Synapse
Energy Economics, Inc.

LMP Electricity Markets:
Market Operations, Market Power, and Value for Consumers

Prepared by:
Ezra Hausman, Robert Fagan, David White, Kenji Takahashi, and Alice Napoleon
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

Prepared for:
American Public Power Association

February 5, 2006

Table of Contents

SECTION III – COMPETITIVENESS AND MARKET POWER

SECTION IV – IMPACTS ON CONSUMERS

GLOSSARY

REFERENCES

List of Tables

List of Figures

Introduction and Executive Summary

Synapse Energy Economics (Synapse) was retained by the American Public Power Association (APPA) to prepare a report on the operation of electricity markets using the Locational Marginal Pricing (LMP) system. In particular, Synapse was asked to review two particular aspects of the LMP approach which are crucial to producing efficient markets and returning benefits to the customers whom the market is designed to serve. These two aspects are (1) the effectiveness of LMP markets in delivering the market efficiencies and investments it was designed to produce, and (2) competitiveness, market power, and market monitoring issues in LMP markets.

By agreement with APPA, we have focused this report primarily on the PJM Interconnection, and to a lesser extent on the New England ISO (ISO-NE). PJM, founded as the Pennsylvania-Jersey-Maryland market operator, now runs electricity markets as the Regional Transmission Organization (RTO) in some or all of 13 states plus the District of Columbia. It is the largest centrally dispatched electricity system in the world, and has been operating electricity markets under the LMP system since 1997. ISO New England has been operating LMP markets since the spring of 2003 and has operated a centralized market since 1999.

In order to address the effectiveness of LMP markets, we reviewed the theory and goals of the LMP construct and held them up to the several years' worth of experience in LMP markets. We asked the following questions:

- Does security-constrained dispatch and LMP pricing work as well in the real world as it should in theory?
- Have the price-signaling aspects of LMP produced the desired outcomes in terms of investments in electricity infrastructure?
- Have the LMP markets been workably competitive, or is market power and price manipulation a concern?
- Have power production costs come down as a result?

One primary goal of LMP, articulated by FERC in approving LMP implementation in PJM,[1] is to produce efficient, accurate economic signals that would spur investment in both electricity market infrastructure and demand response programs where and when they are needed. As part of our review, we evaluated whether the LMP price signals have in fact produced generation and transmission investments and demand response programs where and when needed, leading to the intended benefits for consumers. To the extent that the markets have fallen short of this standard, we have reviewed what obstacles remain, either structural or related to market design, which have limited the effectiveness of this approach.

In reviewing market power and competitiveness issues in LMP-based electricity markets, we investigated whether there are opportunities for exercise of market power, if there is evidence of anticompetitive behavior, and if so, whether this behavior is reflected in market prices. We asked the following questions:

- In these large, complex, dynamic markets, what safeguards can be used to ensure that market outcomes are not distorted by the exercise of market power?
- Have these safeguards been vigorously applied, and if so, are they effective?
- Do they support competition and open access to markets?
- Conversely, are there still ways in which market participants can apply market power in LMP markets, and have these ways been exploited?

In particular, we have delved into the history, market rules, market outcomes, investment histories, and operational data of two of the oldest LMP-based markets in the United States, those administered by the PJM RTO and by the ISO NE RTO. We have reviewed how these two market administrators operationalize the mathematical foundation of LMP, and how that implementation compares to theory. We reviewed the history of generation, transmission and demand-side resource investments since the onset of LMP pricing in these markets to determine if there is a recognizable relationship with price signals. Where these have diverged, we have investigated the causes.

We have reviewed and audited public data on energy bids in order to characterize these data, identify opportunities for the exercise of market power, and highlight examples of

[1] FERC order in Docket No. OA97-261, et al., November 25 1997.

anomalous bidding behavior. While we cannot reach firm conclusions about the competitiveness of energy markets in this analysis, we have used the data to raise questions that have not been adequately addressed in market monitor reports. Where our conclusions differ from those of the market monitor in this area, we reported on the differences. We have also highlighted areas where we feel the market monitor should focus more attention in the future.

Based on our review, we conclude that the LMP approach to electricity pricing generally supports the efficient operation of existing resources, if the LMP pricing and dispatch are based on the short-run marginal cost (SRMC, discussed below) associated with each resource. Under these circumstances, we find that LMP provides an accurate quantification of the need for and value of potential generation and transmission enhancements, as well as valuable diagnostic information regarding needed investment, market performance, and structural opportunities for the exercise of market power. In terms of dispatch, we find that LMP probably represents the best approach available for operating large, interconnected power pools efficiently and reliably.

However, the reality of LMP implementation in deregulated electricity markets is not exactly as described by theory, in large part because electricity markets are bid-based, not cost-based, and electricity markets are not perfectly competitive. To the extent that there is any type of collusion – explicitly or tacit – prices will not reflect the SRMC and some of the value of LMP in market operations may be lost. Simply implementing LMP does not guarantee competitive markets, nor does it prevent the abuse of market power. Because the opportunity for exercising market power is not diminished (and is sometimes enhanced) in LMP-based markets, the role of market monitor remains crucial for assessing and maintaining competitive conditions and successful market operations in conformity with the “just and reasonable” standard of the Federal Power Act.

In terms of investment signals, we find that LMP has not been successful in providing the necessary incentives for socially-optimal investment in generation or transmission infrastructure, nor does it ensure the high levels of reliability demanded by consumers. There is simply no evidence that the price signaling associated with LMP has been an effective spur to investment in generation, transmission or demand response initiatives, and some evidence to the contrary. We conclude that the LMP price signals are overwhelmed by other factors in these areas, such as structural barriers to entry, competing economic incentives, and the lack of a clear mechanism for assuring return on investment in certain types of projects.

Lastly, we found that whatever production cost savings may have occurred as a result of LMP-driven efficiencies, this benefit has not been realized by consumers. The experience in those states in which temporary retail price caps have expired is that consumers face large and burdensome increases in the price of electricity. While this is partly due to recent increases in fuel costs, specifically gas, it is also largely the result of short-term contracting for electricity in a dominant wholesale market in which power is priced at the margin. Pricing electricity based upon the short-run marginal cost exposes Load Serving Entities (LSEs), and ultimately consumers, to a much greater degree of price volatility than would be experienced under cost-of-service regulation, or under a portfolio-based procurement approach that included a large proportion of long-term supply components. The only recourse to protect consumers in such an environment is a greater reliance on long-term contracts, but the trend since deregulation has gone in the other direction. In this sense, consumers have lost the economic benefits of fuel and technology diversity, as prices are completely determined by whatever fuel happens to be on the margin.

Although complementary longer-term procurement options are available in all electricity markets today, these have proven to be an insufficient hedge since the introduction of the shorter-term RTO spot energy market structure. As a result, pricing for many consumers is closely linked to short-term marginal-priced structures of the RTO-administered spot energy markets, illustrating the failure of market mechanisms and/or state and regional-level policy to insulate consumers from short-term price fluctuations. Combined with recent increases in the cost of natural gas, this dynamic has led to much higher costs for consumers and windfall profits for owners of base load generation assets. This is not necessarily a failure of the LMP construct *per se;* it is merely one example of the ways in which the operational benefits of LMP markets are not sufficient to produce just and reasonable prices for consumers.

In fact, LMP appears to be a useful, perhaps necessary but certainly not sufficient component of deregulated, competitive electricity markets. Effective market designs must include both market-based and administrative elements, to ensure that public goods such as electric reliability and efficient transmission investments are provided even when not produced by market forces. Regulatory intervention has been and will continue to be crucial for rectifying the shortcomings of LMP in these areas. Attempts to rely on market solutions where regulatory ones are more appropriate leads not only to socially optimal investments, but to higher prices for consumers.

Summary of Conclusions

Specific findings in each of the topics we investigated are as follows:

Operational Efficiency

We find that while LMP generally favors the lowest cost dispatch given a broad set of market conditions, there are a large number of differences between LMP theory and the implementation of LMP in practice. In particular,

- LMP was originally envisioned as a cost-based optimization algorithm for regulated, vertically integrated utilities.[2] However, in practice it has been implemented as a bid-based pricing and dispatch scheme in deregulated electricity markets. While this may have only a modest effect on dispatch, it opens the door for exercise of market power under certain conditions, which compromises the operational benefits of LMP and results in additional costs for consumers;
- LMP is implemented based on an *approximation* of system conditions, most significantly because system constraints and operational parameters are based on proxy methods and estimates which tend to underutilize full transmission system capacity. This renders the outcome suboptimal to some extent in any operating period;
- The LMP dispatch and prices for any given period are dependent on system conditions and operator decisions that are not necessarily co-optimized with dispatch. These include unit commitment in general, requirements for ancillary services, ramping constraints, minimum up- and down-times, and other factors;
- Because a significant portion of load in PJM is served "out of market" by units selected for operating reserve and voltage support reliability reasons, LMP-based dispatch is not actually solved for system-wide optimization. However, such actions can be socially beneficial and should not be rejected out of hand merely because they are not market-based.

Price Signaling

A frequently stated goal of locational pricing is to provide economically accurate signals to stimulate investment when and where it is needed. LMP, in particular, is designed to provide the incentive for generators to build generation in areas which are "short" of generation relative to demand; and/or for merchant transmission investment to relieve

[2] Schweppe, et al., *Spot Pricing of Electricity*, 1988, Kluwer Academic publishers: "The spot price based energy marketplace is designed to operate in a regulated environment (regulated private company, or government owned)". P. 111

transmission constraints.[3] However, infrastructure investment decisions are based on a large number of considerations in addition to locational prices. In addition, the price signal is retrospective and short-term in nature, while investment decisions are prospective and long-term. This leads to a serious disconnect, especially given the significant volatility of the electricity markets and the many ways in which they can evolve over time. Our review of the effectiveness of price signaling found that:

- While a large number of generators have been built since the onset of the LMP market structure in PJM, there is no clearly discernable causal link between these investments and the presence of LMP-based pricing. It is not clear that the level or locations of generation investment would have been any different had an LMP-based structure not been in place;
- There has also been a significant level of retirements in PJM which, like new generation, have borne no discernible relationship to price signals in either timing or location;
- There has been no significant merchant transmission activity within PJM, demonstrating that market signals alone are inadequate to produce such investments. The reasons for this are well understood. First, the presence of new transmission would reduce or eliminate the congestion costs (price signal) upon which the new transmission would depend, at least in part, to recover its embedded costs. Second, the benefits of such investments in terms of reduced transmission congestion are widely shared, and individual entities are reluctant to shoulder the burden themselves if there is no straightforward mechanism for sharing the cost;
- Demand response resources, a key element of improved reliability of electric systems, have not developed appreciably in response to deregulation and the LMP market structure.

Competitiveness in Electricity Markets

As noted earlier, the LMP system was designed to produce optimal dispatch and price signals based on generator marginal cost for each market interval. In a deregulated, bid-based marketplace, generator offer prices are substituted for generator costs, based on the presumption that these will reflect marginal cost if the markets are sufficiently competitive; however, LMP itself provides no guarantee of this condition. We reviewed both market rules in PJM and in the ISO-NE to investigate how market monitors evaluate market conditions under the LMP. In addition, we investigated the available generator

[3] For example, see Answer of Supporting Companies, 1996, pp. 10-11.

offer data in both markets to explore whether they appear to be consistent with a presumption of competitive market conditions. Our findings are:

- While PJM does not restrict generation bidders in unconstrained areas, it does have the strictest bidding rules of any U.S. LMP-based market for constrained locations, generally requiring an offer cap of 110% of production costs as determined by the market monitor. The New England and MISO markets have less strict provisions that allow for greater increases in offer prices above marginal cost for constrained areas (50% increase above marginal costs in New England; and an increase tied to annual congestion hours and annual fixed costs of a peaking unit in MISO);
- Even in PJM's constrained regions, there are significant opportunities to deviate from cost-based bidding; bid adders of up to 10% above cost are accepted by the PJM market monitor without review as noted above, and many newer resources are exempt from bid mitigation in constrained regions if they pass a three pivotal supplier mitigation test;[4]
- While the PJM market monitor has generally concluded that the exercise of market power is minimal and the spot energy markets are "competitive"[5], we are not convinced that this is supported by the data, as noted in Chapter 6. Further, even the allowable 10% bid adders result in clearing prices that exceed competitive levels by at least a few percentage points, which could result in significant transfers of wealth from consumers to producers;
- Our investigation of bid data has revealed both the opportunity to exercise market power and examples of anomalous bidding behavior, impacting the generation supply curve, that appear to reflect either market manipulation or attempts to "learn" which could lead to exercises of market power;
- The lack of significant and/or persistent short-term demand-side price response calls into question the fundamental premise that the spot markets are able to exhibit competitive behavior during periods when the system supply curve becomes relatively more inelastic (i.e., gets steeper);
- We know of no comprehensive examination of the potential to exercise market power in the forward bilateral markets that comprise much of the volume of transactions in the PJM region.

[4] PJM Open Access Transmission Tariff, Section 6.5 of the Appendix to Attachment K.
[5] For example, PJM 2005 State of the Market Report, page 23.

SECTION I – LOCATIONAL MARGINAL PRICING

1. Overview of Locational Market Pricing

1.1. LMP Theory

The Locational Marginal Pricing system is a construct, based on operations research theory, which is designed to achieve two economic objectives simultaneously:

- Minimize the cost of generating enough electricity to meet load by using the least-cost set of available generators possible given various constraints. This is known as "least-cost, security-constrained dispatch"; and
- Produce the instantaneous price of electricity, at every point in the system, which reflects the instantaneous short-run marginal cost of serving one incremental unit of load at that location.[6] This is what is referred to as the "locational marginal price", or LMP.

The concept of "short-run marginal cost", which is fundamental to understanding electricity markets, is subject to some dispute. SRMC clearly includes avoidable costs such as fuel, emissions costs, and avoidable operation and maintenance costs, which are incurred in proportion to the amount of electricity the unit produces. In a classic discussion of this issue, William Vickery (1992) argues that accelerated depreciation of equipment due to wear and tear should also be included in SRMC. However, there is often some ambiguity over which depreciation costs will be accepted by market monitors as part of cost-based offers. PJM allows for bid increments for depreciation, provided that they "represent actual expenditures that are due to incremental degradation of generating equipment directly related to generation, starts or a combination of both." (PJM Cost Development Guidelines, Manual 15, as revised August 2006.) It is also unclear how this concept should be implemented in a deregulated market in which some above-cost revenues will be necessary to make generation assets viable.

In LMP-based electricity markets, the SRMC is replaced by sell offers from generators, and the two objectives of LMP described above are put into practice as follows. First, each generating plant makes an offer of power at the minimum price for which it is

[6] Schweppe *et al.*, 1987, p. 32; Stoft, 2002, p.393.

willing to sell electricity. In a perfectly competitive market, this price would reflect the unit's short-run marginal cost of producing electricity, as described above. Next, the market operator solves an optimization problem that yields the least cost set of all generator offers to serve all load, subject to transmission and other operational constraints. This same mathematical operation yields what in operations research terms are called "shadow prices", which can be used to calculate the incremental overall value of an increase or decrease in the consumption of electricity at each location.

These prices, the LMPs, also serve as a dispatch signal. If the LMP is at or above a generator's offer price, the offer is taken and the generator is paid at the LMP. If it is below the offer, the offer is not accepted and the generator is not used.[7] This aspect of LMP is similar to that of any competitive single-clearing-price auction—sellers should be willing to sell at any price equal to or greater than their short-run marginal cost. To the extent that the price is above such cost, the extra money (infra-marginal rent) offsets their near-term fixed and long-run costs, such as their cost of capital, and adds to overall profit.

This dynamic is shown schematically in Figure 1.1, which ignores locational aspects and treats the market as a single clearing price auction. The uneven curve in Figure 1.1 represents the generator bid curve which, in a regulated environment, would be the marginal cost supply curve. This is constructed by ordering all generating units in the system from left to right in increasing order of SRMC. The vertical line represents the instantaneous system-wide demand at some point in time, and the point at which these two lines cross sets the clearing price which all generators are paid. Generators to the left of this point are running and earning more than their marginal cost, while generators to the right are not running and are incurring no fuel, operating or other avoidable costs. The generator at this point is indifferent as to whether it runs or not, as its avoidable costs will be exactly offset by revenues; it is probably partially dispatched, running at some level lower than its maximum capacity.

[7] This is a somewhat simplified explanation as other factors such as unit startup costs, ramp rates, system stability requirements, etc. affect the actual plan that is selected and the units dispatched.

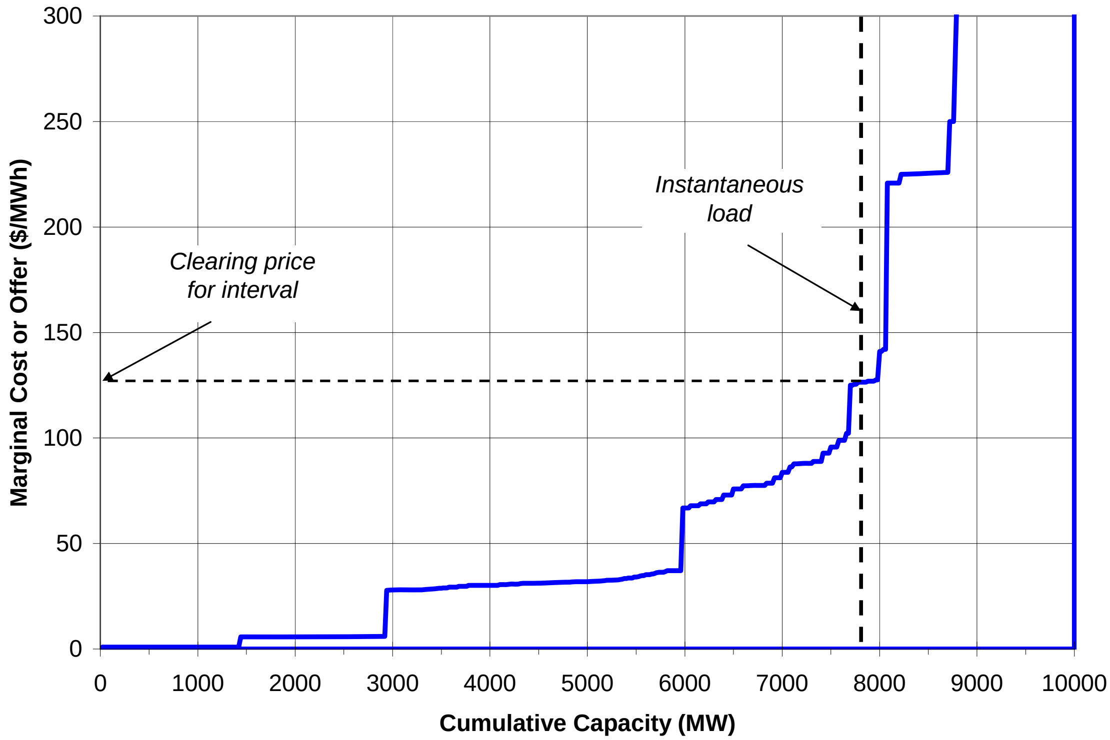


Figure 1.1 Illustrative supply curve and instantaneous demand
The vertical axis can be viewed as representing either short-run marginal cost or offer prices. The clearing price is set by the intersection of demand with the supply curve. Assumes zero demand elasticity.

In a clearing price market such as that represented in Figure 1.1, generating units with low marginal cost (to the left on the supply curve) will be dispatched more often and earn greater short-run profits than higher cost units (to the right); these short-run profits are needed to offset their higher capital costs. In an ideal investment environment, if the "base load" generators were earning more money than they require, new entry would appear and lower the clearing price until equilibrium were reached. Similarly, if they are not earning enough, the poorest performing generating units will retire, or at least no new entry will occur until load growth restores profitability. According to Steven Stoft (2002), "…competitive prices would cover fixed costs and induce the optimal mix of generation technologies with a great deal of precision." (p.132). However, electricity markets are far from ideal. Generation investments are not smooth but "lumpy"[8], and are rife with

[8] Generation and transmission investments are considered "lumpy" because they come in large increments—from several MW to several hundred. In consequence, a single new base-load generator in a small electricity market can drive down prices and severely impact its own revenue stream.

structural and other obstacles that make it hard for competitive players to move the market towards this sort of equilibrium. Furthermore, generation in one area cannot necessarily compete with generation in other areas given limitations on the transmission system. As Stoft concedes, with classic understatement, “transmission constraints may exacerbate the problem a bit…” (p.132).

Finally, we note that if the generator offers were truly SRMC based then the only way that generating units at the far right end of the supply curve could recover their capital costs would be to rely on rare, very high price spikes. These would occur during intervals when load reached the very end of the supply curve and the price was determined by some measure of the value of lost load (VOLL) to consumers. This is an extremely difficult value to estimate—is the lost load an electric teapot or is it life-saving medical equipment?—but it is generally assumed to be quite high.[9] Regulators are usually unwilling to let prices reach these levels that would be far in excess of most production costs, and in any case reliance on infrequent and extreme events would lead to considerable price and revenue uncertainty in the market. This situation has contributed to an apparent failure of existing electricity markets to attract needed investment, and consequently to the development of “capacity” markets as an alternative way for high-SRMC units to recover their capital costs.

1.2. Hedging Congestion Costs: Financial Transmission Rights (FTRs)

Under LMP, all generating units are paid at a price reflecting the applicable locational marginal cost of electricity at its generator bus, and similarly all load pays for electricity at a price reflecting the locational marginal cost at the load bus.[10] The locational prices are determined hourly and can be quite volatile. As a rule, any congestion on the system causes price depression in areas where generation is more concentrated and elevation in areas where load predominates, reflecting the greater value of generating resources which are located electrically closer to load. Also, because the Federal Energy Regulatory Commission (FERC) has ordered that access to the transmission grid is to be completely

[9] See Stoft, 2002, ch. 2-5 for an extensive discussion of VOLL.

[10] In practice, load in PJM and elsewhere generally pays a load-weighted average zonal price for electricity, to limit volatility and perceived inequity associated with intrazonal congestion.

market-based and nondiscriminatory, there is no longer room for historic, firm transmission rights to serve native load. These characteristics of LMP led to the following three concerns about the development of LMP markets:

- *Price uncertainty:* Load serving entities (LSEs) would not know until after the fact what the cost of electricity was to serve their customers;
- *Loss of traditional rights:* The entities that built and/or owned the transmission lines now had no more physical right to the use of these lines than anyone else on the system; further, investors in *new* transmission lines would have no preferential right to use these assets; and
- *Surplus revenues:* Because the marginal cost to deliver an incremental unit of electricity tends to be higher at load buses than at generator buses, the total dollar amount charged to load during any operating period where congestion is present is greater than the total dollar amount paid to generators.

All three of these issues are solved simultaneously through instruments known, in PJM and ISO-NE, as Financial Transmission Rights or FTRs. FTRs are tradable, point-to-point financial rights (or obligations) that represent a MW-for-MW hedge against congestion costs between any two points on the transmission system. An entity who holds a one-MW FTR from point A to point B has the right to receive (or the obligation to pay) the difference of the LMP at B minus the LMP at A for each hour covered by the FTR. In PJM, FTRs are sold in annual and monthly increments, and can represent either on-peak hours, off-peak hours or all hours. The revenue raised through the auctioning of FTRs is allocated to the holders of Auction Revenue Rights (ARRs), which are generally held by the historic owner of the transmission asset (although ARRs can be traded as well.)

FTRs solve the three identified issues as follows:

- *Price uncertainty:* FTRs serve as a MW-for-MW hedge against congestion costs, improving *ex-ante* price certainty for delivery of power to serve load; however, FTRs are not a perfect hedge because they are inflexible in MW-quantity, and because they may not always be fully funded, as described below;
- *Loss of traditional rights:* Traditional utilities, transmission owners and those with the obligation to serve historic native load can be allocated FTRs or ARRs in compensation of the loss of physical firm rights to use the transmission grid. This replacement of physical rights with financial rights means that they will incur no financial penalty if there is insufficient transmission capacity to serve their load from traditional sources, and ideally serves as a mechanism to compensate investors in needed transmission infrastructure;

- *Surplus revenues:* If properly designed and allocated, and assuming no unexpected losses of transmission capacity, the money required to fulfill FTR payment commitments cannot exceed the surplus of revenues collected from load over what is required to pay generators. Any additional surplus congestion revenue can be banked against underfunded periods (for example, when unexpected transmission outages occur.) To the extent that revenues are inadequate to pay all FTR obligations, these obligations can be reduced *pro-rata*.

FTRs can be structured either as *obligations* or as *options*. In the case of obligations, the holder of the FTR has to make a payment to the market operator in the event that the value of the FTR is negative. In the case of options, there is no payment associated with a negative value. FTR obligations are more robust from an operational perspective in that they allow more of the capacity of the transmission system to be represented by FTRs without undue risk of revenue inadequacy; however, many transmission customers prefer options to limit their own exposure to negative congestion charges. One view is that PJM should provide obligations only, and allow financial markets to create options or other risk management derivatives. However, in 2003 PJM yielded to customer demands and became the first market to offer FTRs structured as options. According to a PJM press release of May 22, 2003:

> "The multi-period FTR products and the FTR option products provide more choices, more flexibility and make congestion risk management tools more readily available," said Andrew Ott, PJM executive director of markets coordination. "The new process better meets the needs of PJM customers in the competitive wholesale market. The FTR options reduce risk to customers who have load in areas where transmission congestion is unpredictable."

1.3. LMP, FTRs and Congestion: An Illustrative Example

To illustrate the operation of LMP, FTRs and congestion costs in PJM, we present an example using a highly simplified electricity market with a single constrained line leading into a load pocket.[11] This market is illustrated below in Figure 1.2.

[11] A "load pocket" refers to a transmission-constrained area in which there is insufficient low-cost in-area generation to meet load, thus leading to higher prices within the area than outside it. Northern New Jersey is an example of a large load pocket in PJM.

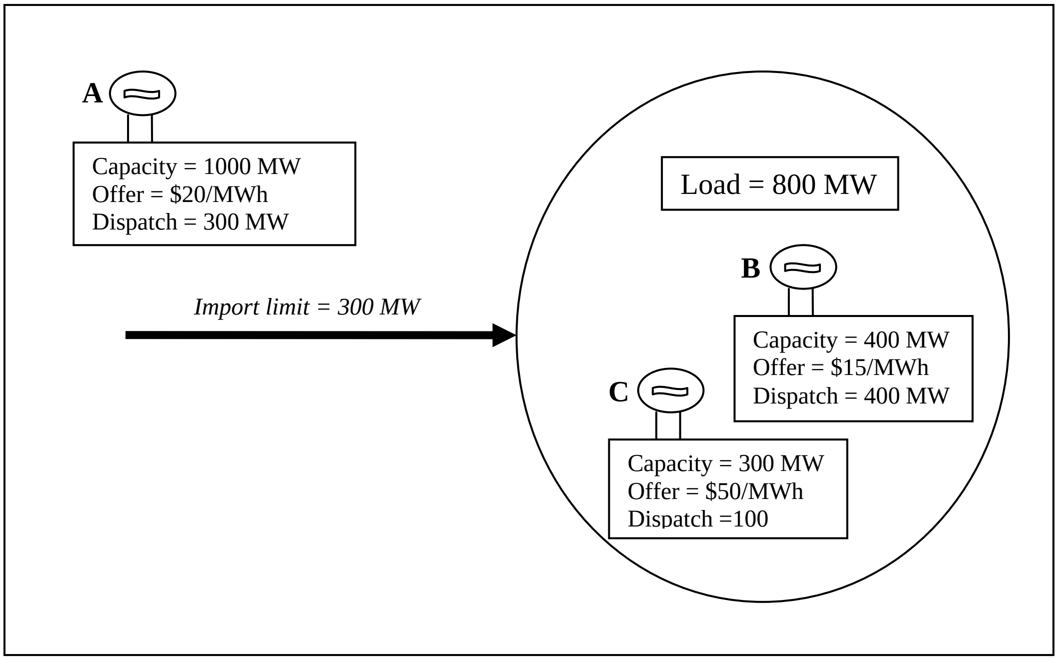


Figure 1.2 Simplified electricity market used in LMP example

Within the load area (represented by the oval), any amount of power can be delivered from generators B and C without concern for transmission capacity. However, there is only enough transmission capacity *entering* the load area to carry 300 MW of power from the external low-cost source (Generator A). This load area might represent a city which has some base-load and some high-cost "peaking" generators within the city limits, but with most low-cost, base-load power available in outlying areas.

In this example, the total load of 800 MW will be met by least-cost dispatch of the generating units subject to the transmission constraint. First the lowest-cost unit (B) will be fully dispatched. Next the intermediate-cost unit (A) will be dispatched, but it cannot deliver more than 300 MW of output to the load area due to the limit on the constraint. Finally, the high-cost unit (C) must be dispatched at 100 MW to meet the total load.

The LMP, which represent the cost to provide one more MW of electric energy at particular points in the system, are straightforward to derive in this simple example. If an incremental MW of energy were needed outside of the load pocket it could be supplied by ramping up generator A, so the LMP in this region is $20/MWh. Inside the load pocket an additional increment of energy would have to be served by generator C, so the

LMP in this area is $50/MWh. Thus the load in the pocket must pay this price--$50/MWh—for all of the energy it purchases in the spot market, in this case 800 MWh per hour, making the total cost $40,000 for the hour. Note that if the load had been only 699 MW, the import constraint would not have been binding; the next MW of load could have been served from generator A and the LMP would have been $20/MWh throughout the system.

