Market Monitoring Unit

REPORT

JUNE CAPACITY MARKET

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

October, 2000

Introduction

On June 1, 2000, prices in the PJM daily capacity credit markets reached the highest level since this market was introduced in late 1998. Daily capacity market prices fell on June 2, but remained high by historical standards for the balance of June. In response to these prices, various members of PJM requested that the Market Monitoring Unit investigate to determine whether market power or market manipulation was the cause of the price increases.

In response to these requests, the Market Monitoring Unit (MMU) performed an investigation and, based on the results of that investigation, provided a verbal report with detailed slides to the Energy Market Committee (EMC) on July 5, 2000, regarding events in the capacity markets for June, 2000. The conclusion reached by the MMU and presented to the EMC was that prices and behavior in the capacity markets for June appeared to be consistent with the underlying supply and demand fundamentals and that there was no evidence of market manipulation.[1]

Prices in the PJM daily capacity market rose on June 1, 2000, and remained high through the end of June as a result of underlying economic fundamentals. These economic fundamentals include, at the most basic level, the level and price sensitivity of demand for capacity and the level and price sensitivity of supply of capacity. There is no reason to believe that market power explains the high prices in the June daily capacity markets or that the daily capacity market prices in June were increased by the unilateral action of a market participant or the joint action of a group of market participants.

Figure 1 shows the prices and quantities traded in daily and monthly capacity markets from January, 1999 through June, 2000. In 1999, capacity market prices averaged $52.86/MW-day over all capacity markets including daily, monthly, and multi-monthly markets. Monthly capacity market prices averaged $70.66/MW-day. Daily capacity market prices averaged $3.63/MW-day while the highest daily market price was $55/MW-Day.[2]

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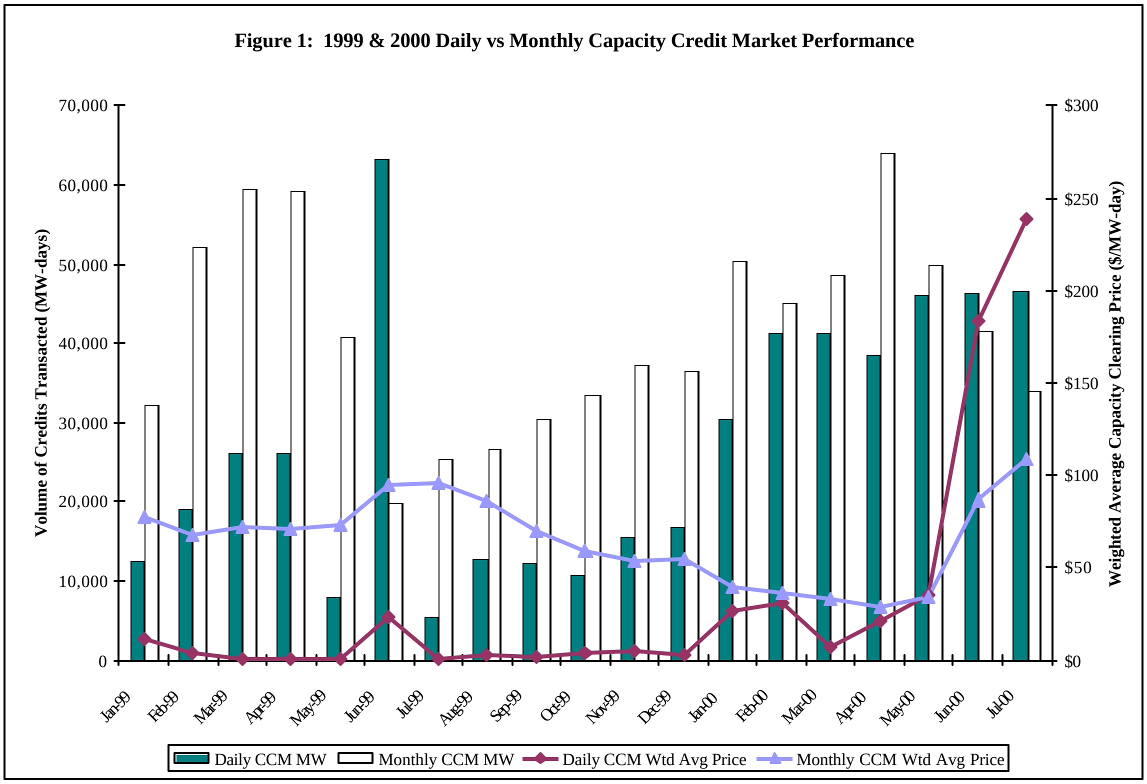
1 A copy of the slides accompanying this verbal report can be found on the PJM web site at pjm.com under the Market Monitoring Unit link.

