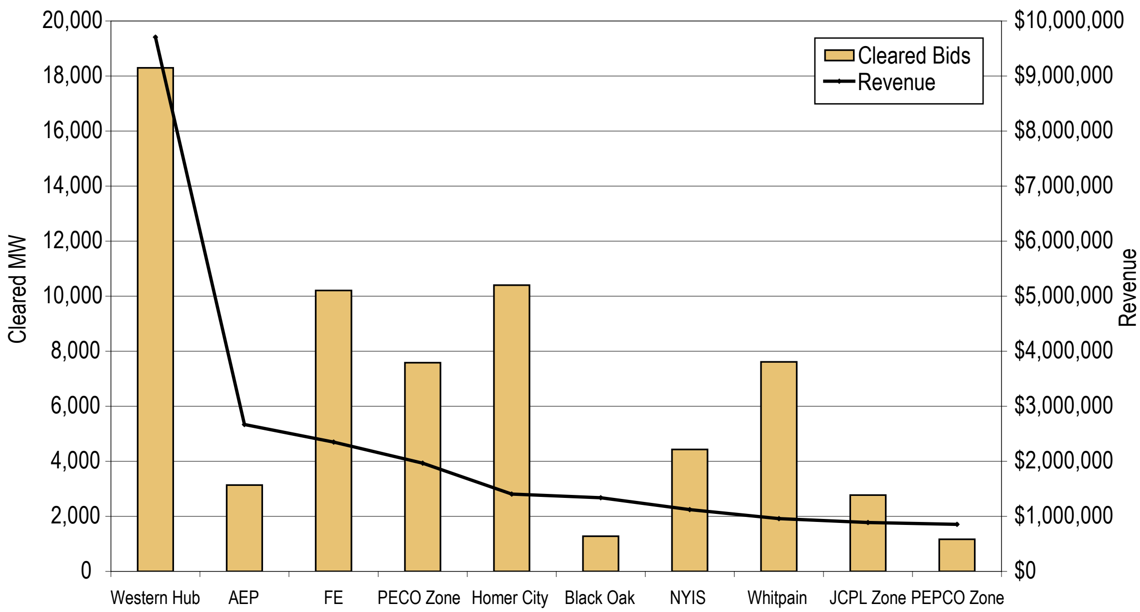
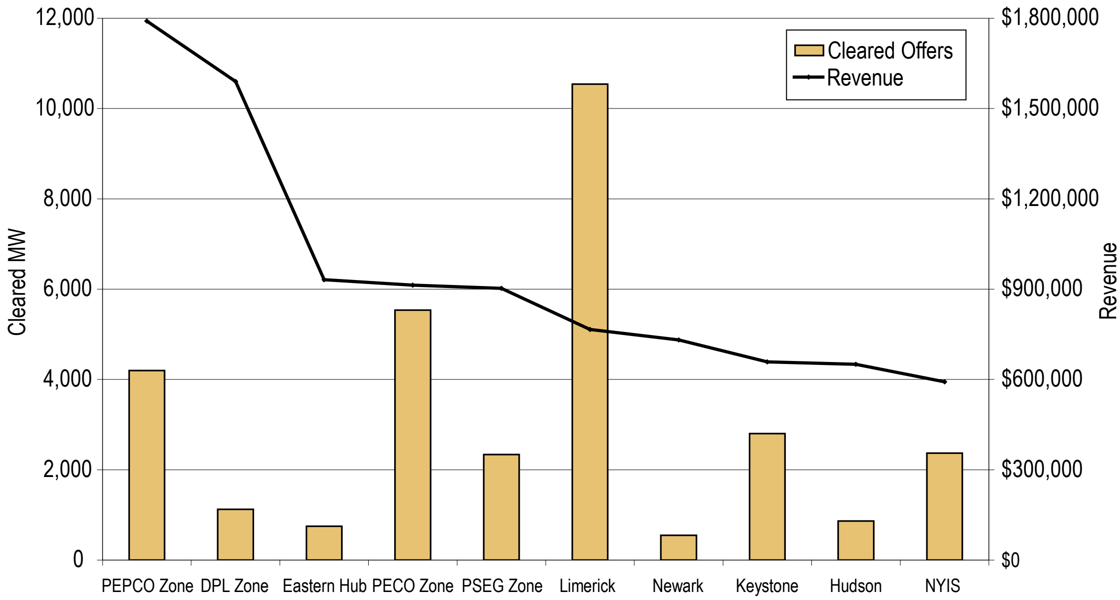


Figure 7-8, "FTR Monthly Auction, Ten Highest Revenue Producing FTR Sources Sold," presents the revenue and MW volume of the 10 FTR sources sold that produced the most revenue. Seven of these 10 are located in Eastern PJM, and these 10 accounted for 41 percent of all FTR offer revenue produced. Also popular were the PEPCO Zone, Keystone Substation, and the NYISO Interface.

Figure 7-8 FTR Monthly Auction

Ten Highest Revenue Producing FTR Sources Sold Revenue and Volume



GLOSSARY

Active load management	Active load management applies to PJM customers whose load can be interrupted at PJM's request. Such requests are emergency actions made prior to voltage reductions.
AECI	The Associated Electric Cooperative, Inc. control area.
Aggregate	Combination of buses or bus prices.
ALM	Active load management.
Ancillary service	A service provided to support the operating system for reliability and/or power flow.
Average hourly unweighted LMP	The simple, average hourly, system-wide LMP is calculated by averaging the hourly LMP without any weighting.
Base load	The quantity of generation that exists continuously during the period.
Bilateral agreement	A formal arrangement between two parties for the sale and delivery of a service.
Black start unit	A generating unit that is able to start without an outside electrical supply or the demonstrated ability of a base load unit to remain operating, at reduced levels, when automatically disconnected from the grid.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the RAA. Such entitlements may not include any entitlement to the output of the capacity resource.
Capacity credit market	The capacity credit market is operated by PJM. It encompasses the clearing of capacity credit trades for short-term daily and longer-term interval, monthly and multi-monthly capacity resources.
Capacity markets	Any market where PJM members can trade capacity.
Capacity resource	Capacity which is either committed to serving capacity obligations within PJM or capacity from resources within the PJM Region which are accredited to the PJM Region per the "Reliability Assurance Agreement" (RAA).
CCM	Capacity Credit Market.
CCT	Combined-cycle turbine.
CDR	Capacity-Deficiency Rate.

Combined-cycle turbine	A combined-cycle system generally consists of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine	A generating unit in which a combustion turbine engine is the prime mover. Combustion turbines have rapid ramp up and, therefore, are commonly used for peak shaving.
Constraint hour	Any hour in which there is at least one constraint.
CT	Combustion turbine.
Day-ahead market	Day-ahead market conditions are forecasted based on least-cost, security-constrained unit commitment and security-constrained economic dispatch. Hourly LMPs are calculated for the next operating day using generation offers, demand bids and bilateral agreement schedules.
Decrement bids	Purchases of a defined MW level of energy up to a specified LMP; above that LMP, the bid is zero. Decrement bids are financial bids that can be submitted by any market participant.
Demand-side management	Program designed to provide an incentive to end-use customers or curtailment service providers to enhance the ability and opportunity for reduction of load when PJM LMPs are high.
Dispatch rate	The control signal, expressed in $ per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the PJM OI in accordance with the offer data.
DSM	Demand-side management.
ECAR	The East Central Area Reliability Coordination Agreement which is one of the NERC Regional Councils.
End-use customer	For purposes of this discussion, an end-use customer is any customer purchasing electricity at retail. Customers may or may not be formal PJM members.
Exports	Exports are the sum of all external transactions where all or part of an internal generating unit is removed from capacity resource status to sell the capacity to a destination outside the PJM Region. Exports of capacity mean that the capacity is delisted from its capacity resource status in PJM.
External resource	A resource located outside metered PJM boundaries.
FERC	United States Federal Energy Regulatory Commission.
Firm point-to-point transmission	Transmission service that is reserved and/or scheduled between specified points of receipt and delivery.

Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility, or other event.
Fixed demand bid	Purchases of a defined MW level of energy, regardless of LMP.
Fixed transmission rights	These are financial instruments entitling their holders to receive revenues based on transmission congestion measured as the hourly energy LMP differences in the day-ahead market measured across a specific path.
FTR	Fixed transmission rights.
FTR auction revenue rights	Rights to collect revenues from the FTR auction that will be allocated to PJM firm transmission service customers after the annual FTR auction is implemented during the planning year that begins on June 1, 2003.
Generation offers	Schedules of MW offered and the corresponding offer price.
Generator owner	A PJM member, that owns or leases with rights equivalent to ownership, facilities for generation of electric energy that are located within the PJM Region.
Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as Accounted-for Deficiency.
Gross excess	The sum of all LSE's individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as "Accounted-for Excess" in the "PJM Accounted-For Obligation Manual" (Manual 17).
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market shares of all firms in a market.
Hertz (hz)	Electricity system frequency is measured in hertz. Hertz measures 60 hz in US electric markets and 50 in those in Europe and many other parts of the world.
ICAP	Installed capacity.
Imports	The sum of all external transactions where a qualified external resource is designated as a PJM capacity resource. Capacity imports from external units must be certified as deliverable using firm transmission, and non-recallable by any external party.
Increment offers	Financial offers to supply specified amounts of MW at or above a given price.

Installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources. Installed capacity can change daily, principally because of exports (delisting) and imports of capacity or a physical change to a generating unit.
Installed capacity market	All arrangements by which load-serving entities acquire capacity comprise the installed capacity market. Arrangements may include self-supply, various bilateral contracts and associated capacity credits.
Intermediate load	The quantity of generation that exists between the base load quantity and the peak load quantity during the period.
Internal bilateral transactions	Bilateral transactions of capacity where the source and sink are internal to the PJM Region. Internal bilateral transactions may reflect capacity credits or unit-specific transactions.
Interval market	The capacity market rules provide for three interval markets, covering the months from January through May, June through September, and October through December.
LMP	Locational marginal price.
Load	Demand for electricity at a given time.
Load aggregator	This is an entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
Load-response program	A PJM demand management program whereby end-use customers may agree to verifiably shed load on an economic basis based either on day-ahead or real-time market conditions.
Load-serving entity	Load-serving entities provide electricity to end-use customers under a host of arrangements, including franchise, load aggregation and bilateral contracts. Load-serving entities may be traditional distribution utilities and new entrants into the competitive power markets.
Locational marginal price	The system PJM uses to price energy and congestion costs for its Region. The technique is based on actual system operating conditions and energy flows and not on contracted paths. It is the cost of supplying the next MW at a specific location at a given time including generation marginal cost plus any transmission congestion cost.
LSE	Load-serving entity.
MAIN	The Mid-American Interconnected Network, Inc. which is one of the NERC Regional Councils.

MAPP	The Mid-Continent Area Power Pool which is one of the NERC Regional Councils.
Marginal unit	This is the next generation unit to be used to supply power under a merit order dispatch system.
Market-clearing price	The price, when the market is in equilibrium, paid by all load and paid to all suppliers.
Market Monitoring Unit	A division of PJM established to monitor and to report on issues associated with operation of the PJM power market including: • Determining transmission congestion costs or the potential of any market participant(s) to exercise market power within the Region; • Evaluating operation of both pool and bilateral markets to detect either design flaws in the operating rules, standards, procedures, or practices as set forth in the PJM Tariff, the "PJM Operating Agreement," the "PJM Reliability Assurance Agreement," the PJM manuals, or "PJM Regional Practices Document" or to detect structural problems in the PJM market that may need to be addressed in future filings; • Evaluating proposed enforcement mechanisms needed to assure pool rule compliance; and • Ensuring the monitoring program is conducted in an independent and objective manner.
Market participant	A PJM member who has met reasonable credit-worthiness standards and is otherwise able to make sales and/or purchases through the PJM Interchange Energy Market, the PJM-East Region Capacity Credit Market or the PJM-West Region Capacity Credit Market.
Markup index	Marginal unit price bid versus the cost bid of the same unit.
MCP	Market-clearing price.
Mean	The arithmetic average.
Median	The midpoint of data values. Exactly half the values are above and half below the median.
Megawatt (MW)	A megawatt is 1,000 kilowatts. A kilowatt is 1,000 watts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt hour (MWh)	An MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Merit order of dispatch	Generators are used or dispatched in order of their offering prices, from the lowest to the highest.

MMU	Market Monitoring Unit.
Monthly CCMs	The capacity credits cleared through PJM single month capacity credit markets (CCMs).
Multi-monthly CCMs	The capacity credits cleared through PJM multi-monthly capacity credit markets (CCMs).
NERC	North American Electric Reliability Council.
Net excess	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of LSE's obligations.
Net exports	Capacity exports (or delists) less capacity imports.
Network transmission service	Transmission service provided pursuant to rates, terms and conditions set forth in the tariff.
Nodal prices	The price of real power at predefined PJM system nodes.
North American Electric Reliability Council	A voluntary organization of US and Canadian utilities and power pools established to assure the coordinated operation of the interconnected transmission systems.
OA	The "PJM Operating Agreement" dated March 28, 1997, and amended from time to time.
Obligation	The sum of all load-serving entities' unforced capacity obligations is determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	All NERC holiday and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 AM.
OI	Office of the Interconnection.
On peak	Weekdays, except holidays, from the hour ending at 8:00 AM until the hour ending at 11:00 PM.
Operating reserve	The amount of generating capacity scheduled to be available for a specific period of an operating day to ensure the reliable operation of, as applicable, the PJM-East Region or the PJM-West Region, as specified in the PJM manuals.
Peak load	The highest quantity of generation that exists during the period over and above the base load plus the intermediate load quantities.