To illustrate the use of FTRs in this example, we assume that the LSE in the load area originally owned the rights to use the transmission link into the load area, but was forced to give this up in return for ARRs upon the restructuring of the wholesale electricity market. However, when the FTRs for this line were auctioned off, this same LSE purchased 80% of them (240 MW) back. In so doing they incurred no net cost, because their FTR auction payments are offset by their ARR settlement payments. Some other market participant bought the remaining 20% of the FTRs as an investment, and that revenue went to the LSE as well. Returning to the three issues identified earlier that FTRs were designed to address:

- *Price uncertainty:* As noted above, at a load of 699 MW the price would have been only $20/MWh everywhere, but once the load exceeded 700 MW, the price jumped to $50/MWh inside the load area. The FTRs serve as a hedge against this kind of volatility in transmission costs, effectively allowing the holder to purchase energy at the price on the upstream side of the constraint. Because the LSE holds 240 MW of FTRs, they can effectively purchase 240 MW of electricity at the $20/MWh price. However, their FTRs only offer them price protection for these 240 MW; any additional imported electricity, or electricity purchased from the source *inside* the load area, now costs them $50/MWh.
- *Loss of traditional rights:* The LSE has chosen to take 80% of its historical physical rights directly as financial rights, so that they have the exact financial equivalent of firm transmission rights on the line. However, they took advantage of the additional flexibility in the FTR construct to accept a cash payment in lieu of those rights for 20% of the rights, either because they didn't expect to need all of them, or because they felt the market value was greater than the value of holding 100% of them as a hedge.
- *Surplus revenues:* Even though the LSE paid for electricity at an LMP of $50/MWh in this example, Generator A was only paid $20/MWh for its share of the production (300 MW) of that energy. Thus the ISO is holding an extra $30/MWh for those 300 MWh, or a total of $9,000 in surplus revenues. Through the FTR settlement, the LSE is paid 80% of that money ($7,200) while the other

> buyer, perhaps a financial speculator, is paid the remaining $1,800; the ISO has allocated the surplus and returned to revenue neutrality in the market.

We will return to this example in Section III of this report, when we discuss hedgeable and unhedgeable congestion costs.

1.4. LMP Implementation in the Real World

As with any applied economic construct, the real-world outcomes will diverge from theoretical predictions to the extent that real-world conditions diverge from the idealization underlying the theory. Thus it is useful to examine the ways in which real-world electricity markets diverge from the frictionless, unconstrained investment environment assumed above. We observe that there are at least three crucial ways in which real world conditions diverge from the theoretical idealization, which can lead to outcomes which are very different from the desired optimum.

The first major difference between LMP theory and reality is that in reality, investment in new generating infrastructure is extremely laborious, expensive, and highly constrained by factors such as the availability of suitable sites, availability and cost of land, access to fuel and transmission lines, requirements for cooling water, and local opposition. It is also risky in an environment of uncertainty regarding future regulations, fuel costs, future emissions prices, and other costs. Whatever the economic incentives, there are only a small number of entities with sufficient risk tolerance and access to capital to invest in generation stock. Similarly, there are often few suitable sites at which to build generating units, and as a rule these sites are not in those areas where capacity is most needed. Because the best locations for new generation are often on existing generation sites, these sites and any associated rights of way are often controlled by the same entities that own existing generation in any electricity market region. Electricity markets simply cannot be characterized as fluid investment environments where independent new entry can take advantage of unambiguously favorable market conditions.

This brings us to a second major difference between LMP theory and reality: the idealization that generation is always sufficiently competitive that each individual facility can be expected to be bid in a way that would maximize its own economic returns. In fact, the vast majority of generating units are held in portfolios, and the companies that *could* invest in new generation to increase overall market efficiency, and that control most of the suitable sites, generally already own generating capacity in the relevant market. Thus their incentive is to maximize *overall* profitability of their generating portfolio, and this incentive will often be inconsistent with investments that would drive down prices for energy and capacity. While most markets have rules to govern bidding behavior of existing generators, there are no rules that can force a competitive market participant to invest in generation that would be against its own self-interest.

Finally, we note that as a mathematical construct LMP assumes well-defined and well-known operational characteristics of generating units, as well as well-defined constraints such as limits on transmission system capacity. In fact, all of these elements can be and are subject to varying conditions and operator judgment in real-world applications. Even apparently straightforward parameters such as the carrying capacity of a transmission line actually change minute-by-minute in response to ambient and system conditions. Further, much of the operational information may be proprietary and only in aggregate or with low precision to system operators. Overall, the physics of electrical systems are simply far too complex for perfect real-time simulation and optimal utilization[12]; in addition, operators and unit owners have varying degrees of risk tolerance in how they manage capital stock. In this sense, LMP can be thought of as a perfect solution to a poorly defined problem—if the constraints were treated slightly and arbitrarily differently, the outcome could be quite different in some cases. In general, market participants have ignored this issue and treated market outcomes as if they were truly optimal and immutable. However, this unquestioned acceptance of these sometimes arbitrary results, with its potentially significant implications for financial settlements and investment, must be seen more as a convenient social compact than as recognition of economic reality.

[12] There is existing technology that could be used to provide better real-time operational information to system operators, based on Phasor Measurement Units (PMUs) and real-time communications. At present use of this technology is widespread in the western United States but comparatively sparse in the east. For information on efforts to expand the use of phasors in the eastern United States, see *http://phasors.pnl.gov/*.

1.5. LMP Approval in PJM

The FERC first accepted LMP as a wholesale market pricing method in its order of November 25, 1997, accepting the proposed structure of the PJM wholesale electricity market.[13] In the order FERC stated:

> We find that Supporting Companies' proposed locational marginal pricing (LMP) model, in conjunction with the use of FTRs, is just and reasonable and should be implemented on a prospective basis...We believe that the LMP model will promote efficient trading and be compatible with competitive market mechanisms. In this regard, we find that the LMP approach will reflect the opportunity costs of using congested transmission paths, encourage efficient use of the transmission system, and facilitate the development of competitive electricity markets. By pricing the use of constrained transmission capacity on the basis of opportunity costs, the proposal will also send price signals that are likely to encourage efficient location of new generating resources, dispatch of new and existing generating resources, and expansion of the transmission system.

In this proceeding, a number of objections had been raised with regard to LMP: that it was too complicated a solution for a fairly minor problem; that it introduced significant uncertainty in transmission costs, which would not be known until after the physical transaction had occurred; and that, by pricing all congestion on the margin, it over-recovered for true congestion costs. Opposing intervenors also argued that it was unnecessary—that PJM's modest congestion costs could be calculated and allocated in a simpler way. As summarized by FERC:[14]

> A number of intervenors maintain that Supporting Companies' proposal is an overly complex answer to a relatively modest problem. Certain intervenors argue, in this regard, that the proposal is so intricate that it cannot be relied upon to produce verifiable rates. The intervenors also maintain that calculations of congestion charges will not be auditable because the data is too voluminous to be conveniently stored and analyzed.
>
> Many parties opposing the proposal also claim that the transmission congestion problem is overstated under the LMP model. They claim that

[13] FERC order in Docket No. OA97-261, et al., November 25 1997, p. 38. The "supporting companies" referenced in this docket were: Atlantic City Electric Company (Atlantic City Electric), Baltimore Gas and Electric Company (BG&E), Delmarva Power & Light Company (Delmarva), Pennsylvania Power & Light Company (PP&L), Potomac Electric Power Company (PEPCO), Public Service Electric and Gas Company (PSE&G), and GPU, Inc. (GPU).
[14] Ibid., pp 41-42. References removed.

> the PJM system experiences constraints less than 10% of the time for a total annual cost of approximately $4 million, a relatively insignificant amount when compared to the total PJM transmission revenue requirement of more than $850 million. The intervenors contend that the congestion charges resulting from the PJM proposal are substantially higher than the congestion costs experienced by PJM in the past ($150 million versus $4 million for a representative annual period). They contend that the PJM proposal intentionally inflates congestion charges for the purpose of transferring monies from power suppliers to RTOs. Certain intervenors add that the LMP approach is not necessary because significant changes in congestion charges should not arise as a result of the changing competitive environment, given that the location of resources and loads will not change or will change slowly, in predictable ways.

All of these objections are valid; the introduction of LMP has introduced enormous uncertainty into transmission costs, and it results in revenue collections for congestion which are more than an order of magnitude greater than the actual costs associated with this issue. For example, in 2005 PJM reported a total of $5.6 billion in transmission costs from load, of which only about $100 million represented actual increases in the cost of producing electricity**.** However, both the uncertainty and the revenue surplus were addressed by the introduction of FTRs. If a market participant holds an FTR that exactly matches an electricity transaction in both location and quantity, the FTR serves as an exact hedge against congestion costs for that transaction. In addition, the FTR serves as a way to reapportion the excess revenues back to market participants—initially to the historical holders of physical transmission rights, but ultimately however the market decides.

FERC recognized that FTRs are not a perfect solution to these problems, given that they only serve as a complete hedge if each market participant has exactly matching FTRs and energy transactions, which is unlikely. The commission also acknowledged that LMP adds significant complexity (although not unmanageable, given “the availability of modern computer technology”) and that it will result in much larger financial transactions between market participants and the RTO. Nonetheless, they concluded that this cost was acceptable and necessary to foster the much more active, competitive, and regionally-integrated electricity markets that they foresaw in the future:

> Notwithstanding the intervenors’ arguments, in these circumstances, in light of the rapidly changing marketplace that we anticipate in the PJM

> region, past experience cannot be relied upon to gauge the magnitude or significance of congestion costs or the likely location of constraints in the restructured PJM markets. Historical congestion costs reflect a system operated for the benefit of the PJM Companies in electricity markets that were subject to far less competition than will be taking place in the future. Future congestion costs are likely to reflect a system operated in response to economic decisions made by numerous market participants in highly competitive electricity markets. *Ibid P. 44*

Thus the great LMP experiment began in PJM, quickly to be followed by New York, New England and the Midwest ISO, the manifestation of a descriptive, idealized economic pricing theory applied administratively to electricity markets to set prices on a real-time basis. Despite the short record on which to judge outcomes, LMP was further endorsed as a model for deregulated electricity markets under FERC's Order 2000 of December 29, 1999, and again as part of the Standard Market Design order of August 29, 2002.

2. Divergence of LMP Implementation from Theory

The operational implementation of LMP diverges from the theoretical underpinnings in a number of ways. In general, we believe that these have a minor impact on operational efficiency, and are probably unavoidable in deregulated, centrally-dispatched markets. However, these distortions are significant enough that they compromise some of the benefits that the LMP construct was designed to produce. As will be discussed, this may be one reason that the real-world experience of LMP-based markets has often not delivered upon all of its promises.

2.1. Bid-based Dispatch

Perhaps most importantly, LMP was originally envisioned as a SRMC-based optimization algorithm for vertically integrated utilities.[15] In practice, it has been implemented as a bid-based pricing and dispatch scheme in deregulated electricity markets. Bid-based dispatch may approach cost-based dispatch in a workably competitive environment with real price-based rivalry among suppliers, and in any case it probably

[15] Schweppe, et al., *Spot Pricing of Electricity*, 1988, Kluwer Academic publishers: "The spot price based energy marketplace is designed to operate in a regulated environment (regulated private company or government owned)". P. 111

has only a modest effect on dispatch order. However, it opens the door for exercise of market power under certain conditions, in which case it would result in a transfer of wealth from consumers to producers with no concomitant operational benefits. The possible exercise of market power in LMP markets is explored below in the analysis of bid-based offer patterns.

2.2. State Estimator

Another compromise to reality in LMP markets is the use of state estimators – data provision tools used by the RTO spot energy market operators to determine or describe detailed power system conditions. These conditions, including voltage levels, power flows, generation levels and load levels, must be estimated in an ongoing fashion from moment to moment as the basis for system operations. The state estimators rely upon data from many kinds of real-time monitoring technology, and they also "estimate" (hence the name) the system conditions that are not directly discernable. They are critical tools that give operators the "big picture" of what is going on system-wide. The state estimators are also used in the algorithms that produce real-time locational marginal prices, with each set of five-minute LMPs relying upon a snapshot of the networked power flow as part of the algorithm that produces prices. Thus, any errors in system representation that may creep into the state estimator will flow through the pricing algorithm. Depending on the nature and magnitude of the error, prices can be affected.

That these estimation errors exist is well known, but what is unknown is the extent to which these errors permeate the state estimators used by operators and flow through to LMP-based pricing. It is likely that operators relying on state estimators tend to be "conservative" in the interest of reliability, leading to an underutilization of the power grid. This can have a significant effect on prices because it may allow for binding constraints to change (increase) prices even though the physical elements may not be approaching their limitations; or may only be limited for a short period though represented as limited for lengthier periods.

Both the replacement of cost-based dispatch with bid-based dispatch and the use of state estimators mean that any price signals derived from LMP markets may not reflect actual costs. In the case of bid-based dispatch, the signals may be subject to market manipulation through strategic bidding. With the state estimator, market participants know that the signals reflect in part the errors in estimation and may be hesitant to invest in response. This will be discussed further in Section III, in which the price-signaling aspects of LMP are explored in detail.

2.3. Out of Merit Dispatch

Market operations in LMP RTOs often require the presence of generation resources in certain areas, especially load pockets or other dense load areas, in order to maintain voltage or provide needed contingency reserve. These resources are not necessarily the least cost generation available to meet such needs. They often need to be postured at minimum operating levels because they have relatively expensive operating costs but must be on in order to be available to provide reserves or voltage support.

Generators are paid for such "out of merit" operation in a number of ways. Some are under longer-term contracts to provide generation for "reliability must run" reasons. Some are paid "operating reserve credits" on a regular (i.e., daily) basis because they do not earn enough money to cover their operating costs based on their energy output alone. In New England, such units receive "net commitment period compensation" to cover start up and minimum load operating costs that are not otherwise covered through revenues from the energy and ancillary services marketplaces. In the MISO region, these units may be designated as "system support resources" and may receive "revenue sufficiency guarantees" to ensure their financial viability while operating at low levels of output. The RTOs allocate the costs of these payments to users of the transmission system.

These resources are generally not eligible to set energy market clearing prices, since their variable costs are much higher than units available in other locations on the system. Thus, LMP-based dispatch is not actually solved for system-wide optimization; these units are considered "out of market". In these cases, paying a portion of supply resources based on their actual costs, rather than at market-clearing prices, results in a reliably-operated system and justly and reasonably compensates providers. This practice is not a market-based mechanism for electricity supply, but it obtains a fair result for generators providing the service and consumers don't overpay for reliability. We conclude that such actions can be socially beneficial and should not be rejected out of hand merely because they are not market-based.

2.4. Observations and Conclusions

The reliance on bid-based dispatch, the use of the state estimator and the role of out-of-market resources are just a few of the ways that LMP implementation diverges from LMP theory. A number of other operational constraints also lead to "imperfect" LMPs, also calling into question the robustness of market outcomes and signals. These include:

- The impact of generation characteristics such as ramp rates, minimum run times, required startup times, and other technical parameters that define how maneuverable a given unit is under different circumstances and result in some units not being "eligible" to set LMP during certain time periods;
- Operator discretion in dispatch decisions;
- Variability of transmission line limitations, such as thermal loading capacities as a function of ambient conditions, and their static or quasi-static representation, rather than a more dynamic presentation in the dispatch and pricing algorithms;
- Boundary issues – external zone price formation and physical transmission rights structures.

LMPs thus arise from an imprecise application of optimization theory. It is not clear that such imprecision is any better or any worse than the imprecision that accompanies pricing in non-LMP markets; it may just be a consequence of the limits of information and technology to employ resources to their theoretical potential. But this reality means that the price signals associated with LMP can be subjective and unreliable, and may be perceived to be arbitrary and subject to change by market participants. The impact of this on the effectiveness of LMP-based price signaling is discussed in the next section of this report.

SECTION II – PRICE SIGNALING

"Differences in locational marginal prices, therefore, are not a plague descended on PJM from academia."

(Brief of Supporting Companies, FERC Dockets OA97-261-000 and ER97-1082-000, December 31, 1996, p. 10.)

3. LMP and Price Signaling: Theory and Background

3.1. Price Signaling Background

A primary goal of setting market prices at LMP is to provide economically accurate signals to stimulate investment where it is needed. Investors will anticipate the revenue benefits of locating in high price areas, and thus the promise is that the market will overcome whatever barriers have limited the entry of needed resources into these areas in the past. These resources can be new generating plants, transmission upgrades and enhancements, or demand response programs—the competitive market should find the most efficient investments to achieve reliability standards and meet load. According to the Supporting Companies in the FERC dockets establishing LMP in PJM,

- "LMPs encourage transmission enhancements that efficiently relieve grid congestion. Locational marginal pricing provides the price signals that will lead to efficient expansion of the transmission grid in the PJM control area. Load that faces high prices resulting from transmission system constraints, and generation that is not fully dispatched or receives a lower price for the same reason, will both have an ability to analyze the costs and benefits of transmission expansion, and an incentive to invest in any appropriate transmission expansions. Pricing systems that are not locational will not provide those incentives.

- "LMPs encourage new generators to locate where the power they produce will have the greatest value. Because locational marginal prices reflect the true cost of power at each location on the grid, prices will be higher where the costs of meeting the load at that location are higher. This gives generators an incentive to locate where they can serve those loads, which will exert a downward pressure on prices.

- "LMPs encourage load to locate where it can be supplied most cheaply. Because load pays the locational marginal price at its location, new loads have an economic incentive to locate where power costs are

> lowest. If prices do not vary by location, particularly when transmission is constrained, load has no price incentive to avoid locating where it will contribute to constraints and higher costs."
>
> *Answer of the Supporting Companies, p. 8-11.*

However, there are a number of reasons actual investments in the real world may not be as responsive to LMP signals as Supporting Companies suggest. First, the obstacles to investment in high-priced areas can be quite significant, including zoning restrictions; cost of land and labor; local opposition; access to fuel sources, transmission lines, or cooling water; and other considerations. Further, there is a fundamental disconnect between the short-term, volatile price signals in LMP markets and the kind of revenue assurance required for large capital projects such as generating plants or major transmission projects. Not only can patterns of congestion and electricity prices change considerably as fuel prices or system conditions change but, due to the lumpy nature of such investments as discussed earlier, building significant generating or transmission capacity in a constrained region can itself negate the price premium which would otherwise provide the needed revenues. Finally, all potential investors have access to the same price signals, and the same limited set of investment options. Thus, particularly with respect to generation, there is a great risk of "herd mentality" investment practices, where a number of entities invest in similar technology in similar areas in response to price signals, to the detriment of all. This may be seen, for example, in the great number of gas-fired combined cycle generating plants built in the U.S. northeast during the last decade, leading to extreme competition and low margins in a certain range of the supply curve. This has led in turn to a high correlation of electricity and natural gas prices, and excessive exposure to price fluctuations in this fuel.

Finally, the disconnect extends into the time needed to plan, permit, design and construct a new generating plant, which for large, base load units can be up to seven years for coal, and much more for new hydro or nuclear capacity. Similar concerns and perhaps even more severe permitting issues apply to transmission expansion projects. Investors would have to be able to anticipate the trends of highly volatile, short-term pricing signals, and to anticipate any decade-scale changes in congestion patterns, transmission planning, and other factors affecting locational electricity prices in order to consider these signals in the decision-making process.

3.2. *Price Signaling: New Generation and Retirements*

In order to investigate the effectiveness of LMP price signals to entice needed generation investment, we reviewed actual generation investments and retirements that have occurred in PJM from 1999 through 2006, and compared these with the LMP price indications of where generation was most needed in the system. Note that it is difficult to make direct year-to-year comparisons because the PJM footprint has grown dramatically during this period. This growth, together with net capacity additions and retirements in the PJM system, is shown in Figure 3.1**.**

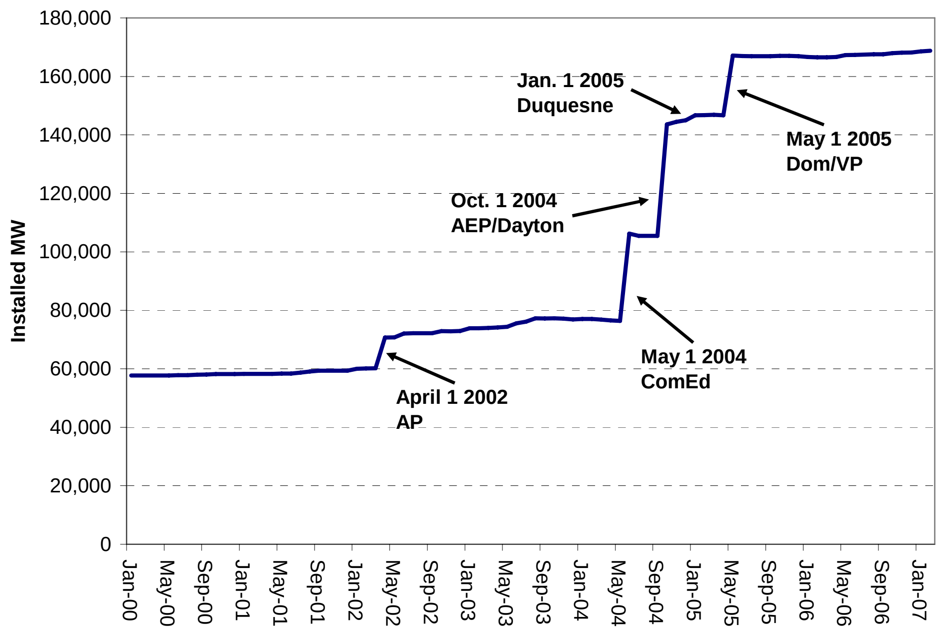


Figure 3.1 Total and projected PJM installed capacity, January 2000 through February 2007
Expansions of the PJM footprint during this period are identified. *Source: PJM Installed Capacity data.*

Price Signals in PJM

To explore whether patterns of investment and retirement are strongly influenced by LMPs, we begin with an overview of price patterns in PJM. Specifically, we focus on PJM's "load zones"[16] to investigate whether generation has followed price signals at this

[16] A map of PJM load zones may be found at http://www.pjm.com/documents/maps/pjm-zones.pdf

level of granularity. All-hours average prices by load zone for 2004 and 2005 are shown in Figure 3.2**.**

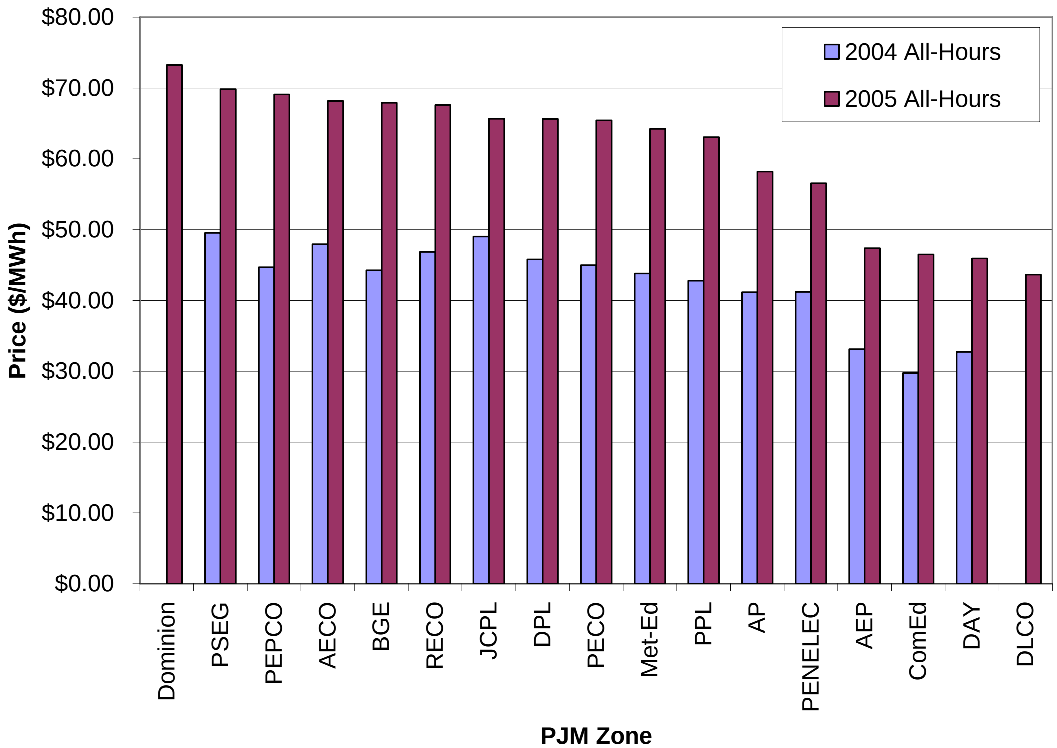


Figure 3.2 All-hours average real-time electricity prices in PJM, 2004 and 2005
Ordered by 2005 all-hours price. *Data source: PJM 2005 SOM Report.*

As seen in Figure 3.2, the largest price differences are between the low-cost, westernmost parts of PJM (AEP and DAY in Ohio, ComEd Illinois, and the AEP regions of the Virginias), versus the congested, highly populated eastern regions such as PSEG in New Jersey and southwest MAAC (PEPCO and BGE in Washington and Maryland). However, because the western regions are recent additions to PJM, there is no long-term record to compare investments in these areas to the eastern regions. A similar issue pertains to the highest-price region in 2005, the Dominion area in Eastern Virginia. Thus we are restricted to reviewing a much smaller range of price signals. These long-term PJM regions can be roughly grouped into four tiers according to 2005 average price as follows:

- *First Tier:* PSEG in Northern New Jersey and PEPCO in the Washington, DC area, with a load-weighted average price of $69.55/MWh;

- *Second Tier:* Atlantic Electric in New Jersey and Baltimore Gas & Electric in Maryland, with a load-weighted average price of $67.99/MWh;
- *Third Tier:* Jersey City, Delmarva, and the Eastern Pennsylvania areas (PECO Energy, Metropolitan Edison and PPL Electric), with a load-weighted price of $65.38/MWh;
- *Fourth Tier:* Allegheny Power and Pennsylvania Electric in western Pennsylvania, with a weighted average price of $57.37.

Of course, these groupings would have been somewhat different had 2004 data been considered instead of 2005. For example, Jersey City (third tier) would have been one of the highest-priced regions, while PEPCO (first tier) might have been among the lowest. In fact, the price differences between the years far outweigh the locational price differences shown. This highlights one of the primary difficulties in relying on locational price signals to spur investment: that the signals are dynamic over much shorter timeframes than those required to make or recover infrastructure investments, both in aggregate (year-to-year variations) and between locations. Nonetheless, the general trend of higher prices in the east than in the west seems to be reliable and persistent, as are certain specific features such as particularly high prices in the Public Service area of northern New Jersey. This observation is strongly supported by the data shown in Figure 3.3**,** which shows monthly real-time prices (on-peak and off-peak) in the Public Service, PPL Energy and BGE areas, and in Figure 3.4, which shows the monthly on- and off-peak price differences between PSEG and PPL. These Figures demonstrate that prices in PSEG have been consistently higher by about $5/MWh on-peak and $2/MWh off-peak throughout this seven-year period. It seems reasonable to imagine that investors would rely on these features, at least, if price signals were the dominant consideration in investment strategies.

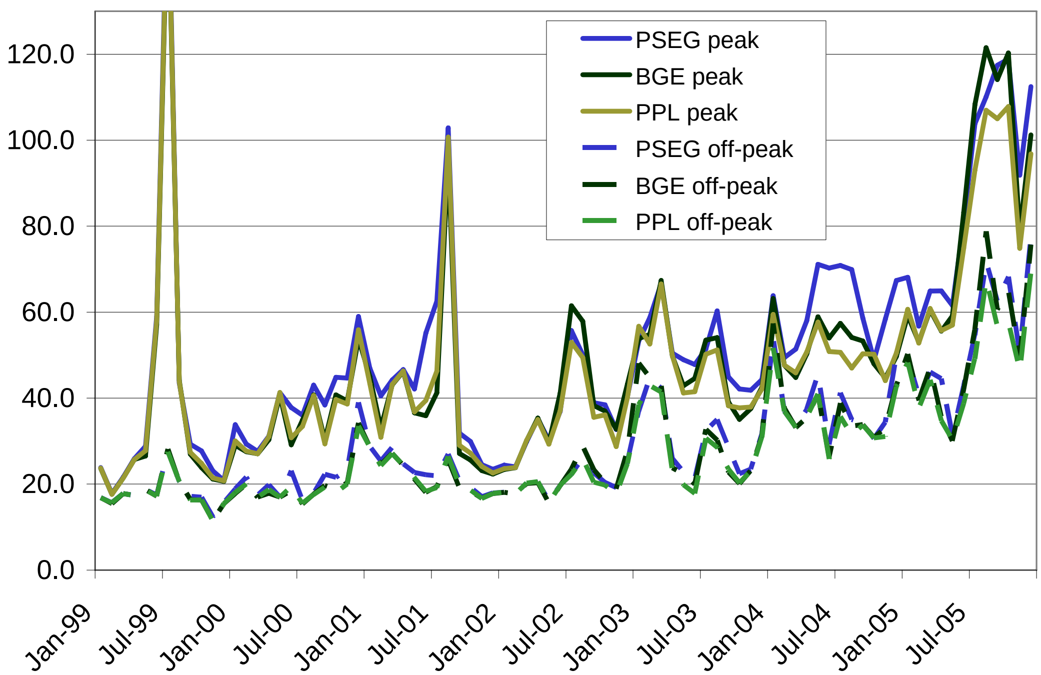


Figure 3.3 Monthly real-time on-peak and off-peak prices in three PJM zones, 1999 – 2005
Data source: PJM Public Price Data.

