PJM Interconnection
State of the Market Report
2000

Market Monitoring Unit
PJM Interconnection, L.L.C.
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PJM Interconnection State of the Market Report 2000

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SUMMARY

Summary and Conclusions

The *PJM Interconnection State of the Market Report 2000* is the third annual report on the state of the PJM markets to the Board of Managers of PJM Interconnection, L.L.C. (PJM). This report was prepared by the PJM Market Monitoring Unit (MMU), fulfilling the commitment described in PJM's Market Monitoring Plan to objectively assess the state of the PJM market and recommend potential enhancements so as to further improve its competitiveness and efficiency.

PJM operates six markets including the day-ahead energy market, the real-time energy market, the daily capacity market, the monthly capacity market, the regulation market and the monthly FTR auction market.[1] PJM introduced full market-based energy pricing with a market-clearing price based on competitive offers on April 1, 1999. PJM introduced a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid 1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM will continue to develop additional markets in a systematic manner; a market in spinning reserves is under development. The markets managed by PJM are the focus of this report.

In this report, the MMU concludes that in 2000 the energy markets were reasonably competitive, the capacity markets were reasonably competitive, the regulation market was competitive and that the FTR auction was competitive and succeeded in its purpose of increasing access to FTRs. The MMU also concludes that there are potential threats to competition in the energy, capacity and regulation markets that require ongoing scrutiny and in some cases may require action in order to maintain competition. Market participants do possess some ability to exercise market power under certain conditions in PJM markets.

Based on the analysis contained in this report and in the State of the Market Report 1999, the MMU concludes that retention of key market rules and/or changes in market rules and market designs are required for the continued positive results in PJM markets and for 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. Retention of the $100/MW bid cap in the PJM regulation market.
3. Evaluation of additional actions to increase demand side responsiveness to price in both energy and capacity markets.
4. Modification of incentives in the capacity market to require all Load Serving Entities (LSEs) to meet their obligations to serve load on a longer-term basis and to require all capacity resources to be offered on a comparable longer term basis.

PJM has already taken actions to address portions of these recommendations. In 1999, 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. PJM has taken several steps to

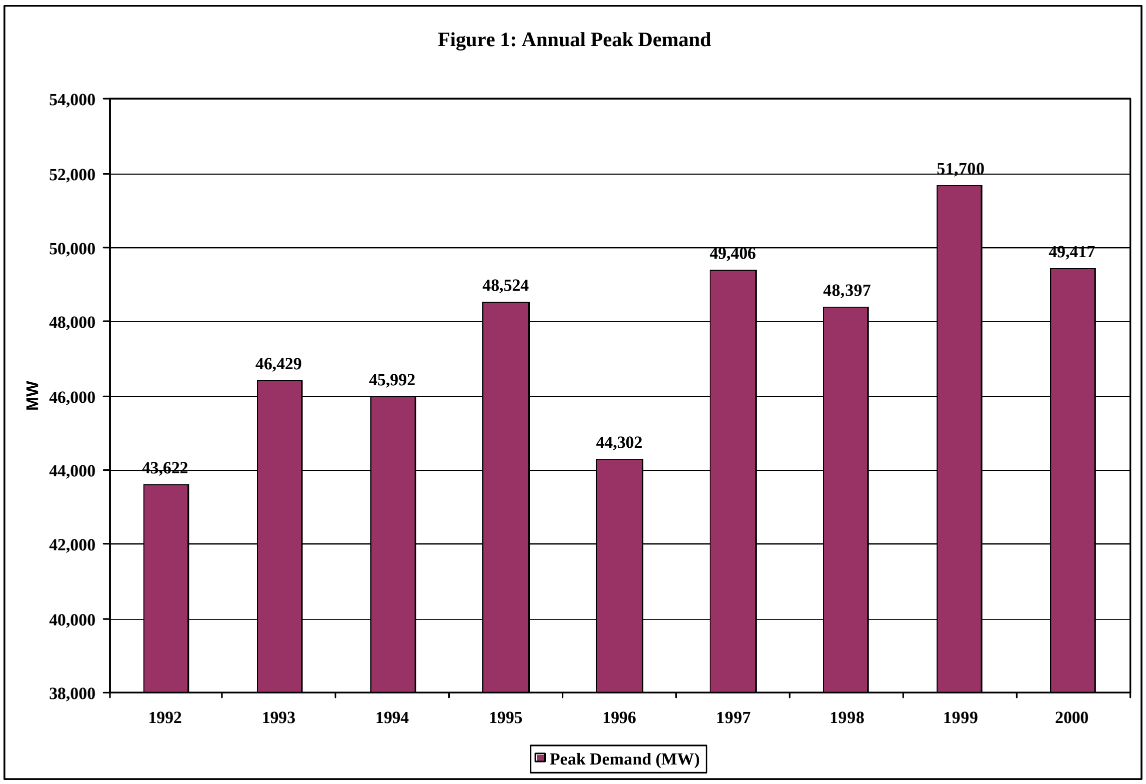
[1] An FTR, or Fixed Transmission Right, is a financial mechanism which permits participants to hedge the risk of paying congestion costs.

encourage demand side price responsiveness in the wholesale markets under the Distributed Generation initiative. PJM has filed a proposal with FERC, which was the result of an extensive stakeholder process, to modify the obligation period in the capacity market.

Based on the experience of the MMU during its second year and this analysis of the markets, the MMU does not recommend any change to the Market Monitoring Unit or the Market Monitoring Plan.

Energy Markets

PJM operates the largest economically dispatched control area in North America and the third largest in the world via a competitive, bid-based market. PJM's peak load of 51,700 MW was established in 1999. (Figure 1.)



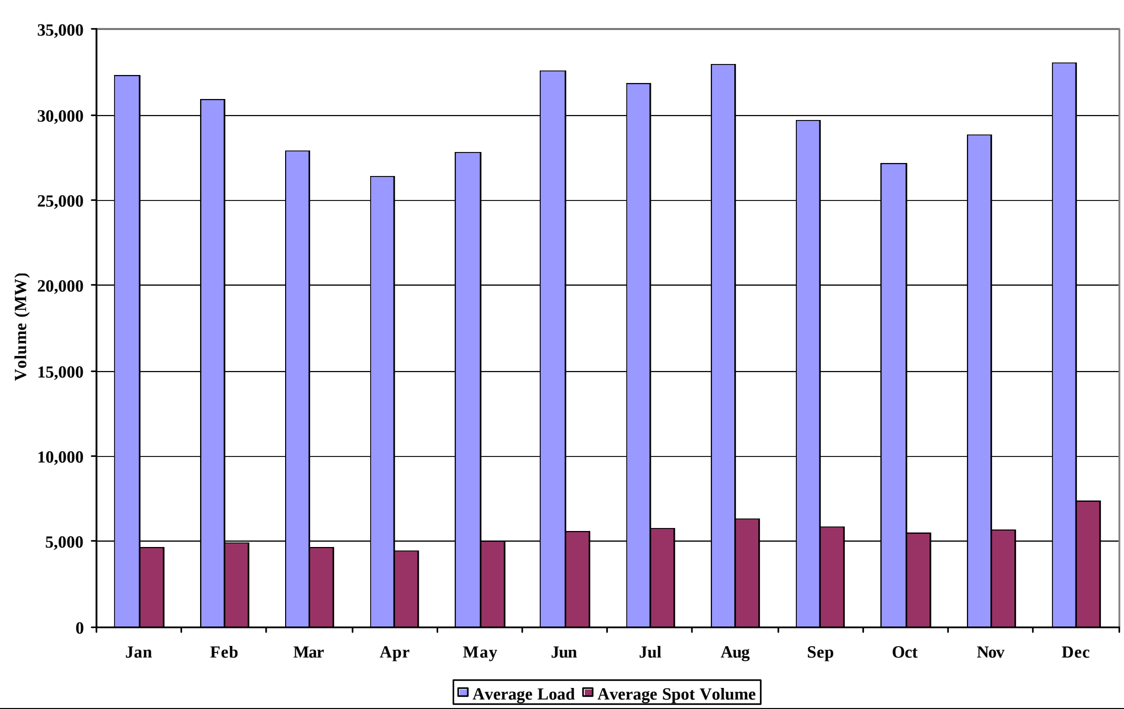
In PJM, market participants wishing to buy and sell energy have multiple options. Market participants decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the day-ahead market or the real-time market. Energy purchases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

PJM introduced the day-ahead energy market on June 1, 2000. The day-ahead market permits both generators and loads to lock in prices and quantities one day ahead of the transactions. The real-time energy market continues to provide a balancing mechanism to ensure that loads are met and generation operated in an efficient manner.

The day-ahead market introduced several new tools for market participants including the ability to bid price sensitive load and the ability to enter financial supply (increment bids) and demand bids (decrement bids). Price sensitive bids submitted by load in the day-ahead market take the form of bids for specified levels of energy at a particular bus or group of buses up to a specified price. While price sensitive demand bids are not a substitute for demand which can respond to price in real time, the ability to submit price sensitive demand bids is a tool now available to loads to help manage price related risk in the day-ahead market. Price sensitive loads have averaged about 2,500 MW per hour, or 8% of day-ahead loads. Increment bids averaged about 6,169 MW per hour, 19% of total day-ahead generation offers plus increment bids, while decrement bids averaged about 4,594 MW per hour in 2000, 14% of total demand bids plus decrement bids.

For the full year, real-time spot market activity averaged about 5,700 MW per hour during peak periods and about 5,000 MW per hour during off peak periods, or 18% of total loads. (Figure 2.) Since the June 1, 2000 introduction of the day-ahead market, it has averaged about 4,200 MW on peak and about 3,800 MW off peak. The day-ahead market is a financial market and thus may be used to provide a hedge against price fluctuations in the real-time spot market.

Figure 2: 2000 PJM Average Hourly Load and Spot Market Volume



The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in spot markets, bilateral markets, forward markets and self-supply. The PJM energy transactions analyzed here include the day-ahead and real-time spot markets. The PJM spot markets are a key benchmark against which results of other types of transactions are measured by market participants. The MMU has reviewed key measures of market structure and performance for 2000, including net revenue, a price-cost mark up index, concentration and prices. The MMU concludes that the energy market was reasonably competitive in 2000.

Net revenue is a significant indicator of overall market performance. Net revenue measures the contribution to capital costs paid by loads and received by generators from energy markets, from capacity markets, and from ancillary services and is thus an indicator of the profitability of an investment in generation as well as a measure of the incentives to build new generation to serve PJM markets. In 2000, the net revenues from the energy market, the capacity market, ancillary services and operating reserves would have covered the fixed costs of peaking units with operating costs of about $45/MWh which ran during all profitable hours. The operating cost of $45/MWh is at the low end of operating cost estimates based on the average cost of gas in 2000 and the heat rate for a peaking unit. The market results in 2000 suggest that the fixed costs of marginal capacity were almost but probably not fully covered by net revenues, given that the estimate of net revenues is an upper bound and that the fixed cost estimate may be somewhat low. Recognizing that market results will vary from year to year, the results in 2000 are consistent with the expected operation of a competitive market. The data do not suggest that generators' net revenues exceeded the fixed costs of generation and thus are consistent with a finding that there was no systematic exercise of market power in PJM during 2000.

The price-cost markup is a widely used measure of market power. While there are several approaches to this measure, the price-cost markup is defined here as the difference between price and marginal cost, divided by price. Overall, the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive in 2000 although the evidence is not dispositive. The MMU will continue to develop this analysis to refine the measure of the markup over competitive prices and to incorporate explicit accounting for opportunity costs, scarcity rents and economic withholding where appropriate. The increase in the mark up index in late 2000 is a cause for concern as it suggests the potential exercise of market power by mid merit steam units during times of moderate demand.

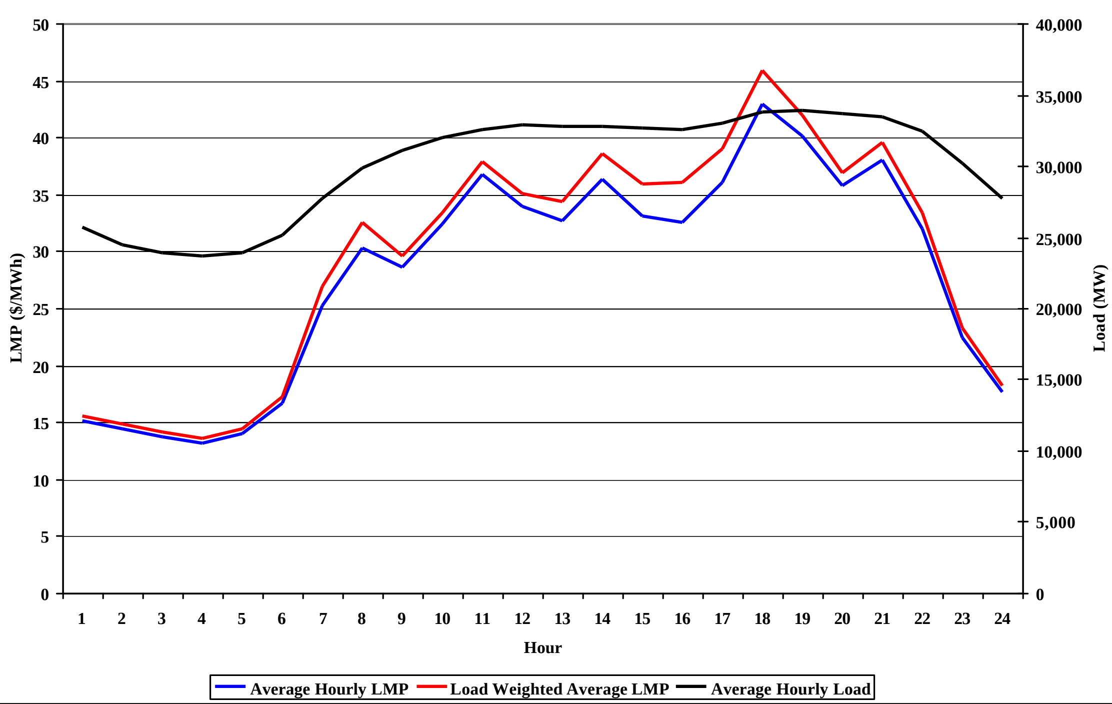
Concentration ratios are used to measure the concentration of ownership in markets, a key element of market structure. As indicated in the State of the Market Report 1999, concentration measures must be used carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive or that market participants cannot exercise market power. However, high market concentration ratios do indicate an increased potential for market participants to exercise market power. Concentration ratios are presented here because they provide useful information on market structure and are a widely used measure of market structure. The structural analysis indicates that overall the PJM control area exhibits moderate market concentration. However, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2000, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those obligations change.

The 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. While load weighted prices were 10% lower in 2000 than in 1999, the level of prices in 2000 was affected by higher fuel costs. When adjusted for hourly loads and increased fuel costs, average prices were 27% lower in 2000 than in 1999.

The simple average system-wide LMP was approximately the same in 1999 and 2000, \$28.32/MWh versus \$28.14/MWh, and 30% higher in both years than in 1998. The load-weighted LMP of \$30.72/MWh in 2000 was 10% lower than in 1999 and 27% higher than in 1998. When increased fuel costs and hourly loads are accounted for, the average load-weighted LMP in 2000 was more than 27% lower than in 1999, \$24.78/MWh compared to \$34.06/MWh.

The pattern of prices within days and across months illustrates that prices are directly related to demand. The fact that price is a direct function of load (Figure 3) illustrates the potential significance of price elasticity of demand in affecting price. The potential for load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale energy market.

Figure 3: PJM Average Hourly System Load and LMP - 2000



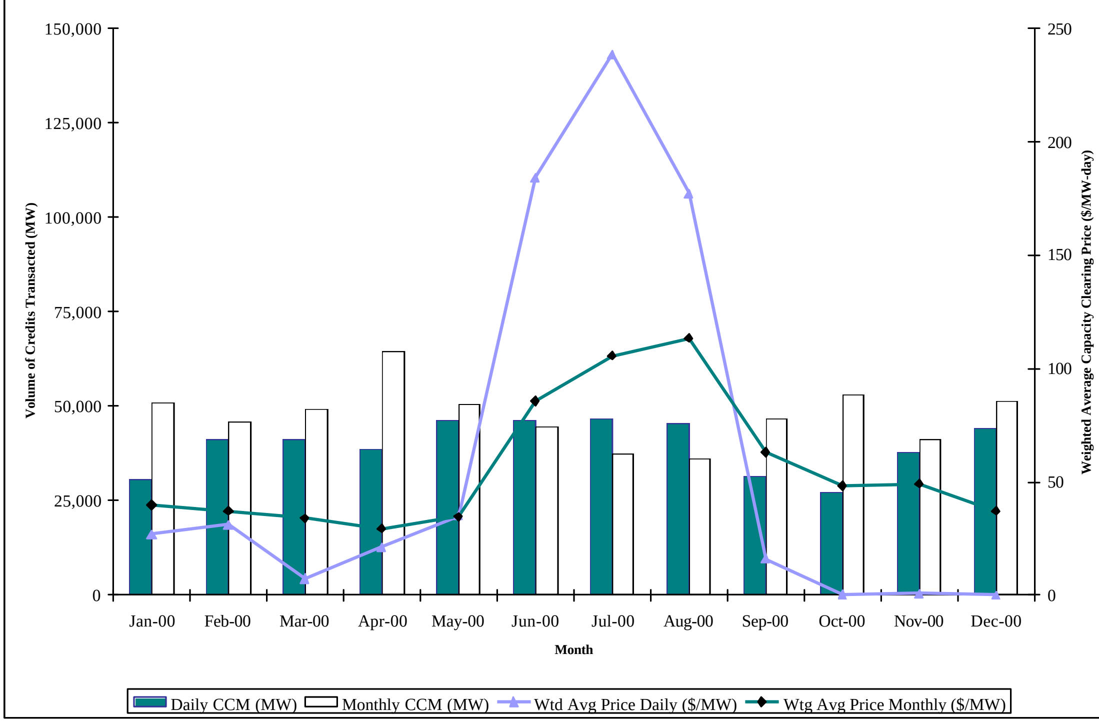
The energy market results for 2000 were in part the result of the relatively moderate weather and thus demand conditions during the year. The concerns identified in the State of the Market Report 1999 remain, including the ability of market participants to exercise market power during periods of high demand. There are additional concerns regarding the observed increase in the level of the price-cost mark up in late 2000 and the relatively high levels of concentration during certain periods in markets defined by transmission constraints.

Capacity Markets

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources greater than or equal to the peak load that it serves plus a reserve margin. LSEs have the flexibility to acquire capacity in a variety of ways. Capacity can be obtained by building units, by entering into bilateral arrangements with terms determined by the parties or by participating in the capacity credit markets operated by PJM. Collectively, these arrangements are known as the ICAP market, for Installed Capacity Market. The PJM capacity credit markets provide the mechanism to balance the supply of and demand for capacity not met via the bilateral market or via self-supply. Capacity credit markets provide a transparent, market based mechanism for new, competitive LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. PJM's daily capacity credit markets ensure that LSEs can match capacity resources with changing obligations caused by daily shifts in retail load. Monthly and multi-monthly capacity credit markets provide a mechanism that matches longer-term capacity obligations with available capacity resources.

The PJM ICAP market plays a critical role in ensuring the reliability of the PJM system by providing a market mechanism to match load obligations of end users in PJM with suppliers of the capacity required to serve those loads reliably. In 2000, 1,048,528 MW days of capacity were bought and sold in the capacity markets operated by PJM. The overall weighted average price of this capacity was $60.55 per MW-day or $22,100 per MW-year. (Figure 4.)

Figure 4: 2000 Daily vs Monthly Capacity Credit Market Performance



The MMU has reviewed the design and structure of the capacity markets, the bidding behavior of market participants and the results of the capacity markets for 2000. The MMU concludes that the capacity markets were reasonably competitive during 2000 although the potential exercise of market power is a concern and there are significant market design issues which require resolution. During 2000, the system of capacity obligations functioned effectively and helped ensure that energy was available during emergency conditions. MMU analysis of the high prices in the daily capacity credit markets during the summer of 2000 concluded that those prices were caused by fundamental market forces rather than market power or market manipulation. Nonetheless, the potential exercise of market power in the capacity markets remains a concern given the extreme inelasticity of demand and given that, at times, only a few generation owners had available capacity to sell. In addition, events in the capacity credit markets during the year 2000 illustrate a key issue identified in the PJM Interconnection State of the Market Report 1999, the impact of the daily capacity market on generator incentives to delist capacity.

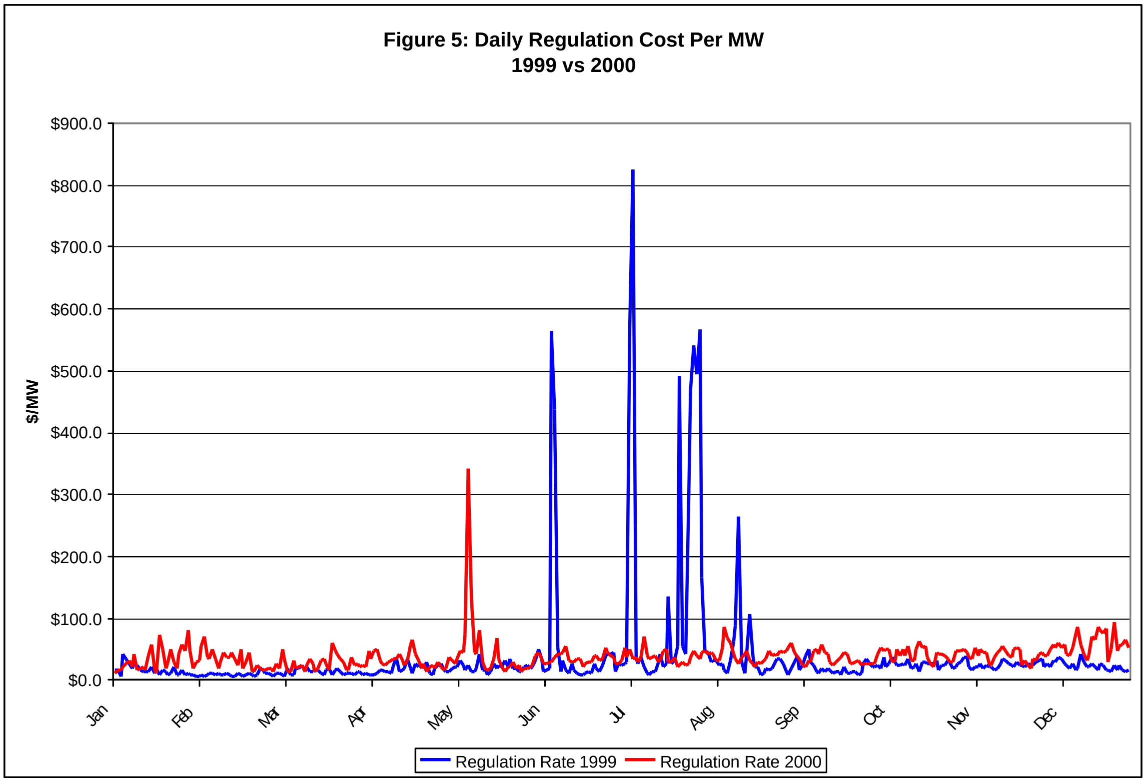
The State of the Market Report 1999 recommended modifications to the capacity credit market rules to better align market incentives with PJM's reliability requirements while limiting the exercise of market power. In particular, the report recommended that the capacity credit market rules should be modified to require that all LSEs meet their obligation to serve load on an annual or semiannual basis and that all capacity resources be offered on a comparable basis. During 2000, the PJM stakeholder Future Adequacy Working Group began developing a set of revised capacity credit market rules that are broadly consistent with the recommendations of the State of the Market Report 1999. PJM and its members are continuing this work to refine the design of the capacity credit markets in order to ensure that incentives to buy and sell capacity remain consistent with PJM's reliability goal.

Regulation Market

PJM introduced a new regulation market on June 1, 2000. Regulation is one of six ancillary services defined by FERC in Order No. 888. The provision of regulation is coordinated by the control area operator, PJM. Regulation is required in order to match generation with short-term increases or decreases in load which would otherwise result in a short-term imbalance between the generation and usage of energy. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. The PJM regulation market supplanted an administrative and cost-based regulation procurement mechanism that had been in place for many years. Market participants can now acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally.

The market design implemented by PJM provides appropriate incentives to owners based on current, unit-specific opportunity costs in addition to the regulation offer price. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of $100 per MW, plus opportunity costs.

The MMU has reviewed the structure of the market, the number and nature of regulation offers, the level of the regulation price and the system regulation performance since the implementation of the regulation market. The MMU concludes that the new regulation market was competitive in 2000. Concerns about the structure of ownership in the regulation market are offset at present by the available supply of regulation capacity from PJM resources compared to the demand for regulation. The price of regulation under the market was approximately equal to the price under the administrative and cost-based system and the price exhibited the expected relationship to changes in demand. (Figure 5.) There is the potential for various forms of non-competitive behavior in the energy market to affect the regulation market, although there is no evidence of such an issue during 2000. The introduction of a market in regulation resulted in a significant improvement in system regulation performance, measured by the availability of regulation and by NERC Control Performance Standards CPS1 and CPS2. The preliminary results from the first seven months of the regulation market are positive, but it is too early to reach a final conclusion regarding the long-term competitiveness of the market in regulation.



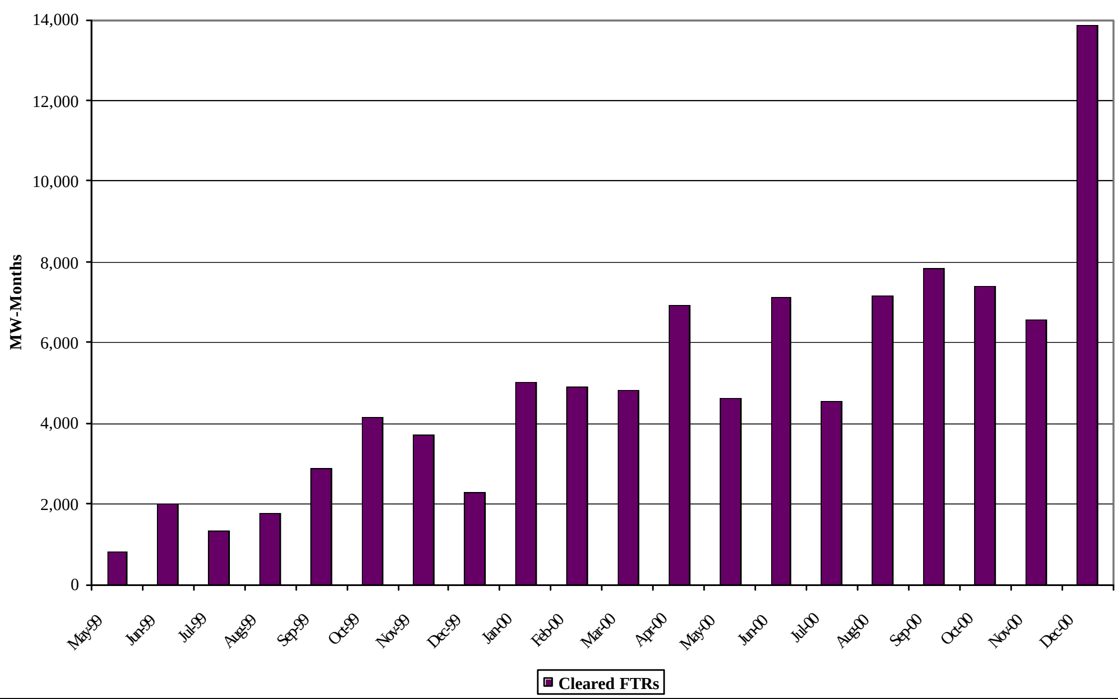
FTR Auction Market

PJM introduced the monthly Fixed Transmission Rights (FTR) auction market to increase FTR liquidity by providing a mechanism to auction the residual FTR capability on the transmission system and to permit the sale and purchase of FTRs. The number of FTR buy bids has increased significantly since the auction was introduced, as have the MW quantities cleared.

In PJM, firm point-to-point and network transmission service customers may request FTRs as a hedge against the congestion that can result from PJM's system of locational marginal pricing (LMP). More precisely, an FTR is a financial instrument that entitles the holder to receive revenues (or charges) based on transmission congestion measured as the hourly energy locational marginal price differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basis risk associated with delivering energy from one bus or aggregate to another bus or aggregate. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

During 2000, several issues related to the FTR Auction process and results were identified. Each of these issues has been successfully resolved so as to enhance the competitiveness of PJM markets. The issues are FTR allocation, creating congestion and transmission outage notification.

Figure 6: FTR Monthly Auction Volume Cleared



While the initial FTR allocation process provided FTRs only to network and firm point-to-point transmission customers and the bilateral market allowed the exchange of those specific FTRs, the FTR Auction Market was designed to make FTRs more available to all market participants. The basic mechanics of the FTR auction have worked as intended, since their FERC-approved inception on April 13, 1999. A review of the operation of the FTR auction process indicates that the FTR auction was competitive and has succeeded in its purpose of increasing access to FTRs. There has been a steady increase in the MW of cleared FTRs which have grown from an average monthly 2,400 MW in 1999 to 6,700 MW in 2000 (13,800 in December 2000). (Figure 6.) The trends in the number of bids, the number of offers and MWs of bids have also been upward.

ENERGY MARKET

Summary and Conclusions

The PJM energy market comprises all types of energy transactions including the sale or purchase of energy in spot markets, bilateral markets and forward markets, and self supply. The PJM energy transactions analyzed here include the day-ahead and real-time spot markets. The PJM spot markets are a key benchmark against which results of other types of transactions are measured by market participants. The MMU has reviewed key measures of market structure and performance for 2000, including net revenue, a price-cost markup index, concentration and prices. The MMU concludes that the energy market was reasonably competitive in 2000.

In 2000, the net revenues from the energy market, the capacity market, ancillary services and operating reserves would have covered the fixed costs of peaking units with operating costs of about $45/MWh which ran during all profitable hours. The operating cost of $45/MWh is consistent with the average cost of gas in 2000. The market results suggest that the fixed costs of marginal capacity were almost, but probably not fully, covered by net revenues, given that the estimate of net revenues is an upper bound and that the fixed cost estimate may be somewhat low. Recognizing that market results will vary from year to year, the results in 2000 are consistent with the expected operation of a competitive market. The data do not suggest that generators' net revenues exceeded the fixed costs of generation and thus are consistent with a finding that there was no systematic exercise of market power in PJM during 2000.

Overall, the data on the price-cost markup are consistent with the conclusion that the energy market was reasonably competitive although the evidence is not dispositive. The MMU will continue to develop this analysis to refine the measure of the markup over competitive prices and to incorporate explicit accounting for opportunity costs, scarcity rents and economic withholding where appropriate. The increase in the markup index in late 2000 and the increase in the markup index for steam units is a cause for concern as it suggests the potential exercise of market power by mid-merit steam units during times of moderate demand.

The structural analysis indicates that the PJM control area exhibits moderate market concentration. However, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2000, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those obligations change.

While load weighted prices were 10% lower in 2000 than in 1999, the level of prices in 2000 was also affected by higher fuel costs. When adjusted for hourly loads and increased fuel costs, prices were 27% lower in 2000 than in 1999. The simple average system-wide LMP was approximately the same in 1999 and 2000, $28.32/MWh versus $28.14/MWh, and about 30% higher in both years than in 1998. The load-weighted LMP of $30.72/MWh in 2000 was 10% lower than in 1999 and 27% higher than in 1998. When increased fuel costs and hourly loads are accounted for, the average load-weighted LMP in 2000 was more than 27% lower than in 1999, $24.78/MWh compared to $34.06/MWh.

The energy market results for 2000 were in part the result of the relatively moderate weather and thus demand conditions during the year. The concerns identified in the State of the Market Report 1999 remain, including the ability of market participants to exercise market power during periods of high demand. There are additional concerns regarding the observed increase in the level of the price-cost markup in late 2000 and the relatively high levels of concentration during certain periods in markets defined by transmission constraints.

Net Revenue

Net revenue is a significant indicator of overall market performance. Net energy revenue measures the contribution to capital costs paid by loads and received by generators from energy markets and is thus an indicator of the profitability of an investment in generation as well as a measure of the incentives to build new generation to serve PJM markets. The product of energy market prices and output determine gross revenue to generators. Gross revenue less variable cost equals net revenue, and a net revenue curve (Figure 1) illustrates the relationship between net energy 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.

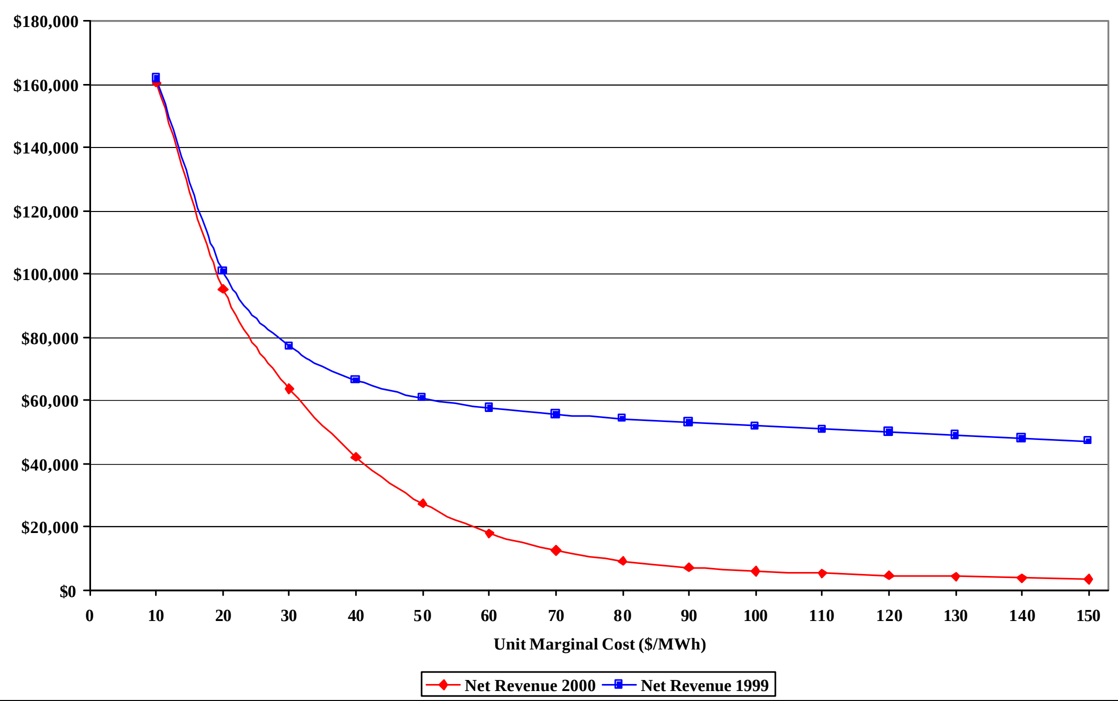
In a perfectly competitive, energy-only market, net revenue would be expected to equal the total of all these fixed costs for the marginal unit, including a competitive return on investment, in long run equilibrium. In other words, net revenue is a measure of whether generators are receiving competitive returns on invested capital and whether energy prices are high enough to encourage the entry of new capacity. The PJM capacity, energy and ancillary services markets are all sources of revenue to cover the fixed costs of generators. In a perfectly competitive market, with energy, capacity and ancillary services payments, the net revenue from all sources would equal the fixed costs of generation, for the marginal unit, in long run equilibrium. The net revenue curves presented here reflect net revenues from energy markets only, while the additional sources of revenue are shown in Table 1.

Figure 1, PJM Energy Market Net Revenue, shows, on its vertical axis, the dollars per MW-year received by a unit in PJM which operated whenever the system price exceeded the variable cost levels ($/MWh) on the horizontal axis. For example, a unit with marginal costs equal to $30/MWh had an incentive to operate whenever the LMP exceeded $30/MWh. If this unit operated in all profitable hours, whenever LMP exceeded $30/MWh, it would have received about $64,000/MW in net revenue during 2000 from the energy market. The net revenue curve is an approximate measure of the contribution to generators’ fixed costs from the energy market and represents the upper bound of such contributions. The net revenue curve does not take account of either forced outages or operating constraints. For example, a twelve hour start up time could prevent a unit from running during two profitable hours in the morning and two profitable hours in the evening, separated by eight non-profitable hours. As another example, ramp limitations might prevent a unit from starting and ramping up to full output in time to operate for all profitable hours.

As shown in Figure 1, the energy market net revenues in 2000 exhibited a different shape than in 1999. In 1999, if a unit with marginal costs of $30/MWh operated in all hours when the LMP exceeded $30/MWh, it would have received about $77,000/MW in net energy revenue versus about $64,000 in 2000. This gap widens for higher marginal cost units. In 1999, if a unit with marginal costs of $50/MWh operated in all hours when LMP exceeded $50/MWh, it would have received about $61,000/MW in net energy revenue versus about $27,000 in 2000.

The difference in the shape and position of the net energy revenue curve between 1999 and 2000 resulted from the different distribution of energy market prices. The difference in the net energy revenue curves illustrates the significance of a relatively small number of high price hours to the profitability of high marginal cost units. While average prices in 2000 were approximately equal to average prices in 1999, average prices in 2000 were actually higher than average prices in 1999 for all hours except hours 1200 through 1800, where 1999 prices significantly exceeded 2000 prices. These peak hours included the hours when 1999 prices spiked to in excess of $900 for a limited number of hours. The 91 hours in 1999 when prices exceeded $150/MWh and the 43 hours in which price exceeded $800 generally occurred during these peak hours and resulted in the shape of the net revenue curve for 1999. In 2000, there were only 27 hours in which the price exceeded $150 and only 1 hour in which the price exceeded $800. The limited number of high price hours in 2000 resulted in lower net revenue for units operating at marginal costs in excess of $30/MWh.

Figure 1: PJM Energy Market Net Revenue - 1999 and 2000



Generators received capacity related revenues in addition to energy related revenues. PJM capacity resources received an average payment from all capacity markets of $60.55/MW-day in 2000, or $23,308/MW for the year. In 1999, the average payment from the capacity markets was $52.86/MW-day or $20,469/MW-year.[1] The differential in net energy revenue between 1999 and 2000 was partially offset by the higher capacity market revenues in 2000. Thus, a PJM capacity

[1] These values are on an installed basis while the capacity prices are on an unforced basis.

resource with a marginal cost of $30/MWh which operated in all profitable hours would have received revenues of about $87,000/MW-year from capacity and energy markets in 2000 versus about $98,000/MW-year in 1999.

Generators also received ancillary service revenues and operating reserve revenues in addition to energy and capacity related revenues. Aggregate ancillary services revenues from regulation amounted to approximately $125,000,000 in 2000. Spread over all installed capacity, this is about $2,200 per MW-year. Regulation revenues represent about $2,600 per MW-year spread over all steam units while spinning reserve revenues represent about $6,700 per MW-year over all combustion turbine units (CTs). Total operating reserve payments were about $216,000,000 in 2000 including payments for spinning reserves. When operating reserve payments are spread over total installed capacity this is about $3,800 per MW-year.

Taking account of all the revenue streams to generation, a PJM capacity resource with a marginal cost of $30/MWh would have received revenues of about $93,000/MW-year in 2000 while a unit with a cost of $50/MWh would have received revenues of about $57,000/MW-year. Table 1 presents the results for units with a range of marginal costs.

To put the net revenues results in perspective, the average gas cost in PJM in 2000 was between $4.50/Mcf and $5.00/Mcf and the corresponding variable cost for a CT was between $45/MWh and $50/MWh. The corresponding variable cost for a combined cycle (CC) was between $30/MWh and $35/MWh, approximately.[2] In addition, 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.

In 2000, the net revenues from the energy market, the capacity market, ancillary services and operating reserves would have covered the fixed costs of peaking units with operating costs of about $45/MWh which ran during all profitable hours. The operating cost of $45/MWh is at the low end of operating cost estimates based on the average cost of gas in 2000.

While it can be expected that in the long run, in a competitive market, net revenues from all sources will cover the fixed costs of investing in new generating resources including a return on investment, actual results will vary from year to year. Revenues from the capacity market, ancillary services and operating reserves clearly vary from unit to unit depending on particular capacity market transactions, the actual provision of ancillary services and the actual receipt of operating reserves. The results in 2000 suggest that the fixed costs of marginal capacity were almost but probably not fully covered, given that the estimate of net revenues is an upper bound and that the fixed cost estimate may be somewhat low. Recognizing that market results will vary from year to year, the results in 2000 are consistent with the expected operation of a competitive

[2] The two key variables are the cost of fuel and the heat rate of the unit.

market. The data do not suggest that generators' net revenues exceeded the fixed costs of generation and thus are consistent with a finding that there was no systematic exercise of market power in PJM during 2000.

Table 1: Net Revenues in 2000 by Marginal Cost of Unit					
	Net Revenue Sources ($/MW-year)				
Unit Marginal Cost	Energy	Capacity	Ancillary Services	Operating Reserves	Total
($/MWh)					
$10	$160,608	$23,308	$2,172	$3,759	$189,847
$20	$95,250	$23,308	$2,172	$3,759	$124,489
$30	$63,675	$23,308	$2,172	$3,759	$92,914
$40	$42,097	$23,308	$2,172	$3,759	$71,335
$50	$27,431	$23,308	$2,172	$3,759	$56,670
$60	$17,990	$23,308	$2,172	$3,759	$47,229
$80	$9,146	$23,308	$2,172	$3,759	$38,385
$100	$6,008	$23,308	$2,172	$3,759	$35,246
$120	$4,671	$23,308	$2,172	$3,759	$33,910
$140	$3,844	$23,308	$2,172	$3,759	$33,083

Net revenues also provide an incentive to build new generation to serve PJM markets. While these incentives clearly operate with a significant lag, the level of applications to build generation in the PJM area reflect the incentives provided by the combination of revenues from the PJM energy and capacity markets. At the end of 2000, about 43,000 MW of capacity are in the generation request queues for construction through 2007, compared to currently installed capacity of about 58,000 MW.

Price-Cost Markup

A widely used measure of market power is the price-cost markup. The goal of the markup analysis is to estimate the difference between the observed market price and the competitive market price. The actual calculation of the price-cost markup is complex and difficult.