2 All figures are in “unforced capacity” terms unless otherwise noted. Unforced capacity was 93.6% of installed capacity for the month of June 2000.



In 2000, both daily and monthly capacity prices remained at or below $40/MW-day in the first five months of 2000. However, on June 1 the daily price rose to $350.43/MW-day. The price on June 1 was close to twice the level of the daily Capacity Deficiency Rate (CDR), or $354.60/MW-day. (The Reliability Assurance Agreement, or RAA[3], provides that the CDR is doubled when the system is deficient.) On June 2, the daily price was $174/MW-day and on June 3, the daily price was about $177 where it remained for the balance of June.

Fundamentals

The total demand for capacity credits is fixed by procedures set forth in the RAA which set capacity obligations based on the peak loads served in the prior year. Thus, this fixed total demand, net of ALM, bilateral contracts and self supply, must be entered into monthly, multi-monthly or daily capacity markets. Demand for capacity in the daily market is thus the residual after capacity is purchased in monthly markets and in the bilateral market, after accounting for ALM resources and for demand which is self supplied. During the May to June period, the total buy bids in the daily capacity markets ranged from about 2.5% to 4.5% of the total capacity obligation of Load Serving Entities

[3] The RAA is an agreement among all Load Serving Entities (LSEs) in PJM the goal of which 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."

in PJM. Demand bids in the daily market can be made for a specific MW amount and a specific price. If an LSE is short, either by choice or by oversight, a mandatory bid will be submitted for the LSE in an amount sufficient to cover its obligation, at a price equal to the CDR.[4] Such mandatory bids can have a significant impact on the market price.

The supply of capacity in all the capacity markets is a function of physical capacity in the PJM area, self supply, contracts to provide capacity to PJM loads, contracts to provide firm energy to external loads and external energy market prices. The existence of physical capacity in the PJM area has no necessary relationship to the supply of capacity in the PJM capacity markets, as capacity can be exported. Capacity which is not committed to serving PJM loads via bilateral contracts or via self supply can be offered into PJM capacity markets or it can be used to serve external firm energy demands. It is these options which makes capacity supply in PJM a function of both capacity market prices as well as external energy market prices.

Generation owners can be expected to sell capacity into the most profitable market. The existence of daily commitments and a daily penalty structure lead to the following profitability calculations. 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.[5] (The net price differential is after the cost of transmission. The tariff-based cost of transmission can vary from about $4/MWh to about $21/MWh depending on whether monthly or annual firm transmission is purchased and how the user assigns costs to time periods, 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 net energy 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 greater than $10/MWh when the system has adequate resources or $20/MWh when the system is short, 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 capacity market 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.

If generators faced only the simple choice between selling energy to external markets or selling capacity and energy to the PJM markets and the markets worked efficiently, the value of capacity would be defined by the difference between the external energy price and the internal energy price. The opportunity cost of selling both capacity and energy to the PJM markets would be defined by the external energy price. Thus the difference between the external energy price and the internal energy price would be the marginal cost of capacity and thus the expected market price.

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4 As noted above, the CDR is doubled, and thus the mandatory bid price is doubled, when the capacity market is deficient.

5 This price is expressed in installed capacity terms rather than unforced capacity terms. The ability to sell energy is a function of the actual capacity of the generating unit rather than the unforced capacity.