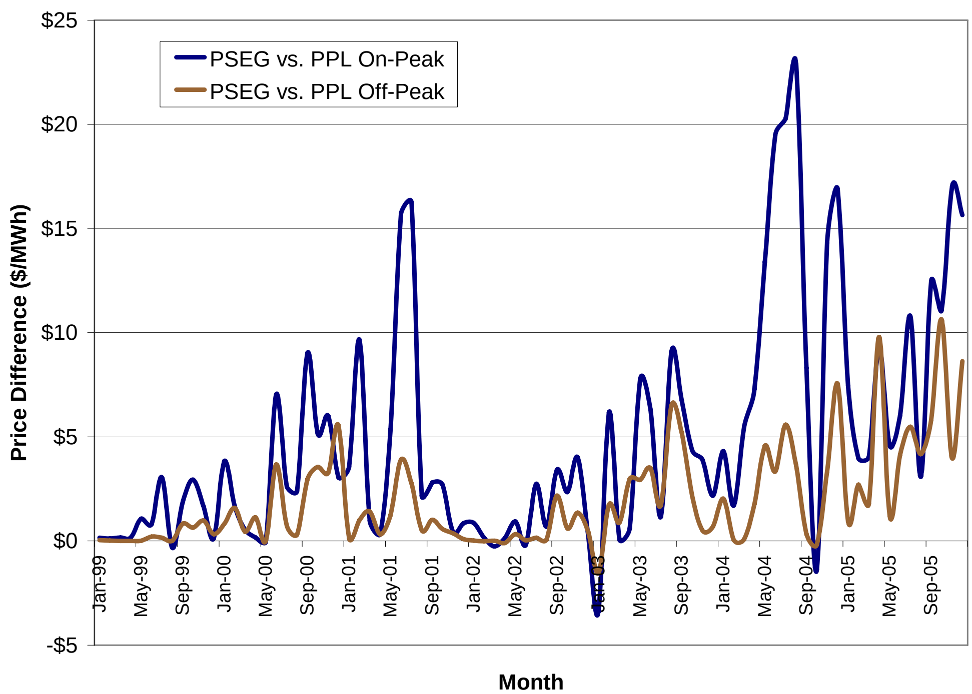


Figure 3.4 Monthly real-time on-peak and off-peak price difference between Public Service New Jersey and PPL Energy of Pennsylvania, 1999 – 2005
Data source: PJM Public Price Data.

New Generation in PJM

The PJM region has seen completion of approximately 16,000 MW of new generation since 1999. Most of this generation has been natural-gas fired, with the majority being either combined cycle or combustion turbine (peaking) units (Figure 3.5).

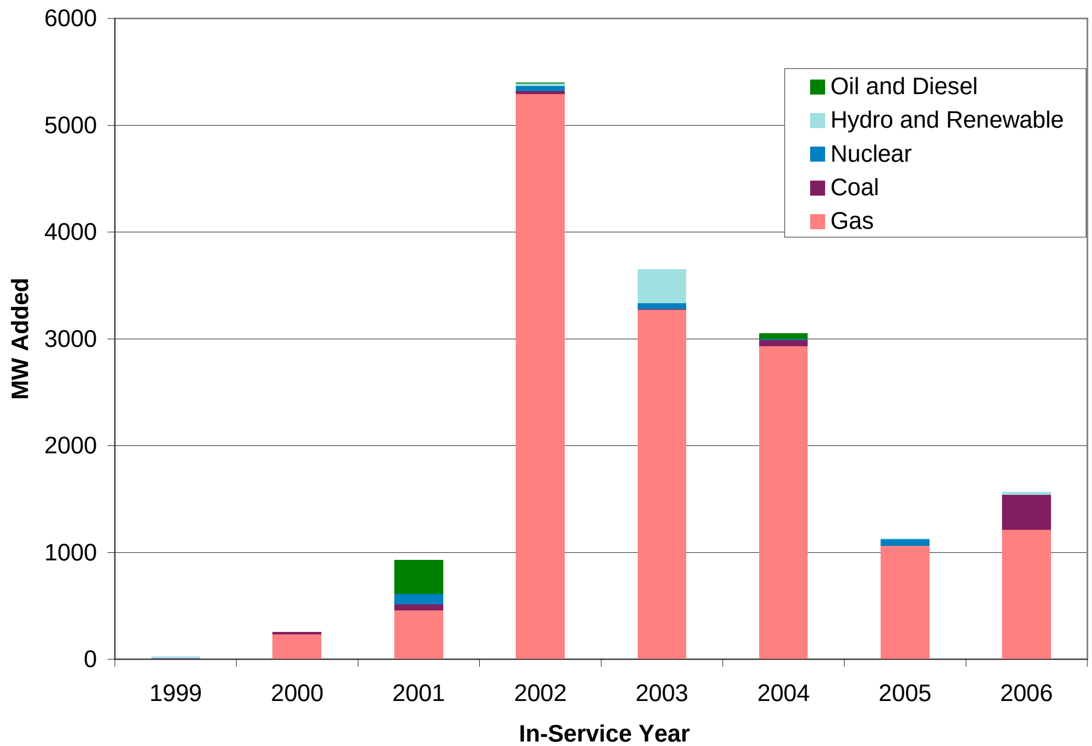


Figure 3.5 New capacity additions in PJM by fuel type, 1999 - 2006

As a general rule, predominant direction of power delivery is from lower-cost producing regions in the west to highly concentrated load areas in the east where higher-cost gas and oil fired generation predominates. However, as shown in Figure 3.6, the location of these additional MW has been divided roughly equally between PJM Eastern regions (the region east of the PJM East interface, including all of New Jersey, as well as the PECO and DelMarVa regions) and PJM Western regions (balance of PJM, including Allegheny, Baltimore Gas & Electric, Metropolitan Edison, Pennsylvania Electric, PEPCO and PPL), despite the consistently higher price in the east.

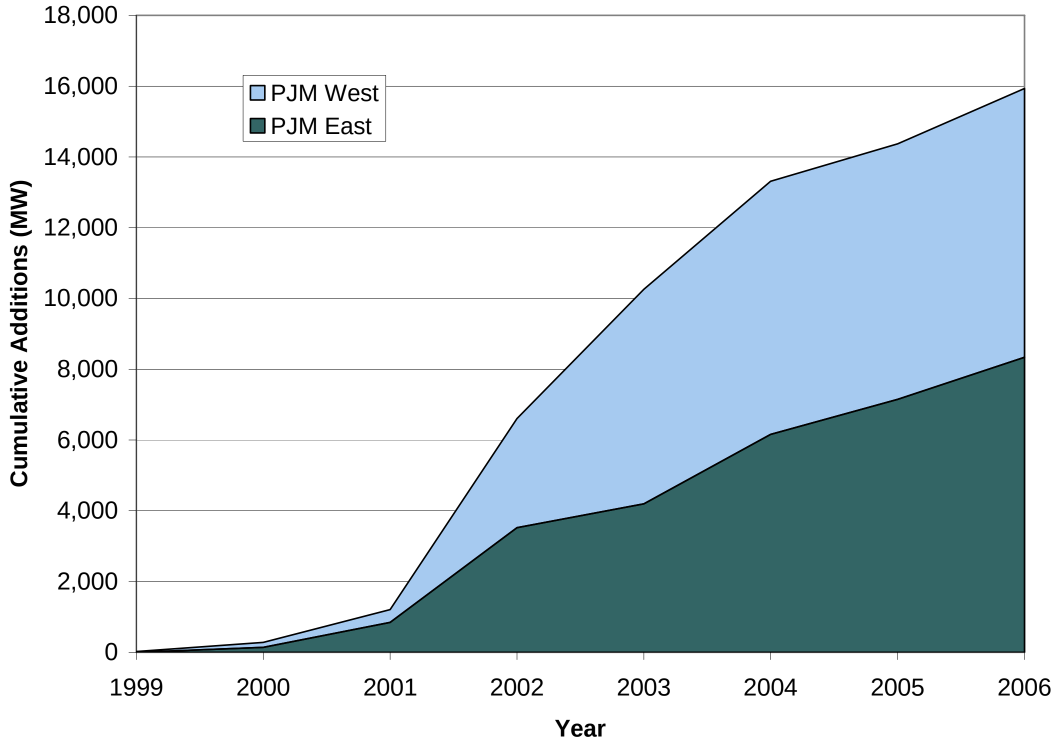


Figure 3.6 Cumulative new capacity additions in PJM East and PJM West since 1999

For another view of how generation additions have compared to price signals, Figure 3.7 groups new additions for each year into the four price tiers identified earlier. Table 3.1 details the generation additions by zone during this period.

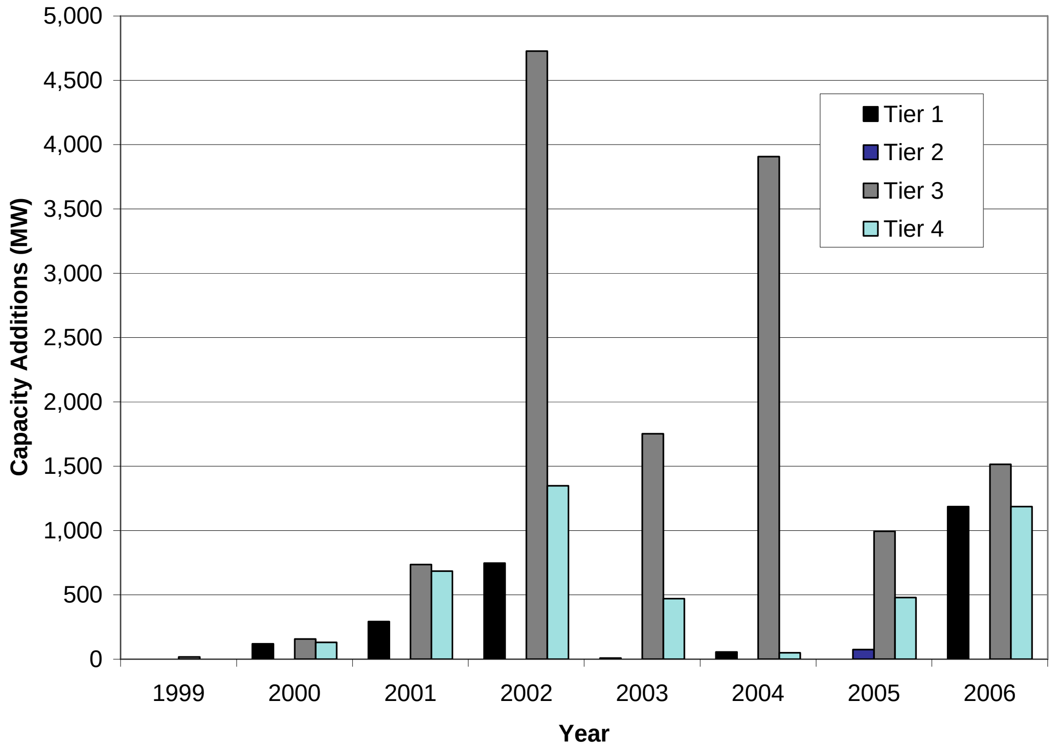


Figure 3.7 Annual new capacity additions by price tier in PJM
Tiers are: (1) PSEG, PEPCO; (2) AECO, BG&E; (3) JCPL, DPL, PECO, METED, PPL; (4) APS, PENELEC. Tier 1 zones had the highest priced zones in 2005, while Tier 4 had the lowest prices.

There is no evidence in these data that higher prices attract more generation investment; to the contrary, most of the new megawatts have been concentrated in the lowest-priced two tiers. A more reasonable interpretation of the data is that that projects have been concentrated in areas where there is abundant access to fuel, land and labor are available, and local opposition is not prohibitive. Again, this grouping into tiers is somewhat arbitrary and only indicative of prices in 2005; further, due to the lumpiness of generation investments, a single project can dominate the overall picture for any given year. However, the same issues that cloud this analysis also confound the ability of generators to make infrastructure investments in response to price signals in the real electricity market.

Table 3.1 Capacity Additions in PJM by Zone and In-Service Year, 1999 - 2006

	In Service Year:	1999	2000	2001	2002	2003	2004	2005	2006	Grand Total	2006 Peak Load (MW)	Additions as % of Peak Load
PJM East	*AECO*					8		9		17	2679	0.6%
	DPL		10	415	600	465	26	480		1996	3994	50%
	JCPL	2		20	765			500		1287	6335	20%
	PECO		8		566	196	1912			2682	8337	32%
	PSEG		120	270	748	6	24		1186	2354	10701	22%
PJM East Total:		***2***	***138***	***705***	***2679***	***675***	***1962***	***989***	***1186***	***8336***	***32046***	***26%***
PJM West	*APS*		88	88	1003	1212	70			2461	8030	30%
	BGE			10			9	63		82	7212	1.1%
	METED		1	10	1232	830		6		2079	2773	75%
	PENELEC	15	11		250	48			329	653	2760	24%
	PEPCO			22		4	33			59	6953	0.8%
	PPL	7	17	93	234	883	979		51	2264	7152	32%
PJM West Total:		***22***	***117***	***223***	***2719***	***2977***	***1091***	***69***	***380***	***7598***	***34880***	***22%***
Grand Total:		***24***	***255***	***928***	***5398***	***3652***	***3053***	***1058***	***1566***	***15934***	***66926***	***24%***

In PJM East generation additions have been distributed over the different service territories, with only the Atlantic Electric Company area seeing relatively little new generation; again there is no indication that highest-priced regions attract more new entry.

Much of the new generation added in the PJM region was planned, constructed and placed in-service prior to the recent increase in average prices, as shown in Figure 3.8. This probably does not suggest that investors anticipated the dramatic increase in prices, however, as these have been mainly the result of higher natural gas costs and the new, primarily gas fired generating resources have seen little to no benefit.

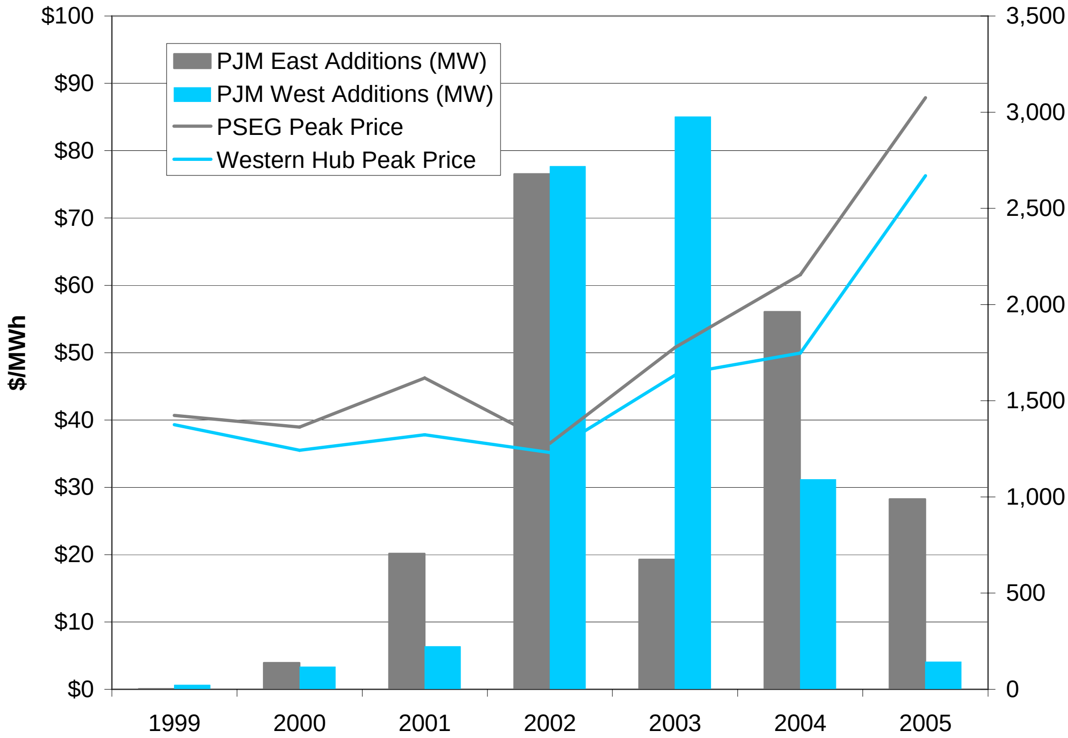


Figure 3.8 Annual new capacity additions and on-peak average electricity prices in PJM East and PJM West
Solid bars and right axis indicate annual MW additions in each zone; lines and left axis indicate annual average peak-hours price for the indicated zone.

In fact, the only clear response to price signals found in the generation addition history is the almost universal choice of gas-fired technologies shown in Figure 3.5. However, far from being a benefit of market-based generation investment, this has highlighted a shortcoming: the “herd mentality” that occurs when all investors respond to the same signals at the same time. The result has been bad for both investors and consumers. Investors have suffered from having too many units in the same region of the supply curve, so that they have limited opportunities to recover more than their marginal cost and to earn a return on investment. As a result, many of these new units have proven uneconomic. Consumers have suffered from an overexposure of the market to the rapidly increasing price of natural gas, with at least part of this increase due to the sharp increase in demand from new gas-fired generating units.

Capacity Retirements in PJM

PJM has seen approximately 5,700 MW of generation retire since 1999, much of it in the ComEd zone at the beginning of 2005. Figure 3.9 shows the total megawatts of new entry (above the line) and retirements (below the line) for each year since 1999, as well as annual and cumulative net megawatts added during this period, for the entire PJM system. Figure 3.10 groups these annual retirements by price tier, defined as above, including only regions which have been in the PJM footprint throughout this period. Figure 3.10 demonstrates that in many years, including 2005 and 2006, the vast majority of megawatt retirements occurred in the most expensive regions of the PJM footprint, contrary to what effective price signaling should have produced. This is dominated by over 440 MW of capacity retirements in PSEG, the highest-priced region in PJM, during these two years.

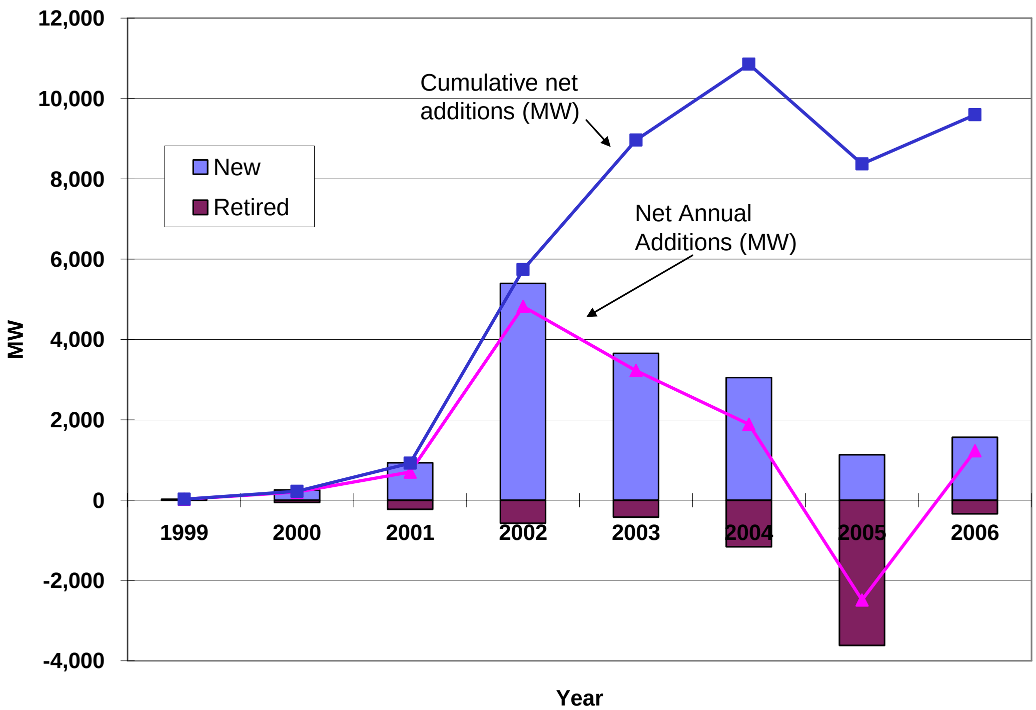


Figure 3.9 Annual and cumulative capacity additions and retirements in PJM
Bars show additions (shown above the zero line) and retirements (shown below the zero line); both the annual net additions and cumulative net additions for the period are shown.

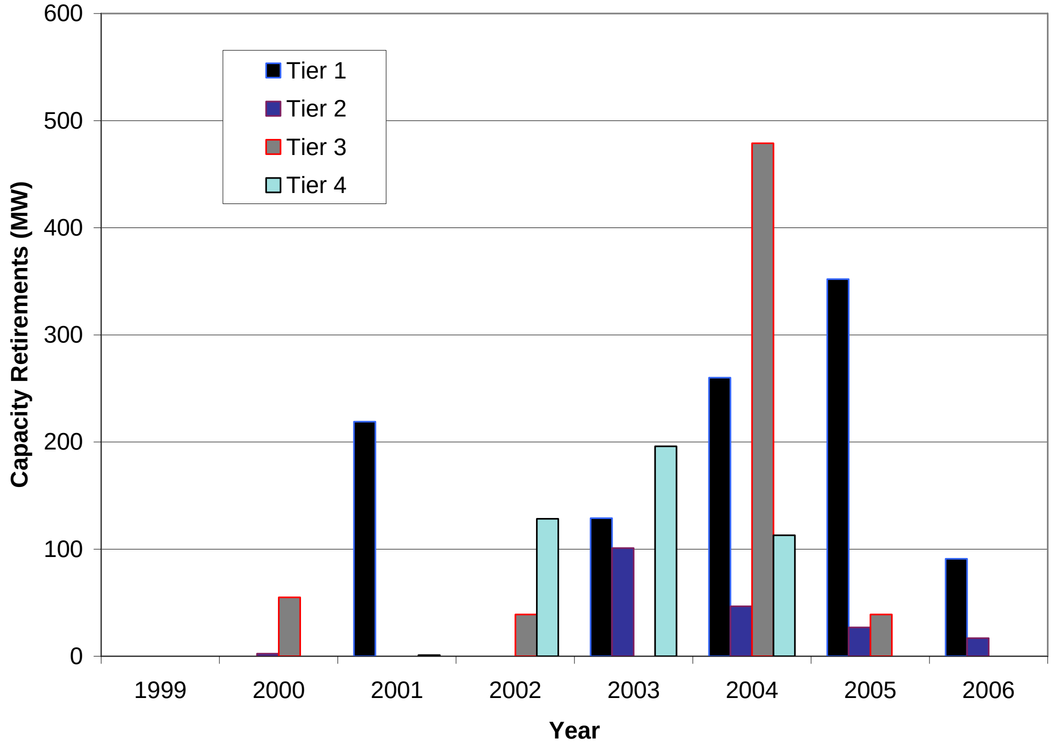


Figure 3.10 Annual capacity retirements by price tier in PJM
Tiers defined as described in the text and shown in

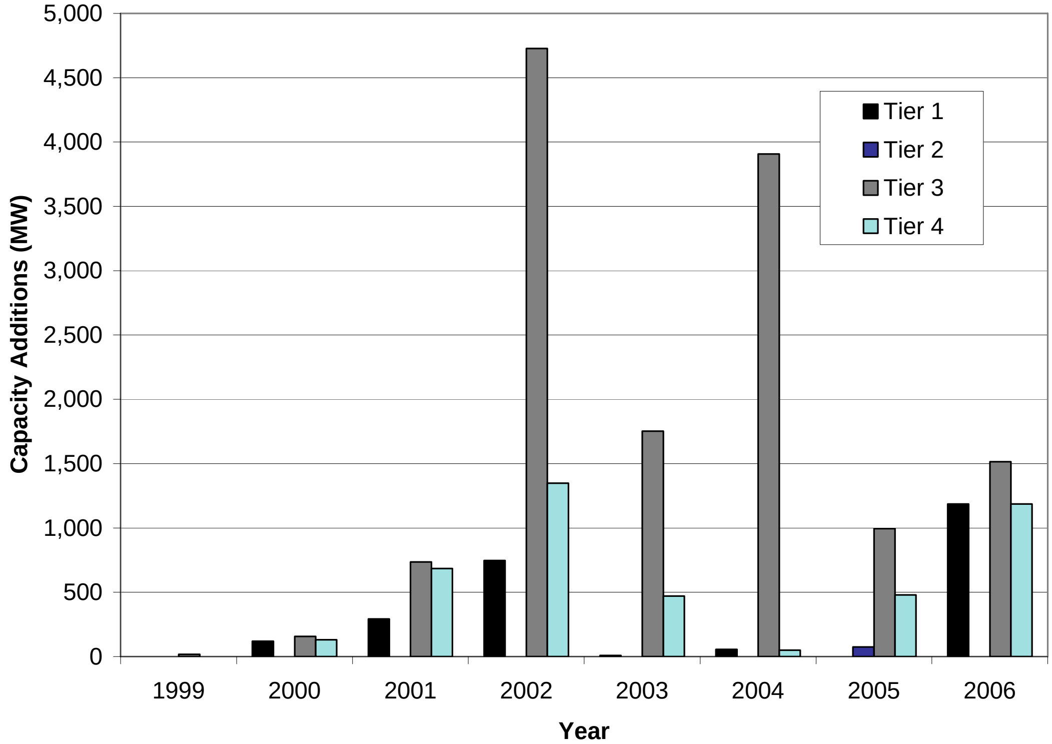


Figure 3.7.

Finally, Figure 3.11 shows the cumulative net change in capacity (additions minus retirements) by price tier during the period 1999 through 2006. The two lower price tiers dominate the capacity additions, while the second highest tier shows a small net loss of capacity during this period. The highest-priced tier shows a very modest increase in total capacity early in the period, but almost no net change in total capacity since 2002. The majority of additions by far occurred with tier 3 regions, with tier 4 housing most of the rest. It is difficult to reconcile these observations with a dominant role for price signals in investment and retirement decisions.

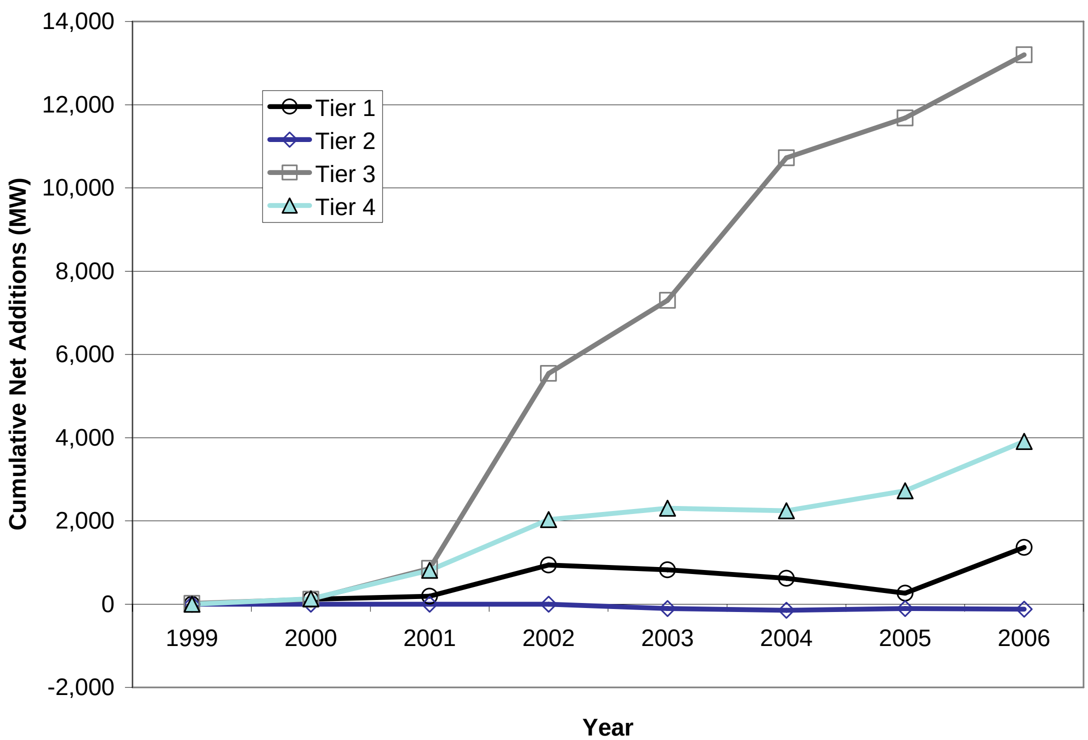


Figure 3.11 Cumulative net change in generating capacity by price tier in PJM

PJM Generation Queue

Figure 3.12 shows that a significant amount of new generation has been proposed within the last two years. The “full” and “partial” categories shown in the figure represent generation quantities that have already been placed in-service. The “construction” and “study” categories indicate generation amounts not yet placed in service. PJM currently has 4,358 MW under construction and 33,500 MW of generation actively under study. It is highly unlikely that all the under study generation will be built; historically, about 35% of queued generation in PJM has been completed.

About two-thirds of the queued generation under study or under construction is located in the lower-priced western or southern parts of PJM. As with generation additions and retirements in recent years, there is no evidence from these data that locational price signals have played a major role in determining where proposed generation would be located.