PJM member	Any entity that has completed an application and satisfied PJM's requirements to conduct business, including transmission owners, generating entities, load-serving entities and marketers.
Price-cost markup index	(Price - Marginal Cost) / Price.
Price duration curve (PDC)	Represents the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary reserves	Spinning reserves.
QIL	Qualified Interruptible Load applies to PJM customers whose load can be interrupted at PJM's request. Such requests are emergency actions made prior to voltage reductions.
RAA	"Reliability Assurance Agreement" among load-serving entities in the PJM Region. It was originally filed with FERC on June 2, 1997.
Real-time market price	The market price based on actual operating conditions.
Regulation service	Generators capable of fluctuating output within five minutes to respond to an automatic telecommunication signal. Such fluctuations are commonly needed to manage the ebb and flow of power demand in a marketplace where power must be supplied and used essentially simultaneously. Power cannot practically be stored.
Residual capacity	Capacity that is unsold after markets clear.
Secondary reserves	Generation that can be held in abeyance, but requires more than ten minutes to ramp up for use in the power system.
Self-scheduled generation	Units can be 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.
Simultaneous feasibility test	A market feasibility test that attempts to ensure the physical transmission system can support all subscribed FTRs during expected system conditions.
Sources and sinks	Sources are the injection end of a transmission transaction. Sinks are the withdrawal or receiving end.
Spinning reserve	Generation that is held on idle so it can be ramped up and used by the grid system within ten minutes of being called.
SPP	The Southwest Power Pool, Inc. which is one of the NERC Regional Councils.

Standard deviation	A measure of data variability around the mean.
System lambda	The cost to the PJM system of generating the next unit of output.
TLR	Transmission load relief.
Transmission facilities	Transmission facilities are defined as facilities that: • Are within the PJM-East Region or the PJM-West Region; • Meet FERC Uniform System of Accounts definition of transmission facilities or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and • Have been demonstrated to the satisfaction of the Office of Interconnection to be integrated with the transmission system of the PJM-East Region or the PJM-West Region and integrated into the planning and operation of the PJM-East Region or the PJM-West Region to serve all the power and transmission customers within the two markets.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Unsubscribed FTRs	FTR’s which have not been assigned.

APPENDIX A—ENERGY MARKET

FREQUENCY DISTRIBUTION OF LMP

Figures A-1, A-2, A-3, A-4, and A-5 provide frequency distribution of locational marginal price (LMP), by hour, for 1998, 1999, 2000, 2001 and 2002.[1] The figures show the number of hours (FREQ.), the cumulative number of hours (CUM FREQ.), the percent of hours (PCT.), and the cumulative percent of hours (CUM PCT.) that LMP was within a given, $10-price interval, or for the cumulative columns, within the interval plus all the lower price intervals.[2]

Comparing the figures, one can see that, during each year, LMP was most frequently in the interval $10 per MWh to $20 per MWh. A decreasing percentage of hours fell in this interval, however, in the years 1998-2001 and then increased again in 2002: 65 percent in 1998; 58 percent in 1999; 51 percent in 2000; 36 percent in 2001; and 43 percent in 2002. In 1998, 1999, 2000, 2001, and 2002, prices were less than $30 per MWh 85 percent, 83 percent, 71 percent, 66 percent, and 70 percent of the hours, respectively. LMP was less than $60 per MWh 99 percent, 97 percent, 92 percent, 92 percent, and 94 percent of the hours, respectively, and less than $100 per MWh 99.4 percent, 98.8 percent, 98.9 percent, 98.4 percent, and 99 percent of the hours, respectively. LMP was $150 per MWh or greater for 29 hours (0.3 percent of the hours) in 1998, 95 hours (1.0 percent of the hours) in 1999, 27 hours (0.3 percent of the hours) in 2000, 60 hours (0.7 percent of the hours) in 2001, and 20 hours (0.2 percent of the hours) in 2002.

FREQUENCY DISTRIBUTION OF LOAD

Figures A-6, A-7, A-8, A-9 and A-10 provide the frequency distribution of PJM load, by hour, for 1998, 1999, 2000, 2001, and 2002. The figures show that with the addition of the PJM-West Region in April, the most frequently occurring load intervals in 2002 were about evenly divided between 30,000 MW to 35,000 MW (26 percent of the hours) and 35,000 MW to 40,000 MW (25 percent of the hours). By contrast, load was most frequently in the 30,000 MW to 35,000 MW range in 2001 and 2000, 34 percent of the hours in each year, and in the 35,000 MW to 40,000 MW range 11 percent of the hours in 2001 and 13 percent of the hours in 2000. In 2002, load was less than 35,000 MW for 52 percent of the hours, less than 50,000 MW for 94 percent of the hours, and less than 60,000 MW for 99 percent of the hours. In 2001 and 2000, load was less than 30,000 MW for 48 percent of the hours, and less than 45,000 MW for 98 and 99 percent of the hours, respectively. A new, all-time peak demand was set in both 2002 and 2001: 63,762 MW in 2002, 54,014 MW in 2001. The previous peak had been 51,700 MW in 1999.

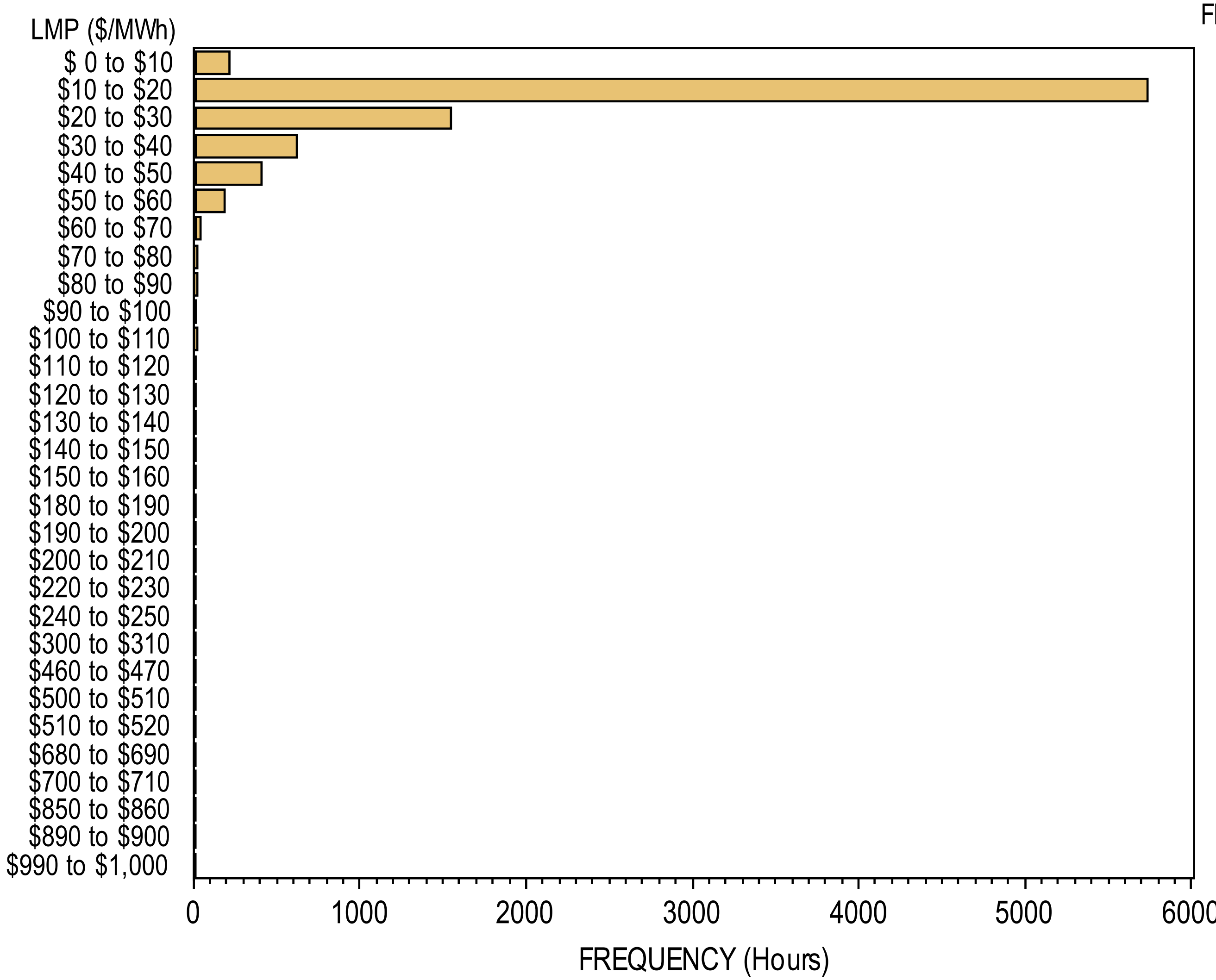
In 1998 and 1999, load was most frequently in the 25,000 MW to 30,000 MW range, 35 percent and 34 percent of the hours, respectively. Load was less than 30,000 MW for 63 percent of the hours in 1998 and 56 percent of the hours in 1999. Load was less than 45,000 MW for 99 percent of the hours in 1998 and 99 percent of the hours in 1999. Load never exceeded 50,000 MW in 1998, whereas a new all-time peak demand of 51,700 MW was set in 1999.

1 LMP was instituted in PJM in April, 1998. Before then, there had been a single system price, the Market-Clearing Price (MCP). It was the system lambda.

2 Only LMP intervals with a positive frequency are included in the figures.

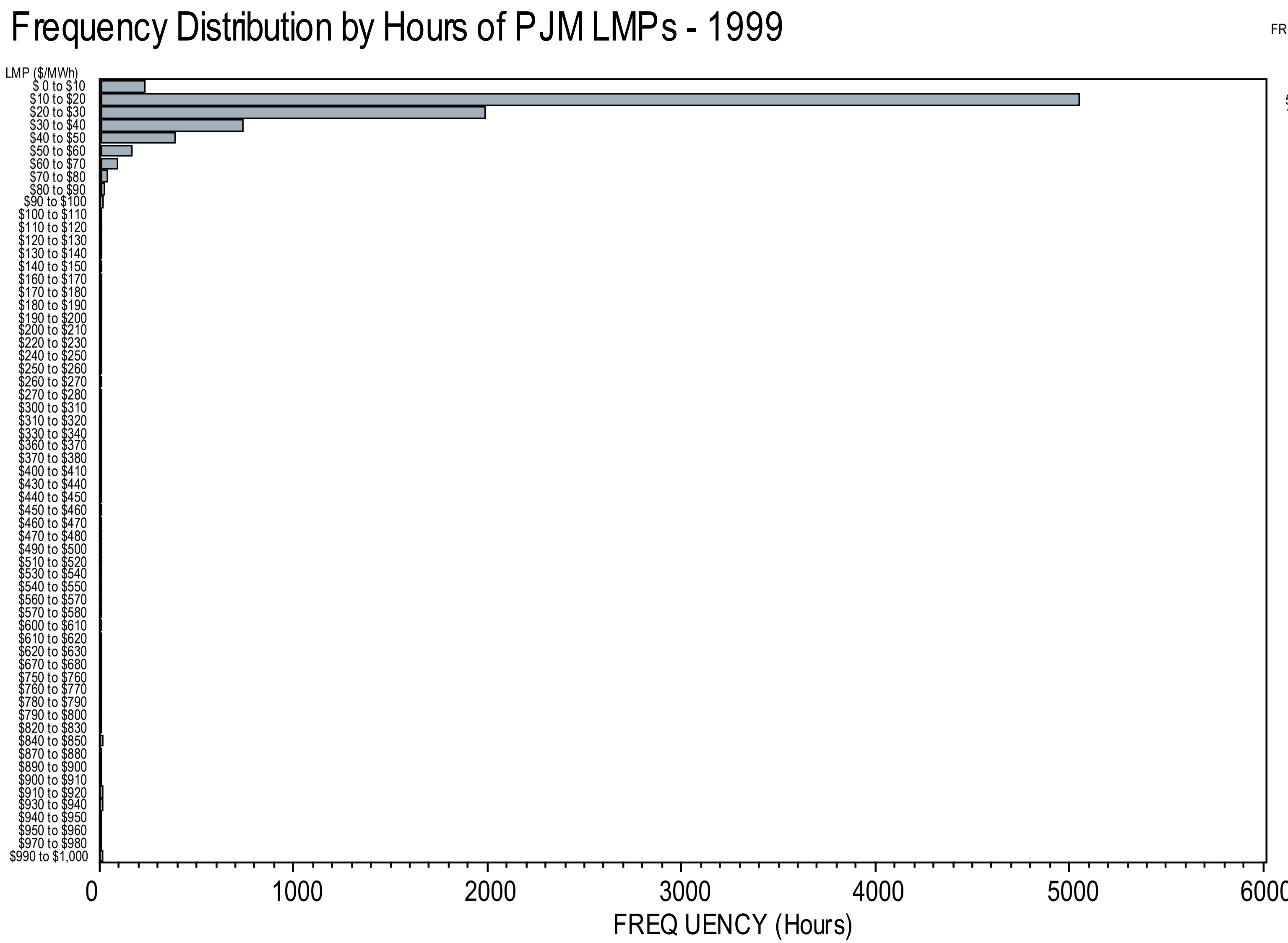
Figure A-1

Frequency Distribution by Hours of PJM LMPs - 1998



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	204	204	2.33	2.33
$10 to $20	5729	5933	65.40	67.73
$20 to $30	1539	7472	17.57	85.30
$30 to $40	607	8079	6.93	92.23
$40 to $50	396	8475	4.52	96.75
$50 to $60	178	8653	2.03	98.78
$60 to $70	27	8680	0.31	99.09
$70 to $80	10	8690	0.11	99.20
$80 to $90	15	8705	0.17	99.37
$90 to $100	6	8711	0.07	99.44
$100 to $110	11	8722	0.13	99.57
$110 to $120	1	8723	0.01	99.58
$120 to $130	1	8724	0.01	99.59
$130 to $140	4	8728	0.05	99.63
$140 to $150	3	8731	0.03	99.67
$150 to $160	6	8737	0.07	99.74
$180 to $190	2	8739	0.02	99.76
$190 to $200	1	8740	0.01	99.77
$200 to $210	1	8741	0.01	99.78
$220 to $230	1	8742	0.01	99.79
$240 to $250	1	8743	0.01	99.81
$300 to $310	5	8748	0.06	99.86
$460 to $470	2	8750	0.02	99.89
$500 to $510	1	8751	0.01	99.90
$510 to $520	1	8752	0.01	99.91
$680 to $690	1	8753	0.01	99.92
$700 to $710	1	8754	0.01	99.93
$850 to $860	1	8755	0.01	99.94
$890 to $900	3	8758	0.03	99.98
$990 to $1,000	2	8760	0.02	100.00

