# PJM Interconnection
# State of the Market Report
# 1999

Market Monitoring Unit
PJM Interconnection, L.L.C.
June 2000

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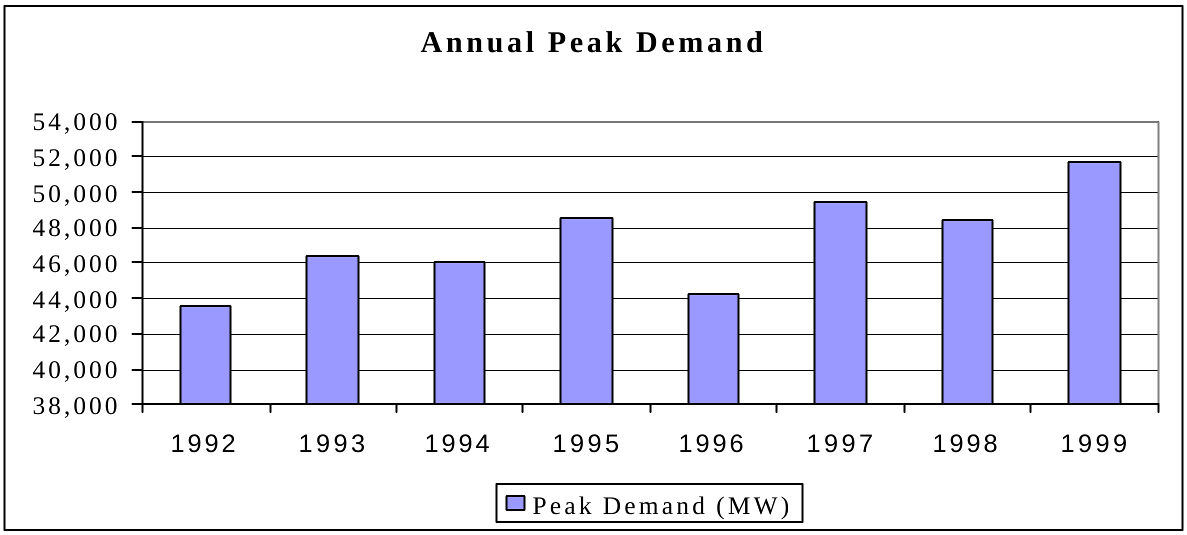
## Contents

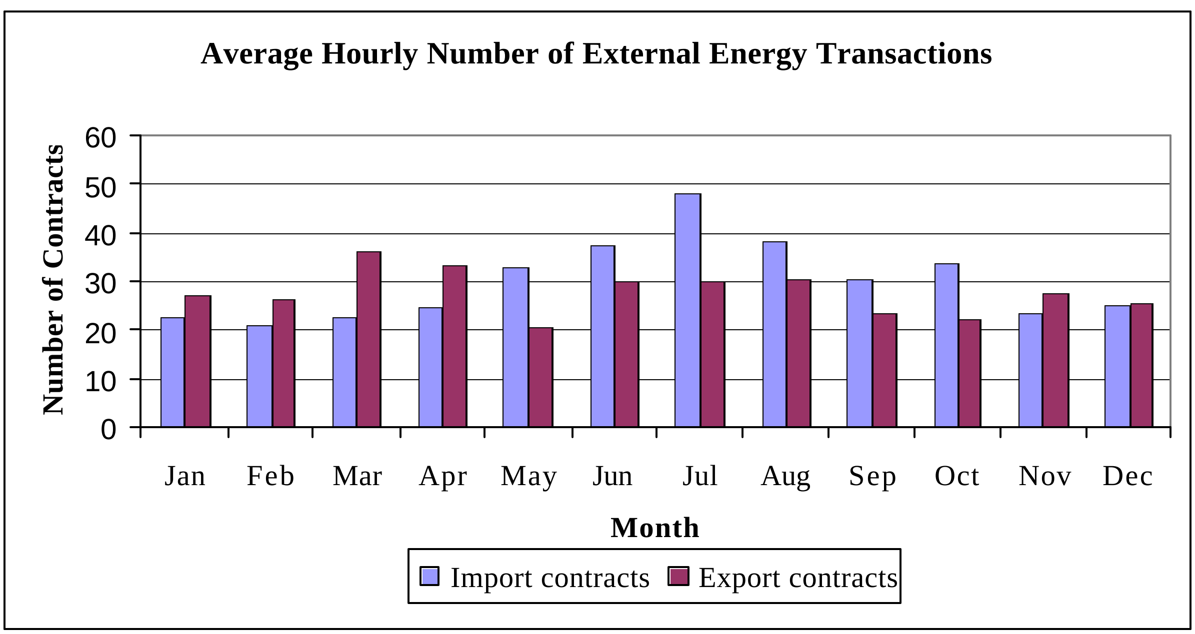
## Summary

The *PJM Interconnection State of the Market Report 1999* is the second annual State of the Market Report to the PJM Interconnection, L.L.C. (PJM) Board of Managers. This report was prepared by the PJM Market Monitoring Unit (MMU), in fulfillment of the commitment described in PJM's Market Monitoring Plan, to objectively assess the state of the PJM market and recommend potential enhancements to further improve its competitiveness and efficiency.

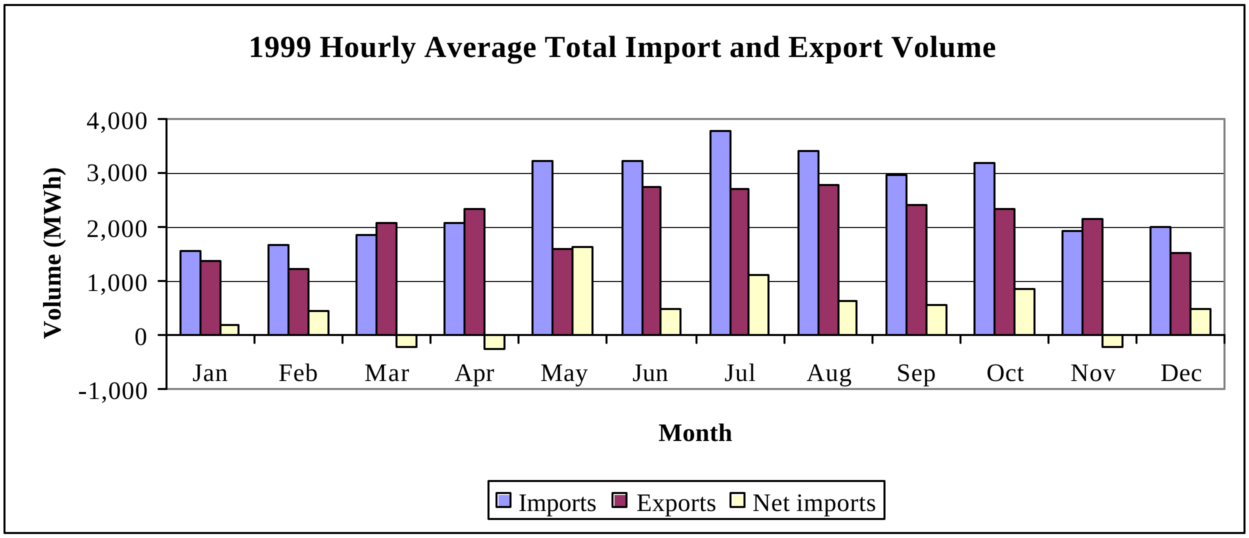
PJM operates the largest centrally dispatched control area in North America and the third largest in the world, via a bid-based market. PJM met a new high in peak load (51,700 MW) during 1999 using internal resources and imports from throughout the Eastern Interconnection.




The markets managed by PJM, in particular the energy and the capacity markets, are the focus of this report. The degree to which the energy market is open is reflected in the number and volume of 1999 exports and imports. The graphs show the average hourly number of import and export



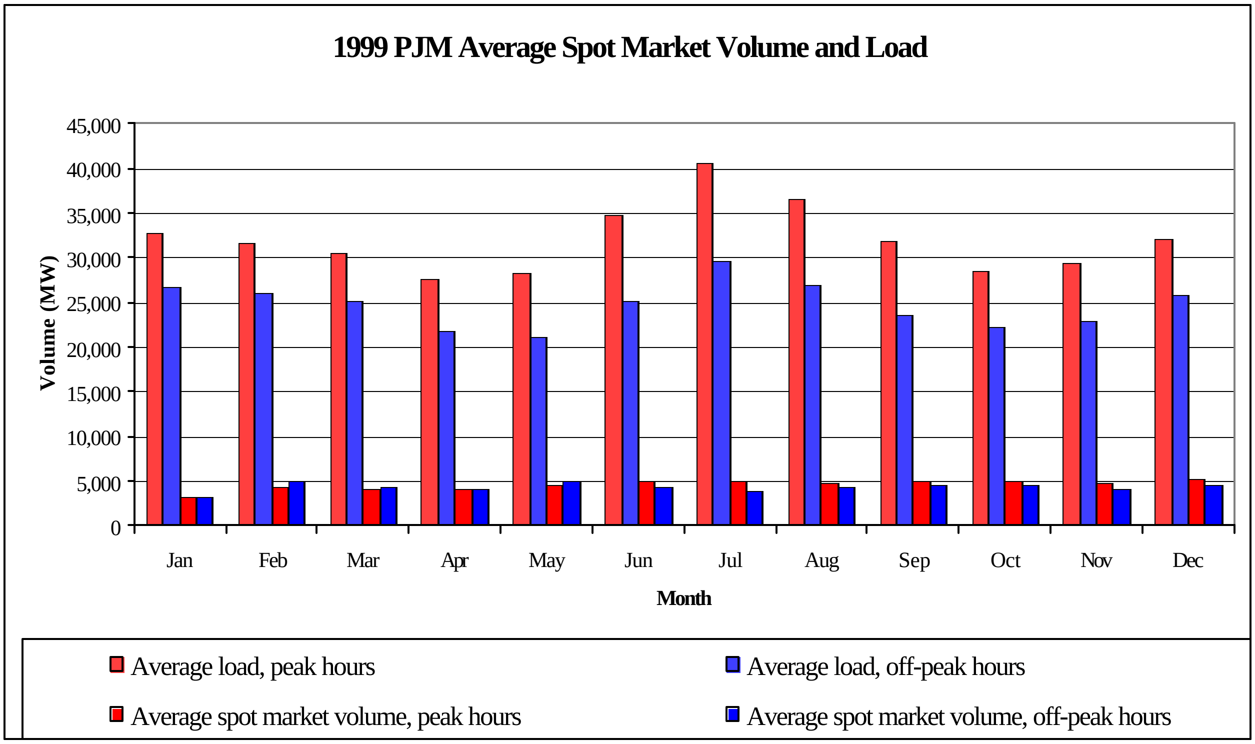
contracts and the average hourly volumes of imports and exports. PJM had a total of more than 264,000 import transactions in 1999 with a total volume in excess of 22,600,000 MWh and more than 240,000 export transactions with a total volume of almost 18,400,000 MWh. The reported transactions are for physical delivery and do not reflect the multiple underlying financial transactions.



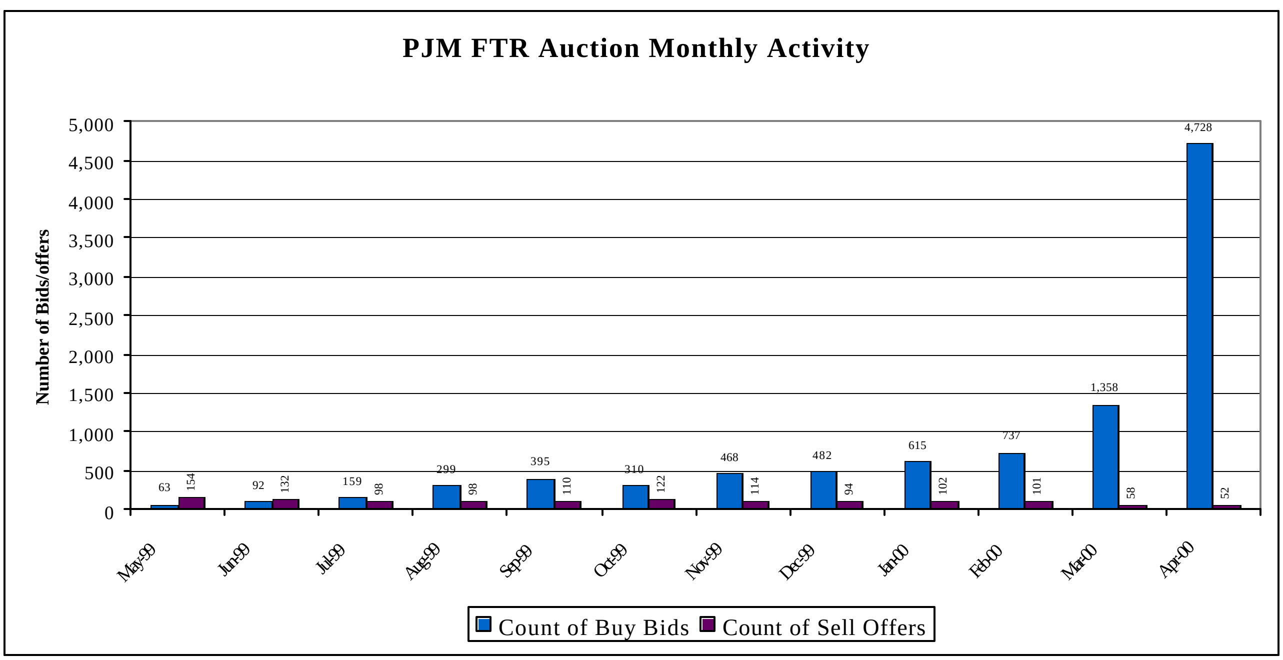

PJM introduced full market-based energy pricing on April 1, 1999 and a competitive auction-based FTR market on May 1, 1999. (FTRs, or Fixed Transmission Rights, are a financial mechanism to hedge the risk of paying congestion costs.) Capacity markets, introduced in late 1998, were broadened to include monthly and multi-monthly markets during 1999.

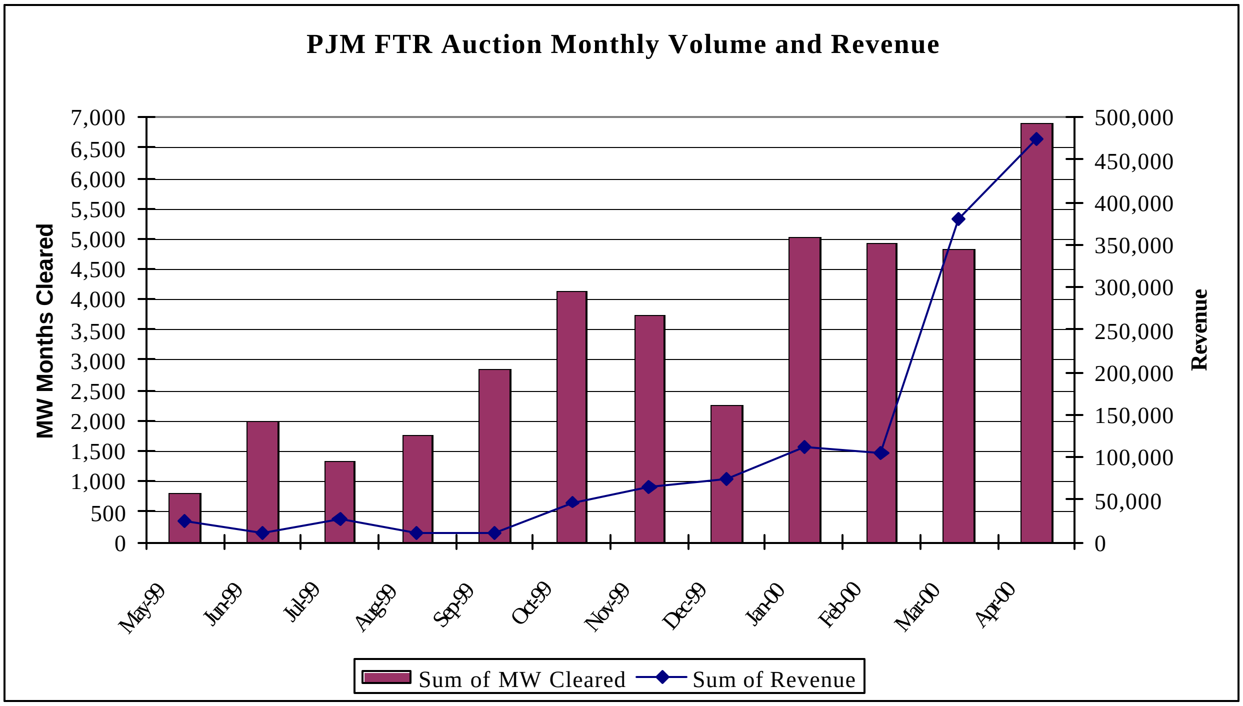
The total value of 1999 market transactions, for physical delivery, billed by PJM was approximately $1.8 billion. This includes spot market energy, capacity market transactions, ancillary services and transmission services, but excludes bilateral capacity and energy transactions and the provision of energy by integrated utilities to their own loads.

The overall size of the energy market averaged about 30,000 MWh with the spot energy market representing 4,500 MWh or about 15%. The bilateral market consisted of an average of about 9,000 MWh per hour, about 30%. Net imports were an average of about 500 MWh per hour. The balance of energy transactions (about 55%) was self-supplied by integrated entities which owned generation resources and served load.

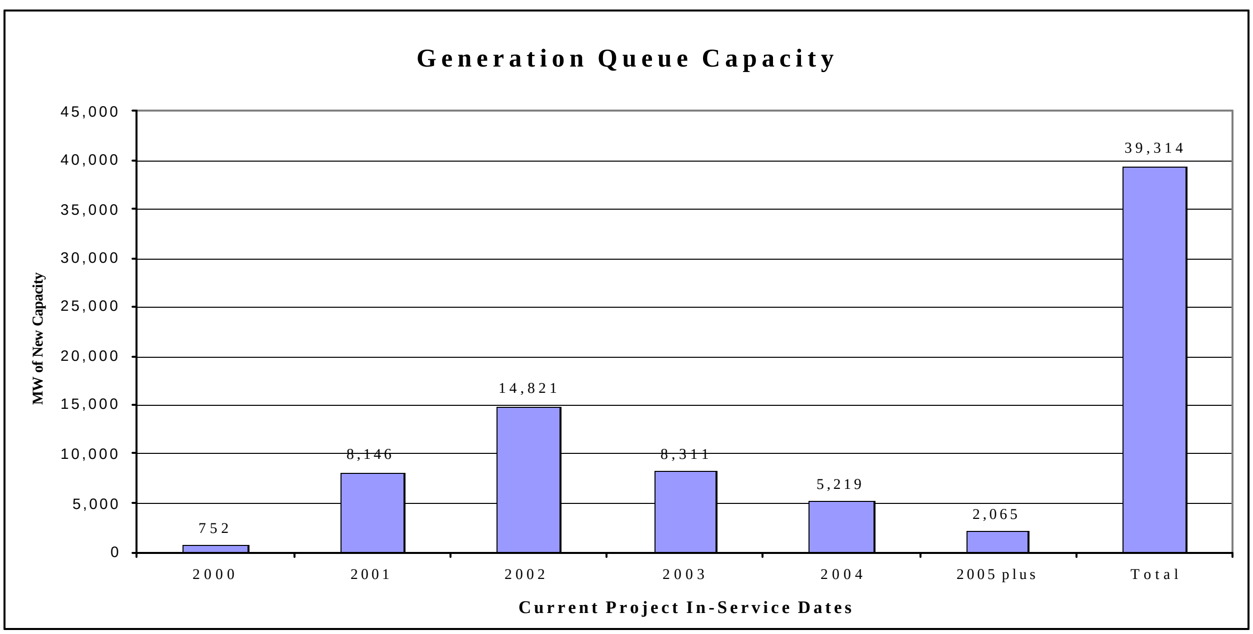



The monthly FTR auction market was introduced to increase liquidity by providing a mechanism to auction the residual FTR capability on the transmission system. The number of FTR buy bids has increased steadily since the auction was introduced, as have the MW months cleared and net revenue from the auction. The FTR auction has facilitated a more robust and liquid market for transmission entitlements.



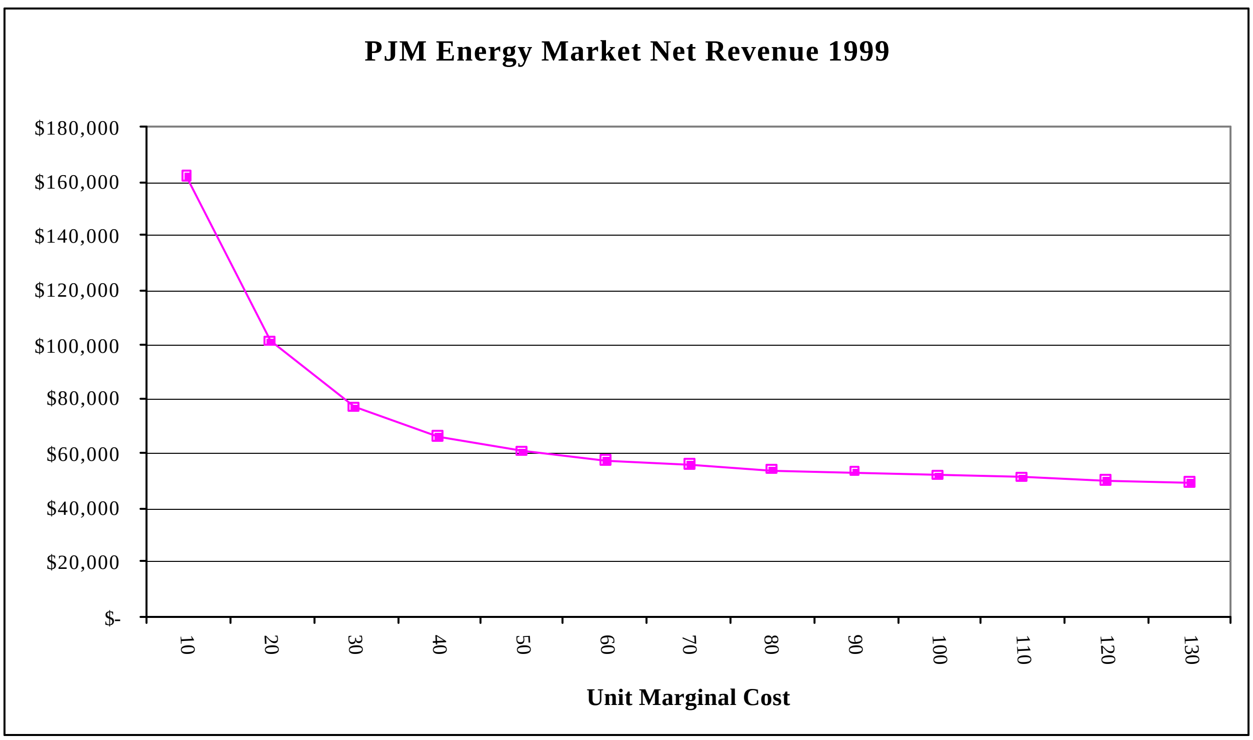



The positive incentives provided by PJM markets were reflected in the level of applications to build generation in the PJM area. In 1999, PJM took responsibility for overseeing the process of adding new generation facilities to the control area. PJM implemented a process to evaluate generation proposals, establishing orderly generation request queues. About 39,000 MW of capacity are in these queues compared to installed capacity of about 58,000 MW.



Fundamentally, the market mechanisms implemented and managed by PJM worked well. PJM calculated locational marginal prices (LMP) every five minutes for more than 2,000 buses and promptly posted them on its web site. PJM also continuously posted dispatch rates in real-time, thus providing a direct reference price signal to all sources of supply both within and outside PJM as well as to loads. These prices signaled the needed energy generation in real-time and opportunities for new generation in the longer term.

Net revenue is a significant indicator of overall market performance. The product of prices, paid by loads, and output determine gross revenue to generators. Gross revenue less variable cost is net revenue, and a net revenue curve illustrates the relationship between net revenue and generation cost. Net revenue represents revenue after *variable* costs, fuel and variable operation and maintenance (O&M) expenses, are covered. Net revenue is available to cover *fixed* costs, including a return on investment, depreciation and *fixed* O&M expenses. In a perfectly competitive, *energy-only* market, net revenue would be expected to equal the total of all these fixed costs, including a competitive return on investment, in long run equilibrium. In other words, net revenue is a measure of whether generators are receiving competitive returns on invested capital and whether energy prices are high enough to encourage the entry of new capacity. PJM has capacity, energy and ancillary services markets, all of which are sources of revenue to cover the fixed costs of generators. In a perfectly competitive market, with *energy, capacity and ancillary services* markets, the net revenues from all these markets would equal the fixed costs of generation, in long run equilibrium.



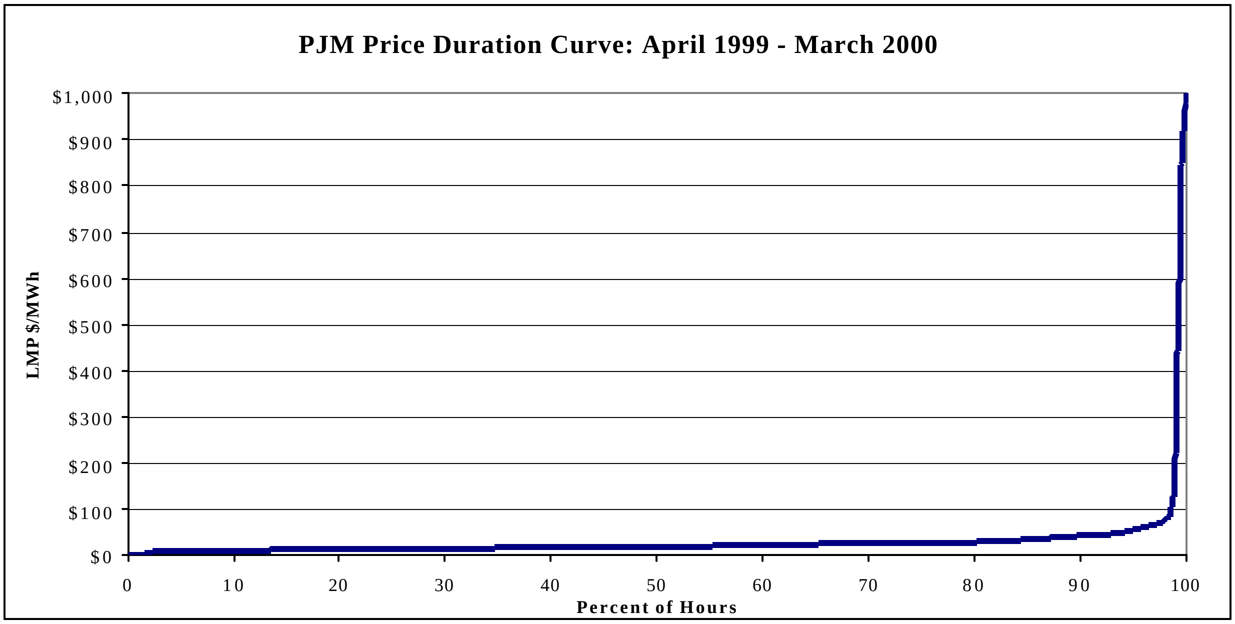
PJM Energy Market Net Revenue 1999 shows, on its vertical axis, the dollars per MW received by a unit in PJM, which operated whenever the system price exceeded the variable cost levels ($/MWh) on the horizontal axis. The curve is an approximate measure of the contribution to generators' fixed costs from the energy market. For example, a unit that operated whenever the LMP exceeded $30/MWh received about $77,000/MW in net revenue during 1999. In other words, a unit with marginal costs of $30 that operated during all profitable hours in 1999 received payments of $77,000/MW from the energy market. In addition, PJM capacity resources received an average payment from all capacity markets of $52.86/MW-day which is equivalent to $19,294/MW for the year. Thus, a PJM capacity resource with a marginal cost of $30/MWh received revenues of about $96,000/MW-year from capacity and energy markets. Similarly, a PJM capacity resource with a marginal cost of $40/MWh received revenues of $85,000/MW-year from capacity and energy markets. A PJM capacity resource with a marginal cost of $100/MWh received revenues of $71,000/MW-year from capacity and energy markets.

To put this in perspective, the PJM Capacity Deficiency Rate (CDR) is $58,400/MW-year. The CDR is designed to reflect the annual fixed costs of a combustion turbine (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/MW-year designed to reflect the difference between the PJM dispatch rate and CT costs during the hours when the CTs ran. Thus the annual fixed cost of a CT in PJM, per the CDR calculations, is about $63,000/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 net revenues from the energy market would have covered the capacity costs of a CT running at a marginal operating cost in the range from $30/MWh to about $45/MWh. When capacity market revenues are considered, the revenues from both energy and capacity markets would have more than covered the capacity costs of a CT running at a marginal operating cost in the range from $30/MWh to in excess of $130/MWh. Thus, without consideration of revenues from ancillary services, revenues from the energy and capacity markets more than covered the fixed costs of peaking units in PJM in 1999.

The end result of market structure and the conduct of individual market entities within that structure is reflected in market prices. The overall level of prices is a good general indicator of market performance and the results of market based pricing, although overall price results must be interpreted carefully because of the multiple factors that affect price levels. The following three sections examine three critical aspects of PJM markets during 1999.

Section 1, Locational Marginal Prices, presents a detailed review of overall prices during the first 12 months following the introduction of market-based prices and compares prices during this period to prices in prior periods. Following the introduction of market-based pricing, average prices increased from $22.04 per MWh in 1998 to $29.53 per MWh in 1999. This represents an increase of about 34% or about 29% after adjusting for higher fuel prices. Market prices were consistent with a competitive outcome for about 98% of the hours in the 12 months after April 1, 1999. Most of the total increase in prices occurred during a total of 96 hours, or about 1.1% of the hours, on the 15 high demand, hot days which occurred in the summer of 1999. During the period from April 1999 through March 2000, spot market prices in PJM were less than $20/MW in about 57% of the hours, less than $30/MW in 80% of the hours, less than $60/MW in 96% of the hours and less than $80/MW in 98% of the hours. PJM prices exceeded $130/MW in 96 hours in 1999. (High prices are defined to start at $130/MWh because this was the approximate operating cost of the highest cost unit on the PJM system in 1999 and thus would have been the highest bid under the cost-based bidding system.)




Section 2, The Energy Market, examines that market on the 15 high demand days. Three of these days are examined in detail including the levels of demand, the shape of the supply curve, the level of imports and exports, the significance of capacity related export recalls and external prices. The analysis concludes that the price increases were the result of a combination of factors including scarcity and market power but that it is not possible to quantify the relative importance of these two factors.

Section 3, The Capacity Market, reviews the operation of that market during 1999 which included the introduction of new capacity market rules effective June 1, 1999, the temporary suspension of mandatory bidding, the supply-demand balance in the capacity market, the import and export of capacity and the recall of energy exports from capacity resources. Capacity obligations contribute to the effective and competitive functioning of the energy market. As the analysis of Section 2 demonstrates, the availability of adequate capacity resources can be critical to ensuring that loads are met on high demand days. The incentives to sell capacity into and out of PJM are examined and the analysis concludes that changes to the incentive structure of the capacity market are necessary to encourage adequate capacity and adequate levels of associated energy.

The *PJM Interconnection State of the Market Report 1999* concludes that, under most conditions, PJM energy and capacity markets have worked effectively and competitively. Nonetheless, market participants do possess some ability to exercise market power on high demand days. This report identifies several key areas where changes in market rules and market designs would result in improvements in the functioning of PJM markets. These include:

1. Retention of the $1,000/MWh bid cap in the PJM energy market and investigation of other rules changes to reduce the incentives to exercise market power.
2. Investigation of real-time market mechanisms to permit the market price to be bid to a level required to attract imports on days of high demand.
3. Evaluation of possible actions to increase demand side responsiveness to price.
4. Modification of incentives in the capacity market to require all Load Serving Entities (LSEs) to meet their obligations to serve load on an annual or semiannual basis and to require all capacity resources to be offered on an annual or semiannual basis.
5. Reevaluation of the criteria used to determine whether generating units qualify for capacity resource status.