While there are several approaches to the calculation, the first approach to the price-cost markup taken here is to calculate a price-cost markup index defined as the difference between price and marginal cost, divided by price, for the marginal unit. (Markup index = (P – MC)/P) This markup index measure varies from 0, when price equals marginal cost and there is no markup, to 1.00 when price is high compared to marginal cost.[3]

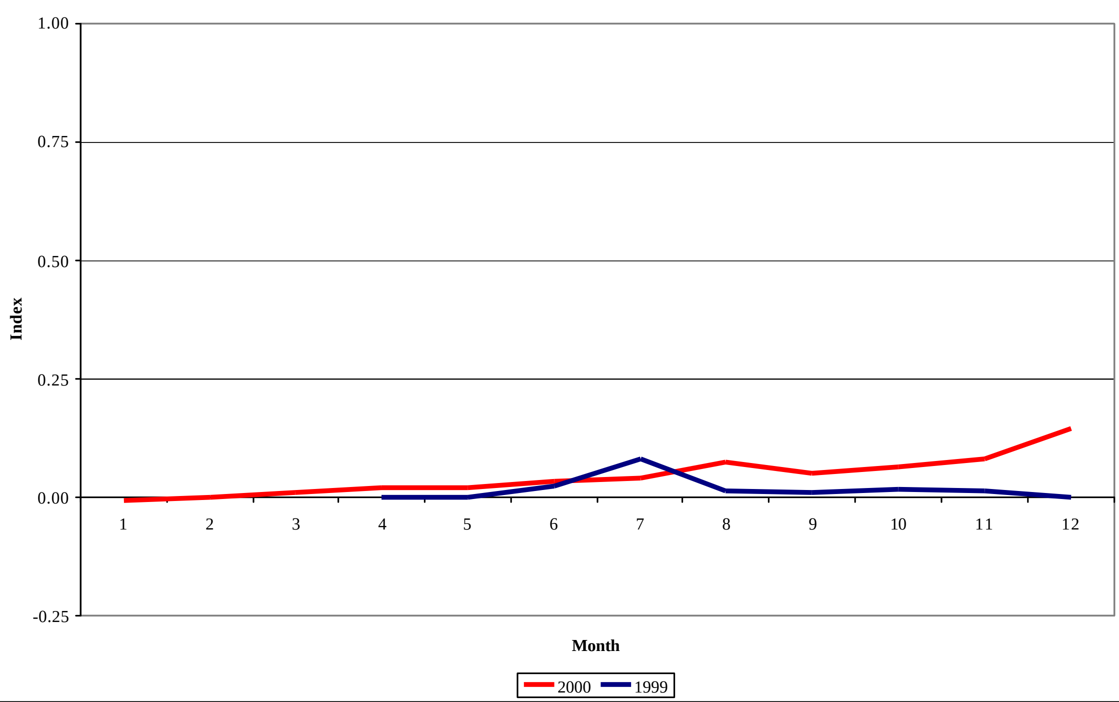
PJM has data on the price and cost offers for every unit in the PJM system for which construction commenced prior to July 9, 1996. The markup can thus be calculated directly for each unit for any time period. The markup is calculated for the marginal unit or units in every

[3] The value of the index can be less than zero if a unit offers its output at less than marginal cost.

five-minute period and compares the price offer to the cost corresponding to the unit's output. The marginal unit is the unit which sets LMP in the five minute interval. There are multiple marginal units when congestion exists. Congestion is accounted for by weighting the markup for each of the multiple marginal units, in a five-minute interval with congestion, by the load that pays the price determined by that marginal unit.[4]

Figure 2 shows the monthly average of the marginal unit markup series starting in April 1999 when PJM introduced the competitive energy market. The average markup in 1999 was about .02, with a maximum markup in July of .08. The average markup increased to .04 in 2000, with a maximum markup in December of .14. In general, the observed average markups over cost by marginal units have been modest, although the increase in December requires further evaluation.[5]

Figure 2: Average Monthly Load Weighted Mark Up Index



In order to understand the dynamics underlying the observed markups, the marginal units were analyzed in more detail including fuel type, plant type and ownership.

Figure 3 shows the markup by fuel type. Units using coal and miscellaneous fuels showed the largest relative increases in the markup index. Coal and miscellaneous fuel units had an average markup of .07 during 2000. The primary fuel types included in the miscellaneous category include methane, petroleum coke, refuse, refinery gas, waste coal, wood and wood waste.

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4 For example, if a marginal unit with a markup index of .50 set the LMP for 3,000 MW of load in an interval and a second marginal unit with a markup index of .01 set the LMP for 27,000 MW of load, the weighted average markup index for the interval would be .06.

5 An unknown number of generators have increased their cost bids by 10 percent so the calculated markup could be low by from a maximum of .10 when the index is 0.00 to a maximum of .08 when the index is .20.

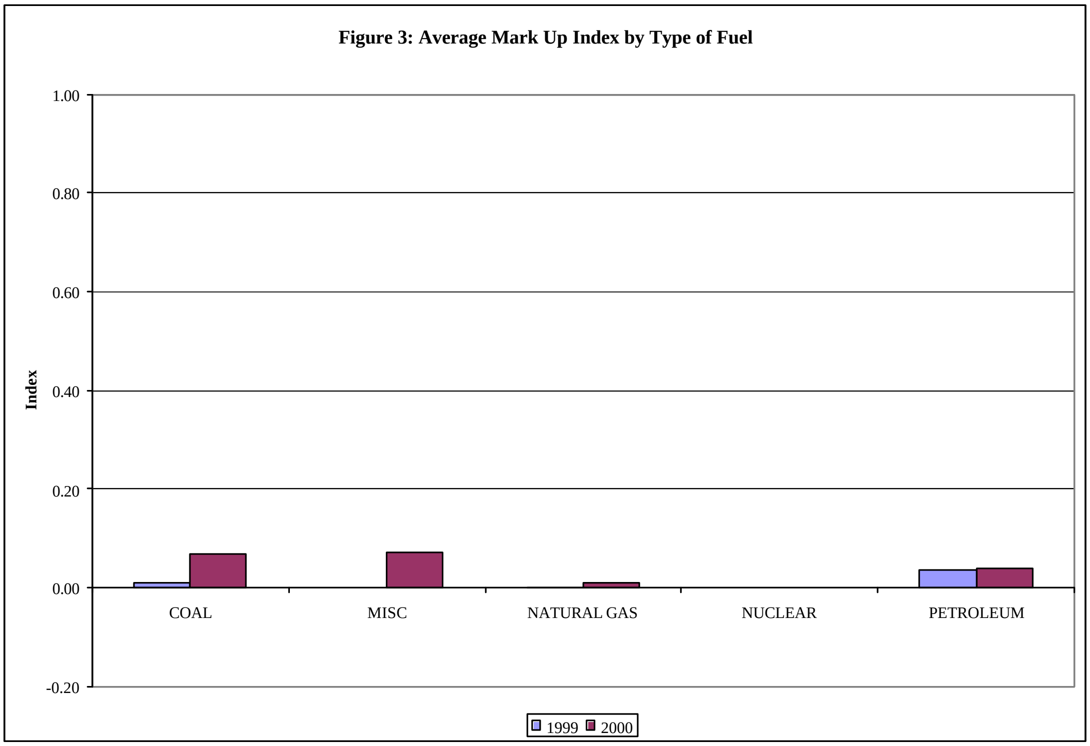


Figure 4 shows the type of fuel used by the marginal units. In 2000, coal-fired units were on the margin 48% of the time, petroleum-fired units about 31% of the time, gas-fired units 18% of the time and nuclear units 2%. Petroleum-fired units share of marginal usage increased from 23% in 1999 to 31% in 2000 while the share of coal, natural gas and nuclear decreased slightly.

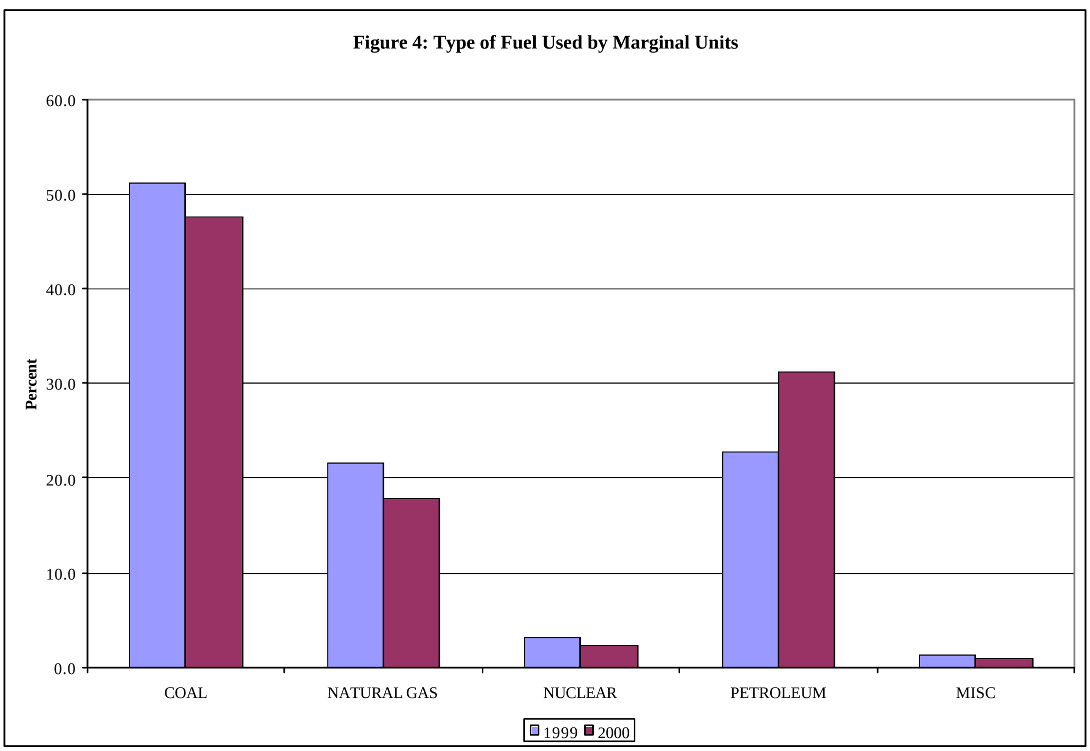


Figure 5 shows the type of units on the margin during 2000. CTs were the marginal unit 29% of the time in 1999 and 36% of the time in 2000, while steam units were the marginal unit 71% of the time in 1999 and 64% of the time in 2000.

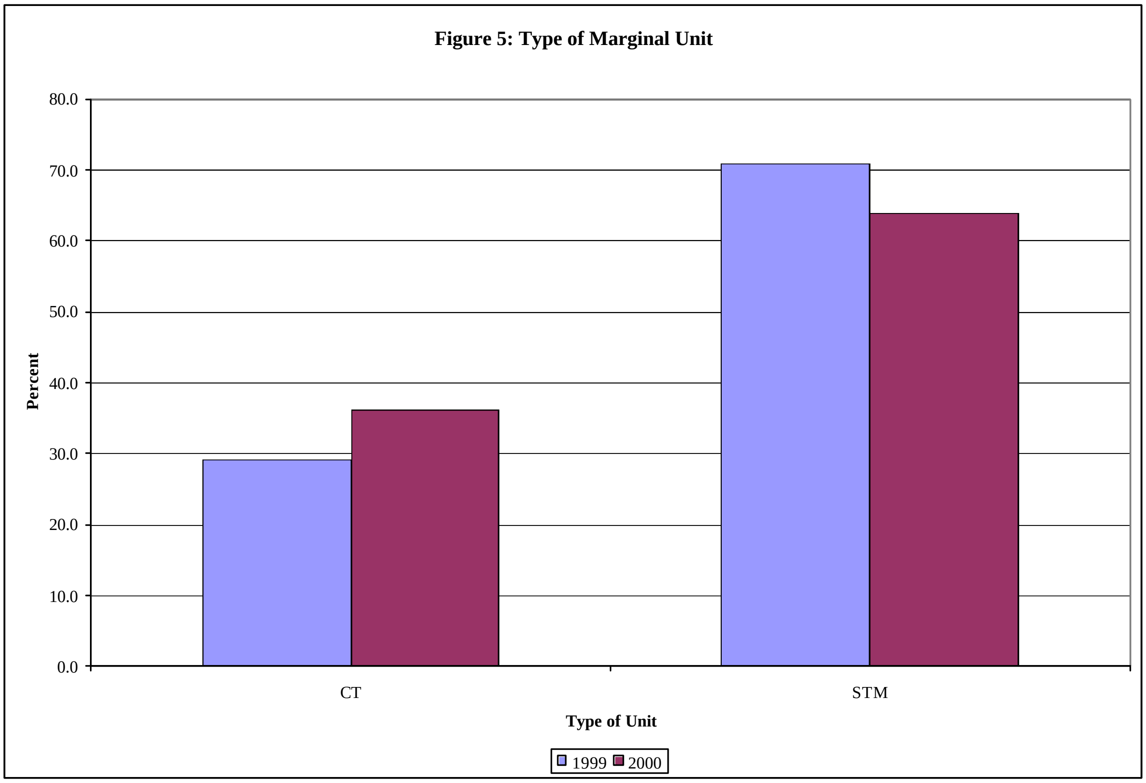
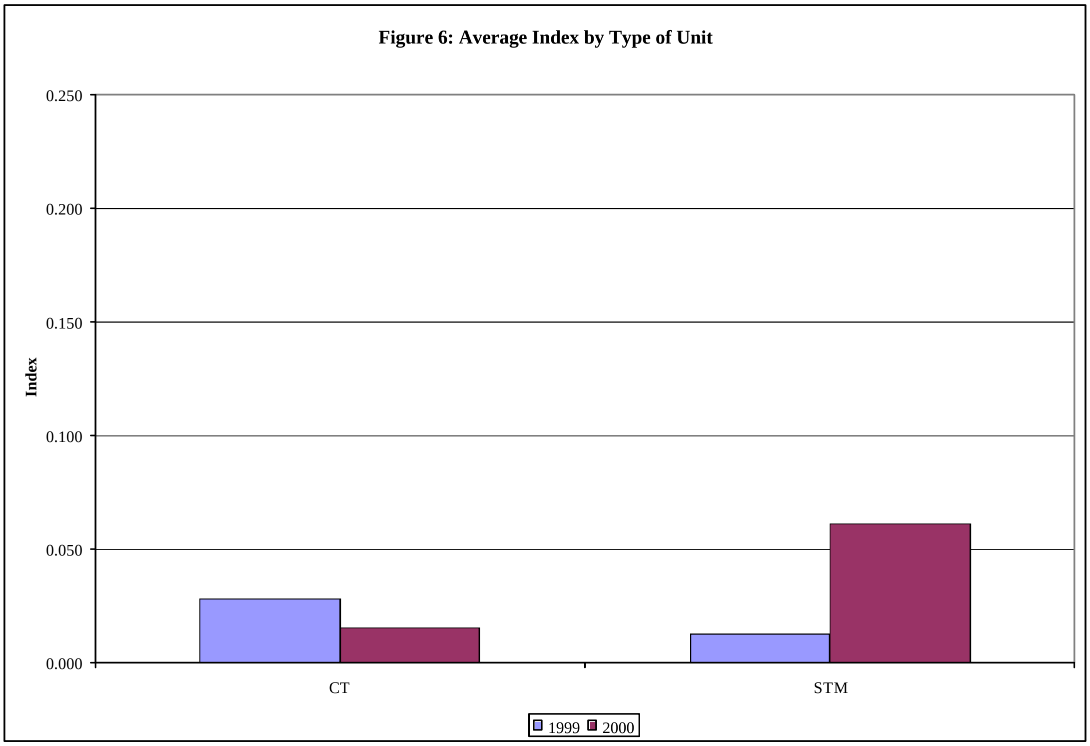


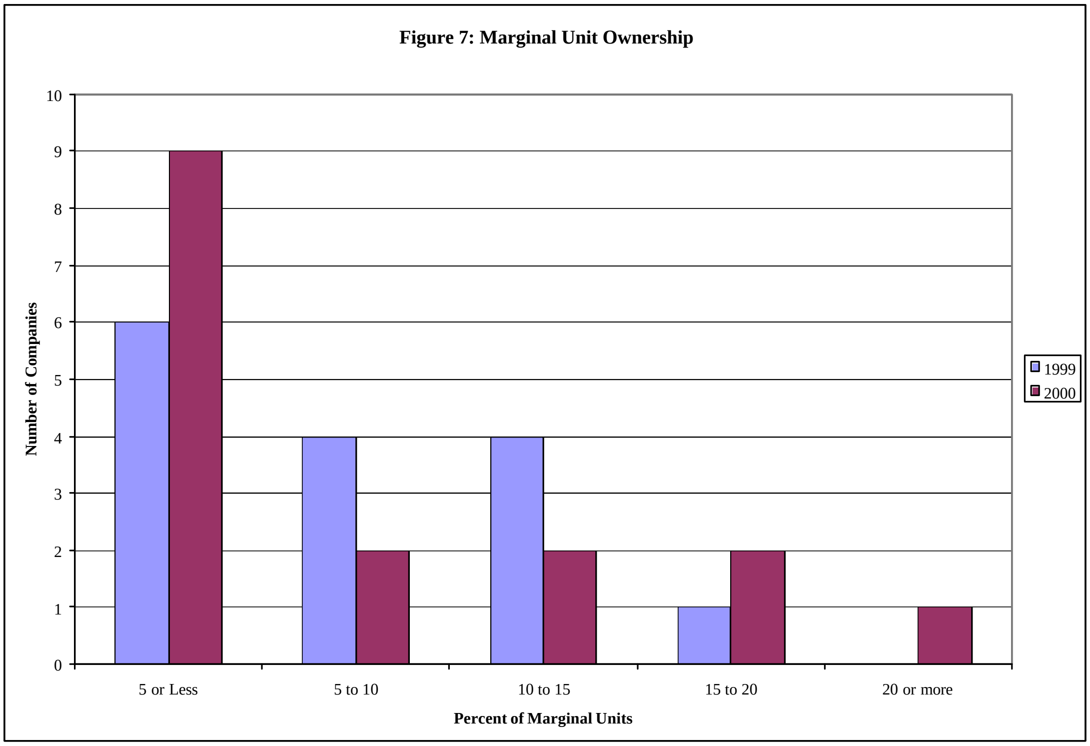
Figure 6 shows the average markup index by type of unit. Although the markup index is relatively small for steam and CT units, the average annual index was higher for steam units than for CTs, and the average annual index increased for steam units in 2000 while it fell for CTs.



An examination of marginal unit characteristics shows that steam units, primarily coal-fired, were the marginal units about two thirds of the time over the 21 month period and that the average markup for steam units increased from .01 to .06 between 1999 and 2000. CTs were the marginal units for the remaining one third of the time. The average markup for CTs decreased from .03 to .02 between 1999 and 2000.

The data presented in Figures 2 to 6 suggest that the somewhat higher markup in 2000 and the higher markup index in late 2000 were the result of bidding behavior by steam units during times of moderately high demand. This is a change from 1999 when the increase in the index during the summer was primarily the result of bidding behavior by CTs during extreme demand conditions.

Figure 7 shows the distribution of ownership of the marginal units. Taking all the units which were on the margin for one or more five minute intervals during the year, in 2000, 20% or more of the marginal units were owned by one company, while 15-20% of the marginal units were owned by two companies. In other words, at least 35% to 40% of the marginal units were owned by three companies in 2000. In 1999, 15-20% of the marginal units were owned by one company. When combined with the information on bidding behavior, the distribution of ownership of marginal units is a further cause for concern.



The price-cost markup for the marginal unit is not a precise measure of market power for a number of reasons, including the shape of the cost-based supply curve, scarcity, opportunity costs and economic withholding. The data on the markup index directly measures only the markup of the marginal units. Additional information is required in order to draw a conclusion about the relationship between observed prices and competitive prices.

Calculation of the price-cost markup using the marginal unit could overstate the markup index when there is significant variation among unit marginal costs and when the rank order of units by price offer differs from the rank order of units by cost offer. For example, there may be a unit on the price-based supply curve with a price offer lower than the price offer of the marginal unit, but with a marginal cost greater than that of the marginal unit. This could result from various bidding strategies, for example. The marginal unit would be different when evaluated on the basis of cost than when evaluated on price. In this example, the observed price would represent a larger markup over the marginal cost of the marginal unit than over the marginal cost of the highest marginal cost unit operating. In other words, the unit specific markup of the marginal unit method could be greater than the markup over the competitive price defined as the marginal cost of the highest marginal cost unit operating.

As a check of the impact of the shape of the cost-based supply curve on the marginal unit method, data on the costs and markups for inframarginal units were examined for the period from June to December 2000. The markup index calculated using the highest marginal cost for an operating unit is systematically lower than the marginal unit markup index shown in Figure 2 (averaging 30% of the marginal unit markup index). Thus, the data indicate that, holding all other factors constant, the marginal unit method overestimates the system markup over the competitive price for the period under review because the marginal unit had, on average, lower marginal costs than did other operating units.

In addition, the marginal unit method is based on the marginal production cost of the marginal operating unit and does not include the marginal cost of the next most expensive unit, the appropriate scarcity rent, if any, or the opportunity cost as a component of cost. Thus, if the marginal unit is a combustion turbine (CT) with a price offer equal to $500/MWh and a corresponding cost of $130/MWh, the observed price-cost markup index would be .74 ((500-130)/500). However, if the unit has the ability to export power and the real-time price in an external control area is $500/MWh, then the appropriately calculated markup would actually be zero.

The marginal unit method does not capture economic withholding. For example, there may be a unit with a price offer higher than the marginal unit that is therefore not operating, but with a marginal cost below that of the marginal unit. This would be a unit economically withheld from the market. In this case, the observed price would represent a smaller markup over the marginal cost of the actual marginal unit (from the price-based supply curve) than over the marginal cost of the marginal unit from the cost-based supply curve. In other words, the unit specific markup of the marginal unit method could be less than the markup over the competitive price, when economic withholding is accounted for.

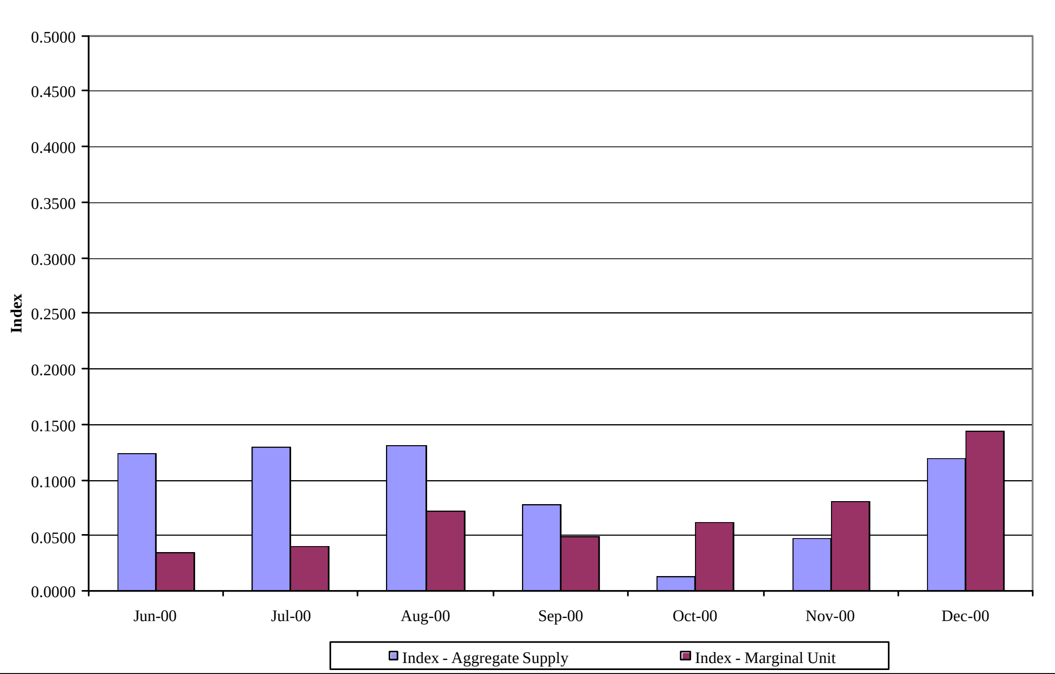
As another approach to the price-cost markup, a markup index was calculated using an aggregate supply curve method for the period from June to December 2000. In the aggregate supply curve method, the markup is calculated by comparing the price from the aggregate price-based supply curve to the cost from the aggregate cost-based supply curve for the level of output defined by the system price for each hourly interval. The aggregate supply curves are constructed from all offers. As with the marginal unit method, there is no necessary correspondence between the units representing each level of output on the price-based supply curve and on the cost-based supply curve.

The aggregate supply curve method does capture economic withholding. The markup is calculated by comparing the price of the marginal unit based on price to the cost of the marginal unit based on cost, where the units may be different. Since all offered units are included in the aggregate cost-based supply curve, units with relatively low costs will affect the calculated markup index even if they were offered in at a price greater than the price of the marginal unit.

While the aggregate supply curve method resolves the potential differences in marginal units based on price and cost, it has significant drawbacks as a measure of the actual markup. The aggregate supply curve method reflects the result of a perfect dispatch in which there are no operating constraints. The aggregate supply curve method does not reflect the real operating constraints associated with units, the related scheduling of units based on their price offers and operating constraints, or outages which occur during the operating day. The impact of these factors on the results of the aggregate supply curve method depends on the relationship between offer price and cost for the units which are included in the markup calculation but which were not actually dispatched due to operational constraints or outages. If the markup for such an individual unit is greater than the markup would have been based on actual dispatch, the aggregate supply curve method overstates the actual markup. The reverse is also true.

The aggregate supply curve method produces results that differ from the marginal unit method. (Figure 8.) The average markup using the aggregate supply curve method is about .12 from June to September versus about .05 for the marginal unit method, while the average markup using the supply curve method is about .06 from October to December versus about .10 for the marginal unit method. Over the seven-month period, the average markup using the supply curve method was .07 while the average markup using the marginal unit method was .09.

Figure 8: Monthly Mark Up Index - Aggregate Supply versus Marginal Unit Method



In summary, the marginal unit method will overstate the markup when inframarginal units have higher marginal costs than the marginal unit. The marginal unit method will also tend to overstate the markup when opportunity costs are significant or in situations of scarcity. The marginal unit method calculated using the highest marginal cost of an operating unit probably provides a minimum measure of the markup, here .02 for the six months from June to December 2000, although it does not account for opportunity costs or scarcity rents. Conversely, the marginal unit method will understate the markup when there is economic withholding.

The aggregate supply curve method may overstate or understate the markup as the result of not accounting for operating constraints and unit outages that occur during the operating day.

Overall, the index results presented here are consistent with the conclusion that the energy market was reasonably competitive in 2000, although the evidence is not dispositive. The analysis of markup by unit type suggests an issue with the bidding behavior by owners of steam units in late 2000. The MMU will continue to develop this analysis to refine the measure of the markup over competitive prices and to incorporate explicit accounting for opportunity costs, scarcity rents and economic withholding where appropriate.

Market Structure

Concentration ratios are used to measure the concentration of ownership in markets, a key element of market structure. As indicated in the State of the Market Report 1999, concentration measures must be used carefully in assessing the competitiveness of markets. The best tests for assessing the competitiveness of markets are direct tests of the conduct and performance of individual participants within markets and their impact on market prices. The price-cost markup test in this section is one such test and direct examination of the offer behavior of individual market participants is another. Low aggregate market concentration ratios do not establish that a market is competitive or that market participants cannot exercise market power. However, high market concentration ratios do indicate an increased potential for market participants to exercise market power. Concentration ratios are presented here because they provide useful information on market structure and are a widely used measure of market structure.

The analysis indicates that the PJM Control Area exhibits moderate market concentration. However, specific areas of the PJM system exhibit moderate to high market concentration that may be problematic when transmission constraints exist. There is no evidence that market power was exercised in these areas in 2000, primarily due to the load obligations of the generators in those areas, but a significant market-power related risk exists going forward should those load obligations change.

Method

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated as the sum of the squares of the market shares of the firms in a market. Hourly energy market HHIs were calculated based on the real-time energy output of generators located in the PJM control area, adjusted for imports. The annual HHIs were calculated based on the installed capacity of PJM generating resources, adjusted for imports. The ability of the transmission system to deliver external energy into the control area was incorporated in the HHI calculations as additional energy can be imported into PJM under most conditions. The maximum hourly HHI was calculated by assigning all actual positive net tie flows to the market participant with the largest market share, while the minimum hourly HHI was determined by assigning net tie flows to five non-affiliated market participants. The maximum annual HHI was calculated by assigning all import capability to the market participant with the largest market share, while the minimum annual HHI was determined by assigning import capability to five non-affiliated market participants. For both hourly and annual HHIs, generators were aggregated by ownership and, in the case of affiliated companies, parent organization.

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

FERC's Merger Policy Statement states that a market can be broadly characterized as unconcentrated when the market HHI is below 1000, as moderately concentrated when the market HHI is between 1000 and 1800 and highly concentrated when the market HHI is greater than 1800.[6]

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[6] 77 FERC ¶ 61,263, Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, pages 64-70.

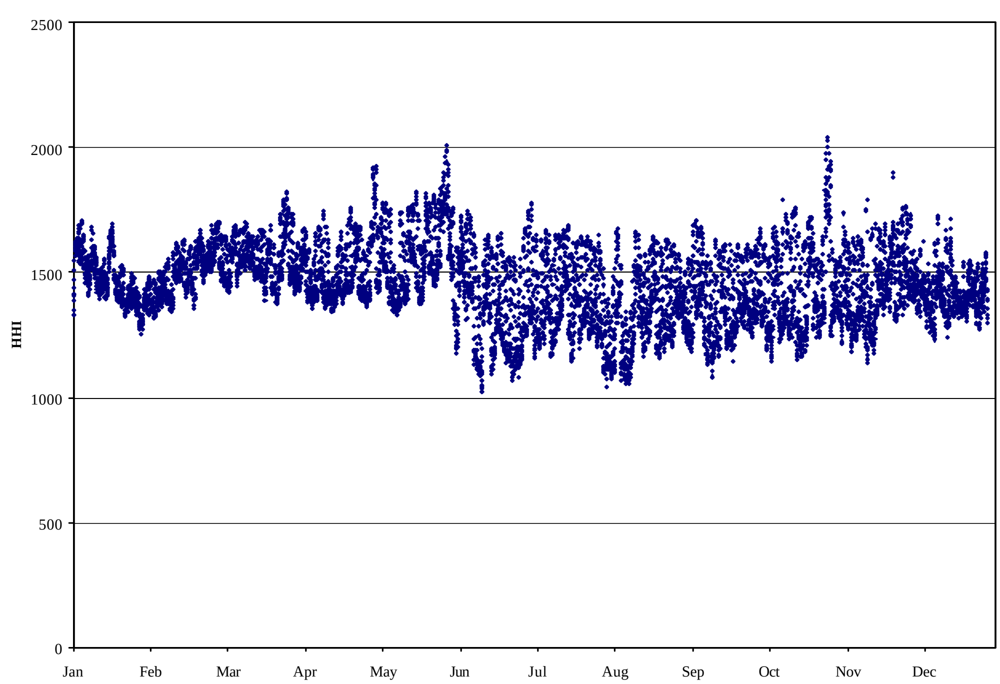
Results

The results of the aggregate PJM HHI calculations for both the annual and the hourly measure indicate that the PJM energy market is, in general, moderately concentrated. (Table 2.) [7]

Table 2: PJM HHIs in 2000		
	Hourly	Annual
Maximum	2067	1390
Average	1544	1270
Minimum	1022	1150

Figure 9 depicts the HHI results for the hourly energy market with net tie flows assigned to five non-affiliated market participants (consistent with the minimum calculation).

Figure 9: 2000 Hourly Energy Market HHI



High Market Concentration and Frequent Congestion Areas

There are four areas within PJM that have high market concentration and experience frequent transmission congestion: Northern Public Service, Northcentral Public Service, Southern Delmarva subareas, and the Eastern PJM Region. [8]

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7 The maximum hourly energy market HHI of 2067 is based on the assumption that all imported energy represented by net tie flows is controlled by the market participant with the largest market share. While this is an important sensitivity, there is no evidence that this has actually occurred.

8 The frequency of occurrence is based on an analysis of historical transmission constraints occurring during 2000.

Northern Public Service was significantly constrained during 2000, with the Roseland-Cedar Grove 230 F line restricting power transfers during 11% of on-peak hours and 5% of all hours. This constraint effectively isolates 3,200 - 4,600 MW of load, depending on load levels, raising spot prices for the customers located in this area. Market concentration in the area is high, with a minimum HHI of 4800. The dominant generation owner, PSEG, remains an integrated utility with load responsibility, substantially mitigating the effects of the high market concentration.

Northcentral Public Service, another area of the PSEG service territory, exhibits relatively high concentration and experienced congestion during 10% of hours in 2000. The Trenton-Plainsboro and Brunswick-Edison-Meadow Road 138 circuits restricted power transfers during 10% of on-peak hours and 5% of all hours. This constraint isolates some 350-550 MW of load, depending on load levels, raising spot energy prices for the customers located in this area. Market concentration varies from a minimum of 2200 through a mid-range of 6060 to a maximum of over 9000. Again PSEG, the dominant generation owner, remains an integrated utility, mitigating the effects of the market concentration.

The Southern Delmarva area exhibits high concentration and experiences significant congestion. HHI varies from a minimum of 2370 through a mid-range of 5065 to a maximum of 7750. The DPL South Interface was constrained over 5% of on-peak hours, raising energy prices for energy consumers located below the Chesapeake and Delaware Canal, approximately 1,200-1,750 MW. Other transmission constraints also occurred on the Peninsula, mostly at the lowest bulk operating voltage of 69 kV, isolating smaller pockets of load. Conectiv is currently upgrading portions of the transmission system on the Delmarva Peninsula. While the reinforcements will improve the reliability of the area it is still likely that the area will experience significant congestion.

The Eastern Region was significantly constrained during 2000, with the Eastern Interface restricting power transfers during 6% of on-peak hours and 3% of all hours. This constraint effectively isolates Eastern PJM from Central, Southwestern, and Western PJM, raising the spot price of energy for the 19-27,000 MW of load located on the eastern side of the interface. Market concentration was moderate to high with minimum, average, and maximum HHIs of 1695, 2270, and 2845. About 60% of new generation projects in the PJM queues are located in the Eastern Region of PJM. These additions should decrease concentration and should also reduce the frequency of congestion in some areas.

High Market Concentration and Moderate Congestion

There are two areas that have high market concentration and experience a moderate amount of transmission congestion: the PECO and the DPL subareas. Market concentration in the PECO area varies from a minimum HHI of 4380 through a mid-range of 7065 to a maximum of 9750, while the HHI in the DPL area ranges from a minimum of 2500 through a mid-range of 4500 to a maximum of 6480.

PJM Energy Market Prices

The result of market structure and the conduct of individual market entities within that structure are 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 remainder of this section discusses PJM energy market prices. Tables are presented in the body of the text while Figures 10-19 are presented at the end. The Appendix provides methodological background and additional, more detailed, price data and comparisons.

Prices in the PJM Real-Time Spot Market

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

The simple average system-wide LMP was approximately the same in 1999 and 2000, \$28.32/MWh versus \$28.14/MWh, and about 30% higher in both years than in 1998. (Table 3.) The load-weighted LMP of \$30.72/MWh in 2000 was 10% lower than in 1999 and 27% higher than in 1998. (Table 5.) When increased fuel costs and hourly loads are accounted for, the average load-weighted LMP in 2000 was more than 27% lower than in 1999, \$24.78/MWh compared to \$34.06/MWh. (Table 6.)

Figure 10 shows the PJM system-wide price duration curves for 1998, 1999 and 2000. A price duration curve represents the percent of hours that LMP was at or below a given price for the year. Figure 10 shows that there was relatively little difference in LMPs for 60% of the hours in each of the three years, and for more than 90% of the hours in 1998 and 1999. Figure 11 shows the price duration curves for hours above the 95th percentile in greater resolution. Figure 11 shows that prices greater than \$150/MWh occurred in each year for 1% or less of the hours.

In 1998 and 1999, the highest prices occurred during the hot, summer months, with LMPs approaching \$1,000/MWh in each year. Although LMPs in 2000 were approximately \$20/MWh higher than in 1998 and in 1999 for about 20% of the hours, LMPs in 2000 did not reach the levels obtained in the previous two years, and did not exhibit the same volatility. The summer of 2000 was much milder relative to the two previous summers, and consequently there were very few price excursions in 2000. Indeed, the highest price in 2000 occurred in December (\$802/MWh), while the next highest prices occurred during an early heat spell in May.

Table 3 provides summary statistics for the relationship among LMPs for the three years. The annual statistics were calculated from the hourly-integrated PJM system-wide LMPs (and MCPs for January – March 1998).[1] The annual averages, for example, are the simple averages of the hourly LMPs. Average system-wide LMP was approximately the same in 1999 and 2000, $28.32/MWh versus $28.14/MWh, and about 30% higher in both years than in 1998. The median LMP shows about the same percentage increase year to year. Notably, the standard deviation of average LMP in 2000 is 65% lower than in 1999 and 18% lower than in 1998. The price dispersion in 1999 and 1998 was much larger than in 2000 due to the hotter summers in those two years.

Table 3: PJM Average Hourly LMP ($/MWh)			
	1998	**1999**	**2000**
Average LMP	21.72	28.32	28.14
Median LMP	16.60	17.88	19.11
Standard Deviation	31.45	72.41	25.69
	% Increase 98 to 99	**% Increase 99 to 00**	**% Increase 98 to 00**
Average LMP	30.4	-0.6	29.6
Median LMP	7.7	6.98	15.1
Standard Deviation	130.2	-64.5	-18.3

PJM Load – 1998, 1999, and 2000

Figure 12 shows the load duration curve for the years 1998, 1999, and 2000. Figure 12 indicates that load in 2000 was higher than load in 1999 for 90% of the hours, while load in 1999 reached overall higher load levels due to the hot summer of that year. Indeed, PJM's all-time peak load of 51,700 MW was established during July of 1999. Load in 2000 was also above that in 1998 during 96% of the hours.

Table 4 presents the summary load statistics for the three years. The average load of 30,113 MW in 2000 was 5.4% higher than in 1998 and 1.6% higher than in 1999, while load in 1999 was 3.7% higher than in 1998. The median load in 2000 was also 5.3% higher than in 1998, and 2.8% higher than in 1999. The variability in load, indicated by the standard deviation, was approximately the same in 2000 and 1998, but 7 – 8% higher in 1999 than the other two years.[2]

Table 4: PJM Load (MW)			
	1998	**1999**	**2000**
Average Load	28,577	29,640	30,113
Median Load	28,653	29,341	30,170
Standard Deviation	5,512	5,956	5,529
	% Increase 98 to 99	**% Increase 99 to 00**	**% Increase 98 to 00**
Average Load	3.7	1.6	5.4
Median Load	2.4	2.8	5.3
Standard Deviation	8.1	-7.2	0.3

[1] MCP is the single market clearing price calculated by PJM prior to implementation of LMP.
[2] See Appendix for more details on load frequency including on-peak and off-peak loads.

Load-Weighted Average LMP – 1998, 1999, and 2000

Hourly LMPs were weighted by the total MW in each hour and then averaged to derive the load-weighted average LMP. Load-weighted LMPs reflect the average LMP paid for actual MWh generated and consumed.

Table 5 shows that the load-weighted LMP of $30.72/MWh in 2000 was 27% higher than in 1998, but 10% lower than in 1999. The median load-weighted LMP in 2000 is 8% higher than in 1999 and 17% higher than in 1998. The standard deviation of the load-weighted average LMP in 2000 is lower than both of the two previous years, again reflecting the relatively mild summer of 2000 compared to the hot summers in 1998 and 1999. Comparing the average load-weighted LMPs in Table 5 with the average hourly LMPs presented in Table 3, it may be noted that in 2000 the load-weighted average LMP is 9% higher than the hourly average LMP, in 1999 it is 20% higher, and in 1998 it is 11% higher.[3]

Table 5: PJM Load-Weighted Average LMP ($/MWh)

	1998	1999	2000
Average LMP	24.16	34.06	30.72
Median LMP	17.60	19.02	20.51
Standard Deviation	39.29	91.49	28.38
	% Increase 98 to 99	**% Increase 99 to 00**	**% Increase 98 to 00**
Average LMP	41.0	-9.8	27.2
Median LMP	8.1	7.8	16.5
Standard Deviation	132.9	-69.0	-27.8

Fuel Cost Adjusted LMPs – 1999 and 2000

To control for differences between 1999 and 2000 average load-weighted LMPs caused by differences in fuel costs between the two years, the year 2000 load-weighted LMPs were adjusted to reflect fuel costs. The weighting procedure took account both of the change in prices of the fuels used to generate electricity in each month of each year, and of the change in MW in each month from the fuel used to fire the marginal generating unit which set LMP.[4]

Table 6 compares 2000 load-weighted, fuel cost adjusted average LMPs to 1999 load-weighted average LMPs. The table shows that after adjusting for fuel price changes between the two years, average load-weighted LMP in 2000 is more than 27% lower than in 1999, $24.78/MWh compared to $34.06/MWh. There is also more than an 11% decrease in the median LMP between the two years, and the dispersion in LMPs is significantly lower in 2000 than in 1999.

Table 6: 1999 Load-Weighted and 2000 Load-Weighted, Fuel Cost Adjusted LMPs ($/MWh)

	1999	2000	% Increase
Average LMP	34.06	24.78	-27.25
Median LMP	19.02	16.80	-11.67
Standard Deviation	91.49	22..04	-75.91

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[3] See Appendix for details on peak and off-peak load-weighted LMPs.

[4] See Appendix for fuel cost adjustment method.

The fuel cost-adjusted results are largely attributable to changes in petroleum and natural gas fuel costs and to the percent of time these fuels were the marginal fuel. On average, petroleum prices were 67% higher in 2000 than in 1999, while petroleum products were the marginal fuel on average 15% more in 2000 than in 1999. Similarly, in 2000 natural gas prices were on average 59% higher than in 1999, while natural gas was the marginal fuel on average 16% more in 2000 than in 1999.

In contrasting Tables 5 and 6, adjusting LMPs by load lowers the 2000 average LMP by 9.8% (36% of the total decrease of 27.25% shown in Table 6) relative to 1999 average LMP. Further adjusting for fuel price and marginal fuel share differences lowers the 2000 average LMP by an additional 17% (64% of the total decrease). Thus, although load in 2000 was on average higher than in 1999, more of that load paid a lower average price in 2000 than in 1999. Likewise, if fuel prices and marginal fuel shares had been the same in 2000 as in 1999, the 2000 average LMP would have been $25.10/MWh.[5]

Day-Ahead and Real-Time Market LMPs

The day-ahead market was initiated on June 1, 2000. The comparisons that follow cover the period June to December 2000. It would be expected that competition would cause the prices in the day-ahead and real-time markets to tend to converge. On average, day-ahead prices were consistently greater than real-time prices during the first seven months of the day-ahead market. As illustrated by Figure 16, there was no significant change in the difference during this period. This stable difference is consistent with a relatively stable risk premium in the day-ahead market and suggests that market forces have kept the two markets aligned from the inception of the day-ahead market.