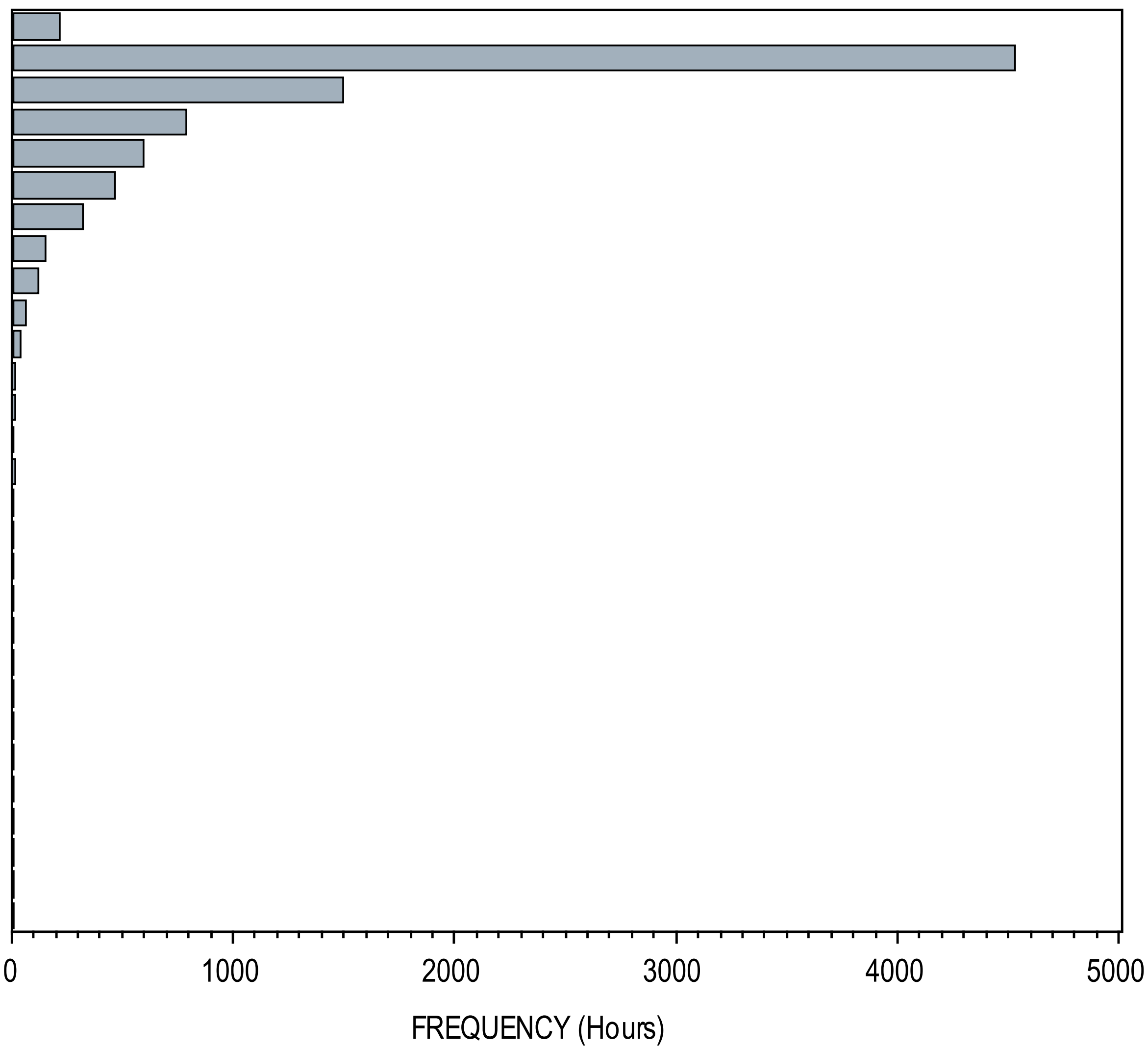
Figure A-2



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	227	227	2.59	2.59
$10 to $20	5042	5269	57.56	60.15
$20 to $30	1982	7251	22.63	82.77
$30 to $40	733	7984	8.37	91.14
$40 to $50	379	8363	4.33	95.47
$50 to $60	154	8517	1.76	97.23
$60 to $70	84	8601	0.96	98.18
$70 to $80	33	8634	0.38	98.56
$80 to $90	13	8647	0.15	98.71
$90 to $100	8	8655	0.09	98.80
$100 to $110	4	8659	0.05	98.85
$110 to $120	3	8662	0.03	98.88
$120 to $130	2	8664	0.02	98.90
$130 to $140	1	8665	0.01	98.92
$140 to $150	4	8669	0.05	98.96
$160 to $170	1	8670	0.01	98.97
$170 to $180	1	8671	0.01	98.98
$180 to $190	1	8672	0.01	99.00
$190 to $200	2	8674	0.02	99.02
$200 to $210	2	8676	0.02	99.04
$220 to $230	1	8677	0.01	99.05
$240 to $250	1	8678	0.01	99.06
$250 to $260	1	8679	0.01	99.08
$260 to $270	1	8680	0.01	99.09
$270 to $280	2	8682	0.02	99.11
$300 to $310	2	8684	0.02	99.13
$310 to $320	2	8686	0.02	99.16
$330 to $340	1	8687	0.01	99.17
$360 to $370	1	8688	0.01	99.18
$370 to $380	1	8689	0.01	99.19
$400 to $410	2	8691	0.02	99.21
$430 to $440	1	8692	0.01	99.22
$440 to $450	2	8694	0.02	99.25
$450 to $460	1	8695	0.01	99.26
$460 to $470	1	8696	0.01	99.27
$470 to $480	3	8699	0.03	99.30
$490 to $500	1	8700	0.01	99.32
$510 to $520	1	8701	0.01	99.33
$530 to $540	1	8702	0.01	99.34
$540 to $550	2	8704	0.02	99.36
$560 to $570	2	8706	0.02	99.38
$570 to $580	1	8707	0.01	99.39
$600 to $610	1	8708	0.01	99.41
$610 to $620	1	8709	0.01	99.42
$620 to $630	2	8711	0.02	99.44
$670 to $680	1	8712	0.01	99.45
$750 to $760	1	8713	0.01	99.46
$760 to $770	2	8715	0.02	99.49
$780 to $790	1	8716	0.01	99.50
$790 to $800	1	8717	0.01	99.51
$820 to $830	1	8718	0.01	99.52
$840 to $850	7	8725	0.08	99.60
$870 to $880	1	8726	0.01	99.61
$890 to $900	1	8727	0.01	99.62
$900 to $910	1	8728	0.01	99.63
$910 to $920	10	8738	0.11	99.75
$930 to $940	11	8749	0.13	99.87
$940 to $950	2	8751	0.02	99.90
$950 to $960	1	8752	0.01	99.91
$970 to $980	1	8753	0.01	99.92
$990 to $1,000	7	8760	0.08	100.00

Figure A-3

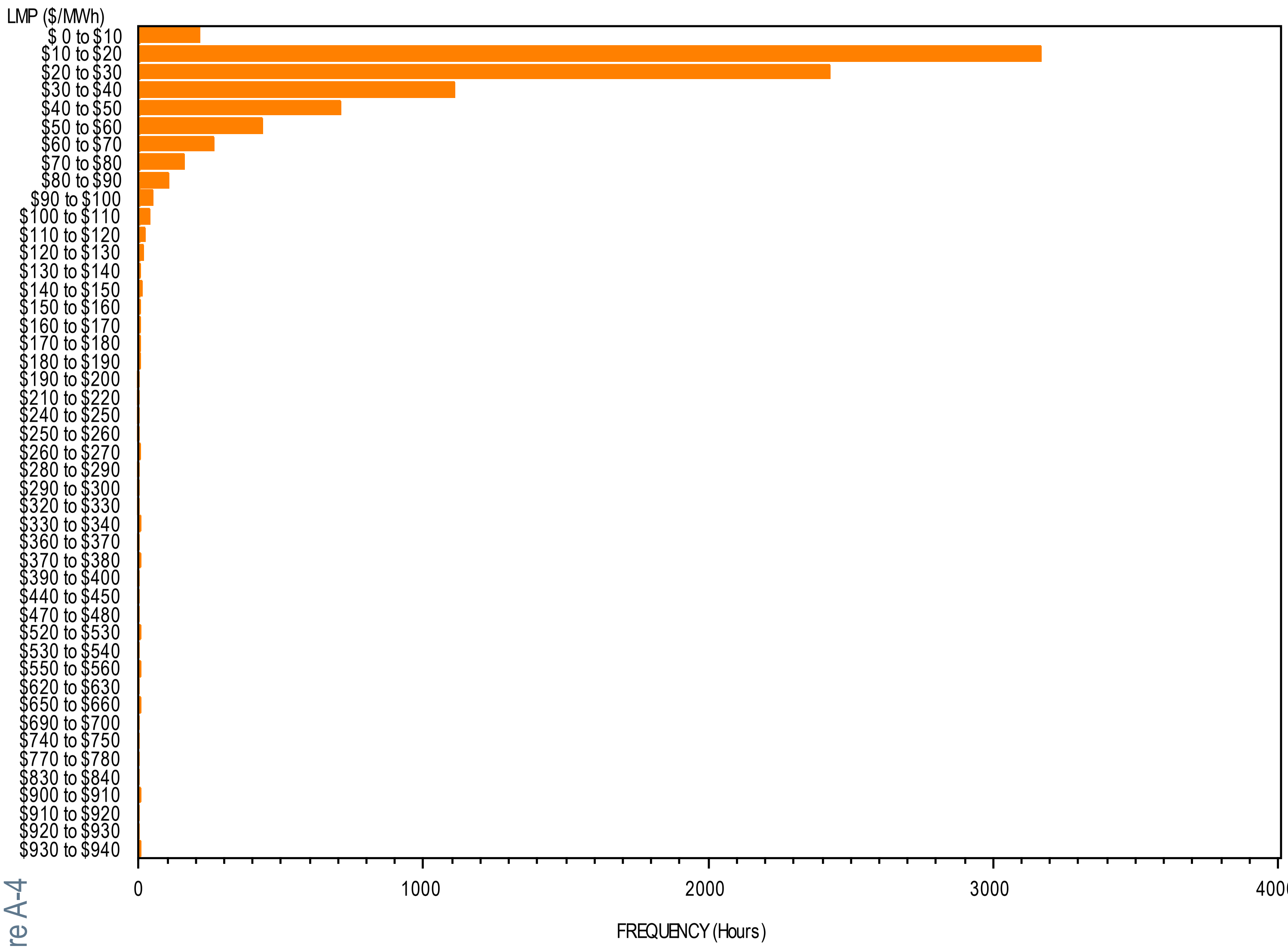
Frequency Distribution by Hours of PJM LMPs - 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	210	210	2.39	2.39
$10 to $20	4522	4732	51.48	53.87
$20 to $30	1494	6226	17.01	70.88
$30 to $40	782	7008	8.90	79.78
$40 to $50	591	7599	6.73	86.51
$50 to $60	459	8058	5.23	91.73
$60 to $70	315	8373	3.59	95.32
$70 to $80	147	8520	1.67	96.99
$80 to $90	115	8635	1.31	98.30
$90 to $100	56	8691	0.64	98.94
$100 to $110	31	8722	0.35	99.29
$110 to $120	9	8731	0.10	99.40
$120 to $130	13	8744	0.15	99.54
$130 to $140	5	8749	0.06	99.60
$140 to $150	8	8757	0.09	99.69
$150 to $160	6	8763	0.07	99.76
$160 to $170	3	8766	0.03	99.80
$170 to $180	2	8768	0.02	99.82
$180 to $190	1	8769	0.01	99.83
$190 to $200	2	8771	0.02	99.85
$210 to $220	1	8772	0.01	99.86
$220 to $230	1	8773	0.01	99.87
$260 to $270	2	8775	0.02	99.90
$280 to $290	1	8776	0.01	99.91
$290 to $300	1	8777	0.01	99.92
$360 to $370	1	8778	0.01	99.93
$480 to $490	4	8782	0.05	99.98
$590 to $600	1	8783	0.01	99.99
$800 to $810	1	8784	0.01	100.00