In fact, generators can remain capacity resources and sell energy to external energy markets. When generators do this, if the capacity markets worked efficiently, the PJM capacity price would be a function of the expected distribution of external energy prices, the expected distribution of internal PJM energy prices and the expected distribution of and cost of recalls. The marginal cost and thus the expected price of capacity would be based on the difference between (a) the opportunity to sell the energy from that capacity externally without risk of recall by delisting and (b) the opportunity to receive capacity payments plus the opportunity to choose the most profitable mix of internal energy sales and external energy sales offset by the costs of recalls. Thus, the expected revenues from selling energy externally will exceed the revenues from selling to PJM by an amount which ranges from zero (or less than zero) to the simple difference between the external price and the internal price. This difference is a function of the expected probability of recall and the expected distribution of external and internal energy prices. The higher the expected probability of recall, the lower the value of selling energy externally while remaining a capacity resource and thus the higher the opportunity cost of remaining a capacity resource.

While generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, the existence of daily capacity obligations and the rules which permit these capacity obligations to be satisfied in the daily capacity markets make the decision more dependent on short term fluctuations in external energy prices than would be the case if capacity obligations were met in markets which were cleared only annually. With longer-term capacity obligations, the likelihood of the net external price differential, evaluated over the entire capacity market period, exceeding the annual capacity penalty 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 obligation and a corresponding annual market would give LSEs and system operators a longer period to acquire additional capacity resources than the daily market provides. The MMU proposed annual obligations as part of the PJM Interconnection State of the Market Report 1999.

Demand

Demand for capacity credits in the daily capacity market ranged from approximately 125 MW to approximately 3,000 MW in the period from June 1, 1999 through June 30, 2000. The total demand for capacity in PJM increased in January, 2000. This increase was based on the peak loads served during the summer of 1999. The total demand for capacity was also affected by the decrease in available ALM resources which fell by about 326 MW from May 31 to June 1, 2000 and by changes to the Installed Reserve Margin and RAA related factors, effective June 1, which decreased the demand for capacity by about 375 MW. The average daily amount of buy bids rose from 1,488 MW in May to 1,774 MW in June.

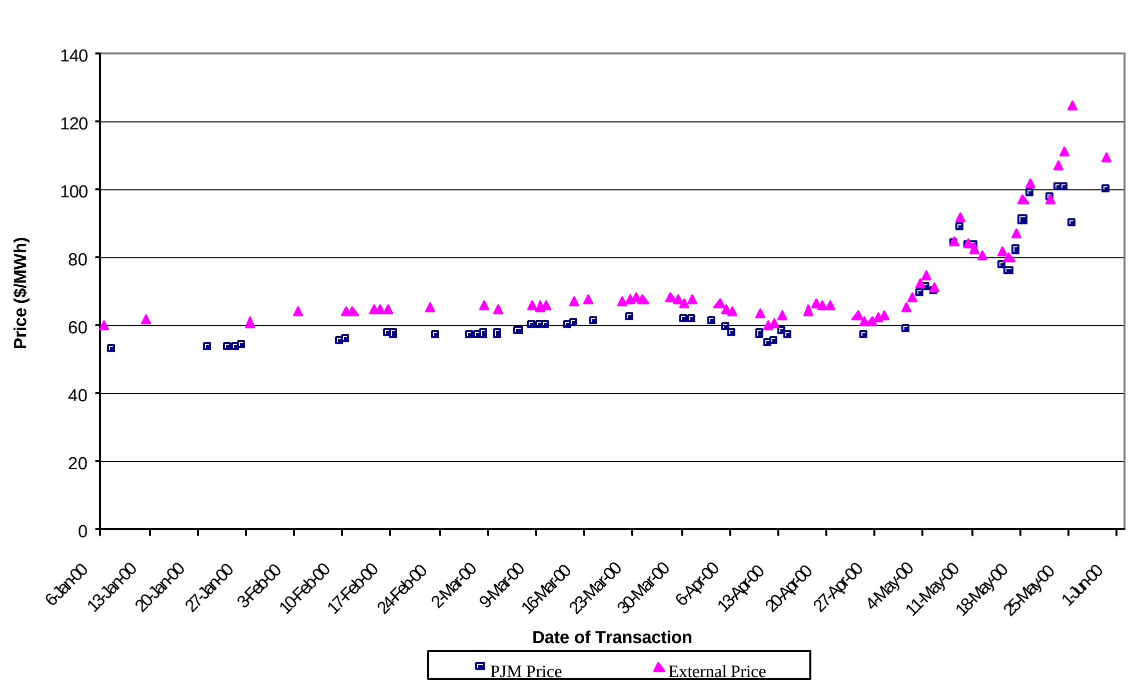
The level of mandatory demand bids began a significant increase in January, 2000 and peaked in June and July, 2000. The average level of mandatory bids was less than 150 MW between the time mandatory bids were reinstated in July, 1999 and December 31, 1999. On June 1, 2000, there were 1930 MW of mandatory demand bids, or more than 80% of the total of 2,374 MW of demand bids. On June 1, the bid price for these mandatory demand bids was $354.70/MW-day or twice the capacity deficiency rate. Clearly this demand behavior had a significant impact on the market clearing price. If the 1,903 MW of mandatory bids had bid in at a lower price, the clearing price would have been lower.