PJM has already taken actions which address portions of these recommendations. In particular, a representative PJM committee determined that it is appropriate to retain the bid cap in the energy market and the capacity market for the immediate future. In addition, the two settlement system implemented on June 1, 2000 addresses parts of recommendations 2 and 3, while PJM has filed with FERC changes that provide penalties on certain categories of capacity resources, consistent with recommendation 4.

Based on the experience of the MMU during its first year and this analysis of the markets, the MMU does not recommend any change to the Market Monitoring Unit or the Market Monitoring Plan. The Market Monitoring Unit published a report on ancillary services markets in PJM on April 1, 2000 and will publish a report on the FTR auction markets in PJM on August 1, 2000.

## LOCATIONAL MARGINAL PRICES

Locational Marginal Pricing was implemented in the PJM control area on April 1, 1998. Upon FERC approval of a petition by the PJM Supporting Companies in June 1997, market-based pricing was implemented on April 1, 1999. Under market based pricing, generating resources within the PJM control area can submit offers that are market based rather than cost based (subject to a cap of $1000/MW).

This section presents comparisons of PJM prices (LMPs) between April 1, 1999 and March 31, 2000, and the prior 12-month period. In this single year comparison, PJM prices were higher after the implementation of market-based prices than under cost-based pricing. The higher prices reflect the interaction of higher demands, particularly during a small number of high-demand days, with the shape of the supply curve, which, in turn, reflects both scarcity rents, and the exercise of market power by generators. The shape of the supply curve also reflects PJM generators being allowed to increase cost based bids by 10% on April 1, 1999. About 69% of the overall increase in prices between 1998 and 1999 occurred on the 15 hot, high-demand days during the summer of 1999. After further adjusting these prices for fuel cost increases, about 84% of the overall increase in prices is accounted for by the 15 high demand days.

Since the PJM control area is predominately summer-peaking, it is instructive to compare the price behavior during the summer of 1999, the first full season of market-based bids, as with the summer of 1998. The following comparisons of LMPs during the two summers begin with observations for all hours and then for constrained hours only. To provide further perspective, a brief comparison with MCPs during the summer of 1997 is offered. Finally, the discussion turns to a comparison of LMPs covering April 1, 1998 – March 31, 1999 and April 1, 1999 – March 31, 2000. This section examines the overall level of hourly LMPs for the two years, and the level of LMPs after adjustment for fuel cost differences. A comparison of LMPs excluding the high-demand hot days is then addressed and overall conclusions drawn.

### Daily Average Prices – Summer 1997, 1998, 1999

Table 1 provides summary statistics for the relationships between average daily MCP and average daily LMPs during the summers of 1997, 1998, and 1999. Figure 1 portrays this

**Table 1**
**Average Daily LMP Summary Statistics ($/MWh)**

| | Summer 1997 (MCP) | Summer 1998 (LMP) | Summer 1999 (LMP) |
|---|---|---|---|
| Average LMP | 23.08 | 29.65 | 53.69 |
| Median LMP | 17.25 | 20.40 | 22.78 |
| Standard Deviation | 17.89 | 58.99 | 140.33 |
| | **% Increase 97 to 98** | **% Increase 98 to 99** | **% Increase 97 to 99** |
| Average LMP | 28.47 | 81.08 | 132.63 |
| Median LMP | 18.26 | 11.67 | 32.06 |
| Standard Deviation | 229.74 | 137.89 | 684.40 |

information graphically. As indicated in Table 1, average summer prices in 1999 were about \$31/MWh higher than in 1997, and about \$24/MWh higher than 1998. The distribution of prices in the summer of 1999 was also much wider than in either of the other two periods. The standard deviation of average daily prices was eight times higher in the summer of 1999 than that in the summer of 1997 and more than twice as high as that in the summer of 1998.

**PJM LMPs – All Hours**

***PJM Price Duration Curves and LMP Frequency Distributions***

Figure 2 shows the PJM system-wide price duration curves for the summer of 1998 and 1999 (for the purposes of this discussion, summer months are June, July, and August).[1] The LMPs used in the graph are the load-weighted, hourly-integrated values used for billing purposes[2]. The curves show the percent of hours that the PJM system-wide LMPs were at or below a given price for the period.

The graph shows that there was little difference in system-wide LMPs between the cost-capped bid summer of 1998 and the market-based bid summer of 1999 for roughly 80% of the hours. LMPs for the summer of 1998 were \$40/MWh or less for 85% of the hours, while LMPs for the summer of 1999 were \$40/MWh or less for 79% of the hours.

Although the system-wide LMPs are similar for about 80% of the hours, the separation of the two curves in Figure 2 indicates that prices were higher during the market-based bid summer of 1999. There were more high prices, and those prices were higher for a larger percentage of the time.

That LMPs were more dispersed during the market-based bid summer of 1999 than the cost-capped bid summer of 1998 can be seen by comparing Figures 3 and 4. The figures show the frequency distribution by hours of PJM system-wide LMPs for the respective periods. 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 LMPs were within a given \$10 price interval.[3]

The shapes of the summer 1998 and summer 1999 frequency distributions are similar. In each summer period the most frequently occurring price interval is \$10-\$20/MWh (47% and 41%, respectively) and each distribution is highly positively skewed. Figures 3 and 4 also illustrate the higher dispersion of LMPs during the market-based bid summer 1999. There are more high prices, with a higher frequency of occurrence during this period. For example, there were 96

[1] The *Reliability Assurance Agreement* defines the peak season for the purposes of maintenance to be the 24$^{th}$ through 36$^{th}$ Wednesdays of the calendar year, approximately mid-June through the second week in September.
[2] PJM system-wide LMPs are load–weighted averages of the LMPs calculated every five minutes for each of the approximately 1470 load buses in the PJM system. The MWs taken at the bus are also determined every five minutes. These five-minute values are then summed and divided by 12 to derive the hourly integrated values of LMP and MW for each load bus. The PJM system-wide, load-weighted, hourly-integrated LMP is then calculated using the hourly integrated values as: $[\Sigma_{\text{all load buses}}(\text{LMP*MW})]/\Sigma_{\text{all load buses}}\text{MW}$ for each hour.
[3] Only LMP intervals with a positive frequency are included in the chart.

hours during the summer of 1999 in which LMPs were higher than $130/MWh (4.3% of the hours) compared to 26 hours (1.2% of the hours) during the summer of 1998.

Table 2 presents summary statistics for the LMPs for the two summer periods. As can be seen from the table, the average LMP in summer 1999 was about $24/MWh higher than the average LMP in summer 1998, $53.69/MWh compared to $29.65/MWh. The median LMP in the two summers is much closer, differing by only $2.38/MWh. That the mean lies to the right of the median in both summers shows the positive skewness of the distribution of the prices, particularly in summer 1999. The larger dispersion in LMPs during summer 1999 is also reflected in the standard deviation during the summer of 1999, which is more than twice the standard deviation in 1998.

**Table 2**
**Summer 1998 LMPs vs Summer 1999 LMPs ($/MWh)**

| | Summer 1998 | Summer 1999 | Difference | % Increase |
|---|---|---|---|---|
| Average LMP | 29.65 | 53.69 | 24.04 | 81.08 |
| Median LMP | 20.40 | 22.78 | 2.38 | 11.67 |
| Standard Deviation | 58.99 | 140.33 | 81.34 | 137.89 |

**Bus-Level Comparisons**

Table 3 presents a monthly comparison of selected statistics for the two summer periods at the bus level. The statistics were calculated from the integrated hourly LMPs at approximately 2000 load and generation buses over the two periods. These LMPs are not load-weighted, so they differ somewhat from the LMP values previously presented.

Table 3 indicates that the monthly average LMPs were higher in each month during the market-based bid summer of 1999. The dispersion of prices, as indicated by the standard deviation, also increased sharply in June and July 1999 compared to the same months in 1998, while price dispersion in August 1998 was slightly higher than price dispersion in August 1999. The monthly median LMP increased comparatively slightly in each month from 1998 to 1999, staying in a range of roughly $15-$27/MWh.

**Table 3**
**Monthly LMPs ($/MWh)**

| | June | | July | | August | |
|---|---|---|---|---|---|---|
| | **1998** | **1999** | **1998** | **1999** | **1998** | **1999** |
| Average LMP | 25.02 | 37.09 | 34.22 | 91.71 | 29.59 | 32.05 |
| Median LMP | 16.76 | 19.16 | 21.68 | 26.94 | 21.3 | 21.73 |
| Stnd.Deviation | 29.82 | 98.29 | 76.20 | 210.97 | 60.25 | 53.87 |
| Max. LMP | 300.10 | 850.0 | 900.0 | 1730.00 | 999.0 | 1886.57 |
| Min. LMP | -22.68 | -57.55 | -124.56 | -198.33 | 0.0 | -44.44 |
| LMP Range | 322.78 | 907.55 | 1024.56 | 1928.03 | 999.0 | 1931.01 |

The relative increase in the difference between the median and the mean in 1999 indicates that LMPs in the summer of 1999 were more positively skewed than in 1998 – a higher frequency of higher prices. The data show the increase in price dispersion in the summer months of 1999 compared to 1998.

Although generation bids are capped at $1000/MWh, LMPs can rise above this level, as the maximum LMPs in July and August 1999 show. LMPs above $1000/MWh can occur when the system is constrained. They show the value of an additional MW injection into the system at a particular bus to help alleviate the constraint. Conversely, a negative LMP is a signal to a bus on one side of the constraint to reduce MW injections, as these injections are exacerbating the constraint. Minimum LMPs were negative in each month except August 1998.

**PJM LMPs During Constrained Hours** [4]

LMPs reflect the marginal cost of energy (generation marginal cost) at each location (bus). The difference among nodal prices, when they differ, is congestion cost. In an LMP system, buyers and sellers experience the actual cost to deliver energy at their location on the transmission system. Full nodal pricing encourages efficient use of the transmission system by assigning revenues to generators and costs to users based on the way energy is actually produced and delivered.

The cost to operate electric generators varies from generator to generator based on many factors including the type of fuel and the generator's efficiency. These costs or prices are bid into the market, where generators are operated to serve the electric demand using economic dispatch. Economic dispatch is a process in which generators within PJM are turned on, based on lowest to highest price as required to meet the energy demand. As demand rises, more generators are operated to satisfy the load, and the overall cost to meet the load increases. Absent power delivery limitations (transmission congestion), the price of electric energy in the entire control area is equal to the cost of the most expensive generator operating to meet the demand. In this case all LMPs are the same, and the market clearing price is set at the marginal cost of the last generator dispatched.

Under some operating conditions, the next least-cost generator cannot be used to meet increasing demand because of power delivery limitations, or constraints, on the transmission system. These delivery limitations restrict the ability to deliver economic generation resources at one location to meet demand at another location on the transmission system. When this occurs, a generator that is more expensive, but at an advantageous location relative to the transmission constraint, must be operated in place of the less expensive one. This increase in the overall cost of electric energy due to the transmission constraint is referred to as *security constrained re-dispatch cost*.

Under the locational price model, the price of energy can vary depending on where the bus is located. For example, if a load bus is located in the east, and there is a transmission constraint inhibiting the flow of energy from the west, the LMP at that bus is dependent on the marginal cost of the generator(s) in the east that can most economically be used to serve the load. Thus,

[4] For the 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.

the price of electric energy at load buses in the east can be different (higher in this case) than the price of electric energy at load buses in the west. In fact, during periods of transmission constraints, prices can differ at every bus location.

From April 1, 1997 to March 31, 1998, prior to the implementation of LMP, a single price during each time period was used at each bus to clear the market. This single Market Clearing Price (MCP) was the system lambda, the incremental cost of generation for a given time period. A major problem with MCP was that proper price signals were not sent during congested periods. Unlike LMP where prices differ at various buses during constrained hours, the single price at every bus under MCP reflected only system generation marginal cost and ignored the very real costs of transmission congestion.

**PJM Price Duration Curves and LMP Frequency Distributions**

Figure 5 shows the PJM system-wide price duration curves during constrained hours for the summer of 1998 and 1999 (summer months are June, July, and August). The PJM system-wide LMPs during constrained hours are the load-weighted, hourly-integrated values and thus are average LMP values. The graph indicates there were 294 constrained hours during the summer of 1998 and 548 constrained hours during the summer of 1999.

The graph further shows there was a marked difference in the distribution of system-wide LMPs during constrained hours between the cost-capped bid summer of 1998 and the market-based bid summer of 1999. LMPs during constrained hours in the summer of 1999 were consistently higher than LMPs during constrained hours in the summer of 1998, reaching appreciably higher levels. For example, constrained LMPs during the summer of 1998 never exceeded about $55/MWh, while constrained LMPs during the summer of 1999 reached a level of about $950/MWh. The separation of the two graphs in Figure 5 indicates that prices were much more dispersed during the market-based bid summer of 1999. There were more high prices, and the prices were higher for a larger percentage of the time.

That LMPs during constrained hours had a different distribution and were more widely dispersed during the summers of 1999 and 1998 can be observed by comparing Figures 6 and 7. The figures show the frequency distribution by hours of LMPs during constrained hours for the respective periods. 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 LMPs were within a given $10 price interval.

As can be seen from Figure 6, LMPs during constrained hours in the summer of 1998 were $30/MWh or less for 84% of the hours, and never exceeded $60/MWh. By contrast, LMPs during the constrained hours of summer of 1999 were $30/MWh or less during only 23% of the hours, and LMPs exceeded $60/MWh for 13% of the hours, reaching a maximum of about $950/MWh. Figure 7 is also much more positively skewed than Figure 6, indicating a higher level of LMP dispersion during constrained hours in 1999.

Table 4 presents summary statistics for the LMPs during constrained hours for the two summer periods. As can be seen from the table, the average LMP in summer 1999 was about $27/MWh higher than the average LMP in summer 1998, $49.78/MWh compared to $22.72/MWh. The median LMP during constrained hours is also higher in summer 1999, by about $14/MWh. That the mean lies to the right of the median in both summers shows the positive skewness of the distribution of the prices. However, as can be seen from a comparison of Figures 6 and 7, the distribution of LMPs in summer 1998 is only slightly skewed, whereas the distribution in summer 1999 has a pronounced positive skewness. The much larger dispersion of LMPs during the constrained hours of summer 1999 is also reflected in the standard deviation, which is more than eight times the standard deviation in 1998.

**Table 4**
**LMPs During Constrained Hours: Summer 1998 vs Summer 1999 ($/MWh)**

| | Summer 1998 | Summer 1999 | Difference |
|---|---|---|---|
| Average LMP | 22.72 | 49.78 | 27.06 |
| Median LMP | 21.23 | 34.83 | 13.60 |
| Standard Deviation | 9.03 | 84.30 | 75.27 |

Table 5 provides a comparison of average LMPs during constrained and non-constrained hours for the summers of 1998 and 1999. In both cases, average LMP and the standard deviation are higher during non-constrained than constrained hours. Higher prices occur when demand is high. When demand is high, more generators are operating, thereby tending to relieve transmission constraints. Transmission constraints tend to occur during intermediate demand periods when not all generators are needed to meet demand, or may be turned off because of economy energy purchases. In addition, the ratio of 1999 prices to 1998 prices is greater during constrained periods (2.2) than during unconstrained periods (1.8).

**Table 5**
**LMPs During Non-Constrained and Constrained Hours ($/MWh)**

| | Summer 1998 | | | Summer 1999 | | |
|---|---|---|---|---|---|---|
| | Non-Const. Hrs. | Const. Hrs. | Diff. | Non-Const. Hrs. | Const. Hrs. | Diff. |
| Average LMP | 30.71 | 22.72 | 7.99 | 54.98 | 49.78 | 5.20 |
| Median LMP | 20.29 | 21.23 | -0.94 | 19.10 | 34.83 | -15.73 |
| Stnd. Dev. | 63.20 | 9.03 | 54.17 | 154.42 | 84.30 | 70.12 |

**Bus-Level Comparisons**

Figures 8 through 10 show the monthly comparison of average LMPs during constrained hours for the summer months of 1998 versus 1999. The average LMPs during constrained hours were calculated from the integrated hourly LMPs at approximately 2000 buses in each of the months. For each of the 2000 buses, the average constrained LMP was calculated over all hours during which there was a constraint on the system for that month. Thus, each point on the graph represents the average constrained LMP and the standard deviation of the LMP at a single bus.

The standard deviation of the constrained LMPs is plotted against the average LMP for each bus to provide an indication of the dispersion of average prices at the bus during constrained hours.

Figure 8 indicates that there were 95 constrained hours in June 1998 and 163 constrained hours in June 1999. Although the pattern of the price distribution is similar in each year, it can be noted that both the average price level and the spread in the prices (as indicated by the standard deviation) are considerably higher in June 1999. Average LMPs in June 1999 were concentrated in a price range of $30-$40/MWh during constrained hours, compared to $20-$30/MWh during constrained hours in June 1998. The standard deviation of prices, indicating price variation at the bus, is concentrated at about $50/MWh in June 1999, while it is concentrated at only about $10/MWh in June 1998.

Figure 9 shows that there were 151 constrained hours in July 1998 and 127 constrained hours in July 1999. The figure shows that the distribution of prices was much different in the month, year to year. In July 1999 average prices were concentrated in a range of about $50-$80/MWh during constrained hours, compared to a price range of $20-$40/MWh in July 1998. Note that in July 1999 the average prices during constrained periods at several buses were much higher than average prices at other buses on the system, ranging from approximately $110/MWh to $170/MWh. Note also that in July 1999 the standard deviation of price increases as the average price level increases. The increased dispersion is in contrast to the relatively stable distribution of prices in July 1998.

Figure 10 shows that there were 48 constrained hours in August 1998 and 258 constrained hours in August 1999. It can again be seen that both the price level and the distribution of prices are considerably higher in August 1999. Average LMPs in August 1999 were concentrated in a range around $51-$53/MWh, with a smaller concentration in the mid $60/MWh range. Average LMPs in August 1998, by contrast, were concentrated in the low $20/MWh range. The standard deviation of prices in August 1999 also shows a tendency to increase as price increases. Again, there is much more spread in the prices as the average price level increases in August 1999 when compared to the spread of prices in August 1998.

**Comparison of LMPs, April to March, 1998 and 1999**

This section contrasts the level and distribution of LMPs during the market-based offer period from April 1, 1999 to March 31, 2000 to the same period in 1998 - 1999, during which time offers were cost-capped. Figure 11 shows the PJM system-wide price duration curves for the two time periods. The LMPs used in the graph are load-weighted, hourly-integrated values. The graphs show the percent of hours that the LMPs were at or below a given price for each of the periods.

Figure 11 and Figures 13 and 14 show there was relatively little difference in system-wide LMPs for approximately 90% of the hours in the two periods (Figure 12 indicates the price duration curves for hours above the 95$^{th}$ percentile in greater resolution). LMPs during April 1998 - March 1999 were $50/MWh or less 97% of the time, while LMPs during April 1999 - March 2000 were $50/MWh or less 94% of the time. Contrasting the figures, it is evident that the frequency distribution of LMPs for the two periods are similar, with the higher dispersion of LMPs during the April 1999 – March 2000 period reflecting the higher price dispersion during the summer of 1999.

Table 6 provides summary statistics for the two periods. The average LMP during April 1999 to March 2000 was 34% higher than the same period in 1998-1999 . The median LMPs for the two periods were much closer, with the median LMP in April 1999 to March 2000 being about 8.5% higher. The standard deviation of the average LMP is much higher during the April 1999 to March 2000 period, about 132% higher, again, reflecting the events during the summer of 1999.

**Table 6**
**April to March, 1998-1999 and 1999-2000 LMPs ($/MWh)**

| | 1998-1999 | 1999-2000 | % Increase |
|---|---|---|---|
| Average LMP | 22.04 | 29.53 | 33.99 |
| Medial LMP | 16.93 | 18.37 | 8.49 |
| Standard Deviation | 31.38 | 72.64 | 131.52 |

**Fuel Cost Adjusted LMPs, April-March, 1999-2000**

In order to control for differences between April 1998 – March 1999 and April 1999 – March 2000 LMPs that are caused by differences in fuel costs between the two years, the April 1999 – March 2000 LMPs were adjusted to account for fuel cost differences between the two periods. A composite index was created for each month of April 1999 to March 2000 that consists of the ratio of 1999-2000 fuel specific prices to 1998-1999 fuel specific prices, multiplied by the fuel type's market share, and then summed across fuel types. Each hourly, load adjusted LMP in the months of April 1999 to March 2000 was then divided by that month's composite index. The composite index of fuel costs was lower in April 1999 – March 2000 for the months of April, May, June, and July (ranging from 9% to 2% lower), and higher for the remainder of the months. The composite index reached a level 17% to 21% higher in the months of January, February, and March, 2000, reflecting the increase in petroleum and natural gas prices.

Figure 15 shows the hourly fuel cost adjusted LMPs during April-March 1998-1999 and April-March 1999-2000. The graph indicates price spikes during the summer of both years, as previously noted, though there were more high priced hours during the summer of 1999.

**Table 7**
**April-March, 1998-1999 and 1999-2000 Fuel Cost Adjusted LMPs ($/MWh)**

| | 1998 | 1999 | % Increase |
|---|---|---|---|
| Average LMP | 22.04 | 28.64 | 29.95 |
| Median LMP | 16.93 | 17.37 | 2.57 |
| Standard Deviation | 31.38 | 74.30 | 136.79 |

Table 7 presents the summary statistics comparing April-March 1998-1999 LMPs to the fuel cost adjusted April-March 1999-2000 LMPs. In contrasting Tables 6 and 7, adjusting the April-March 1999-2000 LMPs for fuel cost differences reduces the increase in average LMP by about

4 percentage points and lowers the increase in the median by about 6 percentage points from the unadjusted LMPs, while increasing standard deviation by about 5 percentage points. Note that adjusting for fuel cost increases accounts for about 12% (4 percentage points) of the 34% increase in average LMP shown in Table 6.

**LMPs Excluding High-Demand Days**

As the previous discussion has indicated, the largest dispersion in LMPs has taken place during the summer months, and in particular, on the high-demand days of the summer months. A final comparison of April-March 1998-1999 to April-March 1999-2000 LMPs was made by examining LMPs during the two years while excluding high-demand days. For the purpose of this discussion, a high-demand day is defined as a day during which the LMP exceeded $130/MWh in any hour. There were 11 such days during April-March 1998-1999, and 15 such days during April-March 1999-2000. During the former year there were high-demand days in May, June, July, August, and September. During the latter year all the high-demand days were in the months of June, July, and August.

Table 8 summarizes the hourly LMPs (not fuel cost adjusted) for the two periods when high-demand days are excluded from both periods. Figure 16 provides the graphic representation. Per the table, average LMP during April-March 1999-2000 is 10.5% higher than the average LMP during the same period in 1998-1999. In addition, the dispersion of the average LMPs during the two periods, as shown by the standard deviation, is only 26% higher in 1999-2000, versus 132% when high-demand days are included.

**Table 8**
**April-March 1998-1999 and 1999-2000 LMPs, No High-Demand Days ( $/MWh)**

| | 1998 | 1999 | % Increase |
|---|---|---|---|
| Average LMP | 20.12 | 22.22 | 10.47 |
| Median LMP | 16.82 | 18.11 | 7.67 |
| Standard Deviation | 10.41 | 13.08 | 25.72 |

Table 9 provides a statistical summary of the hourly fuel-cost adjusted LMPs for the two periods when high-demand days are excluded, while Figure 17 offers a graphical representation. The table illustrates that the average fuel-cost adjusted LMP during April-March 1999-2000 when high-demand days are excluded is only 4.7% higher than the same period in 1998-1999. Also, the median LMP during April-March 1999-2000 is only 1.4% higher than the same period in 1998-1999.

**Table 9**
**April-March 1998-1999 and 1999-2000 Fuel Cost Adjusted LMPs, No High-Demand Days ( $/MWh)**

| | 1998 | 1999 | % Increase |
|---|---|---|---|
| Average LMP | 20.12 | 21.06 | 4.68 |
| Median LMP | 16.82 | 17.05 | 1.36 |
| Standard Deviation | 10.41 | 12.30 | 18.17 |

The difference in the dispersion of the average LMPs during the two years, as shown by the difference in the standard deviations, was reduced by about eight percentage points when fuel cost differences between the two years are considered.

**Conclusions**

The comparisons between price levels and dispersions indicate that both were higher during the market-based bid period of 1999 than during the cost-capped bid period of 1998. These price differences were most pronounced during periods of high-demand, comprising about 69% of the total price increase between the years on an unadjusted basis and about 84% after adjustment for changes in fuel cost.

As will be explained in more detail in Section 3, the higher prices were the result of the interaction of high-demand levels with supply curves that exhibited steep slopes over very narrow ranges of output. Had the supply curves been cost-based, prices would not have increased above the $130 level during the summer of 1999. However it appears that prices above the $130 level were required in order to attract imports to meet PJM loads during some of the high-demand days. Thus, scarcity was responsible for some of the price increase, but market power also played a part, although the relative proportions of the two factors are unclear. Section 3 explores the reasons for the higher prices on the high-demand days.

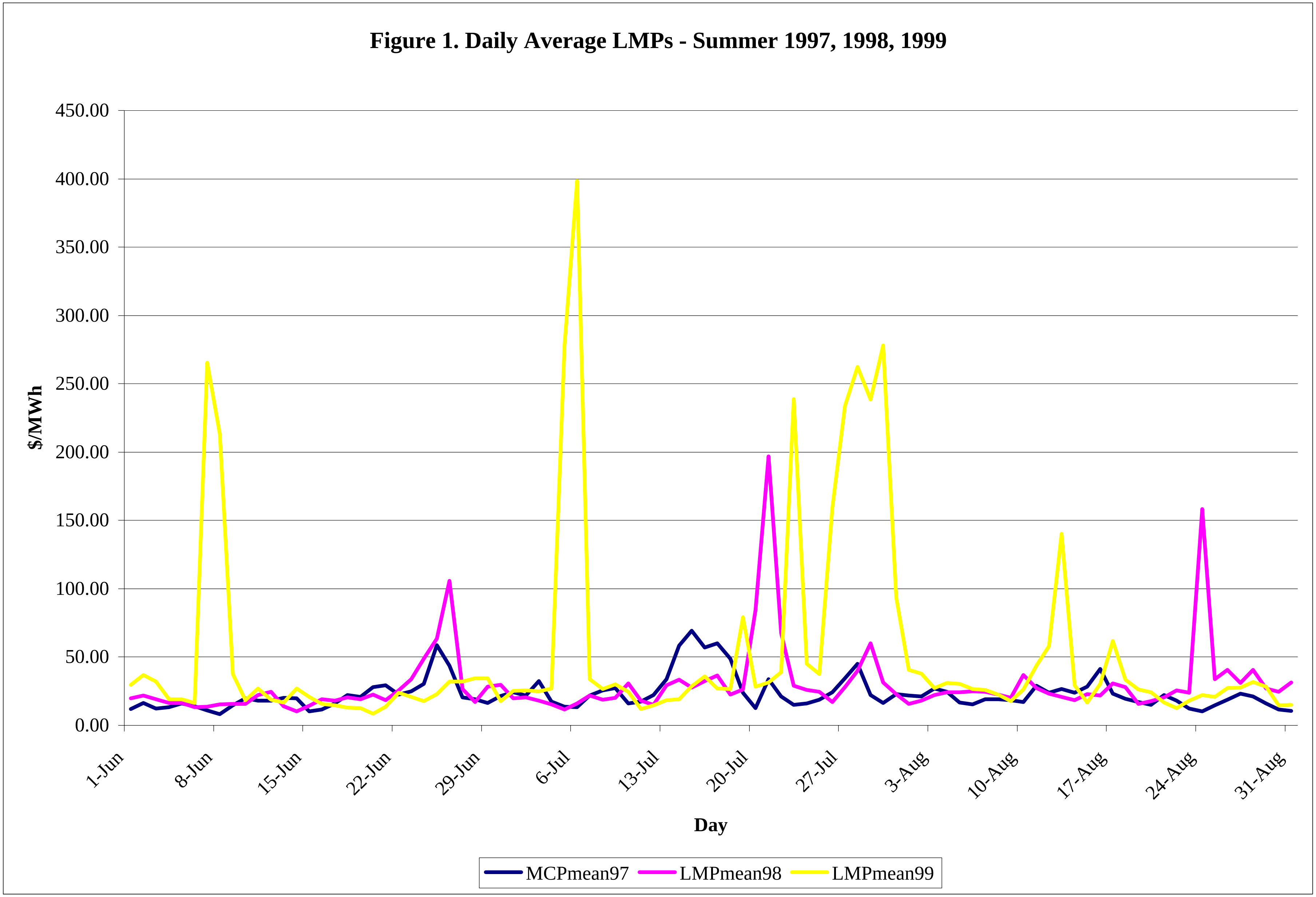


Figure 1. Daily Average LMPs - Summer 1997, 1998, 1999
$/MWh
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
1-Jun
8-Jun
15-Jun
22-Jun
29-Jun
6-Jul
13-Jul
20-Jul
27-Jul
3-Aug
10-Aug
17-Aug
24-Aug
31-Aug
Day
MCPmean97
LMPmean98
LMPmean99