Figure A-4

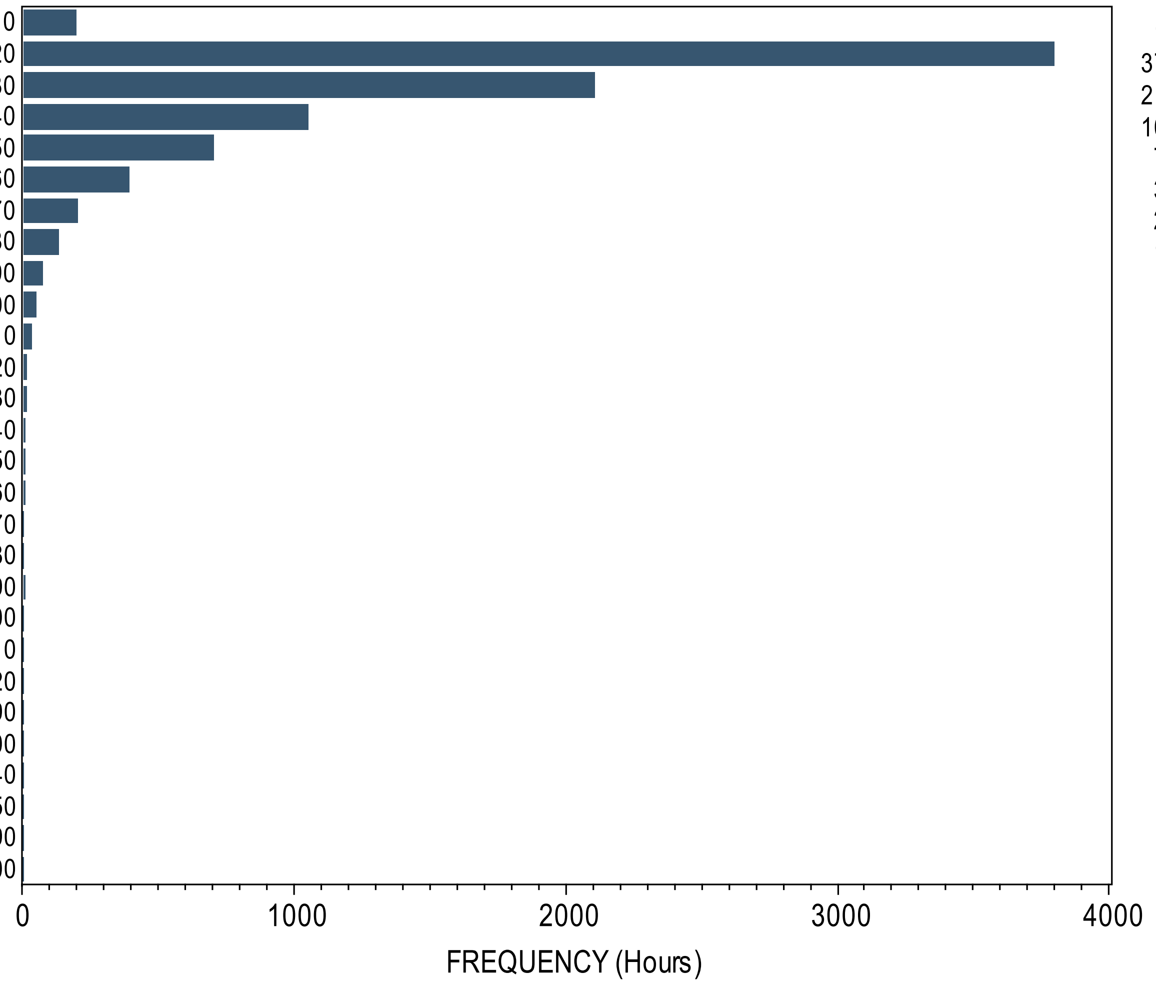
Frequency Distribution by Hours of PJM LMPs - 2001



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	210	210	2.40	2.40
$10 to $20	3167	3377	36.15	38.55
$20 to $30	2423	5800	27.66	66.21
$30 to $40	1109	6909	12.66	78.87
$40 to $50	704	7613	8.04	86.91
$50 to $60	433	8046	4.94	91.85
$60 to $70	264	8310	3.01	94.86
$70 to $80	155	8465	1.77	96.63
$80 to $90	104	8569	1.19	97.82
$90 to $100	50	8619	0.57	98.39
$100 to $110	36	8655	0.41	98.80
$110 to $120	18	8673	0.21	99.01
$120 to $130	13	8686	0.15	99.16
$130 to $140	5	8691	0.06	99.21
$140 to $150	9	8700	0.10	99.32
$150 to $160	6	8706	0.07	99.38
$160 to $170	6	8712	0.07	99.45
$170 to $180	2	8714	0.02	99.47
$180 to $190	5	8719	0.06	99.53
$190 to $200	1	8720	0.01	99.54
$210 to $220	1	8721	0.01	99.55
$240 to $250	1	8722	0.01	99.57
$250 to $260	1	8723	0.01	99.58
$260 to $270	3	8726	0.03	99.61
$280 to $290	1	8727	0.01	99.62
$290 to $300	1	8728	0.01	99.63
$320 to $330	1	8729	0.01	99.65
$330 to $340	2	8731	0.02	99.67
$360 to $370	1	8732	0.01	99.68
$370 to $380	2	8734	0.02	99.70
$390 to $400	1	8735	0.01	99.71
$440 to $450	1	8736	0.01	99.73
$470 to $480	1	8737	0.01	99.74
$520 to $530	3	8740	0.03	99.77
$530 to $540	1	8741	0.01	99.78
$550 to $560	2	8743	0.02	99.81
$620 to $630	1	8744	0.01	99.82
$650 to $660	2	8746	0.02	99.84
$690 to $700	1	8747	0.01	99.85
$740 to $750	1	8748	0.01	99.86
$770 to $780	1	8749	0.01	99.87
$830 to $840	1	8750	0.01	99.89
$900 to $910	3	8753	0.03	99.92
$910 to $920	1	8754	0.01	99.93
$920 to $930	1	8755	0.01	99.94
$930 to $940	5	8760	0.06	100.00

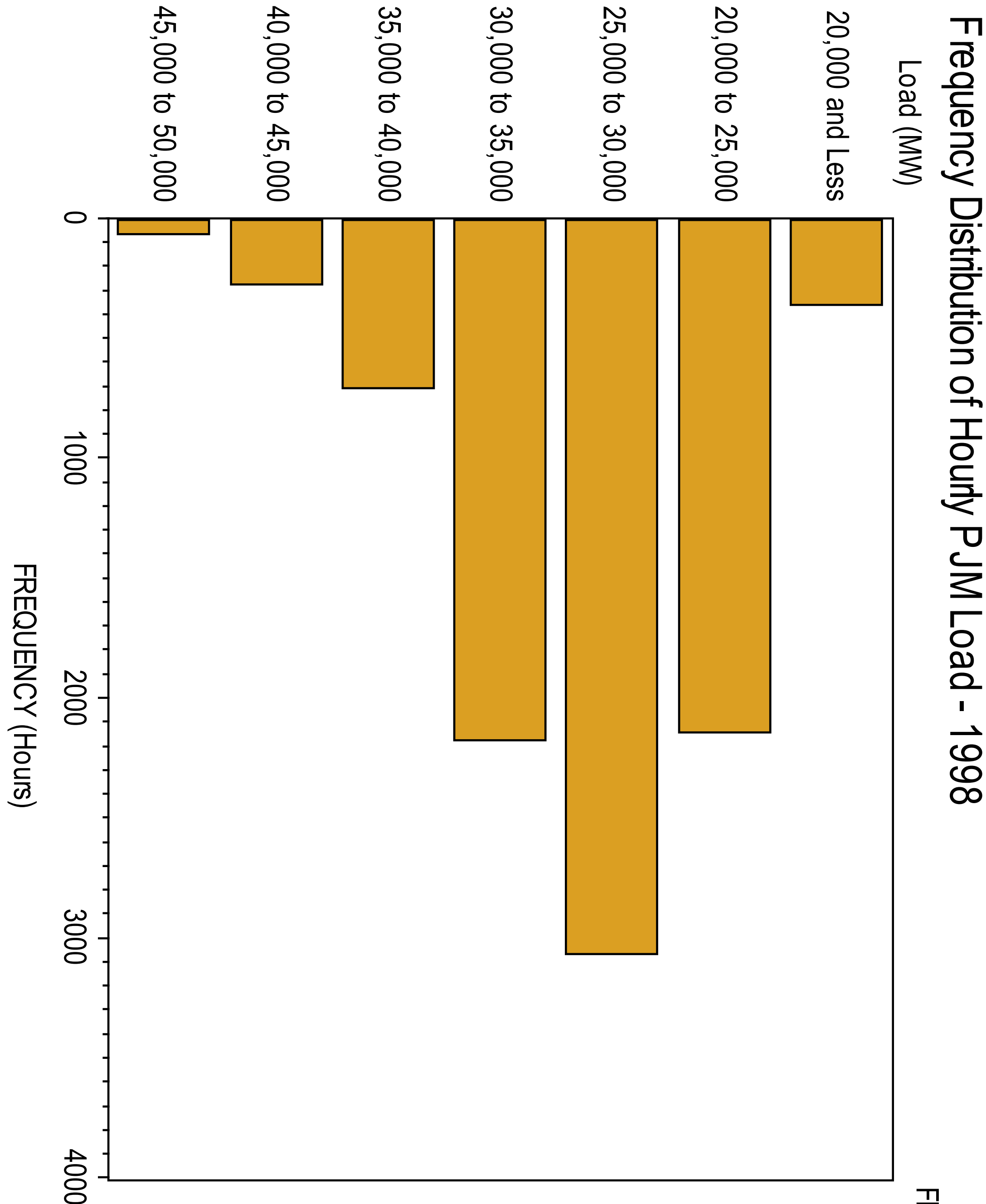
Figure A-5

Frequency Distribution by Hours of PJM LMPs - 2002



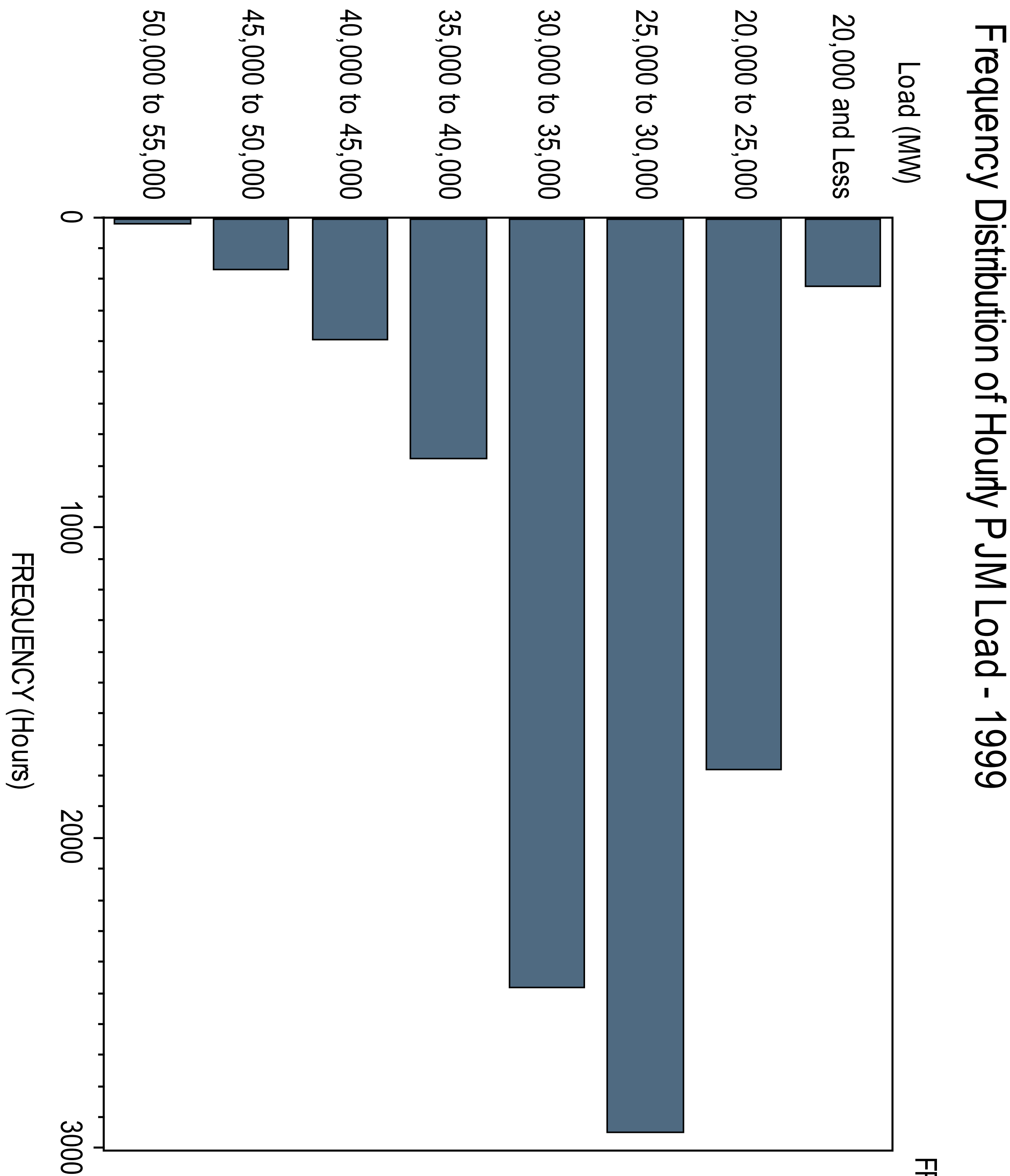
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	195	195	2.23	2.23
$10 to $20	3790	3985	43.26	45.49
$20 to $30	2104	6089	24.02	69.51
$30 to $40	1048	7137	11.96	81.47
$40 to $50	701	7838	8.00	89.47
$50 to $60	391	8229	4.46	93.94
$60 to $70	201	8430	2.29	96.23
$70 to $80	132	8562	1.51	97.74
$80 to $90	69	8631	0.79	98.53
$90 to $100	49	8680	0.56	99.09
$100 to $110	27	8707	0.31	99.39
$110 to $120	13	8720	0.15	99.54
$120 to $130	12	8732	0.14	99.68
$130 to $140	3	8735	0.03	99.71
$140 to $150	5	8740	0.06	99.77
$150 to $160	4	8744	0.05	99.82
$160 to $170	1	8745	0.01	99.83
$170 to $180	1	8746	0.01	99.84
$180 to $190	3	8749	0.03	99.87
$190 to $200	2	8751	0.02	99.90
$200 to $210	1	8752	0.01	99.91
$210 to $220	1	8753	0.01	99.92
$280 to $290	1	8754	0.01	99.93
$290 to $300	1	8755	0.01	99.94
$330 to $340	2	8757	0.02	99.97
$440 to $450	1	8758	0.01	99.98
$580 to $590	1	8759	0.01	99.99
$790 to $800	1	8760	0.01	100.00