Supply

External energy market prices, as reflected in forward market prices, showed a spread over PJM prices for June and a very significant spread over PJM for July and August. The external energy market prices clearly provided a profitable opportunity for owners of uncommitted capacity in PJM.

June 2000[6] Average Forward Prices				**July-August 2000 Average Forward Prices**		
	Min	**Max**	**Average**	**Min**	**Max**	**Average**
PJM	52.60	100.00	63.69	57.00	140.00	97.47
External	60.25	125.00	70.93	131.50	207.50	155.47
Difference	-0.75	35.00	6.63	34.13	81.00	51.59

Figure 2: June 2000 forward energy contract price by transaction date
PJM vs. Highest of Into Cinergy, Into TVA, NYPP price
Source: Power Markets Week Price Index Database



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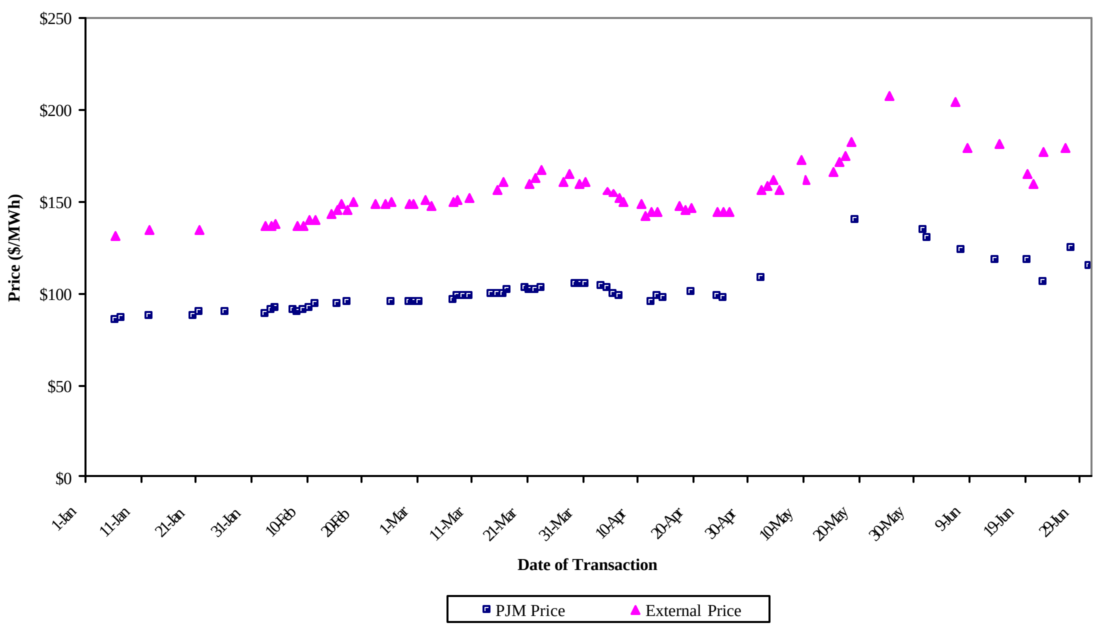
6 The external price is the maximum external forward price. Both PJM and external prices are 5 day averages. The "Difference" row equals the minimum, maximum and average, respectively, of the daily difference between the PJM prices and the external prices.