Figure 13 shows the price duration curve for the two markets, while Figure 14 shows the price duration curve for hours above the 95th percentile. It can be seen in Figures 13 and 14 that prices closely mimic each other in the two markets. Real-time prices are slightly lower than day-ahead prices for the lowest priced 89% of the hours and are somewhat higher for the next 10% of the hours. In the highest priced 1% or less of the hours, real-time prices are much higher than day-ahead prices, reflecting the volatility of real-time operations which was not anticipated in the day-ahead market. Figure 15 shows how the average hourly day-ahead and real-time LMPs have tracked over the period, and Figure 16 shows the difference between real-time hourly LMP and day-ahead hourly LMP (real-time LMP minus day-ahead LMP).[6]

Table 7 presents the summary statistics for the two markets. The average LMP in the day-ahead market was $1.61/MWh or 5.3% higher than the average LMP in the real-time market. The median LMPs in the two markets show a more pronounced difference, with the day-ahead median LMP 21.3% larger than the real-time LMP, an average difference of $4.29/MWh. Consistent with the price duration curve, price dispersion in the real-time market is 18.5% higher than the day-ahead market, with the average difference in standard deviation between the two markets of $4.83/MWh.[7] [8]

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5 See Appendix for details on LMPs during constrained hours.

6 See Appendix for more details on the frequency distribution of prices.

7 See Appendix for more details on peak and off-peak LMPs.

Table 7: Comparison of Day-Ahead and Real-Time Market LMPs ($/MWh)				
	Day-Ahead	Real-Time	Average Difference	% Over Real-Time
Average LMP	31.97	30.36	-1.61	5.3
Median LMP	24.44	20.15	-4.29	21.3
Standard Deviation	21.33	26.16	4.83	-18.5

Day-Ahead and Real-Time Market Generation and Load

Day-Ahead and Real-Time Generation

There are three types of "generation" in the day-ahead market – self-scheduled generation, generator offers, and increment offers (Incs). Self-scheduled generation can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum. Generator offers are schedules of MW offered and the corresponding offer price. Finally, Incs are financial offers of generation in the day-ahead market that permit market participants to hedge their positions. An Inc is an offer to supply a specified amount of MW at, or above, a given price. In all cases, commitments made in the day-ahead market are financially binding. Real-time generation is the actual production of electricity during the operating day.

Figure 17 shows the average hourly values of day-ahead generation, day-ahead generation plus Inc offers, and real-time generation. Real-time generation is always higher than day-ahead generation. However, when Incs are added to day-ahead generation, total day-ahead MW offers always exceed real-time generation.

Table 8 presents the summary statistics for day-ahead and real-time generation and the average differences between the two. The table shows that real-time generation averaged 3,261 MW higher than day-ahead generation, while the median amount of MW generated in the real-time market was 3,390 MW higher. However, when Inc offers are added to day-ahead generation offers, the sum in the day-ahead market is 2,909 MW higher than real-time generation.

Table 8: Day-Ahead and Real-Time Generation (MW)					
	Day-Ahead		Real-Time	Average Difference	
	Generation	Inc Offers	Generation	Generation	DA Generation Plus Incs
Average MW	26,771	6,169	30,031	3,261	2,909
Median MW	26,360	6,112	29,750	3,390	2,701
Standard Deviation	5,159	2,251	5,312		

As can be seen in Figure 17, the differences among the three types of generation widen during the peak hours (hours ending 8 to 23). Table 9 shows the average MW values in the day-ahead and real-time markets during the off-peak and peak hours, while Table 10 shows the average

[8] See Appendix for more details on LMPs during constrained hours.

differences during the two periods. Real-Time generation exceeds day-ahead generation during both periods. The average difference between real-time and day-ahead generation during off-peak hours is 2,975 MW, and the average difference during peak hours is 3,594 MW. When Inc offers are added to day-ahead generation, day-ahead generation exceeds real-time generation during both periods. During off-peak hours day-ahead generation averaged 1,417 MW more than real-time generation, and during peak hours day-ahead generation averaged 4,653 MW more than real-time generation.

Table 9: Day-Ahead and Real-Time Peak and Off-Peak Generation (MW)

	Day-Ahead				Real-Time	
	Off-Peak Generation	**Peak Generation**	**Off-Peak Inc Offers**	**Peak Inc Offers**	**Off-Peak Generation**	**Peak Generation**
Average MW	24,026	29,979	4,392	8,247	27,002	33,573
Median MW	23,669	29,835	4,044	8,199	26,401	33,267
Standard Deviation	4,150	4,301	1,158	1,189	4,218	4,139

Table 10: Average Differences Between Day-Ahead and Real-Time Markets (MW)

	Off-Peak		Peak	
	Generation	**Generation Plus Incs**	**Generation**	**Generation Plus Incs**
Average MW Difference	2,975	1,417	3,594	4,653
Median MW Difference	2,966	1,148	3,663	4,652

Day-Ahead and Real-Time Load

There are three types of load in the day-ahead market. Fixed demand bids represent load that will purchase a defined MW level of energy, regardless of the level of LMP. Price sensitive bids represent load that will purchase a defined MW level of energy only up to a specified LMP; above that LMP, the load bid is zero. Decremental bids (Decs) are similar to price sensitive bids in that they represent load that will purchase a defined MW level of energy only up to a specified LMP and are zero above that LMP. However, Decs are financial instruments that can be submitted by any market participant, regardless of whether they serve load or own generation. As with day-ahead generation offers, all load bids that are cleared in the day-ahead market are financially binding. Real-time load, of course, is the actual load on the system during the operating day.

Figure 18 shows the average hourly values of day-ahead fixed demand, price sensitive load, Decs, and total day-ahead and real-time load (total day-ahead load is defined here as the sum of the three demand components). Table 11 presents the summary statistics for the day-ahead load components, total day-ahead load, real-time load, and the average difference between total day-ahead load and total real-time load. As Figure 18 and Table 11 show, day-ahead load is higher than real-time load by an average of 2,182 MW. The table also shows that fixed demand is the largest component of day-ahead load, 78%, while price sensitive is the smallest component, 8%, with Decs accounting for the remaining 14% of day-ahead load.

Table 11: Day-Ahead and Real-Time Load (MW)						
	Day-Ahead				**Real-Time**	
	Fixed Demand	**Price Sensitive**	**Decs**	**Total DA Load**	**Total RT Load**	**Average Difference**
Average MW	25,894	2,557	4,594	33,045	30,863	2,182
Median MW	25,742	2,658	4,717	33,217	30,754	2,463
Standard Deviation	5,251	924	1,833	6,850	5,822	

As can be seen in Figure 18, the day-ahead load components (except for price sensitive demand, which stays relatively constant over all hours) increase during the peak hours (hours ending 8 to 23), as does real-time load. Table 12 shows the average load MW values in the day-ahead and real-time markets during the off-peak and peak hours. Day-Ahead total load was higher than real

Table 12: Day-Ahead and Real-Time Load During Off-Peak and Peak Hours (MW)										
	Day-Ahead								**Real-Time**	
	Off-Peak				**Peak**				**Off-Peak**	**Peak**
	Fixed Demand	**Price Sensitive**	**Decs**	**Total Load**	**Fixed Demand**	**Price Sensitive**	**Decs**	**Total Load**	**Total Load**	**Total Load**
Average MW	22,705	2,402	3,318	28,425	29,622	2,737	6,087	38,446	27,475	34,824
Median MW	22,250	2,544	2,979	28,232	29,164	2,817	6,037	38,056	26,913	34,097
Standard Deviation	4,049	871	1,246	4,798	3,854	952	1,158	4,554	4,636	4,394

time load during both off-peak and peak hours. The average difference during off-peak hours was 950 MW, while the average difference during peak hours was 3,622 MW. The percentage of day-ahead load comprised by each of the components is similar during the two periods. Fixed demand accounts for the largest percentage of day-ahead load during the off-peak and peak periods, 80% and 77%, respectively, with price sensitive load accounting for the smallest percentage during both periods, 8% and 7%, respectively, and Decs accounting for 12% and 16%, respectively.

Figure 19 shows day-ahead and real-time load and generation on the same graph. Notice, however, that Incs have been subtracted from what was previously called total day-ahead load (fixed + price sensitive + decs). Since Incs look like generation, subtracting them from day-ahead load shows the amount of day-ahead generation that must be turned on to meet the remaining load. Using this definition of day-ahead load, it can be seen that day-ahead load and generation are always less than real-time load and generation.

Another notable difference between the two markets is the lack of transactions in the day-ahead market. In the real-time market, during peak hours load averaged 1,251 MW more than generation. During the same period in the day-ahead market, transactions averaged only 220 MW. A final observation is that there is a relatively constant difference between real-time load and day-ahead load excluding Decs; that is, day-ahead load as fixed plus price sensitive load. During off-peak hours the difference between real-time load and fixed plus price sensitive load averages 2,368 MW, while during peak hours the average difference is 2,465 MW.

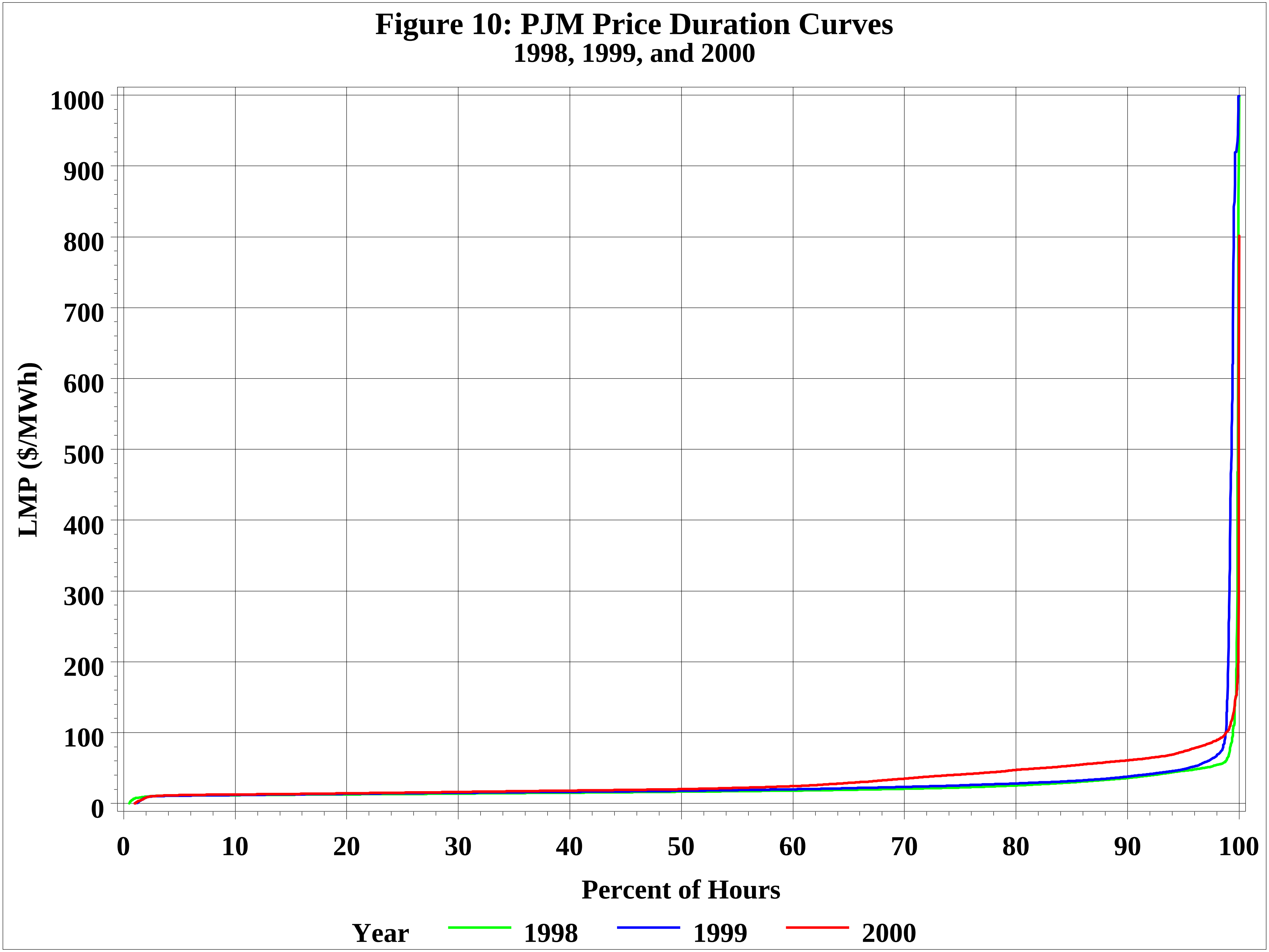


Figure 10: PJM Price Duration Curves
1998, 1999, and 2000
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
80
90
100
Percent of Hours
Year
1998
1999
2000

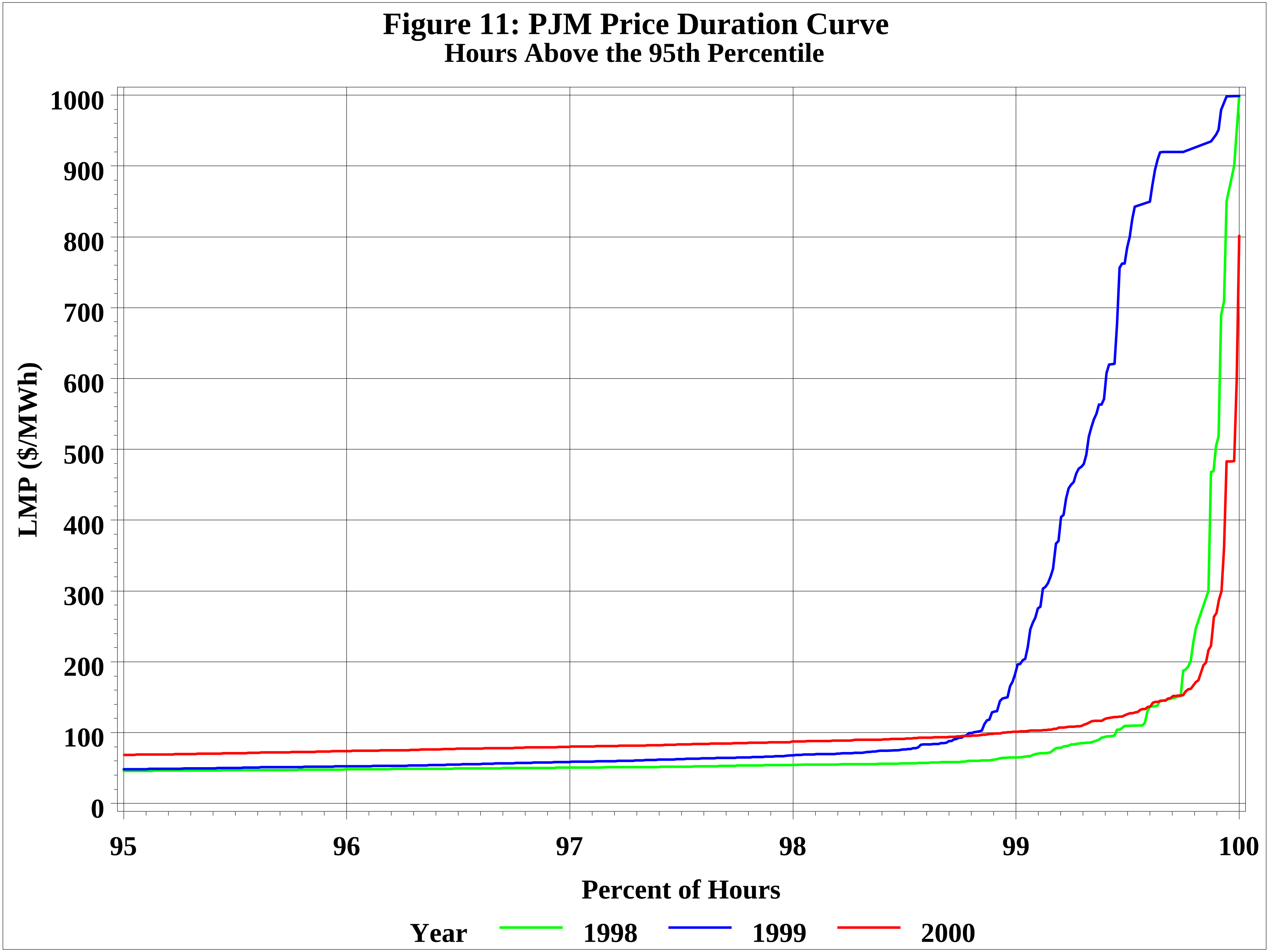


Figure 11: PJM Price Duration Curve
Hours Above the 95th Percentile
LMP ($/MWh)
1000
900
800
700
600
500
400
300
200
100
0
95
96
97
98
99
100
Percent of Hours
Year
1998
1999
2000

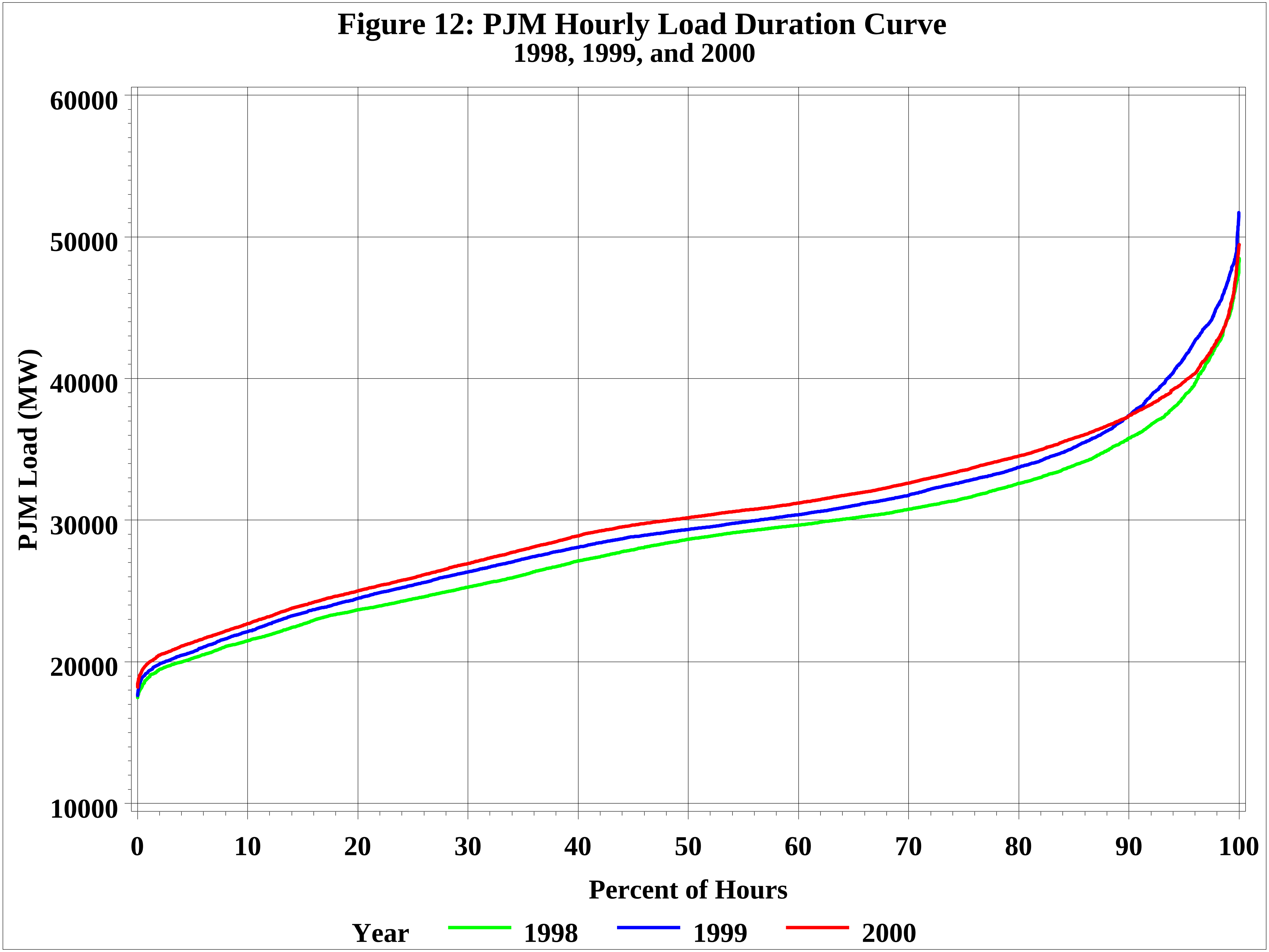
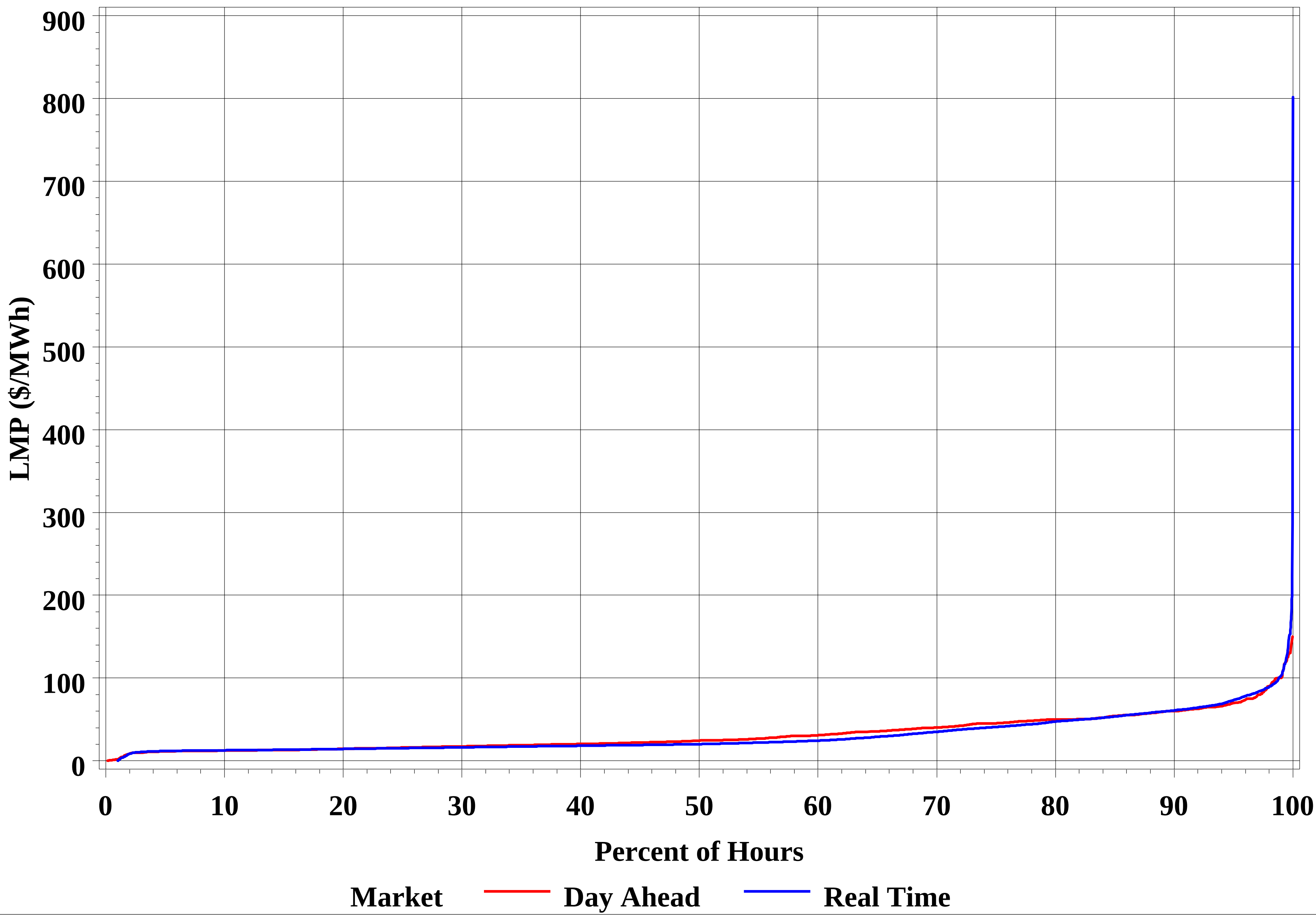


Figure 12: PJM Hourly Load Duration Curve
1998, 1999, and 2000
PJM Load (MW)
60000
50000
40000
30000
20000
10000
0
10
20
30
40
50
60
70
80
90
100
Percent of Hours
Year
1998
1999
2000

Figure 13: PJM Price Duration Curve
Real Time and Day Ahead Markets



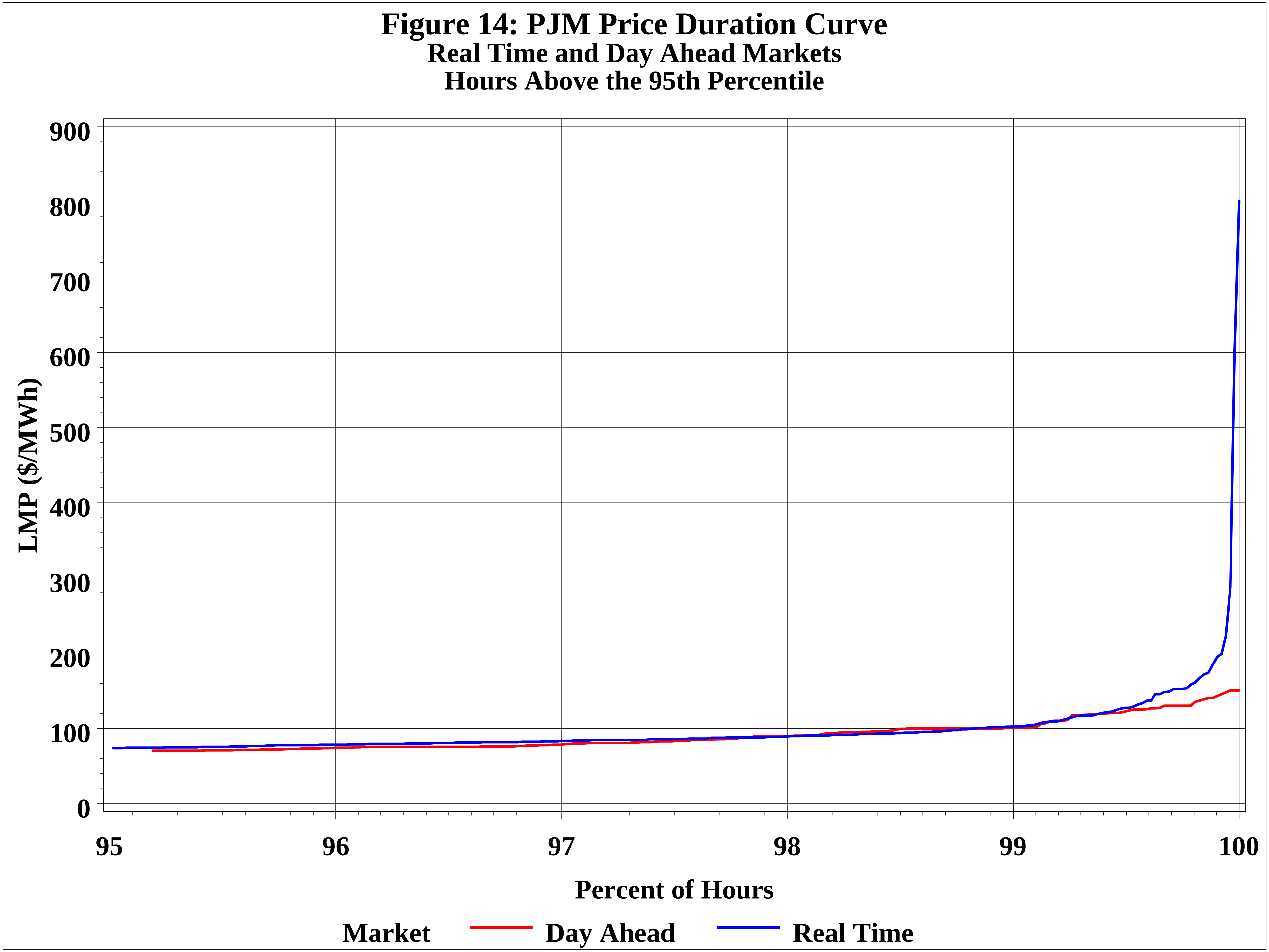


Figure 14: PJM Price Duration Curve
Real Time and Day Ahead Markets
Hours Above the 95th Percentile
LMP ($/MWh)
0
100
200
300
400
500
600
700
800
900
95
96
97
98
99
100
Percent of Hours
Market
Day Ahead
Real Time

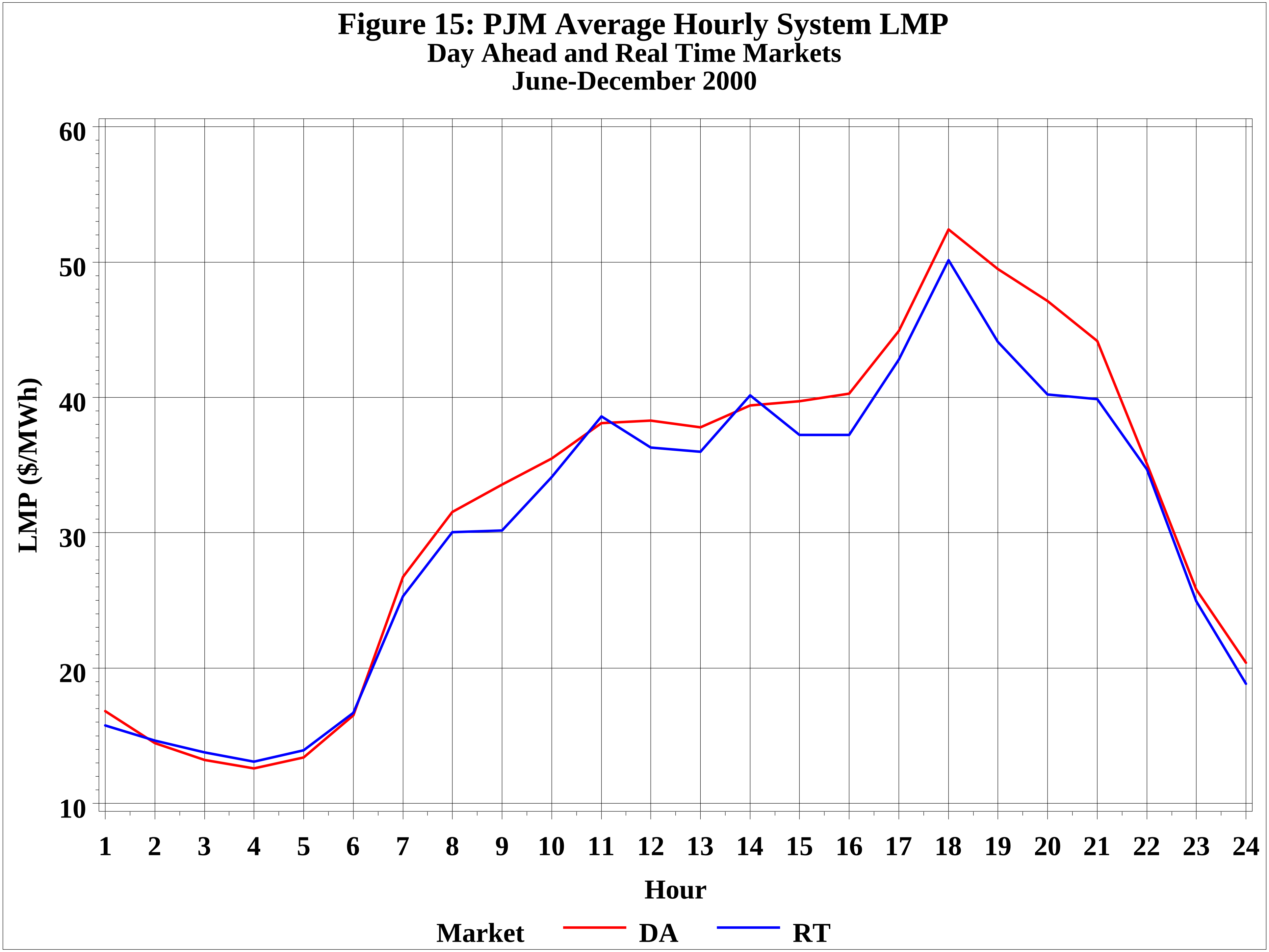


Figure 15: PJM Average Hourly System LMP
Day Ahead and Real Time Markets
June-December 2000
LMP ($/MWh)
10
20
30
40
50
60
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Market
DA
RT

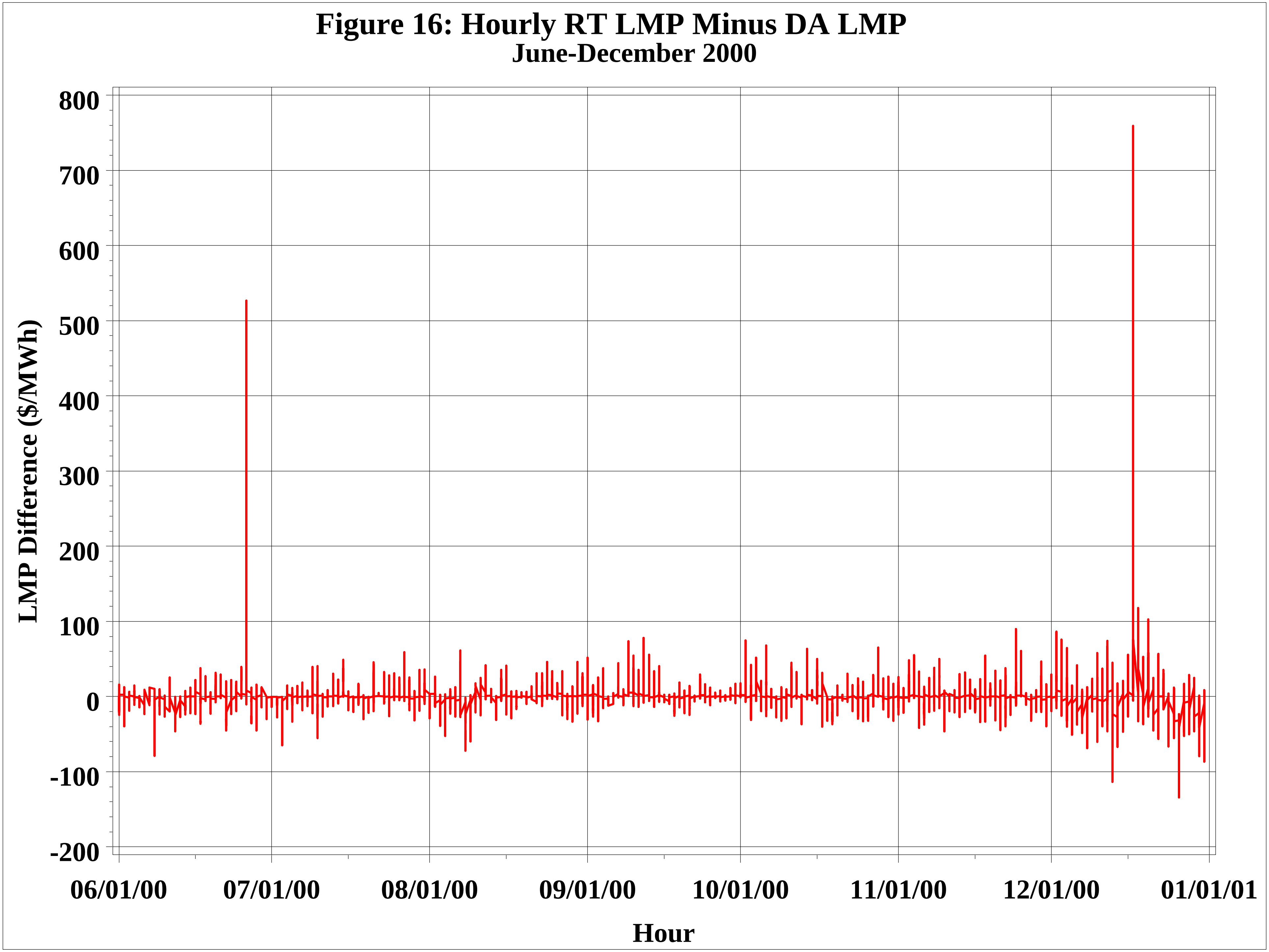


Figure 16: Hourly RT LMP Minus DA LMP
June-December 2000
LMP Difference ($/MWh)
800
700
600
500
400
300
200
100
0
-100
-200
06/01/00
07/01/00
08/01/00
09/01/00
10/01/00
11/01/00
12/01/00
01/01/01
Hour

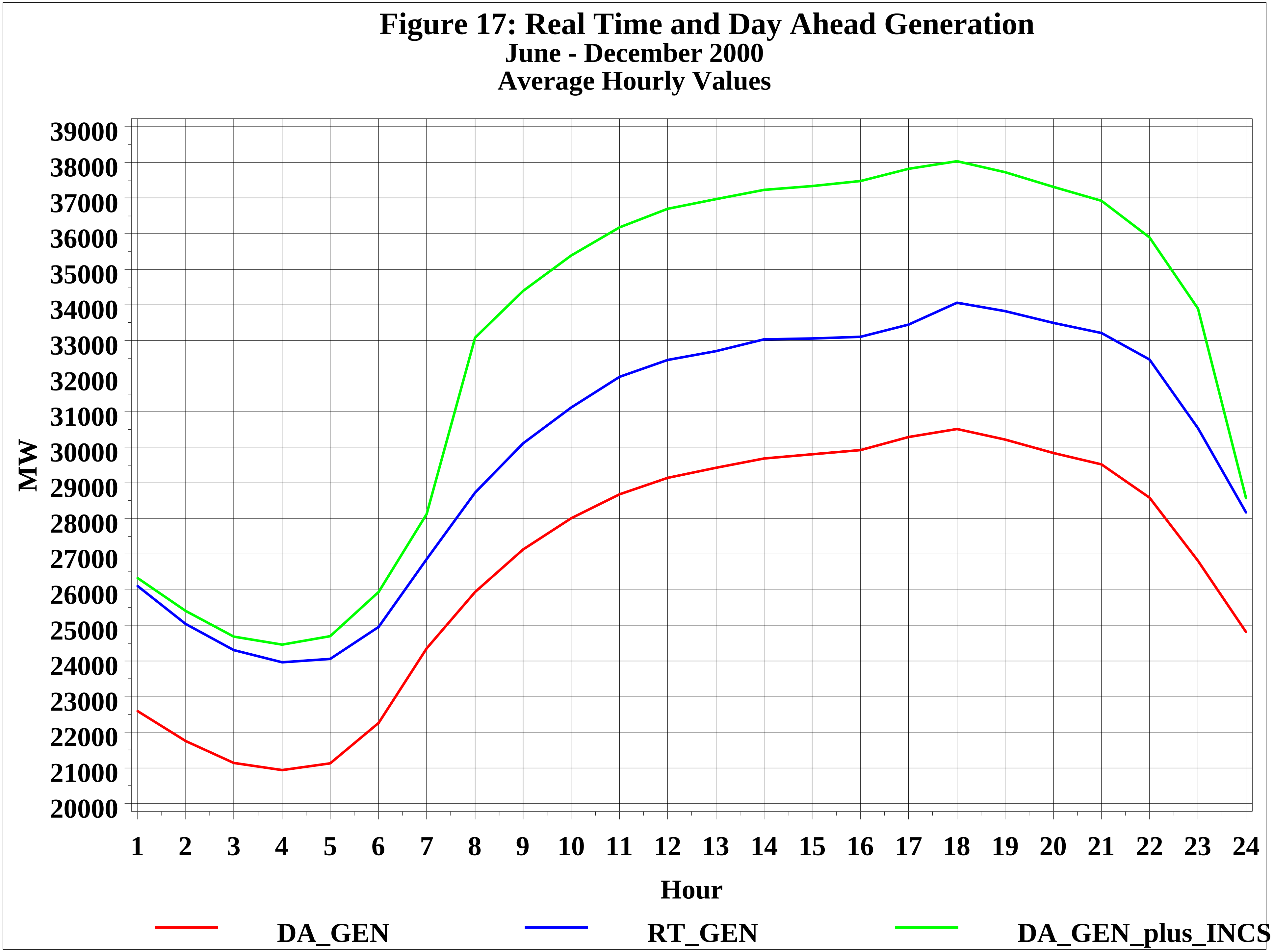


Figure 17: Real Time and Day Ahead Generation
June - December 2000
Average Hourly Values
MW
39000
38000
37000
36000
35000
34000
33000
32000
31000
30000
29000
28000
27000
26000
25000
24000
23000
22000
21000
20000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
DA_GEN
RT_GEN
DA_GEN_plus_INCS