Figure A-6



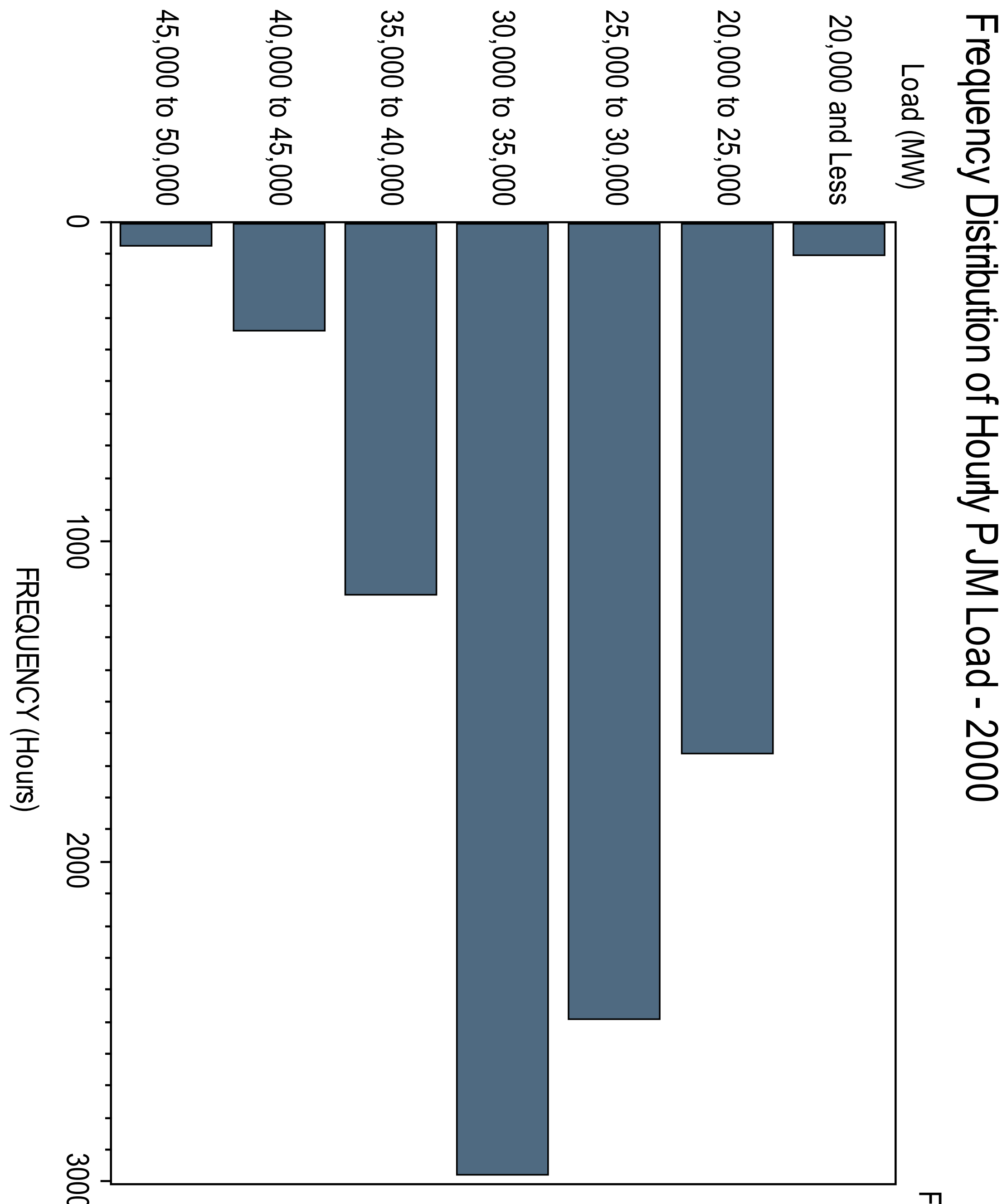
Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	356	356	4.06	4.06
20,000 to 25,000	2137	2493	24.39	28.46
25,000 to 30,000	3063	5556	34.97	63.42
30,000 to 35,000	2171	7727	24.78	88.21
35,000 to 40,000	704	8431	8.04	96.24
40,000 to 45,000	270	8701	3.08	99.33
45,000 to 50,000	59	8760	0.67	100.00

Figure A-7



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	218	218	2.49	2.49
20,000 to 25,000	1776	1994	20.27	22.76
25,000 to 30,000	2944	4938	33.61	56.37
30,000 to 35,000	2476	7414	28.26	84.63
35,000 to 40,000	773	8187	8.82	93.46
40,000 to 45,000	392	8579	4.47	97.93
45,000 to 50,000	166	8745	1.89	99.83
50,000 to 55,000	15	8760	0.17	100.00

Figure A-8



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	99	99	1.13	1.13
20,000 to 25,000	1658	1757	18.88	20.00
25,000 to 30,000	2485	4242	28.29	48.29
30,000 to 35,000	2975	7217	33.87	82.16
35,000 to 40,000	1159	8376	13.19	95.36
40,000 to 45,000	337	8713	3.84	99.19
45,000 to 50,000	71	8784	0.81	100.00

Figure A-9

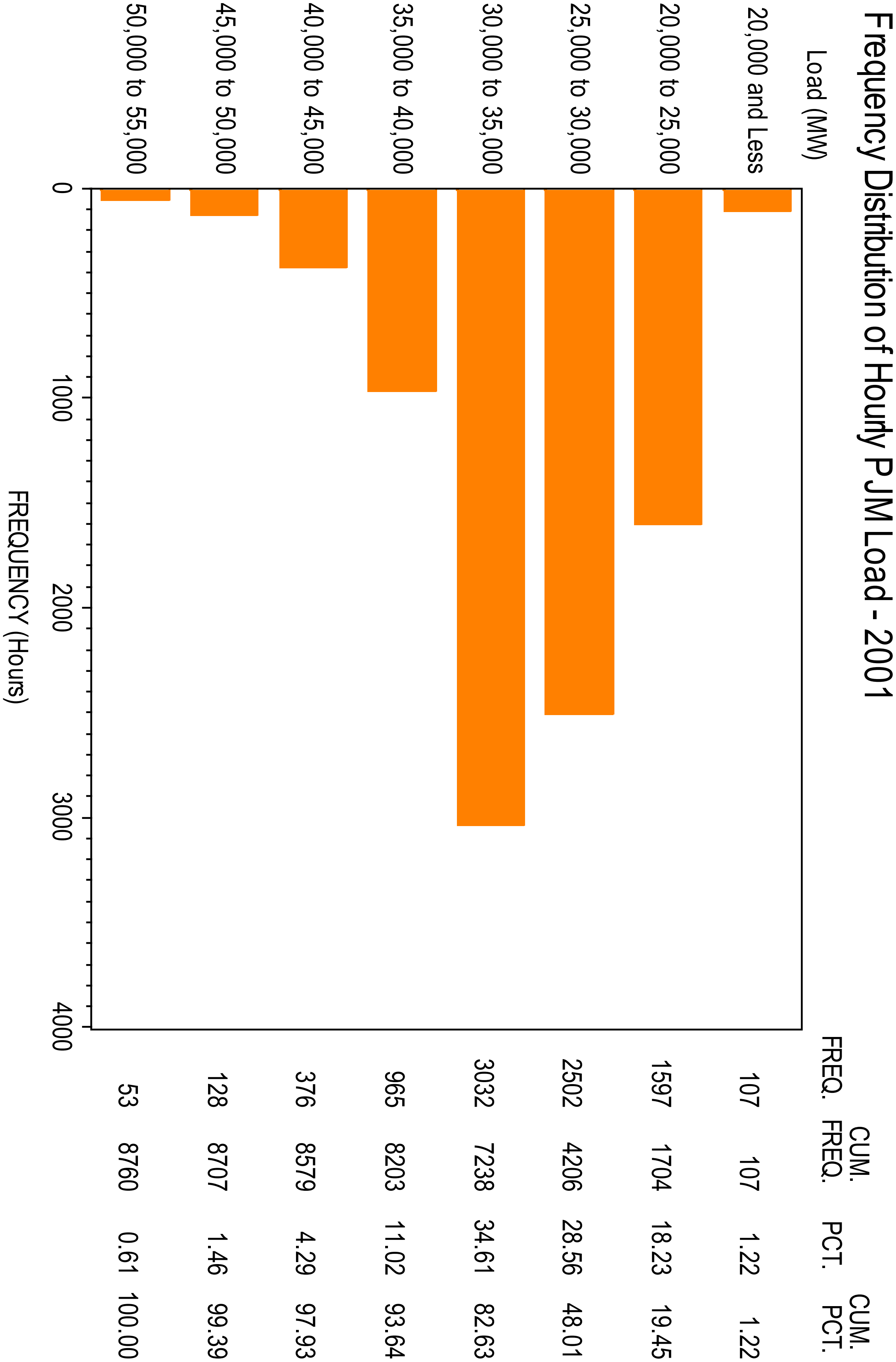
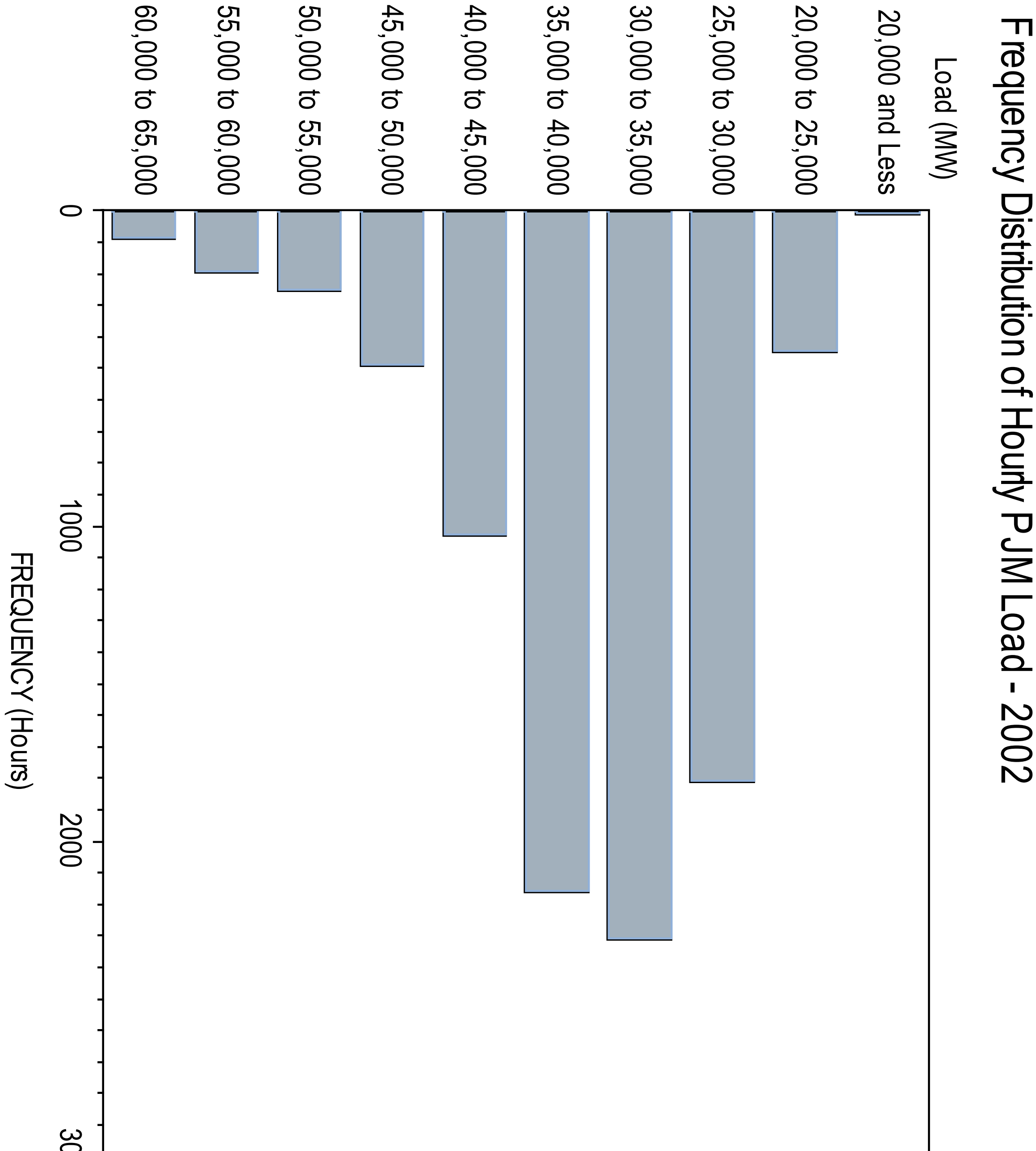

Frequency Distribution of Hourly PJM Load - 2001
Load (MW)
20,000 and Less
20,000 to 25,000
25,000 to 30,000
30,000 to 35,000
35,000 to 40,000
40,000 to 45,000
45,000 to 50,000
50,000 to 55,000
0
1000
2000
3000
4000
FREQUENCY (Hours)
FREQ.
CUM. FREQ.
PCT.
CUM. PCT.
107 107 1.22 1.22
1597 1704 18.23 19.45
2502 4206 28.56 48.01
3032 7238 34.61 82.63
965 8203 11.02 93.64
376 8579 4.29 97.93
128 8707 1.46 99.39
53 8760 0.61 100.00

Figure A-10



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	8	8	0.09	0.09
20,000 to 25,000	443	451	5.06	5.15
25,000 to 30,000	1809	2260	20.65	25.80
30,000 to 35,000	2306	4566	26.32	52.12
35,000 to 40,000	2155	6721	24.60	76.72
40,000 to 45,000	1026	7747	11.71	88.44
45,000 to 50,000	490	8237	5.59	94.03
50,000 to 55,000	248	8485	2.83	96.86
55,000 to 60,000	192	8677	2.19	99.05
60,000 to 65,000	83	8760	0.95	100.00

On-Peak and Off-Peak Load

Table A-1 presents summary load statistics for 1998 to 2002 for the off-peak and on-peak hours, while Table A-2 shows the percentage changes in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday through Friday) as hour ending 0800 to hour ending 2300, excluding holidays. As can be seen from the table, in all five years on-peak load is about 30 percent higher than off-peak load, while median peak load ranges from 20 percent to 30 percent higher. Average load during on-peak hours in 2002 was about 17 percent higher than in 2001 because of the inclusion of the PJM-West Region, 19 percent higher than in 2000, and 21 percent higher than in 1999. Off-peak load in 2002 was 18 percent higher than in 2001, again largely because of the PJM-West Region, and ranged from 17 to 25 percent higher than the other years.