Figure 3: July-August 2000 Forward energy contract price by transaction date
PJM vs. Highest of Into Cinergy, Into TVA, NYPP price
Source: Power Markets Week Price Index Database



The result of the differential in energy prices between PJM and external areas was a significant increase in delisted capacity. Figure 4 shows the relationship between capacity market demand bids and supply offers and capacity market prices for May and June. Figure 4 compares market conditions in May with market conditions in June, showing that the gap between the MW level of demand offers and supply offers narrowed in June. Figure 5 shows capacity exports and the resulting pool capacity position for the year 2000 prior to and including the early June events. Delisted capacity increased from 876 MW on May 31, 2000 to 2,031 MW of installed capacity on June 1, 2000. To put this in context, the average delisted capacity was 906 MW in 1999 and the maximum delisted capacity was 1,776 MW in 1999. The delisted capacity on June 1, 2000 exceeded the maximum delisted capacity in 1999 by 255 MW while the delisted capacity on other June days was less than the maximum level of delisted capacity in 1999. The decrease in supply in the daily capacity credit markets led to an increase in price. In response to this price increase, 552 MW of capacity returned to PJM as capacity resources over the five days after June 1.

Figure 4: Daily Capacity Credit Market Summary
May — June 2000

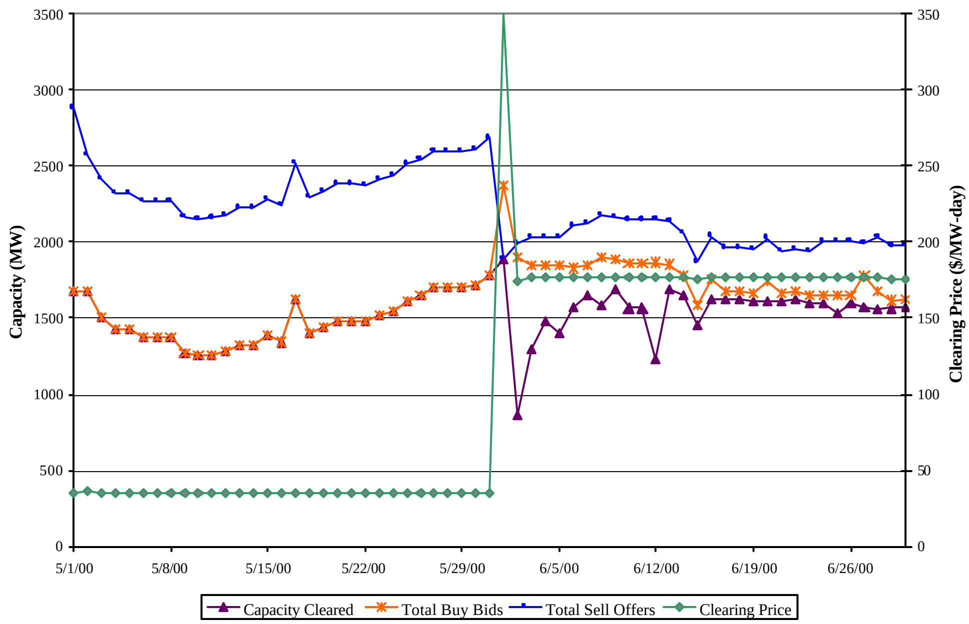
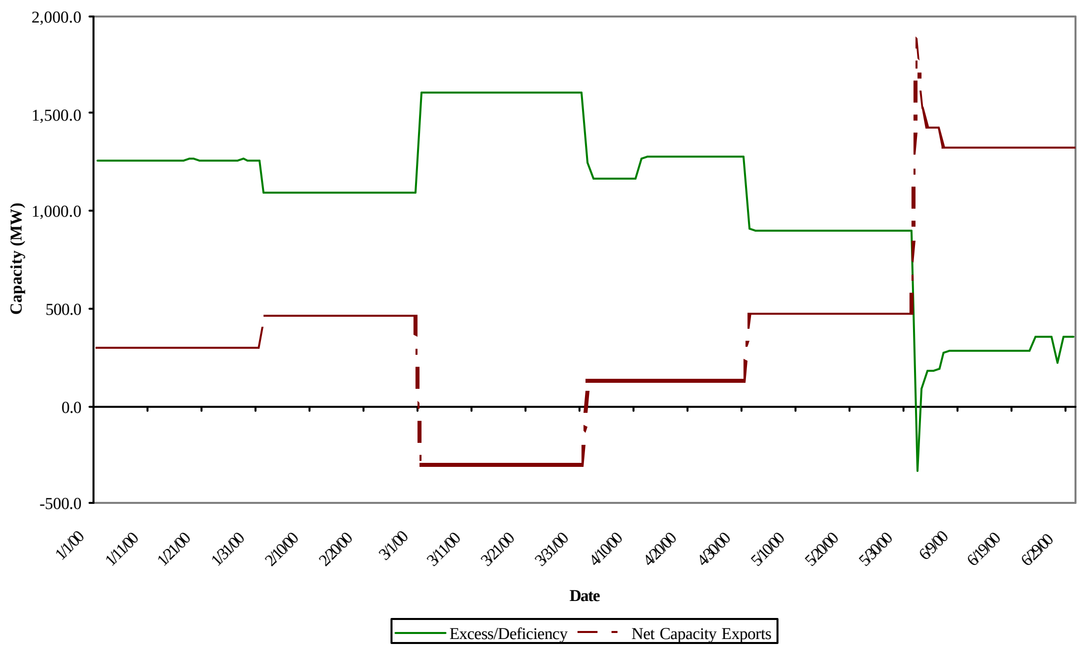