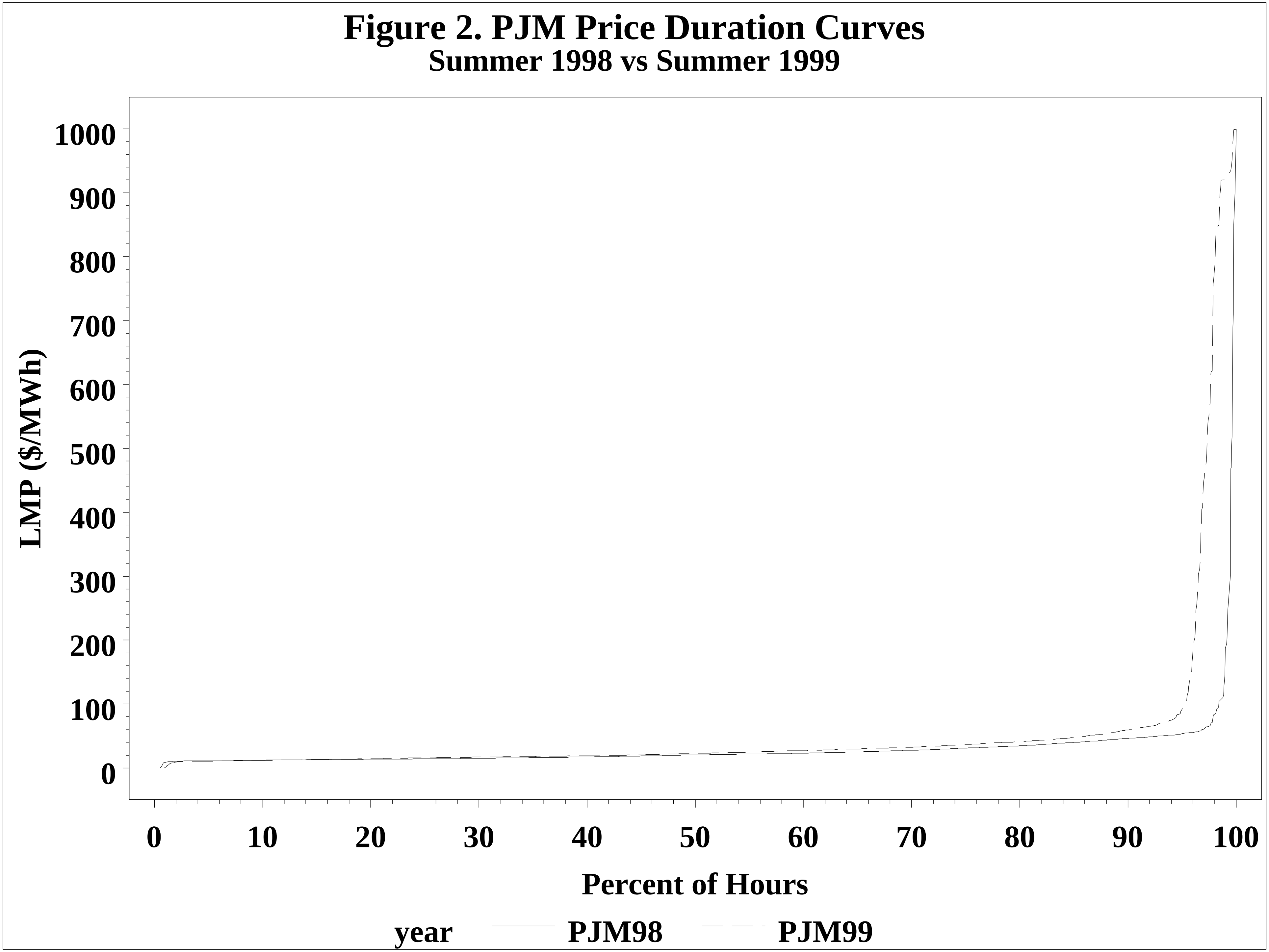
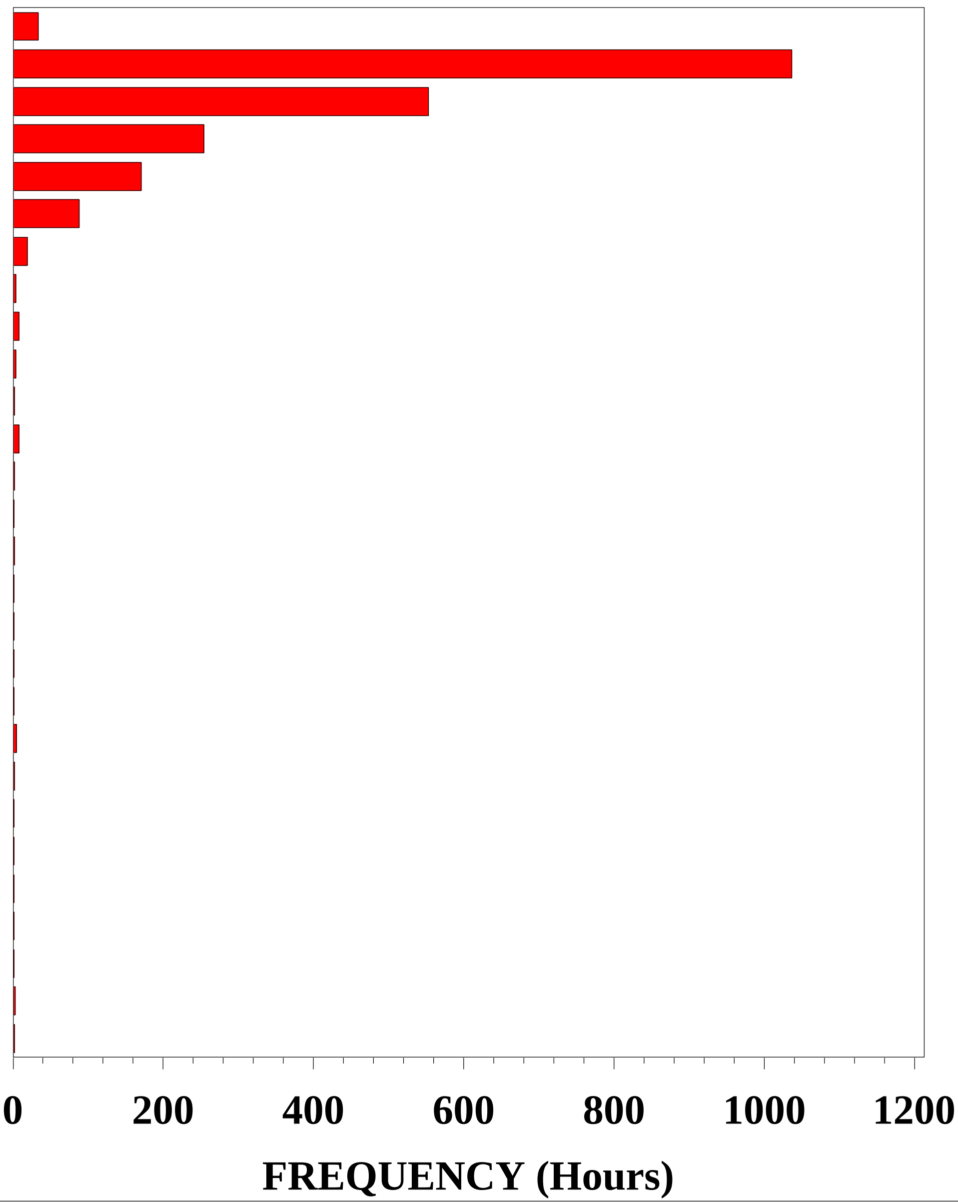


Figure 2. PJM Price Duration Curves
Summer 1998 vs Summer 1999
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
80
90
100
Percent of Hours
year
PJM98
PJM99

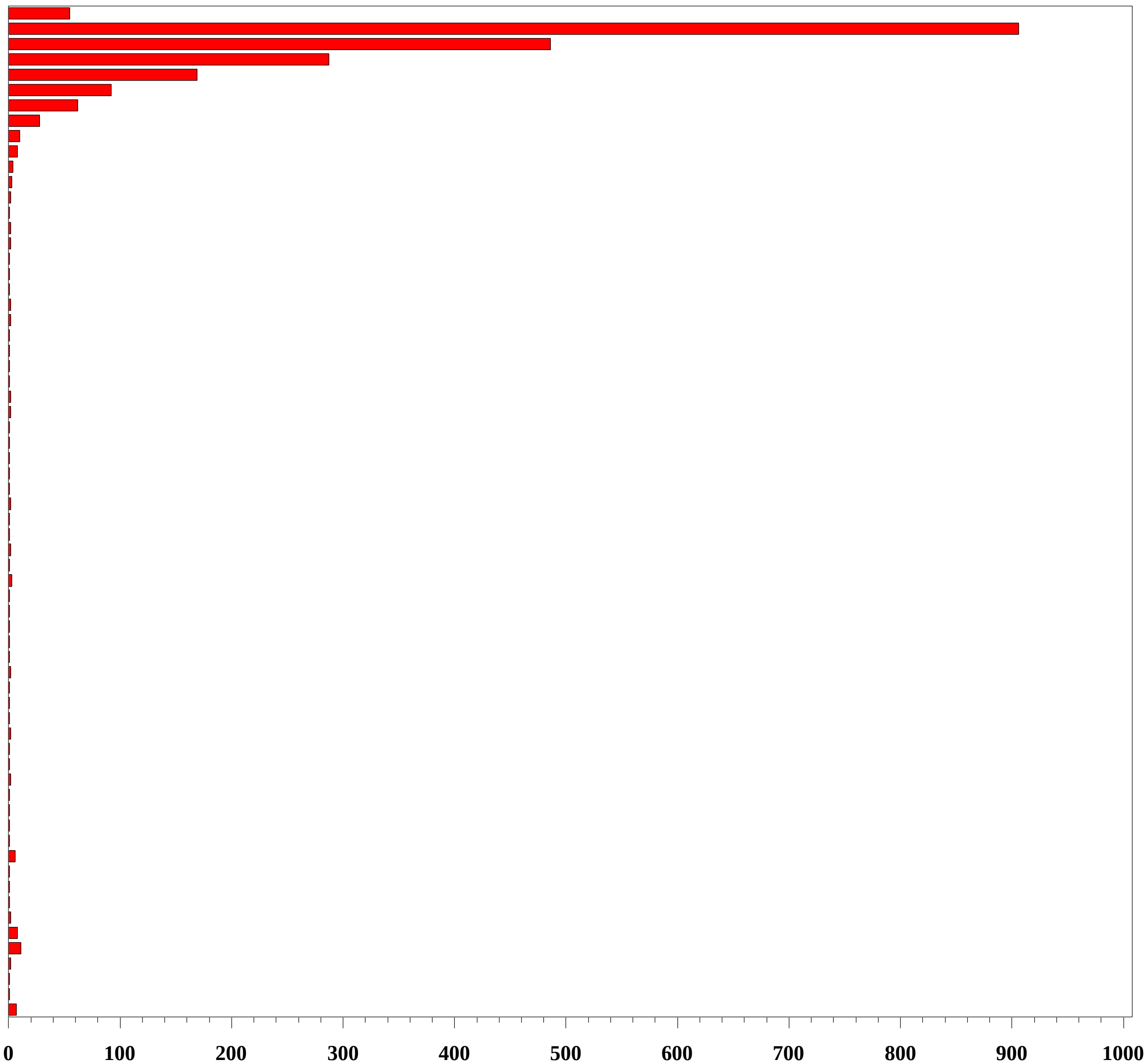
# Figure 3. Frequency Distribution by Hours of PJM LMPs

## June 1, 1998 to August 31, 1998




| LMP ($/MWh) | FREQ. | CUM. FREQ. | PCT. | CUM. PCT. |
|---|---|---|---|---|
| $ 0 to $10 | 34 | 34 | 1.54 | 1.54 |
| $10 to $20 | 1037 | 1071 | 46.97 | 48.51 |
| $20 to $30 | 553 | 1624 | 25.05 | 73.55 |
| $30 to $40 | 254 | 1878 | 11.50 | 85.05 |
| $40 to $50 | 171 | 2049 | 7.74 | 92.80 |
| $50 to $60 | 88 | 2137 | 3.99 | 96.78 |
| $60 to $70 | 19 | 2156 | 0.86 | 97.64 |
| $70 to $80 | 4 | 2160 | 0.18 | 97.83 |
| $80 to $90 | 8 | 2168 | 0.36 | 98.19 |
| $90 to $100 | 4 | 2172 | 0.18 | 98.37 |
| $100 to $110 | 2 | 2174 | 0.09 | 98.46 |
| $110 to $120 | 8 | 2182 | 0.36 | 98.82 |
| $130 to $140 | 2 | 2184 | 0.09 | 98.91 |
| $140 to $150 | 1 | 2185 | 0.05 | 98.96 |
| $180 to $190 | 2 | 2187 | 0.09 | 99.05 |
| $190 to $200 | 1 | 2188 | 0.05 | 99.09 |
| $200 to $210 | 1 | 2189 | 0.05 | 99.14 |
| $220 to $230 | 1 | 2190 | 0.05 | 99.18 |
| $240 to $250 | 1 | 2191 | 0.05 | 99.23 |
| $300 to $310 | 5 | 2196 | 0.23 | 99.46 |
| $460 to $470 | 2 | 2198 | 0.09 | 99.55 |
| $500 to $510 | 1 | 2199 | 0.05 | 99.59 |
| $510 to $520 | 1 | 2200 | 0.05 | 99.64 |
| $680 to $690 | 1 | 2201 | 0.05 | 99.68 |
| $700 to $710 | 1 | 2202 | 0.05 | 99.73 |
| $850 to $860 | 1 | 2203 | 0.05 | 99.77 |
| $900 to $910 | 3 | 2206 | 0.14 | 99.91 |
| $990 to $1000 | 2 | 2208 | 0.09 | 100.00 |

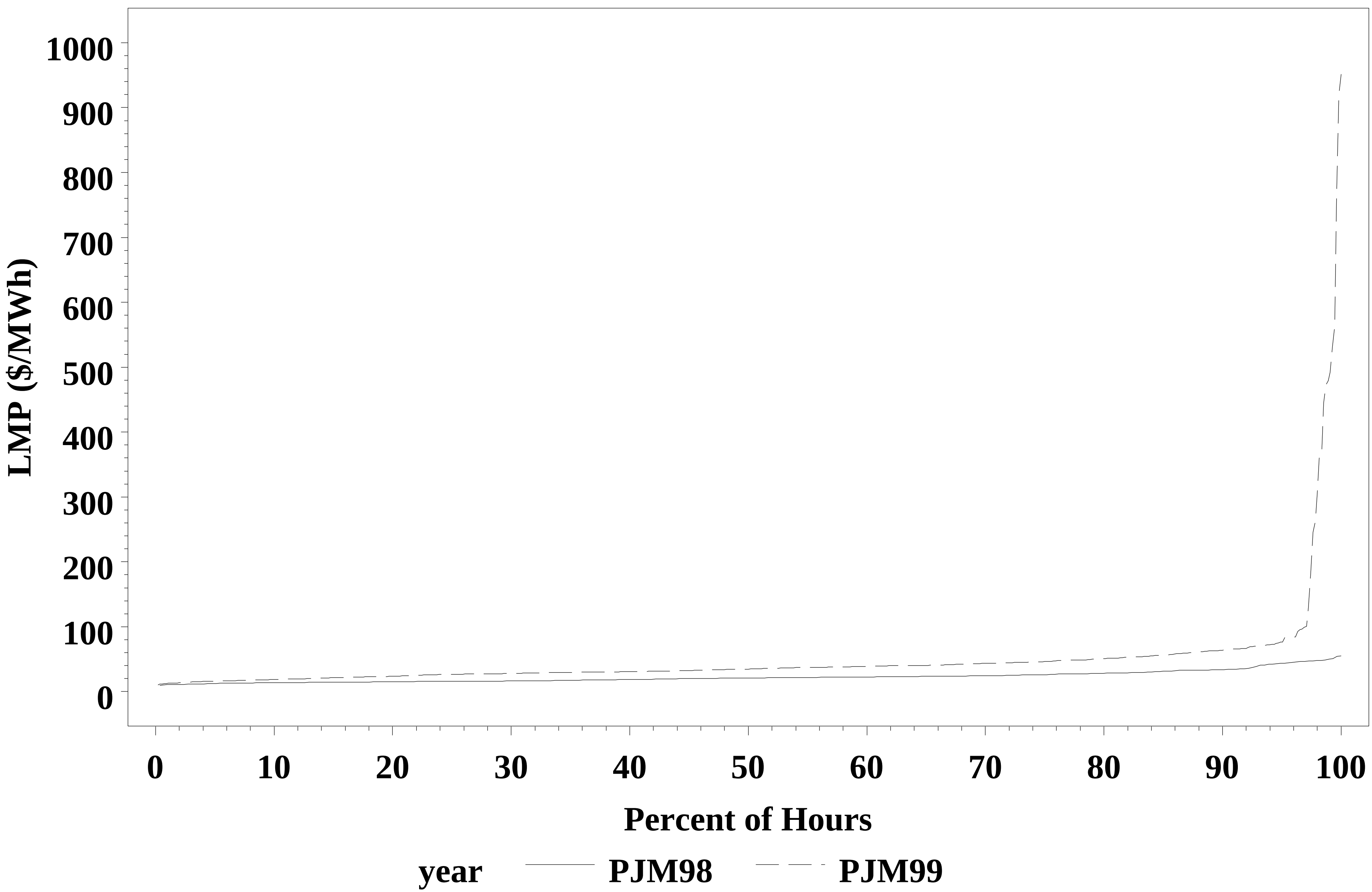
# Figure 4. Frequency Distribution by Hours of PJM LMPs
## June 1, 1999 to August 31, 1999




| LMP ($/MWh) | FREQ. | CUM. FREQ. | PCT. | CUM. PCT. |
|---|---|---|---|---|
| $ 0 to $10 | 55 | 55 | 2.49 | 2.49 |
| $10 to $20 | 906 | 961 | 41.03 | 43.52 |
| $20 to $30 | 486 | 1447 | 22.01 | 65.53 |
| $30 to $40 | 287 | 1734 | 13.00 | 78.53 |
| $40 to $50 | 169 | 1903 | 7.65 | 86.19 |
| $50 to $60 | 92 | 1995 | 4.17 | 90.35 |
| $60 to $70 | 62 | 2057 | 2.81 | 93.16 |
| $70 to $80 | 28 | 2085 | 1.27 | 94.43 |
| $80 to $90 | 10 | 2095 | 0.45 | 94.88 |
| $90 to $100 | 8 | 2103 | 0.36 | 95.24 |
| $100 to $110 | 4 | 2107 | 0.18 | 95.43 |
| $110 to $120 | 3 | 2110 | 0.14 | 95.56 |
| $120 to $130 | 2 | 2112 | 0.09 | 95.65 |
| $130 to $140 | 1 | 2113 | 0.05 | 95.70 |
| $140 to $150 | 2 | 2115 | 0.09 | 95.79 |
| $150 to $160 | 2 | 2117 | 0.09 | 95.88 |
| $160 to $170 | 1 | 2118 | 0.05 | 95.92 |
| $170 to $180 | 1 | 2119 | 0.05 | 95.97 |
| $180 to $190 | 1 | 2120 | 0.05 | 96.01 |
| $190 to $200 | 2 | 2122 | 0.09 | 96.11 |
| $200 to $210 | 2 | 2124 | 0.09 | 96.20 |
| $220 to $230 | 1 | 2125 | 0.05 | 96.24 |
| $240 to $250 | 1 | 2126 | 0.05 | 96.29 |
| $250 to $260 | 1 | 2127 | 0.05 | 96.33 |
| $260 to $270 | 1 | 2128 | 0.05 | 96.38 |
| $270 to $280 | 2 | 2130 | 0.09 | 96.47 |
| $300 to $310 | 2 | 2132 | 0.09 | 96.56 |
| $310 to $320 | 1 | 2133 | 0.05 | 96.60 |
| $320 to $330 | 1 | 2134 | 0.05 | 96.65 |
| $330 to $340 | 1 | 2135 | 0.05 | 96.69 |
| $360 to $370 | 1 | 2136 | 0.05 | 96.74 |
| $370 to $380 | 1 | 2137 | 0.05 | 96.78 |
| $400 to $410 | 2 | 2139 | 0.09 | 96.88 |
| $430 to $440 | 1 | 2140 | 0.05 | 96.92 |
| $440 to $450 | 1 | 2141 | 0.05 | 96.97 |
| $450 to $460 | 2 | 2143 | 0.09 | 97.06 |
| $460 to $470 | 1 | 2144 | 0.05 | 97.10 |
| $470 to $480 | 3 | 2147 | 0.14 | 97.24 |
| $490 to $500 | 1 | 2148 | 0.05 | 97.28 |
| $510 to $520 | 1 | 2149 | 0.05 | 97.33 |
| $530 to $540 | 1 | 2150 | 0.05 | 97.37 |
| $540 to $550 | 1 | 2151 | 0.05 | 97.42 |
| $550 to $560 | 1 | 2152 | 0.05 | 97.46 |
| $560 to $570 | 2 | 2154 | 0.09 | 97.55 |
| $570 to $580 | 1 | 2155 | 0.05 | 97.60 |
| $600 to $610 | 1 | 2156 | 0.05 | 97.64 |
| $610 to $620 | 1 | 2157 | 0.05 | 97.69 |
| $620 to $630 | 2 | 2159 | 0.09 | 97.78 |
| $670 to $680 | 1 | 2160 | 0.05 | 97.83 |
| $750 to $760 | 1 | 2161 | 0.05 | 97.87 |
| $760 to $770 | 2 | 2163 | 0.09 | 97.96 |
| $780 to $790 | 1 | 2164 | 0.05 | 98.01 |
| $800 to $810 | 1 | 2165 | 0.05 | 98.05 |
| $820 to $830 | 1 | 2166 | 0.05 | 98.10 |
| $840 to $850 | 1 | 2167 | 0.05 | 98.14 |
| $850 to $860 | 6 | 2173 | 0.27 | 98.41 |
| $870 to $880 | 1 | 2174 | 0.05 | 98.46 |
| $890 to $900 | 1 | 2175 | 0.05 | 98.51 |
| $900 to $910 | 1 | 2176 | 0.05 | 98.55 |
| $910 to $920 | 2 | 2178 | 0.09 | 98.64 |
| $920 to $930 | 8 | 2186 | 0.36 | 99.00 |
| $930 to $940 | 11 | 2197 | 0.50 | 99.50 |
| $940 to $950 | 2 | 2199 | 0.09 | 99.59 |
| $950 to $960 | 1 | 2200 | 0.05 | 99.64 |
| $970 to $980 | 1 | 2201 | 0.05 | 99.68 |
| $990 to $1000 | 7 | 2208 | 0.32 | 100.00 |

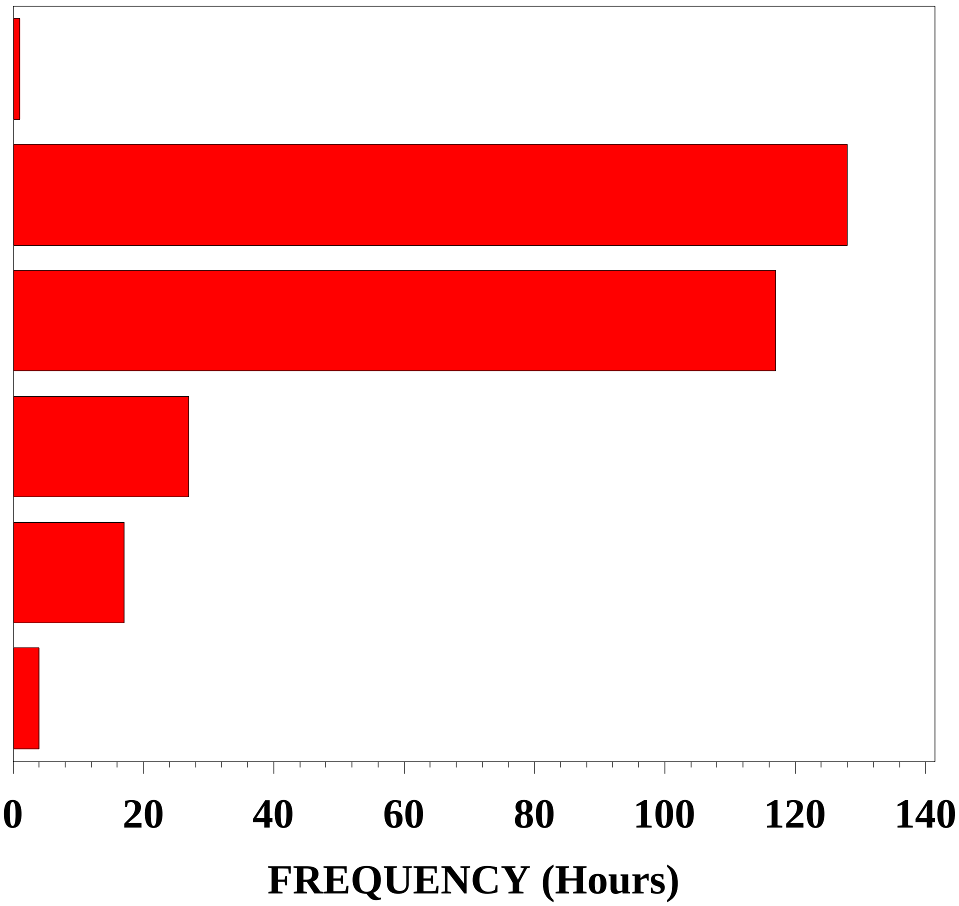
## Figure 5. PJM Price Duration Curves - Constrained Hours

### Summer 1998 vs Summer 1999



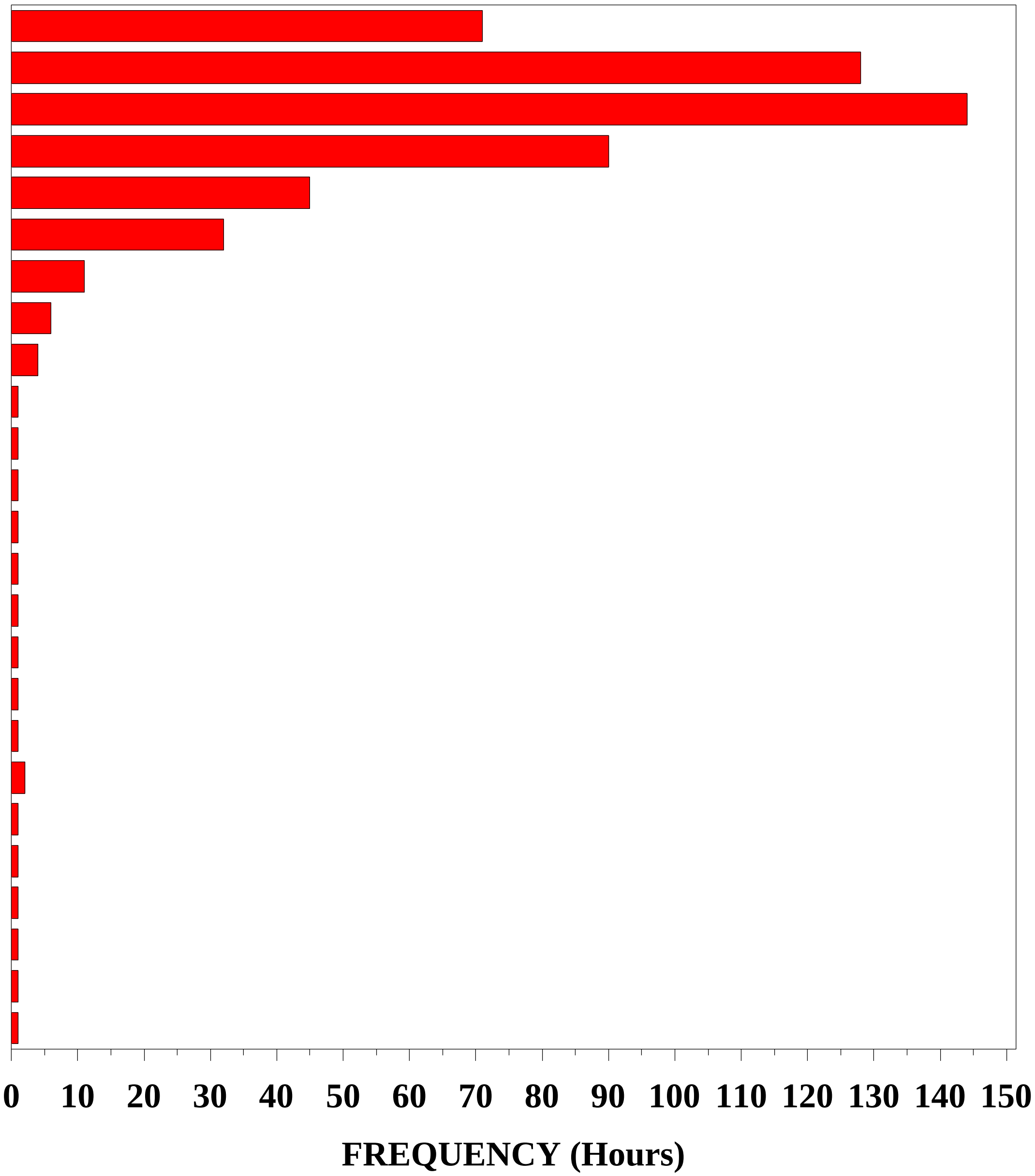

Number of Constrained Hours: 294 - Summer 1998   548 - Summer 1999

**Figure 6. Frequency Distribution by Hours of PJM LMPs During Constrained Hours**
**June 1, 1998 to August 31,1998**




| LMP ($/MWh) | FREQ. | CUM. FREQ. | PCT. | CUM. PCT. |
|---|---|---|---|---|
| $ 0 to $10 | 1 | 1 | 0.34 | 0.34 |
| $10 to $20 | 128 | 129 | 43.54 | 43.88 |
| $20 to $30 | 117 | 246 | 39.80 | 83.67 |
| $30 to $40 | 27 | 273 | 9.18 | 92.86 |
| $40 to $50 | 17 | 290 | 5.78 | 98.64 |
| $50 to $60 | 4 | 294 | 1.36 | 100.00 |

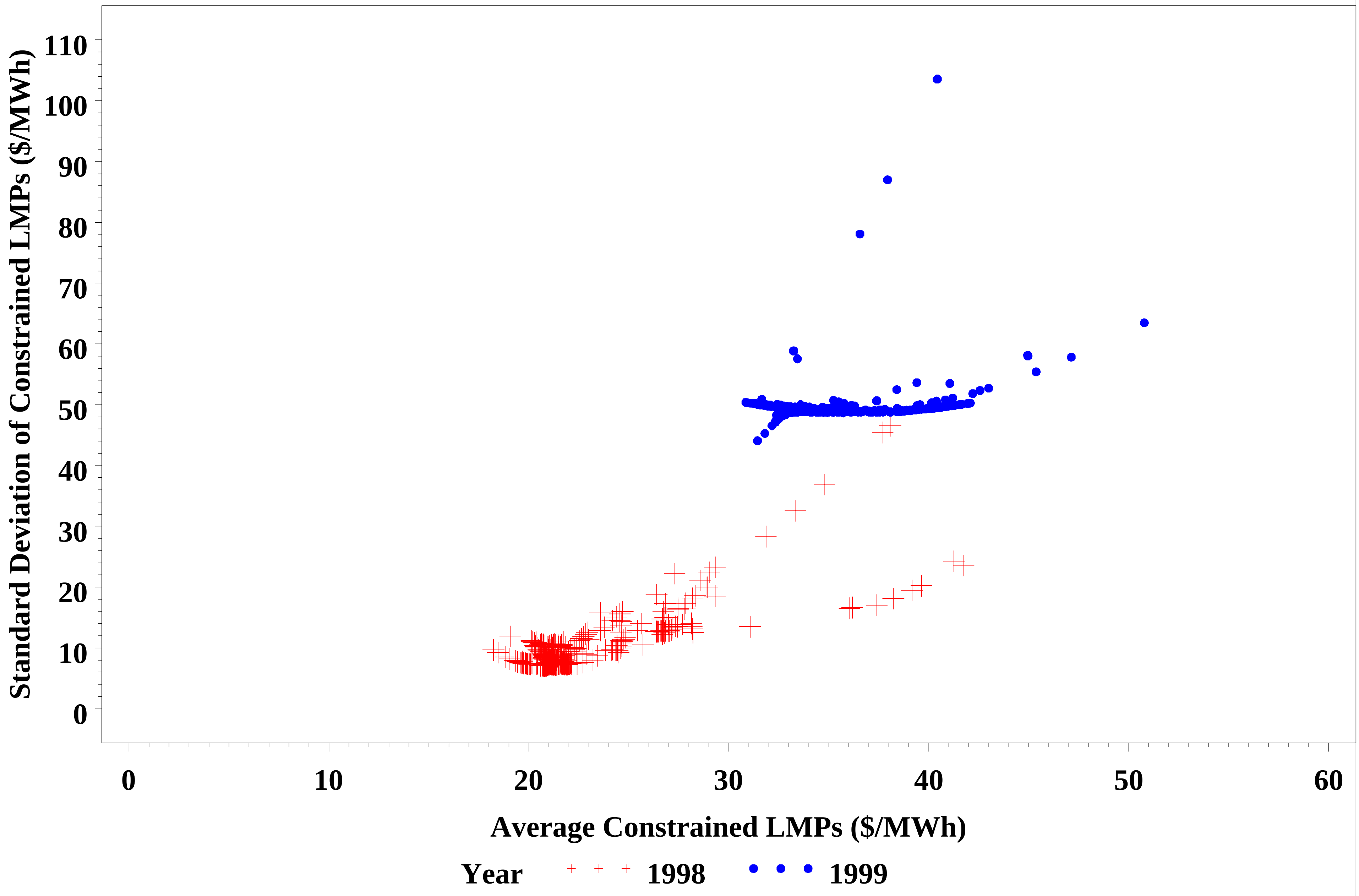
## Figure 7. Frequency Distribution by Hours of PJM LMPs During Constrained Hours
### June 1, 1999 to August 31,1999




| LMP ($/MWh) | FREQ. | CUM. FREQ. | PCT. | CUM. PCT. |
|---|---|---|---|---|
| $10 to $20 | 71 | 71 | 12.96 | 12.96 |
| $20 to $30 | 128 | 199 | 23.36 | 36.31 |
| $30 to $40 | 144 | 343 | 26.28 | 62.59 |
| $40 to $50 | 90 | 433 | 16.42 | 79.01 |
| $50 to $60 | 45 | 478 | 8.21 | 87.23 |
| $60 to $70 | 32 | 510 | 5.84 | 93.07 |
| $70 to $80 | 11 | 521 | 2.01 | 95.07 |
| $80 to $90 | 6 | 527 | 1.09 | 96.17 |
| $90 to $100 | 4 | 531 | 0.73 | 96.90 |
| $100 to $110 | 1 | 532 | 0.18 | 97.08 |
| $120 to $130 | 1 | 533 | 0.18 | 97.26 |
| $180 to $190 | 1 | 534 | 0.18 | 97.45 |
| $240 to $250 | 1 | 535 | 0.18 | 97.63 |
| $260 to $270 | 1 | 536 | 0.18 | 97.81 |
| $300 to $310 | 1 | 537 | 0.18 | 97.99 |
| $360 to $370 | 1 | 538 | 0.18 | 98.18 |
| $370 to $380 | 1 | 539 | 0.18 | 98.36 |
| $440 to $450 | 1 | 540 | 0.18 | 98.54 |
| $470 to $480 | 2 | 542 | 0.36 | 98.91 |
| $490 to $500 | 1 | 543 | 0.18 | 99.09 |
| $530 to $540 | 1 | 544 | 0.18 | 99.27 |
| $560 to $570 | 1 | 545 | 0.18 | 99.45 |
| $760 to $770 | 1 | 546 | 0.18 | 99.64 |
| $920 to $930 | 1 | 547 | 0.18 | 99.82 |
| $950 to $960 | 1 | 548 | 0.18 | 100.00 |