Table A-1—Off-Peak and On-Peak Load – 1998, 1999, 2000, 2001, and 2002 (in MW)

Year	Average Load			Median Load			Standard Deviation		
	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak	Off-Peak	On-Peak	On-Peak/ Off-Peak
2002	31,584	40,102	1.3	30,457	38,243	1.3	6,044	7,400	1.2
2001	26,804	34,303	1.3	26,433	33,076	1.3	4,225	4,851	1.1
2000	26,921	33,766	1.3	26,327	32,771	1.2	4,453	4,226	0.9
1999	26,409	33,291	1.3	25,795	31,987	1.2	4,862	4,870	1.0
1998	25,268	32,344	1.3	24,728	31,081	1.3	4,091	4,388	1.1

Table A-2—Year-Over-Year Percent Change in Load

Year	Average Load		Median Load		Standard Deviation	
	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak
2002	17.8%	16.9%	15.2%	15.6%	43.1%	52.6%
2001	-0.4%	1.6%	1.4%	0.9%	-5.1%	14.8%
2000	1.9%	1.4%	2.1%	2.5%	-8.4%	-13.2%
1999	4.5%	2.9%	4.3%	2.9%	18.8%	11.0%
1998	----	----	----	----	----	----

On-Peak and Off-Peak Load-Weighted LMPs – 2001 and 2002

Table A-3 shows load-weighted average LMP for 2001 and 2002 during off-peak and on-peak periods. In 2001, the on-peak, load-weighted LMP was 110 percent greater than the off-peak LMP, while in 2002 it was about 80 percent greater. On-peak, load-weighted, average LMP in 2002 was 17.7 percent lower than in 2001, and off-peak load-weighted LMP in 2002 was 4.5 percent lower than in 2001. Similarly, both on-peak and off-peak median LMP were lower in 2002 than in 2001, by 3.5 percent and 6.7 percent, respectively. Dispersion in load-weighted LMP, as indicated by standard deviation, was 57.4 percent lower in 2002 than in 2001 during on-peak hours, while the standard deviations were virtually identical in both years during the off-peak hours.

Table A-3, shows that average, on-peak, load-weighted LMP in 2002 was about 18 percent lower than in 2001 while the off-peak, load-weighted average LMP was about five percent lower than in 2001. In both years, average, on-peak, load-weighted LMP was higher than the all-hours, load-weighted average, while off-peak, load-weighted average LMP was lower than the all-hours, load-weighted average.

Table A-3—Off-Peak and On-Peak, Load-Weighted LMP for 2001 and 2002 (in $/MWh)

	2001			2002			% Change 2001 to 2002	
	Off-Peak	On-Peak	On-/ Off-Peak	Off-Peak	On-Peak	On-/ Off-Peak	Off-Peak	On-Peak
Average LMP	$23.59	$48.36	2.1	$22.53	$39.79	1.8	-4.5%	-17.7%
Median LMP	$19.12	$33.50	1.8	$17.79	$32.34	1.8	-6.7%	-3.5%
Standard Deviation	$13.87	$75.86	5.5	$13.88	$32.33	2.3	0.0%	-57.4%

Fuel-Cost Adjustment

Fuel costs for 2001 and 2002 were taken from various published sources. Coal prices were obtained from The Energy Argus and adjusted for transportation costs. Both natural gas and petroleum prices were obtained from Platts and adjusted for transportation costs. Month-end uranium spot prices for 2001 and 2002 were obtained from the Ux Consulting Company, LLC and the Uranium Exchange Company.[3]

The price index for each fuel was calculated as a chain-weighted index, where the weights are the number of MW generated in each month of 2001 and 2002 for which the price was determined by the marginal generating unit firing the indicated fuel. First, an index was calculated using 2001 fuel-specific MW as the weights: Year 2002 fuel-specific prices times Year 2001 fuel-specific MW divided by Year 2001 fuel-specific prices times Year 2001 fuel-specific MW. Second, an index was calculated using Year 2002 fuel-specific MW as the weights: Year 2002 fuel-specific prices times Year 2002 fuel-specific MW divided by Year 2001 fuel-specific prices times Year 2002 fuel-specific MW. The two indices were then chain-weighted by calculating their geometric mean. Each Year 2002 hourly LMP for a month was then divided by the chain-weighted price index for that month to derive the fuel-cost-adjusted LMP. Fuel-cost-adjusted LMPs were then weighted by load to derive the load-weighted, fuel-cost-adjusted LMP.

LMPs During Constrained Hours – 2001 and 2002[4]

Figure A-11 shows the number of constrained hours during each month in 2001 and 2002 and the average number of constrained hours per month for each year. There were 4,823 constrained hours in 2001 and 5,230 in 2002, an increase of approximately eight percent. Figure A-11 also shows that the average number of constrained hours per month was higher in 2002 than 2001 – 436 per month in 2002 versus 402 per month in 2001.

Table A-4 presents summary statistics for the load-weighted average LMP during constrained hours in 2001 and 2002. During constrained hours, the average, load-weighted LMP in 2002 was 15.7 percent lower than in 2001. The median, load-weighted LMP in 2002 was 0.9 percent lower, and the dispersion of LMP about the average, as shown by the standard deviation, was 57 percent lower than in 2001.

Table A-4—2001 and 2002 Load-Weighted Average LMP During Constrained Hours (in $/MWh)

	2001	2002	% Change
Average LMP	$43.79	$36.90	-15.7%
Median LMP	$29.44	$29.18	-0.9%
Standard Deviation	$72.00	$30.93	-57.0%

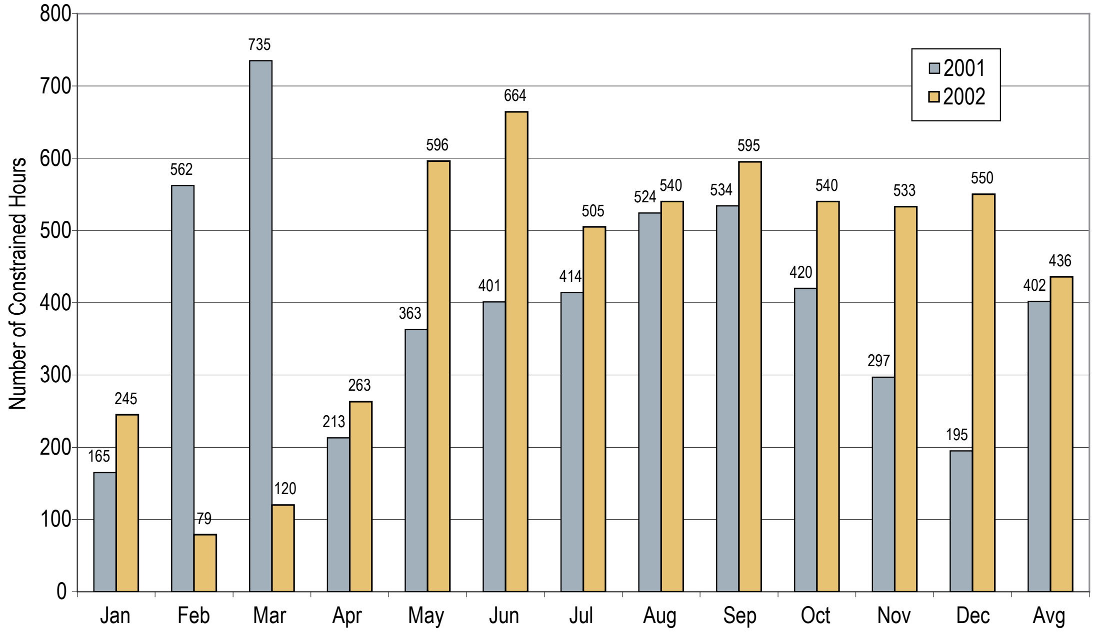
Table A-5 provides a comparison of load-weighted average LMP during constrained and unconstrained hours for the two years. In 2002, average load-weighted LMP during constrained hours was 16.8 percent higher than average load-weighted LMP during unconstrained hours. The comparable number for 2001 is 65.9 percent.

Table A-5—2001 and 2002 Load-Weighted Average LMP During Constrained and Unconstrained Hours (in $/MWh)

	2001			2002		
	Unconstrained Hours	Constrained Hours	Percent Difference	Unconstrained Hours	Constrained Hours	Percent Difference
Average LMP	$26.40	$43.79	65.9%	$31.60	$36.90	16.8%
Median LMP	$19.53	$29.44	50.7%	$23.41	$29.18	24.7%
Standard Deviation	$19.12	$72.00	276.6%	$26.74	$30.93	15.7%

3 See The Ux Consulting Company, LLC (www.uxc.com/review/uxc_prices_mth-end.html).

Figure A-11 PJM Constrained Hours - 2001 and 2002



Day-Ahead and Real-Time Prices

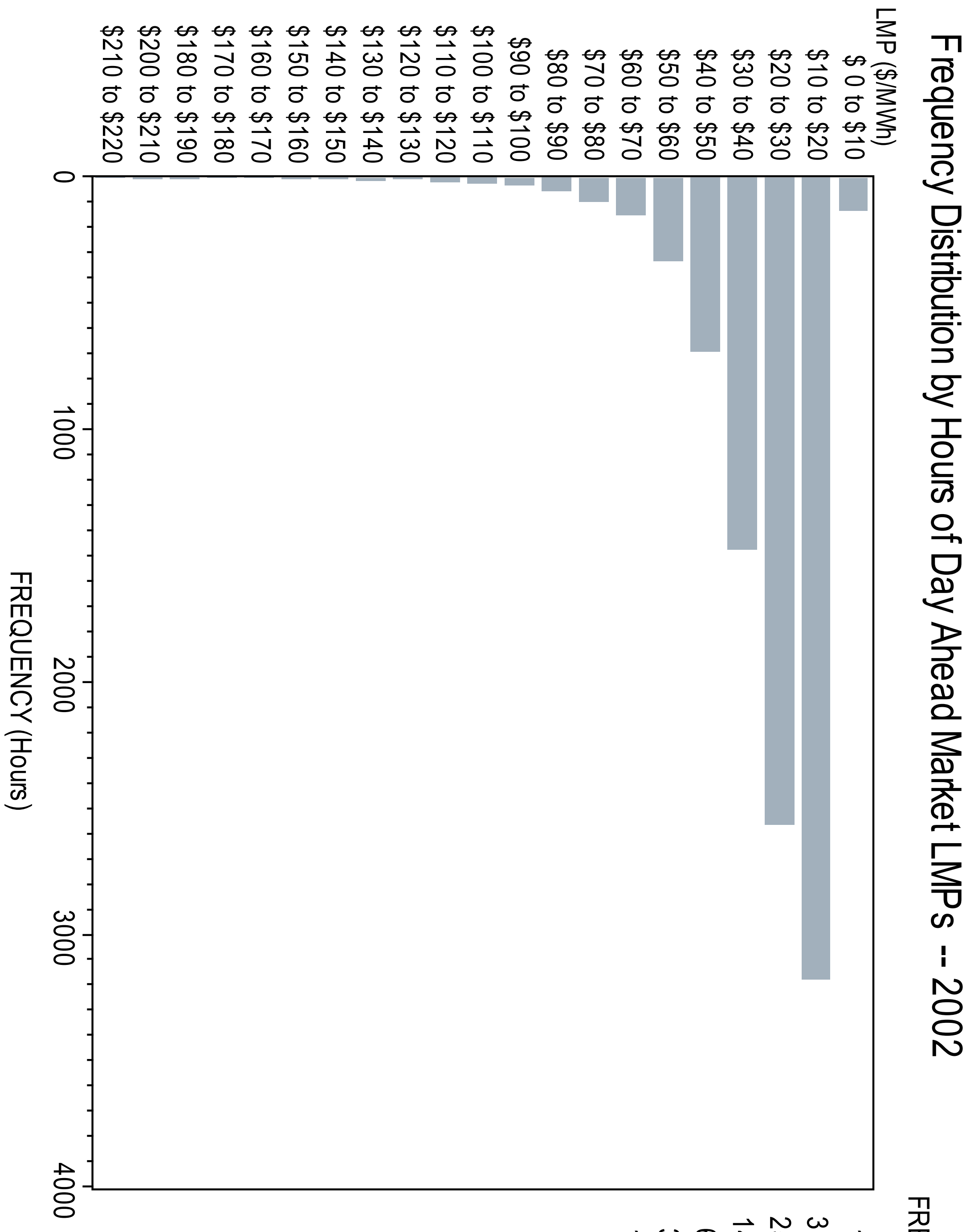
As noted earlier, real-time prices are only slightly lower than day-ahead prices on average, while real-time prices show greater dispersion. This pattern of price distribution for 2002 can be seen in Figures A-5 and A-12. The figures show the frequency distribution by hours for the two markets. In the real-time market the most frequently occurring price interval is $10 per MWh to $20 per MWh, 43 percent of the hours. The most frequently occurring price interval in the day-ahead market is also $10 per MWh to $20 per MWh, but only 36 percent of the hours. In the real-time market, prices are less than $20 per MWh for 45 percent of the hours, while prices are less than $20 per MWh in the day-ahead market for 38 percent of the hours. Cumulatively, prices are less than $30 per MWh for 70 percent of the hours in the real-time market, 67 percent in the day-ahead; less than $40 per MWh for 81 percent in the real-time market, 82 percent in the day-ahead market; less than $50 per MWh for 89 percent of the hours in the real-time and 92 percent of the hours in the day-ahead market. In the real-time market, prices were above $150 per MWh for 20 hours (0.2 percent of the hours), reaching a high for the year of $791 per MWh on July 29. In the day-ahead market, prices were also above $150 per MWh for 20 hours, but only reached a high for the year of $212 per MWh on July 30.