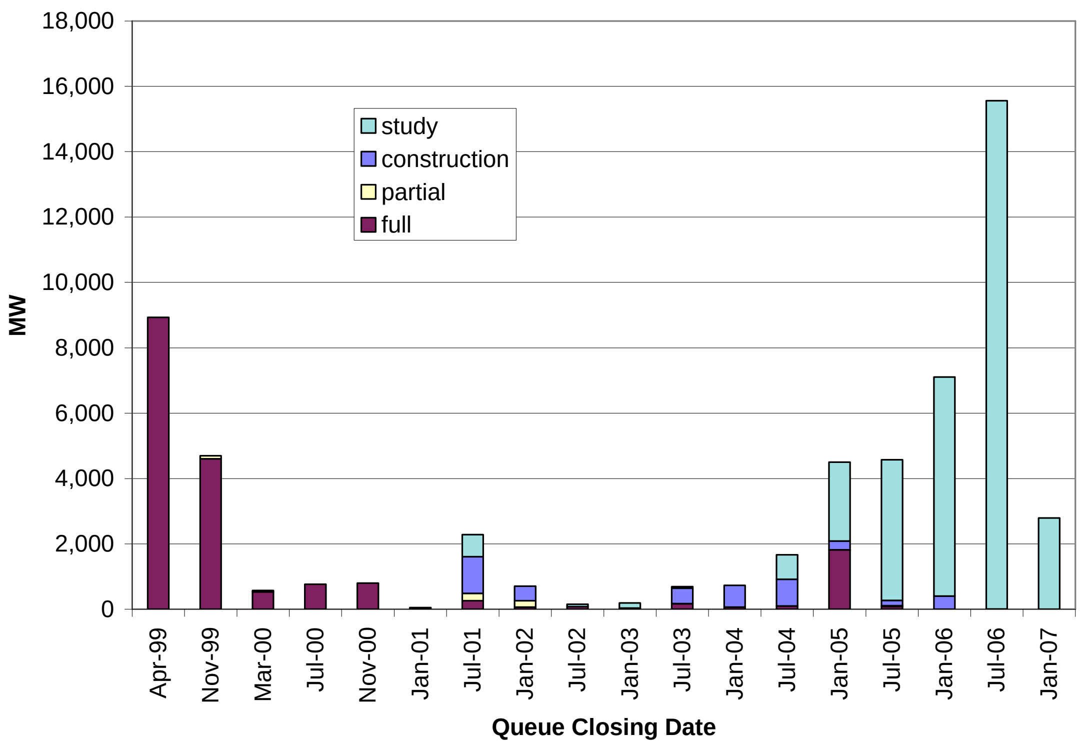


Figure 3.12 New generation resources in the PJM queue
Since 2001 PJM has created a new "queue window" which closes every January and July. Historically, about 35% of queued generation has eventually been completed. *Source: PJM public data.*

At least partly in recognition of the lack of generation investment response to locational price signals, PJM is beginning to implement a locational "capacity" market (the Reliability Pricing Model, or RPM[17]) which will compensate generators for providing capacity, as well as energy, in a manner meant to recognize locations where capacity is

[17] As of this writing, a settlement version of RPM has been conditionally approved by the Federal Energy Regulatory Commission under Docket nos. EL05-148 and ER05-1410. (Order issued December 22, 2006.)

most needed. This will enhance the locational price signals for generation investment and retirement decisions, at an additional cost to consumers which Synapse has estimated will reach over $5 billion annually.[18] Whether these price signals will be more successful in producing generation investments where needed remains unknown.

Price Signaling and Generation Summary

We make the following observations of the effect of LMP price signaling as an incentive for new generation construction and retirement decisions in PJM:

- Most of the new generation constructed in PJM has not been in the higher priced eastern regions; conversely, a large share of the retirements *has* been in high-priced regions.
- Most of the new generation had been planned and constructed prior to the recent increase in electricity prices and, because it is utilizes mostly gas-burning technology, it is not benefiting from those prices;
- Proposed new generation in the PJM queue continues to be disproportionately located in regions outside of the high-priced Eastern zones. In addition, PJM has proposed three new east-west transmission corridors pursuant to the 2005 Energy Policy Act, suggesting that they have perhaps minimal expectation that sufficient generation can or will be built in high priced regions and thus transmission is required for reliability assurance;
- LMP price signals do not appear to be providing effective incentives to build and maintain generation where and when it is most needed.

3.3. Price Signaling: Transmission

Transmission congestion occurs when there is insufficient transmission capacity to reliably transport energy from the least-cost available suppliers to load, causing price separation on the system—LMPs in one area differ from those elsewhere in the system. In such a situation, additional transmission could make the low-cost generation more available to serve high-cost regions. However, while such an enhancement might present considerable value as a public good, it is difficult to design a market that will entice merchant transmission providers to invest where needed:

> Transmission lines can act as both a substitute for and complement to generation. New transmission lines increase competition between suppliers who may therefore oppose them, but they are a public good

[18] Hausman, E. *et al.*, "RPM 2006: Windfall Profits for Existing Base Load Units in PJM—An Update of Two Case Studies", Prepared for Pennsylvania Office of Consumer Advocate, February, 2006.

> because they reduce market power. The siting of a new transmission line is a highly regulated and contentious process. It is also difficult to assign individual physical or financial rights to the power grid in such a way that investors make the appropriate return on their investment.
>
> These complexities make deregulation of the market for transmission lines impossible. The distribution system seems even more difficult to deregulate, and so far there have been few, if any, proposals to do so.
>
> *Steven Stoft,* Power System Economics*, p.26*

Transmission Congestion Background

The existence of transmission congestion in electricity markets reflects the fact that at least some elements of the transmission system are used to their maximum allowable capacity. Under these circumstances, power flow on cannot be increased on those elements without unacceptable risk of failure. Thus the system must be "redispatched" around the constraint, with higher-cost downstream generation replacing lower-cost upstream resources, to ensure that the limits are not violated. Congestion and congestion costs are a normal and expected result of efficient electricity markets. Indeed, any large-scale electricity market that experienced no congestion would clearly have over-invested in transmission infrastructure.

Congestion costs associated with any transmission constraint can be measured directly through the *shadow prices* that are produced by the LMP and dispatch calculation process. These shadow prices reflect the marginal costs associated with each binding transmission constraint—specifically, how much money it would be worth if the constraint could be relaxed by one unit (MW) of flow. During any operating interval, the shadow price for a given constraint, times the flow across that same constraint, yields the gross congestion cost associated with that constraint for the interval. Providing a quantification of congestion costs is one of the price-signaling goals of the LMP system. By identifying and localizing specific costs associated with transmission constraints, LMP can provide an indication both of where transmission congestion exists, and of the economic consequences of that congestion. As with other price-signaling features of LMP, it should enable market participants to recognize and capitalize upon opportunities to profit from resolving inefficiencies in the system. Market participants can, in theory, respond to the same signals by investing in either transmission or generation, yielding the most efficient solution to meeting electrical load. At the same time, all of this information gives analysts an opportunity to track patterns of congestion to their sources and to quantify their impacts on consumers. This makes it possible to investigate whether the market or any administrative entity is acting effectively to address these impacts in a timely and efficient manner.

In fact, LMP signals are a fairly crude indicator of needed transmission upgrades. For one thing, even if the binding constraint and shadow price are identified, this does not necessarily reveal what the benefits of relieving the constraint would be—other constraints could bind, imposing other costs on the system. Also, as noted earlier, many of the constraints on the system are only approximations or proxy estimates of transmission capacity. Both shadow prices and LMPs are highly sensitive to these approximations. Nonetheless, as they are the only signals provided by the LMP construct to indicate where additional transmission would be of value, we are forced to base our analysis on this information.

Hedgeable vs. Unhedgeable Congestion

The total gross congestion cost on the system represents the total increase in cost for load to purchase electricity due to congestion, not counting any hedges such as FTRs or self-supply of generation. In PJM, gross congestion costs are perhaps ten times greater than the actual increase in production costs associated with redispatch around congested transmission constraints. This reflects the fact that all load is charged (and all generators are paid) at the marginal cost of providing the next incremental megawatt at their pricing location. Thus even though a large portion of the load in some area may be served by low-cost generation upstream of a binding transmission constraint, all load pays wholesale prices as if it were the increment of load for which this transmission capacity was unavailable. This was demonstrated by example in Section 1.2.

Total *unhedgeable* congestion cost, on the other hand, is the actual system-wide increase in production cost resulting from transmission congestion. Because this cost represents the real economic losses associated with congestion on a system-wide basis, it cannot be hedged. PJM calculates and publishes unhedgeable congestion costs for each transmission constraint.[19] At least in theory, the difference between unhedgeable and gross congestion costs can be recaptured by load through hedging strategies. The two available strategies are (1) holding FTRs, and (2) having control of inframarginal generation sources within a constrained area, so that the buyer offsets at least part of the higher cost of energy by selling generation into the same high-priced market.[20]

Figure 3.13(a) and Figure 3.13(b) below reproduce the example market introduced in Section 1.2 to illustrate these points. Again we consider an area with a load of 800 MW, served by a single transmission line which connects it to a market with abundant power (Generator A) available at $20/MWh. Within this area there is a 400 MW generator (B) with an offer price of $15/MWh and a 300 MW generator (C) with an offer price of $50/MWh.

Here we consider two alternative cases. In Case I, there is no binding constraint on the capacity of the transmission line. In this case, the generating units are dispatched in merit order (least-cost first) so that the low-cost generator (B) produces 400MW, and the remaining power is imported from outside. This case is shown in Figure 3.13(a). In Case II, the import constraint has a limit of 300 MW, so only 300 MW of power can be imported from Generator (A). The low-cost generator (B) is still fully dispatched at 400 MW, but the remaining 100 MW must come from the expensive generator (C) inside the constrained area. This case is shown in Figure 3.13(b). In both cases we ignore any energy losses on the transmission system.

In Case I, the next increment of load anywhere on the system would be served from Generator A, so the LMP everywhere in the system is $20/MWh.

[19] In reality, it is not possible to state precisely the unhedgeable congestion costs associated with specific constraints, as these costs result from the combined effect of a large number of system characteristics. Similarly, FTRs are not associated with specific constraints in PJM but with price differentials between two points on the network. However, PJM is able to make an estimate based on allocating system-wide unhedgeable costs and estimating how many MWs of FTRs should be associated with a given line in a more general sense.

[20] For a discussion of how PJM calculates unhedgeable congestion, see http://www.pjm.com/committees/stakeholders/ferc-filings/21-exhibit-upp-8.pdf

In Case II, the transmission line is fully utilized and binding. Any incremental load outside of the constrained region could still be served by Generator A, so this outside area still has an LMP of $20/MWh. However, incremental load *inside* the region must be served by additional generation at C. Because the cost to serve the next increment of load in this area is $50/MWh, that is the LMP in the constrained region. This is exactly the same as the example presented earlier in this document.

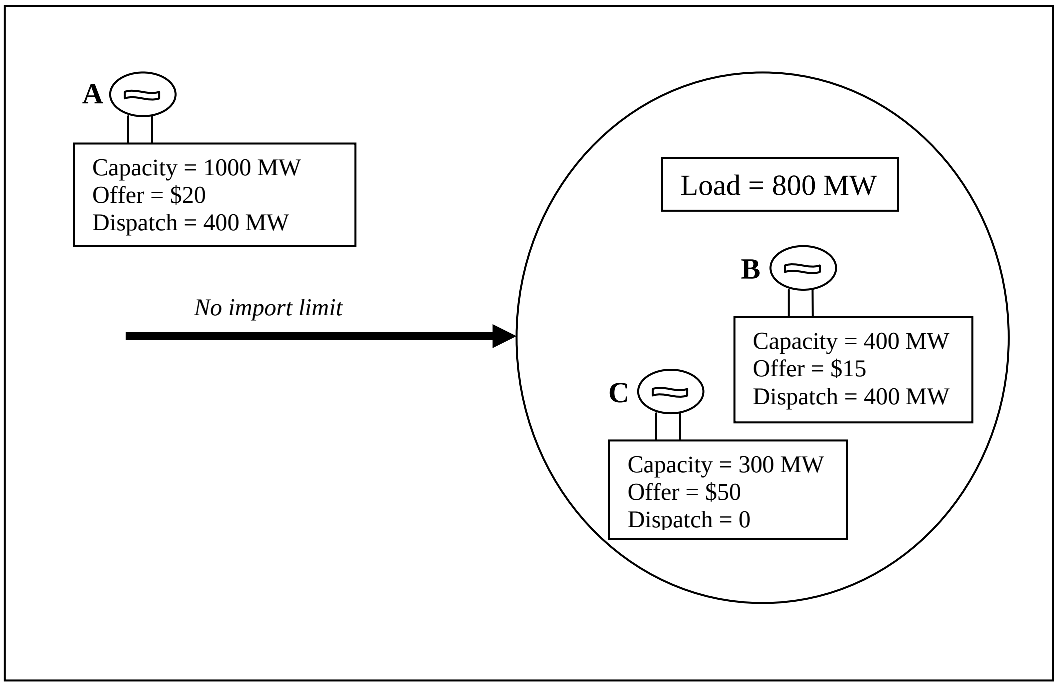


Figure 3.13(a) Schematic diagram of unconstrained case (Case I)

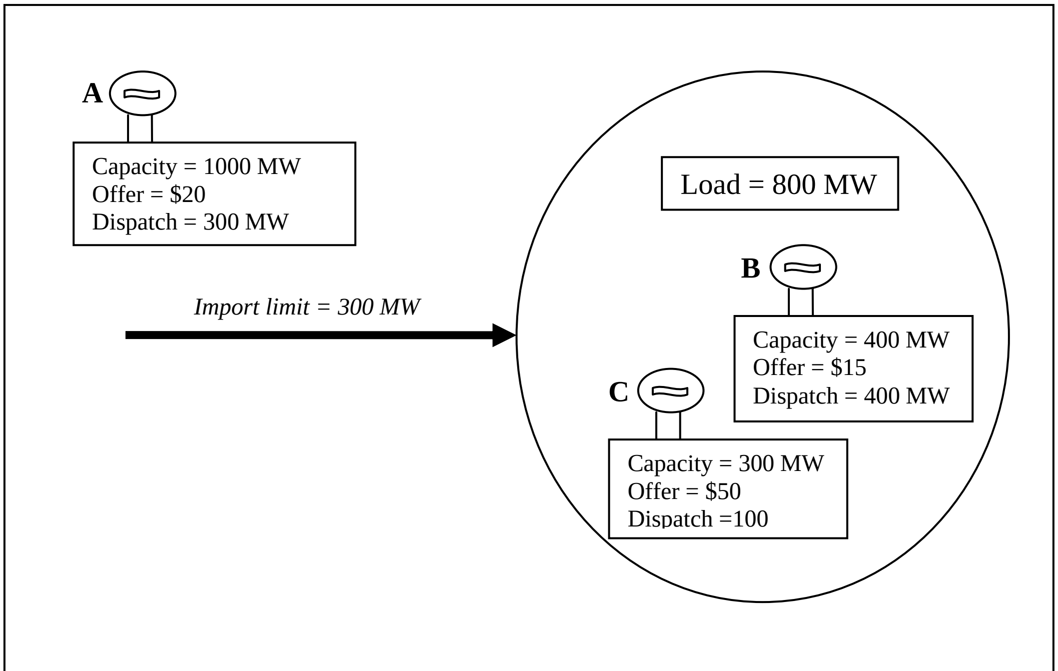


Figure 3.13(b) Schematic diagram of constrained case (Case II)

Table 3.2 shows how these two cases compare in terms of all settlements (energy and FTRs) and how hedgeable and unhedgeable congestion costs are calculated in these two cases.

Table 3.2 Comparison of Cases I and II in Expanded LMP, FTR, and Congestion Example

	Formula	Case I	Case II	Difference
In-Area Load	L	800 MW	800 MW	-0-
Maximum Import Capability		unlimited	300 MW	
Imports from Generator A	a	400 MW	300 MW	-100 MW
Output of Low-Cost Generator B	b	400 MW	400 MW	-0-
Output of High-Cost Generator C	c	0 MW	100 MW	100 MW
Production Cost for Generator A†	C_a = \$20 x a	\$8,000	\$6,000	-2,000
Production Cost for Generator B†	C_b = \$15 x b	\$6,000	\$6,000	-0-
Production Cost for Generator C†	C_c = \$50 x c	\$0	\$5,000	5,000
Total Production Cost	$=C_a + C_b + C_c$	***\$14,000***	***\$17,000***	***\$3,000***
Marginal Unit(s)		A	A, C	
In Area LMP	P_{in}	\$20/MWh	\$50/MWh	\$30/MWh
Rest-of-market LMP	P_{out}	\$20/MWh	\$20/MWh	-0-
Shadow Price on Constraint	$SP = P_{in} - P_{out}$	\$0/MW	\$30/MW	\$30/MW
Revenues for Generator A	$R_a = P_{out}$ x a	\$8,000	\$6,000	-\$2,000
Revenues for Generator B	$R_b = P_{in}$ x b	\$8,000	\$20,000	\$12,000
Revenues for Generator C	$R_c = P_{in}$ x c	\$0	\$5,000	\$5,000
Total Generator Revenues	$=R_a + R_b + R_c$	***\$16,000***	***\$31,000***	***\$15,000***
Profit for Generator A	$R_a - C_a$	-0-	-0-	-0-
Profit for Generator B	$R_b - C_b$	\$2,000	\$14,000	\$12,000
Profit for Generator C	$R_c - C_c$	-0-	-0-	-0-
Total Generator Profit		***\$2,000***	***\$14,000***	***\$12,000***
Total Cost to Load	$=800 \times P_{in}$	***\$16,000***	***\$40,000***	***\$24,000***
Total Congestion Cost	***L x SP***	***\$0***	***\$24,000***	***\$24,000***
Maximum hedging with FTRs	= 300 MW x SP	\$0	\$9,000	\$9,000
Maximum hedging of power cost with in-region generation (congestion and non-congestion related) *	$= R_b - C_b$	\$2,000	\$14,000	\$12,000
Unhedgeable congestion cost		***\$0***	***\$3,000*** **	***\$3,000***

†Assumes that offer price is equal to production cost, which is not necessarily the case.
*This hedge is only available if load controls Generator B, either through direct ownership or through a fixed-price contract. The numbers shown include \$2,000 that could be saved, with or without congestion, if load had access to the output from generator B at the offer price. In the presence of congestion (Case II) the value of this hedge includes the additional \$12,000 because the load is not exposed to the higher LMP for this power.
**Total congestion cost of \$24,000, minus FTR value of \$9,000, minus congestion-related portion of in-region generation hedge (congestion-related profit increment for Generator B) of \$12,000 = \$3,000 of unhedgeable congestion cost.

In Case II, the total congestion cost or the increase in the cost to load for energy because of the existence of the constraint is \$24,000. Of this, only \$3,000 represents an actual additional cost on the system and is thus unhedgeable. The remaining $21,000 is theoretically hedgeable, through a combination of purchasing FTRs and using in-area generation. In addition, in both cases (I and II) load may be able to hedge some of the generation cost if it has access to the output of Generator B at low cost. In PJM, much of the load has had access to such low-cost power as a result of long-term power purchase contracts made at the time of deregulation and divestiture of generating resources from the traditional vertically integrated utilities. As those contracts expire, however, the value of this hedge is likely to disappear.

Historical Patterns of Congestion in PJM

In this section we provide an overview of patterns of gross and unhedgeable congestion in PJM, as well as reviewing the economic consequences of congestion since the onset of deregulated, LMP-based market. This provides a context for our investigation of the effectiveness of economic signaling for attracting new transmission investments when and where needed.

There are two primary data sources of use for investigating congestion patterns and history in PJM, corresponding to locational and transmission perspectives. These are (1) historic locational price data, and (2) historic congestion cost data by transmission constraint. The price data are published for both the day-ahead and real-time spot markets; the day-ahead market carries most of the energy volume, and can be thought of as representing “expected” load conditions. FTRs clear against day-ahead spot market prices, so these price differences and only these can be hedged through this mechanism. The real-time spot market price reflects the cost of any adjustments that have to be made in order to reconcile generator output with real-time load, or to compensate for any changes in conditions (such as a line or generator outage) that may affect real-time dispatch. This is often referred to as a “balancing” market. The prices in the day-ahead and real-time markets should be about the same on average—most systematic or predictable difference between them would be eliminated through arbitrage over time.

Although the two forms of congestion cost data reflect the same information about the impact of transmission constraints on dispatch costs, locational price data is more appropriate for use in analyzing generation investments while constraint-level data is more useful for analyzing transmission. Thus we focus here on the reported congestion costs by transmission element in PJM.

Gross Congestion Costs in PJM

There are hundreds of transmission constraints in the PJM system that can potentially be binding during any service hour, ranging from local system transformers that affect only small load pockets to major interfaces on the high-voltage system affecting east-west flow. As of this writing, PJM congestion cost data are available from August 2003 through June 2006, which we will refer to in this section as the "study period".

Of these, the ten transmission constraints with the greatest gross congestion costs during the study period, accounting for over 82% of gross congestion costs, are shown in Figure 3.14. Total gross congestion cost for this period is also shown.

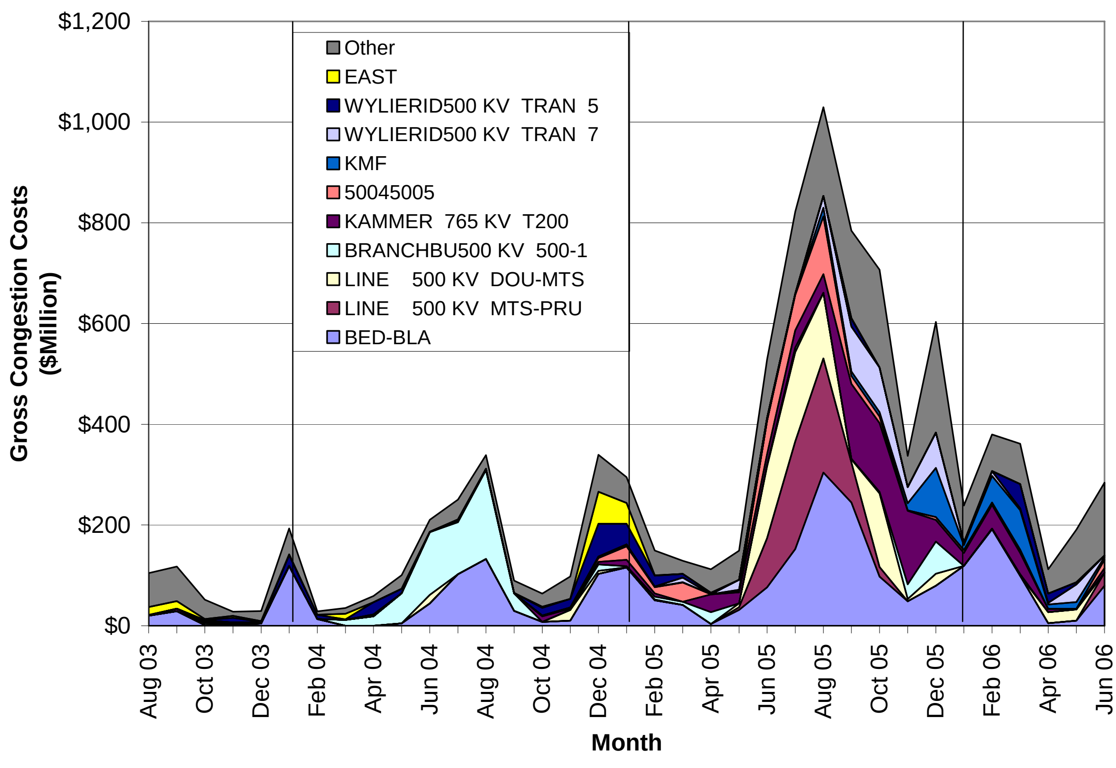


Figure 3.14 Ten constraints with the highest gross congestion costs and total congestion costs in PJM, August 2003 – June 2006

The large-scale structure of these gross congestion cost data can only be understood in the context of the study period they represent**.** Key features of this period that dominate the picture include:

- The data reflect total system-wide congestion costs, and the system has grown significantly during this period (Figure 3.1). This growth has two impacts on reported congestion costs. First, the *total* congestion costs, system-wide, would be expected to increase over time even if nothing changed in operations, simply because congestion is being summed over a broader region. Second, the broader coordinated pool has more low-cost areas from which power could be imported, assuming sufficient transmission was available. It may be that some of these congestion "costs" are really a portion of potential production cost savings that cannot be realized due to transmission constraints.
- The summer of 2005 was an extremely hot summer that stressed the transmission system to an unprecedented degree, leading to the very high congestion costs shown in Figure 3.14 during this period. Notably, the period excludes July and August of 2006, which experienced unprecedented system peak load.
- There was a known transformer problem affecting the Branchburg 500kV constraint in the spring and summer of 2004, seen in the light blue bulge in Figure 3.14 during this period. This problem has largely been resolved.

Total gross congestion costs during the study period were 9.3 billion dollars, or an average of $265 million per month. Of this, over $1 billion was incurred during August 2005 alone, and the average monthly gross congestion costs for June through December of 2005 was over $680 million. Although there were 498 constraints that were congested at least part of the study period, 90% of the congestion costs were spread over 34 constraints as noted earlier. Almost 50% of the gross congestion costs were due to only four constraints, including 7.5% of costs associated with the Branchburg constraint that has been largely alleviated. One single constraint, referred to as Bedington-Black Oak (listed as "Bed-Bla" in Figure 3.14), accounted for 25.6% of all gross congestion costs. This constraint, along with two others (Wylie Ridge and the Eastern Interface) severely limit west-to-east electricity delivery in PJM and restrict the ability of lower cost coal-fired resources to reach the higher-priced eastern markets. Together, these constraints are the subjects of an ongoing transmission review dubbed "Project Mountaineer", and feature prominently in PJM's first 15-year Regional Transmission Expansion Plan (RTEP) announced in June 2006.

Unhedgeable Congestion Costs in PJM

Although the numbers are quite large, gross congestion costs do not ultimately describe the true economic impact of transmission congestion because much of the money is redistributed through FTRs or other hedges, as illustrated by example earlier in this section. Because of this, PJM also estimates unhedgeable congestion costs by transmission constraint, which takes these hedges into account to produce the actual economic impacts associated with transmission congestion.

As with gross congestion costs, PJM reports unhedgeable congestion on a line-by-line basis. In fact, this is not really possible to know with precision. This is because congestion hedges are not physically associated with specific transmission constraints, so certain assumptions have to be made in order to force this association. In addition, from the perspective of load, such a calculation assumes that the hedges in question are actually available to the purchasers of wholesale electricity who incur the congestion costs, which is not necessarily the case. For example, in competitive markets, in-area generation resources are likely to be owned by an independent generating company. Nonetheless, PJM has probably done as good a job as possible in making this association, and it is important information for planning purposes. For the purposes of this study we shall accept PJM’s estimates.

Figure 3.15 shows unhedgeable congestion costs by month, highlighting the nine constraints which together represent 83% of unhedgeable congestion costs during the study period. Here just two constraints—Branchburg 500 kV and Bedington-Black Oak—represent 63% of all unhedgeable congestion costs. As noted above, the Branchburg issue (40% of total) has been resolved, and PJM’s most recent transmission plan attempts to resolve the Bedington issue.

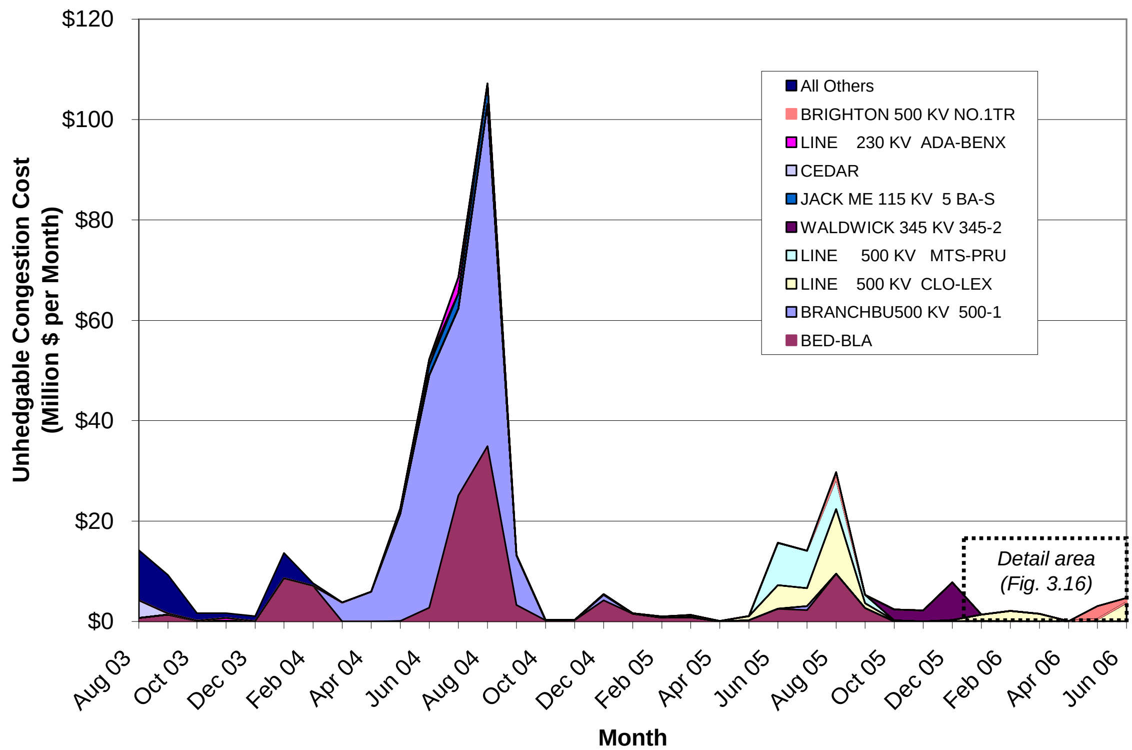


Figure 3.15 Unhedgeable congestion costs in PJM, August 2003 – June 2006

It is interesting to note that while the summer of 2005 remains a prominent feature of Figure 3.15, it does not dominate unhedgeable congestion costs to anywhere near the degree that it dominated gross congestion costs. Load serving entities holding FTRs would have been protected from much of the spike in congestion costs during this period, exactly as intended.

Figure 3.16 highlights unhedgeable congestion costs for only the first half of 2006, the "Detail area" indicated in Figure 3.15. In this case only four constraints represent almost 90% of unhedgeable congestion costs, with the top two representing 81% of costs. (Bedington-Black Oak is the fifth shown, but it represents only about 1.5% of unhedgeable congestion costs during this period and falls to zero after March 2006.) Neither of these was in the top two when the longer period shown in Figure 3.15 was considered. Of course, congestion costs during this period were relatively low compared to the periods when the Branchburg and Bedington-Black Oak constraints were binding frequently.