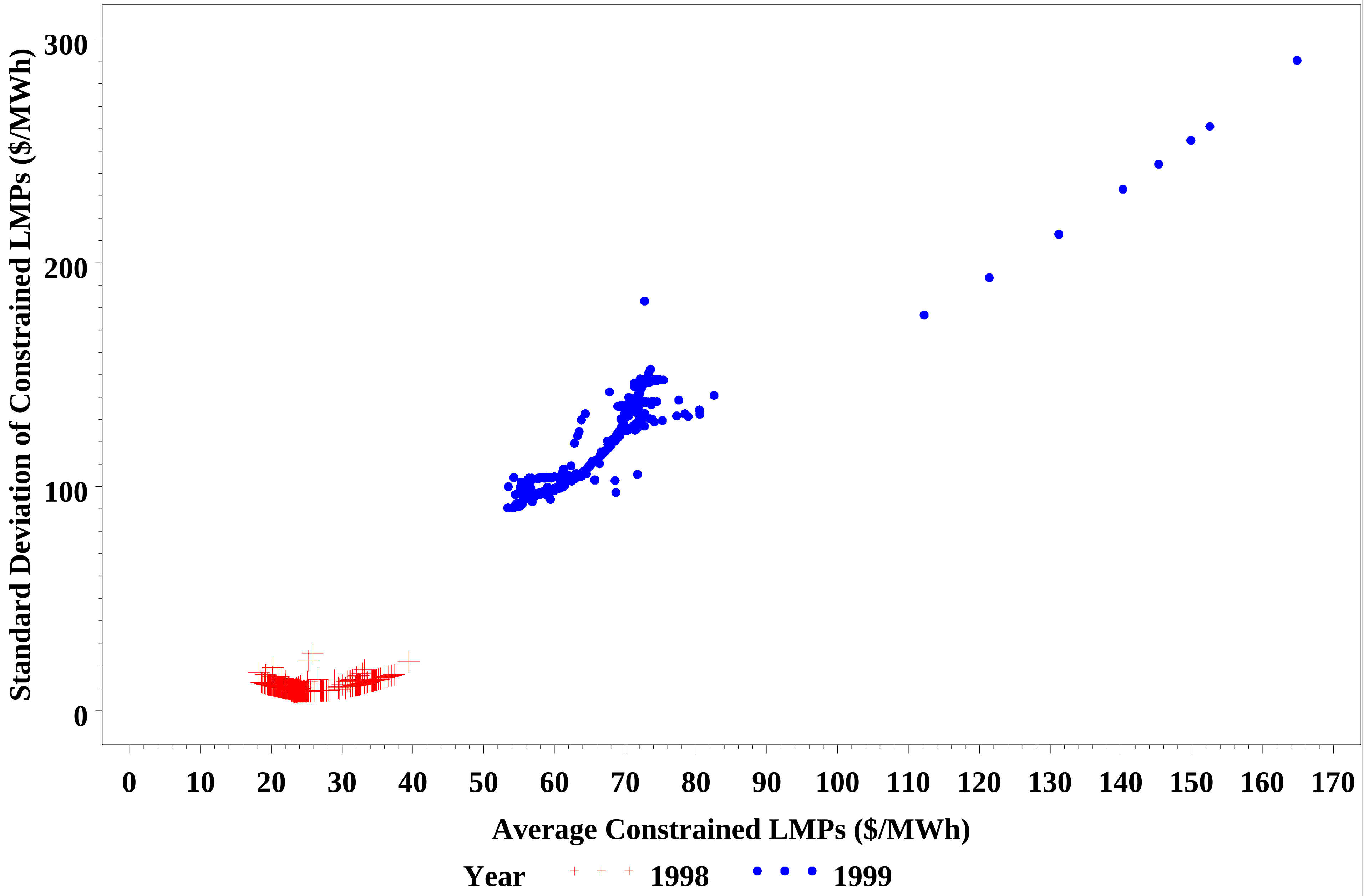
## Figure 8. PJM Constrained LMPs

June 1998 vs June 1999



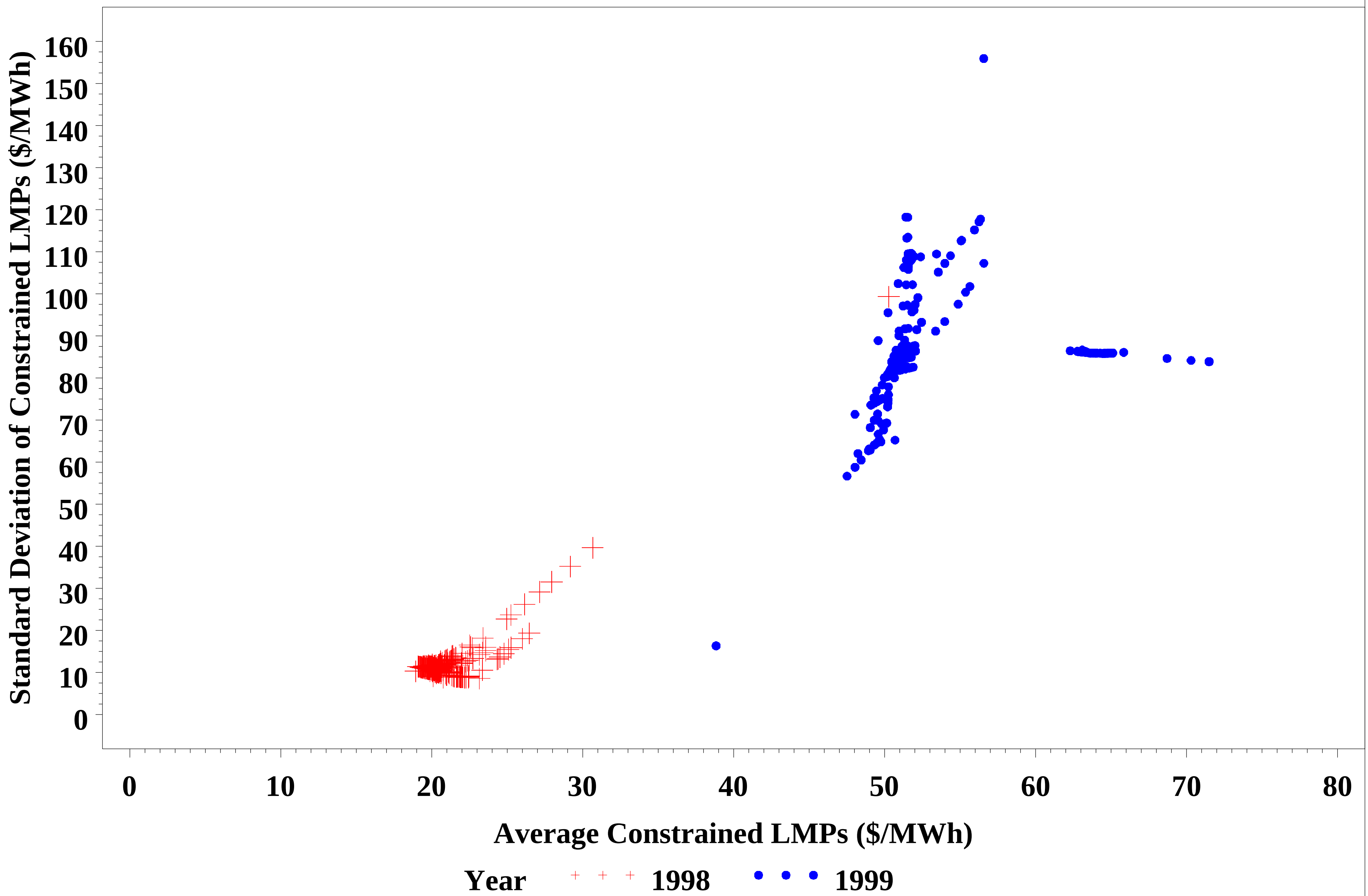

Number of Constrained Hours: 95 - June 1998 163 - June 1999

## Figure 9. PJM Constrained LMPs
### July 1998 vs July 1999




**Number of Constrained Hours: 151 - July 1998   127 - July 1999**

**Figure 10. PJM Constrained LMPs**
**August 1998 vs August 1999**




**Number of Constrained Hours: 48 - August 1998 258 - August 1999**

**Figure 11. PJM Price Duration Curves**
**April to March, 1998-1999 and 1999-2000**

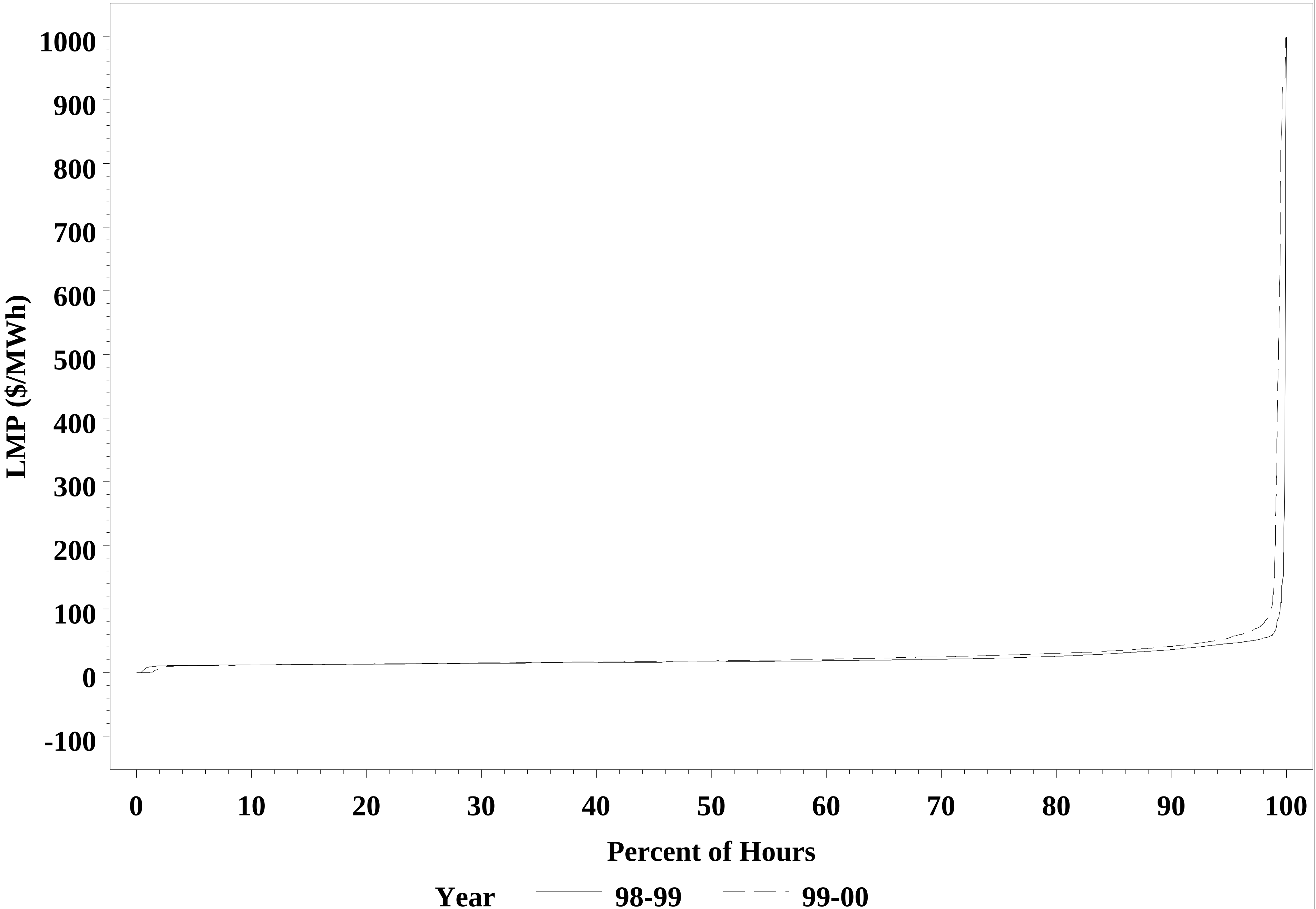
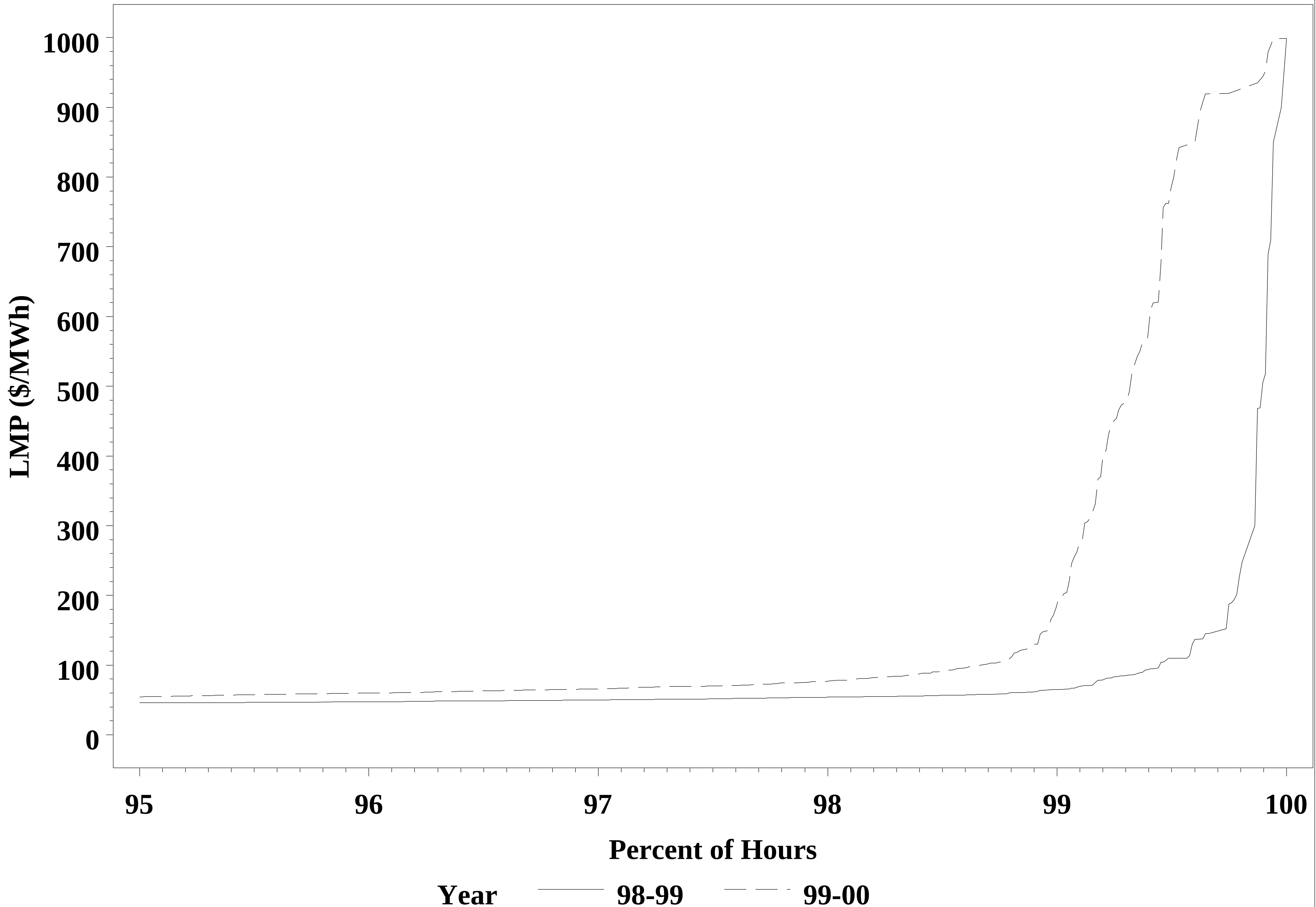
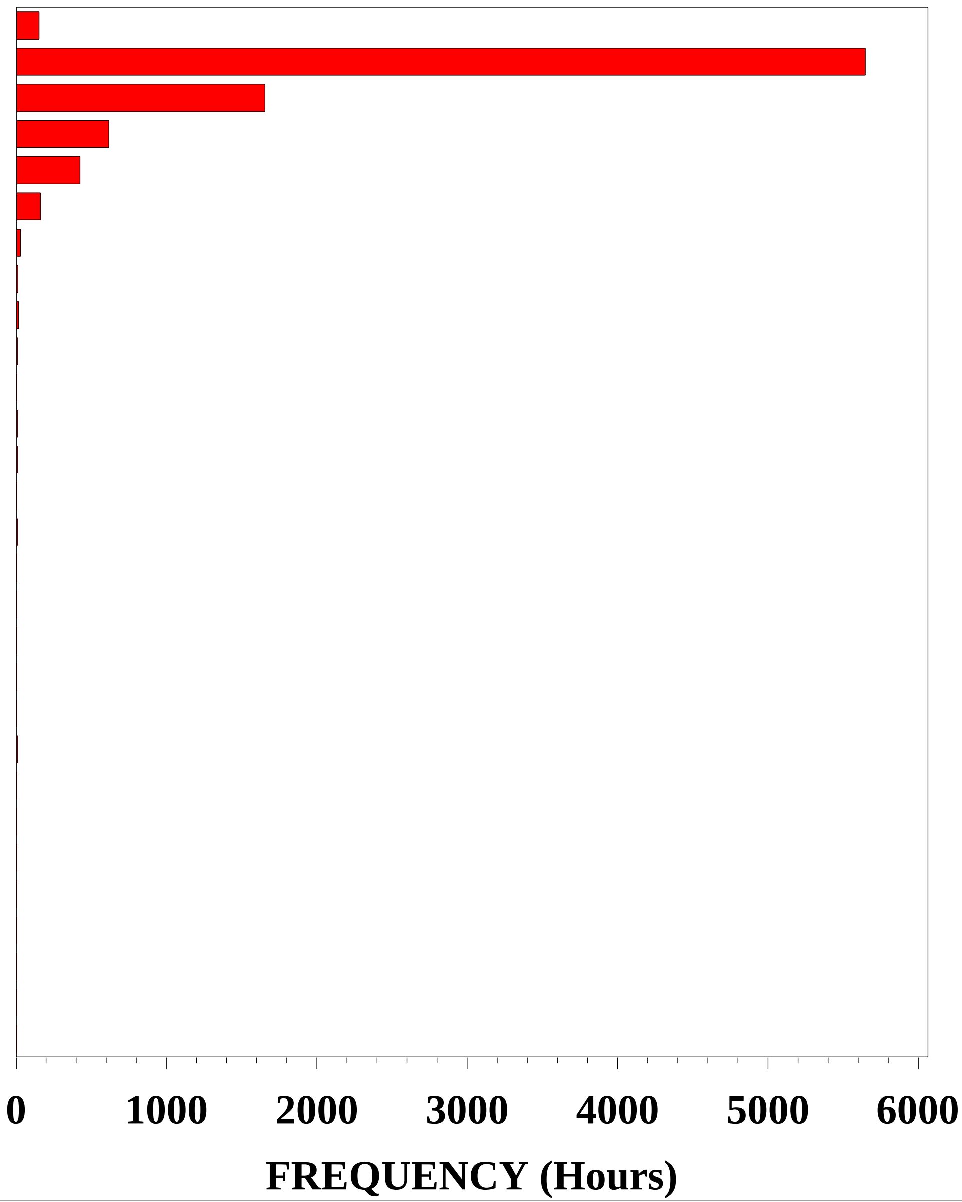


**Figure 12. PJM Price Duration Curves**
**Hours Above the 95th Percentile: April to March, 1998-1999 and 1999-2000**

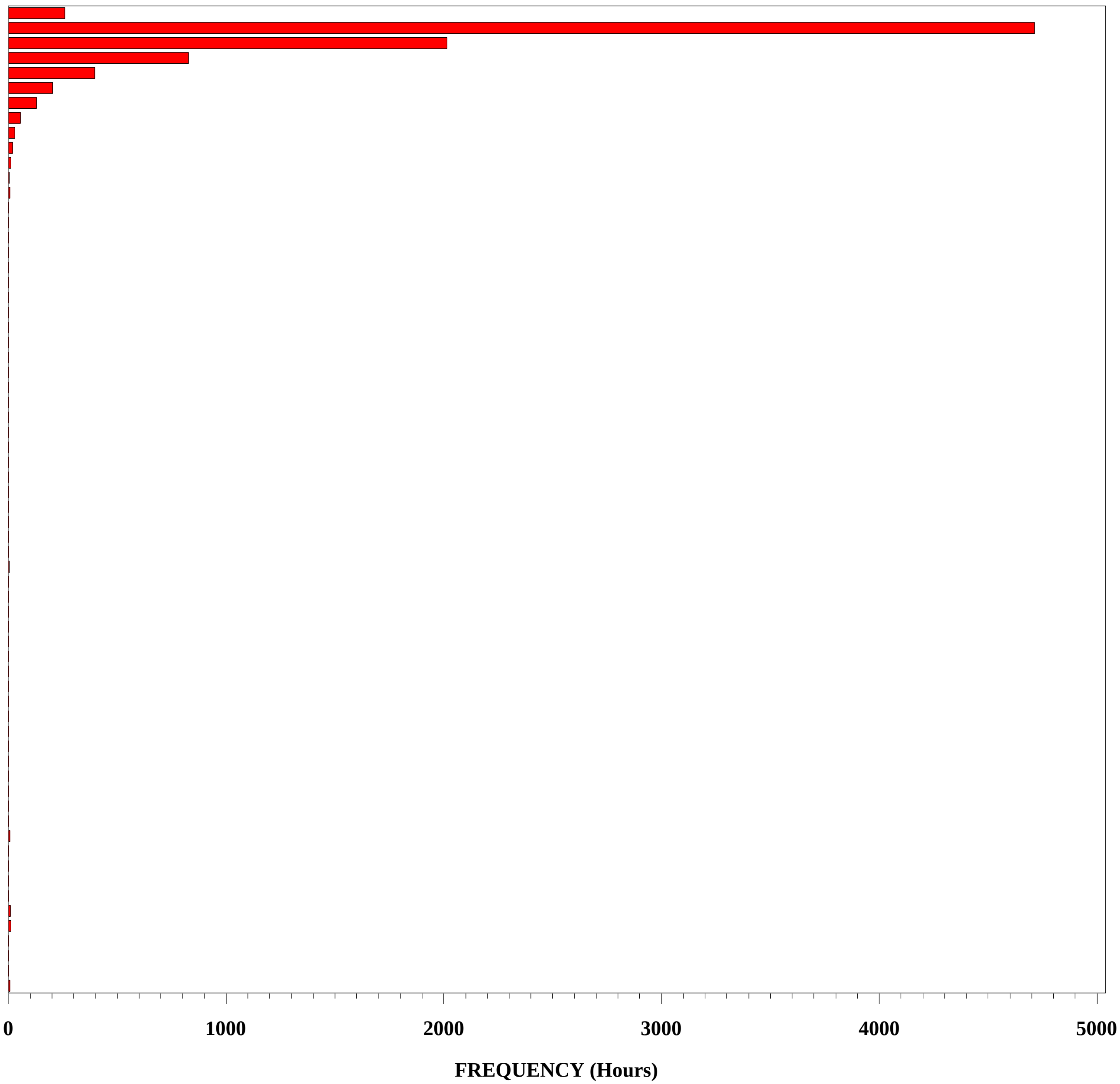


## Figure 13. Frequency Distribution of Hourly PJM LMPs
### April 1, 1998 to March 31, 1999




| LMP ($/MWh) | FREQ. | CUM. FREQ. | PCT. | CUM. PCT. |
|---|---|---|---|---|
| $ 0 to $10 | 150 | 150 | 1.71 | 1.71 |
| $10 to $20 | 5648 | 5798 | 64.47 | 66.19 |
| $20 to $30 | 1655 | 7453 | 18.89 | 85.08 |
| $30 to $40 | 617 | 8070 | 7.04 | 92.12 |
| $40 to $50 | 422 | 8492 | 4.82 | 96.94 |
| $50 to $60 | 161 | 8653 | 1.84 | 98.78 |
| $60 to $70 | 28 | 8681 | 0.32 | 99.10 |
| $70 to $80 | 9 | 8690 | 0.10 | 99.20 |
| $80 to $90 | 15 | 8705 | 0.17 | 99.37 |
| $90 to $100 | 6 | 8711 | 0.07 | 99.44 |
| $100 to $110 | 4 | 8715 | 0.05 | 99.49 |
| $110 to $120 | 8 | 8723 | 0.09 | 99.58 |
| $130 to $140 | 5 | 8728 | 0.06 | 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 |
| $900 to $910 | 3 | 8758 | 0.03 | 99.98 |
| $990 to $1000 | 2 | 8760 | 0.02 | 100.00 |

# Figure 14. Frequency Distribution of Hourly PJM LMPs
## April 1, 1999 to March 31, 2000




| LMP ($/MWh) | FREQ. | CUM. FREQ. | PCT. | CUM. PCT. |
|---|---|---|---|---|
| $ 0 to $10 | 260 | 260 | 2.97 | 2.97 |
| $10 to $20 | 4712 | 4972 | 53.79 | 56.76 |
| $20 to $30 | 2015 | 6987 | 23.00 | 79.76 |
| $30 to $40 | 827 | 7814 | 9.44 | 89.20 |
| $40 to $50 | 397 | 8211 | 4.53 | 93.73 |
| $50 to $60 | 202 | 8413 | 2.31 | 96.04 |
| $60 to $70 | 128 | 8541 | 1.46 | 97.50 |
| $70 to $80 | 54 | 8595 | 0.62 | 98.12 |
| $80 to $90 | 29 | 8624 | 0.33 | 98.45 |
| $90 to $100 | 19 | 8643 | 0.22 | 98.66 |
| $100 to $110 | 11 | 8654 | 0.13 | 98.79 |
| $110 to $120 | 3 | 8657 | 0.03 | 98.82 |
| $120 to $130 | 7 | 8664 | 0.08 | 98.90 |
| $130 to $140 | 1 | 8665 | 0.01 | 98.92 |
| $140 to $150 | 2 | 8667 | 0.02 | 98.94 |
| $150 to $160 | 2 | 8669 | 0.02 | 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 | 1 | 8685 | 0.01 | 99.14 |
| $320 to $330 | 1 | 8686 | 0.01 | 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 | 1 | 8693 | 0.01 | 99.24 |
| $450 to $460 | 2 | 8695 | 0.02 | 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 | 1 | 8703 | 0.01 | 99.35 |
| $550 to $560 | 1 | 8704 | 0.01 | 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 |
| $800 to $810 | 1 | 8717 | 0.01 | 99.51 |
| $820 to $830 | 1 | 8718 | 0.01 | 99.52 |
| $840 to $850 | 1 | 8719 | 0.01 | 99.53 |
| $850 to $860 | 6 | 8725 | 0.07 | 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 | 2 | 8730 | 0.02 | 99.66 |
| $920 to $930 | 8 | 8738 | 0.09 | 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 $1000 | 7 | 8760 | 0.08 | 100.00 |

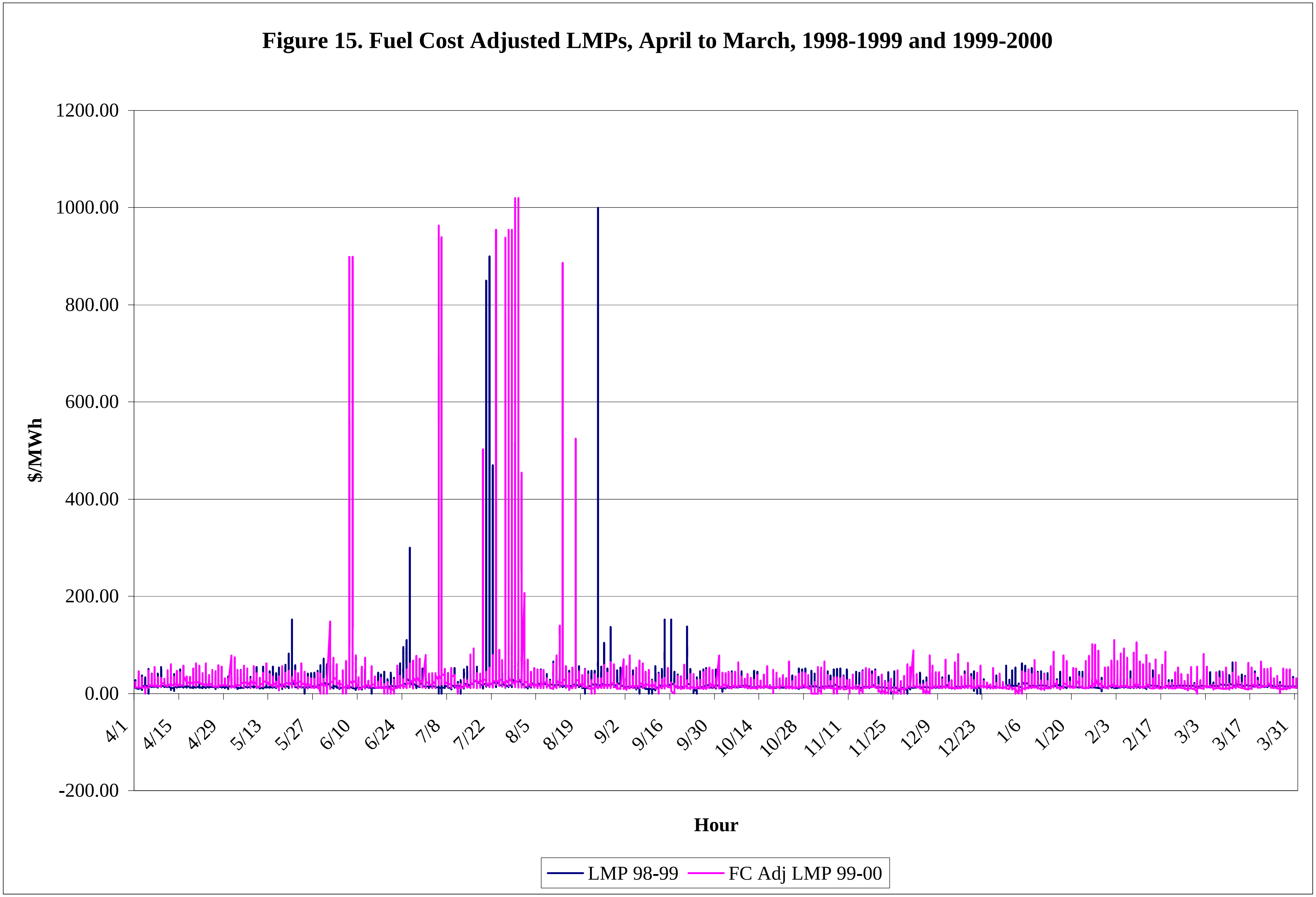
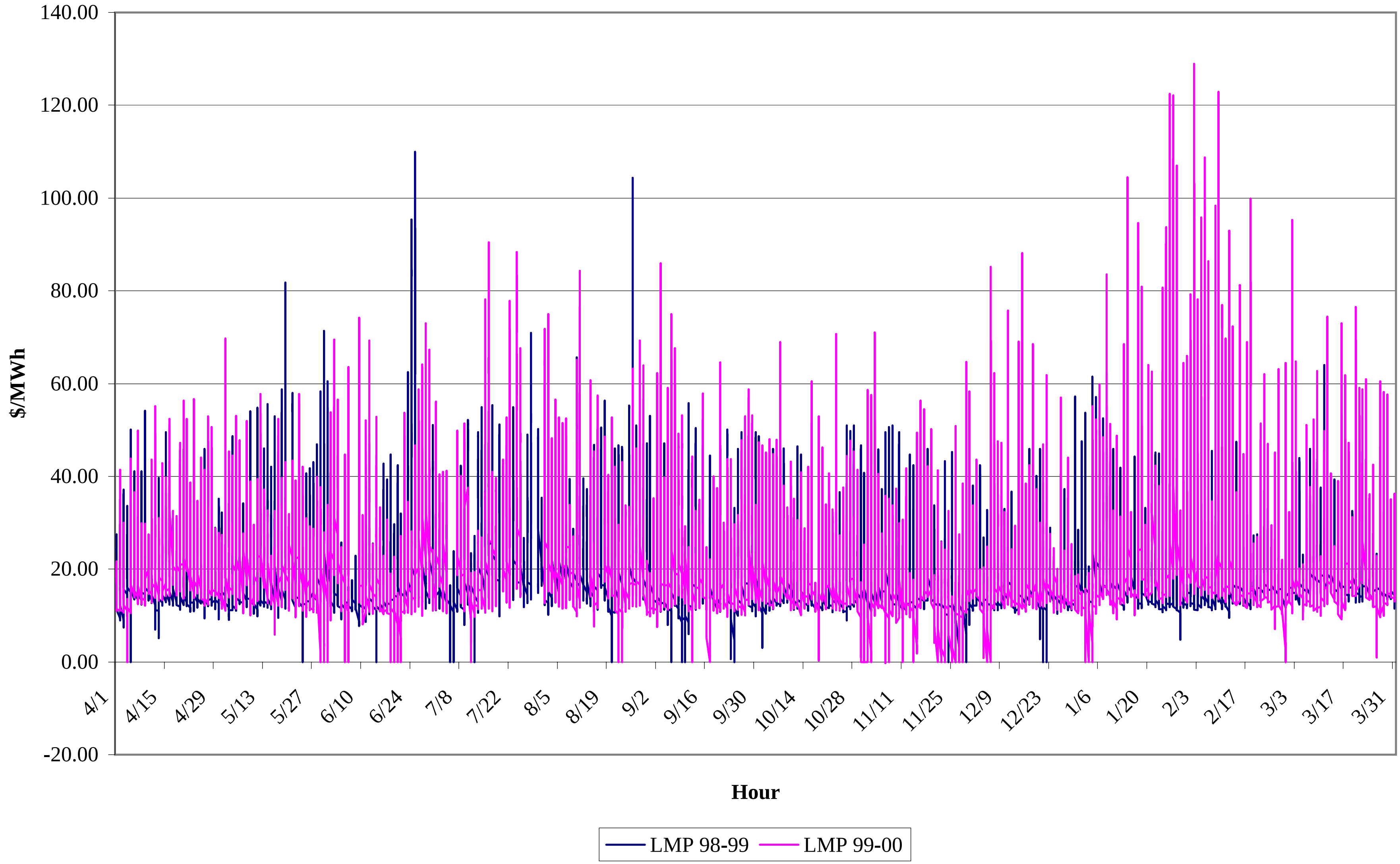