On-Peak and Off-Peak LMP

Table A-6 shows the average LMP during the off-peak and on-peak periods for the day-ahead and real-time markets. Day-ahead and real-time on-peak average LMPs were about twice as high as the corresponding off-peak average LMP. The real-time peak average LMP was 0.6 percent lower than the day-ahead peak average LMP. The median LMPs during on-peak hours were 74 percent and 73 percent higher in the day-ahead and real-time markets, respectively, than the off-peak median LMPs. The day-ahead median on-peak LMP was also 5.5 percent higher than the real-time median LMP.

4 For purpose of this discussion, a constrained hour is defined as one in which the difference in LMP between at least two buses in that hour is greater than $1.00.

Figure A-12



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	129	129	1.47	1.47
$10 to $20	3176	3305	36.26	37.73
$20 to $30	2564	5869	29.27	67.00
$30 to $40	1470	7339	16.78	83.78
$40 to $50	690	8029	7.88	91.66
$50 to $60	329	8358	3.76	95.41
$60 to $70	146	8504	1.67	97.08
$70 to $80	92	8596	1.05	98.13
$80 to $90	50	8646	0.57	98.70
$90 to $100	29	8675	0.33	99.03
$100 to $110	24	8699	0.27	99.30
$110 to $120	16	8715	0.18	99.49
$120 to $130	7	8722	0.08	99.57
$130 to $140	11	8733	0.13	99.69
$140 to $150	7	8740	0.08	99.77
$150 to $160	8	8748	0.09	99.86
$160 to $170	1	8749	0.01	99.87
$170 to $180	2	8751	0.02	99.90
$180 to $190	4	8755	0.05	99.94
$200 to $210	4	8759	0.05	99.99
$210 to $220	1	8760	0.01	100.00

Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the real-time market as compared to the day-ahead market, during both on-peak and off-peak periods (24 percent and 21 percent compared to 18 percent and 17 percent, respectively). The difference reflects the larger positive skewness in the real-time market. During on-peak hours, the standard deviation in the real-time market was about 35 percent higher than in the day-ahead market, while it was 24 percent higher during the off-peak hours.

Figures A-13 and A-14 show the difference between real-time and day-ahead LMP in 2002 during the on-peak and off-peak hours, respectively. The average difference in LMP during on-peak hours was only $0.22 per MWh (day-ahead LMP higher than real-time LMP). By contrast, during off-peak hours, the average difference between the two markets was $0.11 per MWh (day-ahead LMP higher than real-time). The figures show that the largest price differences occurred during the summer on-peak hours when three new all-time peak demands were set.

Table A-6—2002 Off-Peak and On-Peak LMP (in $/MWh)

	Day-Ahead			Real-Time			% Change Day-Ahead to Real-Time	
	Off-Peak	On-Peak	Peak/ Off-Peak	Off-Peak	On-Peak	Peak/ Off-Peak	Off-Peak	On-Peak
Average LMP	$21.03	$36.98	$1.76	$20.92	$36.76	$1.76	-0.5%	-0.6%
Median LMP	$18.00	$31.40	$1.74	$17.23	$29.77	$1.73	-4.3%	-5.2%
Standard Deviation	$9.99	$20.52	$2.05	$12.39	$27.71	$2.24	24.0%	35.0%

LMPs During Constrained Hours – Day-Ahead and Real-Time Markets[5]

Figure A-15 shows the number of constrained hours in each month for the day-ahead and real-time markets and the average number of constrained hours for 2002. Overall, there were 5,230 constrained hours in the real-time market and 7,174 constrained hours in the day-ahead market, 37 percent more. Figure A-15 shows that in every month of 2002 except for May and June the number of constrained hours in the day-ahead market exceeded those in the real-time market. On average for the year, there were 37 percent more constrained hours in the day-ahead market than the real-time market.

Table A-7 shows average LMP during constrained and unconstrained hours in the day-ahead and real-time markets. In the day-ahead market, average LMP during constrained hours was 55.3 percent higher than average LMP during unconstrained hours. In the real-time market, average LMP during constrained hours was 59.4 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 9.5 percent higher in the real-time market than in the day-ahead market. Both markets exhibited greater price dispersion during constrained hours than during unconstrained hours.

Figure A-13

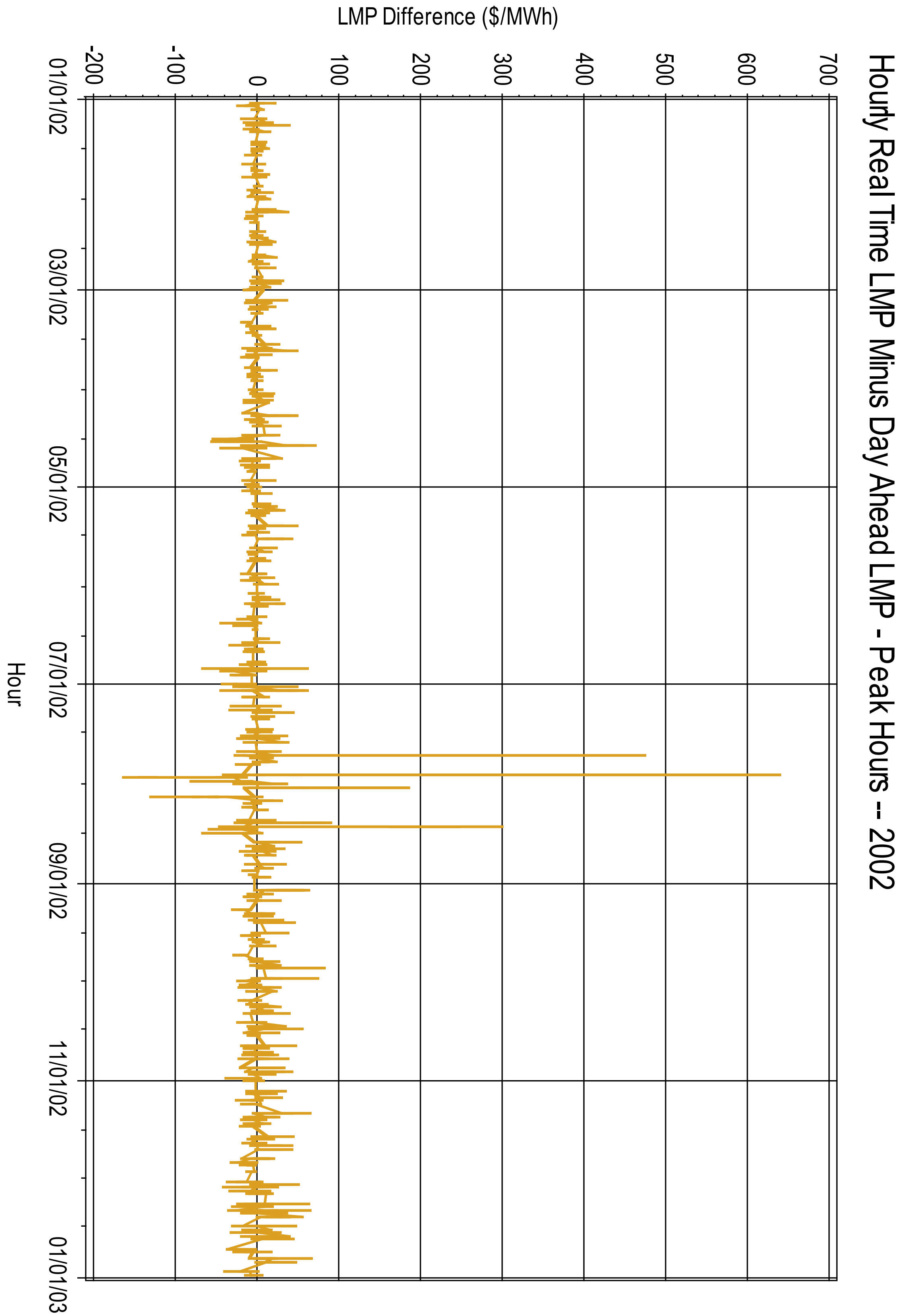

Hourly Real Time LMP Minus Day Ahead LMP - Peak Hours -- 2002
LMP Difference ($/MWh)
700
600
500
400
300
200
100
0
-100
-200
01/01/02
03/01/02
05/01/02
07/01/02
09/01/02
11/01/02
01/01/03
Hour

Figure A-14

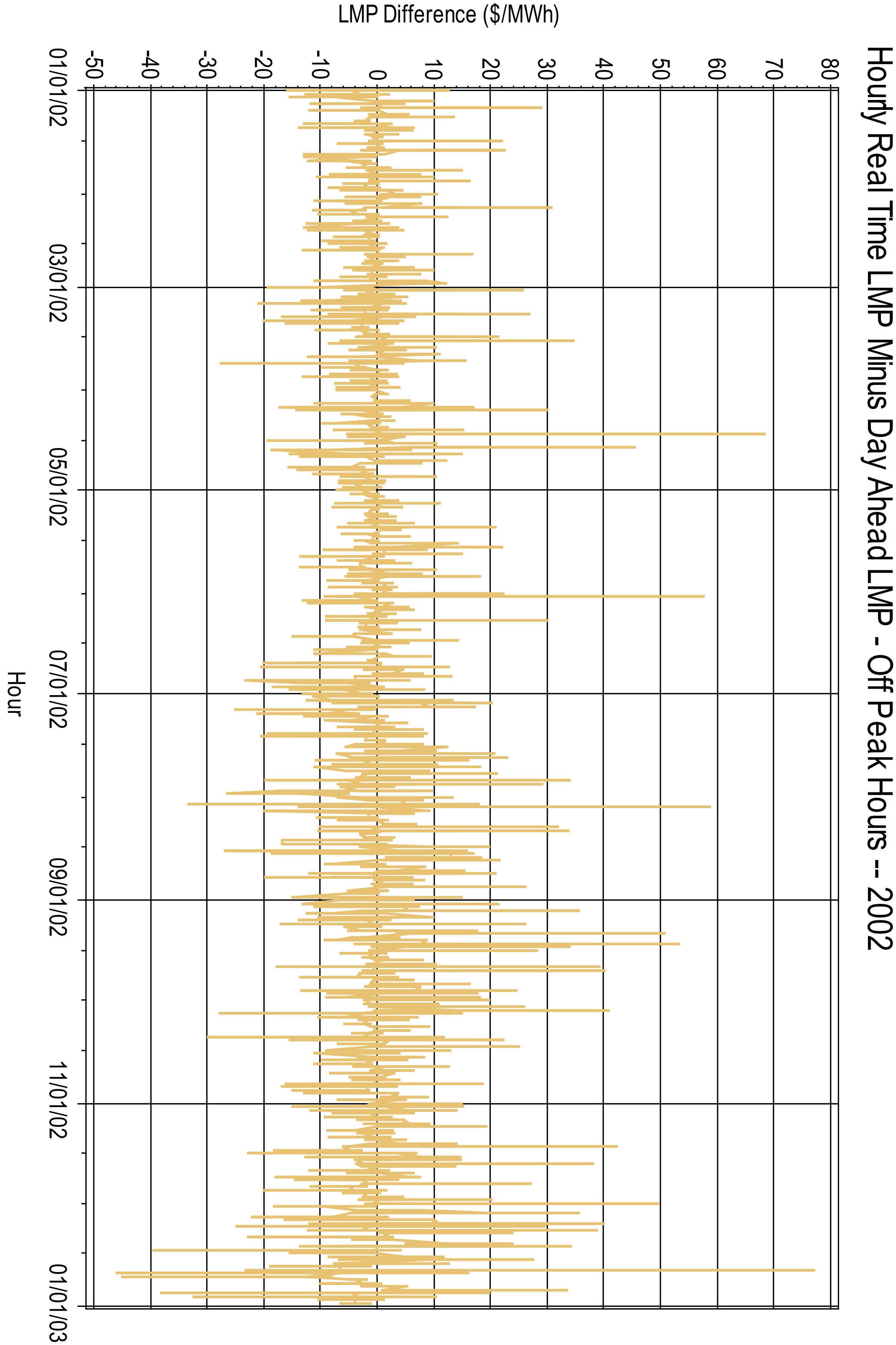

Hourly Real Time LMP Minus Day Ahead LMP - Off Peak Hours -- 2002
LMP Difference ($/MWh)
-50
-40
-30
-20
-10
0
10
20
30
40
50
60
70
80
Hour
01/01/02
03/01/02
05/01/02
07/01/02
09/01/02
11/01/02
01/01/03