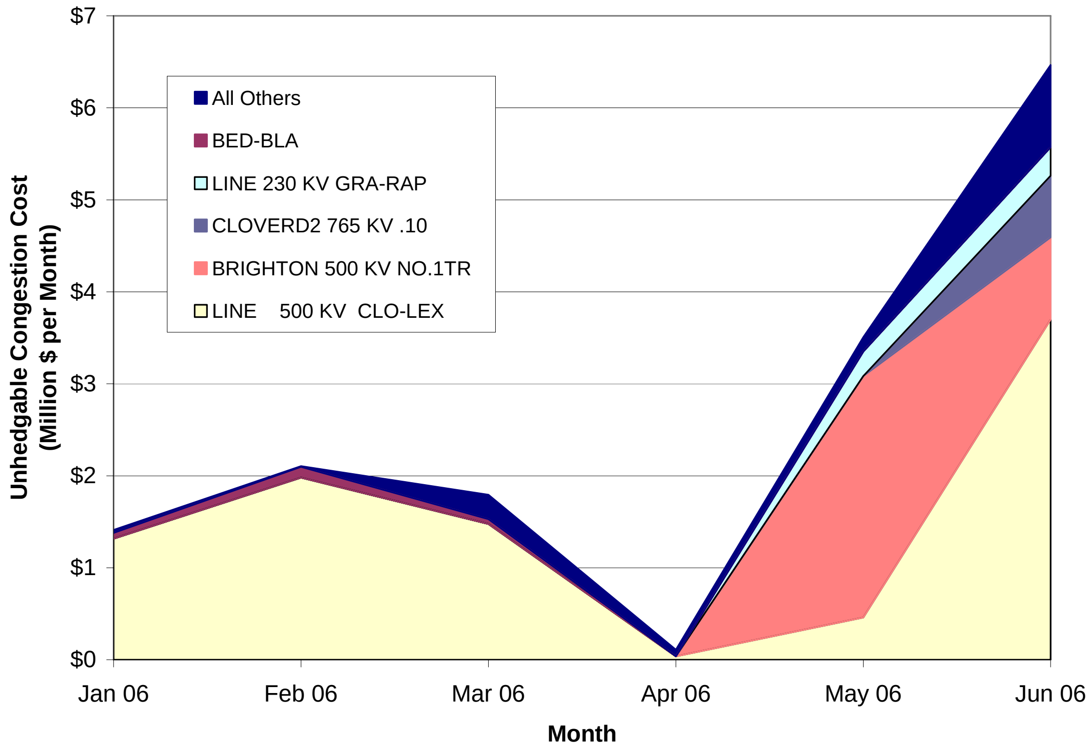


Figure 3.16 Unhedgeable congestion costs in PJM, January through June 2006 (Detail of Figure 3.15)

It is important to note the extent to which the specific lines that present the largest congestion cost, gross or unhedgeable, change over time in response to system conditions. These conditions may include the status of transmission elements, of course, but they are also strongly influenced by fuel price variations, availability of specific generating units (*e.g.*, nuclear unit outages or availability of hydro resources) and other factors. To the extent that natural gas generation is much more expensive than coal, for example, it is likely that the most important transmission constraints will be those that inhibit the flow of power from regions with a high proportion of coal-fired generation to areas more dependent on natural gas generation, and that west-to-east congestion costs will be high. Conversely, if the price of coal-fired generation increases (due to regulation of CO_2 emissions, for example), then these transmission constraints might be significantly diminished, or they may disappear altogether. Finally, we note again that these costs are highly sensitive to uncertain operator approximations and proxy estimates of system characteristics.

Absence of Merchant Transmission in PJM

Merchant transmission "markets" has been unresponsive to transmission needs, reflecting the fact that no clear mechanism exists for cost recovery for merchant transmission projects. In response, PJM has recently introduced a revised "economic planning process" which provides for the development of transmission infrastructure where the economic benefits clearly outweigh the costs, and where no market solution (generation or transmission) has emerged to resolve persistent congestion issues. According to a recent PJM filing in this docket,[21]

> …the significant lack of competition from merchant transmission in the PJM region demonstrates that, in fact, the market alone is inadequate to ensure that appropriate transmission investment occurs. There have been only three significant merchant transmission projects proposed in the PJM Region, and these projects are only at the border of the region, and do not address congestion within PJM. Clearly, market forces alone are not encouraging non-regulated transmission investment. The market simply has not remedied long-standing congestion in PJM such as the constraints at Bedington-Black Oak, Doubs, and Mount Storm. (pp.7-8)

PJM goes on to suggest that part of the reason for this failure was the short term, retrospective price signals, resulting in reliability problems that the market cannot be relied upon to resolve:

> …under the existing process, because PJM did not provide this long-term view, the market simply could not, and did not, respond to gradually growing problems. As a result, PJM now faces huge problems on the horizon that require large-scale solutions that the market cannot possibly provide (p.8).

Even Bill Hogan, one of the intellectual founders and primary proponents of LMP-based electricity markets, has recognized their limitations for providing adequate incentives for transmission investments. Hogan addresses "…a critical choice that must be made for transmission investment policy, drawing a line between merchant and regulated investment."[22] Outlining the lack of a credible cost recovery mechanism and the considerable "free rider" problem with transmission, Hogan concludes:

[21] "Answer of PJM Interconnection, L.L.C." filed in FERC Docket ER06-1474, submitted October 18 2006.

[22] Hogan, William W., "Transmission Rate Design", Presented at conference on Electricity Deregulation at the Bush Presidential Conference Center, Texas A&M University, April, 2003.

> The most prominent examples of problems that are significant and possibly insurmountable for merchant investment arise from economies of scale and scope. In the presence of such effects, investment in transmission expansion might both expand transmission capacity and have a material effect on market prices. The investment might be economic because the savings in total operating costs could be more than the investment cost, but the resulting value of the FTRs at the new locational prices would not be greater than the investment cost…With everyone waiting for the free ride, the investment would never come. This could be important, and it could be the central issue in drawing a line between merchant and regulated transmission. (p. 17)

The experience in PJM thus far has borne out these concerns. The potential returns for merchant transmission have been too poorly defined and uncertain, and have clearly failed to provide an adequate incentive for investment. As a result, PJM has expanded its administrative transmission planning activities to include any projects which are needed for economic efficiency, as well as reliability. The next step, currently under development through a stakeholder process, is to determine how equitably to allocate costs for such transmission projects among the users. The most likely outcome is that PJM will develop a "cost causation" allocation scheme, by which load will be allocated responsibility for upgrade costs in proportion to their impact on flows over constraints to be relieved.[23]

Review of Observations – PJM Transmission

- A majority of the congestion costs in PJM can be attributable to a relatively small number of constrained paths;
- The introduction of LMP has not necessarily clarified the economic benefit of relieving specific congested paths, at least partly because the reported congestion costs are based on energy offers, not on production costs.
- Because the most significant sources of transmission congestion change over time, it is difficult for investors in major capital projects to respond to these signals;
- Even when significant and persistent sources of congestion costs can be identified, it is difficult for merchant generation to respond because there is no clear cost recovery mechanism in place;

[23] For an overview of cost allocation approaches under consideration, see "Cost Allocation Principles for Economic Projects for Discussion Purposes" for the PJM Regional Planning Process Working Group, at http://www.pjm.com/committees/working-groups/rppwg/downloads/20061215-cost-allocation-straw.pdf.

- Due to the previous two considerations, merchant transmission has not been forthcoming in PJM;
- PJM has initiated a process to develop transmission that is needed for economic reasons. While controversial, could be justified on grounds that adequate transmission facilities are probably necessary prerequisites for a competitive energy market to succeed and grow;
- Transmission project cost allocation issues may be more important than getting the right price signal to indicate the need for new transmission, because most benefits are socialized so most major transmission expansion projects will be initiated through an administrative process.

3.4. Price Signaling – Demand Response

Perhaps the most promising area in which price signals might be expected to yield reliability benefits should be in stimulating short-term and/or long-term demand response. Residential, commercial, and industrial electricity consumers have a wide range of low-cost options for reducing electricity use or investing in energy efficiency, if adequate information and compensation are provided. In contrast to generation and transmission investment decisions, demand response:

- Can be developed quickly, with no cumbersome siting requirements, safety standards, major infrastructure construction or design costs, and so forth;
- Can be implemented in any location where there is electrical load; in fact, there is generally the most potential for demand response where load is most concentrated;
- Does not have the “lumpiness” characteristic of other electric sector investments. Demand response can be finely tuned to respond to price signals and reliability needs.

However, investments in demand response have generally lagged well behind other electric infrastructure investments despite almost universal acknowledgement of their availability and benefits to both system reliability and healthy electricity markets. There are a number of reasons for this, including:

- Load has historically been sheltered from price signals. In PJM, wholesale load pays a zonal average price for electricity, receiving a less nuanced price signal that provides a less targeted incentive for investment. Retail load has generally seen no time-varying price signal at all, as most customers pay a flat rate for electricity which, in many PJM states, has been set by a rate cap since deregulation;

- The benefits to individual customers of reducing load during peak periods are generally quite small, on the order of a few dollars per household per year, even though the socialized costs of reducing peak loads can be quite large;
- Commercial and industrial customers can often theoretically respond to price signals through process scheduling, but only if the hourly prices are known at least one day in advance;
- Utilities and owners of generation are in the business of selling power and have not found a successful business model for selling demand response. Even though in many cases targeted demand response would lower system costs much more than they would lower revenues, there has been no effective way of turning this social value into a sufficient and reliable revenue stream for investors. As a result, most residential demand response programs tend to linger as a long series of “pilot programs” with small enrollment rates.

As a result, it has fallen to the RTOs to develop and administer demand response programs. In 2002, PJM submitted filings for two such programs to FERC for approval: Economic Load-Response Program and Emergency Load-Response Program.[24] These programs were approved by FERC and became effective in June 2002. In addition, PJM has an Active Load Management (ALM) program, and certain LSEs run their own incremental demand response incentive programs.

The Economic Load-Response Program provides customers with a mechanism where they can receive payments for load reduction based on hourly wholesale electricity prices. Participating customers join this program through their LSE and have two choices: a day ahead option and a real time option. In the day ahead option, customers can bid to curtail load (relative to a baseline calculated by PJM) in the day-ahead market and can receive payments based on the day-ahead LMP. In the real time option, customers can curtail load real time and receive payments based on the real time LMP. For both real time and day-ahead, when the LMP is less than $75/MWh the payment is net of applicable generation and transmission charges. This prevents double payments for demand reductions under conditions when the system is not overly stressed.

The Emergency Load-Response Program provides participating customers the opportunity to receive a payment equal to the greater of the current wholesale market clearing price, or $500/MWh, when they reduce load in response to a PJM notification of

[24] For further details, see PJM Load Response Program Business Rules, available on the PJM website.

system emergency conditions. The load reduction is calculated either as the measured output of backup (not PJM-dispatched) generation, or as the reduction from the previous hour's load. This program is voluntary and does not impose any penalties to participating customers who do not reduce load. Customers can participate in the program directly with PJM or indirectly through a third party or LSE.

Under ALM, PJM allows LSEs to reduce their capacity obligations by agreeing to reduce loads during system emergencies. LSEs often reduce customers' load through automatic load response measures such as direct load control. Some customers under the ALM also participate in either the Economic or Emergency Load Response program. When PJM calls for ALM resources, load reduction for participating customers is mandatory.

In addition to the PJM administered programs, there are other demand response resources administered by LSEs. In 2005, LSEs in PJM counted 907 MW of load under LSE-administered load response programs. In addition, 3,653 MW of load in PJM was exposed to real-time LMP, giving them the ability and incentive to respond to these price signals.

Table 3.3 shows the load response capacity enrolled in the PJM-administered programs from 2002 to 2005.

Table 3.3 PJM Load Response Programs from 2002 to 2005. Resources which participate in both ALM and another load response program are only counted once in the total.

	2002	2003	2004	2005
PJM Economic Load-Response Program	343	724	724	2210
PJM Emergency Load-Response Program	548	659	1385	1619
Total Economic and Emergency Programs	891	1383	2109	3829
PJM Active Load-Management (ALM) Resources	1569	1207	1806	2065
PJM ALM Resources Also Participating in Load-Response Programs	n/a	(445)	(317)	(260)
Total of PJM Administered Programs	*n/a*	*2145*	*3598*	*5634*
PJM Summer Peak Load		61,568	105,616	134,219
Participation as Percent of Peak Load		3.5%	3.4%	4.2%

Source: PJM 2005 State of the Market Report.

The capacity in the Economic and Emergency Load Response programs has increased from 890 MW in 2002 to 3800 MW in 2005. However, much of this growth is due to the integration of new areas into PJM (Figure 3.1), reflected in the step increases in peak load shown in Table 3.3.

Table 3.4 and Table 3.5 provide information from the 2005 State of the Market Report regarding the performance of the Economic and Emergency Programs from 2002 to 2005, in terms of actual load reductions in response to price signals. The total MWh reduction through the Economic Program increased significantly during this period. Similarly, the Emergency Program yielded much greater MW reductions in 2005, corresponding to extremely high load conditions in the summer of 2005. However, there is no clear relationship between the size of the incentive payments and performance for either program.

Table 3.4 Performance of Economic Load Response Program

	Total MWh	Total Incentive Payments	Incentive Payment per MWh	MWh Reduction per MW Enrolled
2002	6,727	$801,119	$119	21
2003	19,518	$833,530	$43	42
2004	58,352	$1,917,202	$33	35
2005	113,393	$12,000,354	$106	51

Source: PJM 2005 State of the Market Report, Table 2-15.

Table 3.5 Performance of Emergency Load Response Program

	Total MWh	Total Incentive Payments	Incentive Payment per MWh	MWh Reduction per MW Enrolled
2002	551	$282,756	$513	1
2003	49	$26,613	$543	0
2004	0	$0	N/A	0
2005	3,662	$1,859,638	$508	2

Source: PJM 2005 State of the Market Report

To further investigate links between payments and performance, we examine load response activities by zone using more detailed data from the 2005 State of the Market report. Table 3.6, based upon this report, provides the total incentive payment, MWh reduction, payment per MWh reduction, MW enrolled, share of load reduction in peak load, and load response factor[25] for each PJM zone in 2005.

[25] The load response factor is the annual MWh reduced per MW enrolled in a demand response program.

Once again, there is no apparent relationship between the MW enrolled and the total MWh reduction with price signals or incentive payments by zone. As a rule, the zones where participants received the largest incentive payment in dollars per MWh load reduction (BGE, JCPL, PECO, PSEG, all regions with comparatively high electricity prices) did not coincide with the zones with highest MWh reduction (AP, DPL, PPL), with the largest MW enrolled (AEP, AP, ComEd, DPL), or with the greatest load response factor (AP, ComEd, DPL, PENELEC). More importantly, there are no meaningful connections between the load response factor and the size of the incentive payments. Load response factor, measured as the total load reduction in MWh per MW enrolled in each program, measures price response directly for those customers who have already agreed to participate in the program. However, as illustrated graphically in Figure 3.17, there was no apparent increase in customer load reductions in zones with higher average incentive payments in 2005.

Table 3.6 PJM Economic Load Reduction Program Performance by Zone in 2005

	Total Zone Incentive Payments	Total MWh reduction	Incentive Payment per MWh*	MW Enrolled in Zone	MWh Reduction per MW Enrolled
AECO	$300,855	3,477.8	$87.43	5.90	589.46
AEP	$104,606	1,880.8	$55.62	164.50	11.43
AP	$2,791,632	47,509.5	$76.90	195.10	243.51
BGE	$1,272,977	7,419.7	$171.57	120.80	61.42
ComEd	$4,052	76.9	$82.30	1074.50	0.07
DLCO/DUQ	$106,946	3,224.0	$55.93	42.90	75.15
DOM	$35,452	348.0	$101.87	77.50	4.49
DPL	$868,445	39,627.9	$137.93	127.80	310.08
JCPL	$9,177	44.8	$204.84	38.20	1.17
Met-Ed	$36,820	670.0	$54.95	44.80	14.96
PECO	$224,883	1,375.9	$163.44	72.80	18.90
PENELEC	$0	34.1	$108.37	81.80	0.42
PPL	$362,616	6,342.5	$65.67	85.00	74.62
PSEG	$50,424	1,357.5	$210.55	42.40	32.02
RECO	$326	3.3	$98.81	1.00	3.30
Total	$6,169,210	113,392.7	$105.83	2175.00	52.13

*Total incentive payments divided by total MWh reduction

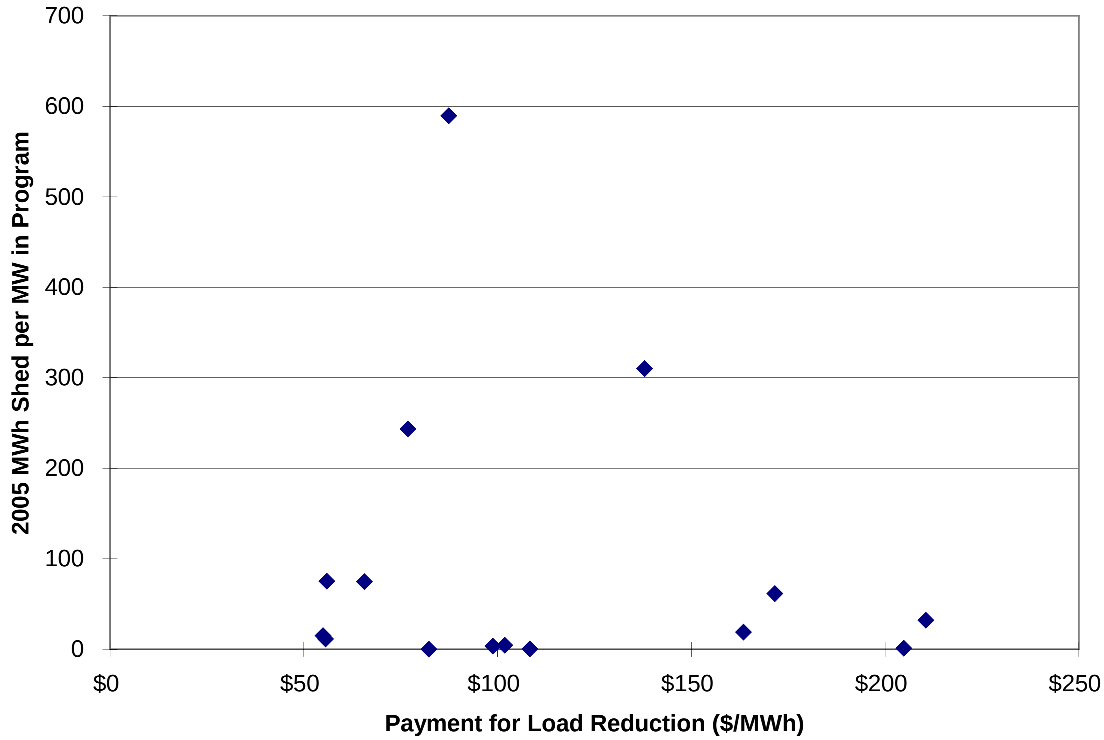


Figure 3.17 MWh reductions per MW enrolled vs. average per-MWh payment by PJM zone in 2005

Perhaps the most important way of examining the impact of prices on demand response is to investigate the relationship between the incentive payment and participation rate of demand response resources as a share of the peak load for each transmission zone. Table 3.7 presents the share of demand response (DR) resources in peak load in 2005 and 2006 and the difference in DR shares between the two year periods. These same data are shown graphically in Figure 3.18(a) for 2005, and Figure 3.18(b) for 2006. Neither graph indicates any relationship between incentive payments for the year and demand response program participation, even though potential customers for 2006 would have had information from 2005 upon which to base their decisions.

Table 3.7 Payment per MWh vs. Level of Demand Response Resources by Zone, 2005 and 2006.

	Incentive Payment per MWh	MW enrolled in 2005	Share of DR 05 in Peak Load*	MW enrolled, Jan - Sep 2006	Share of DR 06 in Peak Load*	Difference in DR Shares from 2005 to 2006
AECO	87.43	5.90	0.2%	4.90	0.2%	0.0%
AEP	55.62	164.50	0.7%	121.00	0.5%	-0.2%
AP	76.90	195.10	2.2%	259.80	2.9%	0.7%
BGE	171.57	120.80	1.6%	161.83	2.2%	0.6%
ComEd	82.30	1074.50	5.0%	85.94	0.4%	-4.6%
DLCO/DUQ	55.93	42.90	1.5%	61.20	2.1%	0.6%
DOM	101.87	77.50	0.4%	108.50	0.6%	0.2%
DPL	137.93	127.80	3.0%	109.80	2.6%	-0.4%
JCPL	204.84	38.20	0.6%	51.86	0.8%	0.2%
Met-Ed	54.95	44.80	1.6%	26.20	0.9%	-0.6%
PECO	163.44	72.80	0.8%	114.60	1.3%	0.5%
PENELEC	108.37	81.80	2.8%	59.10	2.1%	-0.8%
PPL	65.67	85.00	1.2%	148.35	2.1%	0.9%
PSEG	210.55	42.40	0.4%	78.67	0.7%	0.3%
RECO	98.81	1.00	0.2%	1.00	0.2%	0.0%
DAY	n/a	0.00	0.0%	3.50	0.1%	0.1%
PEPCO	n/a	0.00	0.0%	10.30	0.2%	0.2%
Total	105.83	2175.00	1.6%	1406.55	1.0%	-0.6%

*MW enrolled in economic program divided by zonal peak load

Note: The 2005 Summer Peak data is used for estimating the share of DR in both 2005 and 2006 because the comparable 2006 Summer Peak data that excludes real demand reduction effect is not publicly available as of this writing.

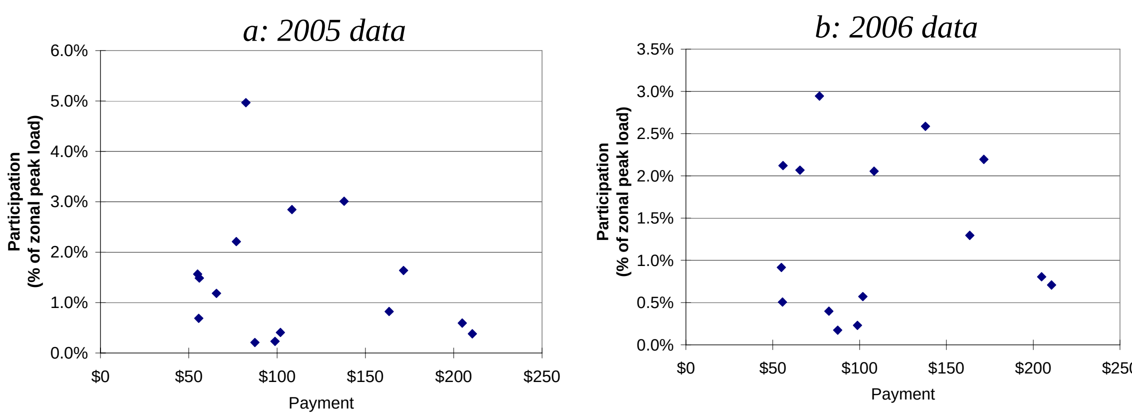


Figure 3.18 Participation rate in Demand Response programs (percent of peak load) as a function of incentive payment level

Each data point represents a single PJM zone. Data from Table 3.7. (a) 2005; (b) 2006.

Further, there does not seem to have been any systematic increase or decrease in the level of demand response participation between 2005 and 2006 as a result of the size of the incentive payment, as shown in Figure 3.19.

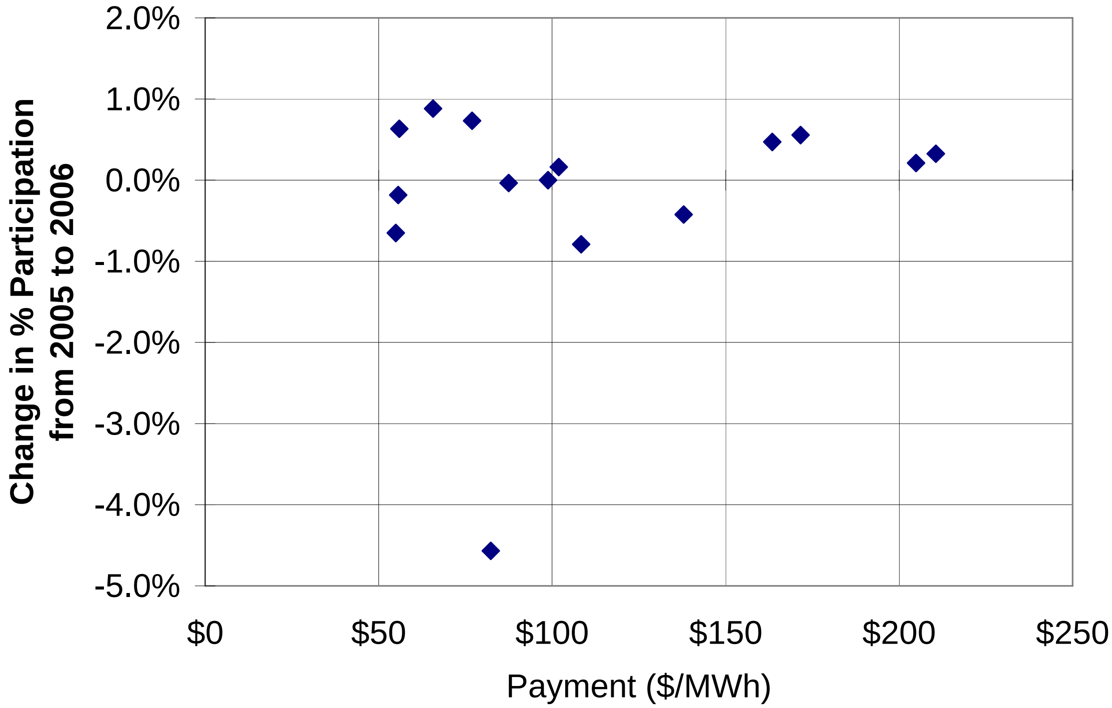


Figure 3.19 Change in participation rate in Demand Response programs (percent of peak load) as a function of incentive payment
Data from Table 3.7.

It is possible that there would be more response to price signals if the demand resources were paid at a price were well above those that have been seen in PJM. An example of this has been seen in New England, where the Boston area has enrolled less than 10 MW of demand response at a price of $1/kW-month. However, an RFP was issued for demand response in southwest Connecticut to meet reliability requirements before needed transmission enhancements could be in place. In this case, over 400 MW of demand response was enrolled, at an average price of $10/kW-month.

In summary, we are unable to identify any metric which suggests that demand response enrollment, participation, or capacity factor is strongly affected by locational price signals, even for the economic response program in which customers are paid for load reductions based on the real-time price of electricity. We conclude that, even in this area, structural factors such as program design, availability of real-time metering, and program promotion are more important determinants of success than getting the prices “right” through LMP.

3.5. Price Signaling Conclusions

We have reviewed the three major areas in which one might expect a market response to price signals—new generation and retirements, transmission investments, and demand response. We have compared activity in PJM to these locational price signals to determine if there is any evidence that they are having the intended effect, which is to promote investment and demand response in those areas where it is most needed for economic and reliability purposes. In all three areas, we have found no evidence that the market is capable of responding to these signals.

In all three cases, the short-term and volatile nature of price signals compared to the time horizons involved in infrastructure investments may be a fundamental obstacle. In addition, for generation and transmission investments there may simply be more compelling reasons for choosing sites, such as access to existing infrastructure and resources, zoning restrictions and local opposition. The lumpy nature of these investments also impedes their ability to respond to nuanced signals, and investors would be rightly concerned that their investments would curtail or eliminate the revenue advantage of a high-priced location. For all three types of investments (generation, transmission and load response), the economic and reliability benefits of locating projects where needed would be broadly shared; however, it is unclear how the existing market structure would return a sufficient portion of this value to the investor to make it worthwhile.

The lack of response by demand resources to locational price signals presents a particular puzzle, as this type of resource does not have the siting or lumpy investment issues characteristic of generation or transmission projects. It may be that the markets are just too young—much of the commercial and industrial load from previously regulated markets has had little opportunity to "learn the ropes" on integrating demand response into their operations.

However, a number of studies[26] suggest other important factors beyond incentive prices that determine the success of demand response programs, including:

- A certain stream of benefits;
- The availability of enabling technologies such as web-based energy information systems, communication and notification technologies, load control devices, interval metering, and back-up generators;
- Customer education and training; and
- The availability of forward contracting options.

It may be that the market and infrastructure simply have not matured to the point where load can respond effectively to locational price signals, even when demand response programs and customer willingness are in place.

We acknowledge the significant limitations to this analysis. The history we are analyzing is short and the markets still developing. We have no way of knowing what investments would have been made in the absence of price signals, and perhaps they would have been less productive in resolving congestion and enhancing reliability. Perhaps major electricity consumers have taken locational prices into account when locating industrial facilities; however, we have no way of detecting this effect. On the other hand, it may be that price signals provide no new and useful information for electricity markets at all—after all, market operators and vertically integrated utilities have always known where transmission was congested and the investments that would reduce overall system costs. It may be that whatever obstacles to investment existed in the past still exist today, and that price signals are merely a formalization of what was already known with no economic or reliability benefits to show.

[26] For example, Goldman, 2004; Lawrence Berkeley National Laboratory, 2002; Neenan Associates *et al.*, 2003.

SECTION III – COMPETITIVENESS AND MARKET POWER

4. Overview of Competitiveness and Market Power

4.1. Competitiveness in Electric Power Markets

An ideal competitive electric power marketplace would consist of many sellers competing for sales to buyers who could usually choose to purchase from alternative sellers. It would exhibit price characteristics reflecting the marginal costs of producing electricity in the short term and the average costs of producing electricity in the longer term. Flexible (somewhat elastic) demand would constantly pressure suppliers to reduce prices: for longer-term contracts, those prices would reflect average costs, and shorter-term sales would reflect marginal costs. If these aims could be met, electricity markets might be said to be "workably competitive", a term of art that recognizes that "perfect" markets are unachievable.