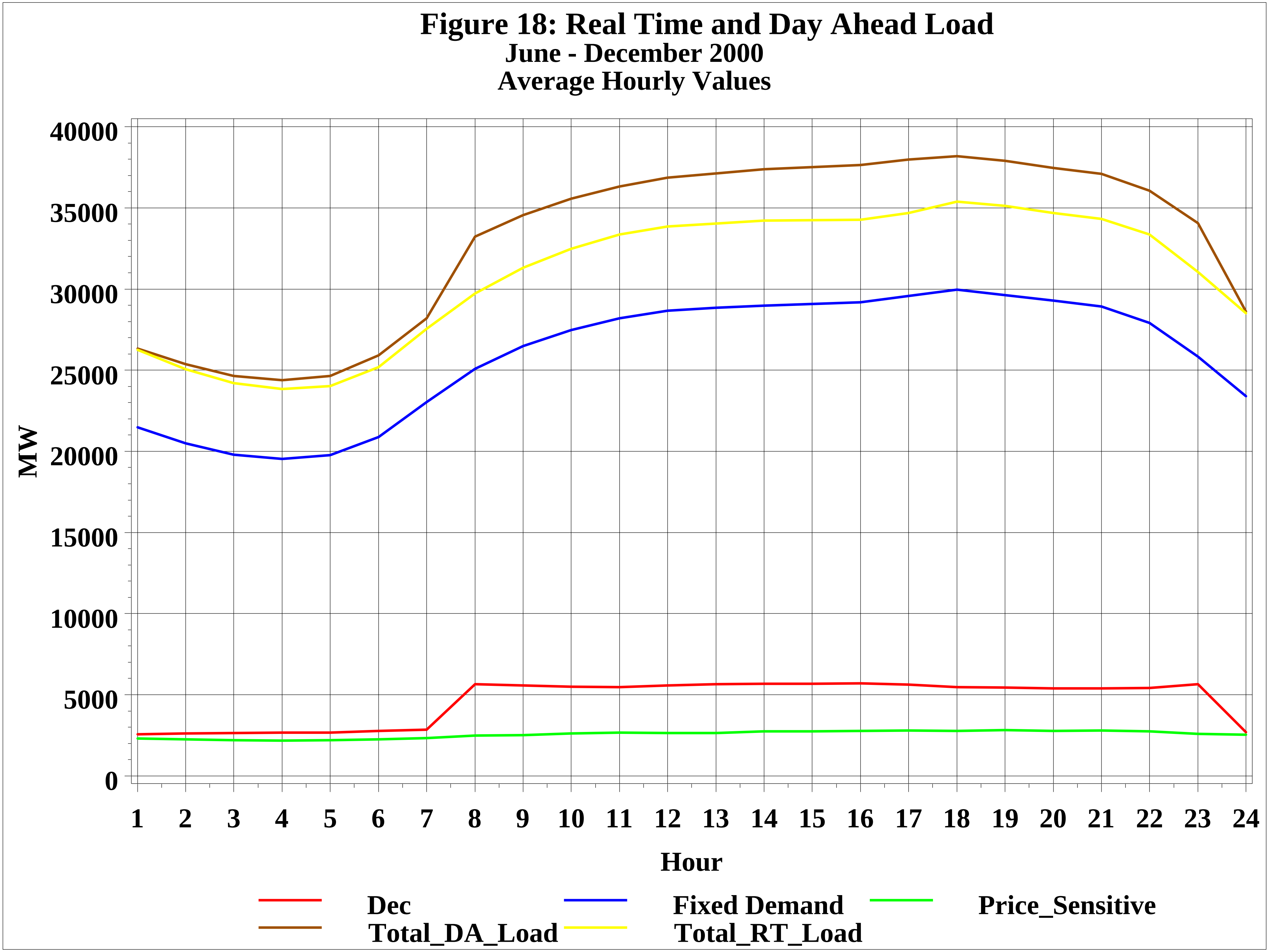


Figure 18: Real Time and Day Ahead Load
June - December 2000
Average Hourly Values
MW
40000
35000
30000
25000
20000
15000
10000
5000
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour
Dec
Fixed Demand
Price_Sensitive
Total_DA_Load
Total_RT_Load

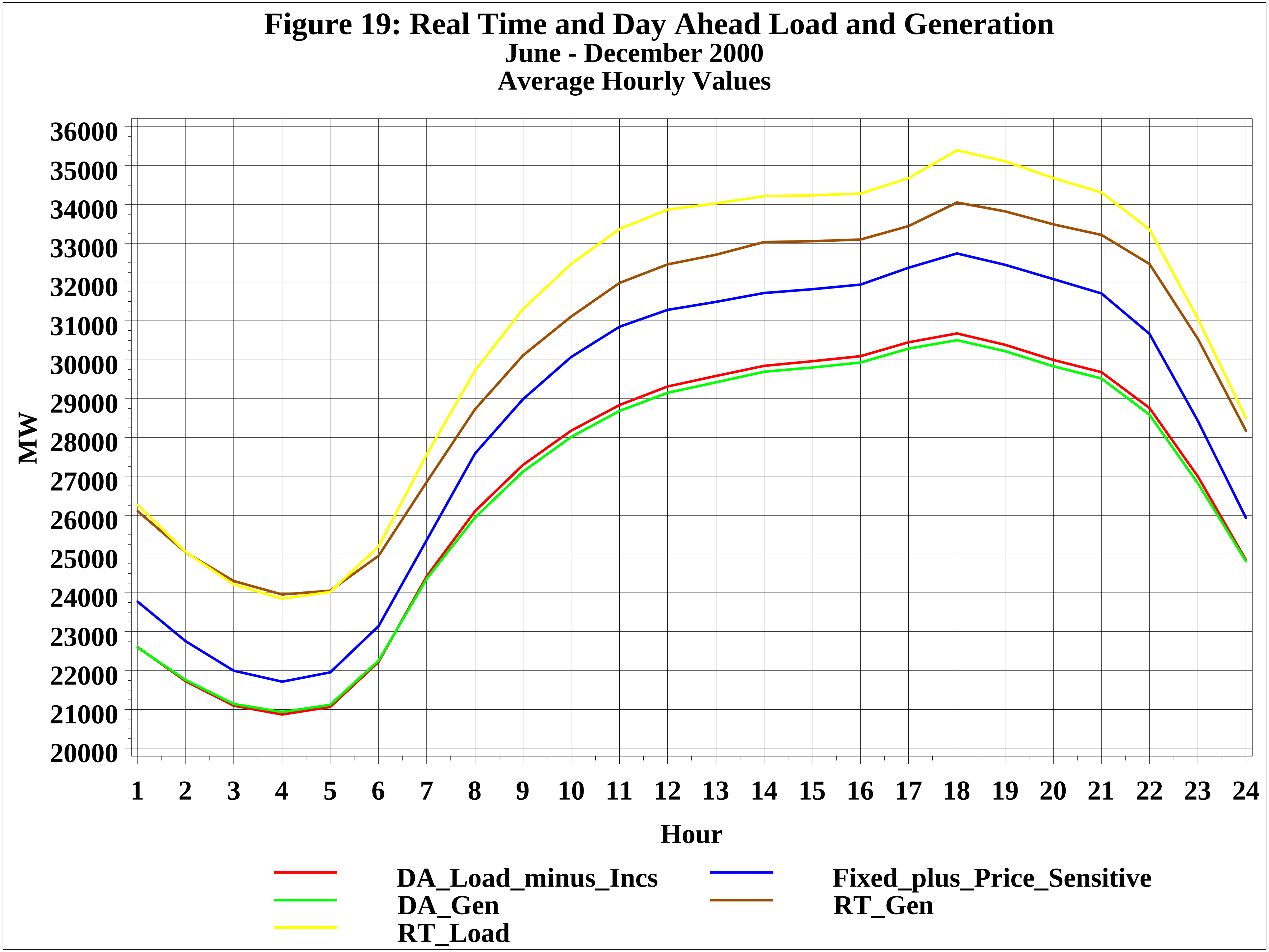


Figure 19: Real Time and Day Ahead Load and Generation
June - December 2000
Average Hourly Values
MW
36000
35000
34000
33000
32000
31000
30000
29000
28000
27000
26000
25000
24000
23000
22000
21000
20000
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
DA_Load_minus_Incs
DA_Gen
RT_Load
Fixed_plus_Price_Sensitive
RT_Gen

Appendix

Frequency Distribution of LMP

Figures A.1, A.2, and A.3 provide the frequency distribution by hours of LMPs for the three years.[9] 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.[10]

Comparing the figures, it can be seen that LMPs most frequently occurred in the interval $10/MWh to $20/MWh in each year. 65% of the hours were in this interval in 1998, 58% in 1999, and 51% in 2000. In 1998, 1999, and 2000, prices were less than $30/MWh 85%, 83%, and 71% of the hours, respectively. LMPs were less than $60/MWh 99%, 97%, and 92% of the hours, respectively, and less than $100/MWh 99.4%, 98.8%, and 98.9% of the hours, respectively. LMP was $150/MWh or greater for 27 hours (0.3% of the hours) in 2000, 95 hours (1% of the hours) in 1999, and 29 hours (0.3% of the hours) in 1998.

Frequency Distribution of Load

A comparison of Figures A.4, A.5, and A.6 shows that in 1998 and 1999 load was most frequently in the range of 25,000 to 30,000 MW, 35% and 34% of the hours, respectively, and that load was less than 30,000 MW 63% of the hours in 1998 and 56% of the hours in 1999. By contrast, load was most frequently in the range of 30,000 to 35,000 MW in 2000, 34% of the hours, and was less than 30,000 MW for 48% of the hours. Load was less than 45,000 MW for 99% of the hours in both 1998 and 2000, and never exceeded 50,000 MW. Again reflecting the hot summer of 1999, in 1999 load was less than 45,000 MW for 98% of the hours, but exceeded 50,000 MW for 15 hours.

On-Peak and Off-Peak Load

Table A.1 presents the summary load statistics for 1998 to 2000 for the off-peak and peak hours, while Table A.2 shows the percentage changes in load year to year. The peak period is defined for each weekday (Monday through Friday) as hour ending 0800 to hour ending 2300, excluding holidays. As can be seen from the table, in all three years peak load is about 30% higher than the off-peak load, while the median peak load ranges from 20% to 30% higher. Average load during peak hours in 2000 is about 1.4% higher than that in 1999, and 4.4% higher than in 1998. Similarly, off-peak load in 2000 is 1.9% higher than that in 1999, and 6.5% higher than in 1998.

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[9] LMPs were instituted in PJM in April, 1998. Prior to April, there was a single system price, the Market Clearing Price (MCP), which was the system lambda.

[10] Only LMP intervals with a positive frequency are included in the figure.

Table A.1: Off-Peak and Peak Load – 1998, 1999, and 2000 (MW)									
	1998			1999			2000		
	Off-Peak	Peak	Peak/ Off-Peak	Off-Peak	Peak	Peak/ Off-Peak	Off-Peak	Peak	Peak/ Off-Peak
Average Load	25,268	32,344	1.3	26,409	33,291	1.3	26,921	33,766	1.3
Median Load	24,728	31,081	1.3	25,795	31,987	1.2	26,327	32,771	1.2
Standard Deviation	4,091	4,388	1.1	4,862	4,870	1.0	4,453	4,226	0.9

Table A.2: Percent Change in Load – 1998, 1999, and 2000						
	Off-Peak			Peak		
	98 – 99	98 – 00	99 – 00	98 – 99	98 – 00	99 - 00
Average Load	4.5	6.5	1.9	2.9	4.4	1.4
Median Load	4.3	6.5	2.1	2.9	5.4	2.5

Peak and Off-Peak Load-Weighted LMPs – 1999 and 2000[11]

Table A.3 shows the load-weighted average LMPs for 1999 and 2000 during the off-peak and peak periods. The peak period is defined for each weekday (Monday through Friday) as hour ending 0800 to hour ending 2300, excluding holidays. As the table shows, in 2000 the peak LMP was 80% of the off-peak LMP, while in 1999 it was 140% of the off-peak LMP. The peak load-weighted average LMP in 2000 is 15% lower than in 2000, while the off-peak LMP in 2000 is 15% higher than in 1999. Both the peak and off-peak median LMPs are higher in 2000 than in 1999, 30% and 5%, respectively. The dispersion in LMPs, as indicated by the standard deviation, is much higher in 1999 during peak hours, 272% that of 2000, while off-peak LMPs show more dispersion in 2000, 23% of that in 1999.

[11] For the remainder of this chapter, only LMPs in 1999 and 2000 will be compared since these are the only years for which a full annual series of LMPs is available.

Table A.3: Off-Peak and Peak Load-weighted LMPs – 1999 and 2000 ($/MWh)								
	1999			2000			% Change 1999 to 2000	
	Off-Peak	Peak	Peak/Off-Peak	Off-Peak	Peak	Peak/Off-Peak	Off-Peak	Peak
Average Lmp	19.16	45.46	2.4	21.94	38.74	1.8	14.5	-14.8
Median LMP	15.70	23.30	1.5	16.47	30.40	1.9	4.9	30.5
Standard Deviation	16.83	118.53	7.0	20.69	31.86	1.5	22.9	-73.1

Contrasting Tables 5 and A.3, the average load-weighted LMP during peak hours in 2000 was 26% higher than the overall load-weighted average for the year, while the off-peak load-weighted average LMP was 29% lower. Similarly, in 1999 the average load-weighted LMP during peak hours was 33% higher than the overall load-weighted average for that year, while the off-peak load-weighted average LMP was 44% lower.

Fuel Cost Adjustment

For coal, petroleum, and natural gas, fuel costs for 1999 and January through November of 2000 (the last month for which fuel costs are available) were obtained from FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*.[12] However, the quality of the Form 423 data has deteriorated over time as non-regulated generators are not required to report on Form 423. The months for which there is underreporting can be determined from Form 423 by observing the drop in the reported quantities of fuel consumed from typical levels for that month. For coal, underreporting began in July 2000, for petroleum in August 2000, and for natural gas in October 2000.

To address this issue for petroleum and natural gas (and to obtain estimates for December), the average basis differential was calculated for the months preceding the decline in reporting. The basis differential for petroleum was calculated as the difference between *Platts Oilgram* New York Harbor Spot Cargo and Barge prices and the Form 423 reported petroleum prices. The basis differential for natural gas was calculated as the difference between the near-month NYMEX futures price and the reported Form 423 reported natural gas prices. The average difference was calculated for each series and then added to the subsequent months oil spot or NYMEX futures prices.

Monthly uranium prices for 1999 and 2000 were obtained from the Ux Consulting Company, LLC and the Uranium Exchange Company.[13] The price series are the historical Ux month-end uranium spot prices posted on their web site.

[12] The states included in the aggregation from Form 423 are Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia – essentially the PJM territory.
[13] Source: The Ux Consulting Company, LLC (www.uxc.com).

The Form 423 coal prices were used as reported. The coal price for December was calculated as the average of the three previous month's prices.

The price index for each fuel was calculated as a chain-weighted index, where the weights are the number of MW generated in each month of 1999 and 2000 while the specified fuel fired the marginal generating unit. First, an index was calculated using 1999 fuel-specific MW as the weights: Year 2000 fuel-specific prices times Year 1999 fuel-specific MW divided by Year 1999 fuel-specific prices times Year 1999 fuel-specific MW. Second, an index was calculated using 2000 fuel-specific MW as the weights: Year 2000 fuel-specific prices times Year 2000 fuel-specific MW divided by Year 1999 fuel-specific prices times Year 2000 fuel-specific MW. The two indices were then chain-weighted by calculating their geometric mean. Each year 2000 monthly hourly LMP was then divided by the chain-weighted price index for the month to derive the fuel cost adjusted LMP, which was then weighted by load to derive the load adjusted, fuel cost adjusted LMP.

LMPs During Constrained Hours – 1999 and 2000[14]

Figure A.7 shows the number and average number of constrained hours during each month in 1999 and 2000. There were 1,671 constrained hours in 1999 and 3,853 constrained hours in 2000 – an increase of 131%. Figure A.7 also shows that the number of constrained hours in each month was always higher in 2000 than in 1999.

Table A.4 presents the summary statistics for the load-weighted average LMP during constrained hours in 1999 and 2000. As can be seen from the table, the average LMP was virtually identical in both years, the median LMP was slightly lower in 2000, and the dispersion of LMPs about the average, as shown by the standard deviation, was much lower in 2000.

Table A.4: 1999 and 2000 Load-Weighted Average LMPs During Constrained Hours ($/MWh)

	1999	2000	% Increase
Average LMP	35.85	35.35	-1.4
Median LMP	27.06	26.15	-3.4
Standard Deviation	59.87	29.98	-49.9

Table A.5 provides a comparison of load-weighted average LMPs during constrained and unconstrained hours for the two years. In 2000, average load-weighted LMP during constrained hours was 33% higher than average load-weighted LMP during unconstrained hours, while the median LMP during constrained hours was 47% higher. The comparable numbers for 1999 are 8% and 53%, respectively. Contrasting Table A.5 with Table 5, the load-weighted average LMP in 2000 during constrained hours was 15% higher than the load-weighted average for all hours, and average LMP during unconstrained hours was 13% lower. The comparable numbers for 1999 are 5% and –1%, respectively.

[14] 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.

Table A.5: Load-Weighted LMPs During Constrained and Unconstrained Hours ($/MWh)						
	1999			2000		
	Unconstrained Hours	Constrained Hours	% Increase	Unconstrained Hours	Constrained Hours	% Increase
Average LMP	33.57	35.85	6.8	26.59	35.35	32.9
Median LMP	17.72	27.06	52.7	17.84	26.15	46.6
Standard Deviation	98.40	59.87	-39.2	26.19	29.98	14.5

Day-Ahead and Real-Time Prices

As noted earlier, day-ahead and real-time prices track closely. This pattern of price distribution can be seen more clearly in Figures A.8 and A.9. The figures show the frequency distribution by hours for the two markets. It can be seen that the most frequently occurring price interval in both markets is $10/MWh to $20/MWh. In the real-time market this interval accounts for 47% of the hours, and prices are less than $20/MWh in 49% of the hours. However, in the day-ahead market, this interval accounts for only 36% of the hours, and prices are less than $20/MWh for only 39% of the hours. Prices are less than $30/MWh for 66% of the hours in the real-time market, 56% in the day-ahead; less than $40/MWh for 74% in the real-time market, 70% in the day-ahead market. At less than $50/MWh the real-time and day-ahead markets have about the same cumulative percent - 82% and 81%, respectively. Above $50/MWh, the cumulative percents in the two markets move together – less than $100/MWh for 99% of the hours; less than $150/MWh for 99.7% and 99.9% percent of the hours; and less than $160/MWh, the highest price interval in the day-ahead market, for 99.8% and 100% of the hours. It is only in the last 0.2% of the hours in the real-time market (11 hours) that prices range from $160/MWh to slightly over $800/MWh.

Figure A.10 shows how the daily average day-ahead and real-time LMPs have tracked over the June – December 2000 period.

Peak and Off-Peak LMPs

Table A.6 shows the average LMPs during the off-peak and peak periods for the day-ahead and real-time markets. Day-Ahead and real-time peak average LMPs were about twice as high as the off-peak average LMPs. The day-ahead peak average LMP was also 9% higher than the real-time peak average LMP. The median LMPs during the peak hours were more than twice the off-peak median LMPs for both the day-ahead and real-time markets. The day-ahead median LMP was also 21% higher than the real-time median LMP. Since the mean lies above the median in both markets, both markets show a positive skewness. However, the mean is proportionately higher than the median in the real-time market than in the day-ahead market, during both peak and off-peak periods (17% and 34% compared to 5% and 27%, respectively) reflecting the larger positive skewness in this market. Although average LMPs are lower or about the same during peak and off-peak hours in the real-time market as compared to the day-ahead market, the dispersion of prices in the real-time market is larger than in the day-ahead market. During peak hours, the standard deviation in the real-time market is about 26% higher than in the day-ahead market, while it is 48% higher during the off-peak hours.

Figures 18 and 19 show the difference between real-time and day-ahead LMPs over the period during the peak and off peak hours, respectively. The average difference in LMP during the peak hours was -$3.59/MWh (day-ahead LMP higher than real-time LMP), while during off-peak hours there was virtually no difference between the two markets on average ($0.09/MWh). The figures show that there was one hour during both the peak and off-peak periods when the real-time price was significantly above the day-ahead price. The figures also

Table A.6: Off-Peak and Peak LMPs ($/MWh)

	Day-Ahead			Real-Time			% Change Day-Ahead to Real-Time	
	Off-Peak	**Peak**	**Peak/Off-Peak**	**Off-Peak**	**Peak**	**Peak/Off-Peak**	**Off-Peak**	**Peak**
Average LMP	21.61	44.09	2.04	21.69	40.50	1.87	0.4	-8.1
Median LMP	17.02	42.06	2.47	16.23	34.75	2.14	-4.6	-17.4
Standard Deviation	14.90	21.33	1.43	22.09	26.90	1.22	48.3	26.1

show that there was more variability in the price differences during the peak hours, and that variability in the price difference increased during both periods in the month of December.

Contrasting Tables 7 and A.6, it may be noted that in the day-ahead market the peak average LMP was 38% higher than the overall average for the day-ahead market, while the off-peak average LMP was 32% lower. Likewise, the real-time average LMP during peak hours was 33% higher than the overall average real-time LMP, while the off-peak average LMP was 29% lower.

LMPs During Constrained Hours – Day-Ahead and Real-Time Markets[15]

Figure A.13 shows the number of constrained hours in each month for the day-ahead and real-time markets and the average number of constrained hours for the period. Overall, there were 2,969 constrained hours in the real-time market and 3,144 constrained hours in the day-ahead market, or 6% greater. Figure A.13 shows that from June through September the number of constrained hours in the real-time market exceeded those in the day-ahead market, while from October to December the situation was reversed.

Table A.7 shows average LMPs during constrained and unconstrained hours in the day-ahead and real-time markets. In the day-ahead market, average LMP during constrained hours was 18% higher than average LMP during unconstrained hours, while the median LMP during constrained hours was 47% higher. In the real-time market, average LMP during constrained hours was 36% higher than average LMP during unconstrained hours, while the median LMP during constrained

[15] 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.

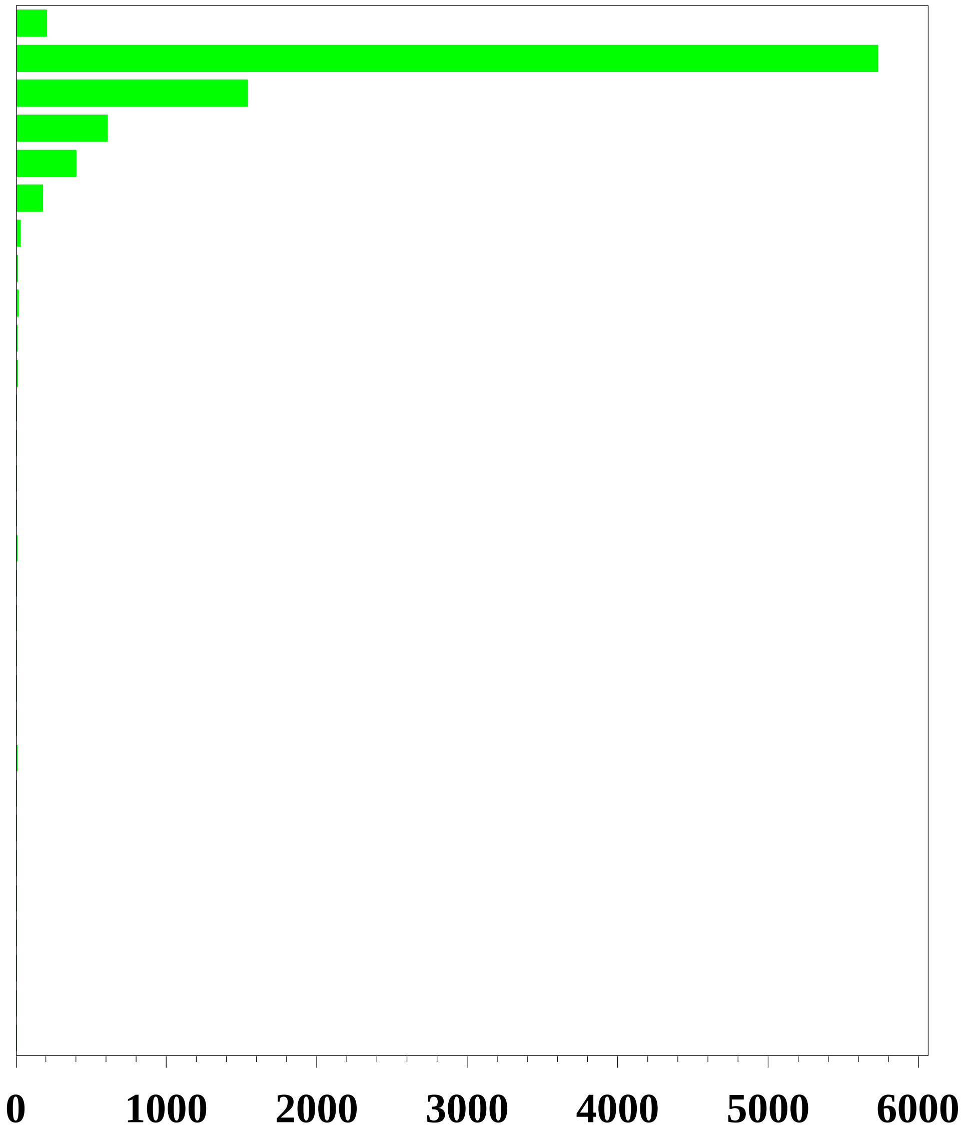
hours was 55% higher. Average LMP during constrained hours was about the same in the day-ahead and real-time markets, while the median LMP was about 8% higher in the day-ahead market. There is more price dispersion in the real-time market during both constrained and unconstrained hours.

Table A.7: LMPs During Constrained and Unconstrained Hours ($/MWh)						
	Day-Ahead			**Real-Time**		
	Unconstrained Hours	**Constrained Hours**	**% Increase**	**Unconstrained Hours**	**Constrained Hours**	**% Increase**
Average LMP	29.12	34.44	18.3	25.68	34.93	36.0
Median LMP	19.33	28.34	46.6	16.96	26.21	54.5
Standard Deviation	22.79	19.64	-13.8	26.78	24.71	-7.7

Contrasting Table A.7 and 7, average LMP in the day-ahead market during constrained hours was about 8% higher than the overall average LMP for the day-ahead market, while average LMP during unconstrained hours was about 9% lower. In the real-time market, average LMP during constrained hours was 15% higher than the overall average LMP for the real-time market, while average LMP during unconstrained hours was 15% lower.

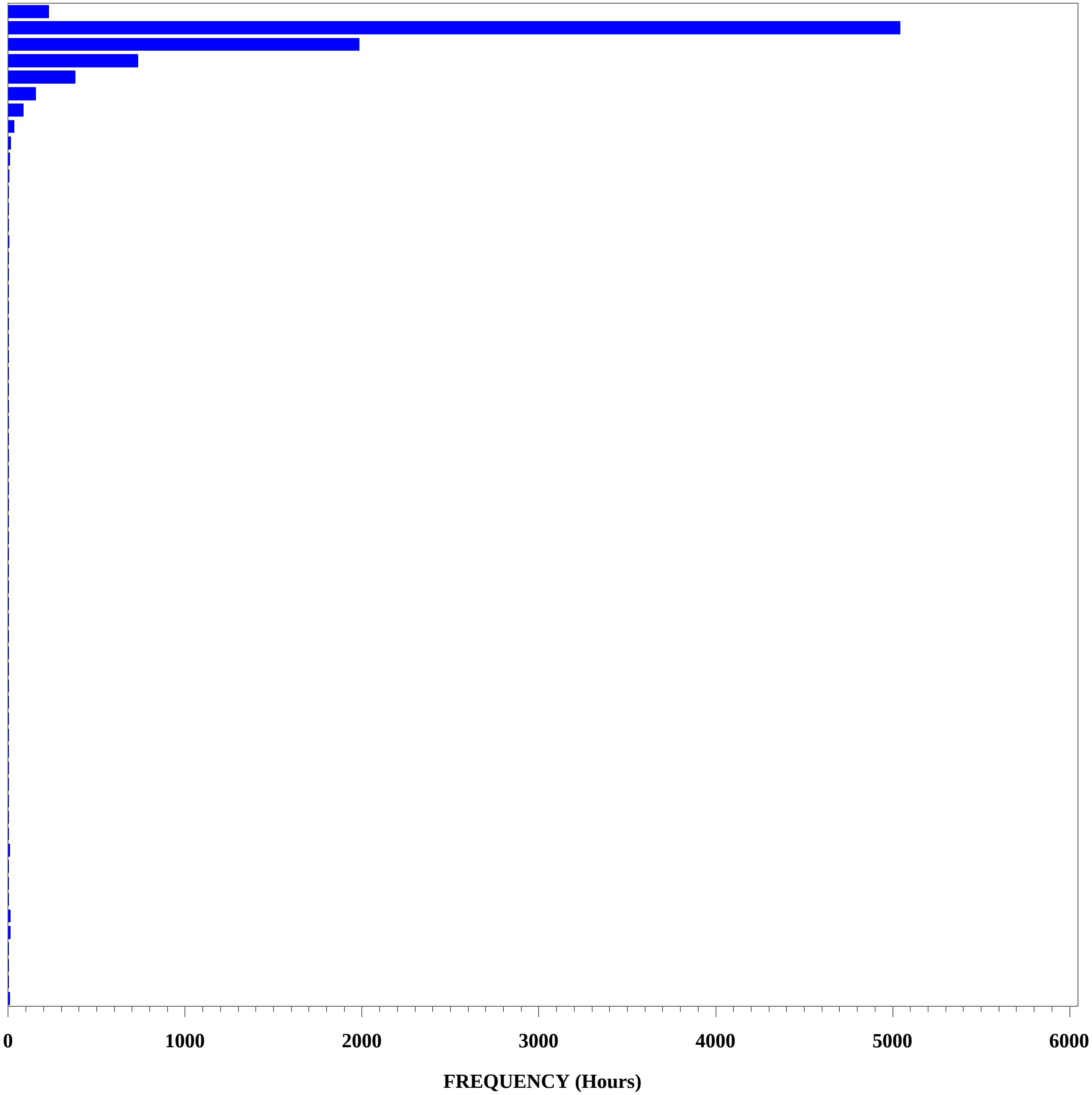
Figure A.1: Frequency Distribution by Hours of PJM LMPs

1998



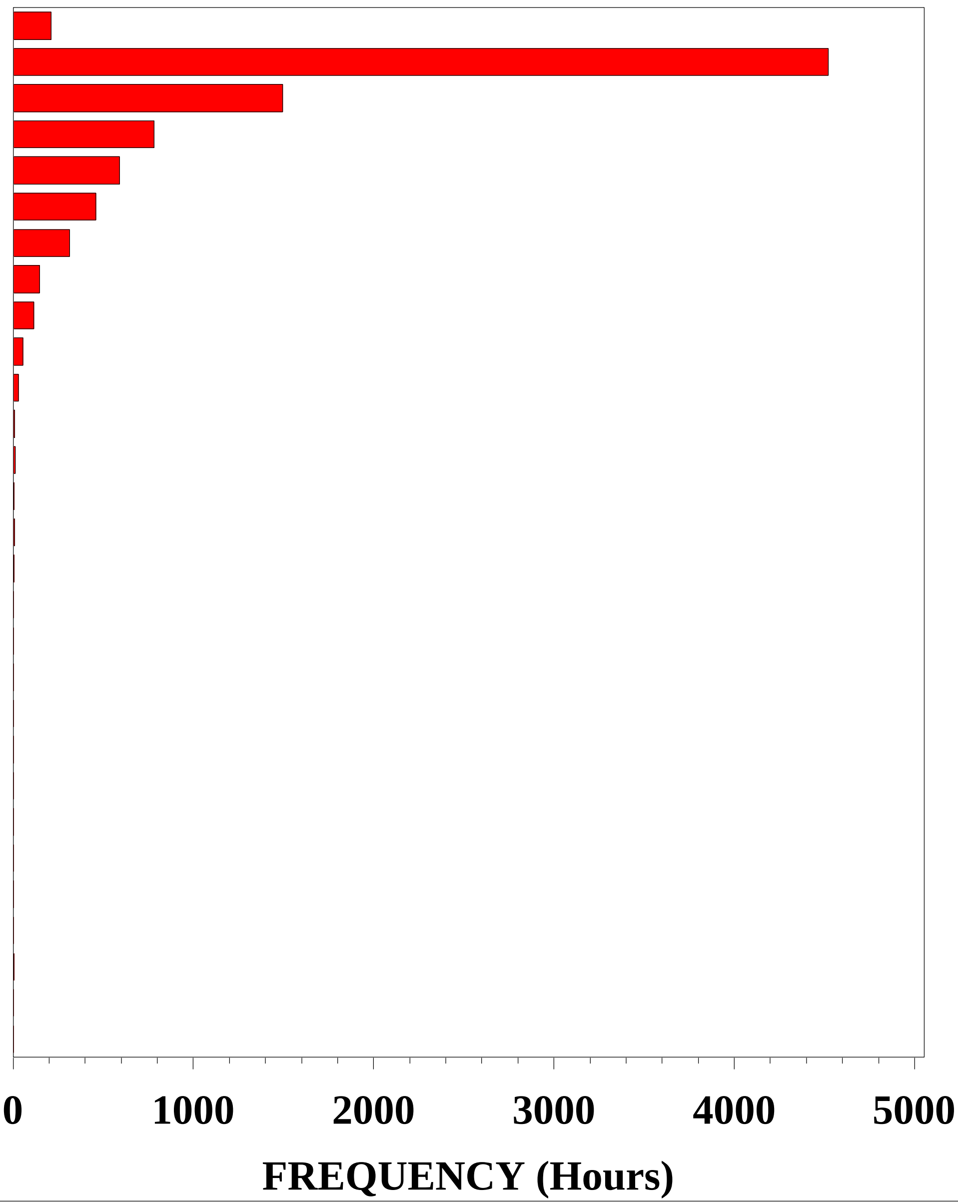
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	204	204	2.33	2.33
$10 to $20	5729	5933	65.40	67.73
$20 to $30	1539	7472	17.57	85.30
$30 to $40	607	8079	6.93	92.23
$40 to $50	396	8475	4.52	96.75
$50 to $60	178	8653	2.03	98.78
$60 to $70	27	8680	0.31	99.09
$70 to $80	10	8690	0.11	99.20
$80 to $90	15	8705	0.17	99.37
$90 to $100	6	8711	0.07	99.44
$100 to $110	11	8722	0.13	99.57
$110 to $120	1	8723	0.01	99.58
$120 to $130	1	8724	0.01	99.59
$130 to $140	4	8728	0.05	99.63
$140 to $150	3	8731	0.03	99.67
$150 to $160	6	8737	0.07	99.74
$180 to $190	2	8739	0.02	99.76
$190 to $200	1	8740	0.01	99.77
$200 to $210	1	8741	0.01	99.78
$220 to $230	1	8742	0.01	99.79
$240 to $250	1	8743	0.01	99.81
$300 to $310	5	8748	0.06	99.86
$460 to $470	2	8750	0.02	99.89
$500 to $510	1	8751	0.01	99.90
$510 to $520	1	8752	0.01	99.91
$680 to $690	1	8753	0.01	99.92
$700 to $710	1	8754	0.01	99.93
$850 to $860	1	8755	0.01	99.94
$890 to $900	3	8758	0.03	99.98
$990 to $1000	2	8760	0.02	100.00

Figure A.2: Frequency Distribution by Hours of PJM LMPs - 1999



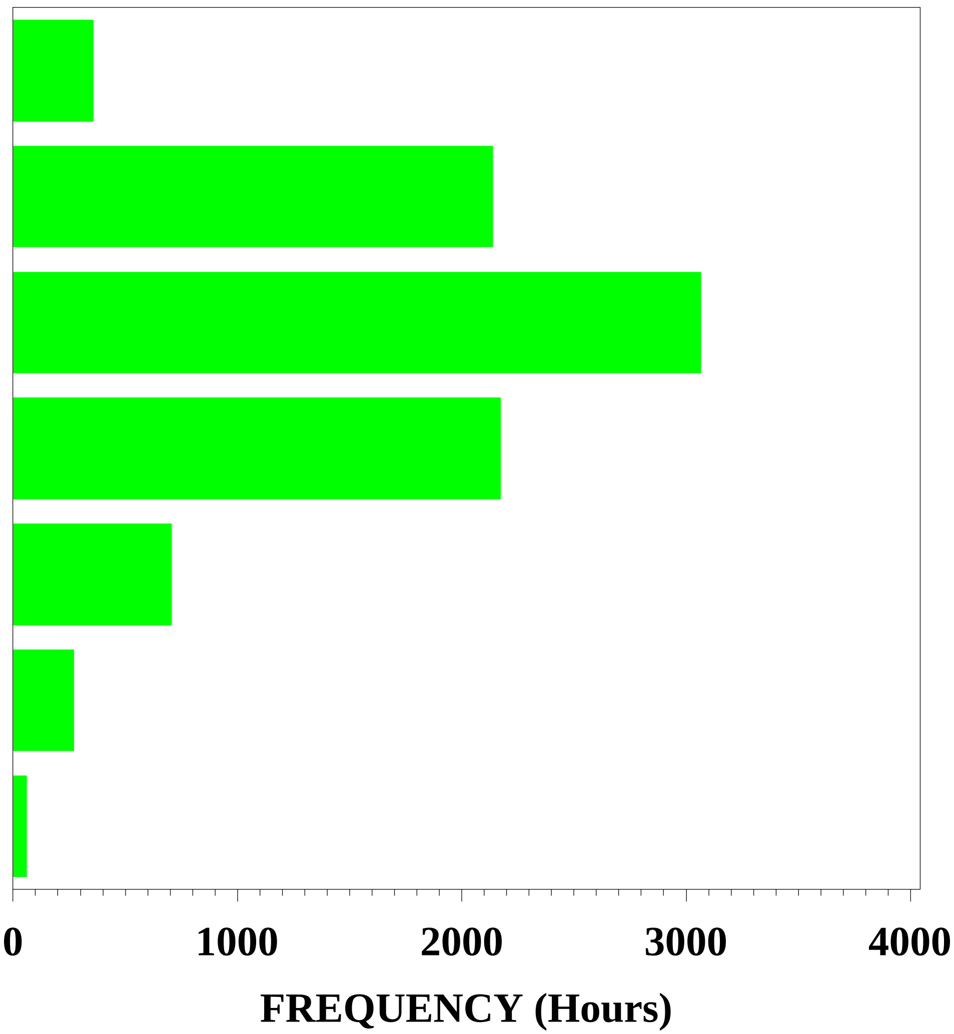
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	227	227	2.59	2.59
$10 to $20	5042	5269	57.56	60.15
$20 to $30	1982	7251	22.63	82.77
$30 to $40	733	7984	8.37	91.14
$40 to $50	379	8363	4.33	95.47
$50 to $60	154	8517	1.76	97.23
$60 to $70	84	8601	0.96	98.18
$70 to $80	33	8634	0.38	98.56
$80 to $90	13	8647	0.15	98.71
$90 to $100	8	8655	0.09	98.80
$100 to $110	4	8659	0.05	98.85
$110 to $120	3	8662	0.03	98.88
$120 to $130	2	8664	0.02	98.90
$130 to $140	1	8665	0.01	98.92
$140 to $150	4	8669	0.05	98.96
$160 to $170	1	8670	0.01	98.97
$170 to $180	1	8671	0.01	98.98
$180 to $190	1	8672	0.01	99.00
$190 to $200	2	8674	0.02	99.02
$200 to $210	2	8676	0.02	99.04
$220 to $230	1	8677	0.01	99.05
$240 to $250	1	8678	0.01	99.06
$250 to $260	1	8679	0.01	99.08
$260 to $270	1	8680	0.01	99.09
$270 to $280	2	8682	0.02	99.11
$300 to $310	2	8684	0.02	99.13
$310 to $320	2	8686	0.02	99.16
$330 to $340	1	8687	0.01	99.17
$360 to $370	1	8688	0.01	99.18
$370 to $380	1	8689	0.01	99.19
$400 to $410	2	8691	0.02	99.21
$430 to $440	1	8692	0.01	99.22
$440 to $450	2	8694	0.02	99.25
$450 to $460	1	8695	0.01	99.26
$460 to $470	1	8696	0.01	99.27
$470 to $480	3	8699	0.03	99.30
$490 to $500	1	8700	0.01	99.32
$510 to $520	1	8701	0.01	99.33
$530 to $540	1	8702	0.01	99.34
$540 to $550	2	8704	0.02	99.36
$560 to $570	2	8706	0.02	99.38
$570 to $580	1	8707	0.01	99.39
$600 to $610	1	8708	0.01	99.41
$610 to $620	1	8709	0.01	99.42
$620 to $630	2	8711	0.02	99.44
$670 to $680	1	8712	0.01	99.45
$750 to $760	1	8713	0.01	99.46
$760 to $770	2	8715	0.02	99.49
$780 to $790	1	8716	0.01	99.50
$790 to $800	1	8717	0.01	99.51
$820 to $830	1	8718	0.01	99.52
$840 to $850	7	8725	0.08	99.60
$870 to $880	1	8726	0.01	99.61
$890 to $900	1	8727	0.01	99.62
$900 to $910	1	8728	0.01	99.63
$910 to $920	10	8738	0.11	99.75
$930 to $940	11	8749	0.13	99.87
$940 to $950	2	8751	0.02	99.90
$950 to $960	1	8752	0.01	99.91
$970 to $980	1	8753	0.01	99.92
$990 to $1000	7	8760	0.08	100.00

Figure A.3: Frequency Distribution by Hours of PJM LMPs
2000 Real Time Market



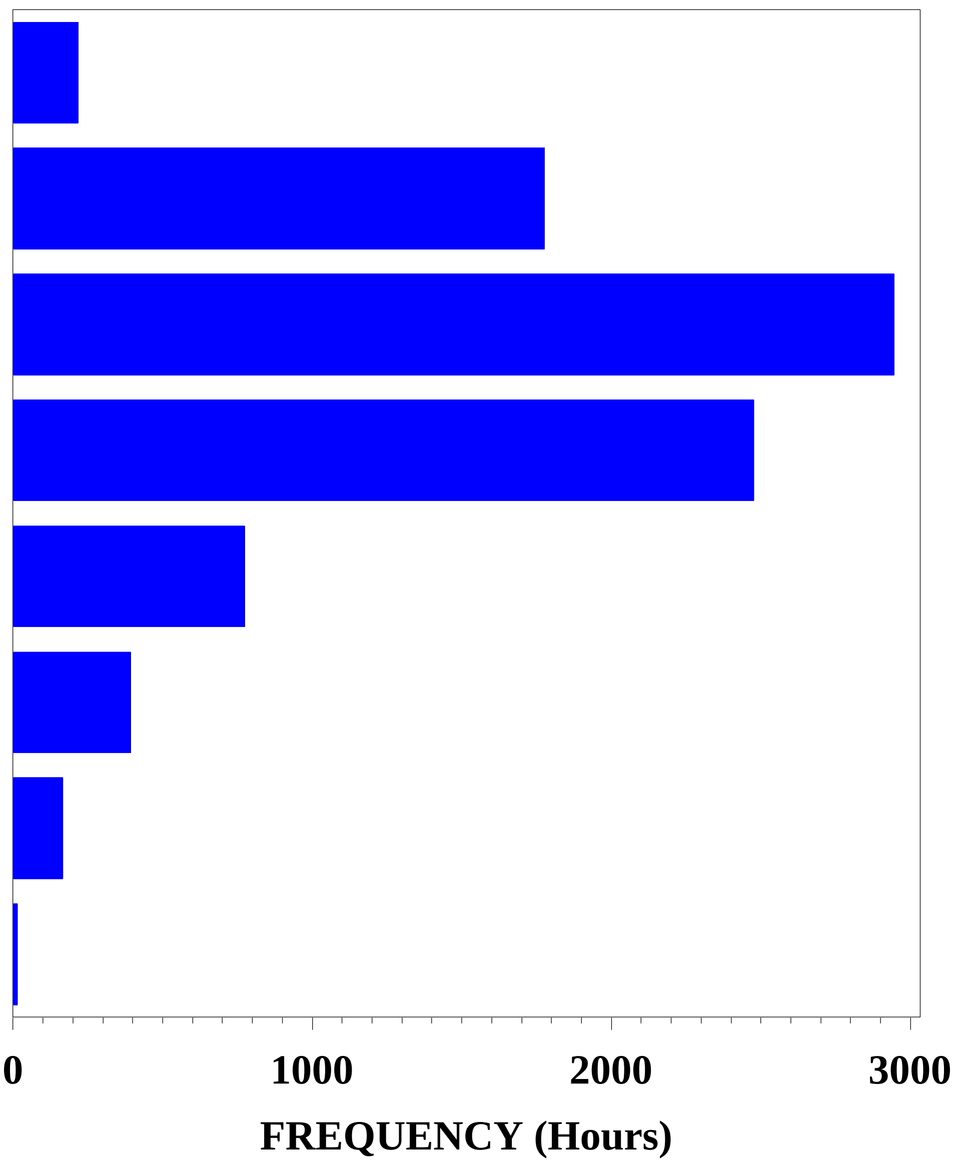
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	210	210	2.39	2.39
$10 to $20	4522	4732	51.48	53.87
$20 to $30	1494	6226	17.01	70.88
$30 to $40	782	7008	8.90	79.78
$40 to $50	591	7599	6.73	86.51
$50 to $60	459	8058	5.23	91.73
$60 to $70	315	8373	3.59	95.32
$70 to $80	147	8520	1.67	96.99
$80 to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