Figure 15. Fuel Cost Adjusted LMPs, April to March, 1998-1999 and 1999-2000
1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
-200.00
$/MWh
4/1
4/15
4/29
5/13
5/27
6/10
6/24
7/8
7/22
8/5
8/19
9/2
9/16
9/30
10/14
10/28
11/11
11/25
12/9
12/23
1/6
1/20
2/3
2/17
3/3
3/17
3/31
Hour
LMP 98-99
FC Adj LMP 99-00

Figure 16. Hourly LMPs, No High-Demand Days - April to March, 1998-1999 and 1999-2000



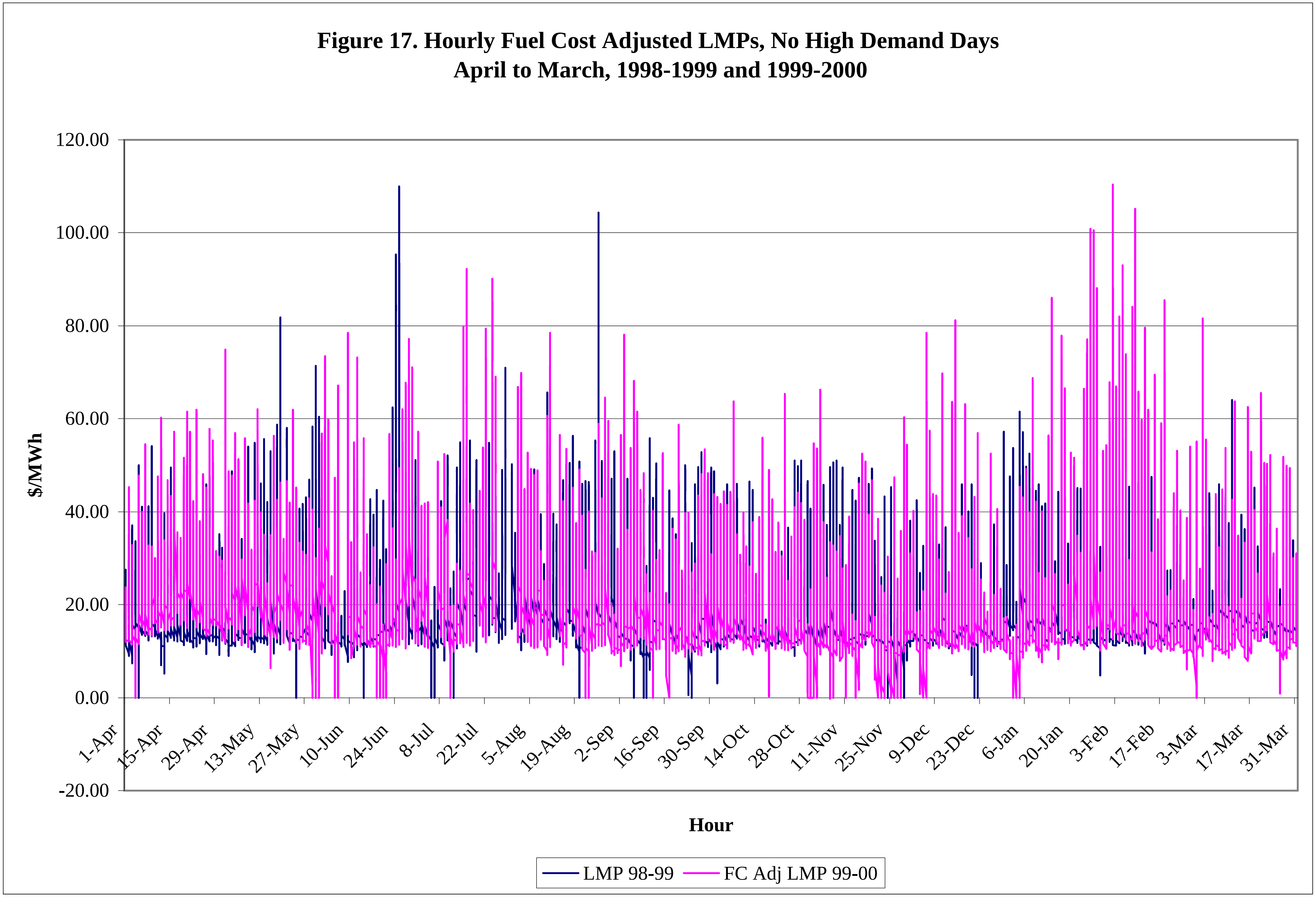


Figure 17. Hourly Fuel Cost Adjusted LMPs, No High Demand Days
April to March, 1998-1999 and 1999-2000
$/MWh
120.00
100.00
80.00
60.00
40.00
20.00
0.00
-20.00
1-Apr
15-Apr
29-Apr
13-May
27-May
10-Jun
24-Jun
8-Jul
22-Jul
5-Aug
19-Aug
2-Sep
16-Sep
30-Sep
14-Oct
28-Oct
11-Nov
25-Nov
9-Dec
23-Dec
6-Jan
20-Jan
3-Feb
17-Feb
3-Mar
17-Mar
31-Mar
Hour
LMP 98-99
FC Adj LMP 99-00

# THE ENERGY MARKET

While overall PJM prices were higher and more variable after the implementation of market-based pricing in April 1999, for most of the year average prices were about the same as in the prior year. Between April 1999 and March 2000, spot market prices were less than $20/MW for 57% of the total hours. They were less than $30/MW for 80%, less than $60/MW for 96% and less than $80/MW for 98% of the total hours. PJM prices exceeded $130/MW for only 96 hours or 1.1% of the total hours in 1999. Thus, a large portion of the total increase in prices from the March 1998 – April 1999, to the March 1999 – April 2000 period occurred on the 15 high demand, hot days, which occurred in the summer of 1999. When prices are adjusted for fuel cost increases, about 84% of the overall average price increase from 1998 to 1999 is accounted for by price increases during the 96 hours which occurred on the 15 high demand days.

Since high demand, hot days are central to the performance of the PJM energy market, this report focuses on analyzing the PJM markets on these days. This section presents examples to illustrate how the PJM energy market functioned on days when demands were extremely high, in order to derive lessons for the design of PJM energy markets. Specifically, the analysis focuses on three hot days during the summer of 1999, which included 30 of the 96 hours during which prices were greater than $130/MW.

## The PJM Market

The goal of the MMU is to help create and maintain robust, competitive and non-discriminatory markets. It is not to ensure that the markets match the perfectly competitive markets of textbooks in every detail, but competitive markets provide a benchmark. The MMU's standards for competition are broader than the legal standards of antitrust enforcement and are more flexible than the textbook definitions of competition. A useful test for the existence of market power is the relationship between price and marginal cost. Such a test must be applied carefully in the context of all the complexities of the real markets. The use of this test does not imply that all cases where the price is greater than the cost of the last unit produced reflect market power. Nor does the use of this test imply that a market is not competitive if the test is not met at all times. The test does provide the ability to identify situations where a withholding strategy is used to profitably increase the market price. The goal is to use the results of this and other analyses to help design detailed market rules, which facilitate even more robustly competitive markets, making it difficult to exercise market power and limiting any on the exercise of such power.

PJM's market includes a number of rules that must be understood prior to any analysis of the potential exercise of market power in the PJM market. It uses bid-based, least-cost, security constrained dispatch to determine the scheduling and operation of generating stations under PJM's control. PJM dispatchers send out a single price signal, the dispatch rate, to all PJM units.[1] Those units generally respond to the dispatch rate based on their offers to supply energy. The units generally follow the dispatch signal because PJM's dispatch is efficient and therefore it is profit maximizing for each unit to do so.

[1] There is a single dispatch rate when the system is unconstrained, which it was on June 7, July 6 and July 28, except for two hours. There are multiple dispatch rates when there are constraints.

Generating units provide energy offers on a day-ahead basis, which are either cost-based or market-based. PJM schedules these units on a day-ahead basis based on their offers and projected loads. During the time period covered by this report, unit offers and PJM's day-ahead scheduling did not constitute or create binding financial commitments to provide a defined amount of energy at a defined price. Units can self-schedule, meaning that they operate regardless of the price and are paid the market price for any spot sales. Units can switch from PJM scheduled to self-scheduled during the day of operation. PJM has an offer cap in the energy market equal to $1,000/MW. No offers greater than $1,000/MW are accepted. This offer cap includes startup and no-load costs.

The reliability (adequacy) of PJM energy supply is addressed via PJM's Reliability Assurance Agreement (RAA) to which all Load Serving Entities (LSEs) in PJM must subscribe. All load must obtain, by ownership or purchase, capacity, which is adequate to serve its load, plus a reserve margin. If, as a result, a generating unit is dedicated to serving load within PJM, it is a Capacity Resource. If a unit is a Capacity Resource, it is either under PJM's control or running for itself (self scheduled). If PJM calls for a unit's energy, and it is not provided, that unit is assessed a forced outage, which reduces its capacity value as a Capacity Resource in the future. The stated purpose of the RAA 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."[2]

PJM maintains markets in Capacity Resources, which vary in duration from one day to 12 months. The capacity markets serve to provide a transparent market mechanism for new market entrants (LSEs), which want to serve load under retail open access programs, to obtain the requisite capacity. Conversely, capacity markets provide a transparent market mechanism which permits existing utilities to sell capacity if it is no longer needed as load migrates to new retail competitors and permits generators without load to sell capacity. LSEs can obtain Capacity Resources in this market and owners of capacity can sell the capacity in this market. Capacity Resource markets cleared at a weighted average price of $52.86/MW/day during 1999, approximately one third of the capacity cost of a combustion turbine (CT).

The link between Capacity Resource status and the reliability of energy supply is that the energy from Capacity Resources is recallable by PJM under Emergency conditions, at the then current market price. Thus, if a generation owner has sold its capacity to an LSE in order to ensure reliable service to loads, but is exporting the energy associated with that capacity, PJM has the right to recall any exports of energy associated with that capacity when it declares an Emergency. If a generation owner has excess capacity, the capacity may be removed from Capacity Resource status. Bilateral exports of energy from units which are not Capacity Resources are not recallable by PJM.

Emergency procedures govern the functioning of the PJM market when demand is high compared to the offered energy supply from units which are operating for PJM plus net scheduled tie flows. This energy supply includes the output of operating generating units net of imports and exports. PJM Emergency procedures include the recall of Capacity Resource related

[2] Reliability Assurance Agreement Among LSEs in the PJM Control Area, page 8.

bilateral energy contracts, a call for Maximum Emergency Generation output levels from units, Active Load Management (ALM), voltage reductions, the purchase of emergency energy and load shedding. Emergency procedures are driven by reliability considerations rather than economic considerations and can be implemented in the order and combination deemed most effective by PJM operators in order to maintain reliability.

Prior to implementing Emergency actions, PJM must have called on all the output of all units which made an offer to supply energy, regardless of price or other operating constraints. Thus, if a unit provides a day-ahead offer to PJM of $999/MW, the output of that unit must be called on and that offer used to set the system price, prior to the implementation of Emergency actions.

PJM has specific operating reserve requirements. PJM has a regulation target during peak hours equal to 1.1% of forecast peak demands. PJM maintains primary operating reserves consisting of spinning reserve and 10 minute, non-synchronized reserves and secondary operating reserves which must be capable of producing within 30 minutes of a request for output.

PJM has rules in place to mitigate the exercise of specific types of market power. PJM permits units which make market-based offers of energy to change their start up and no load offers only twice per year. This provides an incentive to units which wish to run during the year to use start up and no load offers which are consistent with costs and limits the ability of units to make extremely high start up and no load offers during high demand conditions. PJM has the ability to cost cap units on a day-ahead basis when it determines that the units are must-run for reliability. If, on a day-ahead basis, PJM forecasts that a unit will have to run to relieve a transmission constraint, it can limit the impact of such a unit's offer on LMP.[3] The offers of these must run units are capped at their cost plus 10%, but the units are paid the bus LMP if it is higher. This, plus the ability of PJM to require the units to run, ensures that units with local market power due to transmission constraints do not exploit that market power.

**Market Power**

Market power is the ability of a market participant to profitably raise the market price above the competitive market price, and there are a number of ways for a generator to accomplish this. It is also possible in PJM for a generator to profitably raise the market price, but not to a level above the competitive market price, and thus not to exercise market power. The most straightforward way to profitably raise the market price is to withhold output, as demand increases, until a higher price is reached. Withholding can take several forms, the most basic form being physical withholding in which a generator simply refuses to provide energy from a unit. Another form of withholding is economic withholding, implemented by setting the offer price on a unit or units at a target price level, greater than the marginal cost of providing energy from that unit. The actual withholding occurs when the unit is not turned on after the price exceeds the marginal cost of production. This behavior constitutes withholding because the unit does not provide energy during time periods when the unit is capable of producing energy and when it would be profitable for the unit to produce energy. This behavior also gives the unit the ability to set the market price. When the system dispatch rate equals or exceeds the offer price, the offer price sets

[3] This does not apply to generation resources used to relieve the Western, Central and Eastern reactive limits in the PJM Control Area.

the system LMP.[4] In some cases, units with high offer prices may decide to provide energy at a price below the offer price. No withholding occurs in that situation.

In a fully competitive market, withholding would not be a profitable strategy, as the energy withheld by one unit would be made up by other units with similar costs. In the PJM energy market, the profitability of withholding is a function of the number and availability of units that are willing to supply energy at a rate which is equal to or close to the marginal cost of running the units in order to ensure dispatch. The actual profitability of withholding depends on the circumstances which prevail at the time.

There are general market conditions - where there is only a small number of suppliers or where demand elasticity is low – that can make withholding a profitable strategy. Various forms of explicit and implicit collusion can also be employed.

Ownership of generation in PJM is not highly concentrated. There were approximately nine large generation owners plus NUGs (non-utility generators) and municipal owners with more than 500 units inside the PJM area and there are other generation owners and intermediaries willing to provide energy to the PJM market via imports. This would appear to reduce the probability that withholding is, in general, a profitable strategy.

Despite the fact that the PJM market structure appears to pass the basic structural test for competitive markets[5], there are conditions under which withholding can be a profitable strategy, regardless of the significant number of suppliers and the absence of collusion. Such conditions might occur when demand for power is high relative to available capacity, demand is price inelastic, most generators have reached the output limits of their equipment and only one generator retains the ability to produce additional output. Under these conditions, a single generation owner could exercise market power, regardless of the overall ownership structure in the market. Withholding of output by this generator will increase the market price. This situation could occur in a market with low levels of calculated concentration. A generator could be quite small in proportion to the market and still exercise this type of market power.

Situations with these underlying characteristics do arise in the PJM energy market. PJM forecasts demand on a day-ahead basis and makes these forecasts public via the PJM web site. On some occasions, PJM also declares Emergency procedures one or more days ahead of the day of operation. During the summer of 1999 PJM faced levels of forecast demand which equaled or exceeded expected internal levels of available capacity to produce energy. PJM generally faces an inelastic demand curve. When forecast demand is high relative to the available offered supply of energy, the probability increases that PJM will require all energy offers in order to meet loads. As a result, the expected returns to a withholding strategy by one or more suppliers of energy increase. As noted, by rule, PJM must call on all units, or import transactions, which offered to provide energy to PJM via day-ahead offers, prior to implementing Emergency procedures.

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4 This assumes that there is no congestion and that therefore the LMP at each bus is the system LMP. When there is congestion, the offer price may set the price at one or more buses.

5 FERC approved market-based rates for PJM in part based on a structural market power analysis which calculated HHIs for PJM under a variety of scenarios. See Paul L. Joskow and Rodney Frame, Supporting Companies' Report on Market Power, 1997.

Thus, on high demand days in PJM, generators know, with a fairly high degree of certainty, that PJM will have to take all energy which was offered on a day-ahead basis. Thus, high and inelastic demand in PJM creates the conditions for profitable withholding. Since generation owners know that all offered units will be taken, at their offer price, it will be profitable for generation owners, other things equal, to submit some amount of generation with very high offer prices. Depending on the degree of certainty which generators attach to the expected declaration of Emergency conditions, generators can minimize risk by offering only one small unit at a high price, or by offering a series of small units at a range of prices from slightly above cost to the bid cap. In this way, the profit associated with running larger units is never put at risk, but a high price for all units in a generator's portfolio is assured if PJM does take all offers.

Incentives to increase prices vary by generator. Generators who remain responsible for serving their own load, who bear financial risk associated with high prices and who are short in energy, would have no incentive to increase prices. Generators who remain responsible for serving their own load but who are still long in energy during these system conditions could have an incentive to increase prices, if their load serving obligations are covered by bilateral contracts or other arrangements. Generators who are not responsible for any loads, other than via contract, would have the greatest incentive to increase prices.

Low price elasticity of demand, price-inelastic demand, is a significant contributor to the market conditions which make the exercise of market power possible. Demand for energy is currently price-inelastic in PJM. The primary reasons are that most loads cannot observe real-time prices, do not have the capability to react to real-time prices, and would not benefit by reacting to those prices. The majority of residential and commercial customers do not have ready access to real-time prices and, in general, are not charged based on real-time wholesale prices. These customers also do not have meters that record demand by time of use and are charged a fixed rate or an average rate, regardless of the wholesale price at the time of use. Thus, even if the customers were aware of real-time prices and reduced their usage at times of high prices, their time of use is not recorded and this reduction in consumption would not have an impact on their bill.

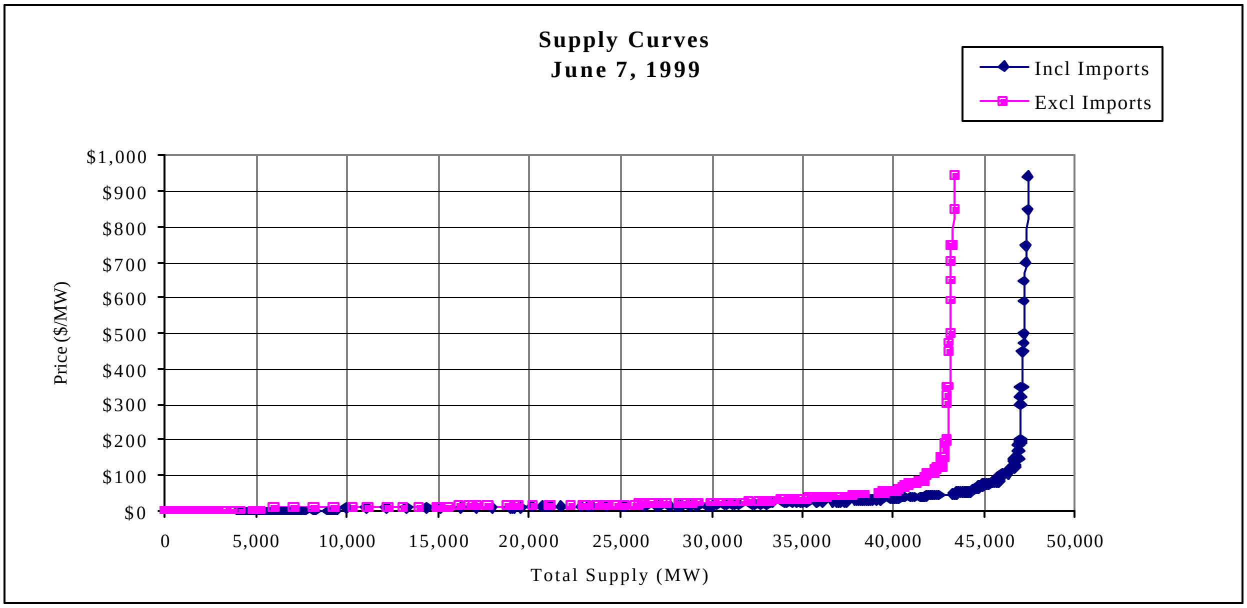
**High Demand Conditions in PJM: June 7**

During the summer of 1999, historically high prices (prices greater than \$130/MW) occurred during 15 days.[6] This subsection focuses on one of those days, June 7, as an example. Hot weather and associated relatively high demands were forecast for June 7 the day before. PJM declared a Maximum Emergency Generation event at 14:13 on June 7. At that time, all economic offers of generation had been accepted and the market price was \$850/MW.

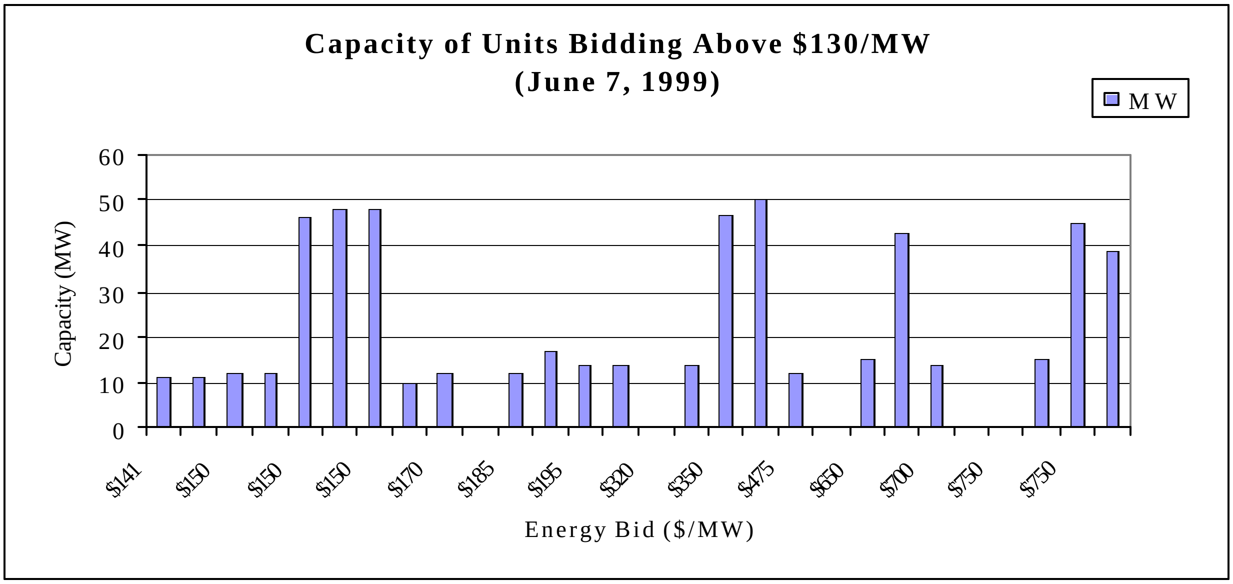
The supply curve for June 7, based on actual units operating at the time of system peak, was characterized by a relatively flat portion at a price less than \$50/MW extending to about 40,000 MW of output, an elbow at prices between \$50/MW and \$130/MW including about 3,000 MW

[6] As noted in the introduction, high prices are defined to start at \$130/MWh because this is the approximate operating cost of the highest cost unit on the PJM system in 1999 and thus would have been the highest bid under the cost-based bidding system.

of output and a steeply sloped portion with prices ranging from \$130/MW to about \$850/MW which includes about 600 MW of output. (See Supply Curves.[7])

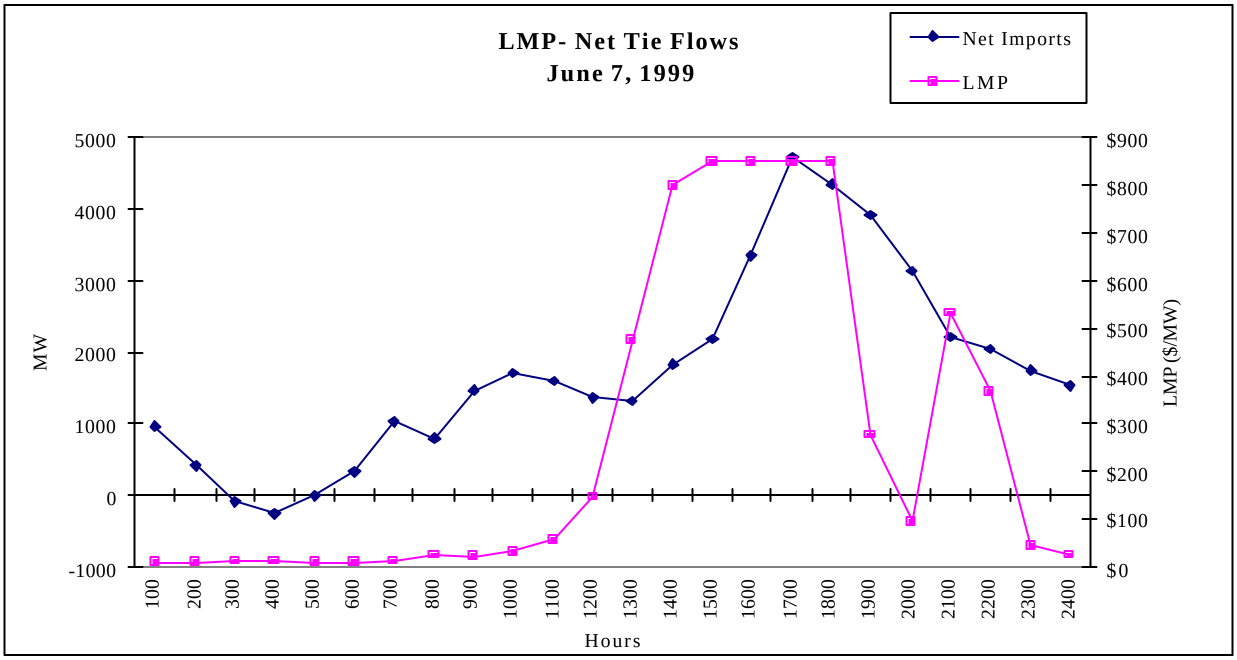



Within the 600 MW which comprise the steeply sloping portion of the supply curve, the distribution of units by output size shows that most of the units were relatively small, less than 20 MW with the largest units less than 50 MW. (See Capacity for Units Bidding Above \$130/MW.) The ownership of these units was highly concentrated. For the 600 MW of output offered at prices greater than \$130/MW, the offer price substantially exceeded the marginal production cost.




[7] The supply curves are represented at one point in time. Thus imports at that time are represented as a shift out in the supply curve.

Demand never exceeded the ability of PJM internal generation plus net scheduled tie flows to meet it. Maximum demand was about 48,000 MW. The maximum output from all economic offers to PJM from internal generation was about 44,000 MW. Net scheduled tie flows were about 4,000 MW during peak demand hours. PJM relied upon a recall of bilateral exports for several hours to meet loads during peak demand hours.[8] PJM maintained regulation objectives as well as all reserve objectives. PJM did not call on Active Load Management (ALM) although some utilities did call on a relatively small level of specific ALM resources.[9] PJM did not make any purchases of Emergency Energy.




## June 7: Market Power?

Does this basic set of facts about one day on the PJM system describe the exercise of market power or simply a competitive market reacting to high levels of demand? Did the high prices reflect the opportunity cost associated with selling inside PJM? Were the high prices necessary in order to attract imports and meet PJM load?

It appears clear that about 600 MW of output was offered to PJM at prices greater than the units' marginal cost of production and that the result was an increase in the market price. The data clearly show that the output of the units which comprised the 600 MW was not made available when the market price equaled and exceeded their marginal cost of production. The units remained turned off for multiple hours during which the price exceeded their marginal production cost, but was below their offer. The units were turned on only after the dispatch signal equaled or exceeded their offer price. It is only at that point that the unit can set the system price. The strategy resulted in an increase in the market price above the marginal production cost

8 Net scheduled tie flows represent the net impact of import transactions and export transactions.

9 ALM refers to curtailable loads. These loads are typically curtailable under retail utility tariffs when PJM declares Emergency conditions.

of the marginal unit (highest marginal cost). The PJM price exceeded $130/MW for 10 hours on June 7. (See LMP – Net Tie Flows.)

The output of some of these units was withdrawn when the system price fell below their offer price, but for others of these units, the output level remained constant for several hours despite the fact that the price was below their offer price.

For example, as the price increased during the day on June 7, the unit which set the $850/MW price did not run while the price was below its marginal production cost and then continued to not run for about two hours during which the price exceeded its marginal production cost. The unit turned on as soon as the dispatch rate exceeded its offer price. The unit continued to run for several hours after the price dropped below its offer price but remained above its marginal production cost and turned off only when the price fell below its marginal production cost.[10]

The owners of the generation in the tail end of the supply curve were unique among generation owners in that they had market-based units and were long in energy, i.e. they were net sellers of energy. These were the only owners in that position and their behavior differed significantly from that of other generation owners. Thus, the behavior of generators was consistent with their incentives.