Figure 5: External capacity transactions and pool excess/deficiency
January through June 2000

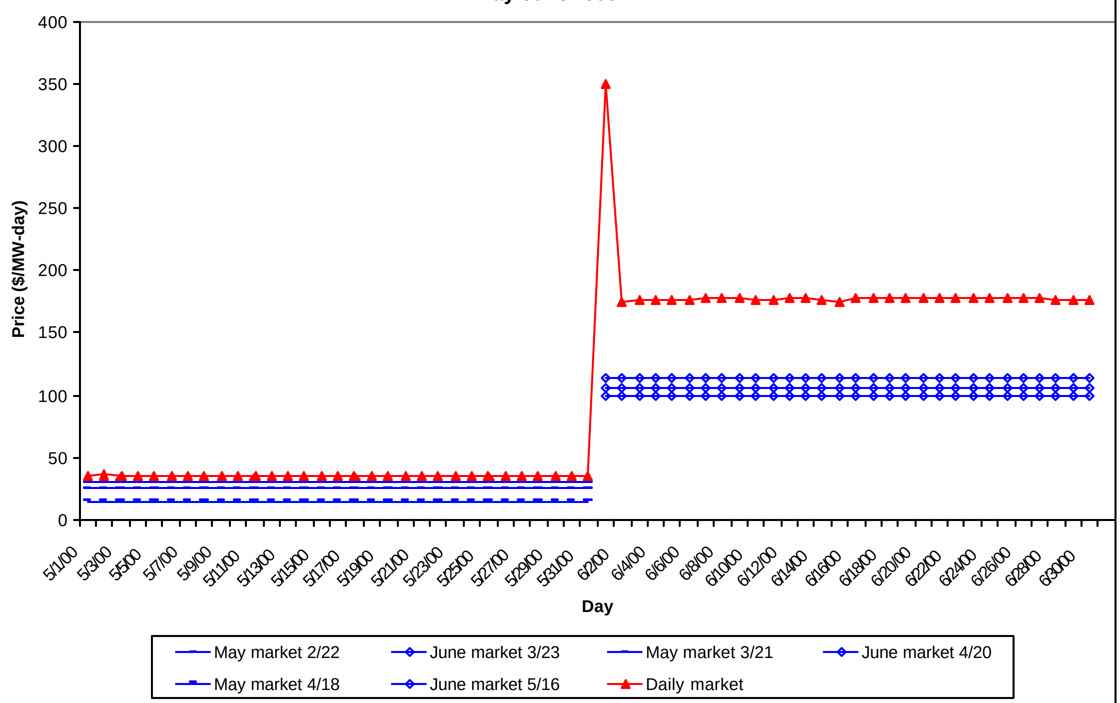


Market Results

On June 1, for the first time since the introduction of the capacity markets in December, 1998, the total demand for daily capacity credits exceeded the total supply of daily capacity credits. The sum of pool capacity obligations exceeded the sum of unforced capacity and thus the pool was deficient. The system was 334 MW deficient on June 1. After June 1, as some of the delisted capacity returned to PJM, the excess capacity ranged from 91 to 358 MW from June 2 through June 30. For the period of January through May, 2000, the system had between 897 MW and 1600 MW of excess capacity.