Figure A.4: Frequency Distribution of Hourly PJM Load
1998



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20000 and Less	356	356	4.06	4.06
20000 to 25000	2137	2493	24.39	28.46
25000 to 30000	3063	5556	34.97	63.42
30000 to 35000	2171	7727	24.78	88.21
35000 to 40000	704	8431	8.04	96.24
40000 to 45000	270	8701	3.08	99.33
45000 to 50000	59	8760	0.67	100.00

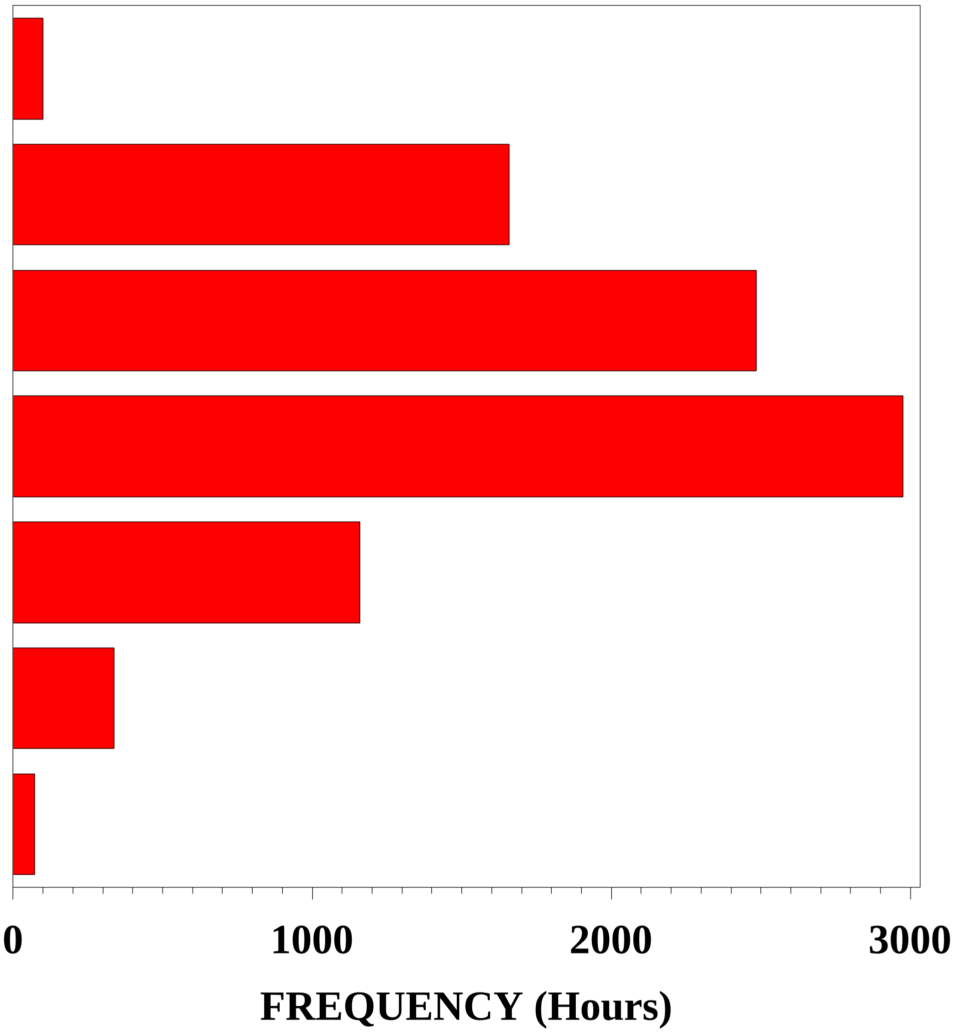
Figure A.5: Frequency Distribution of Hourly PJM Load
1999



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20000 and Less	218	218	2.49	2.49
20000 to 25000	1776	1994	20.27	22.76
25000 to 30000	2944	4938	33.61	56.37
30000 to 35000	2476	7414	28.26	84.63
35000 to 40000	773	8187	8.82	93.46
40000 to 45000	392	8579	4.47	97.93
45000 to 50000	166	8745	1.89	99.83
50000 to 55000	15	8760	0.17	100.00

Figure A.6: Frequency Distribution of Hourly PJM Load
2000

Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20000 and Less	99	99	1.13	1.13
20000 to 25000	1658	1757	18.88	20.00
25000 to 30000	2485	4242	28.29	48.29
30000 to 35000	2975	7217	33.87	82.16
35000 to 40000	1159	8376	13.19	95.36
40000 to 45000	337	8713	3.84	99.19
45000 to 50000	71	8784	0.81	100.00



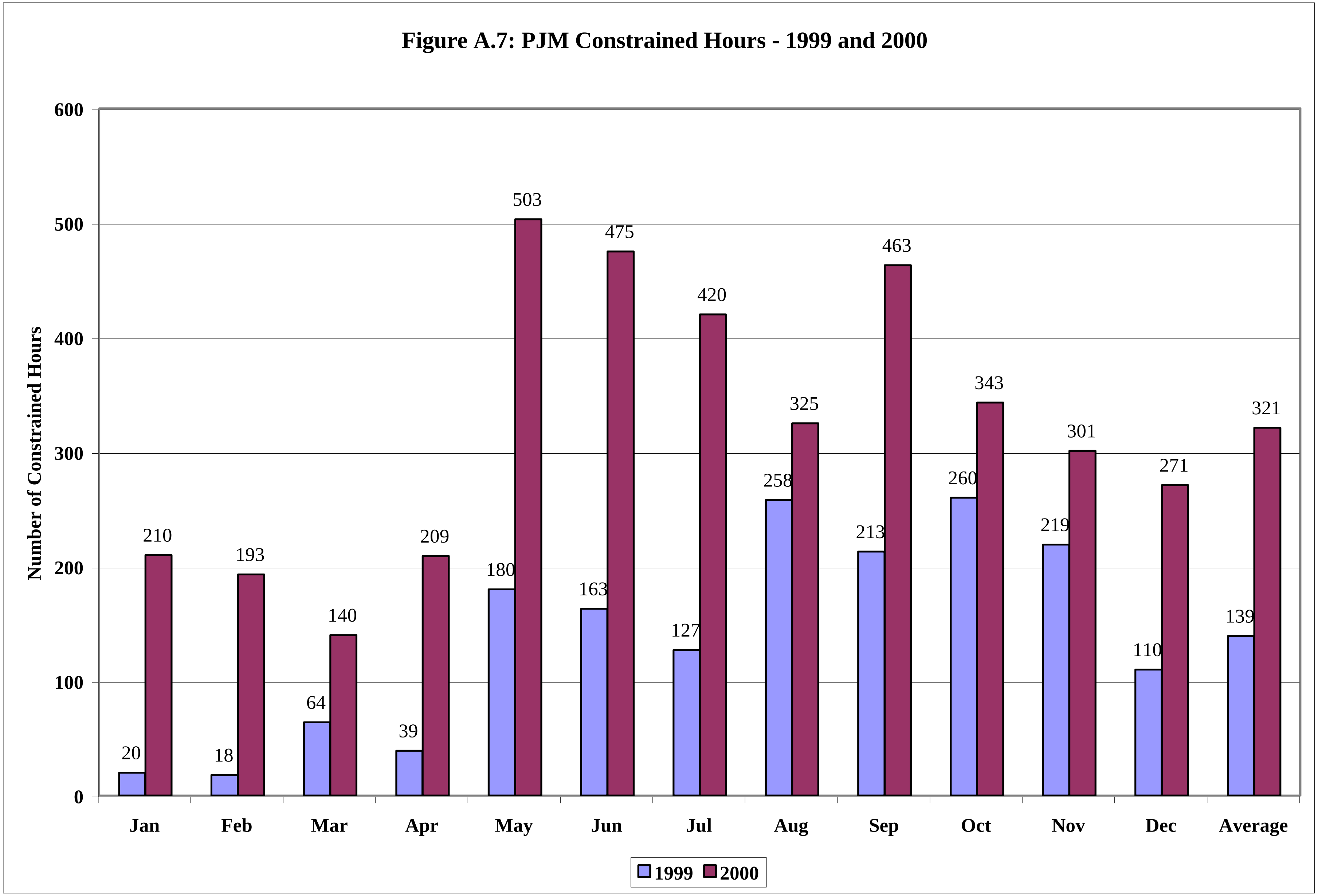
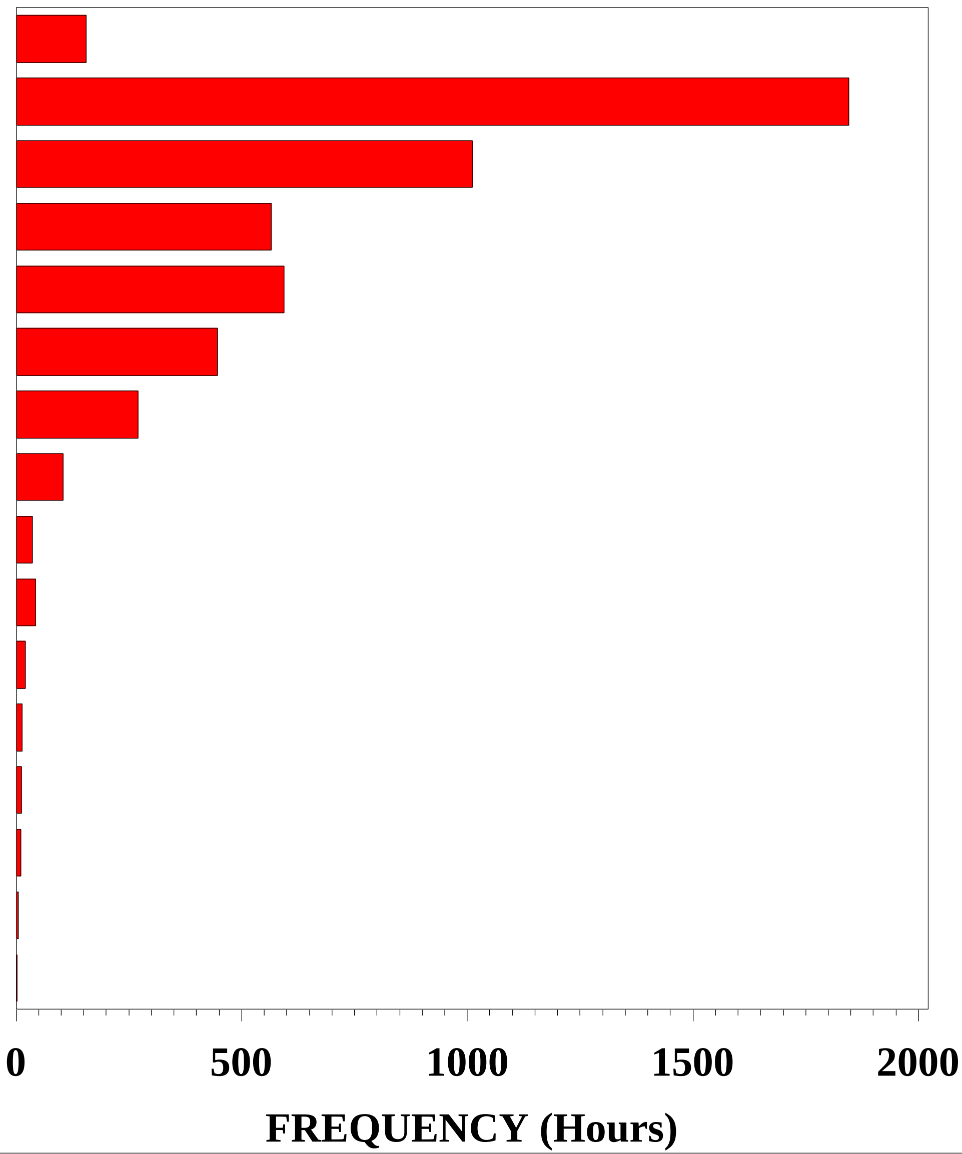


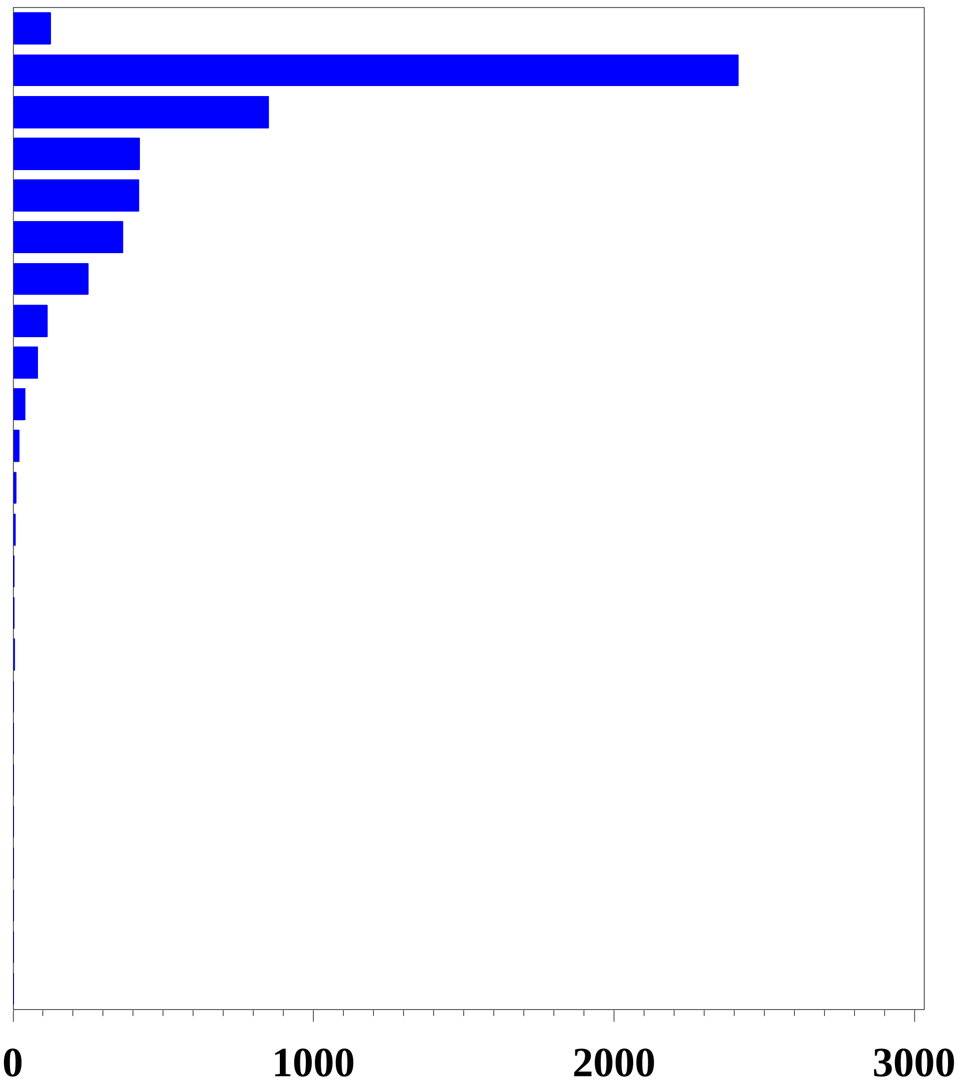
Figure A.7: PJM Constrained Hours - 1999 and 2000
Number of Constrained Hours
0
100
200
300
400
500
600
20
210
18
193
64
140
39
209
180
503
163
475
127
420
258
325
213
463
260
343
219
301
110
271
139
321
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Average
1999
2000

Figure A.8: Frequency Distribution by Hours of PJM LMPs
Day Ahead Market
June-December 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	156	156	3.04	3.04
$10 to $20	1846	2002	35.94	38.98
$20 to $30	1011	3013	19.68	58.66
$30 to $40	565	3578	11.00	69.67
$40 to $50	594	4172	11.57	81.23
$50 to $60	446	4618	8.68	89.91
$60 to $70	271	4889	5.28	95.19
$70 to $80	105	4994	2.04	97.24
$80 to $90	36	5030	0.70	97.94
$90 to $100	43	5073	0.84	98.77
$100 to $110	20	5093	0.39	99.16
$110 to $120	14	5107	0.27	99.44
$120 to $130	12	5119	0.23	99.67
$130 to $140	10	5129	0.19	99.86
$140 to $150	5	5134	0.10	99.96
$150 to $160	2	5136	0.04	100.00

Figure A.9: Frequency Distribution by Hours of PJM LMPs
Real Time Market
June-December 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	125	125	2.43	2.43
$10 to $20	2412	2537	46.96	49.40
$20 to $30	850	3387	16.55	65.95
$30 to $40	421	3808	8.20	74.14
$40 to $50	418	4226	8.14	82.28
$50 to $60	364	4590	7.09	89.37
$60 to $70	250	4840	4.87	94.24
$70 to $80	113	4953	2.20	96.44
$80 to $90	83	5036	1.62	98.05
$90 to $100	39	5075	0.76	98.81
$100 to $110	20	5095	0.39	99.20
$110 to $120	9	5104	0.18	99.38
$120 to $130	8	5112	0.16	99.53
$130 to $140	4	5116	0.08	99.61
$140 to $150	4	5120	0.08	99.69
$150 to $160	5	5125	0.10	99.79
$160 to $170	2	5127	0.04	99.82
$170 to $180	2	5129	0.04	99.86
$180 to $190	1	5130	0.02	99.88
$190 to $200	2	5132	0.04	99.92
$220 to $230	1	5133	0.02	99.94
$280 to $290	1	5134	0.02	99.96
$590 to $600	1	5135	0.02	99.98
$800 to $810	1	5136	0.02	100.00

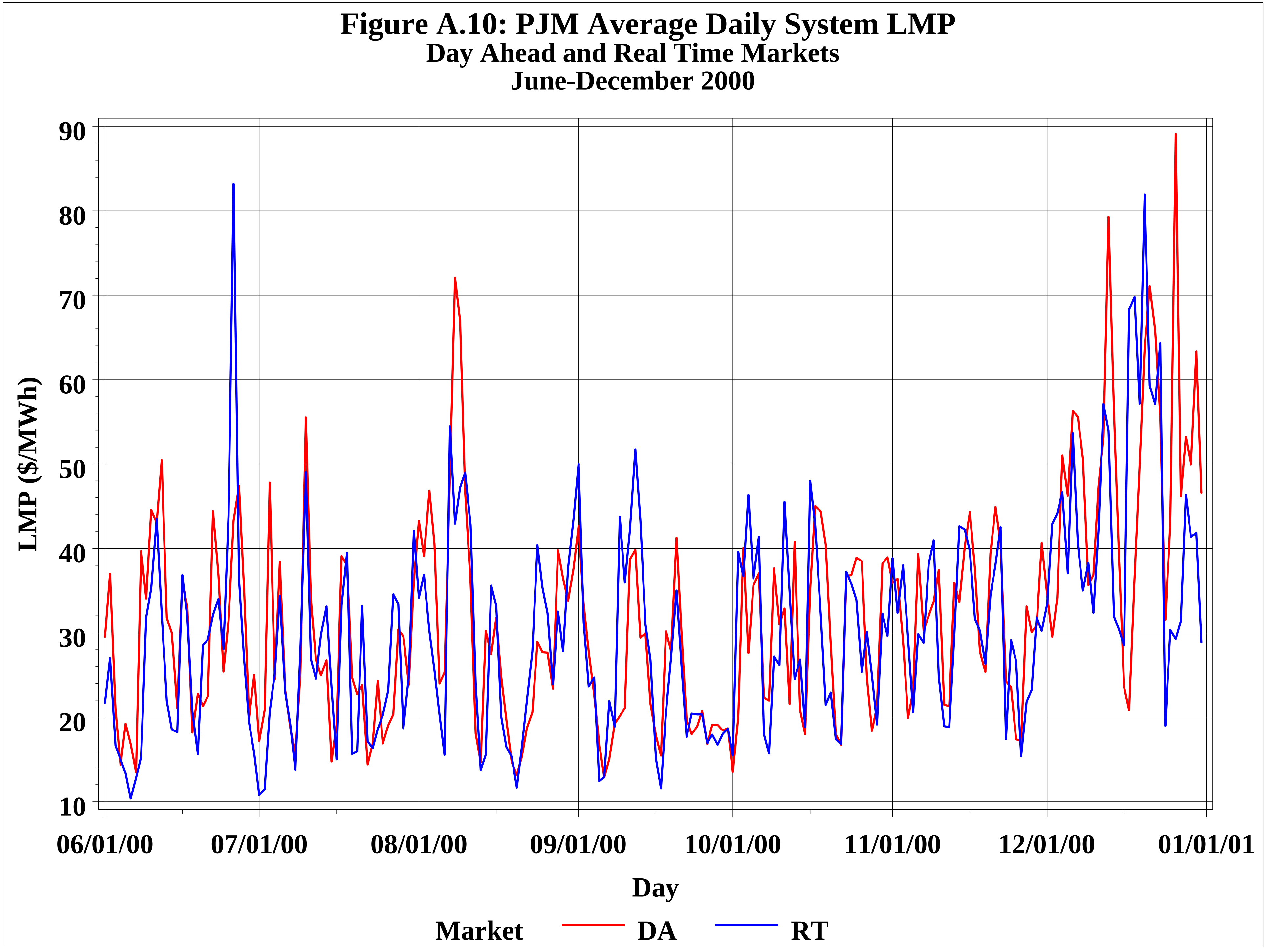
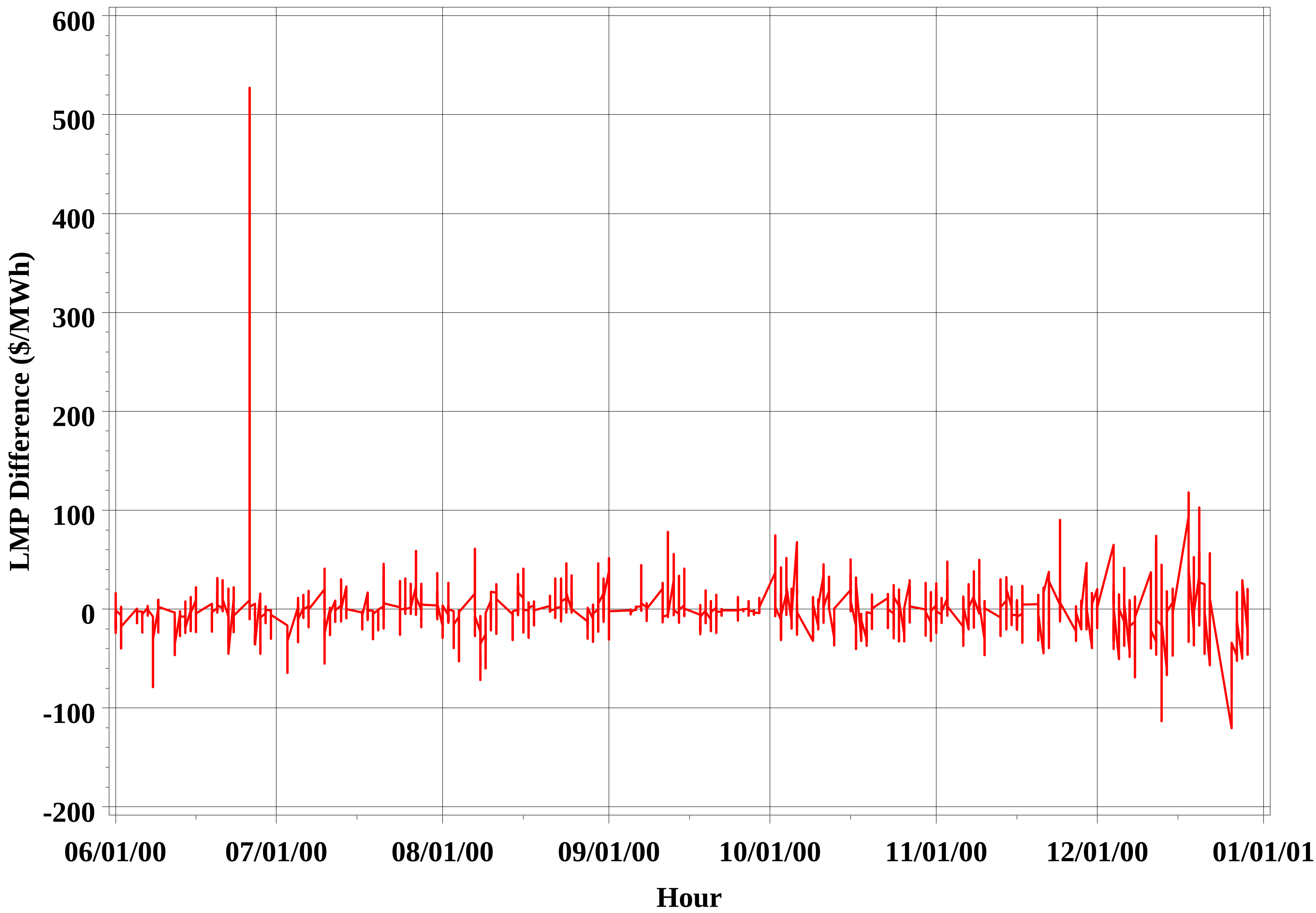


Figure A.10: PJM Average Daily System LMP
Day Ahead and Real Time Markets
June-December 2000
LMP ($/MWh)
90
80
70
60
50
40
30
20
10
06/01/00
07/01/00
08/01/00
09/01/00
10/01/00
11/01/00
12/01/00
01/01/01
Day
Market
DA
RT

Figure A.11: Hourly RT LMP Minus DA LMP - Peak Hours
June-December 2000



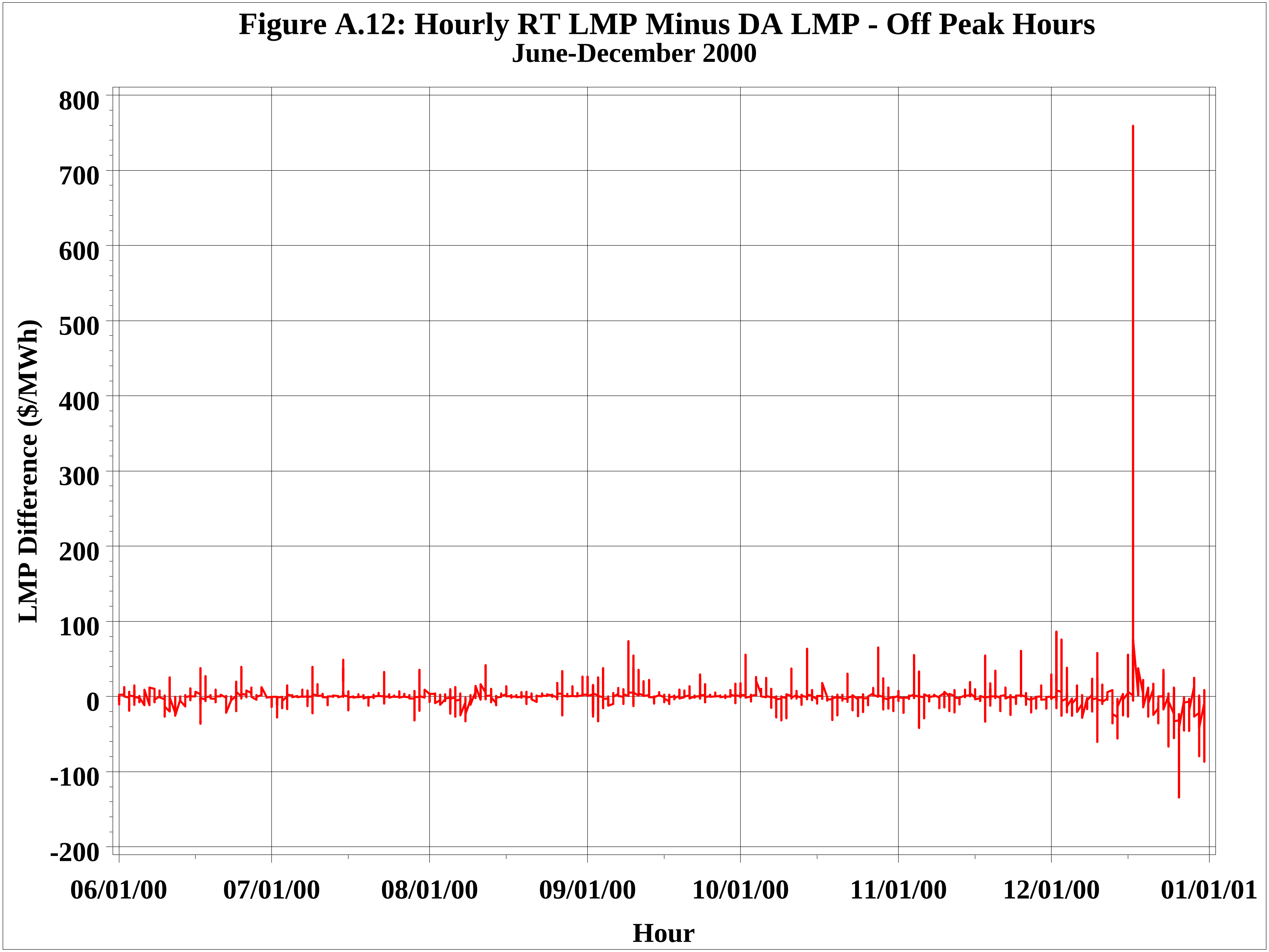
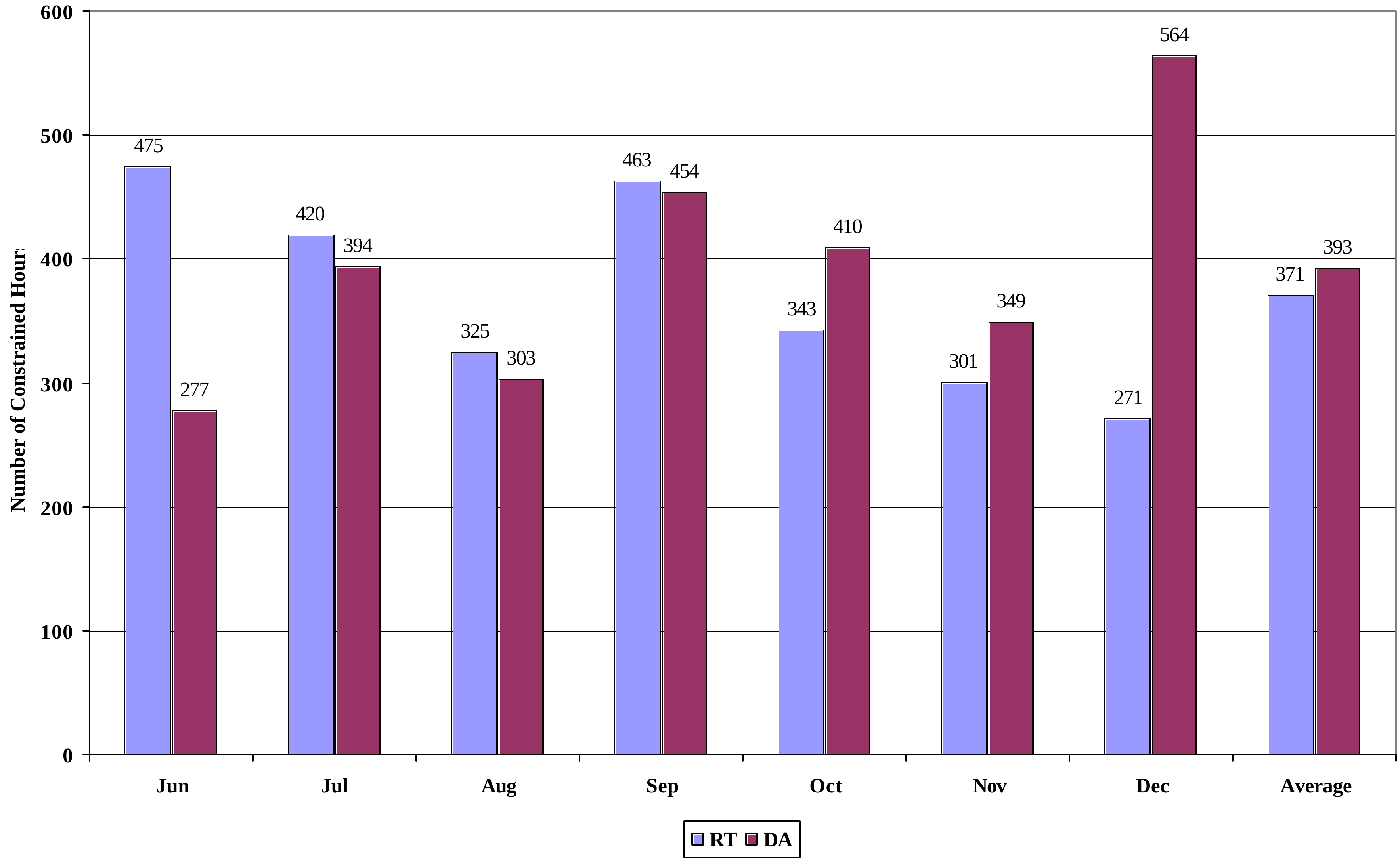


Figure A.12: Hourly RT LMP Minus DA LMP - Off Peak Hours
June-December 2000
LMP Difference ($/MWh)
800
700
600
500
400
300
200
100
0
-100
-200
06/01/00
07/01/00
08/01/00
09/01/00
10/01/00
11/01/00
12/01/00
01/01/01
Hour

Figure A.13: Real Time and Day Ahead Market Constrained Hours



CAPACITY CREDIT MARKET

Summary and Conclusions

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources greater than or equal to the peak load that it serves plus a reserve margin. The PJM Capacity Credit Market (CCM) provides a mechanism to balance the supply and demand of capacity that is not met via the bilateral market or self supply. Sometimes referred to as the capacity market, the PJM Capacity Credit Market is comprised of daily capacity credit markets and monthly and multi-monthly capacity credit markets. These capacity credit markets provide a transparent, market based mechanism for new, competitive retail load serving entities (LSEs) to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. PJM's daily capacity credit markets ensure that LSEs can match capacity resources with daily shifts in retail load while monthly (including multi-monthly) capacity credit markets provide a mechanism that matches longer term capacity obligations with available capacity resources.

The MMU has reviewed the design and structure of the capacity markets, the bidding behavior of market participants and the results of the capacity markets for 2000. The MMU concludes that the capacity markets were reasonably competitive during 2000 although the potential exercise of market power is a concern and there are significant market design issues which require resolution. During 2000, the system of capacity obligations functioned effectively and helped ensure that energy was available during emergency conditions. MMU analysis of the high prices in the daily capacity credit markets during the summer of 2000 concluded that the high prices were caused by fundamental market forces rather than market power or market manipulation. Nonetheless the potential exercise of market power in the capacity markets remains a concern given the extreme inelasticity of demand and given that, at times, only a few generation owners had available capacity to sell. In addition, events in the capacity credit markets during the year 2000 illustrated a key issue identified in the PJM Interconnection State of the Market Report 1999, the impact of the daily capacity market on generator incentives to delist capacity.

The State of the Market Report 1999 recommended modifications to the capacity credit market rules to better align market incentives with PJM's reliability requirements while limiting the exercise of market power. In particular, the report recommended that the capacity credit market rules should be modified to require that all LSEs meet their obligation to serve load on an annual or semiannual basis and that all capacity resources be offered on a comparable basis. During 2000, the PJM stakeholder Future Adequacy Working Group (FAWG) began developing a set of revised capacity credit market rules that are broadly consistent with the recommendations of the State of the Market Report 1999. PJM and its members are continuing this work to refine the design of the capacity credit markets in order to ensure that incentives to buy and sell capacity remain consistent with PJM's reliability goal.

Overview

At PJM, capacity obligations have played a critical role in maintaining reliability and contributing to the effective, competitive operation of the energy market. Adequate *capacity resources*, as defined by the PJM Operating Agreement (OA) and Reliability Assurance

Agreement (RAA) ensure that energy will be available to loads in PJM on even the highest load days.

A critical link between capacity obligation and reliability is that generation owners sell a recall right to the energy generated by their units and sold to entities outside PJM when they sell capacity resources to PJM LSEs. This recall right enables PJM to recall energy exports from capacity resources when it invokes Emergency procedures.[1] The recall right establishes a link between capacity and the actual delivery of energy when it is needed. Thus the energy from all capacity resources can be called upon by PJM in order to serve load within the PJM area. When recalled, the energy supplier is paid the PJM energy market price.

A second link between capacity obligation and reliability is the requirement that owners of capacity resources offer the output of these resources into PJM's day-ahead energy market. When LSEs purchase capacity, they ensure that the resources will be available to provide energy on a daily basis and not solely in emergencies. Since day-ahead offers are financially binding, resource owners must provide the offered energy at the offered price. This energy must be provided either from the specific unit offered or, if that unit is unavailable, by purchasing the energy at the spot market price and reselling the energy at the offer price.

From the inception of the pool, PJM and its members have relied upon capacity obligations as one of the methods 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. 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 load.

The PJM ISO introduced transparent, open, PJM-run markets in capacity credits on January 1, 1999, in response to the requirements of retail restructuring. New retail market entrants needed a way to acquire capacity credits to meet obligations associated with load gained through the competitive process and the existing utilities needed a way to sell capacity credits no longer needed, if load was lost to new competitors. The PJM capacity credit market is the mechanism that balances the supply and demand for capacity credits that is not met via the bilateral market or via self supply. The capacity credit markets provide a transparent market in which new competitors can buy capacity, new and existing generators can sell capacity and all competitors can buy and sell capacity based on need. The PJM capacity credit markets provide another mechanism to exchange capacity credits among market participants as obligations change and as available capacity varies.

PJM's RAA 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

1 PJM Emergency procedures are defined in the PJM Manual for Emergency Operations.

and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace."[2]

Under the RAA, each load-serving entity (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 obligations, LSEs may own or purchase generating capacity which meets the PJM criteria to be a capacity resource. If an LSE's capacity resources are less than its obligation, the LSE is deficient. Deficient LSEs pay a penalty equal to the Capacity Deficiency Rate (CDR) which is $177.30/MW-day.

Capacity resources may be purchased in three different ways. Collectively, these arrangements are known as the ICAP market, for Installed Capacity Market.

- 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 defined in terms of unforced capacity and measured in MW.
- From the PJM daily, monthly or multi-monthly 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.
- From a generating unit external to the PJM control area. These capacity imports must meet PJM criteria including that the imports are from specific units and that the seller must have firm transmission from the identified units to the metered boundaries of the PJM Control Area.

Capacity resources are MW of net generation capacity which meet specified criteria and are committed to serving specific PJM loads, or MW of net generation capacity within the PJM Control Area which meet specified 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.[3]

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

3 See RAA, Capacity Resources, page 2.

Fundamentals

The total demand for capacity credits is determined by procedures set forth in the RAA which set total capacity obligation for PJM. The RAA also includes rules for allocating this total capacity obligation to individual LSEs. This fixed total demand, net of ALM, bilateral contracts and self-supply, must be bid into monthly, multi-monthly or daily capacity credit markets. Demand for capacity credits in daily markets reflects the residual after capacity credits are purchased in monthly and multi-monthly markets or through bilateral transactions. If an LSE is short and does not submit a buy bid in the daily market, 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 credits in all the PJM capacity credit markets is a function of physical capacity in the PJM control area, prices in the PJM capacity market, capacity resource imports, prices in the PJM energy market and prices in external energy markets. The existence of physical capacity resources in the PJM control area has no necessary relationship to the supply of capacity in the PJM capacity markets, as capacity resources can be delisted, or exported, from the PJM control area and imported from external control areas. It is the option to delist capacity resources, as well as the more limited ability to import capacity resources, which makes capacity supply in PJM a function of both capacity market prices and the spread between internal and 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 result in quantifiable incentives. 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 standard 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 standard energy contract. As a result, with a net price spread between PJM and external markets 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 credit market, even at the maximum possible daily capacity credit 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 capacity credit 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 in the PJM markets would

4 As discussed in more detail below, 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 installed capacity of the generating unit rather than the unforced capacity.

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.

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 and cost of recalling external energy sales. The marginal cost and thus the expected price of capacity would be based on the difference between (a) the opportunity to delist and thus sell the energy from that capacity externally without risk of recall, 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 possibility that the external energy sales may be recalled. 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.

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 credit markets, make the generators' decision more dependent on short term fluctuations in external energy prices than if capacity obligations were met in markets which were cleared only annually. With annual capacity obligations, the likelihood of the net external price differential, evaluated over a year, exceeding the capacity penalty for the period is lower and therefore the incentives to sell the system short are lower.

The balance of this section provides PJM system-wide data and analysis of the capacity markets for the year 2000. The data include the components of the capacity markets: installed capacity, unforced capacity, obligation, excess, deficiency, imports, exports (delists), internal bilateral transactions, Capacity Credit Market exchanges, Active Load Management (ALM) credits (defined later in this section), outage rates and capacity credit prices. The Appendix to this section defines and describes the principal components of capacity requirements in further detail.

System Capacity, Obligation, and Net Excess Capacity[6]

System net excess capacity can be determined using installed capacity, unforced capacity, obligation, the sum of members' excesses, and the sum of members' deficiencies. Table 1 presents these data for 2000. The net excess is the net pool position, and reflects a comparison of total capacity resources and obligation. Obligation includes expected load plus a reserve margin. Thus a net pool position of zero is consistent with the established reliability objectives. During 2000, the pool was, on average, long by about 1,200 MW. The maximum and minimum net excess capacity data indicate that the pool was long by almost 2,500 MW on one or more days and that the pool was deficient on one or more days by a maximum amount of almost 900 MW. A deficiency means that there were less capacity resources in the pool than required to meet the pool's reliability objectives as defined by the total capacity obligation of all LSEs.