Perfect markets would require, for example, low supplier concentration, perfect foresight on the part of buyers and sellers, perfect information, continuous elasticity of demand and supply, and no barriers to entry or exit. In recognition of the fact that perfectly competitive markets do not exist in the real world, economists developed the concept of "workably competitive markets", which approximate these attributes. However, these prerequisites are largely absent in electricity markets. Short-term demand is notoriously inelastic; barriers to entry for new generation is high; supplier concentration during certain times and in certain regions is high; information transparency is minimal; and market players, both generators and load, exhibit myopia much more frequently than foresight.

Because of these attributes of the electric power marketplace, neither wholesale nor retail markets can be free from regulation, although regulatory oversight affects some market segments more than others. Further, the process of "deregulation" has allowed large segments of the marketplace to escape certain forms of regulation in the hope that competition would produce the "just and reasonable" prices required by the Federal Power Act of 1920.

The wholesale marketplace for electricity is actually composed of numerous sub-segments. Those include:

- Short-term (day-ahead and real-time) spot energy markets coordinated by RTOs;
- Longer-term bilateral energy transactions, reflecting a wide range of time periods and horizons (e.g., energy for next week, next month, or next year, or energy for the next 20 years) and not coordinated by RTOs; some of these transactions are cost-regulated through state utility commissions.
- Longer-term auction-clearing markets, or contracts resulting from issuance of RFPs, such as those used for standard offer or default service provision in a number of RTO states, including New Jersey, Illinois and Maine.
- Ancillary service markets, both spot (coordinated through RTOs) and longer-term (bilateral); these are for provision of short-term operating reserve and regulation capacity;
- Installed capacity markets, both spot (coordinated by RTOs) and bilateral;

Regulatory and market monitor oversight of RTO-administered spot energy and ancillary markets garners more attention than monitoring or mitigation efforts in bilateral markets; and such oversight is addressed in this report. But the majority of expenditures for electric power are transacted outside of the RTO spot markets, even though the RTO-controlled transmission system and associated centralized dispatch results in the physical delivery of almost all electric power to load servers within RTO regions. The degree to which these transactions are the result of a workably competitive environment is questionable, as there is a lack of comprehensive, publicly available information on bilateral market prices such as exists for the RTO spot energy and ancillary service markets. For example, the bilateral marketplace from which supply offers are drawn for standard offer service auctions (such as New Jersey's BGS auctions) is subject only to limited forms of monitoring and no direct mitigation; prices are wholly market-determined.

4.2. Market Power Analysis Overview

Market power in electricity markets is defined as the ability of a firm to profitably artificially increase prices above competitive levels for a sustained period of time. According to a 2000 Department of Energy report,

> A firm is said to have market power when it…can maintain prices at a non-competitive level for a significant time period. A firm with market power can profitably influence prices by raising its bid above its variable cost or otherwise reducing its output, in order to drive up prices and earn a higher level of total profit notwithstanding the loss of profit on the potential output it withholds. (DOE 2000, p. 2)

It is the ability of energy suppliers to either withhold supplies or bid into markets strategically in such a way that prices are elevated above what would otherwise be the marginal cost, for a sustained period of time, which defines market power. In order for market power to be exercised, however, it must be profitable for firms to behave in this manner—any lost profits on withheld resources, for example, must be more than compensated with increased revenues on the rest of their portfolio. Both theory and tradition hold that this is only the case either when one firm holds a dominant market position, or when a small enough number of firms control the market that they can implicitly or explicitly act in concert to profitably raise prices.

In practice, in order to measure market power in the electricity market it is necessary to define product markets in order to determine how many firms have access to each market. Clearly the market for all electricity in the United States is too broad a definition of a product market—suppliers on the West Coast cannot reasonably meet demand on the East Coast, for example. Thus smaller geographic regions must be considered, often traditional utility control areas (RTO-run spot markets span multiple traditional utility control areas and generally comprise numerous product markets, separated by both temporal and geographic/electrical characteristics). In addition, the number of competitors that can sell power into a particular region may be limited by transmission constraints; it may be that a large percentage of the power in a given region must be generated locally, further reducing the number of competitors who should be considered. Product markets are also narrowed by the kind of service provided, such as load-following or black-start service, which can only be provided by certain kinds of resources. Finally, product markets are narrowed by the cost of producing electricity. During off-peak hours when prices are low, only a limited set of base-load units are able to compete to provide low-cost electricity, while during peak hours a larger number of generators can participate economically.

For each product market, FERC guidelines hold that both "economic capacity" and "available economic capacity" should be analyzed in market concentration studies. Economic capacity includes all power that could be delivered into a product market under a certain threshold. However, for many utilities the bulk of their power may not be available for offer into competitive markets, because it may already be committed to serve their own load. Looked at another way, these utilities may be both buyers and sellers in the market, substantially reducing any incentive for exercising market power. Thus FERC applies the separate available economic capacity test, limiting the potential power that could be delivered into a product market to that which is not already committed to serve load, and considering only transmission capacity that would not already be similarly committed. Once again, this may substantially alter the outcome in terms of market concentration metrics.

The complexity and dynamic nature of product markets in the electric industry—transmission constraints and prices can change hourly, for example—makes it difficult to draw firm conclusions on the ability of firms to exercise market power. Different conclusions will be drawn depending on who is doing the analysis and how they define the product markets. Further, the requirement that firms be able to sustain above-cost prices for a significant period of time, and to do so profitably, makes the existence of market power in electricity markets extremely difficult to establish on a case-by-case basis. In response, FERC has followed the lead of the Department of Justice in establishing diagnostic guidelines for establishing the presence of market power through structural tests, as detailed below. Individual RTOs monitor conduct and performance of their own spot energy markets and take additional steps in an attempt to mitigate the potential for exercise of market power

4.3. Structure, Conduct and Performance Reviews in Electric Power Markets

Market Structure

Assessing market competitiveness often includes reviews of market structure, market participant conduct and market performance. Traditional structural tests include horizontal market concentration indices as measured by the Herfindahl-Herschmann Index (HHI), which is applied to a defined product and geographical market or markets. The HHI is calculated as the sum of the squares of market shares for all market suppliers, measured in percent. For example, if a market is composed of five participants with equal market share (20% each), the HHI would be $5 \times 20^2 = 2000$. According to the Department of Justice, HHI values less than 1000 indicate an "unconcentrated" market, values between 1000 and 1800 indicate a "moderately concentrated" market, and markets with values greater than 1800 are considered "highly concentrated."[27]

The Department of Justice and the FERC define a "delivered price test" (DPT) when assessing mergers and in reviewing market-based rate authority applications to determine if the exercise of market power is possible. The DPT is an example of the application of concentration metrics to defined product and geographic markets, and results in the structural characterization of electric power markets.

FERC's merger guidelines mandate that the DPT be used to test the concentration of suppliers at different points of the demand curve, for example across peak and off-peak load periods and during different seasons. In addition, the guidelines set forth an approach to estimating the allocation of limited transmission capacity in order to determine how much imported power can compete to supply the region under study. This is referred to as a "structural market screen" to determine if market concentration will increase above specific thresholds as a result of a proposed merger; if these thresholds are not exceeded, no further review is undertaken.

Other measures of market structure include the extent to which a supplier or suppliers are "pivotal", or whose output is necessary in order to meet projected load. FERC uses

[27] US Department of Justice Merger Guidelines, as revised April 8, 1997.

pivotal supplier determinations as part of its market power screening mechanisms. The PJM Market Monitoring Unit (MMU) uses pivotal supplier screening to assess measures of local market power.

Under FERC policy, if a company “passes” the applicable market structure screens, there is a presumption of no market power potential; a failure results in a presumption of market power. Either of these presumptions is rebuttable, by either the company or by intervenors. If an entity is shown to have market power, then different mitigation measures may be applied as a condition for merger approval or for market-based rate authority to be granted.

Market Conduct and Performance

If FERC establishes that no structural market power concern is warranted, the next level of oversight occurs at the RTO/ISO level. Here market participants’ conduct (e.g., the nature and level of supply offers, and the extent to which physical withholding of generation capacity may be present) and market performance can still be assessed. Market participant conduct is reviewed by market monitors to determine if withholding strategies appear to be present. If so, mitigation measures may be applied to specific sell offers from the entity in question. Such measures are typically some type of price cap on the supply offer, usually in reference to the supplying generator’s marginal costs. The next section describes these mitigation measures in detail.

Market monitors also review the overall performance of the RTO/ISO markets. This is done by analyzing price trends and concentration metrics, and by determining the extent to which prices are consistent with competitive levels. For example, Table 4.1 illustrates the price markup in PJM and New England as indicated by the Lerner Index, which measures what portion of the annual average wholesale cost of electricity represents markup above SRMC. The Lerner Index is calculated as the difference between the price and the marginal cost, divided by the price.

Table 4.1 Price Cost Markup: Quantity-Weighted Lerner Index for PJM and ISO NE

Year	PJM Raw	PJM Adjusted	ISO NE
2002	2.0 %	11.0 %	
2003	3.0 %	12.0 %	9 %
2004	3.4 %	8.4 %	3 %
2005	0.3 %	3.9 %	6 %
Sources: PJM State of the Market Reports for 2005, 2004, 2003 and 2002; ISO NE 2005 Annual Markets Report			

Two metrics are presented for PJM in Table 4.1, representing the "raw" and "adjusted" Lerner Index values. PJM allows a 10% adder to actual calculated marginal costs for all generators, so the "raw" index is based on an already-inflated cost basis. The "adjusted" metric is based on the assumption that all reported costs include the full 10% adder and accounts for this as part of the above-cost markup. PJM describes this as an extreme assumption and treats the resulting adjusted index as the upper bound to the actual markup.

Because of the sheer size of the PJM market, each percentage point markup in the Lerner index represents a potentially large financial impact on consumers. According to the PJM website, the system serves 728 million MWh of electricity annually. In 2005, the load-weighted average wholesale price of electricity in PJM was close to $68/MWh. Thus each 1% increase in the price due to strategic bidding would have cost consumers $495 million in 2005, if actual consumer prices reflect the spot price. If the true Lerner index is close to a 10% markup over competitive prices, the annual spot price tag for above-cost bidding would have been close to five billion dollars.

Table 4.2 lists HHI concentration metrics for PJM local markets in 2005. PJM evaluates the level of generation concentration associated with local markets by determining the concentration of suppliers which have the ability to relieve specific transmission constraints. PJM may place offer caps on suppliers if a pivotal supply test indicates that up to three suppliers in combination could be pivotal in setting prices to relieve the constraint. Over half of the constraints listed should be considered "highly concentrated"; an HHI value of 10,000 indicates that a single supplier controls all of the capacity to relieve the constraint in question, and several of these constraints either reach or approach that level of concentration. The table also includes the overall magnitude of congestion associated with each constraint (see Chapter 3 for a discussion of PJM congestion costs) and the level of affected load, which provides a measure of the relative importance of each constraint to consumer impact.

Table 4.2 HHI concentration indices for relieving local constraints in PJM, 2005.

Region or Interface	Constraint	HHI	2005 gross congestion costs ($M)	Average affected load (MW)
PSEG	Roseland-Cedar Grove	8198	45	541
	Branchburg transformer	2998	125	565
Eastern interface	-	1575	35	5,940
AECO	Laurel-Woodstown	9012	24	81
PENELEC	Erie West transformer	3306	7	142
PECO	Chichester-Linwwood	2988	12	901
AEP	Cloverdale-Lexington	1078	158	3,327
	Kanawha R-Matt Funk	1066	151	1,694
	Mahans Lane-Tidd	10000	12	160
AP	Mitchell-Shepler Hill	10000	6	17
	Mt. Storm-Pruntytown	1048	766	10,094
	Bedington-Black Oak	1083	922	3,912
Western interface	-	1130	140	9,388

Source: 2005 PJM State of the Market Report, pages 62-67.

For comparison, Table 4.3 lists HHI concentration metrics for the New England and MISO regions.

Table 4.3 HHI Metrics for ISO NE and MISO in 2004 and 2005.

	2005			2004	2005
ISO NE Entire Region	582		MISO Entire Region	356	548
Select ISO NE Areas:			***Select MISO Areas:***		
Connecticut	1351		Central	770	1253
SW Connecticut	744		East	1745	2072
Norwalk-Stamford	1069		West	1275	2397
Middletown	4727		WUMS	2642	2918
Boston	1245				

Sources: ISO NE and MISO State of the Market Reports for 2004 and 2005

The summary HHI and Lerner Index metrics in Table 4.1 through Table 4.3 indicate that in PJM, the results of the spot energy market performance deviate from competitive levels, and that both PJM and in parts of the MISO region, concentration indicators show the potential for exercise of market power.

5. Market Monitoring and Market Power Mitigation in LMP RTOs

5.1. Overview of Monitoring and Mitigation in RTOs

All U.S. RTOs employ market monitoring oversight and market power mitigation practices. The four eastern RTOs/ISOs have a designated market monitor, but with different combinations of RTO-internal and external oversight. PJM's market monitoring unit is internal to PJM, but is claimed to be "fully independent" even though the MMU reports to the PJM Board. In contrast, MISO does not have an "internal" market monitor. RTO market monitors produce regular reports on at least an annual basis.

Table 5.1 summarizes the structure of the market monitoring and energy market mitigation policies in place at each of the four eastern RTOs.

Table 5.1 Summary Review of Market Monitoring and Mitigation Structure and Policies in the Four Eastern/Midwestern RTOs.

	PJM	ISO NE	MISO	NY ISO
Structure	Internal market monitoring unit	Internal and external market monitoring unit	External market monitoring unit	Internal and external market monitoring unit
Market Monitoring Plan	Attachment M of the PJM Tariff	Appendix A of Market Rule 1, Section III of the ISO-NE Tariff	Module D of the Transmission and Energy Market Tariff (TEMT)	Attachment H of the NYISO Tariff
Energy Offer Cap	$1,000/MWh	$1,000/MWh	$1,000/MWh	$1,000/MWh
Energy Market Mitigation	Offer capping at 110% of marginal cost for local market power as determined using three pivotal supplier test when transmission constraints bind.	Conduct-impact thresholds and mitigation to marginal cost in constrained areas; less restrictive mitigation for system-wide offers.	Mitigate supply offers to marginal cost only when transmission constraints bind in narrowly constrained areas (NCAs).	Conduct-impact thresholds and automatic bid mitigation in New York City if thresholds are exceeded.

While the eastern RTOs share similar overall monitoring and mitigation structures, as would be expected given FERC oversight of all of the RTOs, there are differences in the detailed monitoring protocols and the way in which mitigation is implemented at each of the RTOs. These protocols and mitigation measures are listed in detail in the tariffs of each of the RTOs, and also summarized on the FERC website.[28] All have some form of mitigation structure, usually tied to offer capping at some fraction of marginal cost, and usually based on whether or not transmission constraints are binding in the respective regions.

5.2. Market Monitoring and Mitigation Policies in the PJM RTO LMP Markets

Monitoring

The objectives of PJM's market monitoring plan include: 1) the monitoring and reporting on PJM market operations issues, including the potential of any participant to exercise market power; 2) the evaluation of spot and bilateral markets to detect market design flaws or structural problems; 3) the evaluation of enforcement mechanisms; and 4) ensure independence and objectivity of the monitoring program.[29]

PJM's market monitoring unit aims to achieve these objectives by monitoring participants and market structure for:

(1) compliance with PJM market rules;
(2) actual or potential design flaws in the PJM market rules;
(3) structural problems in the PJM market that may inhibit a robust and competitive market; and
(4) the potential for a market participant to exercise market power or violate any of the Commission's market rules.[30]

The MMU may recommend changes to market rules (including the market monitoring plan) in the annual State of the Market report and, as appropriate, in other reports to the

[28] http://www.ferc.gov/industries/electric/indus-act/rto/handbook.asp
[29] PJM Market Monitoring Plan, Attachment M to the PJM Open Access Transmission Tariff, Section I.
[30] PJM Open Access Transmission Tariff, Attachment M, Section III.

PJM Board, the FERC, or PJM Committee.[31] With approval from the PJM Board, the MMU can also file reports or complaints with FERC, state regulatory commissions, state attorneys general or make other appropriate regulatory filings to address design flaws, structural problems, compliance, market power, or other issues, and make recommendations on appropriate action. If PJM does not follow the MMU's recommendations, the MMU can communicate its concerns to PJM members and the FERC. The MMU is also allowed to consider and evaluate a broad range of additional enforcement mechanisms.

The MMU develops indices or standards to evaluate the information it collects and maintains. The State of the Market report provides summary analysis of ownership concentration metrics (HHI, ownership concentration for marginal units), portion of hours in which a supplier is pivotal (RSI), price-cost markup, and offer-capping level, in addition to load levels and prices (LMP). The MMU also considers individual company market share, offer behavior, and net revenue (i.e., generator revenue over and above marginal operating costs).

Mitigation – Energy

PJM's spot energy market mitigation polices include 1) a broad market offer cap of $1,000/MWh for all suppliers, and 2) offer caps on generation resources when transmission constraints bind, if a three pivotal supplier test is failed. The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal, i.e., incremental generation from the three suppliers can be replaced by incremental generation from other sources at a cost of no more than 150% of the clearing price.[32] In other words, other than the $1,000/MWh offer cap for all resources at all times, mitigation measures are imposed only when transmission constraints bind and suppliers are jointly pivotal.

There are two categories of generation that are exempt from these caps:

[31] PJM Open Access Transmission Tariff, Attachment M, Sections IV and VII.
[32] The details of how the three pivotal supplier test is carried out are contained in Section 6.4.1 e) and f) of the Appendix to Attachment K of the PJM Open Access Transmission Tariff.

- Generation resources used to relieve the western, central and eastern reactive power limits in the MAAC Control Zone and APS South Interface. The MMU recently released a report indicating its preference to remove all offer capping exemptions and instead rely upon the three pivotal supplier test for all generators providing reactive power relief when transmission constraints bind. PJM itself does not believe, at this time, that offer capping exemption removal is necessary.[33]

- Units for which construction began before September 30, 2003 and sometime after April 1999.[34] The basis for this exemption was that their development was contingent on a now-overturned rule that exempted certain post-1996 units from offer capping. A unit that has been grandfathered under this provision may be subject to mitigation; however, if the MMU or PJM makes a filing to the FERC concluding that the unit can exercise significant market power.

The offer caps that do apply during these situations are set at one of four levels that the seller specifies in advance. The incremental costs of a unit, plus 10%, is most often referred to as the offer cap; however, three other values can be used: one tied to the LMP at the unit's location, one based on marginal cost plus a specified adder that increases for more frequently mitigated units; and lastly one based on an agreement between the seller and PJM. The offer caps are then used as part of the determination of the LMP; and it is the LMP, and not the offer cap itself, which is paid to the seller.

In the event of "scarcity" conditions, the offer capping regime is discontinued. Scarcity conditions exist when PJM must take at least one of a series of emergency actions designed to maintain reliability of supply in the short-term, such as operating generation in their "maximum emergency" range. This scarcity pricing regime is intended to send

[33] PJM Staff Summary and Evaluation of the PJM Market Monitoring Report on Offer Capping Exemptions for PJM Reactive Transmission Interfaces, December 12, 2006, as posted on the PJM website under the Market Implementation Committee section at http://www.pjm.com/committees/mic/downloads/20061220-item-05-response-to-mmu-exempt-interface-rpt.pdf .

[34] The initial date for the exemption window depends on the region in which the generation is located and the date at which that region announced its intention to join PJM. For example, it is April 1, 1999 for the PJM "classic" region; and as late as May 28, 2002 for the Dominion (Virginia Power) region.

price signals that encourage more generation to be available and for load to reduce consumption during particularly critical (and unusual) circumstances.[35]

Mitigation – Capacity and Ancillary Services

PJM's new RPM (reliability pricing model) capacity market includes mitigation provisions applicable to suppliers failing a preliminary market screen. These measures cap a supplier's capacity offer (i.e., the offer into the PJM capacity auction) to the avoided costs of providing capacity. The "avoided costs" of capacity include eight different categories of costs that are unavoidable to a supplier if a unit is to be available as a capacity resource. Those categories include, for example, operations and maintenance labor, and administrative expenses.[36]

PJM's regulation market (a combination of Mid-Atlantic, Western and Southern region regulation sources) is currently structured as cost-based for dominant suppliers; the MMU has proposed allowing market-based offers only where suppliers pass the three pivotal supplier test in the real time regulation market. If the three pivotal supplier test is failed, the market would be cost-based for those suppliers in those hours. The spinning reserve market is currently mitigated as it has not been found to be structurally competitive; all offers are capped at marginal cost plus an opportunity cost adder of $7.50 per MWh.

6. Mechanisms for Exercise of Market Power in LMP Energy Markets

In order to investigate both the potential for and evidence of the exercise of market power in the LMP electricity markets, we reviewed the publicly available data on wholesale power offers from generators in PJM and ISO NE. Given the voluminous data involved, the complexity of the system, and the limited utility of the most important data as discussed below, we cannot draw firm, independent conclusions about market behavior in

[35] Scarcity pricing provisions are included in Section 6A of the Appendix to Attachment K of the PJM Open Access Transmission Tariff.
[36] All categories of costs and the offer cap construct will be contained in Section 6.8 of Attachment DD to the PJM Open Access Transmission Tariff. This version of the tariff is not yet posted in the tariff section of the PJM website.

either market. What we have done is to characterize the energy offers to see if there is any evidence which suggests strategic bidding, and review how this might be reflected in price outcomes in the relevant electricity markets.

6.1. Quantitative Analysis of Bid Data - PJM

Although the public bid data available from PJM are complete in terms of representing the full set of power offers into the LMP market, these data are of limited use because the owners and the plant identities are masked, and no information is available about the locations of specific resources. Likewise data regarding the actual costs underlying the bids are unavailable, although that information is supplied to PJM by generators. No information is available regarding the bilateral transactions which comprise about a third of the wholesale energy transactions in PJM, which may mitigate any opportunities to exercise market power.

Finally, there is some unresolved ambiguity in interpretation of the PJM bid data. PJM removes several fields from the data before making it available to the public. Beyond location, perhaps the most severe is the ambiguity over whether sets of price/quantity bids for a single resource should be considered as block bids (or “steps”), or points on a continuously sloping bid curve. According to PJM market monitor Joe Bowring, offerors into the market may use either form of bid, but the selection is not represented in the public data.[37] Synapse has been unable to find any official documentation of or explanation for this omission, which severely restricts the usefulness of the data.

Market price outcomes are available in much greater detail, with day-ahead and real-time hourly prices published for hubs, zones, interfaces and buses throughout the system. Similarly, load data are readily available for three market regions, fourteen load zones and seven load sub-zones. Unit-level operational data (commitment, dispatch, unit outages, etc.) are not publicly available.

[37] Personal communication with Joe Bowring, PJM Market Monitor, November 2006.

Price Differences between Locations

Example locational prices, in this case for the various PJM-defined trading hubs, are shown in Figure 6.1 (on-peak hours, *i.e.*, weekdays from 7 am to 11 pm) and Figure 6.2 (off-peak, *i.e.*, all other hours). The price differences between hubs are generally greatest in the summer and winter. As noted earlier, prices in eastern PJM are generally higher then those in western PJM, and these price differences are similar during on-peak and off-peak time periods. As a rule, higher prices (by location or operating hour) correspond with fewer uncommitted competing resources available to deliver the next increment of power, and thus with better opportunities to apply upward pressure on price by withholding power or strategic bidding.

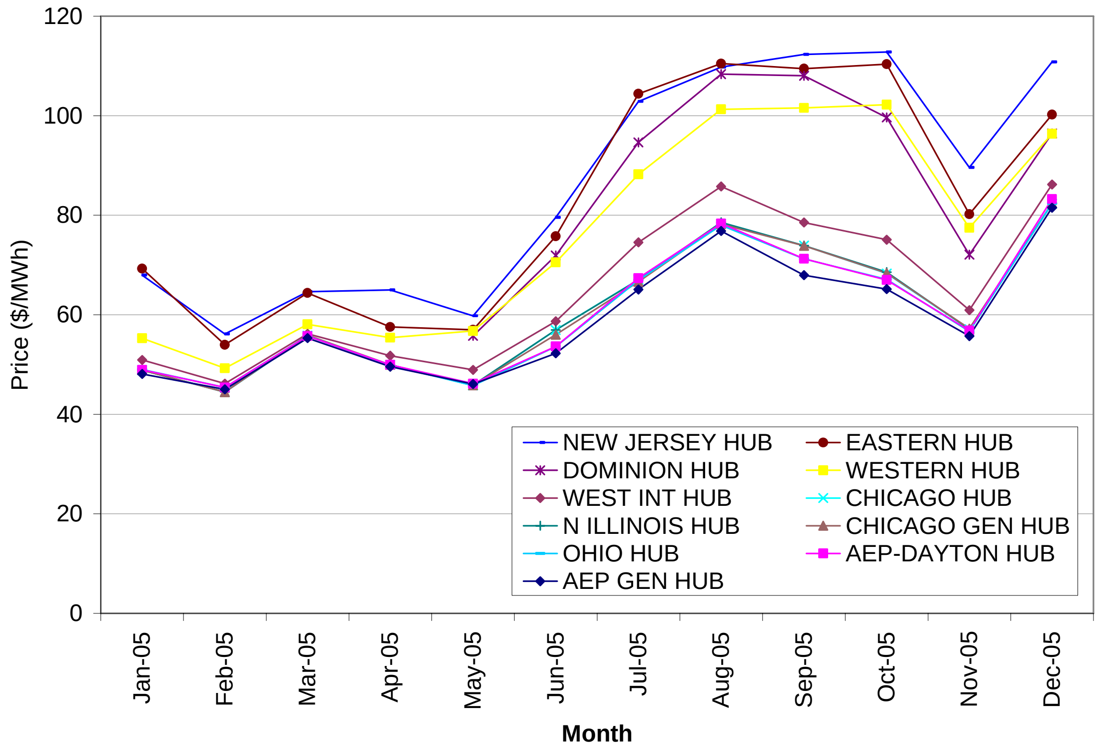


Figure 6.1 Monthly average, on-peak real-time energy prices at selected PJM hubs
Source: PJM public price data.

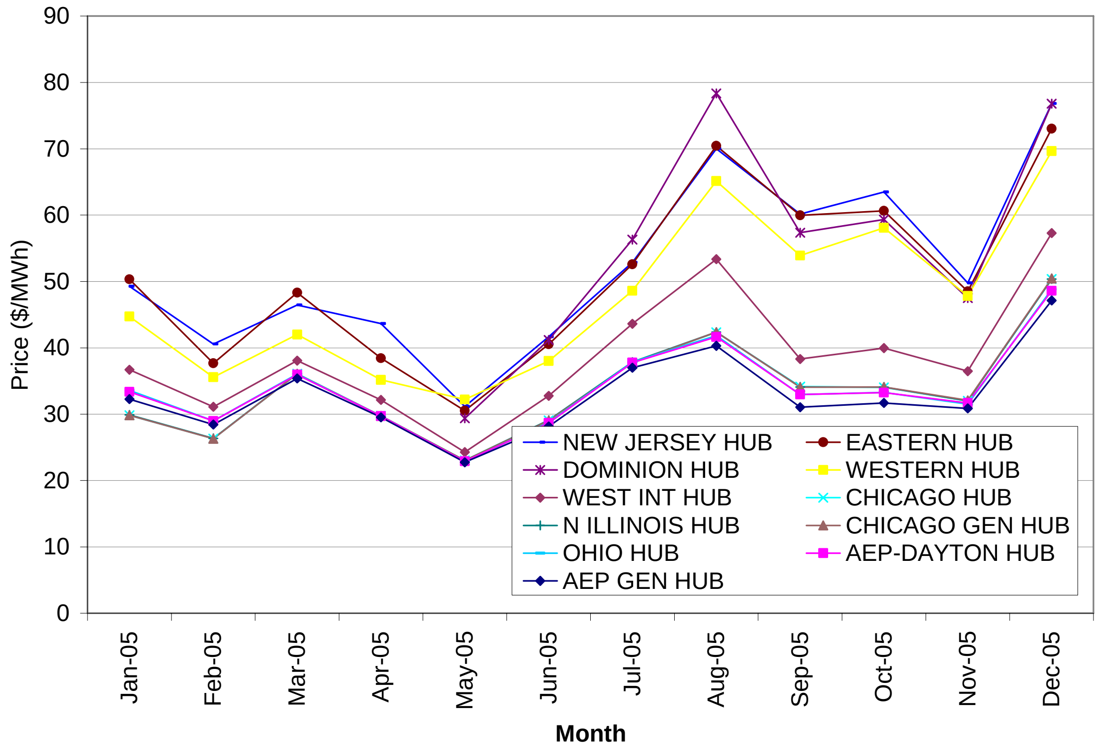


Figure 6.2 Monthly average, off-peak real-time energy prices for peak hours only at selected PJM hubs
Source: PJM public price data.

A comparison of hourly prices from July 2005 for an eastern (New Jersey) and western (Northern Illinois) hub (Figure 6.3) shows that they followed similar patterns and on some days tracked closely to each other. However, important differences are readily apparent in the hourly and daily price differences between these two locations (Figure 6.4). In addition to a persistent west-to-east price difference which averaged about $25/MWh for the month, on quite a few days the peak period prices were much higher and more volatile in the East, suggesting that transmission from west to east is constrained and the pool of competing generators is limited.