When evaluating the relationship between price and marginal cost, the relevant marginal cost includes opportunity cost in addition to the marginal cost of production. The opportunity cost of selling into PJM is the value of selling out of PJM for the same period. One measure of the opportunity cost of making energy sales within PJM, at the PJM price, is the net revenue which could have been received had the sale been made outside PJM, at the available price outside PJM.[11]

The value of the foregone opportunity when there is an external sale from a unit which is not a Capacity Resource, is simply the available net external price. If a unit is a Capacity Resource, its energy is subject to recall. The calculation of opportunity cost for a Capacity Resource must consider that recallability.

On a day-ahead basis, the owner of a Capacity Resource can compare the day-ahead price for external sale with the day-ahead price for sale to PJM, in the forward market. The export related opportunity cost for a Capacity Resource is a function both of the net price from sales to the external areas and the expected cost of being recalled, which would be determined in part by the liquidated damages provision of the sales contract. Such liquidated damages provisions typically require payment of the replacement energy cost, which is the real-time external energy price during the period of recall. The cost of being recalled is this replacement energy cost net of the revenues earned from the sale of the recalled energy to PJM. While this total opportunity cost per MW may be greater than or less than the PJM price, the value of the external opportunity depends on the expected hours of recall and the relationship between the internal and external prices during the period of recall.

10 The Market Monitoring Unit has access to cost curves submitted by each PJM unit as well as the market-based bids submitted by each unit.

11 Net revenue is the energy price less transmission costs and other transactions costs, on a risk adjusted basis.

In real-time, the value of the foregone opportunity is the real-time net external price. Regardless of the day-ahead bid, any unit can sell its power externally on an hourly basis.[12] The fact that a generator chooses to sell into PJM rather than externally indicates that such a sale is the most profitable course and therefore that the opportunity cost is less than or equal to the internal price. Thus if an hourly sale is made into PJM, the opportunity cost of a real-time external sale is less than or equal to the benefit from selling into PJM.

In real-time, opportunity cost is not an explanation for a failure to produce when the price is greater than the marginal cost of production for a unit. Even if a unit is bid into PJM on a day-ahead basis, based on the opportunity to sell outside PJM in the day-ahead market, that bid does not determine the profitability of production in real-time. Production in real-time is profitable whenever the PJM price, or the external price, is greater than the marginal cost of production. Units can self schedule and produce when it is profitable and units can decide to export if it is more profitable than selling into PJM.

On June 7, export sales were being made until bilateral sales were recalled. Imports were also flowing and imports exceeded exports in every peak hour and in every hour except the hours ended 0300 and 0400. The available day-ahead forward price data for the areas surrounding PJM is for firm energy sales for the 16-hour peak period on the next day. The day-ahead prices for firm 16-hour energy for the PJM market were higher than the comparable day-ahead prices for the surrounding areas. Based on the fact that net scheduled tie flows were positive into PJM at all times of the day and at all price levels experienced during the day, and based on the limited real-time price evidence which also shows PJM prices higher than prices in surrounding areas, it does not appear that opportunity cost can explain the day-ahead offer behavior of the units which offered relatively high prices inside PJM or the real-time behavior of these units.[13]

Opportunity costs can result from other features of generating units. For example, certain units may have a limited number of hours during which they are permitted to operate under air quality regulations. Opportunity cost, in this case, is defined inter-temporally rather than by a simultaneous opportunity. If a unit has a choice as to whether to produce now or save its limited output for a higher price period, the potential lost opportunity to produce at a higher price represents a possible source of opportunity cost of current production. The fact that, during a high load summer like 1999, there were 96 high price hours, suggests that the inter-temporal opportunity cost was not a determinant of marginal cost.

It can be reasonably concluded that the units in the 600 MW tail of the supply curve offered output at a price greater than marginal cost, including both production cost and opportunity cost.

Imports were necessary to meet PJM loads. On June 7, net imports met about 4500 MW of load at the peak level of imports. Imports clearly responded to the PJM price. Imports which do not offer energy into PJM on a day-ahead basis with a dispatchable offer cannot set LMP. Other than

[12] Here, day-ahead bid refers to 1999, prior to the implementation of the two settlement system. A generator can take control of its unit with 45 minutes notice.

[13] The limited real-time price data is taken from the Quarterly Transaction Reports filed with FERC by marketers and utilities.

such dispatchable imports, real-time imports are price takers.[14] The bulk of the imports on this day were price takers at the PJM price. A comparison between the LMP path and the level of net imports illustrates the response of imports to the price within PJM. Net scheduled imports were positive for the entire on peak period and virtually the entire day. As the PJM price increased, net scheduled imports increased steadily, with a lag, and began to decrease at about the time the price fell from its peak level.

Imports and thus net scheduled tie flows were a positive, although unknown, function of real-time PJM prices.[15] In the absence of offers greater than the marginal cost of production, the PJM price would not have risen above about $130/MW. While it is not known what scheduled tie flows would have been in the absence of the actual price increases observed on this day, prices greater than $130/MW were essential to attracting imports. Thus, the competitive price was greater than $130/MW.

Price sensitive imports are a source of competition for internal generation. In theory, imports serve to limit both the level of prices and the duration of prices above some level. In practice, due to the lags associated with importing into PJM and the shape of the internal supply curve, imports do not serve to prevent high prices but can serve to limit the duration of high prices. For June 7, the LMP path illustrates the impact of net tie flows on the price.

Scarcity is a possible explanation for high prices. Scarcity exists when demand is greater than supply at a price equal to the cost of the last unit produced from the highest cost generating unit. If scarcity exists, the competitive price will exceed the cost of the last unit produced from the highest cost generating unit, if the demand curve exhibits elasticity. In PJM, as for most electric markets, demand is inelastic. Thus, scarcity exists when the inelastic demand is greater than or equal to the supply at a price equal to the cost of the last unit produced from the highest cost generating unit. In other words, scarcity exists when the demand curve is to the right of the supply curve at the maximum output level represented by the supply curve. In the situation without exports or imports, scarcity exists when demand is greater than or equal to the physically available energy output of Capacity Resources. If demand is price inelastic, then the competitive price is not defined under these conditions, although it should be considered to be greater than the cost of the last unit produced. In the situation with exports and imports, the definition of scarcity is not as clear. Under PJM rules, there is no defined supply curve for imports which respond, in real-time, to price signals. As noted, these imports are price takers and PJM has no real-time information regarding their price elasticity. There is a transmission based limitation on the level of MW which can be imported into PJM. Thus, at some point the supply curve of internal resources plus imports reaches a maximum MW level. Again, scarcity exists when demand is greater than the available supply from internal and external resources.

There was not a physical scarcity of energy in PJM on June 7. PJM was never short of energy. The supply of energy from Capacity Resources plus imports always exceeded demand at the market price. There were also additional resources in PJM which were not used. PJM did not

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14 Price taker here means that real-time imports are paid the current spot market price but does not mean price taker in the sense of perfect competition as the term is used in economic theory.

15 While the actual response of imports to observed prices is known for each day, the response of imports to a different set of prices on that day is not known.

call on ALM resources, although some utilities did call on a relatively small portion of total ALM resources in the PJM area. Reserves were not reduced as a result of high demand levels. The demand curve did intersect the supply curve. However, there was scarcity in the economic sense at a market price of $130/MWh because demand exceeded supply at that price. A higher price was required in order to induce a response from imports adequate to meet total demand.

In practice, the high offers of some PJM units increased the PJM price enough to attract imports adequate to meet PJM loads. At present, there is no mechanism for PJM prices to reflect the cost of resources other than those internal and external resources which make day-ahead offers. Real-time imports do not make offers; they are price takers. The demand side does not make offers. In the absence of high internal offers and adequate net imports, PJM can make emergency purchases via an open bidding process as part of emergency procedures. The bids of emergency purchases are not capped and do not affect the market price.

To assess whether market power was exercised in a meaningful fashion on June 7, it would be necessary to determine the competitive market price which would have permitted the market to clear in the absence of price setting by internal PJM units. If the competitive market price during the relevant hours was equal to or greater than the actual maximum price of $850/MW then the price setting behavior by PJM units did not cause any economic harm. If the competitive market price was less than $850/MW then the price setting behavior resulted in an excessively high price with the economic costs that entails. The limited data on real-time external prices suggests that it was probably not necessary to have an internal price of $850 to attract imports and therefore that market power was exercised to some degree. Thus, while it appears that the competitive price was probably below $850, it is not possible to identify the competitive market price with any certainty primarily due to uncertainty about the price responsiveness of imports and the limited data on real-time external prices. Therefore it is not possible to quantify the extent to which market power and scarcity explain the high prices on June 7.

While it is not possible to identify the competitive market price for June 7, it is possible to establish a framework which could define some bounds on the competitive market price. If a supply curve were established for imports, for reserves, for ALM and for capacity backed exports, the relative significance of these elements of the market for affecting price can be seen. At the margin, a relatively small change in the MW supplied to the PJM market can have a significant impact on price. On June 7, during the peak demand hours, an increase in supply or a decrease in demand of 500 MW would have reduced the price by about $100/MW. An increase in supply or a decrease in demand of 1,000 MW would have reduced the price by in excess of $200/MW. An increase in supply or a decrease in demand of 2,000 MW would have reduced the price by about $400/MW.[16]

This sensitivity of the market price to relatively small changes in supply demonstrates that the market is subject to the exercise of market power by changes in the behavior of small increments of supply. The sensitivity of the market price to relatively small changes in demand demonstrates that the introduction of relatively small amounts of price sensitive demand could have a significant impact on the ability of PJM units to exercise market power. The PJM area includes

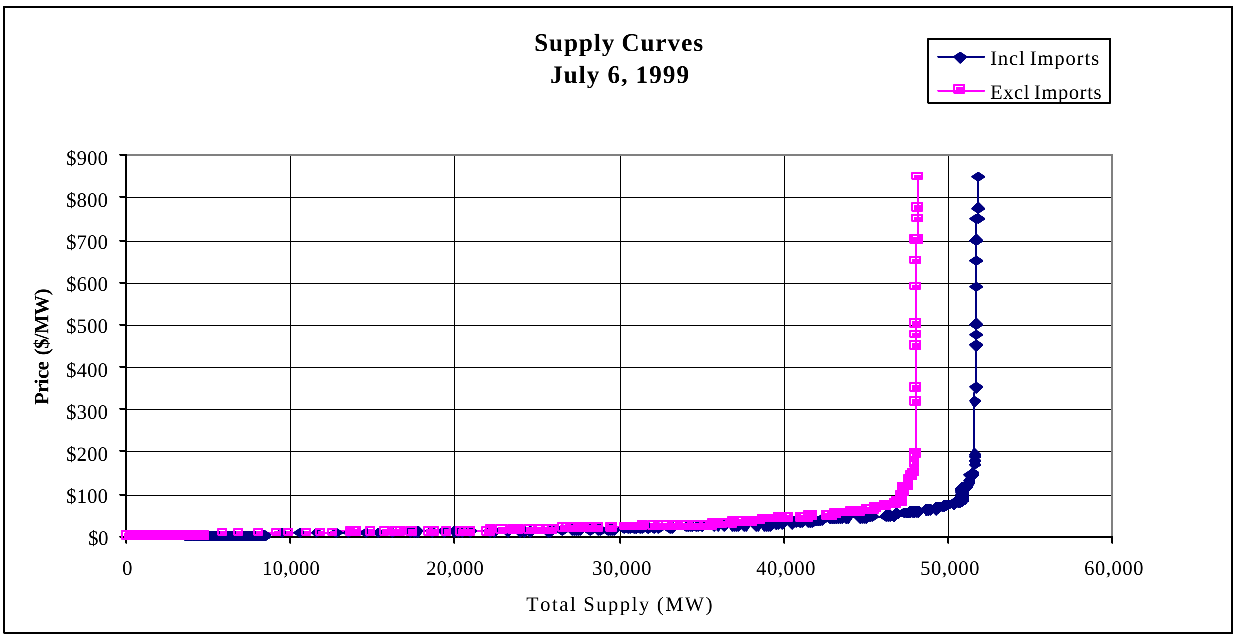
[16] The price responses to changes in demand are conservative in that they assume imports are highly responsive to price.

about 2,000 to 2,500 MW of ALM in the form of curtailable load. Under current rules, PJM calls on ALM only when it is required for reliability. ALM was not required for reliability on June 7. If ALM were dispatchable for economic reasons or if ALM had the ability to offer an explicit demand curve to PJM, the price impact could have been significant on June 7.

**High Demand Conditions in PJM: July 6**

Hot weather and associated relatively high demands were forecast for July 6 on July 5. PJM declared a Maximum Emergency Generation event at 13:02 on July 6. At that time, all economic offers of generation had been accepted and the market price was $920/MW.

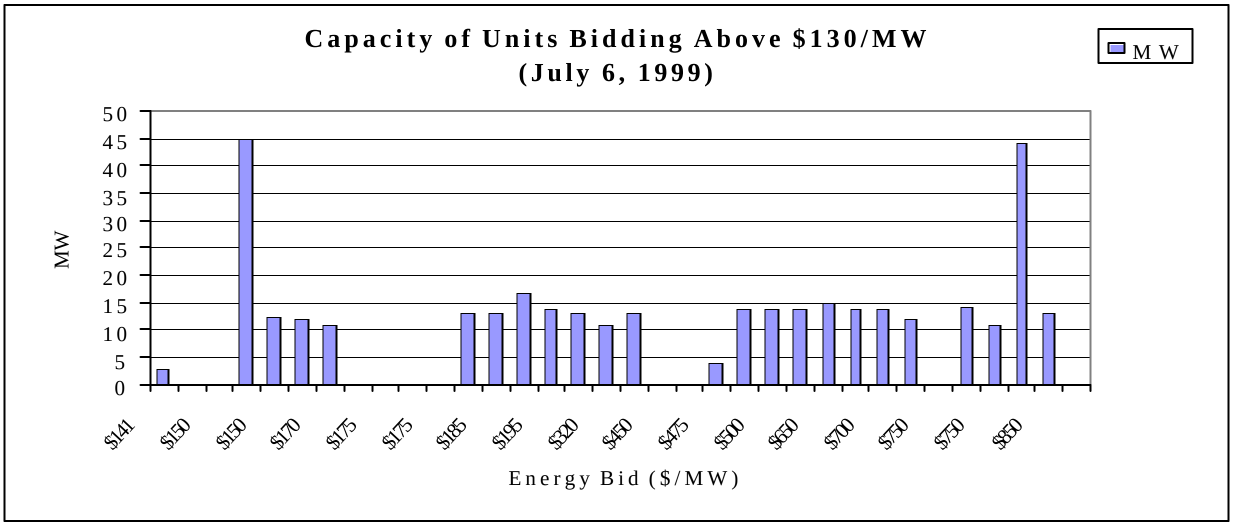
The supply curve for July 6, based on actual units operating at the time of system peak, was characterized by a relatively flat portion at a price less than $50/MW extending to about 43,500 MW of output, an elbow at prices between $50/MW and $130/MW including about 4,500 MW of output and a steeply sloped portion with prices ranging from $130/MW to $920/MW which includes about 360 MW of output. (See Supply Curves.[17])



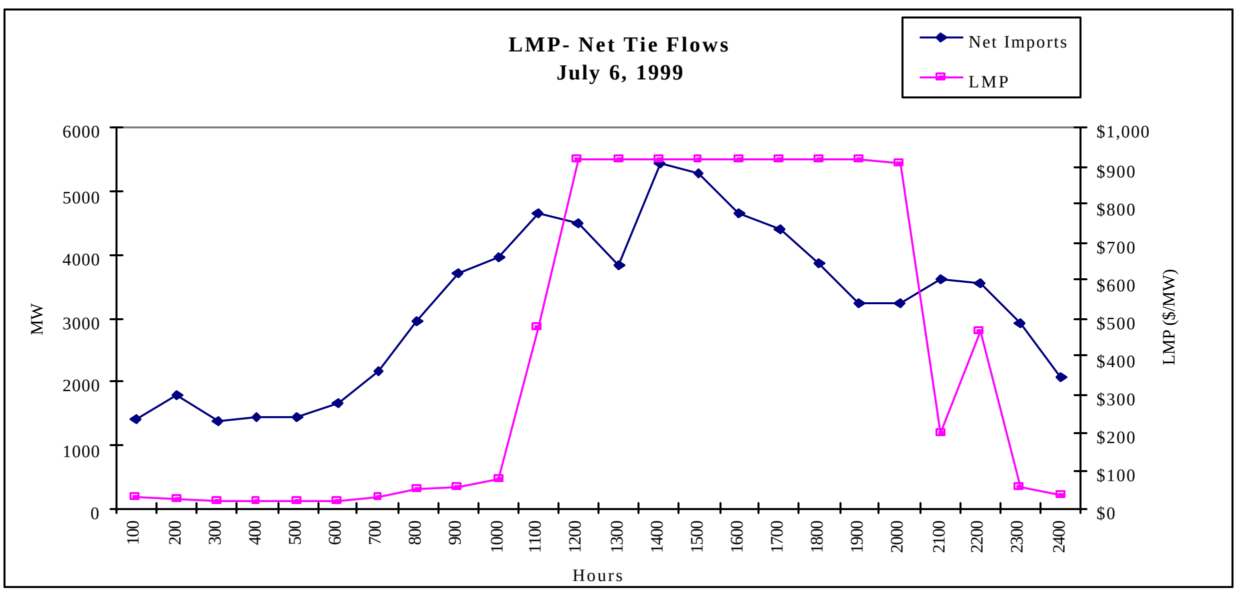

Within the 360 MW which comprise the steeply sloping portion of the supply curve, the distribution of units by output size shows that most of the units were relatively small CTs, less than 20 MW, with the largest CTs less than 50 MW. (See Capacity for Units Bidding Above $130/MW.) The ownership of these units was highly concentrated. For the 360 MW of output offered at prices greater than $130/MW, the offer price substantially exceeded the marginal production cost.

17 The supply curves are represented at one point in time. Thus imports are represented as a shift out in the supply curve.

Demand never exceeded the ability of PJM internal generation plus net scheduled tie flows to meet it. Maximum demand was about 52,200 MW. The output from all economic offers to PJM from internal generation was about 48,500 MW at the time of peak. Net scheduled tie flows were




about 3,600 MW at the time of peak demand.[18] PJM maintained regulation objectives as well as all reserve objectives. PJM called on the available ALM resources. PJM did not make any purchases of Emergency Energy.




18 Net scheduled tie flows represent the net impact of import transactions and export transactions.

**July 6: Market Power?**

On July 6 about 360 MW of output was offered to PJM at prices greater than the units' marginal cost of production resulting in an increase in the market price. The data clearly indicate that the output of the units which comprised the 360 MW was not made available when the market price equaled and exceeded their marginal cost of production. The units remained turned off for multiple hours during which the price exceeded their marginal production cost, but was below their offer. The units were turned on only after the dispatch signal equaled or exceeded their offer price. It is only at that point that the unit can set the system price. The strategy resulted in an increase in the market price above the marginal production cost of the marginal unit (highest marginal cost). The PJM price exceeded $130/MW for 12 hours on July 6. (See LMP – Net Tie Flows.)

The owners of the generation in the tail end of the supply curve were unique among generation owners in that they had market-based units and were long in energy, i.e. they were net sellers of energy. These were the only owners in that position and their behavior differed significantly from that of other generation owners on July 6.

On July 6, net imports were positive for the entire day. The only exports made during the peak demand hours were those associated with a capacity backed export and a long term export contract. The available day-ahead prices for firm 16 hour energy for the PJM market were greater than the comparable day-ahead prices for the areas outside PJM, after adjusting for the cost of transmission. The limited real-time price data also suggests that PJM real-time prices were higher than prices in surrounding areas. Based on the fact that net scheduled tie flows were positive into PJM at all times of the day and at all price levels experienced during the day, and based on the limited price evidence, it does not appear that opportunity cost can explain the day-ahead offer behavior of the units which offered relatively high prices inside PJM or the real-time behavior of these units.

It is reasonable to conclude that the units in the 360 MW tail of the supply curve offered output at a price greater than marginal cost, including both production cost and opportunity cost.

Imports were necessary to meet PJM loads. On July 6, net imports met about 5500 MW of load at the peak level of imports. Imports clearly responded to the PJM price. The bulk of the imports on this day were price takers at the PJM price. A comparison between the LMP path and the level of net imports illustrates the response of imports to the price within PJM. Net scheduled imports were positive for the entire on peak period and virtually the entire day. As the PJM price increased, net scheduled imports increased steadily, with a lag, fluctuated, and began to decrease at about the time the price fell from its peak level.

Imports and thus net scheduled tie flows were a positive, although unknown, function of real-time PJM prices. In the absence of offers greater than the marginal cost of production, the PJM price would not have risen above about $130/MW. While it is not known what scheduled tie flows would have been in the absence of the actual price increases observed on this day, prices greater than $130/MW were essential to attracting imports.

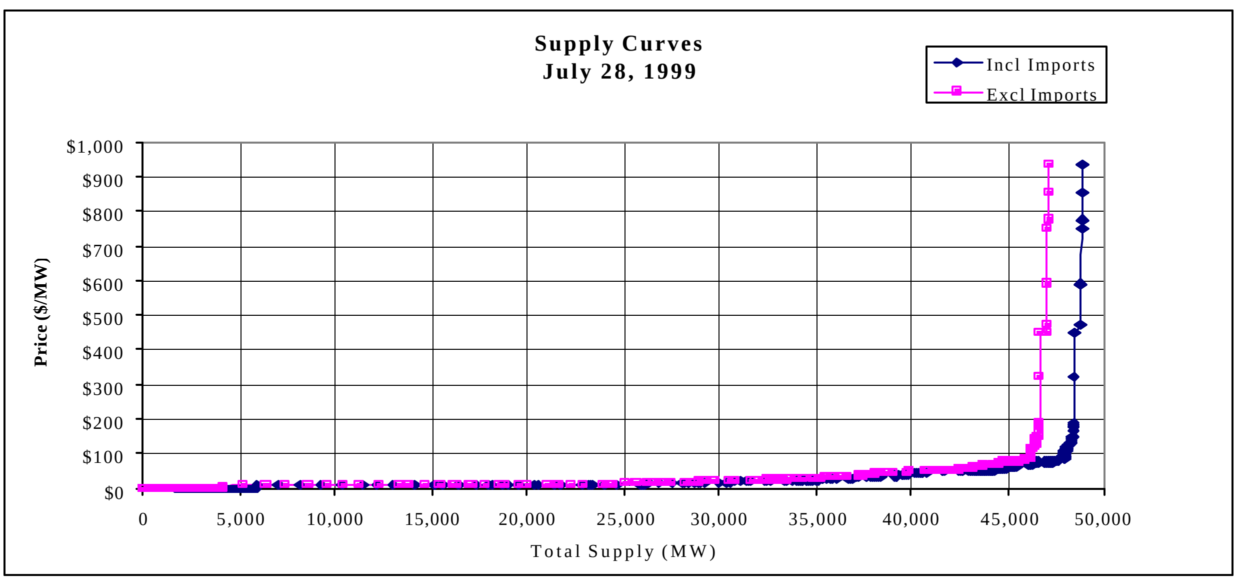
There was not a physical scarcity of energy in PJM on July 6. PJM was never short of energy. The supply of energy from Capacity Resources, including recalls, plus imports always exceeded demand at the market price. There were also additional resources in PJM which were not used. The demand curve did intersect the supply curve. Again however, there was scarcity in the economic sense at a market price of $130/MWh because demand exceeded supply at that price. A higher price was required in order to induce a response from imports adequate to meet total demand.

The limited data on real-time external prices suggests that it was probably not necessary to have an internal price of $920 to attract imports. Thus, while it appears that the competitive price was probably below $920, it is not possible to identify the competitive market price with any certainty primarily due to uncertainty about the price responsiveness of imports and the limited data on real-time external prices. Therefore it is not possible to quantify the extent to which market power and scarcity explain the high prices on July 6.

**High Demand Conditions in PJM: July 28**

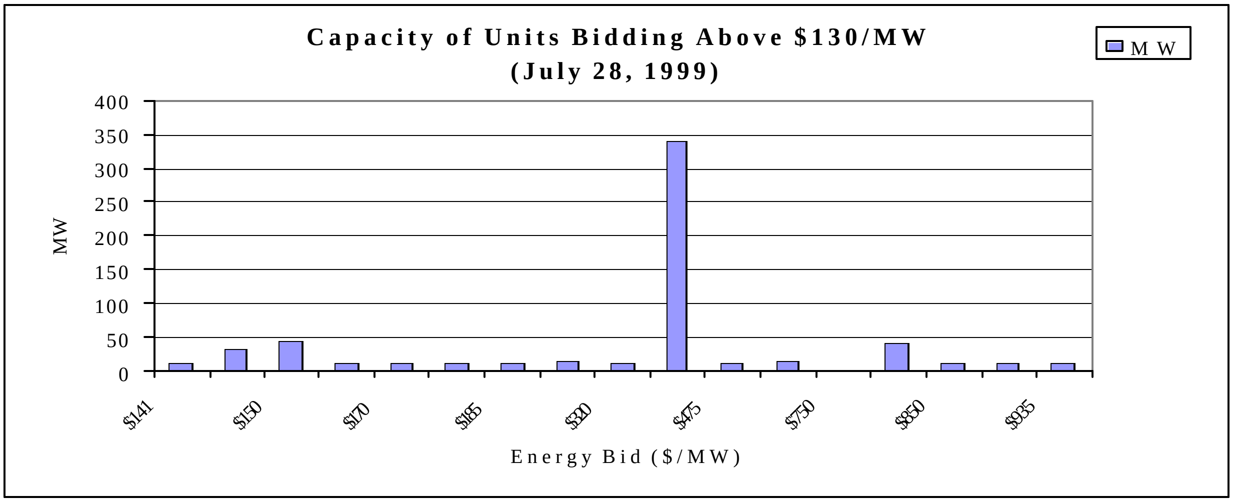
Hot weather and associated relatively high demands were forecast for July 28 on July 27. PJM declared a Maximum Emergency Generation event at 12:55 on July 28. At that time, all economic offers of generation had been accepted and the market price was $935/MW.

The supply curve for July 28, based on actual units operating at the time of system peak, was characterized by a relatively flat portion at a price less than $50/MW extending to about 41,000 MW of output, an elbow at prices between $50/MW and $130/MW including about 5,000 MW of output and a steeply sloped portion with prices ranging from $130/MW to $935/MW which includes about 600 MW of output. (See Supply Curves.[19])

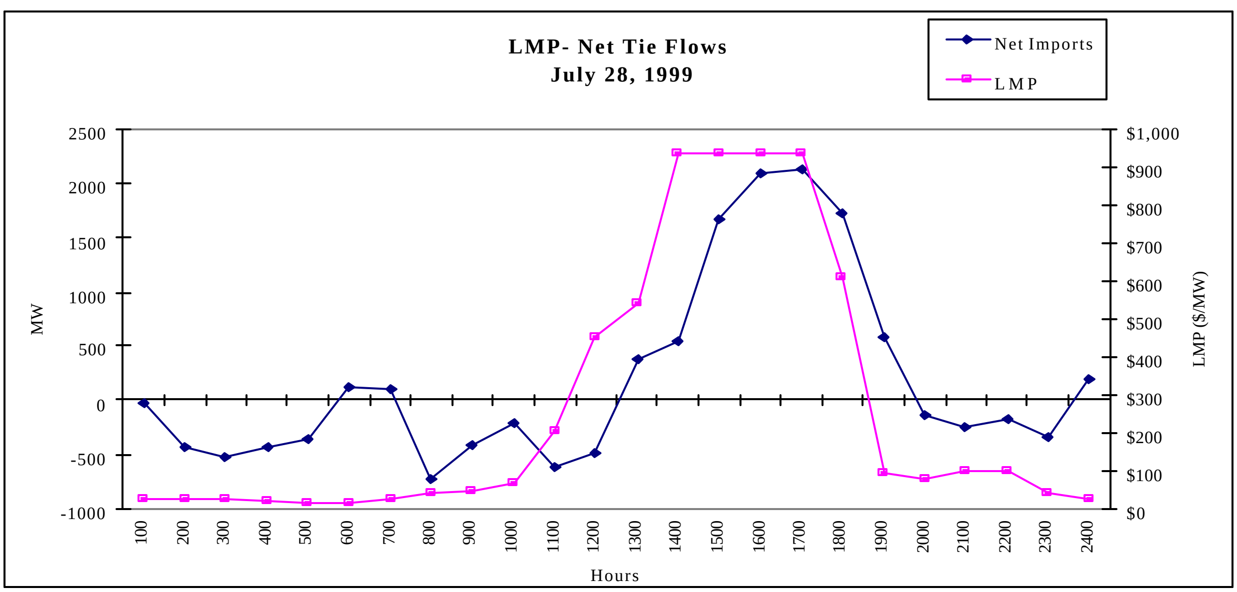



19 The supply curves are represented at one point in time. Thus imports are represented as a shift out in the supply curve.

Within the 600 MW which comprise the steeply sloping portion of the supply curve, the distribution of units by output size shows that most of the units were relatively small CTs, less than 20 MW, with the largest CT less than 50 MW, and one steam unit with a capacity of about 350 MW. (See Capacity for Units Bidding Above $130/MW.) The ownership of these units was highly concentrated. For the 600 MW of output offered at prices greater than $130/MW, the offer price substantially exceeded the marginal production cost.




Demand never exceeded the ability of PJM internal generation plus net scheduled tie flows to meet it. Maximum demand was about 48,800 MW. The output from all economic offers to PJM from internal generation was about 47,000 MW at the time of peak. Net scheduled tie flows were about 1,800 MW at the time of peak demand. PJM relied upon a recall of bilateral exports to meet loads during peak demand hours. PJM maintained regulation objectives as well as all reserve objectives. PJM called on a portion of the available ALM resources. PJM did not make any purchases of Emergency Energy.



**July 28: Market Power?**

Some 600 MW of output was offered to PJM at prices greater than the units' marginal cost of production and the result was an increase in the market price. The data show that the output of the units which comprised the 600 MW was not made available when the market price equaled and exceeded their marginal cost of production. The units remained turned off for multiple hours during which the price exceeded their marginal production cost, but was below their offer. The units were turned on only after the dispatch signal equaled or exceeded their offer price. It is only at that point that the unit can set the system price. The strategy resulted in an increase in the market price above the marginal production cost of the marginal unit (highest marginal cost). The PJM price exceeded $130/MW for 8 hours on July 28. (See LMP – Net Tie Flows.)

The owners of the generation in the tail end of the supply curve were unique among generation owners in that they had market-based units and were long in energy, i.e. they were net sellers of energy. These were the only owners in that position and their behavior differed significantly from that of other generation owners on July 28.

On July 28, exports exceeded imports by a relatively small amount up to the time that PJM recalled bilateral sales from Capacity Resources. The available day-ahead prices for firm 16 hour energy for the PJM market were below the comparable day-ahead prices for the areas to the west and south and above the comparable day-ahead prices for New York, after adjusting for the cost of transmission.

The day-ahead forward price data suggests that it would have been profitable for a unit not subject to recall to sell energy out of PJM to the west. However, for a unit subject to recall, the more limited real-time price data also suggests that the liquidated damages payments of a recall would reduce the opportunity costs to below the PJM price for the 16 hour period. This is likely to be true in general unless the total external price benefit over the 16 hour peak period is expected to outweigh the liquidated damages costs associated with a recall of exports for even a few hours at a high real-time price differential. Based on this opportunity cost information and based on the fact that net scheduled tie flows were relatively close to zero prior to the recall of bilateral sales, it does not appear that opportunity cost can explain the day-ahead offer behavior of the units which offered relatively high prices inside PJM or the real-time behavior of these units. The units in the 600 MW tail of the supply curve offered output at a price greater than marginal cost, including both production cost and opportunity cost.

Bilateral recalls were necessary to meet PJM loads. PJM recalled about 3000 MW of bilateral exports associated with Capacity Resources. The result was during the hours of recall that net imports increased from about zero to about 2000 MW. In the absence of the recall, net imports would have become negative.