Table 1: Summary of members' net excess capacity, January – December, 2000 (MW)

	Mean	Minimum	Maximum	Standard Deviation
Installed capacity	57,406	55,433	58,556	627
Unforced Capacity	53,891	51,802	55,126	721
Obligation	52,697	52,662	52,741	36
Sum of Excess	1,233	0	2,460	658
Sum of Deficiency	40	0	939	129
Net Excess	1,193	-867	2,459	719

Bilateral Capacity Transactions

PJM capacity resources may be traded bilaterally within and outside of the PJM control area. Table 2 presents PJM bilateral capacity transaction data for 2000. In 2000, an average of 435 MW of capacity resources was imported into PJM and an average of 957 MW was exported (delisted) for an average net export (delist) of 522 MW of capacity resources. The maximum net export (delist) was almost 2,500 MW, while the minimum net import was about 400 MW.

Table 2: Bilateral Capacity transactions, January – December, 2000 (MW)

	Mean	Minimum	Maximum	Standard Deviation
Imports	435	3	1,173	308
Exports (Delists)	957	81	2,465	402
Net Exports	522	-373	2,461	580
Internal bilaterals	31,535	24,459	43,921	6,530

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

PJM Capacity Credit Market (CCM)

PJM operates daily, monthly and multi-monthly capacity credit markets. Tables 3A and 3B present data on these markets in 2000 and in the second half of 1999. In 2000, the daily capacity credit market averaged 1,304 MW of transactions, or about 2.5% of the average capacity obligation. Trading in PJM capacity credit markets in 2000 showed an increase over trading in these markets in the second half of 1999, when the definitions of the components of the capacity credit markets were comparable.

Table 3A: PJM Capacity Credit Market Exchanges, January – December, 2000 (MW)				
	Mean	Minimum	Maximum	Standard Deviation
Daily CCMs	1,304	758	4,216	331
Monthly CCMs	634	239	1,287	267
Multi monthly CCMs	927	866	1,027	64
All CCMs	2,865	2,173	5,873	366

Table 3B: PJM Capacity Credit Market Exchanges, June-December 1999 (MW)				
	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 Credits

Active Load Management (ALM) reflects the ability of individual customers, under contract with their local utility, to reduce specified amounts of load when PJM declares an emergency. ALM credits, measured in MW of curtailable load, reduce LSE’s capacity obligation. Data on ALM credits in PJM during 2000 and in the second half of 1999 are presented in Tables 4A and 4B. In 2000, ALM credits averaged about 1,800 MW, down from a level of about 2,000 MW in the second half of 1999.

Table 4A: PJM ALM Credits, January – December, 2000 (MW)				
	Mean	Minimum	Maximum	Standard Deviation
ALM credits	1,819	1,656	2,005	158

Table 4B: PJM ALM Credits, June-December, 1999 (MW)				
	Mean	Minimum	Maximum	Standard Deviation
ALM credits	2,007	1,841	2,080	75

Capacity Obligation Served in Capacity Credit Markets

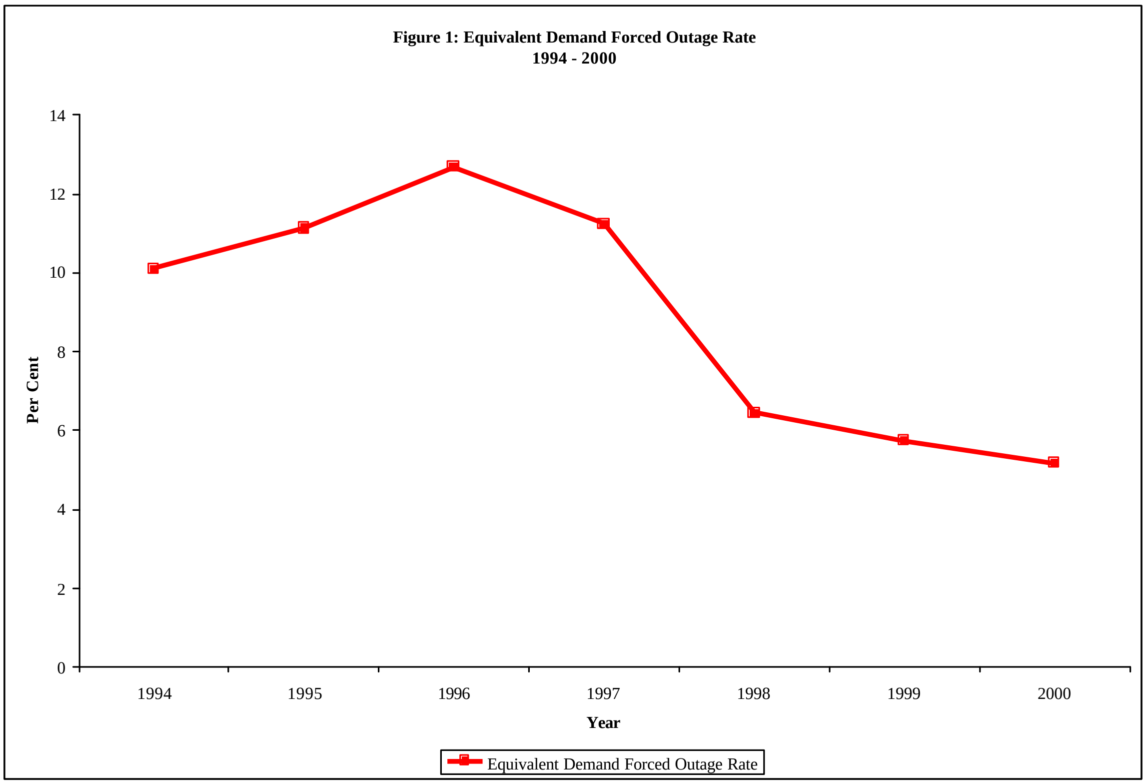
Companies that are not affiliated with investor-owned utilities rely on PJM markets to a greater extent than do affiliated companies or all companies, as shown in Table 5. The monthly share of total PJM member capacity obligation served from the PJM capacity credit markets during 2000 ranged from 4.87% to 6.53% averaging 5.41%, while the share of the total capacity obligation of non-affiliated participants served from the capacity credit markets ranged from 22.40% to 53.91% averaging 33.10%. The “Non-IOU” (Non-Investor-Owned Utility) category includes all companies other than investor-owned utilities. The category “Non-Affiliated with IOU” also excludes companies that are affiliated with investor-owned utilities.

Table 5: Percent of capacity obligation served by PJM Capacity Credit Markets

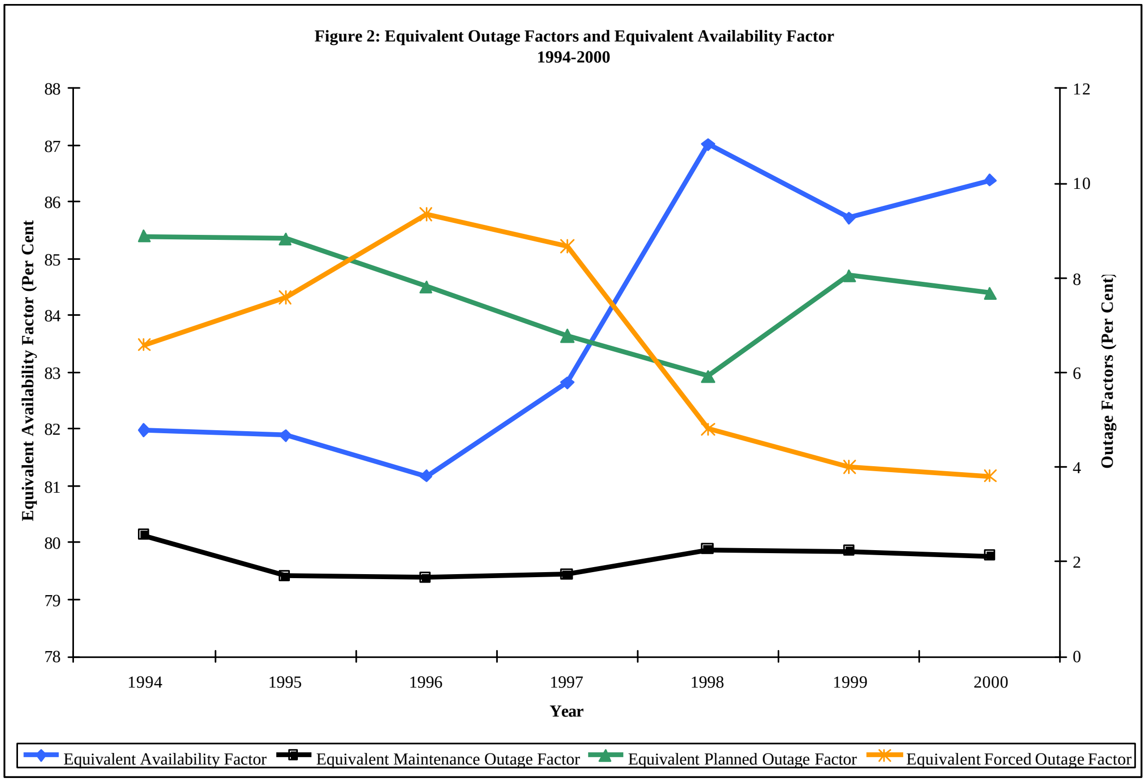
Month	All Companies	Non-IOU	Non-Affiliated with IOU
January	4.87%	29.83%	34.99%
February	5.57%	26.03%	30.82%
March	5.54%	22.53%	22.40%
April	6.53%	24.20%	24.89%
May	5.91%	27.53%	28.49%
June	5.77%	50.77%	53.91%
July	5.12%	40.83%	43.10%
August	4.99%	39.17%	41.27%
September	4.93%	38.66%	40.59%
October	4.92%	28.49%	29.57%
November	4.98%	26.40%	27.30%
December	5.84%	23.65%	24.54%
For the year 2000	5.41%	31.21%	33.10%

Capacity Availability

The existence of the ICAP market creates an incentive to minimize forced outages because the amount of capacity resources available from a specific unit is directly related to the forced outage rate of the unit. The existence of a competitive energy market also creates an incentive to minimize forced outages as units must run when called upon in order to receive revenues. PJM's equivalent demand forced outage rate has trended down slightly since 1998. The equivalent demand forced outage rate is a statistical measure of the probability that a unit will fail, either partially or totally, to perform when needed. The equivalent demand forced outage rate (EFORd) was 10.1% in 1994, rose to 12.7% in 1996, then declined to 11.2% in 1997, 6.5% in 1998, 5.7% in 1999 and 5.2% in 2000. Figure 1 shows the equivalent demand forced outage rates.



Certain outage statistics are calculated by reference to the total hours in the year, rather than statistical probabilities. Figure 2 shows these other performance measures for PJM units. The Equivalent Availability Factor, for example, represents the proportion of hours in the year that a unit was available to generate, in effect, at full capacity. The sum of the Equivalent Availability Factor, the Equivalent Maintenance Outage Factor, the Equivalent Planned Outage Factor and the Equivalent Forced Outage Factor equals 100%. The PJM aggregate Equivalent Availability Factor was 82.0% in 1994, declined slightly to 81.2% in 1996, then rose to 87.0% in 1998, declined slightly in 1999 to 85.7%, and increased in 2000 to 86.4%.

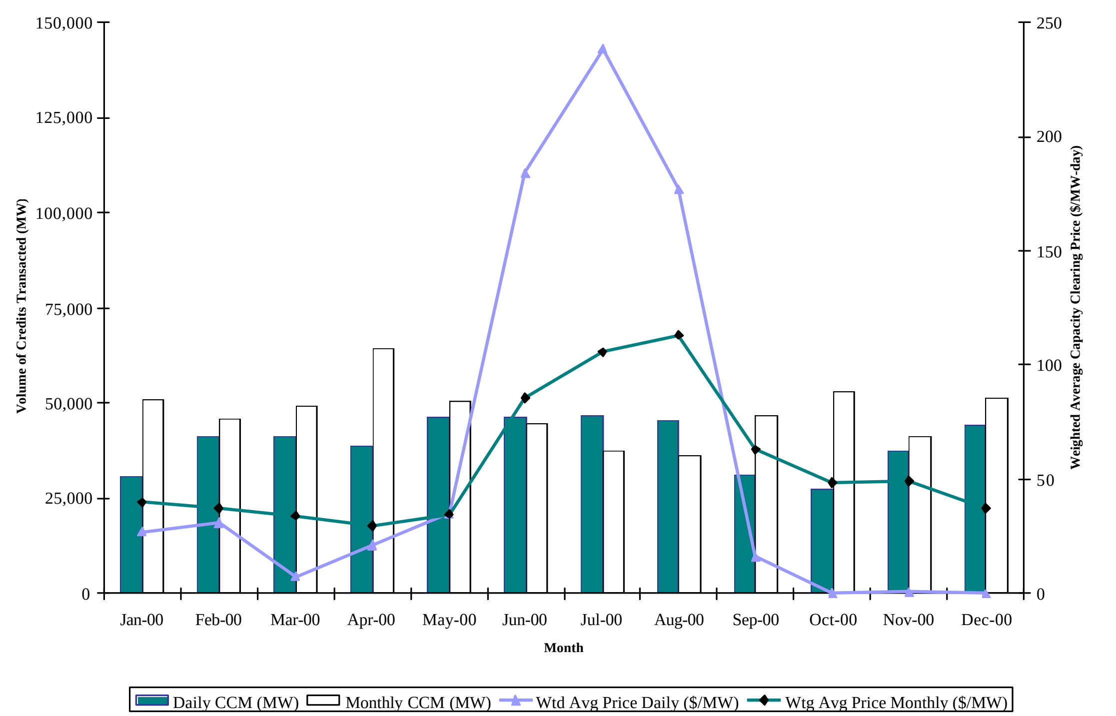


The 2000 PJM Capacity Market

Capacity Credit Market prices

Capacity credit market prices and volumes for the entire year are shown in Figure 3 below and in Table 6. The volume-weighted average price for the entire year was $53.16/MW-day in the monthly and multi-monthly capacity credit markets and $69.39/MW-day in daily capacity credit markets. The volume-weighted average of all CCMs for 2000 was $60.55/MW-day.[7] Prices in the capacity credit markets in 2000 are somewhat higher overall than in 1999 and exhibit a different relationship between monthly prices and daily prices. In 1999 the volume-weighted average of all CCMs was $52.86/MW-day, $7.69 lower than in 2000. Prices in the monthly and multi-monthly capacity credit markets were $70.66/MW-day, $17.50 higher than in 2000, while the daily capacity credit market price averaged $3.63/MW-day, $65.76 lower than in 2000.

Figure 3: 2000 Daily vs Monthly Capacity Credit Market Performance



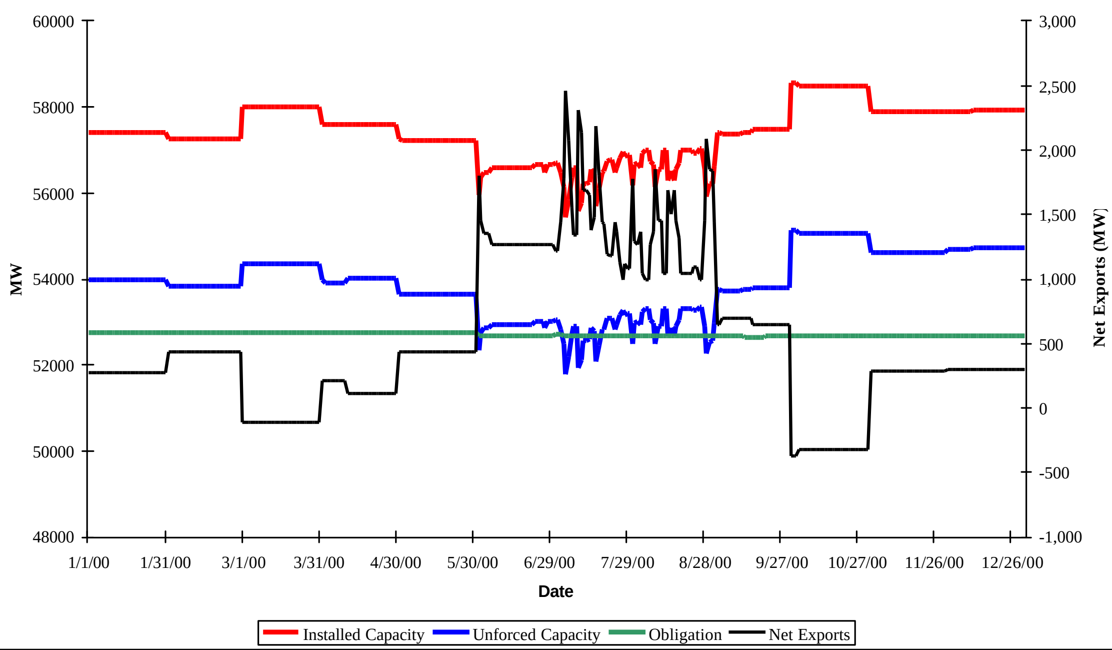
[7] The data in the graph and the average price data are all in terms of unforced capacity . Capacity credits are, by definition, in terms of unforced capacity.

Table 6: PJM Capacity Credit Market, 2000						
Month/Year	Daily (MW)	Monthly and Multi-Monthly (MW)	Combined (MW)	Weighted Average Price Daily ($/MW-Day)	Weighted Average Price Monthly and Multi-Monthly ($/MW-Day)	Weighted Average Price Combined ($/MW-Day)
Jan-00	30,579	51,057	81,636	26.96	39.95	35.09
Feb-00	41,383	45,756	87,139	31.07	37.22	34.30
Mar-00	41,430	49,228	90,658	7.38	33.97	21.82
Apr-00	38,676	64,590	103,266	21.24	29.45	26.37
May-00	46,134	50,480	96,614	35.07	34.76	34.91
Jun-00	46,479	44,685	91,164	184.05	85.61	135.80
Jul-00	46,569	37,268	83,837	238.35	105.70	179.38
Aug-00	45,585	36,137	81,722	177.07	113.22	148.84
Sep-00	31,381	46,545	77,926	16.08	63.05	44.13
Oct-00	27,417	52,979	80,396	0.26	48.37	31.96
Nov-00	37,656	41,100	78,756	0.70	49.19	26.00
Dec-00	44,046	51,367	95,413	0.02	37.36	20.12
For The Year	477,336	571,193	1,048,528	69.39	53.16	60.55

Capacity Supply and Demand in PJM

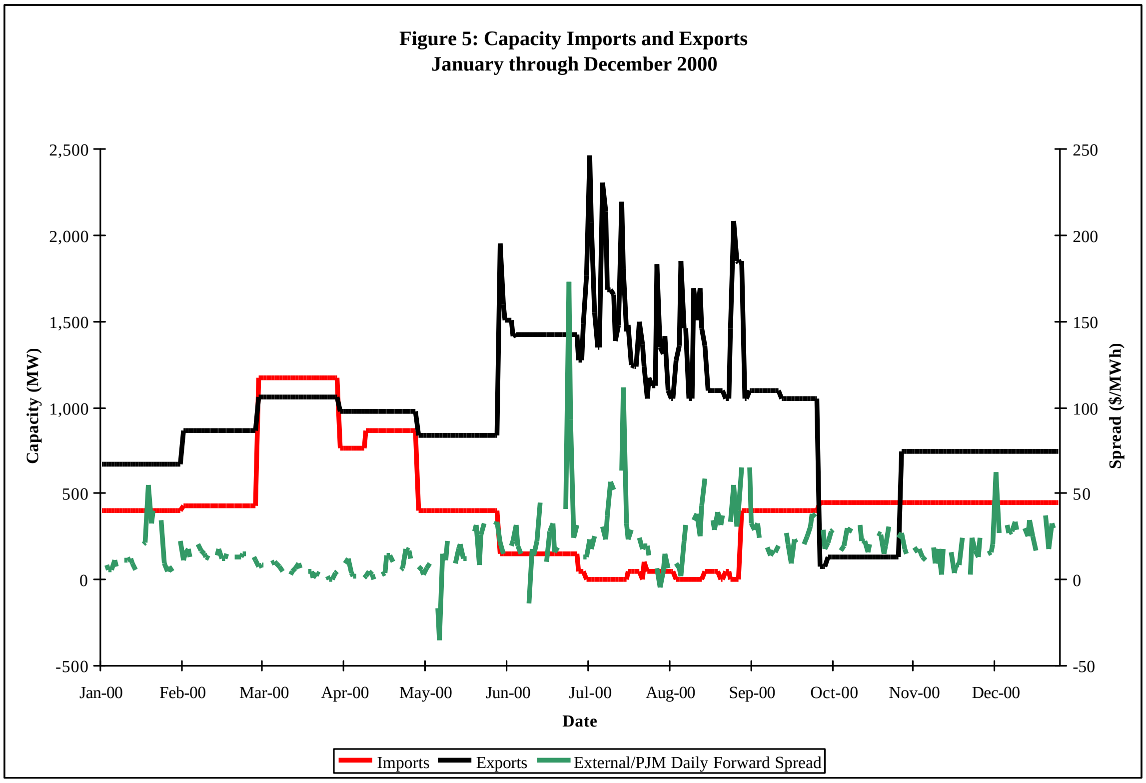
During 2000, capacity resources exceeded capacity obligation by approximately 1,200 MW on average (Table 1). However, for the first time since the introduction of PJM capacity credit markets in December 1998, PJM was capacity deficient for days in June, July and August 2000, as shown in Figure 4. While the pool capacity obligation is determined for the year, the amount of capacity resources in PJM on any day is a function of decisions to list or delist capacity resources which in turn are a function of market forces. In 2000, market forces, operating in the context of PJM market rules, resulted in the availability of capacity resources falling below that required by PJM reliability objectives.

Figure 4: Capacity and Obligation
January through December 2000



Exporting (delisting) capacity

As shown in Figures 4 and 5, owners of capacity increased their external sales of capacity resources for periods during which external prices exceeded the PJM price. 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]



8 These daily forward prices are for week days, which are not holidays, only.

Capacity Markets in June 2000

On June 1, 2000, the capacity resources in PJM were less than the total capacity obligation and prices in the PJM daily capacity credit markets reached the highest level since this market was introduced in late 1998. Daily capacity credit market prices fell on June 2, but remained high by historical standards for the balance of June.

Figure 3 depicts the prices and quantities traded in daily and monthly capacity credit markets during 2000. Both daily and monthly capacity credit 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, close to twice the level of the daily Capacity Deficiency Rate (CDR), or $354.60/MW-day. (The RAA 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.

Demand

Demand for capacity credits in the daily capacity credit market ranged from 761 to 2,374 MW from January to June 2000. The average daily volume 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 demand 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. On June 1, the bid price for these mandatory demand bids was $354.60/MW-day or twice the CDR. This demand behavior had a significant impact on the market-clearing price.

Supply

External forward energy market prices, shown in Table 7 and Figures 6 and 7, showed a spread over PJM prices for June and a very significant spread over PJM prices for July and August. The external energy market prices clearly provided a profitable opportunity for owners of uncommitted capacity in PJM. The relatively high level of capacity delistings was a direct response to these price differentials.

Table 7: Comparison of External Forward Prices vs. PJM Forward Prices

	June 2000[9] 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

9 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 and thus does not equal the difference between the monthly PJM and external minimum, maximum or average prices.

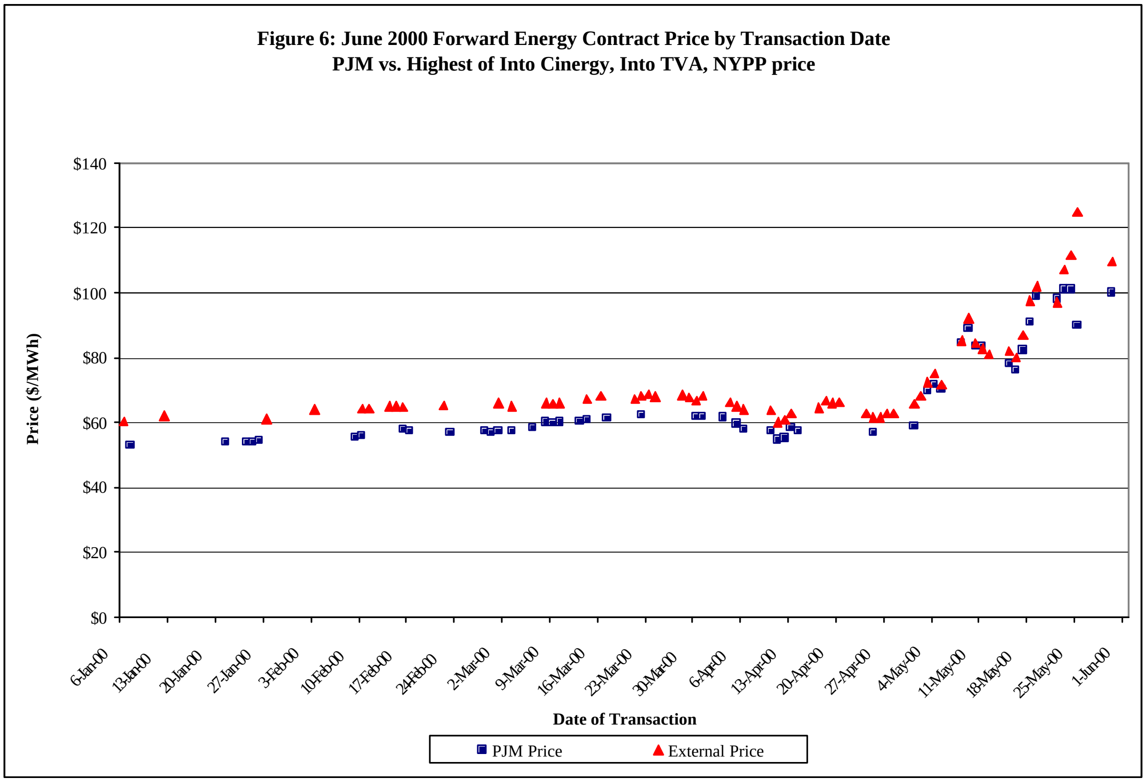


Figure 6: June 2000 Forward Energy Contract Price by Transaction Date
PJM vs. Highest of Into Cinergy, Into TVA, NYPP price
Price ($/MWh)
$140
$120
$100
$80
$60
$40
$20
$0
6-Jan-00
13-Jan-00
20-Jan-00
27-Jan-00
3-Feb-00
10-Feb-00
17-Feb-00
24-Feb-00
2-Mar-00
9-Mar-00
16-Mar-00
23-Mar-00
30-Mar-00
6-Apr-00
13-Apr-00
20-Apr-00
27-Apr-00
4-May-00
11-May-00
18-May-00
25-May-00
1-Jun-00
Date of Transaction
PJM Price
External Price

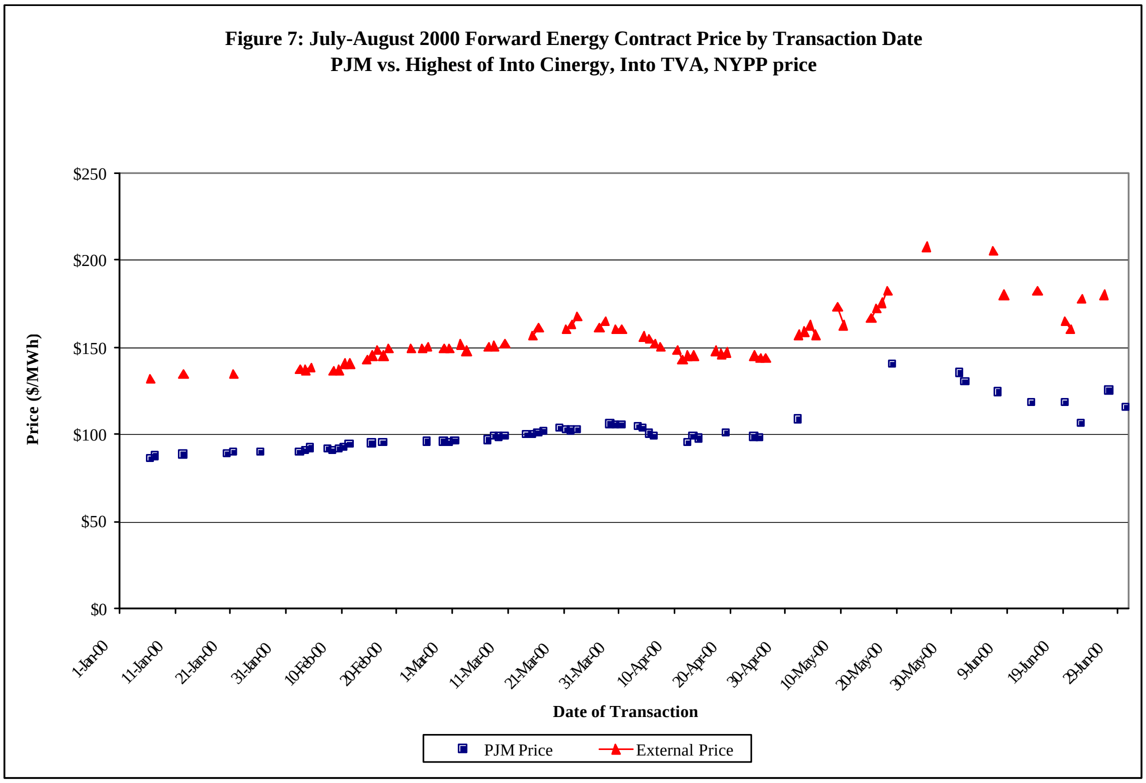
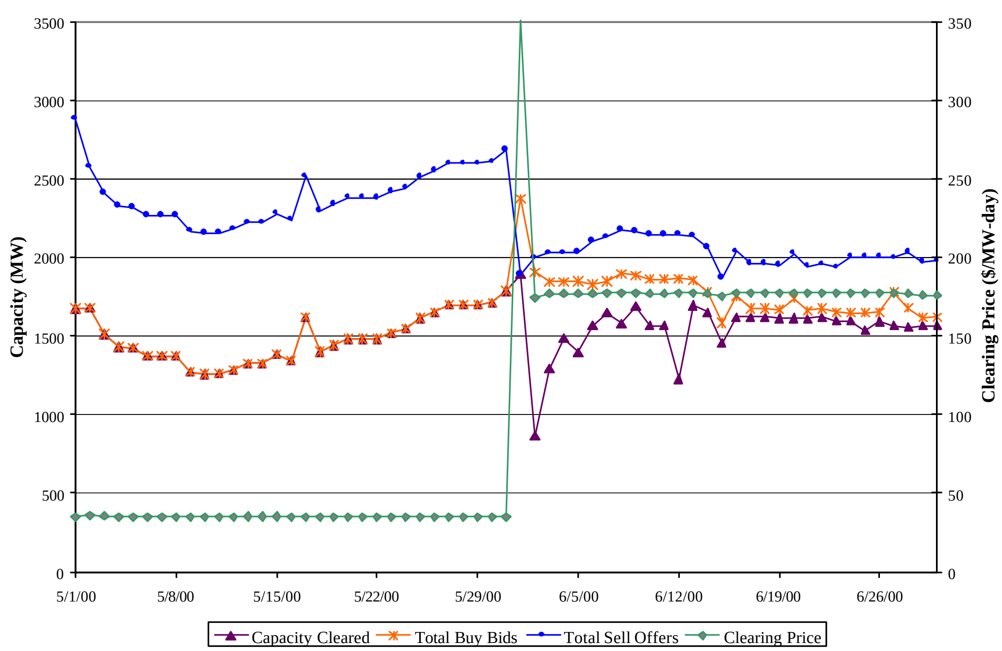


Figure 7: July-August 2000 Forward Energy Contract Price by Transaction Date
PJM vs. Highest of Into Cinergy, Into TVA, NYPP price
Price ($/MWh)
$250
$200
$150
$100
$50
$0
1-Jan-00
11-Jan-00
21-Jan-00
31-Jan-00
10-Feb-00
20-Feb-00
1-Mar-00
11-Mar-00
21-Mar-00
31-Mar-00
10-Apr-00
20-Apr-00
30-Apr-00
10-May-00
20-May-00
30-May-00
9-Jun-00
19-Jun-00
29-Jun-00
Date of Transaction
PJM Price
External Price

Figure 8 shows the relationship among capacity credit market demand bids and supply offers and capacity credit market prices for May and June. Figure 8 compares market conditions in May and June, showing that the gap between the MW level of demand bids and supply offers narrowed in June. Figure 5 shows capacity exports (delists) and Figure 4 shows the resulting pool unforced capacity position for 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, in 1999 the average delisted capacity was 906 MW and the maximum delisted capacity was 1,776 MW. 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 8: Daily Capacity Credit Market Summary
May — June 2000



Market Results

On June 1, 2000 for the first time since the introduction of the capacity credit markets in December, 1998, the total demand for daily capacity credits exceeded the total supply of daily capacity credits. The pool capacity obligation exceeded the sum of unforced capacity and thus the pool was deficient by 334 MW. After June 1, some of the delisted capacity returned to PJM and excess capacity ranged from 91 to 358 MW from June 2 through June 30.

The combination of an increase in demand and a decrease in supply had a significant impact on the capacity credit market price. Daily capacity credit market prices for each day in May were approximately $35/MW-day. Monthly prices for May capacity credits, in auctions occurring in February, March, and April ranged from $14.99 to $29.74/MW-day. As Figure 8 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.

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. To assess 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 summer 2000 capacity credit markets, opportunity costs appear to explain the level of supply available to the daily capacity credit markets, delisting and imports by capacity owners and thus the position of the supply curve, the offer behavior of capacity owners and thus the shape 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 observed level of market prices. Thus, it does not appear that the capacity credit market prices observed in the summer months were the result of market power or market manipulation.

Despite these conclusions regarding 2000, conditions in the capacity credit markets make the potential exercise of market power a continuing concern. Demand is extremely inelastic since 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 demand elasticity that characterizes the capacity markets.

New Incentives

Markets play a major role in ensuring the reliability of supply in PJM. For example, there is no requirement that capacity in the PJM area be sold to PJM loads. Generators choose to sell capacity to PJM loads when it is in their economic interests. Thus, market design can have a significant impact on reliability. The introduction of market-based bidding for energy in PJM and surrounding control areas has created a new set of incentives for entities providing and purchasing energy in the larger region. 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.

To continue to meet the fundamental goal of reliability, PJM capacity credit markets must provide a set of incentives consistent with attaining the desired level of reliability. The current structure of incentives does not appear to be optimal for attaining PJM's reliability objectives.

Both the required term for meeting the capacity obligation and the cost of being deficient require adjustment.

The provision for daily markets in the capacity credit market rules is central to the current incentive structure facing participants in the PJM capacity credit markets. The ability of LSEs to meet their capacity obligation 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 that fall short of maximizing the reliability of the PJM system. While generators can be expected to continually evaluate the opportunities to sell capacity over a variety of time frames, the existence of daily capacity credit markets makes the decision more dependent on daily fluctuations in external energy prices, than would be the case if capacity credit markets were cleared only annually or biannually. With longer term capacity credit markets, the likelihood of the net external price differential exceeding the annual value of capacity, evaluated over the entire period, is lower and thus the incentives to sell the system short are lower.

Appendix

The general requirement for each Load-Serving Entity is:

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

Where:

Unforced Capacity for capacity resource "i" = (*Installed capacity*$_i$) * (*12 mo rolling average EFORd*$_i$)

Unforced capacity obligation[10] *for LSE "j"* = [(*Weather-adjusted actual coincident peak load*$_j$ * *Diversity factor*) - *ALM adjustment*$_j$] * [(1 + *PJM Reserve margin*) * (1 – *PJM 5yr average forced outage rate*)]

Unforced capacity and unforced capacity obligation are compared on a daily basis to determine whether a Load-Serving Entity is deficient. A deficiency results in a penalty of $160/MW-day of deficiency, or, in unforced capacity terms, $177.30/MW-day. Both the capacity and obligation sides of the equation can change on a daily basis, as illustrated in the data presented in this section.

The outage rates used in crediting units with capacity are based on the 12-month rolling average outage rates 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 capacity obligation in capacity markets is based on the prior year weather-adjusted actual peak load, prior year ALM load credits and the approved forecast reserve margin. A significant increase in observed loads would not have an impact on the current year capacity obligation.

Definitions of key capacity market terms are presented below:

- **Capacity Resource**. Capacity which is either committed to serving capacity obligations within PJM or capacity from resources within the PJM control area which are accredited to the PJM control area per the RAA.
- **Installed Capacity.** System total installed capacity measures the sum of the *installed capacity* (in installed terms, not unforced terms) from all internal and qualified *external resources* designated as PJM *capacity resources*. Installed capacity can change on a daily basis principally due to exports (delisting) and imports of capacity or when a physical change is made to a generating unit, although on 79 percent of the days in this time period installed capacity was unchanged from the prior day.

[10] 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).

- **Unforced Capacity**. System total unforced capacity is the installed capacity adjusted for outage rates. Installed capacity was between 6.2 percent and 7.0 percent greater than unforced capacity over this time period, reflecting unforced outage rates in effect over the time period.
- **Obligation**. The sum of all Load-Serving Entities' unforced capacity obligations is determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
- **Gross excess.** The sum of all LSE's individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as *Accounted-for Excess* in the PJM Accounted-For Obligation Manual (Manual 17).
- **Gross deficiency.** The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as *Accounted-for Deficiency*.
- **Net excess.** The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of LSE's obligations. Net excess averaged 1,839 MW/day and ranged from 426 MW/day to 2,486 MW/day.
- **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.
- **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 of capacity mean that the capacity is delisted from its capacity resource status in PJM.
- **Net exports.** Capacity exports (or delists) less capacity imports.
- **Internal bilateral transactions**. Bilateral transactions of capacity where the source and sink are internal to the PJM control area. Internal bilateral transactions may reflect capacity credits or unit-specific transactions.
- **Daily Capacity Credit Market (Daily CCMs).** The *Capacity Credits* cleared through PJM daily *Capacity Credit Markets (CCMs)*.
- **Monthly CCMs.** The *Capacity Credits* cleared through PJM single month *Capacity Credit Markets (CCMs)*.
- **Multi-monthly CCMs**. The *Capacity Credits* cleared through PJM multi-monthly *Capacity Credit Markets (CCMs)*.

REGULATION MARKET

Summary and Conclusions

PJM introduced a new regulation market on June 1, 2000. Regulation is one of six ancillary services defined by FERC in Order No. 888. The provision of regulation is coordinated by the control area operator, PJM. Regulation is required in order to match generation with short-term increases or decreases in load which would otherwise result in a short-term imbalance between the generation and usage of energy. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. The PJM regulation market supplanted an administrative and cost-based regulation procurement mechanism that had been in place for many years. Market participants can now acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally.

The timing of the introduction of the regulation market was consistent with PJM's incremental approach to the introduction of markets. Implementation of the market-priced energy market was completed after a year's experience with a cost-based energy market incorporating locational pricing, and after a careful, collaborative development process. The introduction of the regulation market was completed after 14 months experience with a market-priced energy market. The new regulation market is a step towards PJM's goal of implementing a market-based approach to all components of the energy, capacity and ancillary services markets, where it is viable.

The MMU has reviewed the structure of the regulation market, the number and nature of regulation offers, the level of the regulation price and the system regulation performance since the implementation of the regulation market. The MMU concludes that the new regulation market functioned effectively and was competitive in 2000. Concerns about the structure of ownership in the regulation market are offset at present by the available supply of regulation capacity from PJM resources compared to the demand for regulation. The price of regulation under the market was approximately equal to the price under the administrative and cost-based system (Figures 1 and 2) and the price exhibited the expected relationship to changes in demand (Figure 3). There is the potential for various forms of non-competitive behavior in the energy market to affect the regulation market, although there is no evidence of such an issue during 2000. The introduction of a market in regulation resulted in a significant improvement in system regulation performance, measured by the availability of regulation (Figure 4) and by NERC Control Performance Standards CPS1 and CPS2 (Figure 5). While the preliminary results from the first seven months of the regulation market are positive, it is too early to reach a final conclusion regarding the long-term competitiveness of the market in regulation.

Regulation Service

The PJM control area maintains regulating capability in order to eliminate any short-term imbalances between the supply and usage of energy. Regulation helps to maintain the balance between load and generation by moving the output of selected generators up and down via an automatic control signal.

The generating units assigned to meet PJM regulation requirements must be capable of responding to the Area Regulation (AR) signal within five minutes and must increase or decrease their outputs at the ramping capability rates specified in the unit-specific offer data submitted to PJM. The regulation service supplied by individual generating units is defined as: “The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal.”

Not all generating units are equipped to provide regulation service. Moreover, the amount of regulation a properly equipped generating unit can supply is limited by the physical ability of the unit to increase or decrease output within five minutes. The regulation capability of an individual generator is the difference between its current operating level and the level that it could ramp to, either up or down, within five minutes. Of the 540 generating units in the PJM area[1], 111 are qualified to provide regulation.[2] In the PJM area there are more than 56,000 MW of generating capacity while about 1,701 MW of regulation capability have been identified in this analysis.[3]

The PJM control area establishes separate area-wide regulation requirements for both peak hours (hours ended 0600-2400) and off-peak hours (hours ended 0100-0500 hours). The regulation requirement for the peak period is 1.1 percent of the forecast peak load; for the off-peak period it is 1.1 percent of the valley load forecast.[4] During 2000, this requirement ranged from approximately 200 MW of regulation capability for the off-peak period to approximately 550 MW for the peak period.[5]

Responsibility for the control area’s hourly regulation requirement is assigned to all Load Serving Entities (LSEs) within the PJM control area based upon each LSE’s share of the control area’s hourly load. The LSE’s regulation obligation can be met by self-scheduling of its own generators, bilateral purchases or purchases through the PJM operated regulation market.[6] Only the regulation requirements not met via bilateral contracts or via self-scheduled resources are obtained via the PJM regulation market.

Regulation for the PJM control area must be supplied by generators located within its metered electrical boundaries. Thus, the largest relevant geographic market for regulation service in PJM is the PJM control area. Within the PJM control area, there are no geographic restrictions on generators that can supply regulation service, nor transmission costs involved in supplying regulation. In general, even when there are internal transmission constraints within PJM, regulation still can be supplied from any generators electrically within the PJM control area. Suppliers in the relevant geographic market include all entities owning generating capacity in the market that can be used to provide regulation.

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1 Mid Atlantic Area Council, Regional Reliability Council EIA-411 Report, April 1, 1999.

2 In this analysis, the units which are qualified to provide Regulation are those which have actually provided Regulation during a recent time period. See below for details.

3 This Regulation capability is net of forced outages based on average forced outage rates.

4 PJM Manual for Scheduling Operations, Manual M-11, page 3-4.

5 This excludes the off-peak regulation requirement imposed for the transition to Y2K which was two times the otherwise required off-peak requirement.