Figure A-15

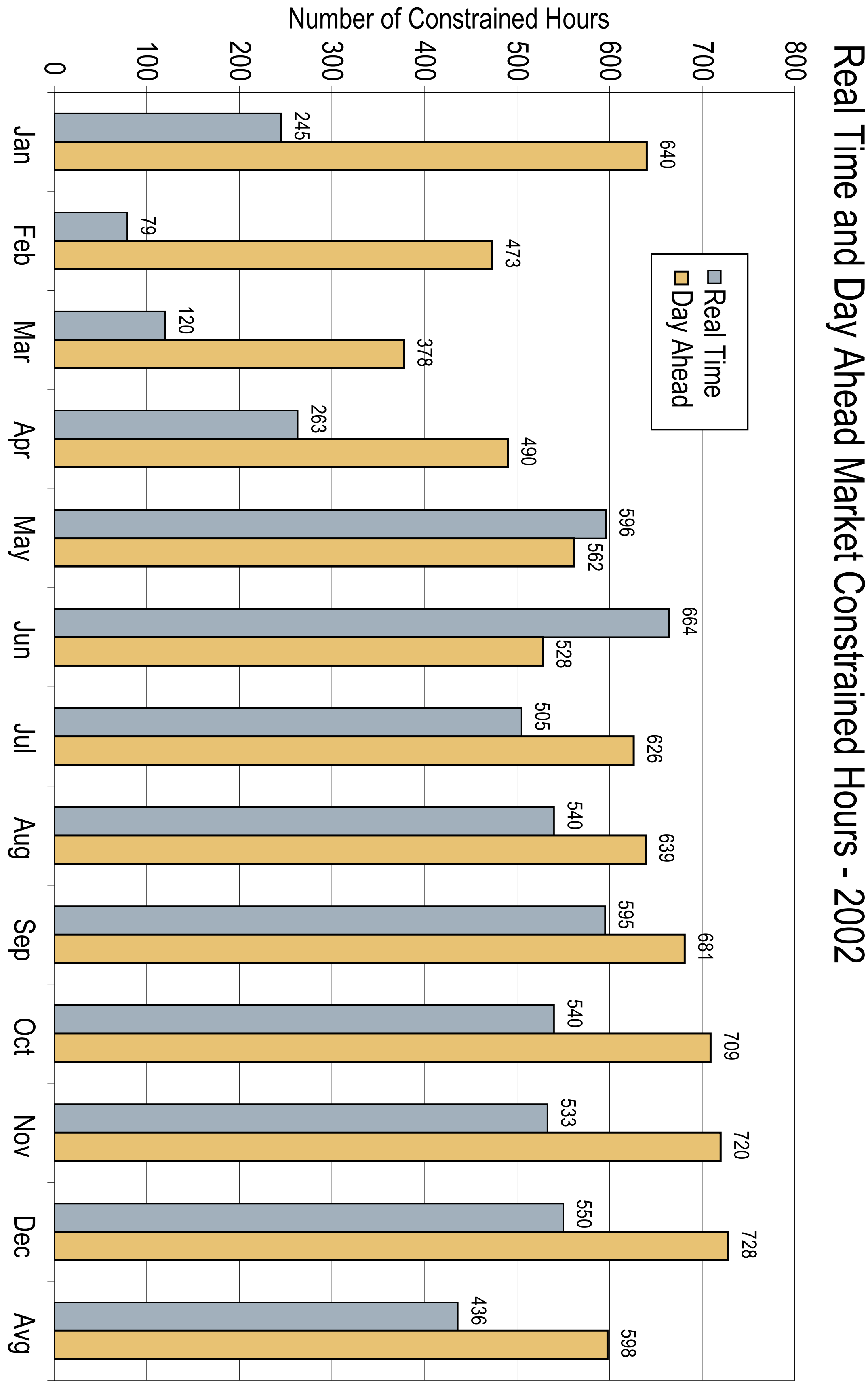

Real Time and Day Ahead Market Constrained Hours - 2002
Number of Constrained Hours
0
100
200
300
400
500
600
700
800
Real Time
Day Ahead
Jan
245
640
Feb
79
473
Mar
120
378
Apr
263
490
May
596
562
Jun
664
528
Jul
505
626
Aug
540
639
Sep
595
681
Oct
540
709
Nov
533
720
Dec
550
728
Avg
436
598

Table A-7—2002 LMP During Constrained and Unconstrained Hours (in $/MWh)

	Day-Ahead			Real-Time		
	Unconstrained Hours	Constrained Hours	Percent Change	Unconstrained Hours	Constrained Hours	Percent Change
Average LMP	$19.59	$30.42	55.3%	$20.89	$33.30	59.4%
Median LMP	$17.00	$25.27	48.7%	$17.73	$25.96	46.4%
Standard Deviation	$9.45	$18.46	95.3%	$10.84	$26.45	144.0%

Table A-7 shows that average LMP in the day-ahead market during constrained hours was 6.9 percent higher than the overall average LMP for the day-ahead market, while average LMP during unconstrained hours was 31.2 percent lower. In the real-time market, average LMP during constrained hours was 17.7 percent higher than the overall average LMP for the real-time market, while average LMP during unconstrained hours was 26.2 percent lower.

5 For purpose of this discussion, a constrained hour is defined as one in which the difference in LMP between at least two buses in that hour is greater than $1.00. This definition is slightly different than the one used in the Congestion Section.

APPENDIX B—CAPACITY MARKETS

CAPACITY MARKET BACKGROUND

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually. Combined with state regulatory requirements to build and incentives to maintain adequate capacity, this system created a reliable pool, where capacity and energy were adequate to meet customer needs, and where capacity costs were borne equitably by members and their loads.

Capacity obligations continue to be critical to maintaining reliability and to contribute to the effective, competitive operation of PJM energy markets. Adequate capacity resources, equal to expected load plus a reserve margin, help to ensure that energy is available on even the highest load days.

On January 1, 1999, in response to retail restructuring requirements, PJM introduced a transparent, PJM-run market in capacity credits.[1] New retail market entrants needed a way to acquire capacity credits to meet the obligations associated with competitively gained load. Existing utilities needed a way to sell excess capacity credits when load was lost to new competitors. The PJM capacity credit market provides a mechanism to balance the supply and demand for capacity credits not met in the bilateral market or via self-supply. The PJM capacity credit market is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

The "Reliability Assurance Agreement Among Load-serving entities in the PJM Control Area" (RAA) states that the purpose of capacity obligations as competitive markets evolve is to "ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within the PJM Control Area, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace."[2] When the PJM-West Region joined PJM, a new reliability assurance agreement was developed, the "PJM-West Reliability Assurance Agreement Among Load Serving Entities in the PJM-West Region," that specified the capacity market rules implemented in the PJM-West Region.

Under the RAA for both the East and West Regions, each load-serving entity (LSE) must own or purchase capacity resources greater than or equal to its capacity obligation. To cover this obligation, LSEs may own or purchase capacity credits, unit-specific installed capacity, or capacity imports

On April 1, 2002, the PJM-West Region joined PJM .

1 The first capacity credit markets (CCMs) were run in late 1998 with effective dates starting January 1, 1999.

2 "Reliability Assurance Agreement Among Load-serving entities in the PJM Control Area," revised March 21, 2000 (RAA), Article 2—Purpose, page 8.

CAPACITY OBLIGATIONS

For both the PJM-East and the PJM-West Regions, an annual load forecast is used to determine the forecast peak load for each region. These forecast peak load values are further adjusted to determine capacity obligations.

- **The PJM-East Region.** In the PJM-East Region, the adjusted forecast peak load value[3] is multiplied by the Forecast Pool Requirement (FPR) to determine the unforced capacity obligation. The FPR is equal to one plus a reserve margin which is then multiplied by the PJM-East Region unforced outage factor. An LSE's unforced capacity obligation is its forecast peak load multiplied by the FPR. The FPR is set for each planning period which commences every June 1.
- **The PJM-West Region.** In the PJM-West Region, the forecast peak load is multiplied by six percent to determine, for each entity, its maximum Daily Available Capacity Obligation (DACO). Unlike the PJM-East Region in which the unforced capacity obligation is set annually and must be met on a daily basis, the DACO of the PJM-West Region is set daily, based on the daily load forecast, and must be met on a daily basis. The DACO cannot exceed 106 percent of the Forecast Period Peak Load (FPPL).

Meeting Capacity Obligations

- The PJM-East Region. In the PJM-East Region, an LSE's load may change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily by comparing its capacity resources to its capacity obligation to determine whether any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the Capacity Deficiency Rate [(CDR), currently $174.73 per MW-day], times the number of days in an interval.[4] If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval multiplied by each MW of deficiency.
- **The PJM-West Region.** In the PJM-West Region, an LSE's load changes on a daily basis, both because of customers switching suppliers and because of changing daily load forecasts. In the PJM-West Region only currently available units can be used to meet the DACO. If an LSE remains deficient, it is charged the PJM-West Region Capacity Deficiency Rate [(CDR), currently $12,755.29 per MW-day], for each deficiency day. In no circumstance, is an LSE required to pay more than $63,776.45 for each deficient MW during the period from June 1, 2002 to May 31, 2003. LSEs are permitted to pay only a daily CDR, currently $174.73 per MW-day, for their deficiency if they choose to carry a portfolio of installed capacity valued at 118 percent of their respective Forecast Peak Period Load.

3 Adjusted for Active Load Management (ALM) and load diversity.

4 The CDR is a function both of the annual carrying costs of a Combustion Turbine (CT) and the forced outage rate and thus may change annually. The CDR was changed to $176.83 per MW-day effective June 1, 2001.

CAPACITY RESOURCES

Capacity resources are defined as MW of net generating capacity meeting specified PJM criteria. They may be located within or outside of the Region, but they must be committed to serving specific PJM loads. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[5]

Capacity resources may be bought in three different ways:

- **Bilateral, from an internal PJM Region source.** Internal, bilateral purchases may be in the form of a sale of all or part of a specific generating unit, or in the form of a capacity credit, defined in terms of unforced capacity and measured in MW.
- **Bilateral, from a generating unit external to PJM Region.** External, bilateral purchases (capacity imports) must meet PJM criteria, including that imports are from specific generating units and that sellers have firm transmission from the identified units to the metered boundaries of the PJM Region.
- **Capacity credit markets.** Market purchases may be made from PJM daily, monthly, multi-monthly or interval capacity credit markets.

The sale of a generating unit as a capacity resource within PJM entails obligations for the generation owner:

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by the units and sold outside PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[6] The recall right establishes a link between capacity and the actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the PJM area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time, spot market energy price.
- **Day-Ahead Energy Market Offer Requirement.** Owners of capacity resources are required to offer their output into PJM's day-ahead energy market. When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, resource owners must provide the offered energy at the offered price. This energy can be provided either from the specific unit offered or by purchasing the energy bilaterally or at the spot market price and reselling the energy at the offer price.
- **Deliverability.** In order to qualify as a capacity resource, the energy from the generating unit must be deliverable to load on the PJM system.
- **Generator Outage Reporting Requirement.** Owners of capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.

5 See RAA, Capacity Resources, page 2.

6 PJM emergency procedures are defined in the "PJM Manual for Emergency Operations."

- **Fixed Transmission Rights.** A Fixed Transmission Right (FTR) is available to load only if a specific capacity resource is identified as the source of the delivered energy. Since a capacity credit is not unit-specific, it cannot be the basis for an FTR. The FTR requirement adds value to the decision to be a capacity resource because this requirement creates an incentive for loads to enter into bilateral arrangements with capacity owners for unit-specific capacity where load is otherwise unhedged against the risk of congestion. A related, bilateral market has emerged in which a generation owner trades unit-specific capacity for capacity credits. The actual terms of such a transaction depend on the relative values of the two commodities. For example, unit-specific capacity may be more valuable to a purchaser because of the relative locations of that capacity and the purchaser's load and the value of the associated FTRs. The result could be that the purchaser would be willing to trade more than the equivalent amount of capacity credits for a MW of such capacity.

The first three obligations associated with sale of capacity resources are clearly essential to the definition of a capacity resource and contribute directly to system reliability. The importance of the link between capacity resources and FTRs is less clear.

MARKET DYNAMICS

RAA procedures determine PJM's total capacity obligation and thus the total demand for capacity credits. The RAA includes rules for allocating total capacity obligation to individual LSEs. This obligation is equivalent to a fixed total demand, net of active load management (ALM), bilateral contracts and self-supply, that must be bid into interval, multi-monthly, monthly or daily capacity credit markets. Demand for capacity credits in daily markets is the residual demand after capacity credits are purchased in longer-term capacity credit markets or through bilateral transactions.

The supply of capacity credits in all PJM capacity credit markets is a function of:

- Physical capacity in the PJM Region;
- Prices in external energy and capacity markets;
- Prices in the PJM energy and capacity markets;
- Capacity resource imports; and
- Transmission service availability and price.

While physical generating units in the PJM Region are the primary source of capacity resources, capacity resources can be delisted, i.e. exported, from the PJM Region and imported from regions external to PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of prices in both internal and external capacity and energy markets.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into the PJM market is the additional revenue foregone from not selling into an external energy and/or capacity market.

Generation owners can be expected to sell capacity into the most profitable market. The competitive price in the capacity markets is a function of the marginal cost of capacity. The marginal cost of capacity is, in turn, determined by the time period over which a choice is made as well as the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal costs would include the incremental costs of maintaining the unit so that it can qualify as a capacity resource and any relevant opportunity costs. If an owner is considering whether to sell a capacity resource for a day, the only relevant costs are the opportunity costs. The opportunity cost associated with the sale of a capacity resource is a function of the expected probability that the energy will be recalled and the expected distribution of the difference between external and internal energy prices.

Generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, depending on the rules of the capacity markets. The existence of interval markets makes the generators' decisions more dependent on assessments of seasonal energy market price differentials and recall probabilities. With longer capacity obligations, the likelihood of the net external price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.