On July 28, net imports were slightly negative prior to the recall of bilateral exports. However, gross imports reached about 5700 MW, almost balancing the maximum level of exports. It appears that imports and exports responded to the relative level of PJM and external prices, both on a forward market basis and on a real-time basis. The bulk of the imports on this day were price takers at the PJM price. Gross imports began to decline as PJM prices rose to their maximum level and continued to decline through the four hour period of $935 prices and beyond. Exports consisted of recallable exports from Capacity Resources and capacity backed exports from units which had been delisted.[20] Imports were coming in from New York, where prices were lower than PJM prices and exports were going to areas to the south and west where prices were higher than PJM prices.

Imports, exports and thus net scheduled tie flows were a function of PJM prices and external prices. In the absence of internal generator offers greater than the marginal cost of production, the PJM price would not have risen above about $130/MW. While it is not known what scheduled tie flows would have been in the absence of the actual price increases observed on this day, prices greater than $130/MW might not have been essential to attracting imports as the imports appear to have been a function of the price differential between New York and areas to the west. Net imports, holding aside recalls, were slightly negative all day.

There was not a physical scarcity of energy in PJM on July 28. PJM was never short of energy. The supply of energy from Capacity Resources, including recalls, plus imports always exceeded demand at the market price. There were also additional resources in PJM which were not used. The demand curve did intersect the supply curve. Unlike June 7 and July 6, on July 28 it does not appear that there was economic scarcity. PJM resources were adequate to meet the demand and thus supply should have equaled demand at a price equal to $130/MWh.

While it is not possible to precisely identify the competitive market price for July 28, it is possible to draw some preliminary conclusions with respect to the competitive market price. It appears clear that some generation owners, with an incentive to raise the price, did attempt to exercise market power by economically withholding the output of some units. It is also relatively clear that on July 28 the result was to increase the price of energy above the competitive market level. To the extent that net imports were zero, the price increase did not appear necessary to attract imports to serve load. Load was entirely served by internal PJM generation, including the recall of some external sales from Capacity Resources.

## Conclusion

The goal of PJM's MMU is to help create and maintain robust, competitive and non-discriminatory markets, limiting the exercise of market power. Market power exists when a market participant can profitably raise the market price above the competitive level. The examples illustrate some of the practical difficulties associated with applying this definition to real markets. Nonetheless, it is clear that some generation owners, with an incentive to raise the price, did attempt to exercise market power by economically withholding the output of some units and apparently, based on the limited evidence, did successfully exercise market power in some cases. It is clear that the result was to increase the price of energy although the level of the increase directly related to market power as opposed to scarcity is not known. Thus market power was apparently exercised, although the precise extent of the impact of market power on prices is not quantifiable. Generation owners have the ability to exercise market power in PJM on high demand days.

[20] See Capacity Resources chapter.

The analysis of the high demand days during the summer of 1999 suggests potential market design changes, which could improve the operation of PJM markets and limit the ability of generation owners to exercise market power under such circumstances. In particular, this analysis suggests the need for PJM to consider modifying the market rules so as to reduce the market power of the last economic offers on high demand days, to consider methods for increasing the price responsiveness of demand, and to consider a market mechanism that would permit the orderly bidding up of the PJM energy market price to levels required to attract imports on days when PJM demand exceeds internal PJM energy resources.

The availability of energy supply, especially on high demand days, is a key factor in the functioning of the energy market. Chapter Four examines the impact of capacity market rules on the availability of energy supply including the incentives to provide capacity resources to PJM and the incentives to ensure that those capacity resources are capable of delivering energy when it is needed.

## THE CAPACITY MARKET

In PJM, capacity obligations play a critical role in both maintaining reliability and contributing to the effective and competitive functioning of the energy market. Capacity obligations must be met by the provision of *capacity resources*.[1] The rules governing capacity resources are designed to provide the assurance that energy will be available to loads in PJM on even the highest load days. *Capacity markets* provide the transparent, market-based mechanism enabling new, competitive retail Load Serving Entities (LSEs) to acquire the capacity resources needed to meet their obligations and to sell capacity resources when no longer required. During 1999, this system of capacity obligations functioned effectively and helped ensure that energy was available during the hot and high demand days of the summer as well as the rest of the year. The functioning of the capacity markets in 1999 also suggested several areas where improvements in design could ensure that incentives to buy and sell capacity remain consistent with PJM's reliability goals.

PJM's Reliability Assurance Agreement among LSEs in the PJM Control Area states that the purpose of capacity obligations 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]

Under the Reliability Assurance Agreement, each (LSE) must own or purchase capacity resources greater than or equal to the load that it serves, plus a reserve margin. In order to cover their load obligations, LSEs may own or purchase generating capacity that meets the criteria to be a PJM capacity resource.

Capacity resources may be purchased in three different ways. First, it may be purchased on a bilateral basis from a source internal to the PJM control area. Internal bilateral transactions 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*, which is a unit of unforced capacity measured in MWs of unforced capacity per day. Second, capacity resources may be purchased from the PJM Capacity Credit Markets (CCMs). These markets, administered by PJM for terms of a day, a month, or multiple months, facilitate the exchange of capacity credits. Third, capacity may be purchased from a generating unit external to the PJM control area. These imports must be from specific units and must have firm transmission to the metered boundaries of the PJM Control area.

Capacity resources are MW of net generation capacity committed to serving specific loads, or MW of net generation capacity within the PJM Control area which meet certain criteria. All capacity resources must pass tests regarding the capability of the generation to serve load and the deliverability of the energy to PJM load, which requires adequate transmission service.

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[1] Capacity obligation and capacity resource are defined by the Amended and Restated Operating Agreement (OA) of PJM Interconnection, L.L.C. and the Reliability Assurance Agreement (RAA).

[2] Reliability Assurance Agreement Among Load Serving Entities in the PJM Control Area, revised March 21, 2000, Article 2—Purpose, page 8.

The specific formulas for measuring capacity and obligations changed in the planning period beginning June 1, 1999.[3] While the fundamentals of capacity planning did not change, many of the formulas for precisely defining capacity and obligations were different in the period prior to June 1, 1999 than in the post-June 1, 1999 period. The following subsection describes and summarizes the June through December period, while the January through May period is addressed later.

**PJM Capacity: June through December 1999**

This subsection describes the principal components of capacity requirements and provides summary PJM system-wide data for each item from June through December. These components include installed capacity, unforced capacity, obligation, excess, deficiency, imports, exports, internal bilateral transactions, Capacity Credit Market exchanges, and Active Load Management (ALM) credits. The general requirement for each LSE as of June 1, 1999 is:

Sum of *Unforced Capacity* from *capacity resources* $\geq$ *Unforced capacity obligation.*

Where:

$$\textit{Unforced Capacity for capacity resource ``i''} = (\textit{Installed capacity}_i) * (\textit{12 mo rolling average unforced outage rate}_i)$$

$$\textit{Unforced capacity obligation}^4 \textit{ for LSE ``j''} = [(\textit{Weather-adjusted actual coincident peak load}_j * \textit{Diversity factor}) - \textit{ALM adjustment}_j] * [(1 + \textit{PJM Reserve margin}) * (1 - \textit{PJM 5yr average forced outage rate})]$$

Unforced capacity and unforced capacity obligation are compared on a daily basis to determine whether an LSE is deficient. A deficiency results in a penalty of $160/MW-day of deficiency of installed capacity, or, in unforced capacity terms, $176.83/MW-day. Both the capacity and obligation sides of the equation can change on a daily basis.

The outage rates used in crediting units with capacity are based on the 12-month rolling average outage rate for the units, applied with a two-month lag. An unusually high occurrence of forced outages on a given day would not affect the amount of unforced capacity credits effective that day, but would affect the amount of capacity credits for 12 months starting two months after the event. The load obligation in capacity markets is based on the prior year actual peak load, prior year ALM load credits and a forecast of the reserve margin. A significant increase in actually observed loads would not have an impact on the current year load obligation.

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3 Accounted-For Obligation Manual (#17), Installed Capacity: Generation Data Systems Manual (#18), Load Data Systems Manual (#19), PJM Reserve Requirements Manual (#20), and Rules and Procedures for the Determination of Generating Capability Manual (#21).

4 Schedule 7 of Reliability Assurance Agreement Sections B.1 and B.2. The Forecast Pool Requirement is defined in Schedule 4.1 and can be simplified to (1+ reserve margin) * (1-forced outage rate).

*System capacity, obligation, and net excess capacity*[5]

System net excess capacity can be determined using installed capacity, unforced capacity, unforced capacity obligation, the sum of LSE excesses, and the sum of LSE deficiencies. Each item is described below, and Table 1 presents the PJM system net excess capacity by day along with each of the components. All items are assessed on a daily basis.

- **Capacity Resource**. Capacity, either committed to serving load obligations within PJM or from resources within the PJM control area that are accredited to the PJM control area.
- **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 averaged 57,071 MW from June through December 1999 and ranged from 55,795 MW to 57,751 MW. Installed capacity can change on a daily basis principally due to exports and imports of capacity or when a physical change is made to a generating unit, although on 77 percent of the days in this time period installed capacity was unchanged from the prior day.
- **Unforced Capacity**. System total unforced capacity is the installed capacity adjusted for outage rates. The sum of the *unforced capacity* of all *capacity resources* from June through December 1999 averaged 53,611 MW and ranged from 52,415 MW to 54,246 MW. Installed capacity was between 6.3 percent and 6.5 percent greater than unforced capacity over this time period, reflecting unforced outage rates in effect over the time period.
- **Obligation**. The sum of all LSE unforced capacity obligations averaged 51,779 MW. The level of capacity obligations varied due to changes in ALM contracts. However, on 93 percent of the days this item was unchanged from one day to the next.
- **Gross excess.** This is the sum of all LSE individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as *Accounted-for Excess*. The sum of LSE excess averaged 1,839 MW and ranged from 626 MW to 2,486 MW.
- **Gross deficiency.** This is the sum of all companies' individual capacity deficiencies, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as *Accounted-for Deficiency*. The sum of companies' system deficiency averaged 7 MW and ranged from 0 MW to 352 MW.
- **Net excess.** This is the net of gross excess and gross deficiency and, as a result, is the total PJM capacity resources in excess of the sum of obligations. Net excess averaged 1,839 MW and ranged from 426 MW to 2,486 MW.

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5 These data will be posted on a monthly basis at www.pjm.com under the Market Monitoring Unit link. Each item presented in this subsection is a PJM system total, expressed in MW of unforced capacity, unless otherwise noted.

**Table 1: Summary of members' net excess capacity, June - December, 1999 (MW)**

| | Mean | Minimum | Maximum | Standard deviation |
|---|---|---|---|---|
| Installed capacity | 57,071 | 55,795 | 57,751 | 437 |
| Unforced capacity | 53,611 | 52,415 | 54,246 | 411 |
| Obligation | 51,779 | 51,691 | 51,989 | 83 |
| Sum of excess | 1,839 | 626 | 2,486 | 467 |
| Sum of deficiency | 7 | 0 | 352 | 36 |
| Net excess | 1,832 | 426 | 2,486 | 479 |

***Bilateral Capacity Transactions***

PJM capacity resources may be traded bilaterally within and outside of the PJM control area. The following items describe the numbers of these transactions and Table 2 presents system summary data.

- **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. Imports averaged 331 MW and ranged from 3 MW to 493 MW.
- **Exports.** 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 control area. Exports averaged 860 MW and ranged from 235 MW to 1,676 MW.
- **Net exports.** Capacity exports less capacity imports. Net exports averaged 529 MW and ranged from –118 MW (reflecting net imports of 118 MW) to 1,672 MW.
- **Internal bilateral transactions**. Bilateral transactions of capacity where the source and sink are internal to the PJM control area. Internal bilateral transactions, which may reflect capacity credits or unit-specific transactions, averaged 19,729 MW and ranged from 18,741 MW to 24,349 MW. They increased in December, when they represented at least 23,000 MW each day. Daily internal bilateral transactions as a percentage of daily load obligations averaged 38 percent and ranged from 36 percent to 47 percent.[6]

**Table 2: Bilateral Capacity transactions, June-December 1999 (MW)**

| | Mean | Minimum | Maximum | Standard deviation |
|---|---|---|---|---|
| Imports | 331 | 3 | 493 | 106 |
| Exports | 860 | 235 | 1,676 | 346 |
| Net exports | 529 | -118 | 1,672 | 399 |
| Internal bilaterals | 19,729 | 18,741 | 24,349 | 1,674 |

[6] Note that a given MW of capacity may be traded multiple times. As a result, the level of bilateral transactions and the percent of load obligation served may overstate the level of capacity resources provided by bilateral markets.

### *PJM Capacity Credit Market (CCM)*

Capacity credits, defined in terms of unforced capacity, are traded on a daily, monthly, and multi-monthly basis. Table 3 summarizes the volume of PJM capacity market exchanges.

- **Daily Capacity Credit Market (Daily CCMs).** The *Capacity Credits* cleared through PJM daily *Capacity Credit Markets (CCMs)* averaged 374 MW per day and ranged from 125 MW to 846 MW per day.
- **Monthly CCMs.** The *Capacity Credits* cleared through PJM single-month *Capacity Credit Markets (CCMs)* averaged 241 MW per day and ranged from 53 MW to 420 MW per day. There were 22 monthly CCMs in which capacity was traded for the months of June through December, reflecting the fact that there are typically at least three markets for each month.
- **Multi-Monthly CCMs**. The *Capacity Credits* cleared through PJM multi-monthly *Capacity Credit Markets (CCMs)* averaged 740 MW per day and ranged from 610 MW to 876 MW per day. There were 7 multi-monthly markets that included the June through December 1999 period. One of these markets had a term of four months, three had terms of 7 months, two were for 9 months, and one was for 12 months.

**Table 3: PJM Capacity Credit Market Exchanges, June-December 1999 (MW/day)**

| | Mean | Minimum | Maximum | Standard deviation |
|---|---|---|---|---|
| Daily CCMs | 374 | 125 | 846 | 148 |
| Monthly CCMs | 241 | 53 | 420 | 114 |
| Multi-Monthly CCMs | 740 | 610 | 876 | 114 |
| All CCMs | 1,355 | 796 | 2,027 | 320 |

### *Active Load Management (ALM) Credits*

ALM credits are credits, based on interruptible loads, against LSE capacity obligations (Table 4). ALM credits averaged 2,007 MW and ranged from 1,841 MW to 2,080 MW.

**Table 4: PJM ALM Credits, June-December, 1999 (MW)**

| | Mean | Minimum | Maximum | Standard deviation |
|---|---|---|---|---|
| ALM credits | 2,007 | 1,841 | 2,080 | 75 |

## PJM Capacity: January through May 1999

In the 1998-1999 planning period, which ran from June 1, 1998 to May 31, 1999, capacity obligations and many of the formulas for determining capacity and obligations were different than in the post-June 1, 1999 period.

In the 1998-1999 planning period, the capacity requirement for each LSE was:

*Installed capacity* plus *ALM* $\geq$ *capacity obligation*, where
*capacity obligation* is defined as the share of PJM's forecast peak plus the reserve margin.

Table 5 presents capacity market data for the January through May period. All capacity data are presented in terms of "installed capacity," which has been approximately 6 percent higher than unforced capacity. The "unforced capacity" concept was not part of capacity planning during this period.

Imports were significantly higher in the January through May period (2,433 MW) than in the June through December period (331 MW). The difference was the result of the termination of a large import arrangement and a change in the way certain units were modeled for planning purposes. After June 1999, certain units were treated as internal rather than external but there was no impact on the amount of capacity available.

The average level of daily internal bilateral transactions was 25,071 MW from January through May. The maximum level of internal bilateral transactions was 28,795 MW, the maximum level of exports was 1,369 MW and the maximum level of imports was 3,032 MW.

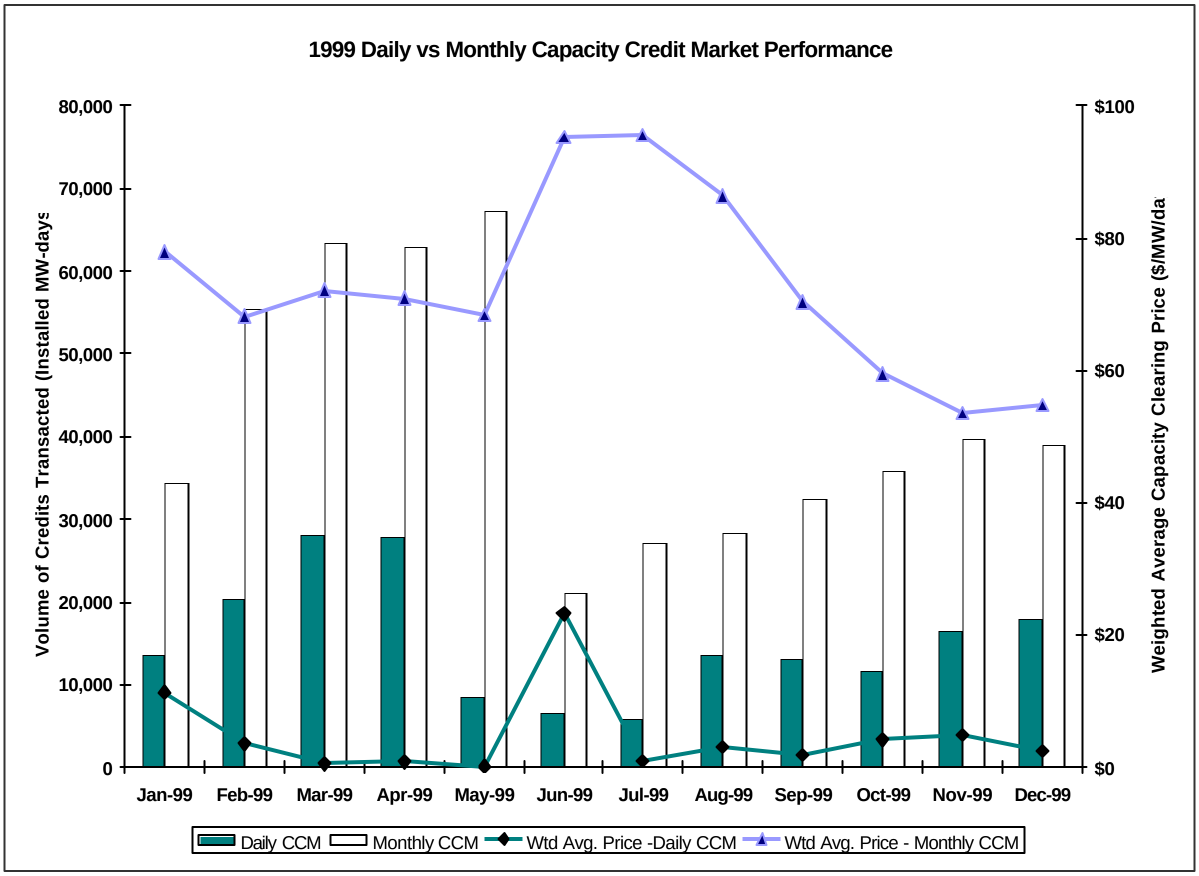
**Table 5: Summary - Components of Capacity Markets, January - May, 1999 (MW)**

| | Mean | Minimum | Maximum | Standard Deviation |
|---|---|---|---|---|
| Installed capacity | 58,134 | 57,590 | 58,891 | 343 |
| ALM credits | 2,613 | 2,594 | 2,667 | 22 |
| Obligation | 58,010 | 58,009 | 58,010 | 0 |
| Sum of excess | 2,743 | 2,269 | 3,478 | 331 |
| Sum of deficiency | 6 | 0 | 121 | 22 |
| Net excess | 2,737 | 2,247 | 3,478 | 336 |
| Imports | 2,433 | 1,775 | 3,032 | 352 |
| Exports | 613 | 0 | 1,369 | 552 |
| Net exports | -1,819 | -2,632 | -882 | 573 |
| Internal bilaterals | 25,071 | 20,853 | 28,795 | 3,143 |
| Daily CCMs | 641 | 10 | 1,364 | 305 |
| Monthly CCMs | 999 | 236 | 1,294 | 400 |
| Multi-monthly CCMs | 872 | 872 | 872 | 0 |
| All CCMs | 2,479 | 1,118 | 3,175 | 573 |

## Overall 1999 PJM Capacity Market

### *Capacity Credit Market prices*

Capacity market prices and volumes for the entire year are shown in the graph below. The volume-weighted average price for the entire year was $70.66/MW-day in monthly and multi-monthly markets and $3.63/MW-day in daily markets. The volume-weighted average of all CCMs for 1999 was $52.86/MW-day.[7]



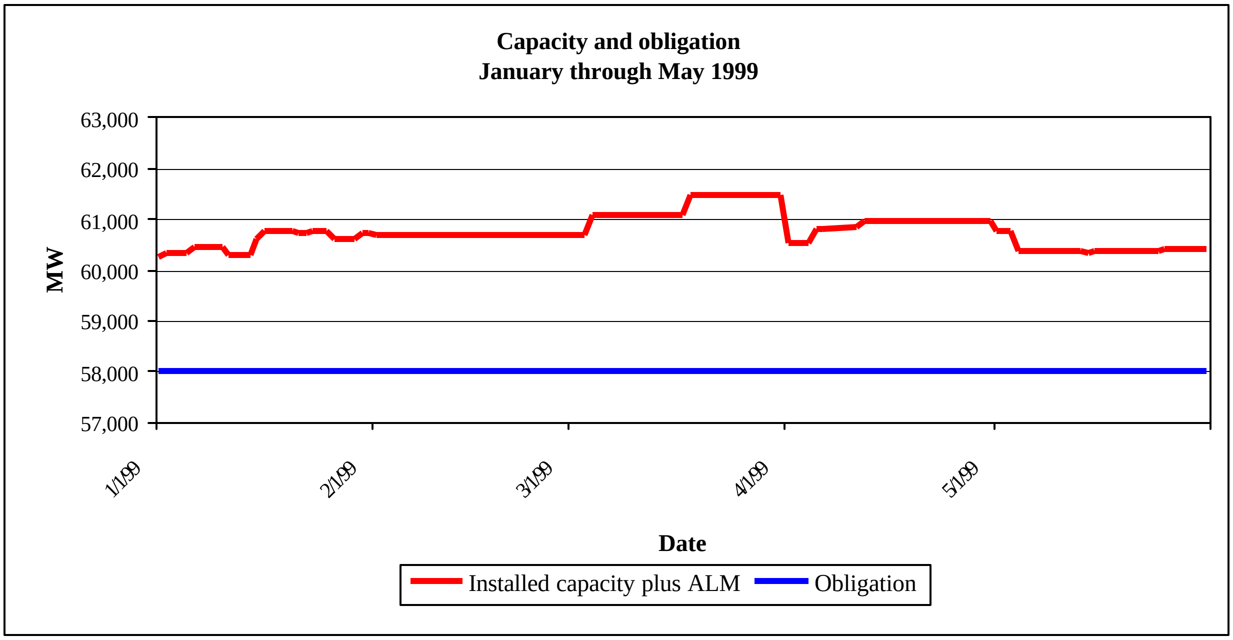

### *Excess Capacity in PJM*

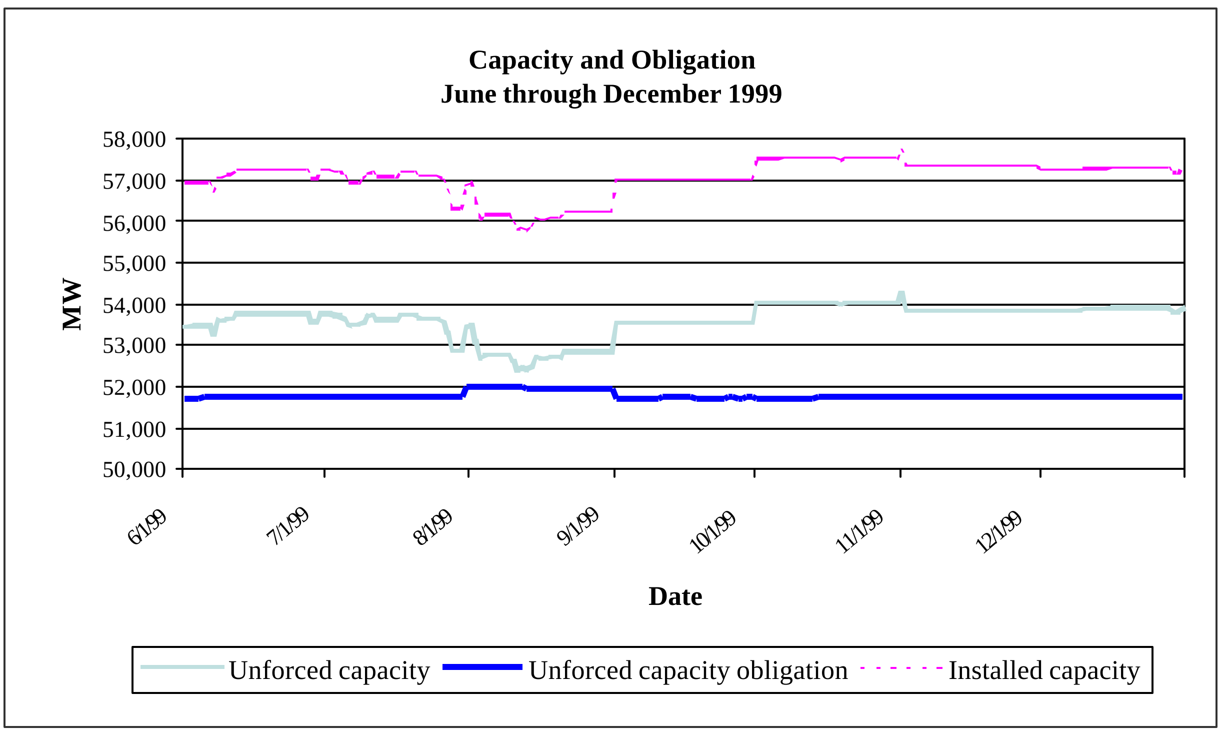
In 1999, capacity resources exceeded capacity obligations by approximately 500 MW to 3,500 MW in installed capacity terms. While there were days on which individual LSEs were short of capacity, there were no days when system capacity fell short of system capacity obligations. Between June and December, system net excess capacity averaged 1,832 MW (approximately 1,950 MW in terms of installed capacity).

Net excess capacity was higher in the first half of the year, averaging 2,737 MW in installed terms. The primary difference was capacity imports, which were significantly higher in the first half of the year. Net excess capacity was also less variable in the first half of the year. The range

[7] The data in the graph and the average price data are all in terms of installed capacity for comparability.

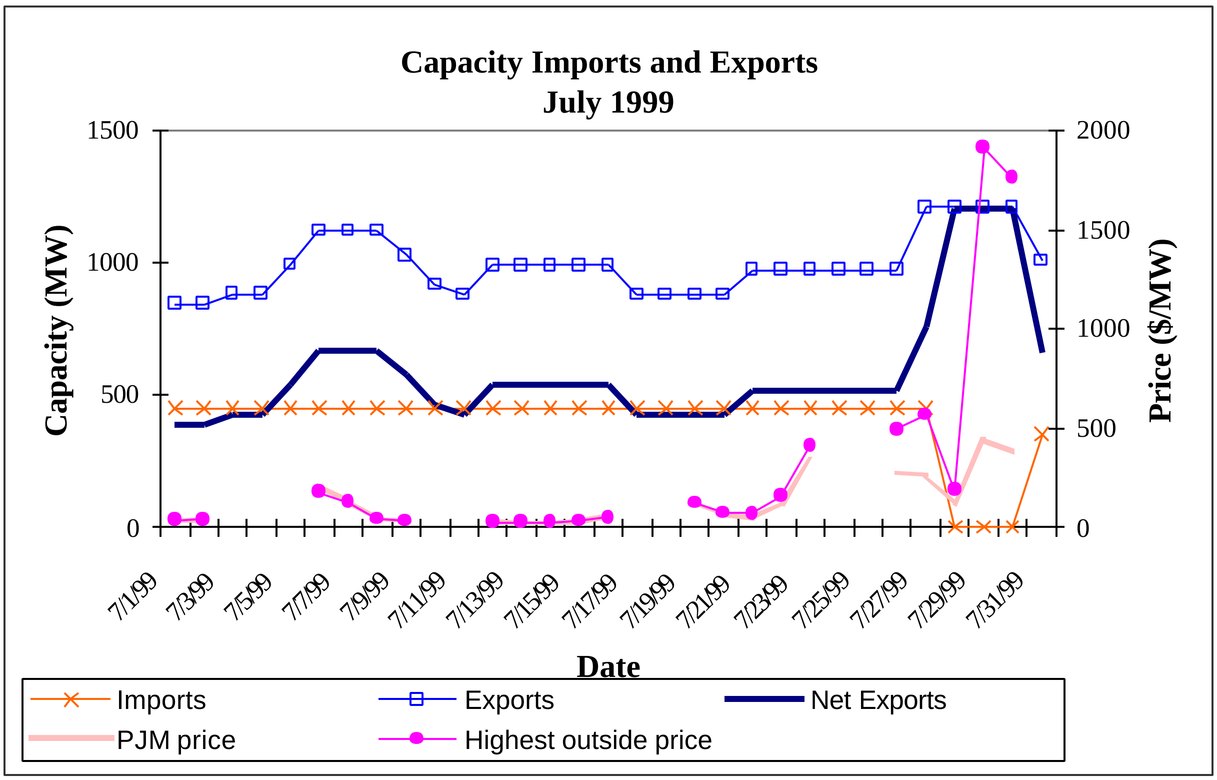
and standard deviation of net excess capacity were narrower in the first half of the year. The range of excess capacity values was 1,231 from January through May, while it was 2,060 MW from June to December. The standard deviation of net excess capacity was 336 MW from January through May and 479 MW from June through December.