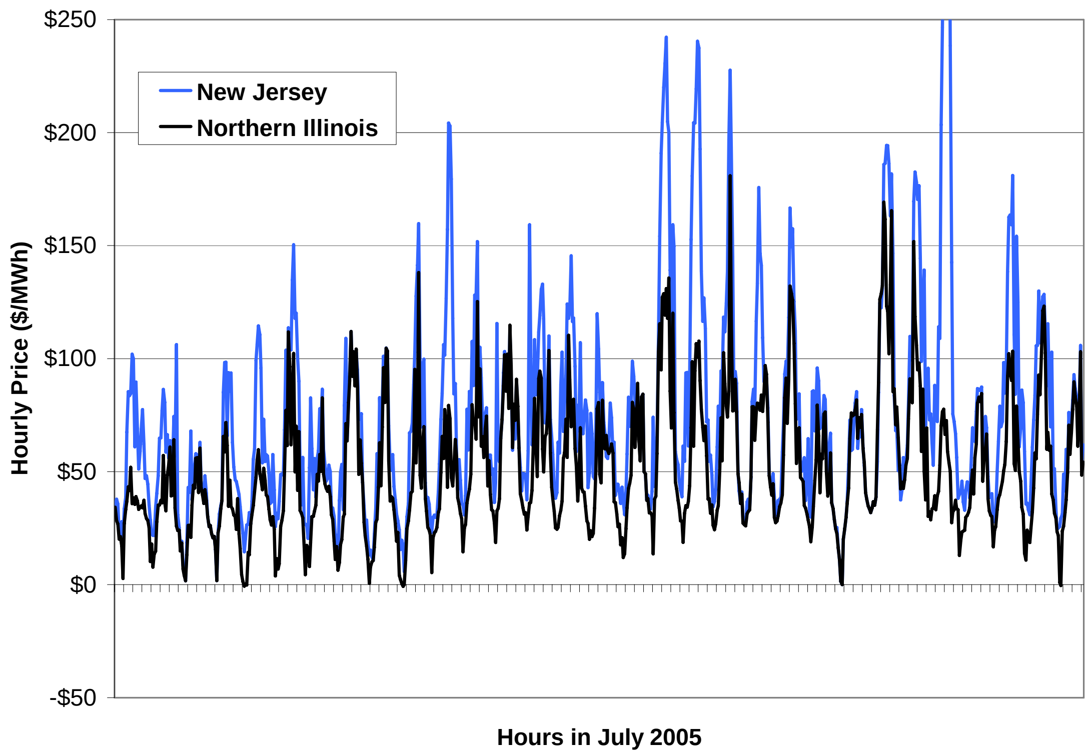


Figure 6.3 Hourly real-time prices in New Jersey and Northern Illinois, July 2007

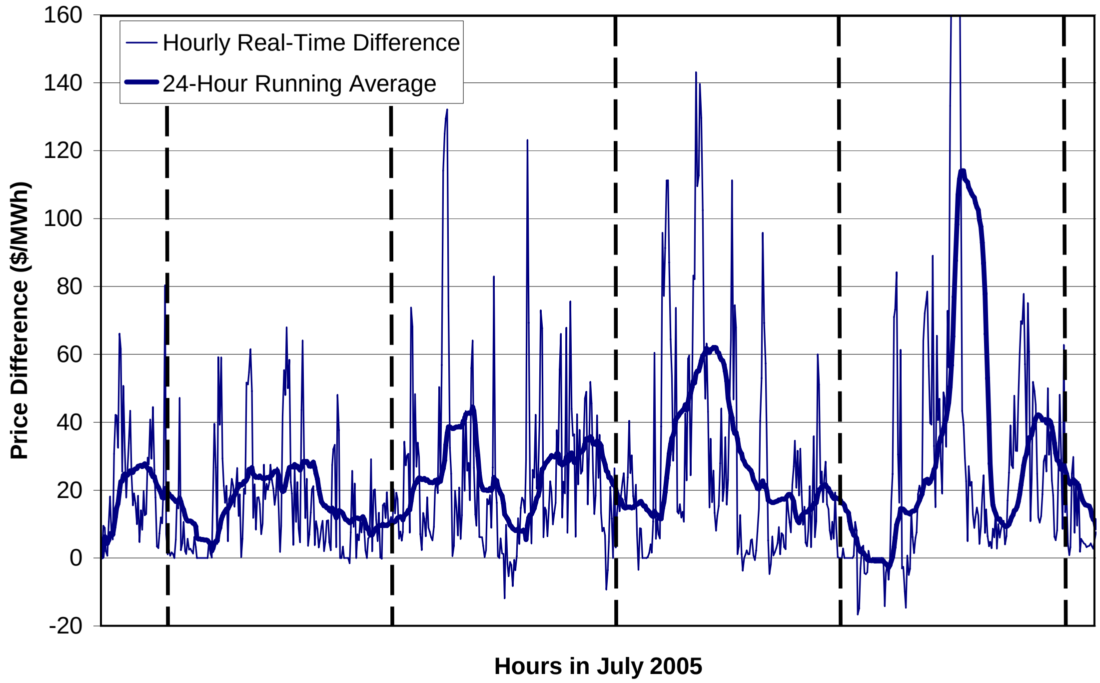


Figure 6.4 Differences (hourly and smoothed) between the time series shown in Figure 6.3 for July 2007
Heavy vertical dashed lines indicate midnight on Sunday.

Relationship of Load to Price

Loads and prices are closely related, but similar load levels can be associated with a wide range of prices for different time periods. Figure 6.5 shows the load-price relationship for PJM as a whole for July 2005.

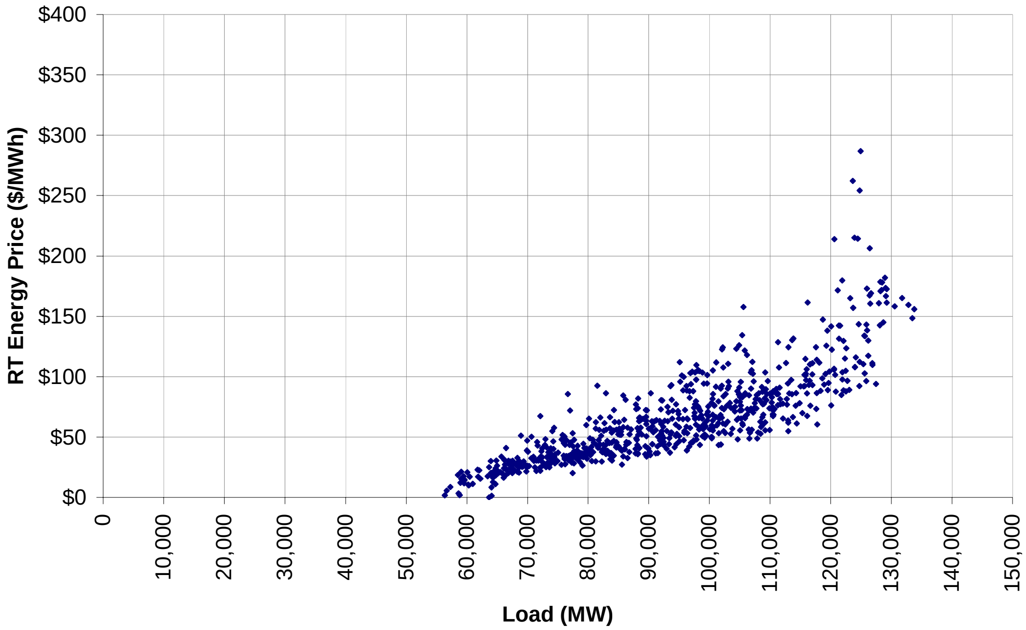


Figure 6.5 RTO-wide load-weighted average energy price vs. total load in PJM, July, 2005

Using the PJM bid data we are able to estimate the summer 2005 supply curve; this reconstruction is shown juxtaposed with the observed load/price data in Figure 6.6. Note that the supply curve shown is shifted slightly to the right (smaller quantity of power at any given price) because it does not include about 4,000 to 6,000 MW of hydropower, which varies in availability by hour of the day. The market prices average about 25% above the equivalent bid curve prices. These differences, between the offer-based supply curve and market price outcomes, is attributable to a number of factors, including congestion and unit operational constraints, as well as to above-cost offers, which may reflect the exercise of market power.

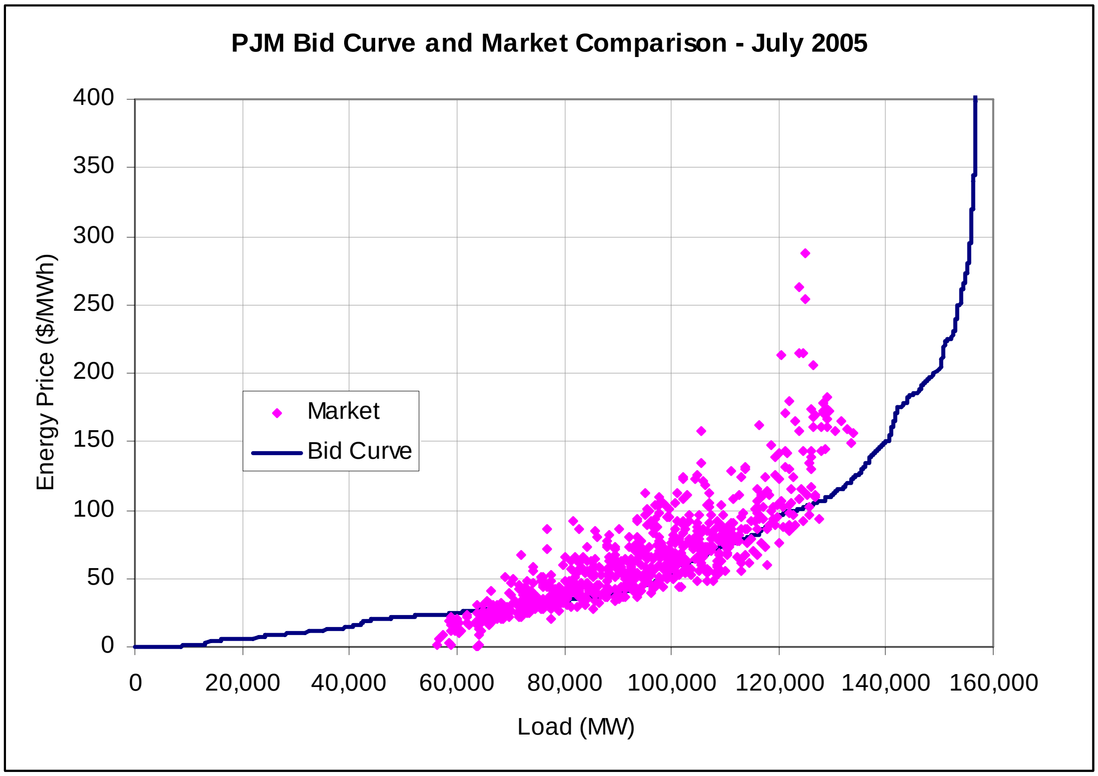


Figure 6.6 Reconstructed PJM bid curve based on energy offers from July 2005, compared to energy market outcomes from the same month

Company and Unit Bidding Behavior

Using the available data, we reviewed examples of changes in generating unit offer prices from day to day within the month of July, 2005. Although we do not have access to unit specific cost data for these specific units, electricity generation technologies generally exhibit only minimal day to day changes in production cost. The variations in offer prices, therefore, represent intriguing and apparently anomalous behavior.

Figure 6.7 shows a graph of the average daily offers in July 2005 for units associated with a single owner, denoted in the bid data as company E1. Each line in the graph shows the daily offers, in $/MWh, for a single resource. Note the group of resources in the middle of the price range whose offers vary dramatically from one day to the next. They start the month at a $200/MWh level then jump for three days to over $300/MWh, fall again for seven days and rise again there after to over $300/MWh. On the 25th they drop by about $100/MWh and then jump back up. The quantity offers appear to be constant through all of these price changes. Other companies and resources show similar behavior, which seems difficult to reconcile with the notion of cost-based bidding into the market.

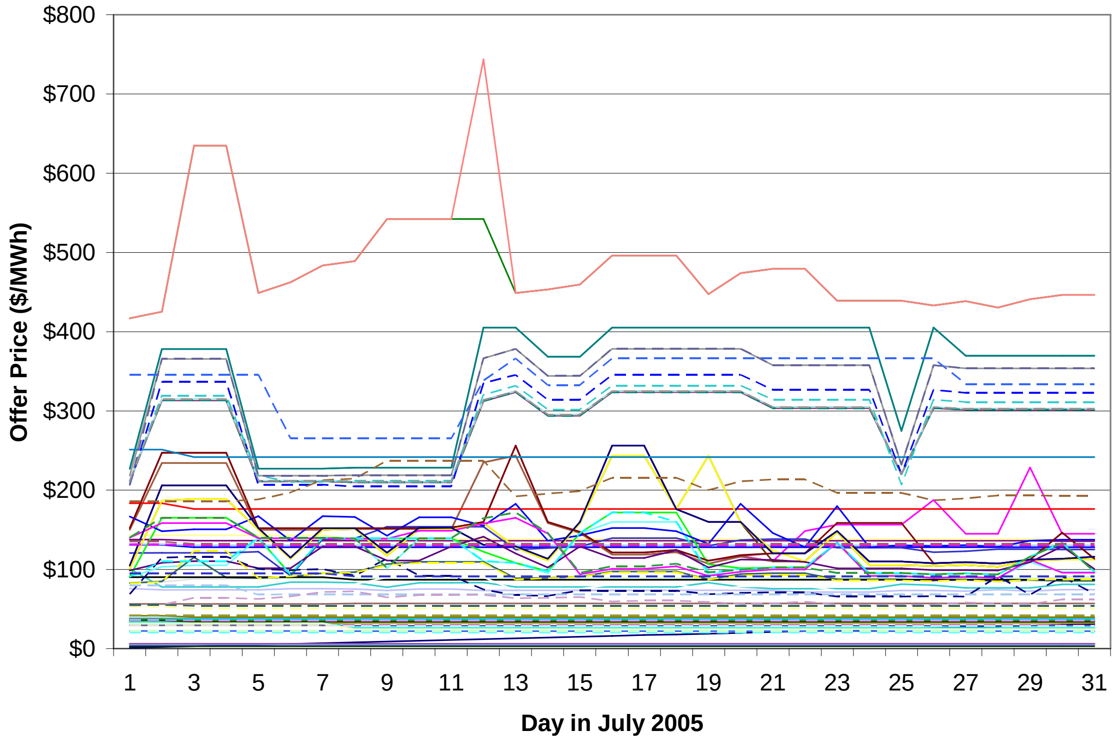


Figure 6.7 Daily energy offer prices for resources owned by Company "E1" in the PJM real-time market

This leads to the question of whether these changes in offer price affect the overall supply curve. The evidence is that they do. Figure 6.8 shows the supply curve for company E1 on two consecutive Wednesdays in July, with the difference between the two curves shown as the shaded area. The upper end of the curve, representing over a 1,000 MW is shifted upward by $50 to $100 per MW between the two dates.

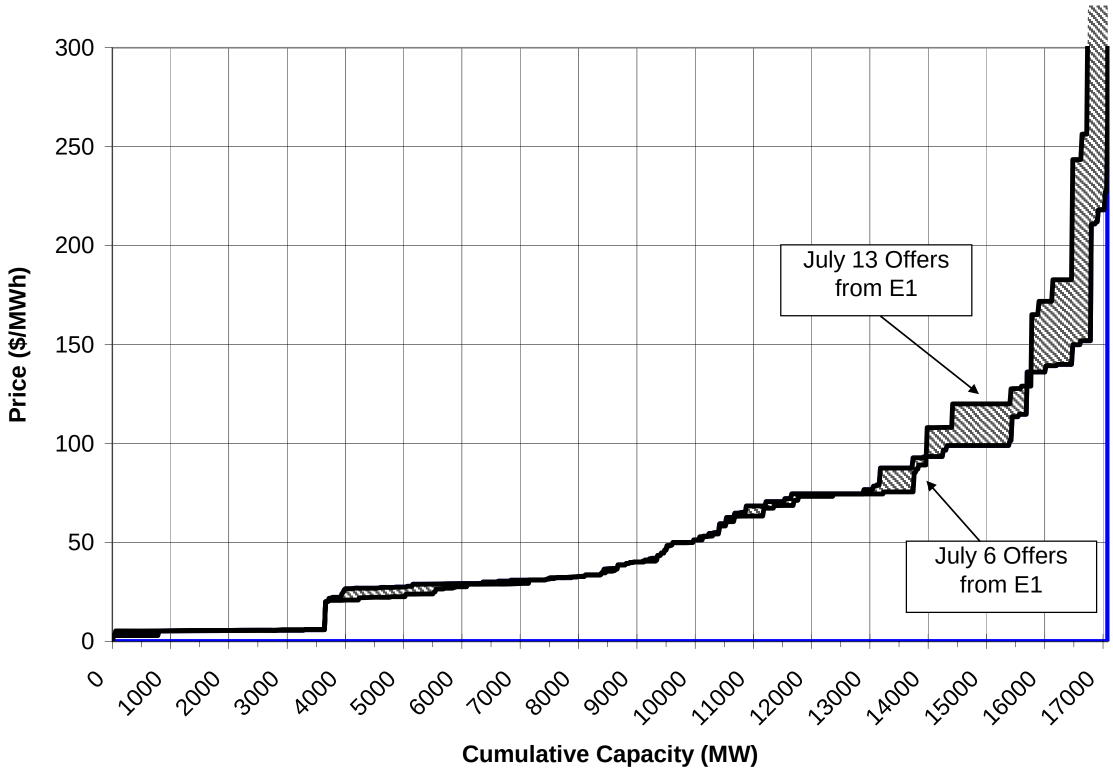


Figure 6.8 Comparison of bid curves for Company "E1" on July 6 and July 13, 2005

The difference between two offer curves for another company ("N8") for the same pair of dates shows a similar situation (Figure 6.9). Here a 2000 MW section of the curve is raised again by $50 to $100 per MWh, before rejoining the lower curve.

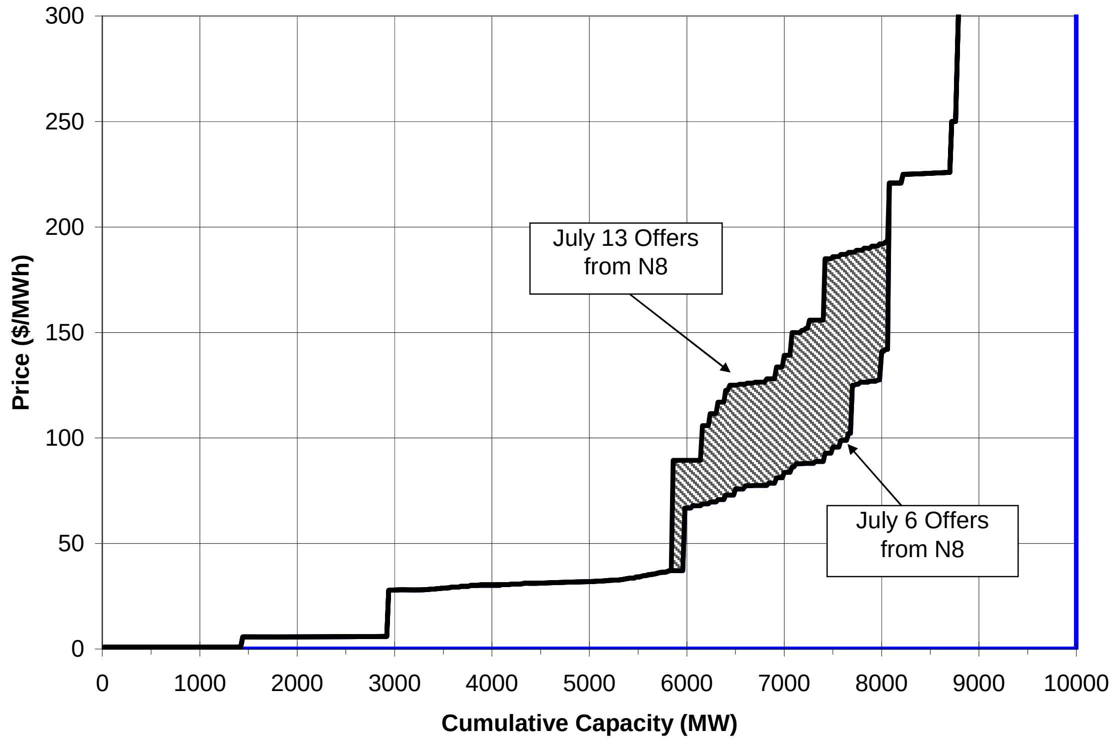


Figure 6.9 Comparison of bid curves for Company "N8" on July 6 and July 13, 2005

Without more information about the locations of the resources, as well as the loads and congestion during these days, we can not determine the specific impacts on market prices. However, Figure 6.10 shows the aggregate difference in the supply curves for these two dates. There is no doubt that prices were affected by changes in the supply curve of this nature, to different degrees in different locations. Unfortunately, the reasons for the difference cannot be determined without additional, currently unavailable data. The evidence that this difference and other features like it represent market power, however, is compelling.

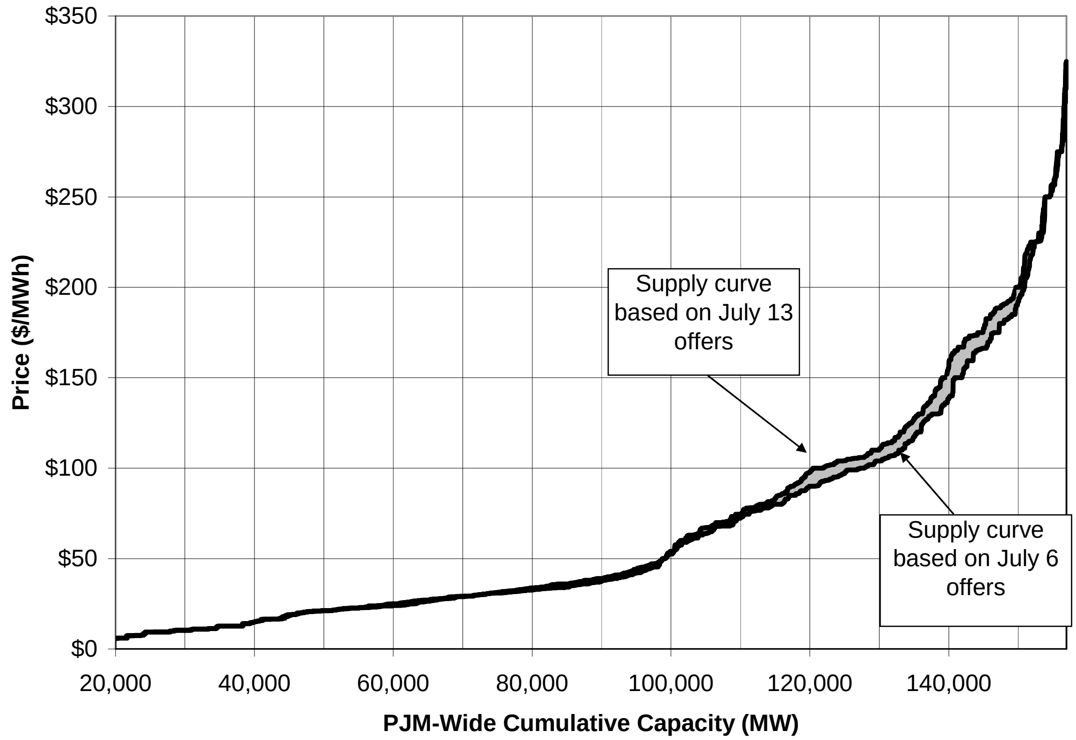


Figure 6.10 Comparison of aggregate PJM bid curves for July 6 and July 13, 2005

6.2. Quantitative analysis of bid data – ISO-NE

New England is a much smaller market than PJM with about one-tenth of the total resource base. It is also more compact, consisting of the six contiguous New England states. These states have a long history of cooperation on planning and transmission issues under NEPOOL prior to the formation of the New England ISO.

As with PJM, offer data available from ISO-NE is complete in terms of representing the full set of power offers into the LMP market, but again the owners and the plant identities are hidden, and no information is available about the locations of the resources. No data are provided on actual production costs. Another limitation in analyzing this market is that more than 60% of the load obligations are either forward contracted or covered by a physical hedge.[38]

[38] p.122, "2005 Annual Markets Report", ISO New England, June 2006.

For ISO-NE, hourly day-ahead and real-time prices are published for eight load zones, along with similarly resolved load data.[39] Unit-level operational data (commitment, dispatch, unit outages, etc.) are not publicly available.

Price Differences between Locations

Example price differences among locations in ISO-NE are shown in Figure 6.11. As with PJM, these differences are greatest in the summer and winter. Connecticut, specifically the southwest corner of the state, most often experiences congestion and higher prices relative to the rest of the region. Maine, which has the benefit of abundant low cost generation but only limited transmission capability to export power, has the lowest prices in the region. In general, the seasonal pattern of monthly prices is similar to that of PJM, but prices are about $10/MWh higher than those in PJM on average. The graph of monthly peak hour prices reflects hot weather conditions and system stress from the summer of 2005, followed by extremely high natural gas prices during the fall of 2005.

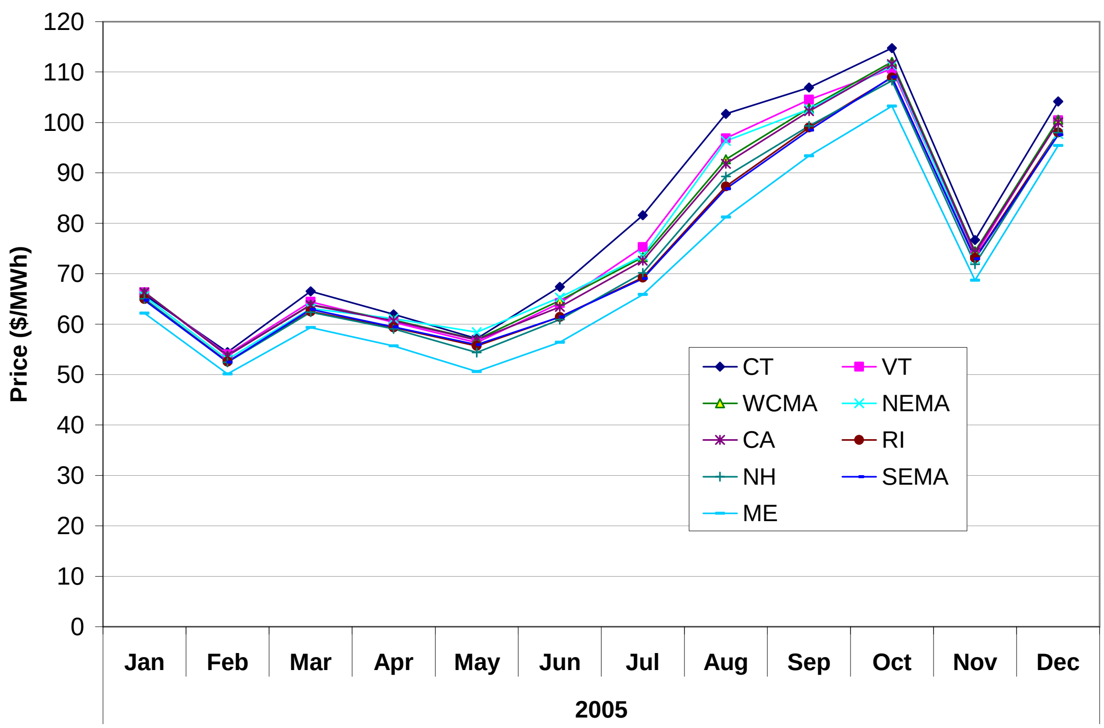


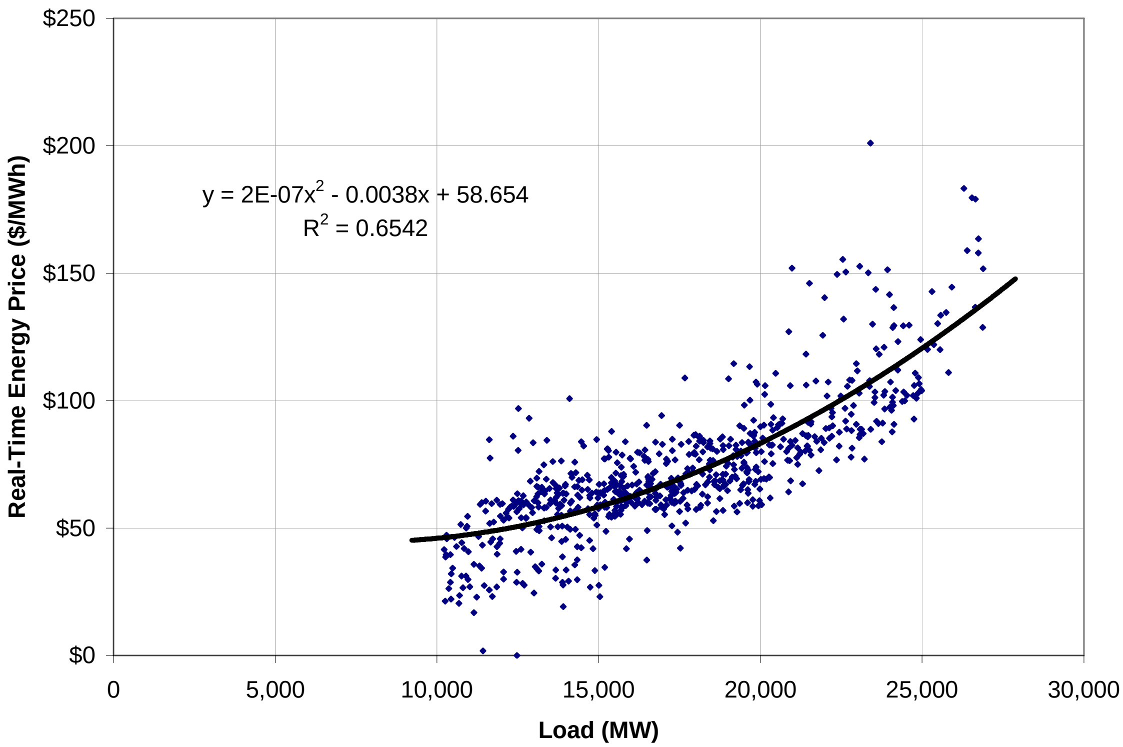
Figure 6.11 Monthly average zonal prices in ISO-NE

[39] The regions correspond to the six New England states, with Massachusetts further divided into three subregions: NEMA=Northeast MA & Boston, SEMA=Southeast MA & WCMA=West Central MA.