6 PJM Open Access Transmission Tariff, Attachment K--Appendix.

As noted, internal transmission constraints do not affect the geographic extent of the regulation market. However, internal transmission constraints may affect the cost structure of regulation offers via their impact on opportunity costs, a component of such offers. As an example, if, on a day-ahead basis, it is determined that the eastern interface is constrained, regulation to the west of the interface could be more economic than regulation to the east. The eastern interface constraint could make LMPs higher to the east and thus could increase the regulation market offers of units in the east by increasing the opportunity costs of those units relative to the units in the west. Then, the western supply of regulation could serve the entire system because the amount of regulation required is quite small in comparison to the size of the eastern interface transmission limit and would have no significant impact on operating the system.[7] The actual opportunity costs of specific units would depend both on the LMP at the unit bus and the energy offer of the unit. (The opportunity cost is the difference between the LMP and the energy offer.) In general, the amount by which the opportunity costs in the east and the west differ would be a function of both the LMPs in the east and west and the energy offers of regulating units in the east and west and could vary over a wide range, from positive to negative.

The Regulation Market

Generators wishing to participate in the PJM regulation market submit offers for specific units by 1800 of the day prior to the operating day. Regulation offers include the attributes of the unit's regulation capability and are subject to a $100/MWh offer cap. PJM uses the day-ahead LMPs and generation schedules, which result from clearing the day-ahead market, together with the regulation offers, to calculate opportunity costs by unit for each hour of the operating day. Regulation offers and opportunity costs are added to create a total offer price which, in aggregate, results in a regulation supply curve. The supply curve and the PJM demand curve for regulation are used to calculate a Regulation Market Clearing Price (RMCP).

During the operating day, PJM calculates the actual opportunity cost for each unit based on the real-time LMPs. The real-time opportunity costs and the regulation offer prices are added to create a total offer price for each unit and to create, in aggregate, a real-time supply curve. The real-time supply curve is used to select the most economic units to supply regulation in real time. Units selected to provide regulation in real time are compensated at the higher of the RMCP or the regulation offer plus the real-time opportunity cost.[8]

For units that were made available for energy and regulation in the day-ahead market, regulating capability can be decreased but not increased during the operating day. This market rule is designed to prevent withholding from the regulation market, which determines the RMCP, and then providing regulation at the resultant higher price during the operating day. In order to effect decreases in regulating capability in real time, regulating units can modify certain attributes of their offer on an hourly basis in real time including regulation capability in MW, regulation limits in MW and regulation status. Regulation capability is the MW amount by which the unit

[7] For example, transmission capability into the eastern portion of PJM from the rest of PJM is, in general, approximately 6,000 MW. (The precise number varies depending upon actual operating conditions on the network.) The regulation requirement for the eastern portion of PJM alone would be about 250 MW. The regulation requirement in the east, net of self-scheduled requirements, would be even lower.

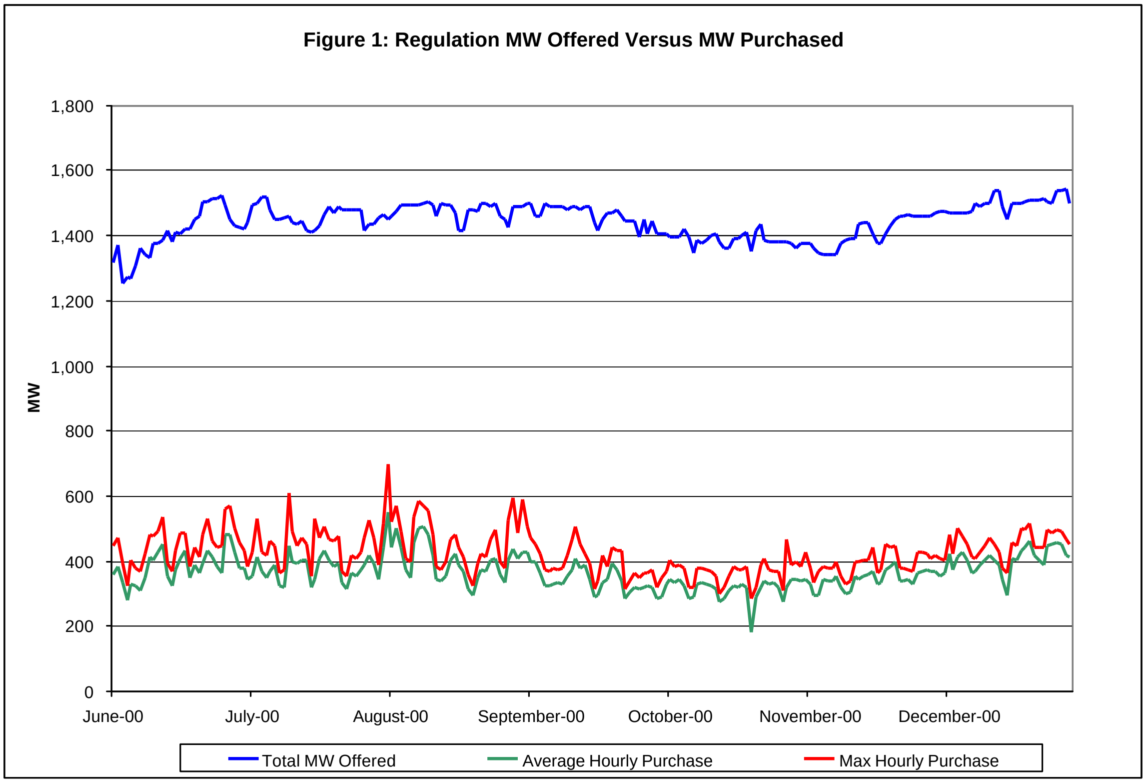
[8] The use of actual opportunity costs, calculated by PJM, permits generators to be compensated for opportunity costs without requiring the addition of a risk premium to the offer to cover the risk associated with a distribution of opportunity costs which is unknown before the fact.

can change output within five minutes in response to the regulation signal. Regulation limits refer to the maximum and minimum MW a unit can produce while providing regulation. Regulation status refers to whether the unit is available or unavailable to provide regulation and whether the unit is self-scheduled for regulation. Real-time changes to regulation status can include: available to unavailable, self-scheduled to unavailable and available to self-scheduled. Units that were not made available for energy in the day-ahead market but become available during the operating day may be made available to provide regulation to the market or to be self-scheduled in real time. Bilateral regulation transactions are accounting transactions that take the form of transferring regulation obligation between parties. Bilateral transactions can be entered through 1200 the day after the transaction starts.

When units are paid RMCP, the positive difference, if any, between RMCP and the sum of the unit specific offer price and the unit specific opportunity cost, is a credit against PJM's obligation to pay make-whole operating reserves from the energy market. PJM guarantees that a generator will receive all start up and no load costs not covered by energy market payments. Any such payments are made from operating reserves. The difference between the market clearing price received by a unit in the regulation market and unit specific regulation costs also offsets any unrecovered start up and no load costs and thus reduces operating reserve payments.

Regulation Market Structure

The MMU recommended, in an affidavit filed with FERC, that PJM be permitted to implement a regulation market, based, in part, on a traditional measure of market structure, a concentration ratio, as measured by the HHI or Herfindahl-Hirschman Index.[9] Concentration ratios measure the concentration of ownership in a market, in this case, the concentration of ownership of regulation assets. The HHI concentration ratio is the sum of the squares of the market shares of the firms in a market. An analysis of HHIs since the introduction of the regulation market indicates that seasonal HHIs fall between 1700 and 1800, which is categorized as "moderately concentrated" under the 1992 joint Department of Justice/Federal Trade Commission Horizontal Merger Guidelines and FERC's Merger Policy Statement. A moderately concentrated market is one with an HHI between 1000 and 1800. The fact that several entities have large shares of the available supply of regulation is also a cause for concern. Offsetting these concerns, the available supply of regulation is substantially larger than the demand for regulation. During 2000, the total regulation offers exceeded regulation purchases by a factor of more than three as illustrated in Figure 1.



9 Federal Energy Regulatory Commission, Docket No. ER00-1630, Affidavit of Joseph E. Bowring, February 2000.

Regulation Market Results

As Figure 2 shows, despite several significant, short-lived spikes in the cost of regulation, most notably in the summer of 1999 and in May 2000, hourly regulation costs have been relatively stable since January 1999. Price spikes were experienced under the cost-based regime because the credit paid to sellers of regulation was a function of the difference between hourly LMP and the regulation cost.

Figure 2: Hourly Regulation Cost Per MW

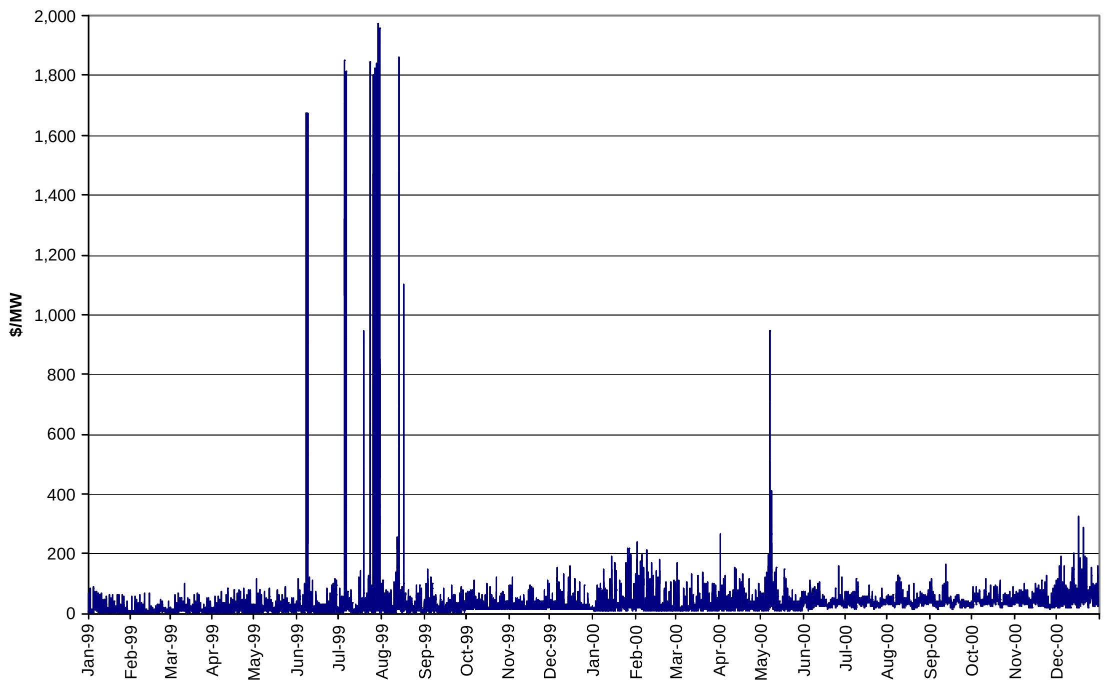
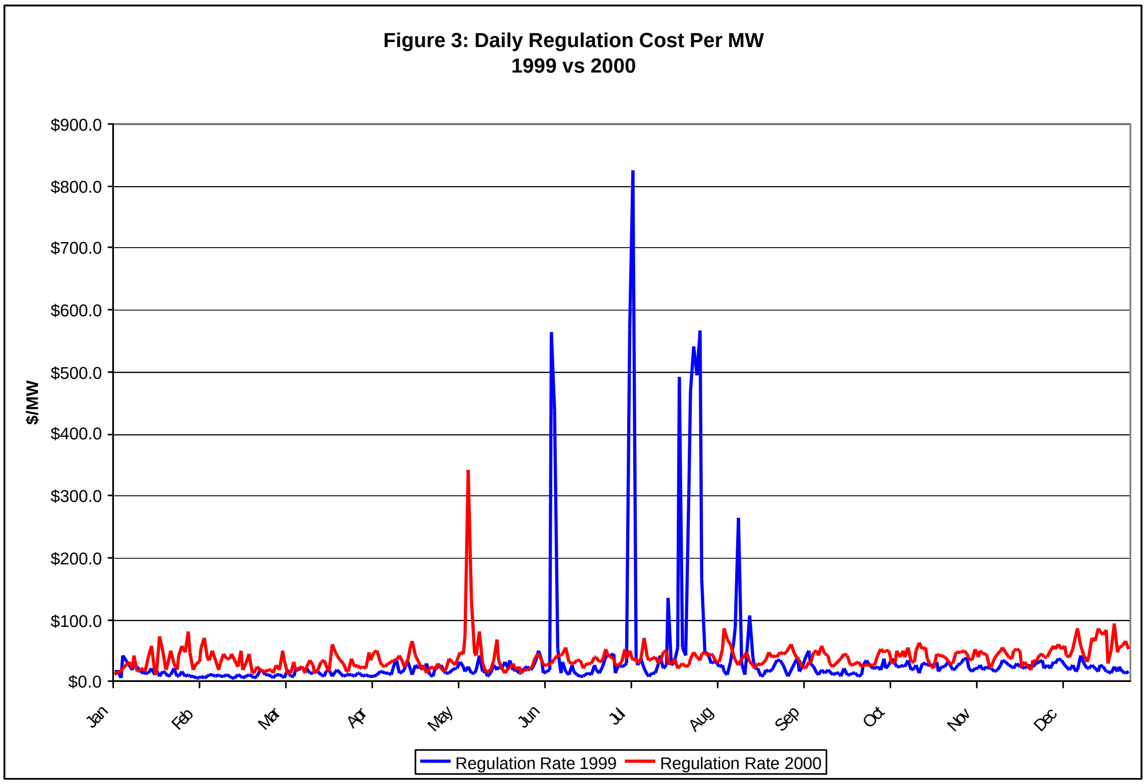


Figure 3 compares the average daily cost of regulation for 1999 and 2000 including the seven months in 2000 after the introduction of the regulation market. The total cost of regulation was about 7% lower in 2000 than in 1999 (about $9.4 million) and was about 30% lower from June 1, 2000 than for the comparable period in 1999 (about $30.3 million). The latter decrease was largely the result of high demand conditions in the energy market in the summer of 1999 which were not repeated in 2000.

Figure 3 also shows a slight increase in the cost of regulation in December 2000. This increase appears to be the result of an increase in demand for regulation in December as well as an increase in the opportunity cost component of regulation cost.

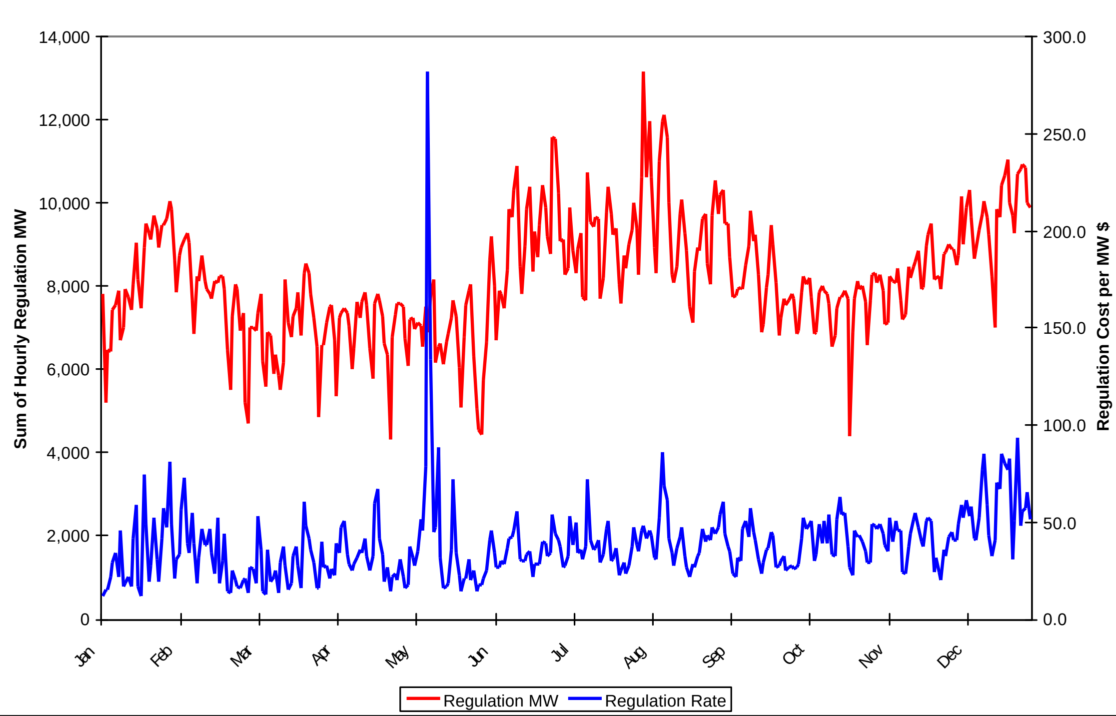


The data presented in Figures 2 and 3 show that the price of regulation during the first seven months of the market was approximately equal to the price of regulation under the cost-based system in place prior to market implementation. This is one test that suggests that the regulation market was competitive in the latter half of 2000.

Figure 4 compares the regulation cost per MW to the demand for regulation during 2000. The demand for regulation is a linear function of forecast energy demand, as noted above. Loads increased in December and the demand for regulation increased as a result. In addition, the increase in system LMP led to an increase in opportunity costs because the spread between LMP and the energy offers of the regulating units increased. The system LMP increased because the units on the margin, which were setting LMP, were generally using fuels which had experienced significant cost increases. Regulation is provided primarily from coal-fired steam plants and from hydro. Neither the cost of hydro nor the cost of coal rose as rapidly as the cost of the fuels which were primarily on the margin in December. The basic structure of the regulation offer supply curve was unchanged in December from prior months.

The data presented in Figure 4 show the expected relationship between demand and price. Price is a positive function of demand as would be expected with an upward sloping supply curve. Again, the result is consistent with the conclusion that regulation market was competitive in the latter half of 2000.

Figure 4: Daily Regulation MW Purchased Compared to Cost Per Unit



The close relationship between the regulation market and the energy market is essential for the efficient and competitive provision of both energy and regulation. However this close relationship also creates the potential for market issues in the energy market to be transferred to the regulation market. For example if the price in the energy market is above competitive levels, this will tend to increase the price of regulation. Economic withholding in the energy market could also impact the regulation market. While there is no evidence that such behavior affected the price of regulation in the latter half of 2000, the potential for issues requires ongoing scrutiny.

Regulation Performance

System regulation performance is related to the incentives to provide regulation, both under the prior administrative approach and the market-based approach. Under the administrative regime, the system had less than the target amount of regulation at times during some off-peak hours and at times during the transition between off-peak and on-peak periods. This could well have resulted from the fact that the administrative payments for regulation were based on the difference between the current hourly LMP and a fixed regulation cost based on an historical average energy cost calculation. The result, during some off-peak hours, was that there might have been little incentive to provide regulation. The regulation market design provides better incentives to owners based on current, unit-specific opportunity costs and the submission of a current regulation offer price.

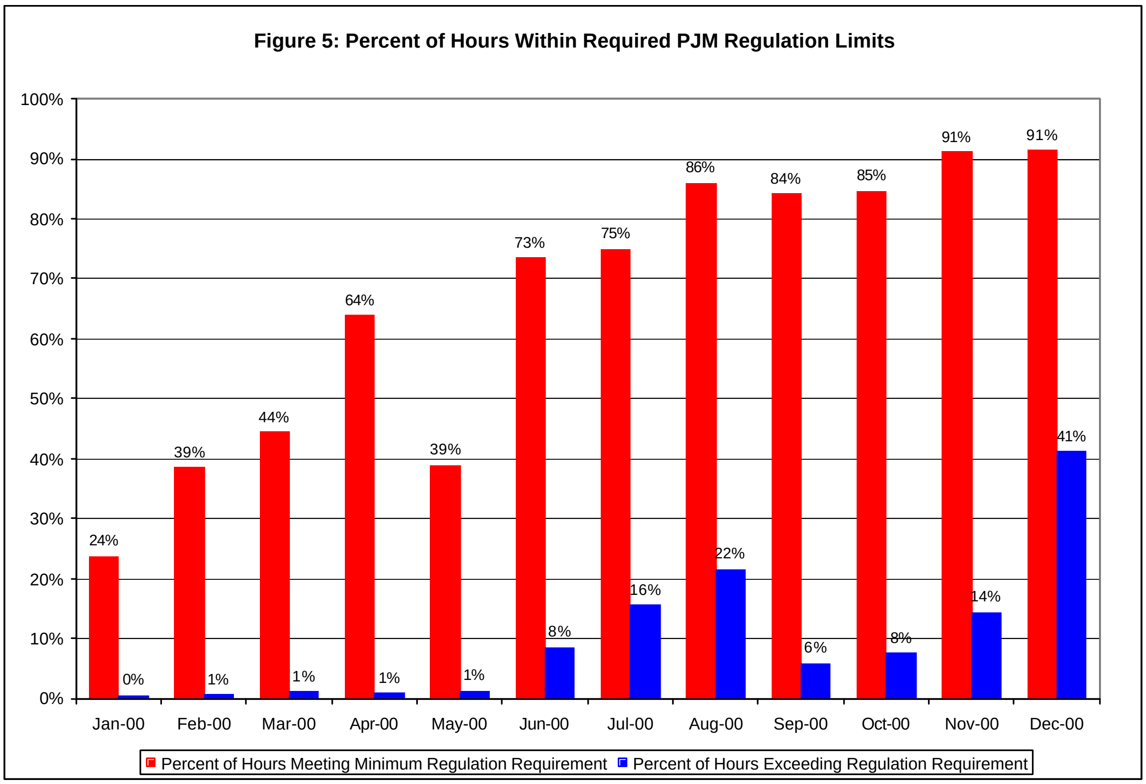
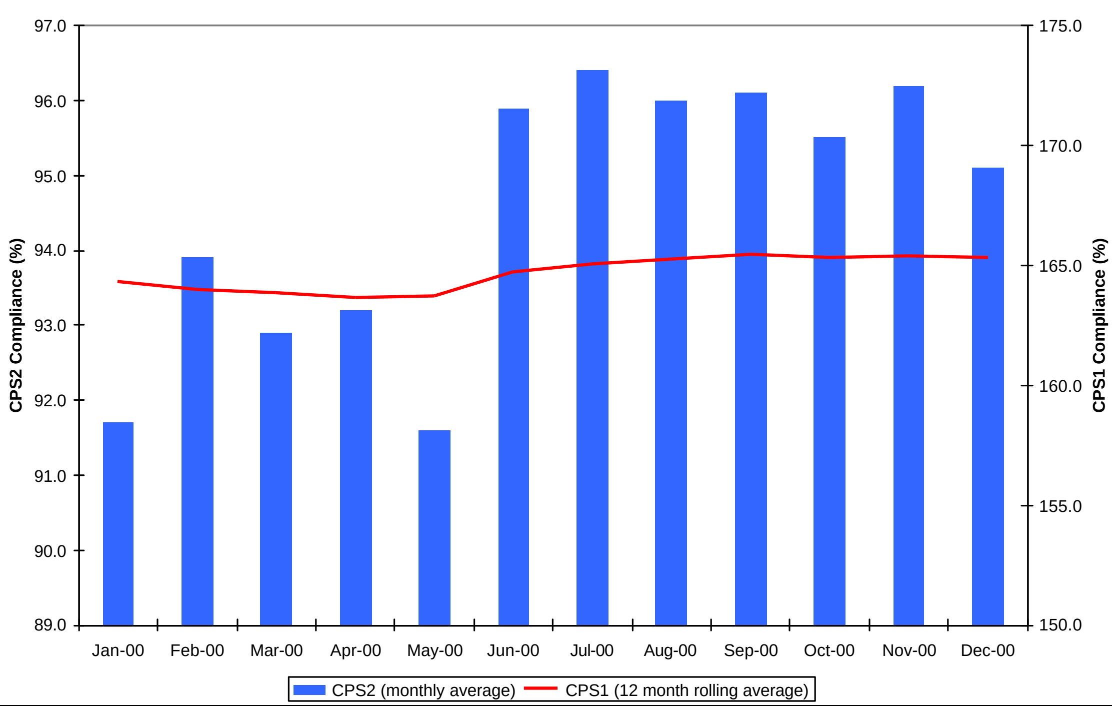


Figure 5 shows that during 1999 and the first five months of 2000, the supply of regulation was consistently less than the target level of regulation. After the introduction of the regulation market, the availability of regulation increased significantly. The proportion of hours in which PJM met the minimum regulation target doubled from an average of about 42% in the first five months of 2000 to about 84% in the months after the introduction of the regulation market. The proportion of hours in which PJM exceeded the minimum regulation target increased from less than 1% in the first five months of 2000 to more than 16% on average in the seven months after the introduction of the regulation market.

Regulation helps to maintain the balance between load and generation by moving the output of selected generators up and down via an automatic control signal. The balance between load and generation is defined in terms of the frequency of the system, measured in Hertz (Hz). Regulation is the PJM control action to correct for changes in load or generation that may cause the power system to operate above or below 60 Hz. The response to the PJM regulation control action is the variable energy produced by units under automatic control, independent of the economic cost signal and within five minutes of the need for it.[10] While the improved availability of regulation illustrated in Figure 4 is important, the ultimate success of regulation in balancing load and generation is measured by NERC Control Performance Standards CPS1 and CPS2.[11]

Figure 6 shows PJM's regulation performance as measured by the NERC Control Performance Standards CPS1 and CPS2. These standards measure the relationship between generation and load. CPS1 is measured on a 12-month rolling average and provides what NERC terms a "frequency-sensitive evaluation" of how the control area meets it demand requirements. CPS2 measures the balance between load and generation on a 10-minute basis. Figure 6 shows that the CPS1 measure has improved since the introduction of the regulation market. Figure 6 also shows that the CPS2 measure has improved since the introduction of the regulation market.

Figure 6: CPS1 and CPS2 Performance



The data presented in Figures 5 and 6 illustrate the improvement in regulation performance which occurred after the implementation of the regulation market. The evidence is consistent

10 PJM documents with information on regulation include the PJM Manual for Pre-Scheduling Operations, Manual M-10, PJM Manual for Scheduling Operations, Manual M-11.

11 NERC Operating Manual, March 29, 2001.

with a significant increase in performance resulting from the introduction of a market. As with the other evidence, it must be remembered that the regulation market was in place for only seven months in 2000 and that further experience is required before a final conclusion can be reached regarding the competitiveness of the regulation market. The early evidence is quite positive.

FTR AUCTION MARKET

Summary and Conclusions

In PJM, firm point-to-point and network transmission service customers may request Fixed Transmission Rights (FTRs) as a hedge against the congestion charges that can result from PJM's system of locational marginal pricing (LMP). More precisely, an FTR is a financial instrument that entitles the holder to receive revenues (or charges) based on transmission congestion measured as the hourly LMP differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basis risk associated with delivering energy from one bus or aggregate to another bus or aggregate. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

While the initial FTR allocation process provided FTRs only to network and firm point-to-point transmission customers and the bilateral market allowed the exchange of only those specific FTRs, the FTR Auction Market was designed to make FTRs more available to all market participants. The basic mechanics of the FTR auction have worked as intended, since their approval by FERC on April 13, 1999.[1] A review of the operation of the FTR auction process indicates that the FTR auction was competitive and has succeeded in its purpose of increasing access to FTRs. There has been a steady increase in the MW of cleared FTRs which have grown from an average monthly 2,400 MW in 1999 to 6,700 MW in 2000 (13,800 in December 2000). (See Figure 1.) The trends in the number of bids, the number of offers and MWs of bids have also been upward. (See Figures 2, 3 and 4.)

While the FTR auction has been successful, several issues related to the FTR Auction process and results were identified in 2000. Each of these issues has been successfully resolved so as to enhance the competitiveness of PJM markets. The issues, described in detail later in this section, are FTR allocation, creating congestion and transmission outage notification.

Overview

On November 25, 1997, the Federal Energy Regulatory Commission (FERC) approved the comprehensive restructuring of the PJM marketplace, establishing PJM as an Independent System Operator ("ISO"). [2] Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC 61,257 (1997) ("November 25 Order"). In the November 25 Order, the Commission conditionally approved a locational marginal pricing method (LMP) for managing transmission congestion.

1 87 FERC ¶61,054 (1999).

2 Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997) ("November 25 Order").

As part of the November 25 Order, FERC directed PJM to file a proposal addressing any lack of price certainty that might exist under LMP. On December 31, 1997, the PJM Supporting Companies[3] filed proposed amendments to Schedule 1 of the Operating Agreement to implement an FTR auction, which, they concluded, was one way to address the lack of price certainty. On March 25, 1998, PJM filed in support of the FTR auction proposal of the PJM Supporting Companies.

On April 1, 1998, PJM implemented LMP for energy and offered FTRs as a transmission congestion hedging mechanism to all firm transmission service customers. The initial allocation of FTRs was for a 2-month transition period from April 1 through May 31, 1998. The first long-term FTRs were effective for the 1998-1999 Planning Period, June 1, 1998 through May 31, 1999.

The Commission issued an Order on February 11, 1999, [4] rejecting the Supporting Companies' proposal regarding the FTR auction, and directing PJM to develop, with stakeholder input, another FTR auction proposal addressing the Commission's concerns within 90 days. [5]

On March 2, 1999, in compliance with the February 11 Order, PJM made a filing revising the FTR auction proposal. PJM's Members Committee unanimously ratified the revised FTR auction proposal on March 26, 1999. [6] PJM filed revised pages to the PJM Open Access Transmission Tariff (OATT) and Operating Agreement (OA) establishing an FTR auction.[7] On April 13, 1999, the Commission issued an Order conditionally accepting the FTR Auction filing with an effective date of April 13, 1999.[8]

On June 1, 2000, PJM introduced the Two-Settlement System under which the energy market consists of two separate markets (settlements): a day-ahead and a real-time, or balancing, market. The day-ahead market permits market participants to lock in energy prices one day ahead of real-time. Differences between market participants' day-ahead and real-time energy injections and withdrawals are settled in the balancing market at real-time prices. The most significant feature of the Two-Settlement System for FTRs is that transmission congestion is now hedged by FTRs only in the day-ahead market. FTRs are settled at day-ahead energy market prices. Market participants are hedged in real-time to the extent that their energy schedules in the real-time market are consistent with their energy schedules in the day-ahead market.

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3 The PJM Supporting Companies were Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, PP&L, Inc., Potomac Electric Power Company and Public Service Electric and Gas Company.

4 86 FERC ¶61,147 (1999).

5 Id. at 61,527.

6 Letter from counsel for PJM dated March 26, 1999.

7 Attachment K-Appendix to the OATT and Schedule 1 of the OA.

8 87 FERC ¶61,054 (1999).

PJM FTR Mechanics

Each FTR is defined from a point of receipt, where power is injected into the grid, to a point of delivery, where the power is withdrawn from the grid.[9] For each hour during which congestion occurs on the transmission system and the FTR is in the same direction as the congested flow, the FTR holder is awarded a share of the transmission congestion charges collected from market participants. This share is the participant's transmission congestion credit. The transmission congestion charges are allocated to FTR holders based on the target allocation. FTR holders pay a charge if the FTR is in the direction opposite to the congested flow.

If constraints exist on the transmission system and FTRs were a perfect hedge, each FTR holder would receive a credit equal to its FTR MW reservation multiplied by the LMP difference between the point of delivery and the point of receipt of their FTR. This is termed the transmission credit target allocation. Credits are paid to all FTR holders, for paths with LMP differentials, regardless of who delivered energy or how much energy was delivered across the constrained path.

An FTR can provide financial benefits or liabilities. An FTR provides a benefit when the path designated in the FTR is in the same direction as the congested flow, i.e., the point of withdrawal LMP is higher than the point of injection LMP. The value of the FTR is equal to the FTR MW reservation times the positive difference between the point of withdrawal LMP and the point of injection LMP. An FTR can be a liability when the designated path is in the direction opposite to the congested flow, i.e. the point of injection LMP is higher than the point of withdrawal LMP. In this case, the value of the FTR is equal to the FTR MW reservation times the negative difference between the point of withdrawal LMP and the point of injection LMP. Regardless, an FTR holder that delivered energy on the designated path consistent with the FTR would either receive FTR revenues or make FTR payments equal to congestion charges or congestion credits. The result would be no net congestion-related benefits or liabilities.

PJM time-stamps and processes all FTR requests in the order in which they are received. PJM approves FTRs based on the results of the Simultaneous Feasibility Test, and market participants must confirm approved FTRs for them to become effective.

Simultaneous Feasibility Test

The Simultaneous Feasibility Test (SFT) is a market feasibility test that attempts to provide revenue adequacy by ensuring that the transmission system can support the subscribed set of FTRs during expected system conditions. If an FTR passes the Simultaneous Feasibility Test, it is considered feasible and may be awarded. If the FTRs can be supported under expected system conditions and congestion occurs, PJM will collect sufficient revenues through congestion charges to cover the FTR congestion credits payable to the holders of FTRs, and revenue adequacy will exist. The primary purpose of the Simultaneous Feasibility Test is to preserve the economic value of FTRs by attempting to ensure that all FTRs awarded can be fully funded.[10]

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9 Point of injection and withdrawal refers to one or more buses.

10 PJM Manual for Fixed Transmission Rights, Manual M-06.

FTR Values

Tables 1a and 1b include FTR target allocations for the highest value transmission paths, measured by target allocations, from the first auction for May 1999 through the last auction in 2000. FTR target allocations represent the FTR revenues needed to fully hedge FTR holders against congestion. During this period, FTR target allocations totaled $129,000,000 on approximately 672 different transmission paths.

Table 1a lists the twenty-five FTRs with the largest financial benefits for the period. These FTRs account for 72% of the total target allocations and twenty-three of these had target allocations greater than $1,000,000. Most of these are from sources in Western and Central Pennsylvania to destinations in Eastern PJM, such as PSEG, PECO, DPL, and AECO zones.

Table 1a. FTR Target Allocations by Path, Twenty-Five Largest Financial Benefit

Path	Target Allocations
Peach Bottom – PSEG Zone	$ 14,810,505
Edgemoor – DPL Zone	$ 11,410,971
Peach Bottom – PECO Zone	$ 7,338,635
Martins Creek – PSEG Zone	$ 6,689,113
Muddy Run – PECO Zone	$ 6,320,513
Mercer – PSEG Zone	$ 5,436,620
Homer City – PENELEC Zone	$ 5,387,099
Conemaugh – PSEG Zone	$ 4,743,046
Keystone – PSEG Zone	$ 3,938,831
Brunner Island - PPL Zone	$ 3,705,818
Conemaugh - PECO Zone	$ 2,845,979
Keystone – PECO Zone	$ 2,785,848
Collins – Newberry	$ 2,777,399
Limerick – PECO Zone	$ 2,741,105
Burlington - PSEG Zone	$ 2,717,724
Montour - PPL Zone	$ 2,340,599
Homer City – Springboro	$ 2,195,856
Susquehanna - PPL Zone	$ 1,852,317
TMI - JCPL Zone	$ 1,838,203
Yards Creek - PSEG Zone	$ 1,727,886
TMI - PENELEC Zone	$ 1,392,592
Peach Bottom - AECO Zone	$ 1,205,002
Vienna – Tasley	$ 1,020,421
Adams – Metuchen	$ 962,346
Susquehanna – Sewaren	$ 887,875
TOTALS	$ 99,072,303

Table 1b. FTR Target Allocations by Path, Twenty-Five Largest Financial Liability

Path	Target Allocations
NYPP-East – Western Hub	$ (357,737)
Western Hub – VP	$ (319,955)
Western Hub – First Energy	$ (298,993)
Meadow Road – Dey Road	$ (217,224)
AP – PEPCO Zone	$ (168,784)
Metuchen – Adams	$ (144,172)
Titus – METED Zone	$ (128,274)
PENELEC Zone - Western Hub	$ (124,145)
Bergen – Shawnee	$ (123,278)
Warren – METED Zone	$ (122,001)
Salem – PECO Zone	$ (119,528)
Bayonne – Shawnee	$ (114,268)
Western Hub - AP	$ (102,302)
Dickerson - PEPCO Zone	$ (92,589)
Aldene – Susquehanna	$ (87,437)
Warren – PENELEC Zone	$ (85,232)
Branchburg - Somerville	$ (69,483)
AECO Zone - PSEG Zone	$ (60,204)
Homestead - Shawnee	$ (59,418)
PENELEC Zone - AECO Zone	$ (58,660)
Warren – JCPL Zone	$ (58,345)
Titus – PENELEC Zone	$ (58,326)
Montville - Wescosville	$ (44,228)
Traynor - Wescosville	$ (43,975)
Summit - Wescosville	$ (43,913)
TOTALS	$(2,852,366)

Table 1b lists the twenty-five FTR paths with the largest financial liabilities over the same period. These FTRs account for $2,852,366 of the $4,229,713 negative target allocations on 249 different paths that were financial liabilities. These FTRs tend to be in an east to west direction. These negative target allocation FTRs account for about 3% of total FTR target allocations.

Acquisition of FTRs

As noted earlier, there are four ways to acquire FTRs:

- Network Integration Service
- Firm Point-to-Point Service
- Bilateral FTR Market
- FTR Auction

FTRs can be obtained together with Network Integration Service and Firm Transmission Service. The Bilateral Market and the FTR Auction allow trading of existing FTRs, regardless of how the FTRs were acquired.

Network Integration Service FTRs

Network customers may select FTRs from any combination of their network resources to their network load in an amount up to their total peak load, and are free to add or drop FTRs at any time, subject to the Simultaneous Feasibility Test. PJM permits changes to the designation of network resources and loads at any time, subject to the Simultaneous Feasibility Test. Network FTRs are designated along paths from the specific, selected capacity resources, or the interconnection point with an external control area, to customers' aggregate loads. The generators selected for FTRs are referred to as designated network resources.

FTRs are determined to be feasible from a capacity resource to a particular company's aggregate load. However, the FTRs from this specific capacity resource may not be feasible to a different company's aggregate load and therefore cannot be automatically reconfigured. As a result, FTRs associated with specific capacity resources cannot be directly transferred to meet a different company's aggregate load. In general, buyers of FTRs must request the FTRs subject to the Simultaneous Feasibility Test. In order to establish feasibility, FTRs associated with capacity sales are available to the buyer only if the specific generating units and capacity amounts are identified. FTRs cannot be obtained for capacity credit transactions.

Firm Point-to-Point Service FTRs

PJM members may obtain FTRs with firm point-to-point transmission service, and may request FTRs up to the amount of their transmission service. As in the case of network service, PJM approves all, part, or none of any FTR request based on the results of the Simultaneous Feasibility Test. The FTRs remain in effect for the duration of the transmission service, which may be one year, one month, one week, or one day. Table 2, Transmission Service and FTR Request and Approval Timeline, details the required lead and response times and maximum terms for point-to-point service requests and FTRs.

Firm point-to-point transmission service is generally used in PJM for transmission out of PJM or through PJM. The associated FTRs are for the transmission path specified in the transmission reservation. The point of injection (receipt) may be, for example, a generation resource within the PJM Control Area or the interconnection point with an external control area. The point of withdrawal (delivery) may be, for example, one of the PJM aggregates or the point of interconnection with an external control area.

Table 2. Transmission Service and FTR Request and Approval Timeline				
Event	**Annual**	**Monthly**	**Weekly**	**Daily**
Earliest Request	No Limit	18-months	2-weeks	3-days
Latest Request	2-months	14-days	7-days	2-days
OI Respond	1-month	Per tariff	2-days	4-hours
Customer Confirm	15-days after PJM approves OR By 12 noon on day before service starts			
Maximum Term	No Limit	1-month	2-weeks	2-days

Bilateral Market FTRs
FTRs may be traded among buyers and sellers on the secondary market. Such bilateral trades can be made using PJM's eFTR trading system or they can be made independent of PJM's system. The data here reflect only those bilateral trades made using PJM's system. [11] Table 3 shows that a total of 4,349 MW of FTRs were traded in 35 separate transactions during the period from June 1, 1999 to May 31, 2000, while 4,501 MW of FTRs were traded in 42 transactions period from June 1, 2000 to May 31, 2001. Ninety-eight percent (98%) of the second half trades were continuations of the first-half trades, and 92% of all bilateral transactions were trades between affiliates.

Table 3. Bilateral Market Statistics By Period			
FTR Contract Period	**Sum (MW)**	**Count**	**Average (MW)**
June 1 - December 31, 1999	4349	35	124
January 1 - May 31, 2000	4349	35	124
June 1- December 31, 2000	4501	42	107

Monthly Auction FTRs
PJM conducts a monthly auction of both FTRs associated with the residual capability of the PJM transmission system and FTRs offered by market participants. The residual capability of the transmission system is that remaining after network and firm point to point transmission FTRs have been awarded. PJM members and transmission customers may participate in the FTR auction.

Each monthly auction is comprised of both an on-peak and an off-peak auction. The on-peak auction is for FTRs that are valid for hours ending 0800 to 2300 on weekdays, while off-peak

11 PJM does not track bilateral FTR trades made outside its system.

FTRs are valid for hours ending 2400 to 0700 on weekdays and all weekend and NERC holiday hours. All auction FTR contracts are for a period of one month.

Auction FTRs may be obtained between single buses, between a single bus and a combination of buses for which an LMP is calculated and posted or between such combinations of buses, subject to the Simultaneous Feasibility Test. These combinations of buses include hubs, zones, aggregates, and single buses either internal or external to PJM. Auction FTRs may be designated between any injection and withdrawal points.

Table 4, FTR Auction Timeline, details the timing of key events in the FTR auction. As indicated, the auction bidding period opens fifteen days prior to the effective date of the transmission rights being auctioned. PJM calculates and posts estimates of non-simultaneous available FTR capability for the PJM operating and external interfaces. The bids undergo pre-processing where they are verified for proper syntax and the ownership of sell offers is verified. Rejected bids are sent back to the owner for correction and resubmittal.

Table 4. FTR Auction Timeline

Time	**Activity**
15-days Prior to FTR Period	Bidding Period Opens
10-days Prior to FTR Period	Bidding Period Closes
2-days After Bidding Period Closes	Market is Cleared and Results Posted

Bidding closes ten business days prior to the start date of the period for which the FTRs were auctioned. The auction analysis determines a new set of feasible FTRs by calculating a market-clearing price for every location in PJM and then selecting the highest valued (bid-based) combination of feasible FTR paths. The value of an FTR path is the difference between the source and sink market clearing prices. Buy bids which have prices above the clearing price pay the path clearing price and sell offers which have prices below the path clearing price receive the path clearing price. The winning set of bids is the simultaneously feasible set of FTRs that maximizes the value of the awarded FTRs to the buyers.

The auction solution includes residual system capability plus FTRs offered into the auction. The auction solution does not attempt to match buy and sell offers on particular paths. FTRs offered for sale on particular paths can make additional FTRs available on different, seemingly unrelated paths. Such reconfiguration of FTRs can change the total amount of FTRs available and make available a different, previously infeasible set of FTRs. As a result, buyers can buy FTRs which are different from the FTRs explicitly offered by sellers. Conversely, certain FTRs offered for sale may not clear because they would introduce an infeasible condition.