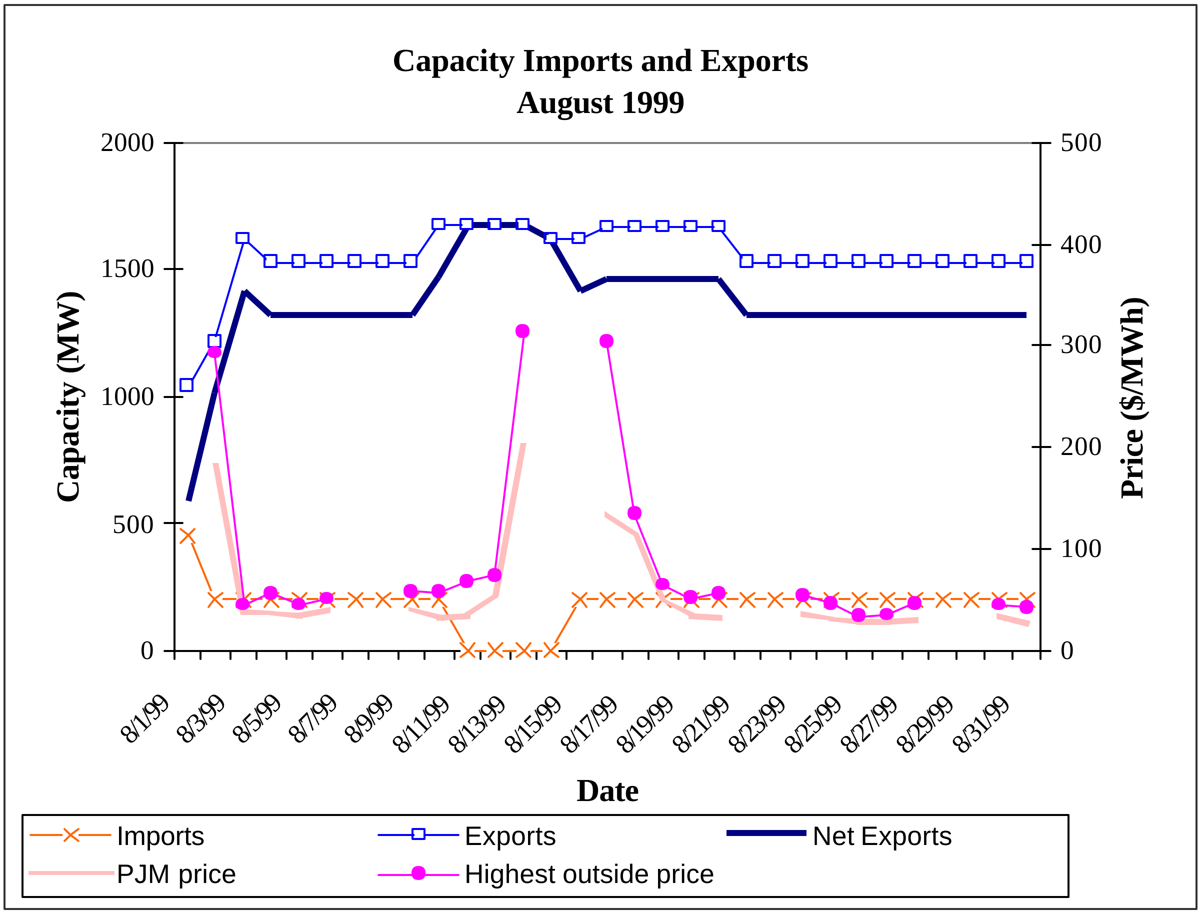



*Exporting capacity on high demand days*

Some companies increased their external sales of capacity resources on days when the external prices increased and, in particular, when external prices exceeded the PJM price, as indicated in the graphs below. This is an expected, competitive response to such a price differential. The PJM price in these graphs is the firm, daily forward on-peak PJM Western Hub energy price, while the external price is the highest firm, daily forward on-peak price in regions surrounding PJM.[8] On July 6, when both PJM 16-hour energy prices and external 16-hour energy prices rose above $200/MWh, external sales rose to 1,122 MW, up from 883 on July 2 and July 3. On July 27, external sales increased to 1,211 MW from 974 the previous week as the difference in energy prices increased to about $1500/MWh. External sales of capacity remained at about 1,500 MW throughout August, while the energy price differential increased on a few days. While the relationship between daily internal and external forward prices is less clear in August, the increase in the average level of capacity exports for August is consistent with the increase in the monthly forward price differential for August which occurred at the end of July. As a result of this exporting behavior, there was some reduction in overall system surplus capacity on high demand days in PJM. The average system net excess was 1,408 MW on the high demand days and 2,207 MW overall, an 800 MW reduction.

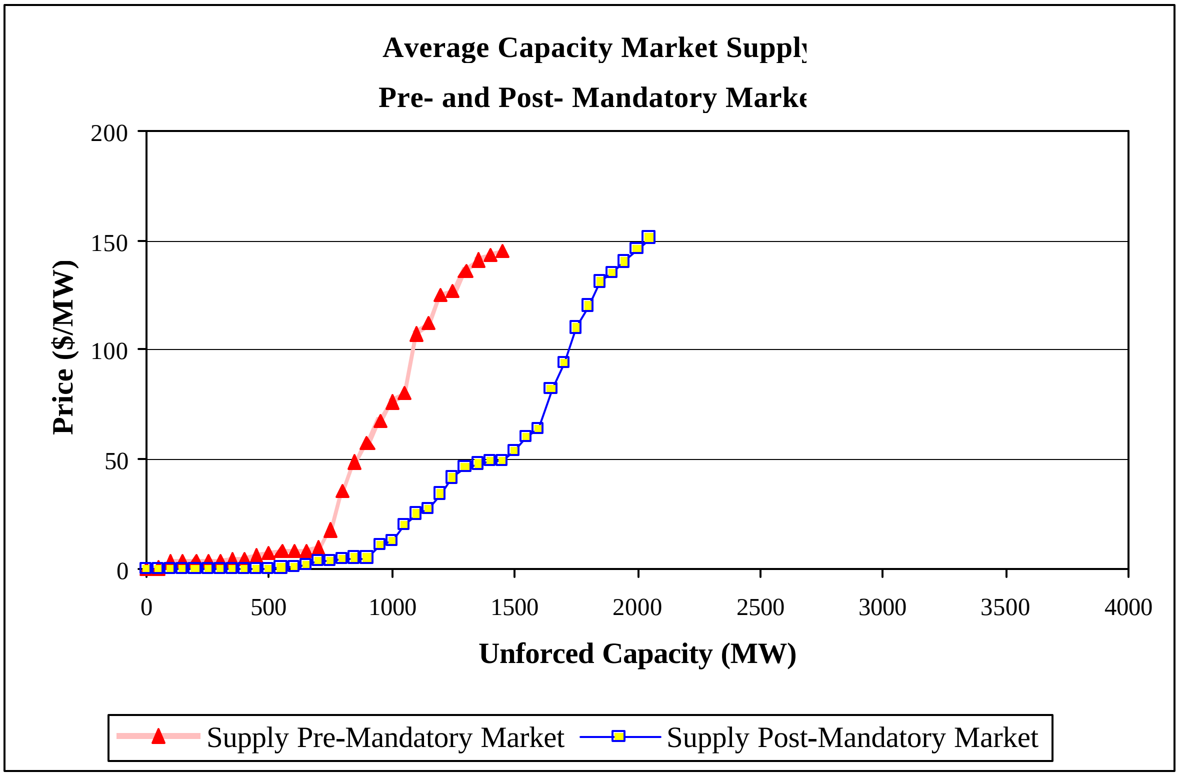



[8] Theses daily forward prices are for weekdays, which are not holidays, only. For each region and each day, the prices are the average of the forward prices reported in *Power Markets Week, Megawatt Daily* and *PricewaterhouseCoopers PowerTrax*.


Capacity Imports and Exports
August 1999
2000
1500
1000
500
0
500
400
300
200
100
0
Capacity (MW)
Price ($/MWh)
8/1/99
8/3/99
8/5/99
8/7/99
8/9/99
8/11/99
8/13/99
8/15/99
8/17/99
8/19/99
8/21/99
8/23/99
8/25/99
8/27/99
8/29/99
8/31/99
Date
Imports
Exports
Net Exports
PJM price
Highest outside price

**Effects of the Mandatory Market**

The mandatory market rule in daily capacity markets automatically enters supply offers at $0/MW-day when a company's Capacity Resources exceed its obligation; it enters demand




offers at $176.83/MW-day when a company's obligation exceeds its Capacity Resources. A comparison of the MW supplied in the daily markets for the five days prior to the July 10,1999 mandatory market (average price per quantity segment over the five days) and five days after the mandatory market shows that more capacity became available at every price after the re-introduction of the mandatory capacity market.

The Mandatory Market rule reduced individual LSE capacity deficiencies by requiring capacity-deficient companies to purchase capacity from daily Capacity Credit Markets. Individual company deficiencies occurred on 14 days between July 10 and December 31, 1999 after the re-introduction of the mandatory market. During June one company was deficient every day of the month (apparently due to an oversight) even though the daily market price was a relatively small proportion of the penalty it paid. Had the mandatory market been in effect, the company would not have had to pay this penalty.

*Capacity credit market activity*

The data show that new entrant companies, which are not affiliated with the original PJM utilities, relied on PJM markets to a larger extent than did affiliated companies or all companies combined. The monthly share of total load obligations served from the PJM Capacity Credit markets for all companies during 1999 ranged from 1.68% to 5.5%, while the share of the total load obligations of new entrants (i.e. Non-affiliated with IOU) ranged from 4.99% to 81.0%. The data are presented in the table below. The "Non-IOU" category includes all companies other than the traditional large PJM utilities. The category "Non-affiliated with IOU" also excludes companies that are affiliated with the traditional large PJM utilities. The percent of load obligation served by PJM Capacity Credit Markets is defined as the sum of each group's purchases of capacity in the capacity credit markets divided by the sum of each group's load obligation.

**Table 6: Percent of load obligation served by PJM Capacity Credit Markets**

| Month | All companies | Non-IOU | Non-affiliated with IOU |
|---|---|---|---|
| January | 2.79% | 44.47% | 68.75% |
| February | 4.88% | 30.33% | 80.99% |
| March | 5.32% | 32.97% | 75.68% |
| April | 5.45% | 32.52% | 77.92% |
| May | 4.13% | 21.31% | 73.83% |
| June | 1.68% | 2.44% | 4.99% |
| July | 1.93% | 3.30% | 9.41% |
| August | 2.44% | 7.47% | 28.25% |
| September | 2.75% | 6.88% | 25.33% |
| October | 2.77% | 5.15% | 18.44% |
| November | 3.41% | 6.34% | 22.79% |
| December | 3.33% | 5.77% | 16.22% |

**Capacity Availability**

If capacity requirements are to continue to play their role in maintaining reliability, there must be some certainty that generating capacity which is qualified as capacity resources can be relied upon to provide energy to meet loads on high demand days when the energy from those resources is needed in PJM. This subsection presents the results of an analysis of the status of the capacity resources in PJM on one high demand day, July 6, 1999. That day witnessed the highest demand in PJM history, and capacity resources were less available than expected. The total unavailable capacity was 6882 MW, and the total unaccounted for unavailable capacity was about 2058 MW, or 3.6% of total capacity resources. Other high demand days exhibited similar results.

*Supply and Demand*

On July 6, PJM had approximately 57,200 MW of installed capacity.[9] At the peak, total uncorrected PJM demand was 52,125 MW.[10] All available internal generation was loaded. Internal generation was supplying 48,425 MW and actual imports were 3700 MW.[11] PJM had invoked maximum emergency generation and load management steps 1 & 3 an hour earlier. The total unavailable capacity was 6886 MW, after netting out 2139 MW of regulation and operating reserves, or about 12.0% of total installed capacity. As a benchmark, the total unavailable capacity was about 1452 MW, or 27%, greater than the 5434 MW expected value of unavailable capacity, using the historical system average forced outage rate of 9.5%.

Table 7 details the various components of the 9025 MW total PJM generating capability which was not producing energy on peak. Primary and secondary operating reserves and reported/recorded outages are deducted from the total generating capability which was not producing energy, to arrive at the unaccounted unavailable generating capability. Table 7 shows that total unaccounted unavailable generating capability was 2062 MW, or about 3.6% of the 57,200 MW system capacity.

**Table 7. July 6, 1999 Unavailable Generating Capability Summary.**

| **Capacity Component** | **(MW)** |
|---|---|
| Total Capability Not Generating | 9025 |
| Reserves & Regulation | 2139 |
| Total Unavailable Generating Capability | 6886 |
| Reported/Recorded Outages | 4824 |
| Unaccounted Unavailable Generating Capability | 2062 |
| Unaccounted Unavailable Generating Capability as a Percentage of Total Installed Generating Capability | 3.6% |

Analysis provides no evidence that physical withholding occurred. The generators with the most incentive to withhold had the lowest levels of unaccounted unavailable capacity. The analysis does suggest several areas of possible improvement in the measurement of capacity resources.

The duration of peak loads and the capacity situation experienced suggest a need to examine the procedures and methodologies used to determine whether, and at what MW level, generation resources qualify as capacity resources. PJM should consider a strengthened verification and compliance program for capacity resources or the implementation of market-based incentives to provide energy from capacity resources at levels consistent with claimed capacity credits. Consideration should also be given to extending the duration for which a plant must demonstrate its generating capability in order to ensure that rated capacity is achievable over longer peak periods like those recently experienced.

9 Based on the 1999 PJM EIA-411.

10 The official peak load was 51,600 MW.

11 Included in the generation total was an extra 250 MW of energy that was provided by units that were generating above their rated capacities.

**Market power in the capacity market**

In the capacity market, as in other markets, market power is the ability of a market participant to profitably increase the market price above the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate the competitive market price, which is the marginal cost of producing the last unit of output, assuming no scarcity. As the data above indicates, there was no scarcity of capacity in PJM during 1999. Given the excess of supply over demand in the 1999 capacity market, the short run marginal production cost of capacity, at the level of actual demand, was probably relatively low, including the operating and maintenance expenses necessary to maintain the capacity as a viable energy producer. If new capacity had been needed, the cost of supplying extra capacity would have been much higher. In addition, marginal costs include 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. As a result, if a PJM capacity resource could, by delisting as a capacity resource, increase net revenues by $90/MW for a day, then this $90/MW-day is appropriately included in the competitive price for the daily capacity credit market.

An evaluation of opportunity costs for the monthly capacity markets during 1999 suggests that, on average, the level of capacity market prices was consistent with the opportunity costs. However, daily and monthly opportunity costs do not explain the daily and monthly levels of capacity market prices. While there is no clear evidence that market power was exercised, the data cannot rule out the exercise of market power, during specific months, in the capacity market. Observed market behavior was in part a function of the fact that capacity markets were new and participants were learning as they participated.

Conditions in the capacity markets make the potential exercise of market power an issue. Demand is relatively inelastic as it is a function of 12-month historical loads and PJM's capacity requirement rules. There were only a few generation owners who had excess capacity and were therefore in a position to sell capacity. Even with more generators offering capacity into the market, economic theory suggests that significant market power may exist in the presence of the low elasticity of demand that appears to characterize the capacity markets.

From the early days of the PJM pool, capacity requirements have been one of the methods used by PJM members to ensure reliability. Prior to the advent of retail restructuring, the original PJM members determined their loads and their related capacity obligations on an annual basis. Each member was required to have installed capacity equal to their load plus a reserve margin, or to purchase such capacity. There was a non-transparent bilateral secondary market in PJM capacity credits that permitted members short on capacity to buy from members long on capacity. A capacity credit reflected the sale and purchase of the annual rights to capacity, for purposes of the PJM capacity obligation. The penalty for being short, on an actual, after-the-fact basis, was the value of capacity, a yearly filed rate which is an estimate of the cost to build a combustion turbine in PJM. The historical capacity obligation system resulted in incentives to build adequate capacity and to forecast load accurately. When combined with state regulatory requirements and incentives to maintain adequate capacity, the system of PJM capacity obligations resulted in a reliable pool, with the cost of capacity obligations borne equitably by members and their loads and with capacity and energy adequate to serve peak and off peak loads.

In late 1998 the PJM ISO introduced transparent, open markets in capacity credits in response to a need created by retail restructuring. In the PJM area, this restructuring took place first in Pennsylvania and has been followed by restructuring in Delaware, New Jersey and Maryland. Retail restructuring created the opportunity for new entrants to compete to serve retail loads. These new entrants must meet PJM's criteria for reliability that include the requirement that LSEs have installed capacity equal to their annual peak load plus a reserve margin. New entrants need a way to acquire capacity to meet loads gained through the competitive process and the existing utilities need a way to sell capacity no longer needed, if load is lost to new competitors. The PJM capacity market is the mechanism to balance supply and demand for capacity, which is not met by the bilateral market or self-supply. The capacity credit markets serve to provide a transparent, liquid market in which new competitors can buy capacity and utilities could sell capacity and, ultimately, in which all competitors can buy and sell capacity. As the data reported in this subsection indicate, the PJM capacity markets have performed these functions effectively.

***Capacity requirements and reliability***

The critical link between the capacity requirement and actual reliability is the ability of PJM to recall exports from capacity resources by invoking Emergency procedures. Absent this right of recall, there would be no connection between a capacity resource and the actual delivery of energy when PJM loads require energy. PJM can recall only after it has called on all the energy from all units which offered energy into the PJM market and it has determined that this energy is not adequate to serve expected loads. Consequently, the energy from all capacity resources can be called upon by PJM to serve load within the PJM area. When recalled, the recalled energy will be paid the PJM energy market price.

As markets evolve both within and outside PJM, the incentives to maintain adequate capacity have also changed. The introduction of market-based bidding for energy in PJM and surrounding control areas has created a new set of incentives for entities providing energy and for entities purchasing energy in the larger region. The owners of generation have an incentive to sell to the energy market with the highest net price, regardless of location.[12] Prior to the introduction of market-based bidding in the areas surrounding PJM, integrated utilities serving loads in PJM did not, in general, have an incentive to sell energy off-system. Nor did they have an incentive to avoid the purchase of capacity to generate the required energy to meet their PJM load obligations. The new incentives will gain impetus as ownership and control of capacity diverge from the responsibility to serve loads. Integrated utilities continued to predominate in PJM in 1999 but that is changing as more divest generation. The interaction between the evolving incentives, market structure, and PJM's capacity market rules will have a significant impact on the reliability of the PJM system.

The new incentives raise several questions about whether the current rules governing the PJM capacity markets need to be modified in order to continue to provide the desired level of

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12 The net price received by the seller is the market price net of all the costs associated with the export of energy including transmission and the risks associated with delivery off the PJM grid, including interruption due to NERC Transmission Loading Relief Procedures (TLRs).

reliability. It is not clear that the current capacity market structure will continue to provide the necessary incentives required to provide the desired level of reliability.

***Capacity market rules and load forecasts***

The new capacity market rules in PJM attenuated the relationship between capacity obligations and reliability by changing the method used to calculate load obligations. Prior to the creation of the current capacity market, load obligations were based on actual peak loads.[13] Member utilities paid a penalty based on the relationship between actual peak loads and their capacity. Under the new market rules, load obligations are an estimate.[14] The new capacity market rules determine load obligation based on the peak load during the prior 12 months. It would be possible, under the new market rules, to have the level of capacity required by the rules, yet not have enough capacity to meet the actual peak load. The use of the historical peak load to set obligations creates a lag, and in times of growing loads virtually ensures that the load obligations will be too low. The new capacity market rules diminish the incentive for accurate load forecasting and weaken the incentive to have capacity adequate to meet actual peak load. In addition, the new capacity market rules weaken the incentive of LSEs to manage their loads and, as a result, weaken the link between wholesale prices and demand response.

***Capacity market rules and incentives to deliver energy***

The main purpose of the PJM capacity obligation is to ensure that there is adequate energy to serve loads at times of peak demand. Capacity has value because it represents the capability to deliver energy. Thus, in addition to addressing the incentives related to providing adequate capacity, the incentives to actually deliver that energy must also be addressed. It appears that the current rules governing the PJM capacity market do not create an adequate linkage between capacity and the actual delivery of energy. Physical capacity results in capacity credits that cover load obligations regardless of whether that capacity can or does deliver energy on a peak day. A unit can be out of service on the peak day of the year and the owner of the unit will receive full credit for that capacity.

The capacity market rules define the cost borne by generation owners when their units experience forced outages. This cost appears to be too low. Under the current capacity market rules, a forced outage affects the level of capacity that the unit can provide in PJM's markets for the next 12 months. If a unit is forced out for 24 hours on the peak load day of the year, the resultant total annual cost is less than $200/MW of capacity forced out, using the full Capacity Deficiency Rate (CDR) as the market value of capacity. In other words, a unit could take a forced outage on the peak day of the year and the cost to the generation owner would be $12.50/MWh over the 16 peak hours or $8.33/MWh over the full 24-hour period. The cost of a forced outage is consequently low compared to the actual cost of replacing a MWh of energy on a peak day, which could range from $30/MWh to $1,000/MWh in PJM and higher in areas outside PJM.

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13 The PJM utilities forecast their loads, but the actual obligation, which was the basis for a potential penalty, was based on the actual peak loads.

14 The current rules use an estimate of the current summer's peak load, which is determined by the actual peak load in the prior summer.

The cost of a forced outage is relevant because it represents the equivalent of a liquidated damages clause in a contract for an external sale of energy. An energy sale contract typically includes a liquidated damages provision specifying the amount that the seller, for example, owes the buyer if the seller does not perform, i.e. does not delivery energy when agreed. A typical liquidated damages provision would require the seller to pay the buyer the price the buyer actually had to pay to obtain replacement energy from the market, if the seller were unable to deliver. The financial consequences of the failure of capacity resources to deliver energy to PJM are generally much lower than the financial consequences of the failure to deliver energy to external buyers. This, in turn, provides an incentive for generators that have the ability to sell power externally, to sell power externally backed by their more reliable units and to leave their less reliable units to provide energy within PJM. This incentive, which first existed during the summer of 1999, could have significant implications for PJM's reliability.

PJM should consider a rule change that would create an incentive to deliver energy to PJM loads from capacity resources equivalent to the incentive to deliver energy to loads external to PJM, as defined by liquidated damages clauses in energy sales contracts. Such a market-based incentive structure would be preferable to a requirement for additional inspections or tests for generation performance. If generators are effectively selling a call on the energy from capacity resources, generators should also be prepared to provide energy from another source or the financial equivalent if the energy is not provided from the capacity resources.

Some PJM capacity resources currently face higher penalties for non-performance than $1/365^{th}$ of the annual capacity cost. Schedule 14 of the RAA provides, under Emergency conditions in PJM, that if ALM is not implemented as directed, the relevant member will pay a penalty equal to the full annual value of an equivalent amount of capacity. PJM has been pro-active in this regard, filing with FERC, on behalf of the Reliability Committee, proposed changes to Schedule 14 of the RAA which would impose an annual penalty on any capacity resource that was capable of providing energy but did not, under Emergency conditions in PJM.

***Capacity incentives/market rules – Considerations/Recommendations***

The RAA obligation process does not impose long-term commitments on LSEs. The new capacity market rules permit members to sell themselves short and to sell the system short, under certain conditions. The ability of members to sell themselves and the system short, when combined with the incentives to do so, raises an issue regarding capacity market rules.

There is no requirement that capacity in the PJM area be sold to PJM loads. Generators will sell capacity to PJM loads when it is in their economic interests to do so. Under current rules, individual capacity owners may, in certain circumstances, "delist" that capacity and declare that it is no longer a capacity resource. Delisting means that a unit is formally removed from PJM capacity resource status. Delisting can occur with at least two days notice and, depending on the facts, what can be, in practice, a minimum of an hour's notice. A decision to delist has several consequences. The delisted generation capacity cannot be used to meet LSE obligations to serve load and the capacity can be sold off the PJM system. The capacity can be sold off the system by selling energy from the capacity, which cannot be recalled by PJM, by selling the capacity into a capacity market external to the PJM market, or by doing both. The important point is that once a generating unit is delisted as a capacity resource, the energy output associated with the unit is not recallable by PJM, for any reason. In effect, the delisting of capacity resources reduces the energy available to serve PJM loads. As a result, the ability to delist capacity resources has potential reliability implications.

Under the current rules, a generation owner can delist capacity, which is excess to both the owner's obligations, and the system's required capacity; a generation owner can delist capacity such that it is short of capacity; and, a generation owner can delist capacity such that the system is short of capacity. If a generation owner owns capacity resources that are in excess of the capacity requirement defined for the system, the selling of that capacity off-system does not sell the system short. Selling the system short is defined as selling capacity resources with the result that total system capacity resources are less than total system load obligations. A generation owner with capacity resources and load can sell itself short for one or more days by delisting some or all of its capacity resources which are required to meet its load obligations on a specific day, up to about 36 hours prior to the day of the transaction. However, as long as there is additional capacity available in the market, the system is not sold short and the generation owner that is short is automatically bid into the daily capacity market and pays the market-clearing price for the relevant day. If the PJM system is short of capacity, the utility is charged a penalty equal to $2/365^{th}$ of the annual value of capacity.[15]

Under the capacity market rules, a generation owner can sell the system short if the generation owner has capacity resources in excess of that owner's load obligations but which are required to meet the system capacity requirement. An owner may delist capacity resources that are required to meet loads within PJM, when the loads are the obligation of another entity. This could occur, for example, if an integrated utility were to divest its generation. In such a case, the new generation owner has no load obligations and the utility has no capacity resources. If the new generation owner were to delist all or part of its new capacity, the utility could be in a position where it cannot obtain capacity resources adequate to serve its loads. In this case, the rules for the capacity market would have been followed but the system would be short and the system reliability objective would not be met. The same result could occur if an existing integrated utility generation owner loses load to a new LSE competitor. In this case, the generation owner would have excess capacity and the new LSE would have the obligation to obtain capacity resources. If the generation owner chose to delist its excess capacity, the new LSE could be in a position where it cannot obtain capacity resources adequate to serve its loads. In this case, as in the prior case, the rules for the capacity market would have been followed but the system would be short and the reliability objective would not be met.

The potential for a generation owner to sell the system short increases as utilities divest generation resources and as new competitive entrants take on obligations to serve load. The question is whether the capacity market is appropriately structured to provide incentives consistent with maintaining PJM's overall reliability objectives. The current structure of incentives does not appear to be optimal for maintaining PJM's reliability objectives. Both the required term for meeting the capacity obligation and the penalties for being deficient require review.

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15 RAA, Schedule 11.

The provision for daily markets in the capacity market rules is central to the current incentive structure facing participants in the PJM capacity markets. The ability of LSEs to meet their load obligations in a daily market and the corresponding ability of generators to make a daily decision about where to sell their capacity helps create a set of incentives which does not appear to be designed to maximize the reliability of the PJM system.

An LSE can obtain capacity in the daily capacity credit market to cover its capacity obligation. In other words, an LSE can take on an obligation to serve load for a year but is not required to enter into any long-term arrangement to ensure that capacity is available to serve that load. On June 1, an LSE can have load obligations greater than capacity credits for every summer day. However, as long as the LSE successfully purchases capacity credits in the day-ahead capacity credit market, its reliability requirements are met. In retrospect, this would have been a financially attractive and successful strategy in 1999. The average price in the PJM daily capacity credit markets was low and significantly lower than the price in the monthly and the multi-monthly auctions. This term structure of the capacity market provided little incentive for LSEs to obtain capacity resources to cover their annual reliability obligations to PJM. While the reliability obligation is defined to be an annual obligation, current market rules permit the obligation to be met entirely in a daily market.

While the system functioned reasonably well during the summer of 1999, this may not be the case in the future. If LSEs with substantial loads decide to purchase capacity primarily in the daily capacity markets, daily external energy market conditions will play a significant role in whether the system has adequate resources. If forward prices in external energy markets make it profitable to sell energy in external markets, the generators holding the capacity which would otherwise be offered in the daily capacity market will have an incentive to delist the capacity for the summer or for specific summer days and to sell the energy in the external markets. The result will be to increase the probability that some LSEs will be short capacity and therefore that the system will be short capacity. The result will also be to increase the price in PJM capacity markets as summer approaches. The external energy price differential over the internal price does not have to be very large in order for this to occur.

The penalty structure in the capacity market rules provides incentives to LSEs and generation owners both directly and by defining the opportunity costs associated with selling capacity into PJM. The penalty for being short of capacity on the peak demand day of the year is 1/365$^{th}$ of the annual value of capacity.[16] The annual value of capacity is \$58.40/KW-year or \$58,400/MW-year. The daily value of capacity (1/365$^{th}$ of the annual amount), based on the penalty, is consequently \$160/MW-day, or twice that, \$320/MW-day, if the system is short of capacity.

A maximum capacity market price of \$160/MW-day is equivalent to a net energy price differential of \$10/MWh for a 16-hour forward market energy contract. (The net price differential is after the cost of transmission. The tariff-based cost of transmission can vary from

[16] The penalty can increase, per a formula in the RAA, Schedule 11, as the number of days on which an LSE is deficient increases. However, the penalty does not increase until the number of deficient days exceeds 30. In addition the penalty becomes 2/365 times the annual value of capacity on days on which the system is short of capacity, as noted above.

$4/MWh to $21/MWh depending on whether monthly or annual firm transmission and how the costs are assigned to portions of the year, assuming no congestion costs.) Even if an LSE is expected to be willing to pay $320/MW-day for capacity, this is equivalent to a price differential of $20/MWh for a 16-hour forward market energy contract. As a result, with a net price spread between PJM and external markets of $10 or $20/MWh, when the system has adequate resources, the incentives would make it rational for a generator to delist and sell energy externally rather than to hold the capacity and sell it in the daily capacity market, even at the maximum possible daily price. In other words, the opportunity cost associated with selling capacity into PJM could exceed the maximum possible price for capacity in the PJM daily market.

While generators can be expected to evaluate the opportunities to sell capacity on a continuous basis, over a variety of time frames, the existence of daily capacity markets makes the decision more dependent on daily fluctuations in external energy prices than would be the case if capacity markets were cleared only annually or biannually. With longer-term capacity markets, the likelihood of the net external price differential exceeding the annual value of capacity, evaluated over the entire period, is lower and therefore the incentives to sell the system short are lower. Even if the system were sold short, the existence of an annual market would give LSEs and system operators a longer period to acquire additional capacity resources than the daily market provides.

LSEs can go short by acquiring load obligations for a year but not acquiring capacity resources for the same period. If the LSE is short on a specific day and there are available capacity credits, the short LSE is automatically bid into the daily capacity market and pays the market-clearing price for the day. In consequence, the incentives also make it rational for an LSE to make low bids into the daily capacity market because it can pay low prices on most days and to bid higher prices only on days when external daily forward energy prices are relatively high compared to internal daily forward energy prices. The result can be that an LSE could pay the maximum daily value of capacity on only a few days.

Similar incentives hold for an integrated utility.  It could be rational for such a utility to delist capacity resources and sell itself short by selling the energy associated with the generation capacity outside of PJM if it could obtain an adequate margin on the external sale of energy. Again, the benefit would exceed the cost if the net differential between the internal and external price were at least $10/MWh or $20/MWh when the system is short. In the case of regulated utilities, such a scenario also depends on the ability of state regulators to take action if an integrated utility were to sell itself short.

The recall rules of the capacity market also create an incentive to exercise market power in the energy market. If the owner of capacity resources is selling the energy associated with the resources to an external buyer, that energy may be recalled under Emergency Conditions. This recall imposes an opportunity cost on the capacity resource owner, to the extent that the external energy price is greater than the internal energy price. This creates an incentive for the capacity resource owner to attempt to bid the internal price up, prior to the implementation of external energy sales recalls.

There is an identifiable modification to the capacity market rules that would align market incentives more closely with PJM's reliability requirements while limiting the exercise of market power. The capacity market rules should be modified so as to require that all LSEs meet their obligations to serve load on an annual or semiannual basis and that all capacity resources be offered on a comparable basis in annual or biannual capacity markets. This would explicitly include ALM in the annual requirement. Market power is a potential issue in the capacity markets and could reasonably be expected to be an issue in such longer-term capacity markets. In order to limit the exercise of market power, this market should have a bid cap and other mechanisms to limit the exercise of market power should be explored. To ensure liquidity and thereby facilitate shifts in load among LSEs, there would have to be a shorter-term trading mechanism for annual capacity at the annual price.

This rule change would help modify incentives consistent with the provision that adequate capacity in PJM be obligated to serving PJM loads. The rule, and the associated guaranteed annual payments, would provide a substantial incentive to generation owners to lock in for an annual period, to cover load plus a reserve margin and consequently not to sell the system short.[17] The rule would also reduce the incentive of loads to run the risk of going short on peak demand days. Further, it would strengthen the incentive of LSEs to manage their loads and thus increase the price sensitivity of demand. The rule would improve the alignment of incentives with the value of capacity to PJM, to generation owners and to loads. For example, if an LSE were short, it would not be possible to cover capacity requirements by buying capacity for one day to cover the peak demand day of the summer. Similarly, if a generator were to sell itself short, it would be required to obtain annual capacity rather than buying capacity for one day to cover its position.

There are other approaches to reliability than the use of capacity requirements. There is no reason to believe that those approaches are superior to the use of capacity requirements and associated capacity markets. However, it is not the intent of this report to address that question. Should PJM's Members decide to pursue alternative means of achieving reliability, the modifications proposed here should still be pursued in order to make the current system function more effectively in the short term and to serve as a useful transition to an alternate approach in the longer-term.

In summary, based on the analysis of the capacity market rules and incentives, it would be appropriate to consider rule changes for the capacity markets as follows:

1. Implementation of a market-based incentive to deliver energy from capacity resources to PJM loads at a level consistent with the claimed capacity of the units.
2. Requirement that all LSEs meet their obligations to serve load on an annual or semiannual basis and that all capacity resources be offered on an annual or semiannual basis with a bid cap.

17 Since a capacity resource can sell energy off system, except when it is recalled in Emergency conditions, the costs of being recallable are the liquidated damages payments when recalled, which are the price at which the external load could replace the energy less the PJM price. The maximum revenues from being recallable are the $58,400/MW capacity resource payments.