The combination of an increase in demand and a decrease in supply had a significant impact on the market price. Daily market prices for each day in May were approximately \$35/MW-day. Monthly prices for May capacity, in auctions occurring in February, March, and April were between \$14.99 and \$29.74/MW-day. As Figure 6 shows, on June 1 the daily price rose to \$350.43/MW-day. On June 2, the daily price fell to \$174/MW-day and on June 3, the daily price was about \$177/MW-day where it remained for the balance of June.

Figure 6: PJM monthly and daily capacity market prices
May-June 2000



Alternative Supply Sources for June Capacity

There were three monthly markets for June capacity that cleared on March 23, April 20, and May 16 respectively. There were 895 MW of capacity offered for sale in the final June monthly market, which was run on May 16, of which only 290 MW cleared. Thus, 605 MW offered in the monthly market were not purchased. The 605 MW did not clear because demand bid prices were lower than supply offer prices. The highest demand bid price was $130.10/MW-day. Of this 605 MW, 600 MW were offered at prices under $177.30/MW-day. If this capacity had been purchased, LSE's could have covered the 334 MW shortage on June 1, if other supply offers for June 1 had remained the same.

Status of delisted capacity

Capacity resources must be bid into the PJM energy market and made available to PJM if called upon. When capacity is delisted, the capacity may be sold off system in the form of firm energy, the capacity may be used to produce energy for sale within PJM, the capacity may be held in anticipation of an energy sale at attractive prices either within PJM or in markets external to PJM, or the energy from the unit may simply be withheld.

In order to check the status of the delisted capacity, several tests were applied. First, each delisted capacity resource was checked to determine if a capacity-backed transaction was entered in the transaction scheduling system for that resource and the delisted capacity MW. Second, each generation owner's firm transmission export capacity was compared to the MW level of the delisted capacity resources. Finally, the energy production of each delisted capacity resource was checked against the MW energy production level of that unit.

It appears that some of the capacity that was delisted as a capacity resource was not entered as a capacity-backed transaction in the PJM transaction scheduling system. Generation owners must enter capacity-backed transactions in the scheduling system on a day ahead basis. If a transaction is not capacity-backed then it is subject to recall.[7] Although companies had delisted 2,031 MW of capacity via the PJM eCapacity system, 697 MW were not entered as a capacity-backed sale. Thus, this 697 MW were subject to recall by PJM under Emergency conditions.

The fact that some of the delisted capacity was not explicitly associated with a capacity-backed transaction suggests that the relevant generation owners did not have a specific transaction associated with the capacity and/or did not expect a recall on the relevant days.

Generation owners did have adequate firm transmission capacity to cover exports of delisted capacity with one exception. Thus, owners of delisted capacity were, in general, in a position to provide firm deliveries of energy to the PJM border.

[7] However, if a unit is delisted but not associated with a specific transaction on a day ahead basis, the generation owner can resubmit the transaction to PJM in real time and the sale will be made without recall.

The delisted units generally produced energy in excess of the level of delisted capacity. Thus, it does not appear that resource owners were withholding energy.

Summary and Conclusions

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. 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.

For the June 2000 capacity markets, opportunity costs appear to explain the level of supply available to the daily capacity markets, the nature of the supply curve and the ultimate market price. Demand behavior was also critical in determining the market price. The high levels of mandatory bids, particularly when the market was deficient, contributed to the market prices which were observed. Thus, it does not appear that the capacity market prices observed in June were the result of market power or market manipulation.

Despite these conclusions for June, 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. 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. The Market Monitoring Unit will continue to carefully monitor the capacity markets.