After the auction is completed, successful bids are loaded into the FTR auction database and transferred to the PJM accounting and billing systems. Winning bids are posted in publicly available files on eFTR, PJM's internet-based FTR auction management system, no later than two days after the bidding period closes, and all bids are posted after six months. Buyers and sellers settle at path clearing prices for the FTRs they acquire or sell. This settlement is separate from the transmission congestion settlements. Auction revenues, net of payments made to the FTR sellers, are allocated among the regional transmission owners in proportion to their respective transmission revenue requirements.

Results of the FTR Auction

As noted earlier, the FTR Auction was designed to make FTRs available to any bidder. The auction has worked as intended, was competitive and has succeeded in increasing the availability of FTRs. Auction activity has increased steadily since the inception of the auction as shown by the data in Table 5 and Figures 1 to 8 below.

Table 5. FTRs by Type

	FTRs				Percent of Total			FTRS	% Total
Period	**Network (MW)**	**Pt. To Pt. (MW)**	**On-Peak Auction (MW)**	**Total (MW)**	**Network (%)**	**Pt. To Pt. (%)**	**On-Peak Auction (%)**	**Secondary (MW)**	**Secondary (%)**
May-99	30,684	607	357	31,648	97%	2%	1%	4,349	14%
Jun-99	29,808	1,107	184	31,099	96%	4%	1%	4,349	14%
Jul-99	28,058	1,107	708	29,873	94%	4%	2%	4,349	15%
Aug-99	32,144	1,107	873	34,124	94%	3%	3%	4,349	13%
Sep-99	32,144	1,107	1,721	34,972	92%	3%	5%	4,349	12%
Oct-99	31,550	1,107	1,729	34,386	92%	3%	5%	4,349	13%
Nov-99	31,178	1,107	1,874	34,159	91%	3%	5%	4,349	13%
Dec-99	31,178	1,107	1,332	33,617	93%	3%	4%	4,349	13%
Jan-00	30,936	750	2,817	34,503	90%	2%	8%	4,349	13%
Feb-00	30,936	750	2,567	34,253	90%	2%	7%	4,349	13%
Mar-00	30,936	750	2,585	34,271	90%	2%	8%	4,349	13%
Apr-00	30,936	750	3,565	35,251	88%	2%	10%	4,349	12%
May-00	30,981	750	2,396	34,127	91%	2%	7%	4,349	13%
Jun-00	30,213	750	3,752	34,715	87%	2%	11%	4,501	13%
Jul-00	29,916	750	2,307	32,973	91%	2%	7%	4,501	14%
Aug-00	30,053	750	3,838	34,641	87%	2%	11%	4,501	13%
Sep-00	30,038	250	4,026	34,314	88%	1%	12%	4,501	13%
Oct-00	30,038	250	3,706	33,993	88%	1%	11%	4,501	13%
Nov-00	29,655	250	3,017	32,922	90%	1%	9%	4,501	14%
Dec-00	29,655	250	7,311	37,216	80%	1%	20%	4,501	12%
1999 Average	30,843	1,045	1,097	32,985	94%	3%	3%	4,349	13%
2000 Average	30,357	583	3,491	34,431	88%	2%	10%	4,438	13%
Overall Average	30,552	768	2,533	33,853	90%	2%	7%	4,402	13%

Note: Auction data are On-peak FTR purchases.

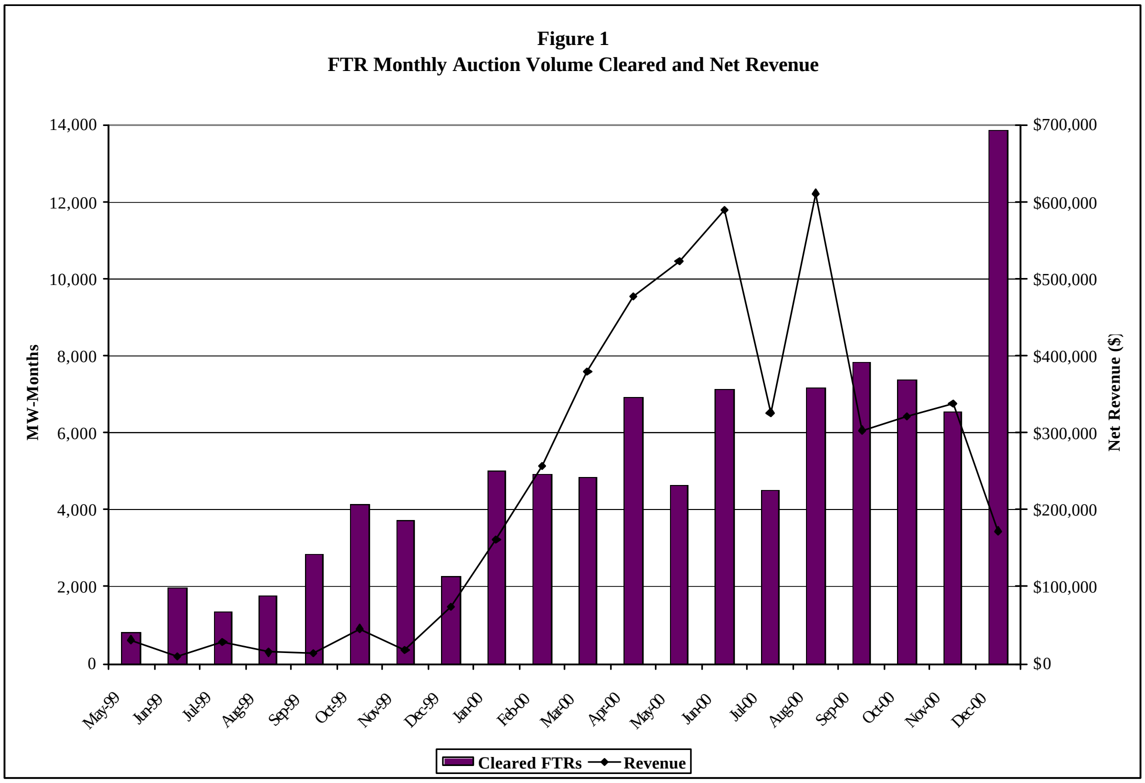
Table 5 presents FTRs by type. The data show that auction FTRs increased from an average of 3% in 1999 to 10% in 2000 and that the trend accelerated at the end of 2000. In the December 2000 Auction 7,311 MW of FTRs cleared, about 20% of all FTRs for the month. Network FTRs comprise about 90% of all FTRs since market inception and about 88% during 2000. Point-to-point FTRs represent about 2% of all FTRs. About 13% of FTRs were traded on the secondary FTR market.

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

In the MMU's FTR Auction Report covering the first year of the FTR auction, all buy bids were categorized as purchases regardless of whether the buy bid was in the same direction as the congested flow or in the opposite direction.[12] The data in Table 5 reflect this convention. However, in the figures in this section, bids and offers are categorized as buys or sells based on whether they are in the same direction as the congested flow or in the opposite direction.

[12] Report to the Federal Energy Regulatory Commission: FTR Auction, PJM Market Monitoring Unit, August 1, 2000.

Figure 1, FTR Monthly Auction Volume and Net Revenue, depicts the total cleared bid and offer volume in MW-months together with the total auction revenue generated each month. Average auction revenue increased from $30,000/month in 1999 to over $371,000/month in 2000, while the total cleared bid and offer volume increased from 2,300 MW-months in 1999 to over 6,700 MW-months in 2000.



As shown in Figure 2, FTR Monthly Auction Activity, the number of buy bids increased steadily until April 2000, when a substantial increase occurred, from an average of 400 bids per month for the prior period to about 3,700 bids per month thereafter. Although the number of offers has consistently been lower than the number of bids during most of the auction's existence, the number of offers also increased significantly in September 2000, from an average of 175 bids per month prior to September, to over 1,000 per month thereafter.

Figure 2
FTR Monthly Auction Activity
Bid and Offer Count and Average Bid Clearing Price

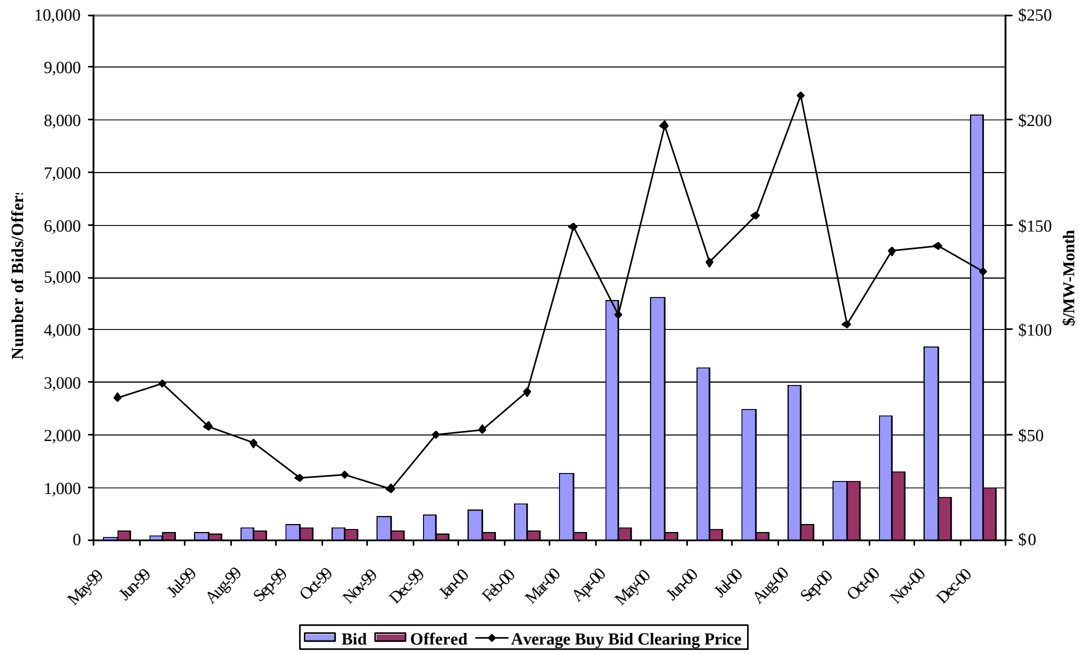


Figure 3, Bid and Offer Volume, presents the MW volume of the submitted and cleared bids and offers. Monthly bid volume increased from nearly 6,000 MW in 1999 to over 31,000 MW in 2000, while offer volume decreased from 9,200 MW in 1999 to 5,500 MW in 2000. A significant increase in bids occurred during the fourth quarter of 2000, increasing to 66,700 MW from the 19,400 MW average of the first nine months. Much of this increase can be attributed to market participants bidding FTRs in conjunction with incremental and decremental bids in the day-ahead market, as discussed later in this section. Cleared bid volume increased from about 1,500 MW to over 4,500 MW, while cleared offers increased from 850 MW to 2,200 MW over the same period. On average, cleared bids exceed cleared offers by 2,300 MW per month indicating that some 2300 MW per month of the cleared bids are consuming residual system capability.

Figure 3
Bid and Offer Volume

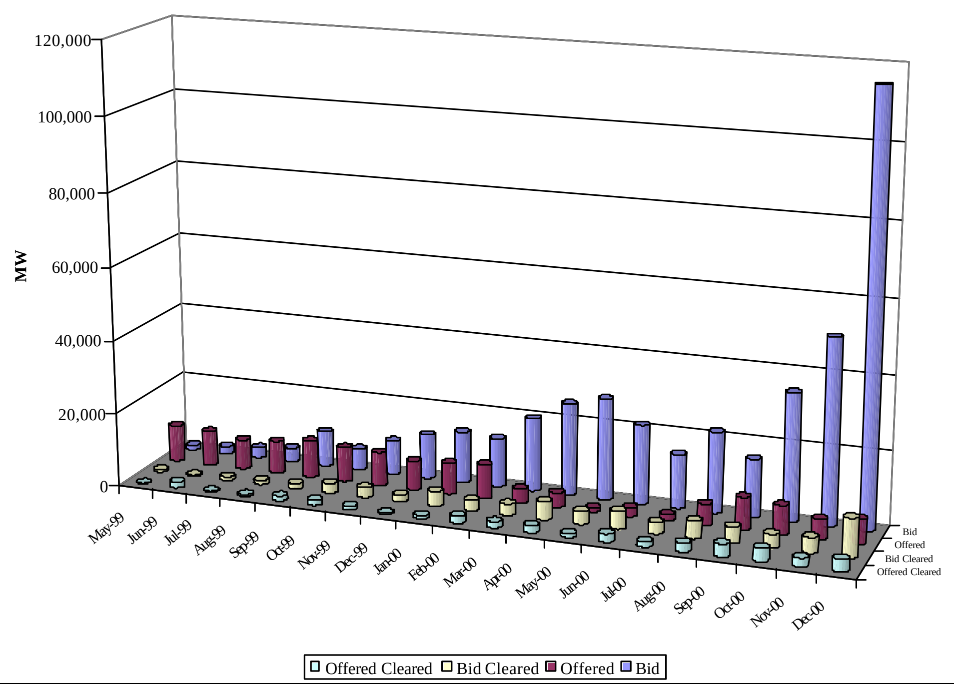


Figure 4, Percentage of Bid and Offer Volume Cleared, indicates the percentage of bids and offers that cleared. The average level of offers that cleared increased from 9% in 1999 to 51% in 2000, while cleared bids decreased from 30% in 1999 to 18% in 2000.

Figure 4
Percentage of Bid and Offer Volume Cleared

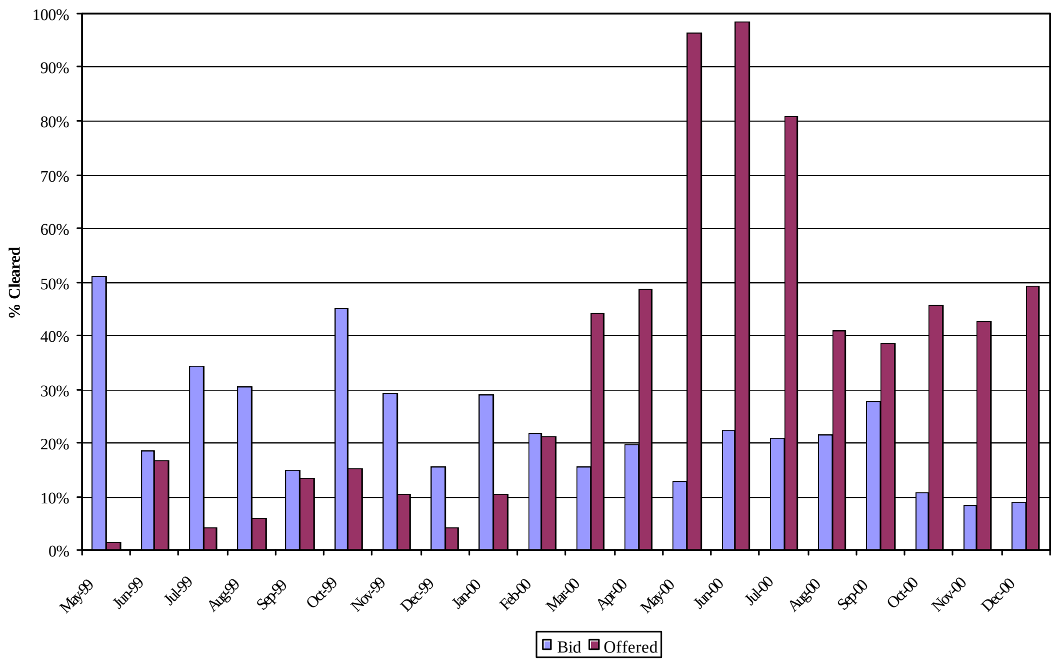


Figure 5, Ten Highest Revenue Producing FTR Sinks Purchased, depicts the revenue and volume of the ten FTR sinks that produced the most revenue and their MW volume. Seven of these ten are located in Eastern PJM, and these ten accounted for 62% of all FTR bid revenue produced.

Figure 5
Ten Highest Revenue Producing FTR Sinks Purchased
Revenue and Volume

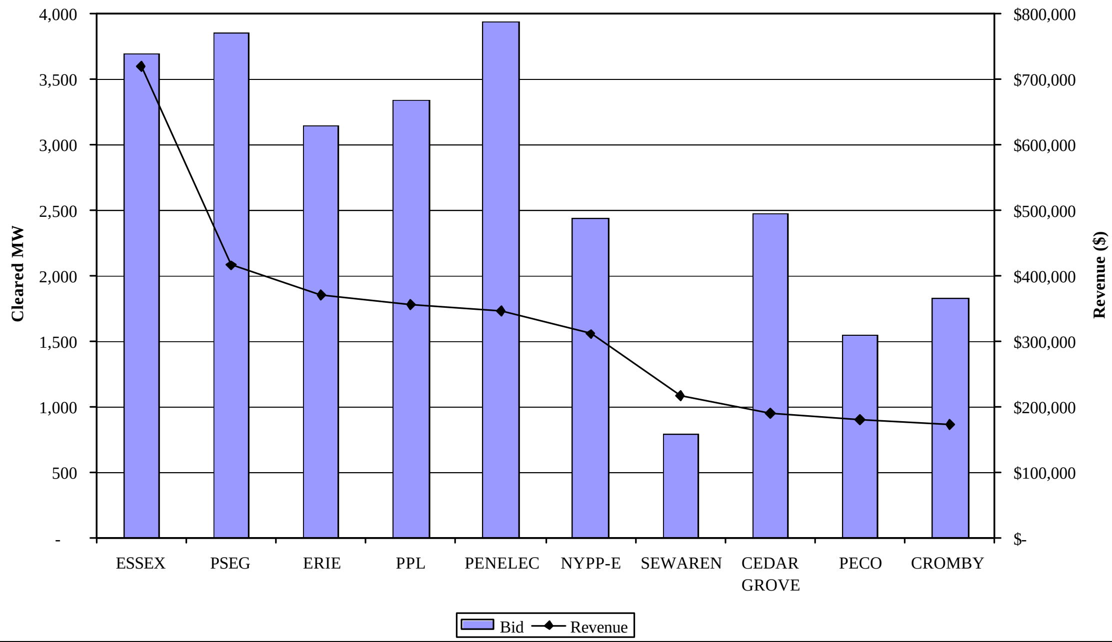


Figure 6, Ten Highest Revenue Producing FTR Sinks Sold, depicts the same data for FTRs sinks sold. These ten accounted for 68% of all FTR offer revenue produced, but were dispersed throughout the system.

Figure 6
Ten Highest Revenue Producing FTR Sinks Sold
Revenue and Volume

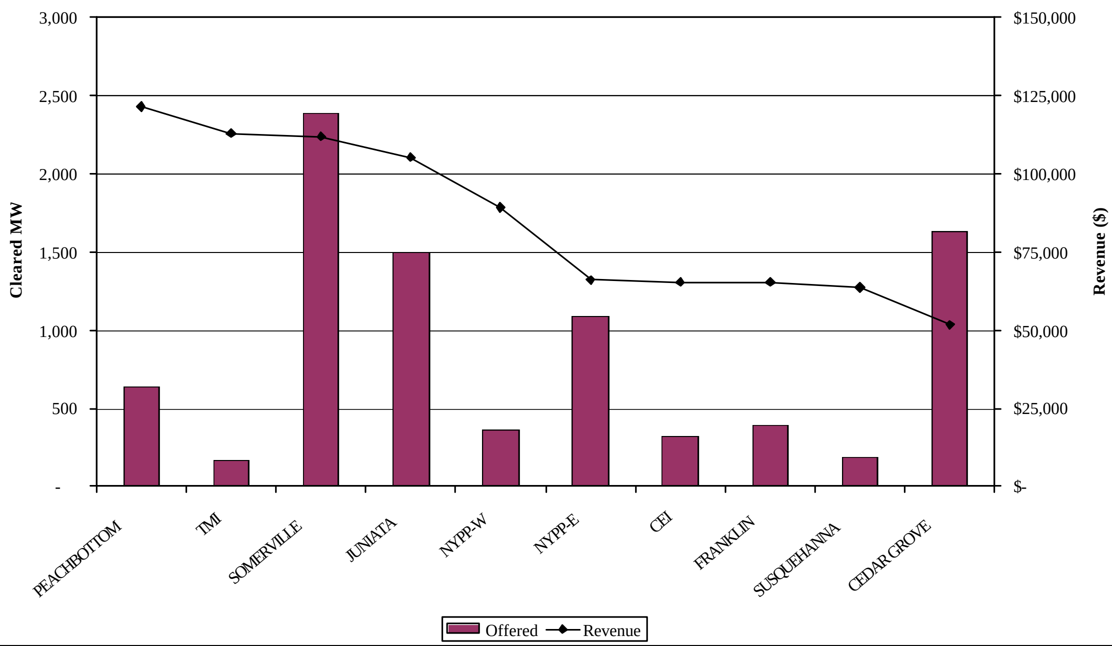


Figure 7, Ten Highest Revenue Producing FTR Sources Purchased, depicts the revenue and volume of the ten FTR sources that produced the most revenue and their MW volume. These ten accounted for 65% of all FTR bid revenue produced. The top three are located in Western PJM and accounted for 36% of all FTR bid revenue produced; six of the top ten were in Eastern PJM and accounted for 25% of all FTR bid revenue.

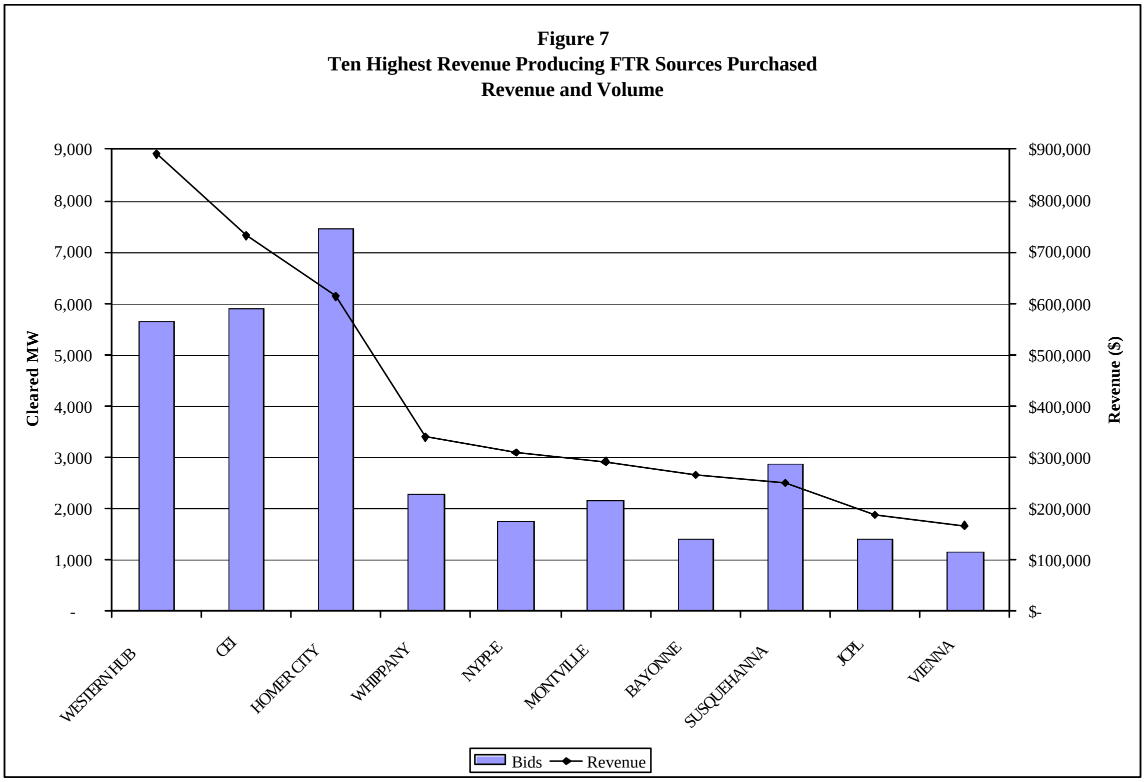
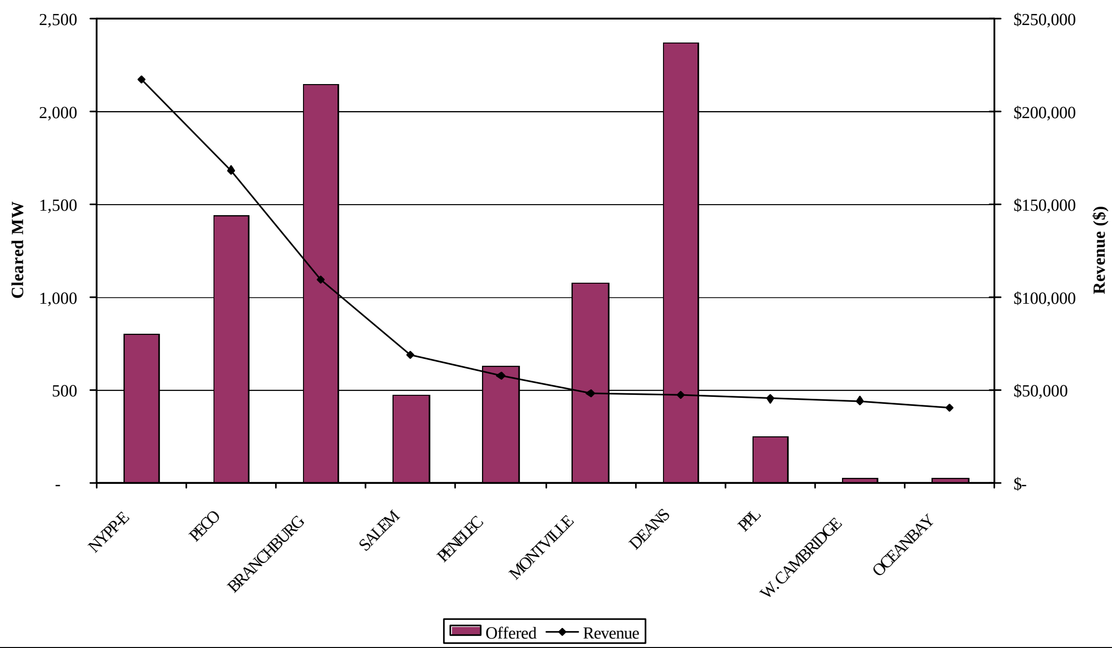


Figure 8, Ten Highest Revenue Producing FTR Sources Sold, presents the same data for FTR sources sold. These ten accounted for 55% of all FTR offer revenue produced; eight of the ten are located in Eastern PJM and accounted for 49% of all FTR offer revenue produced.

Figure 8
Ten Highest Revenue Producing FTR Sources Sold
Revenue and Volume



As shown in the summary data of Table 6, there were 7,040 congestion-event hours during 2000, a 230% increase from the 2,134 hours in 1999, and a 465% increase from 1998. (Type "0" data is the total of all facilities statistics while types "1" through "4" are by locale, voltage class and facility type.) A congestion event exists when a unit or units must be dispatched off cost in order to control the impact of a contingency on a monitored facility or to control an actual overload. There were 185 different monitored facilities on which congestion occurred. There were 227 unique congestion events, defined as unique pairs of monitored facilities and causal contingencies. This does not mean that the system was constrained 7,040 hours because constraints are frequently simultaneous. In fact, the system was constrained 44% of the time during 2000.

Type "1" data provide subtotals by facility type: line, transformer, and interface. As shown, transmission lines account for 71% of all congestion-event hours, with the remaining 29% split equally between interfaces and transformers.

Type "2" data provide subtotals by voltage class: 34, 69, 115, 138, 230, 345, and 500 kV. The data show that 69 kV facilities account for 40% of all congestion-event hours, followed by 230 kV with 24%, 138 kV with 15% and 500 kV with 10%.

Type "3" data combine types "1" and "2", further breaking down the facility type by voltage class. As shown, 69 kV lines account for 39% of all congestion-event hours, with 230 kV and 138 kV lines a distant second and third at 14% and 12%. 500 kV interfaces are fourth at 8%.

Finally, type "4" data provide subtotals by location, which can be either substations or interfaces, with more than 100 hours of congestion events. The locations listed in the table account for 75% of all congestion-event hours, with the rest spread over numerous others. As shown, Oak Hall substation in Southern Delmarva is the most frequently constrained, accounting for 8% of all congestion-event hours. In fact, Southern Delmarva facilities accounted for approximately one-third (35%) of all congestion-event hours. North and Northcentral Public Service is next, which includes Cedar Grove, Brunswick, Edison, and Bayonne, accounting for about 15% of all congestion-event hours. Other frequently congested locations are Erie, the PJM Eastern Interface, Cly substation in Western Met-Ed, Towanda in Northern Penelec, Cedar in Northern Atlantic Electric, and the PJM Western Voltage Interface.

Table 6. Congestion-Event Summary

Locale	Voltage	Facility	Type	Number Of Unique Facilities	Year 2000 Congest. Event Hours	% Year 2000 Congest. Event Hours	Year 1999 Congest. Event Hours	Year 1998 Congest. Event Hours	Year 2000 Increase From 1999
			0	185	7040	100%	2134	1244	4906
		Line	1	131	4984	71%	1383	1002	3601
		Int	1	7	1039	15%	406	17	633
		Trf	1	47	1017	14%	345	225	672
	069 kV		2	35	2826	40%	147	0	2679
	230 kV		2	72	1674	24%	818	588	856
	138 kV		2	33	1045	15%	819	362	226
	500 kV		2	29	684	10%	189	203	495
	345 kV		2	5	491	7%	148	74	343
	115 kV		2	10	315	4%	13	17	302
	034 kV		2	1	5	0%	0	0	5
	069 kV	Line	3	34	2762	39%	147	0	2615
	230 kV	Line	3	51	1008	14%	454	540	554
	138 kV	Line	3	29	869	12%	767	362	102
	500 kV	Int	3	4	533	8%	146	17	387
	345 kV	Trf	3	4	475	7%	146	60	329
	230 kV	Int	3	2	442	6%	260	0	182
	115 kV	Line	3	10	315	4%	13	17	302
	230 kV	Trf	3	19	224	3%	104	48	120
	138 kV	Trf	3	4	176	3%	52	0	124
	500 kV	Trf	3	20	142	2%	43	117	99
	069 kV	Int	3	1	64	1%	0	0	64
	345 kV	Line	3	1	16	0%	2	14	14
	500 kV	Line	3	5	9	0%	0	69	9
	034 kV	Line	3	1	5	0%	0	0	5
Oakhall			4	2	590	8%	109	0	481
Cedargrove			4	4	515	7%	188	361	327
Erie West			4	1	447	6%	118	5	329
Easton			4	3	444	6%	0	0	444
Interface East			4	1	345	5%	73	17	272
Cly			4	1	232	3%	0	0	232
Hallwood			4	1	231	3%	21	0	210
Interface DPLSouth			4	1	229	3%	260	0	-31
Interface Towanda			4	1	213	3%	0	0	213
Centreville			4	1	201	3%	0	0	201
Cedar			4	2	192	3%	0	0	192
Kings Creek			4	1	182	3%	10	0	172
Brunswick			4	1	175	2%	95	0	80
Edison			4	1	170	2%	24	174	146
Cheswold			4	2	139	2%	39	0	100
Mt Olive			4	1	137	2%	0	0	137
Talbot			4	2	130	2%	0	0	130
Church			4	3	125	2%	0	0	125
Vienna			4	2	123	2%	22	0	101
Loretto			4	2	120	2%	0	0	120
Lewis			4	1	118	2%	0	0	118
Bayonne			4	2	112	2%	0	158	112
Interface Westvolt			4	1	111	2%	0	0	111

The supporting data of Table 7, Congestion Event Summary, Changes Greater Than 100 Event Hours, include all buses where there was a change in congestion hours which exceeded 100 hours between 1998 and 2000. All but one of these facilities experienced significant increases in congestion-event hours between 1999 and 2000. There was one substation, Plainsboro in Southcentral Public Service, which had an appreciable decrease in congestion-event hours, from 520 in 1999 to 95 in 2000. The facilities listed also showed increases in congestion-event hours between 1998 and 1999 except for Bayonne and Edison. Table 7 shows that the Oak Hall substation had the largest increase in congestion events, from 0 in 1998, to 109 in 1999, and 590 in 2000. Southern Delmarva facilities represented 10 of the 20 largest increases in congestion-event hours between 1999 and 2000.

Table 7. Congestion-Event Summary, Changes Greater Than 100 Event-Hours

Substation	2000 Congest. Event Hours	1999 Congest. Event Hours	1998 Congest. Event Hours	2000 Increase From 1999	2000 Increase From 1998	1999 Increase From 1998	2000 % Incr. From 1999	2000 % Incr. From 1998	1999 % Incr. From 1998
OAK HALL	590	109	0	**481**	590	109	441%	100%	100%
EASTON	444	0	0	**444**	444	0	100%	100%	100%
ERIE WEST	447	118	5	**329**	442	113	279%	8840%	2260%
CEDARGRO	515	188	361	**327**	154	-173	174%	43%	-48%
INTERFACE EAST	345	73	17	**272**	328	56	373%	1929%	329%
CLY	232	0	0	**232**	232	0	100%	100%	100%
INTERFACE TOWANDA	213	0	0	**213**	213	0	100%	100%	100%
HALLWOOD	231	21	0	**210**	231	21	1000%	100%	100%
CENTREVILLE	201	0	0	**201**	201	0	100%	100%	100%
CEDAR	192	0	0	**192**	192	0	100%	100%	100%
KINGS CREEK	182	10	0	**172**	182	10	1720%	100%	100%
EDISON	170	24	174	**146**	-4	-150	608%	-2%	-86%
MT OLIVE	137	0	0	**137**	137	0	100%	100%	100%
TALBOT	130	0	0	**130**	130	0	100%	100%	100%
CHURCH	125	0	0	**125**	125	0	100%	100%	100%
LORETTO	120	0	0	**120**	120	0	100%	100%	100%
LEWIS	118	0	0	**118**	118	0	100%	100%	100%
BAYONNE	112	0	158	**112**	-46	-158	100%	-29%	-100%
INTERFACE WESTVOLT	111	0	0	**111**	111	0	100%	100%	100%
VIENNA	123	22	0	**101**	123	22	459%	100%	100%
PLAINSBORO	95	520	16	**-425**	79	504	-82%	494%	3150%
OAK HALL	590	109	0	481	**590**	109	441%	100%	100%
EASTON	444	0	0	444	**444**	0	100%	100%	100%
ERIE WEST	447	118	5	329	**442**	113	279%	8840%	2260%
INTERFACE EAST	345	73	17	272	**328**	56	373%	1929%	329%
CLY	232	0	0	232	**232**	0	100%	100%	100%
HALLWOOD	231	21	0	210	**231**	21	1000%	100%	100%
INTERFACE DPLSOUTH	229	260	0	-31	**229**	260	-12%	100%	100%
INTERFACE TOWANDA	213	0	0	213	**213**	0	100%	100%	100%
CENTREVILLE	201	0	0	201	**201**	0	100%	100%	100%
CEDAR	192	0	0	192	**192**	0	100%	100%	100%
KINGS CREEK	182	10	0	172	**182**	10	1720%	100%	100%
BRUNSWICK	175	95	0	80	**175**	95	84%	100%	100%
CEDAR GROVE	515	188	361	327	**154**	-173	174%	43%	-48%
CHESWOLD	139	39	0	100	**139**	39	256%	100%	100%
MT OLIVE	137	0	0	137	**137**	0	100%	100%	100%
TALBOT	130	0	0	130	**130**	0	100%	100%	100%
CHURCH	125	0	0	125	**125**	0	100%	100%	100%
VIENNA	123	22	0	101	**123**	22	459%	100%	100%
LORETTO	120	0	0	120	**120**	0	100%	100%	100%
LEWIS	118	0	0	118	**118**	0	100%	100%	100%
INTERFACE WESTVOLT	111	0	0	111	**111**	0	100%	100%	100%
PLAINSBORO	95	520	16	-425	79	**504**	-82%	494%	3150%
INTERFACE DPLSOUTH	229	260	0	-31	229	**260**	-12%	100%	100%
ERIE WEST	447	118	5	329	442	**113**	279%	8840%	2260%
OAK HALL	590	109	0	481	590	**109**	441%	100%	100%
CEDAR GROVE	515	188	361	327	154	**-173**	174%	43%	-48%
BAYONNE	112	0	158	112	-46	**-158**	100%	-29%	-100%
EDISON	170	24	174	146	-4	**-150**	608%	-2%	-86%

FTR Issues Resolved

FTR Allocation

A change to the annual FTR allocation process was developed and approved in 2000 for implementation on June 1, 2001. Under the existing method, once a network customer has been allocated FTRs, the customer may keep the FTRs as long as its network load exceeds the amount of the FTRs. Under the new method, network service FTRs will be reallocated each spring and priority will no longer be given to the existing FTR allocation. The basis for requesting FTRs will not change and will continue to be based on the capacity of the capacity resources which are to be delivered and may not exceed the peak load of network customers, native load customers or non-zone network load. Under the new method, if the total FTRs requested exceed the amount which passes the Simultaneous Feasibility Test, the FTRs will be allocated following specified rules. The allocation is a direct function of the level of requested FTRs, an inverse function of the impact of the requested FTRs on binding transmission constraints and a positive function of the priority assigned to each FTR by the participant. Market participants assign a priority from 1 to 4 to each of their desired FTRs, with each priority level limited to 25% of their peak load share. PJM processes and grants feasible priority level 1 FTRs, followed sequentially by priorities 2, 3, and 4.

The purpose of the new FTR allocation method is to give all customers an equal opportunity to obtain their highest priority FTRs and to prevent customers from holding highly desirable FTRs forever, limiting the ability of new entrants to compete to serve native load. This change to the allocation method was designed to enhance competition.

Creating Congestion

Shortly after the introduction of the two-settlement market, a related market design flaw was discovered. The rules governing the submission of increment offers and decrement bids in the day-ahead market permitted market participants to create congestion in the day-ahead market on paths where they held FTRs, without incurring financial risk, in order to make their FTRs more valuable.[13] Increment offers and decrement bids are financial commitments made in the day-ahead market to supply power or take power off the system, respectively. Participants obtained FTRs in the monthly FTR auction for specific paths and then used increment and decrement bids in the day-ahead market to cause transmission congestion across the paths where they had purchased FTRs. Congestion and thus differences in LMPs made the FTRs valuable because the value of an FTR is equal to the MW FTR position from point A to point B times the difference in LMP between point A and point B.

A new market rule was developed using a process involving all stakeholders. The rule was implemented on November 10, 2000. The rule requires market participants to return profits derived from FTR positions that resulted from the use of increment and decrement bids in the day-ahead market that created more congestion on a path in the day-ahead market than exists on that path in the real-time market. The rule allows market participants to recover congestion charges from FTRs in the day-ahead market as long the congestion created in the day-ahead

13 The rules governing increment offers and decrement bids are in the PJM Operating Agreement, Schedule 1, Section 1.10.1a(i).

market is consistent with real-time congestion. The text from the Operating Agreement implementing the rule is attached as an Appendix.

The result of this rule change is to limit anti-competitive behavior and thus to improve the competitiveness of PJM markets.

Transmission Outage Notification

There was an issue regarding the FTR auction unrelated to either the mechanics of the auction or the level of liquidity provided by the auction. The establishment of the FTR auction created concerns related to knowledge of the timing of transmission outages. The concern was that any party with prior knowledge of transmission outages might use that information to take profitable positions in the FTR auction market. Specifically, transmission owning companies would have knowledge of planned transmission outages prior to the posting of that information and could take positions in the FTR market based on information not publicly available prior to the close of the auction.

A complaint was filed with the MMU regarding a specific incident in which the timing of transmission outage notification was at issue. While the MMU found no evidence that inappropriate activity or transfer of information occurred in that case, in order to maintain confidence in the markets and minimize the potential for gaming the markets, the MMU recommended that PJM clarify and strengthen the transmission outage notification provisions of the PJM Manuals.

The PJM Manual for Transmission Operations, Manual M-03, in the Scheduling Transmission Outages section states: "The Transmission Owners notify the PJM OI at least three office working days before the time of the planned outage." The Manual also states, in the Requesting Planned Transmission Outages (Work Requests) section: "In order to maintain planned transmission outage status and priority, a Work Request must be submitted at least three office working days before the removal of the equipment from service."

However, the Manual, in the General Principles section, states that: "Each Transmission Owner submits the tentative dates of all transmission outages of Designated Transmission Facilities to the PJM OI as far in advance as possible."[14] The Manual also states in the Scheduling Transmission Outages section: "Each Transmission Owner submits the tentative dates of all planned transmission outages of Designated Transmission Facilities to the PJM OI as far in advance as possible. … The PJM OI maintains a planned transmission outage schedule for a period of at least the next 13 months. The planned transmission outage schedule is posted, subject to change, on the PJM Open Access Same-time Information System (OASIS)."[15] The Manual also states in the Requesting Planned Transmission Outages (Work Requests) section: "All 500 kV outages are communicated to the PJM OI as early as possible."[16]

As noted earlier, to maintain confidence in the markets and minimize the potential for gaming the markets, the MMU recommended that all participants should be notified through the OASIS,

14 PJM Manual for Transmission Operations, Manual M-03, Section 4, page 4-1.
15 PJM Manual for Transmission Operations, Manual M-03, Section 4, Page 4-3.
16 PJM Manual for Transmission Operations, Manual M-03, Section 4, Page 4-5.

as far in advance as possible, of planned transmission outages. If such general notification occurs prior to the close of the relevant FTR auctions, it gives all market participants an opportunity to hedge against the risk of congestion created by the scheduled outages.

The MMU further recommended that all transmission owners be required to provide notice of transmission outages to PJM for posting on the OASIS at least two days prior to the bidding deadline for the FTR auction which applies to the month of the outage. In addition, the MMU recommended to PJM that all transmission owners be required to submit Planned Outage Schedules one year in advance and that such be updated on a regular basis.

As a result of these recommendations, the Energy Market Committee created the PJM Transmission Outage Reporting Working Group (TORWG). Led by the MMU, the TORWG began a process involving all stakeholders to develop new transmission outage notification procedures. This process was successfully completed in 2001.

Appendix
PJM Operating Agreement:
Increment/Decrement Bids in Conjunction with Auction FTRs

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Fixed Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Fixed Transmission Right between specified delivery and receipt buses acquired the Fixed Transmission Right in a Fixed Transmission Rights Auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Fixed Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in locational marginal prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in locational marginal prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Fixed Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Fixed Transmission Right in the Fixed Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Fixed Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Fixed Transmission Right delivery and receipt buses that were acquired in the Fixed Transmission Rights Auction.