As with PJM, we focus our analysis on electricity offers for July, 2005.

Relationship of load to price

As we found in PJM, while loads and prices are related, similar load levels are often associated with a wide range of prices. Figure 6.12 shows a plot of the July hourly New England Hub prices[40] against loads for the New England Control Area, along with a quadratic line of best fit relating the two. While there is a general relationship between loads and prices, similar load levels can have price differences of over $100/MWh at different hours. The average standard deviation of the prices relative to the trend line is close to $15/MWh, but the variation increases at higher prices and load levels. Clearly, as in PJM and all other markets, there is not a single simple supply curve but many factors acting to influence the observed market price.

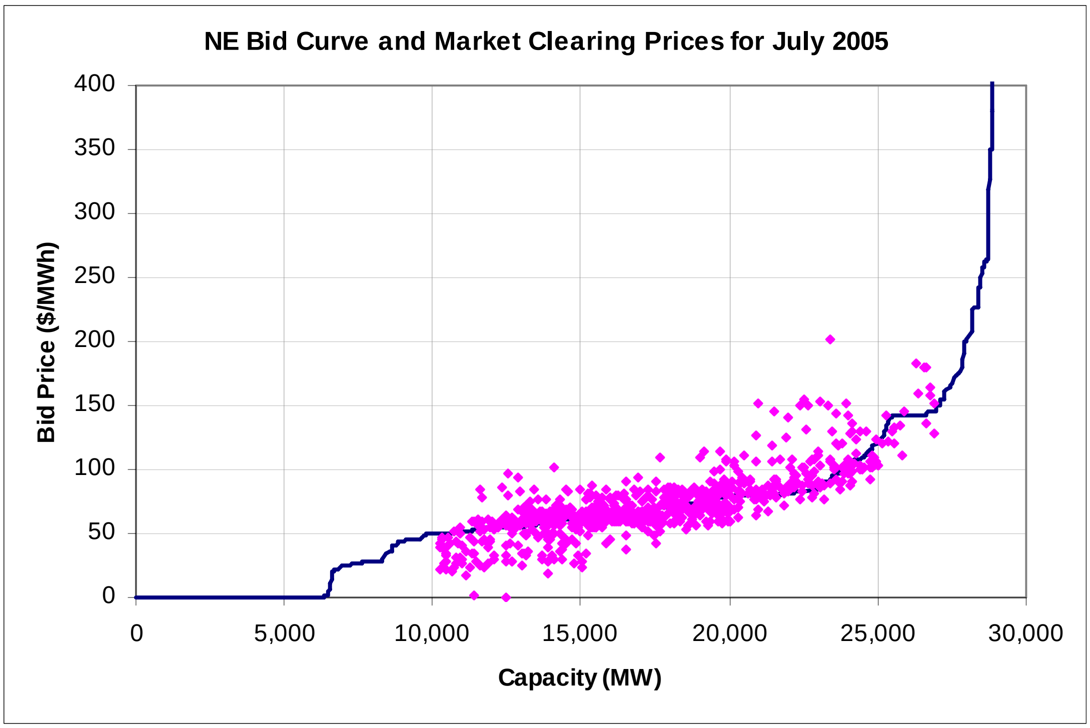


[40] The New England Hub is a location in central Massachusetts commonly used as the location for wholesale electricity transactions. The price at this location is considered to be the “uncongested price” for the New England market.

Figure 6.12 July, 2005 hourly New England Hub prices and loads with quadratic line of best fit

We next analyzed the detailed offer data to investigate the behavior of the supply curve serving the ISO-NE region. Each resource in the New England market is represented by up to ten blocks of power, with a single price for each block. Additional information is provided for each resource such as the cold, warm and hot start costs, and the low and high operating limits. Another significant difference from the PJM data is that bids are specified on an hourly basis for all units, including hydropower resources.

Figure 6.13 shows a supply curve for New England reconstructed from the July 2005 offer data, based on the average offer price over the month for each block of energy from each resource in the system. This reconstructed curve corresponds fairly closely to that presented in the New England Markets Report.[41] Superimposed on the reconstructed supply curve are the system hourly loads and real-time New England Hub prices for that same month. The market clearing prices are fairly tightly clustered around the supply curve, but again there is considerable scatter related to operational constraints and congestion in the New England market.



[41] http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2005/2005_annual_markets_report.pdf.

Figure 6.13 Reconstructed NE-ISO supply curve based on average offer prices in July 2005, shown with hourly load vs. price for the same month

Following our analysis of PJM, we investigated the offer curves from three days (in this case, July 25 through July 27), which had fairly high loads and prices. Figure 6.14 shows the offer curves for 1:00 pm on July 26 and July 27.

There are significant and anomalous differences between the offer curves for these two days, particularly in the range between cumulative capacities of 22,600 and 26,600 MW where the marginal unit is likely to lie. In this range, the offer prices for July 26 are between $20/MWh and $50/MWh higher than the corresponding offer prices for the next day. During the three days considered, ISO load fell into in this range during 23 hours, so the price impact of this difference in offer prices would have been felt about one-third of the time.

The impact of this difference is not trivial. For example, if the price difference were $35/MWh and the load averaged 25,000 MW for those 23 hours, the total revenue difference just for those hours would be over $20 million. Of course, much of the load may have been protected from the real time price through bilateral contracts, but on the other hand we have investigated only a very small part of the market. The nature and rationale for these kinds of anomalous bidding patterns is worthy of a more detailed investigation than we can perform given our limited access to the underlying data.

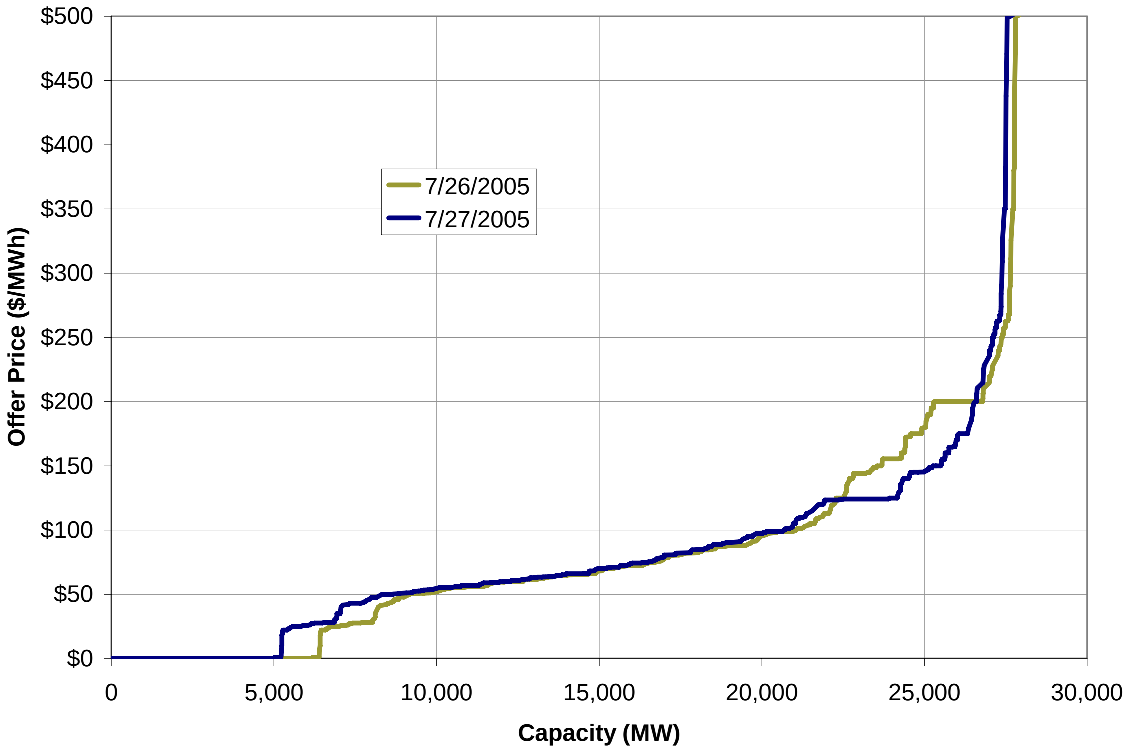


Figure 6.14 Comparison of ISO-NE offer curves for 1:00 pm on July 26 and July 27, 2005

Company and Unit Bidding Behavior

In further analyzing the data we identified two resources, from a single offeror, that had significantly different offers for these two days. The graph below shows the offer data for that company, identified as company 423710 in the public bid data, for 1:00 pm on July 26 and July 27. The offer price differences ranged from $25/MWh to $75/MWh for about 2000 MW of resources. Because these offers are in the price range of the differences seen in the aggregate offer curve, we conclude that the offers for this one company, the second largest in ISO-NE, account for most of the differences observed in the aggregate bid curve, and for large differences in the spot market electricity price during these hours. Of course, the identity of the company and the locations of the affected resources are not made public by ISO-NE.

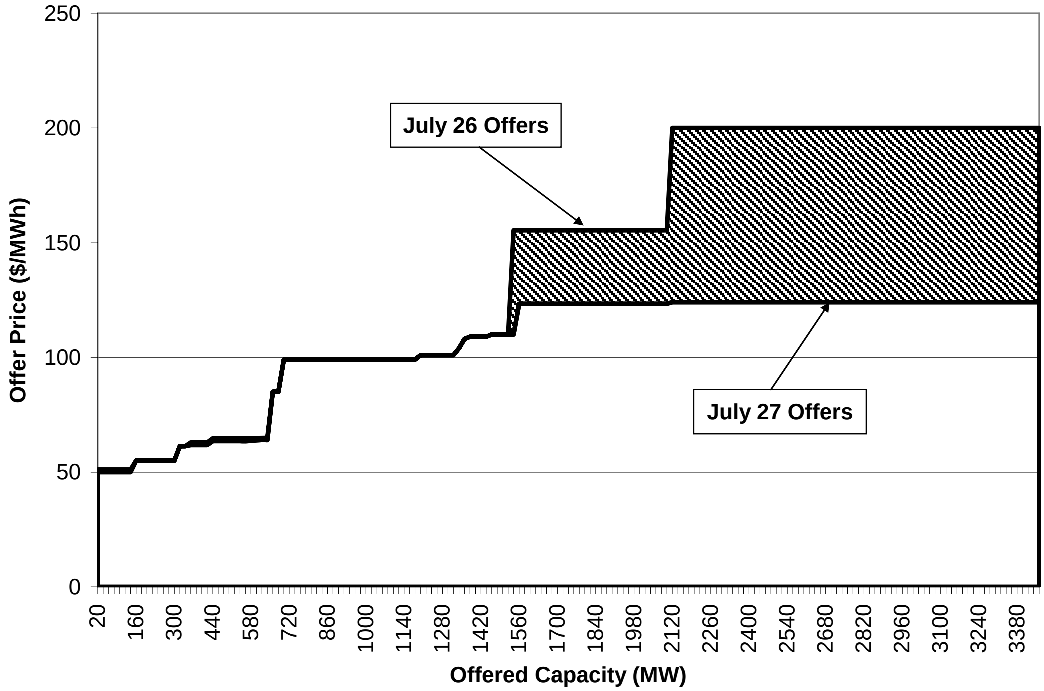


Figure 6.15 Energy offers from company 423710 for two consecutive days in July, 2005

There is no public information available regarding the reasons for these bids or the observed differences between these two days. We present it merely as an example of a single company having a dramatic effect on the bid curve and probably on market clearing prices based on a seemingly arbitrary change in bidding behavior.

Without more information about the locations of the resources, as well as the loads and congestion during these days, we cannot establish whether these examples represent the exercise of market power, nor can we determine the actual impacts on locational market prices in New England. However, there is little doubt that prices could be affected by changes in the bid curve of this nature, and thus the potential for market power appears to be both present and significant.

SECTION IV – IMPACTS ON CONSUMERS

7. Overall Impact of LMP

What overall conclusions can be drawn from the development and operations of LMP-based electricity market structures in the northeastern United States? We have presented a summary of our findings on operational efficiency, price signaling, and competitiveness in electricity markets at the beginning of this report. It is also useful to consider briefly the overall impact of LMP-based electricity markets on consumers.

The promise attached to the development of LMP-based electricity markets and the concomitant deregulation of the generation and retail sectors was to provide greater reliability to consumers at a lower overall cost. This promise appeared to be realized during the first few years of the deregulated LMP-based markets, as low natural gas prices and a rash of new generation investment produced surplus generating capacity and generally low spot prices for wholesale power. In addition, retail price caps during "transition" periods for retail deregulation ensured that consumers could not be impacted by price increases in the wholesale market once these favorable conditions began to erode. As these transition periods end and gas prices remain high, what is in store for electricity consumers? The outlook is not as promising as it was 10 years ago:

- Recent increases in the price of natural gas have led to substantial and sustained increases in the offer prices from gas-fired generators, who base their offers on the current marginal opportunity cost of natural gas even if they are purchasing gas at lower prices secured through long-term contracts;
- The overinvestment in gas generation in PJM and New England means that gas is the marginal fuel (at least in the eastern part of the region) much of the time, leading to a high correlation between natural gas and electricity prices. Recent volatility in gas prices has led to parallel volatility in power prices;
- Profit margins for low-marginal cost units, such as base load coal, nuclear, and hydropower, have soared as these resources have benefited from the combined impact of price deregulation, increasing gas prices, and LMP without incurring concurrent increases in costs. As long-term contracts on many base load and nuclear assets expire over the coming decade, these profits will increase substantially;
- While bilateral markets have traditionally been less prone to market manipulation than real-time markets, the rise to prominence of the standard offer auction

creates a situation in which large blocks of power will *have* to be purchased in advance in order to participate in such auctions. This will open a new opportunity for both price manipulation and undue influence over the auction outcomes for wholesale suppliers.

- Proposed marginal capacity pricing under PJM's Reliability Pricing Model (RPM) and ISO-NE's Forward Capacity Market (FCM) will lead to further increases in electricity prices for consumers, which may or may not be accompanied by increases in system reliability.

These concerns stem in large part from the presence of a spot market that clears based on marginal offer prices, coupled with purchasing trends that emphasize short term procurement. Shorter-term purchase prices reflect spot market price expectations rather than long-term average costs of generation; thus consumers have little protection from the effects of price deregulation and marginal offer pricing.

The presence of locational marginal pricing serves to highlight the short-term differences in resource value due to transmission constraints. LMP is not to blame for the retail pricing outcomes seen in many RTO states, but it also does not hold any promise to alleviate likely impacts on consumers. It achieves its original (pre-deregulation) goal of improved efficiency of power system operations in the short-term operational time frames by explicitly addressing the effects associated with power transmission over the interconnected grid. However, the subtle price signals associated with LMP are often overwhelmed by other factors in the marketplace, such as fuel price fluctuations, regulatory uncertainty, operational and siting issues, and – perhaps most important – market power. While the LMP construct is a useful tool to handle the complexities of transmission and generation operation on a shared system, it cannot be a panacea for policymakers concerned with achieving balanced infrastructure development and just and reasonable rates for consumers.

GLOSSARY

Available Economic Capacity (AEC) — Generating capacity that is both economically competitive (can deliver power for less than 105% of the market price) and uncommitted to serving other load, which can serve a specified electricity market. FERC uses AEC from each competing supplier as one approach to measuring HHI, or market concentration. See also *economic capacity*.

Base Load Capacity — Any generating capacity that is used for a high proportion of hours to meet load under a wide range of conditions. Base load facilities generally have high fixed costs and low variable costs.

Bid-Based Market — A market where suppliers offer a service or product at any price that the supplier chooses. Offer prices are not necessarily based upon costs and may fluctuate throughout the day. In electricity markets, offers from suppliers are generally accepted in order of increasing prices, with the lowest price accepted first, until the demand is met for the product or service.

Bid Curve — A curve representing the change in energy price in $/MWh as load increases for a given market.

Binding Transmission Constraint — See *Transmission Constraint.*

Bus — Any physical electrical interface where devices share an electric connection, allowing power to be transferred between devices.

Capacity — See *Generating Capacity.*

Clearing Price (or Market Clearing Price) — The final transaction price that all buyers pay and all sellers receive for transacting during a specific market interval.

Construction Queue (or Generation Queue) — The list of those fixed facilities for generation, transmission or distribution services which are under construction or not yet in service, generally ordered by application date. Only a fraction of the facilities in a construction queue are likely ultimately to enter into service.

Day-Ahead Market — An hourly forward market in which market participants may submit offers to sell and bids to buy electric energy for the next day.

Demand (or Load) — The total or regional requirement for electricity at a given point in time.

Demand Response Resources — The reduction of load via changes in normal electric consumption patterns by end-use customers in response to changes in electricity prices or via incentive payments. Demand response resources are designed to lower overall electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Delivered Price Test — A structural market power screen used by the FERC in reviewing merger applications, to determine if the affected markets are or will become overly concentrated as a result of the merger.

Dispatch — The process of coordinating the production and distribution of energy by directing the operation of generating facilities on a moment-to-moment basis to meet changing load requirements.

Economic Capacity (EC) — Generating capacity that is economically competitive (can deliver power for less than 105% of the market price) to serve a specified electricity market. FERC uses EC from each competing supplier as one approach to measuring HHI, or market concentration. See also *available economic capacity*.

Economic Withholding — Effective removal of generating resources from a market by offering them at a high enough price that they are unlikely to be accepted. The purpose of economic withholding in electricity markets is to increase the market price for power and earn sufficient additional revenues on other resources to more than offset forgone profits on the withheld resource.

Federal Energy Regulatory Commission (FERC) —A commission of the U.S. Government that regulates, among other matters, wholesale electricity markets and the transmission of electricity across state borders. Decisions are made by five commissioners who are appointed by the president and serve five-year terms.

Financial Transmission Rights (FTRs) —Financial instruments that provide their holders with a right or obligation to receive or pay a share of the congestion charges collected by the RTO. Financial transmission rights (FTRs) often are called by other names in different RTOs, such as “auction revenue rights,” “contracts for differences,” or “transmission congestion contracts.”

Firm Transmission Rights — The physical right to preferential use of a transmission resource. Firm transmission rights have generally been replaced with financial rights (FTRs) in LMP-based electricity markets.

Fixed Costs — Those costs incurred by generating resources independent of level of energy output. Fixed costs include certain operation and maintenance costs, capital costs, property taxes, and personnel costs.

FTR Obligation — FTRs structured such that the holder must pay the ISO any negative price difference between the source and sink locations represented by the FTR.

FTR Option — FTRs structured such that the holder is not required to pay the ISO any negative price difference between the source and sink locations represented by the FTR.

Generating Capacity — The physical capability to generate or otherwise provide electric energy. Capacity may refer to one or more electric generating units, or to a purchase contract tied to generating units that can provide energy when needed.

Generation — Conversion of a fuel or other source of energy into electric energy for delivery to customers. Generating technologies used in the United States include coal, nuclear energy, hydro power, natural gas, fuel oil, and renewable energy sources such as solar, wind, landfill methane gas, and geothermal power from underground formations.

Generator (also Generating Unit, Electric Generating Unit) — A producer of electrical energy, referring either to a facility that produces energy or to the party that operates such a facility. A “generating unit” or “electric generating unit” refers to any device that transforms another type of energy into electricity.

Generator Bus — Physical location on an electricity grid at which a generating facility injects power into the grid.

Gross Congestion Cost — The difference between the total cost to purchase electricity in the presence of congestion at LMP, versus what the total cost would have been had there been no congestion, such that the whole system could have been dispatched in merit order. Gross congestion cost represents the total increase in purchase cost due to congestion, not counting any hedges such as FTRs or self-supply of generation.

Herfindahl-Herschmann Index (HHI) — A commonly accepted measure of market concentration. HHI is calculated by squaring the market share (in percent) of each firm competing in a market, and then summing the resulting numbers. The HHI number can range from close to zero to 10,000, with greater competition falling lower on this scale and monopolies falling high on this scale.

Independent Power Producers (IPPs) — Companies that have built or purchased generating plants in order to sell electricity in wholesale markets, but which are not affiliated with investor-owned utilities.

Independent System Operator (ISO) —An entity that operates, but does not own, the transmission lines within a region and dispatches generating units to meet load.

Inelastic Demand — Demand for electric energy which does not increase or decrease in response to the price of electricity.

Inframarginal Generation — Generation with an offer price that is below the prevailing locational clearing price.

Installed Capacity — The sum of the rated production capacities of all generating units used in a system (including new entrants and omitting retirements).

ISO New England — A FERC-approved regional transmission organization (RTO) operating the energy, ancillary services, forward capacity, and FTR markets in New England; and centrally coordinating the New England transmission system.

Lerner Index — Named after the economist Abba Lerner, this index measures the impact of market power on market prices. The Lerner Index is calculated as the difference between the price and marginal cost, divided by the price.

Load — See *Demand.*

Load Bus — Physical location on an electricity transmission grid at which a load-serving entity withdraws power for use on the local distribution system.

Load Pocket — A transmission-constrained area in which electricity prices are often elevated relative to the surrounding area as a result of unavailability of sufficient transmission capacity to deliver lower cost energy into the area.

Load-Serving Entity (LSE) —A utility that has a responsibility to provide electricity to retail customers and that purchases or generates electricity to satisfy that responsibility.

Locational Marginal Pricing (LMP) —A method of pricing electricity and other services purchased from an RTO spot market based on the location of the generation and consumption. Under LMP, the electricity price in each location reflects the short-run marginal cost (based on generator offers) of delivering power to that location.

Lumpiness — With regard to electricity market investments, lumpiness describes the tendency for capacity or transmission investments to result in large jumps in capacity over time, rather than continuous increases in response to increases in load.

Marginal Unit — The specific unit which sets the clearing price of electricity at a point in time. At any time there may be one or more marginal units in any electricity market.

Market Monitoring Unit — The authority responsible for monitoring bidding behavior in RTO-administered electricity markets and maintaining competitive market conditions.

Market Power — The ability of an energy supplier or a set of suppliers, colluding implicitly or explicitly, to profitably raise market prices over a sustained period of time through physical or economic withholding of resources.

Maximum Import Capability — The maximum number of megawatts that can be brought into a load pocket across transmission lines from outside of that region.

Midwest Independent Transmission System Operator (MISO) — The first regional transmission operator in North America. MISO's authority covers parts of the transmission grid in the Midwest United States and one province of Canada. MISO also operates the wholesale power market in the Midwest.

Native Load — The retail load served by a vertically-integrated utility in its historically chartered service area.

New Entry — Any recently built or proposed generating unit.

Out-of-Market Dispatch — Describes when generating units are selected out of least-cost-first order for reliability or other operational reasons.

Peaking Capacity (or Peaker) — Any generating capacity intended to be used infrequently, primarily to meet peak load. Peaking facilities generally have low fixed costs and high variable costs.

Peak Load (or Peak Demand) — Denotes the maximum power requirement of a system at a given time, or the amount of power required to supply customers at times when need is greatest. Refers to either the load at a given moment (e.g. a specific time of day) or to averaged load over a given period of time (e.g. a specific day or hour of the day).

Physical Withholding — Removal of generating resources from an electricity market. The purpose of physical withholding in electricity markets is to increase the market price for power and earn sufficient additional revenues on other resources to more than offset forgone profits on the withheld resource.

Pivotal Supplier — One or more owner(s) of generating capacity whose capacity *must* be accepted by the ISO to meet system load. A pivotal supplier or group of pivotal suppliers has the ability, acting alone or in concert, to set market clearing prices.

Price Signal — A message sent to producers and/or consumers in the form of a price paid or charged for a commodity; usually indicates a message intended to produce a particular result. As an example, increasing prices during periods of shortage is a price signal to producers to provide additional resources and to customers to cut back on energy consumption during these periods.

Product Market — A defined subset of electricity sales, based on geography, price, or operational characteristics, in which a subset of available producers can compete.

Real-Time Market — An energy market in which prices for energy are determined based on actual operating conditions and costs (rather than projected conditions and costs). The amounts of energy that a market participant is deemed to purchase (sell) in the real-time market are based on the differences in each hour between its schedule of energy commitments as cleared in the day-ahead market and the energy actually used (produced) to meet the market participant's requirements.

Regional Transmission Organization (RTO) —A transmission operator that meets certain criteria and performs functions specified by the Federal Energy Regulatory Commission. RTO functions include congestion management, market power monitoring, and planning, and coordination of transmission upgrades.

Reliability Pricing Model (RPM) — The locational capacity market model proposed for the PJM region to signal the need for investment in new power supplies, transmission investments or demand response in the PJM market. Capacity prices vary by location under RPM to signal where new generation, transmission, and demand response are needed relative to load locations and transmission constraints.

Shadow Price On Constraint — Prices which reflect the marginal costs associated with each binding transmission constraint--specifically, how much money it would be worth to relax the constraint by one megawatt of electricity flow.

Short-Run Marginal Cost (SRMC) — The cost incurred for an incremental unit of output, either from an individual generating resource or on the system as a whole. This cost includes costs such as fuel, emissions costs, and avoidable labor and materials costs and does not include costs associated with capital equipment or overhead of the producer.

State Estimator — A data estimation tool used by the RTO to determine or describe detailed power system conditions from moment to moment as the basis for system operations. State estimator variables include instantaneous voltage levels, power flows, generation levels and load levels.

Tariff — A written document, approved by the Federal Energy Regulatory Commission or a state commission, which lists the terms, conditions and prices for provision of generation, transmission and distribution service.

Transmission — Bulk, high-voltage power lines over which electricity travels between sources of generation and load regions.

Transmission Congestion — A condition in which insufficient transmission capacity is available to implement all of the most economical transactions simultaneously.

Transmission Constraint — A physical or operational limit to the total electricity flow that can be carried from one region of the grid to another. Transmission constraints are said to be *binding* if this limit is reached. Any transmission system has a large number of transmission constraints, of which zero, one or many can be binding at any point in time.

Unhedgeable Congestion Cost — Gross congestion costs less any available hedges for load, such as FTRs or self-supply of generation. Unhedgeable congestion cost is the total increase in production cost that results from the presence of transmission congestion.

Variable Costs — See *Short-Run Marginal Cost.*

Wholesale Electricity Market — The market through which electricity is sold to utilities that in turn sell the electricity to the final consumer, known as the “end user”.

REFERENCES

Commonwealth of Massachusetts, *An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein*, 1997.

Cromton, P. and S. Stoft, "A Capacity Market that Makes Sense", *Electricity Journal,* 18, 43-54, August/September 2005.

Federal Energy Regulatory Commission, *Order On Rehearing, Clarification, And Compliance Filings, Establishing Further Hearing Procedures, And Consolidating Proceedings,* Docket EL03-236, July 5, 2005.

Federal Energy Regulatory Commission, *Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control over Jurisdictional Facilities, and Denying Rehearings,* Consolidated dockets under OA97-261, issued November 25, 1997.

Goldman, Charles, 2004. "Demand Response Programs: Lessons from the Northeast" a presentation to Mid Atlantic Demand Response Initiative on December 10, 2004.

Hausman, E., P. Peterson, D. White and B. Biewald, "RPM 2006: Windfall Profits for Existing Base Load Units in PJM—An Update of Two Case Studies", Prepared for Pennsylvania Office of Consumer Advocate, February 2006. Available at *www.synapse-energy.com*.

Hogan, William W., "Market-based Transmission Investments and Competitive Electricity Markets", August 1999.

Hogan, William W., "Contract Networks for Electric Power Transmission: Technical Reference", Revised as of February 1992.

Hogan, William W., "Transmission Market Design", Prepared for the conference *Electricity Deregulation: Where to From Here?* At the Bush Presidential Conference Center, Texas A&M University, April 2003.

ISO New England, *ISO New England State of the Market Report 2005*, 2005.

ISO New England, *2005 Annual Markets Report*, 2005.

Lawrence Berkeley National Laboratory, "Customer Load Participation in Wholesale Markets: Summer 2001 Results, Lessons Learned and Best Practices." 2002.

Market Monitoring Unit, PJM Interconnection, LLC. *2005 State of the Market Report*. March 2005.

MISO State of the Market Report, 2005.

Neenan Associates, Lawrence Berkeley National Laboratory, and Pacific Northwest National Laboratory, "How and Why Customers Response to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance", 2003.

PJM Interconnection, LLC., "Answer of PJM Interconnection, L.L.C.", filed in FERC Docket ER06-1474, October 2006.

Schweppe, F., M. Caramanis, R. Tabors and R. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishers, 1987.

Shanker, Roy J., Affidavit submitted under FERC Docket ER06-1474 on behalf of the PSEG Companies, September 2006.

Stoft, Steven, *Power System Economics: Designing Markets for Electricity*, IEEE Press, Wiley-Interscience, 2002.

Supporting Companies in FERC Dockets no. ER96-2516-000, EC96-28-000, and EL96-69-000, "Answer of the Supporting Companies", September 3, 1996.

Supporting Companies in FERC Dockets no.ER97-1082 and OA97-261, "Brief of Supporting Companies re compliance of PA-NJ-MD Interconnection w/Order 888 under OA97-261 et al.", December 31, 1996.

U.S. Department of Energy, *National Electric Transmission Congestion Study*, August 2006.

U.S. Department of Energy, Office of Economic, Electricity and Natural Gas Analysis, Office of Policy, "Horizontal Market Power in Restructured Electricity Markets", March 2000.

U.S. Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines, Revised April 8, 1997, Section 1.51 General Standards.

Weiss, Leonard W., ed., *Concentration and Price*, The MIT Press, Cambridge, Massachusetts, 1989.