GETTING THE PRICES RIGHT IN PJM:
Analysis and Summary: April through September[1]

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The connection between prices and operating decisions often receives cursory treatment in the electricity restructuring process. Market participants want flexibility and choice, but object to consistent pricing as too complex. This is a mistake, and produces only an illusion of simplicity. If customers have flexibility in the choice of generation, spot purchases, bilateral transactions, and so on--then prices matter and competitive prices should reflect marginal costs. In large part, control of operating decisions is moving from engineers motivated by principles of technical efficiency, to market participants motivated by prices and profits. This is a major purpose of electricity restructuring--to change the locus of such key decisions. If we want the market to be guided by prices, and we expect and intend for people to take these prices seriously, it becomes important to follow the usual advice to "get the prices right." The experience in the first months with a consistent market pricing system in PJM underscores the point and provides empirical heat to help dispel the fog of confusion covering one of the central problems in electricity markets: pricing to allocate use of scarce transmission capacity.

INTRODUCTION

In the United States, the move to a competitive electricity market with a consistent pricing system for allocating scarce transmission capacity entered a new phase beginning in April 1998 with the introduction of spot market locational pricing in the Pennsylvania-New Jersey-Maryland Interconnection (PJM). The new system includes a spot market coordinated by the Independent System Operator (ISO). The ISO accepts both bilateral schedules and voluntary bids of the market participants. Using these schedules and bids, the ISO finds an economic, security-constrained dispatch for power flows and the associated locational marginal cost prices. Even without transmission constraints, this coordinated and transparent spot market provides significant benefits. When the transmission system is constrained, the spot prices can differ substantially across locations. Sales through the spot market are at the locational prices. The transmission usage charge for bilateral transactions is the difference in the locational prices between origin and destination. An accompanying system of Fixed Transmission Rights (FTR) provides financial

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[1] This note provides an update of an analysis with the same title for previous months beginning in April 1998. See also the Electricity Journal, September 1998.

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hedges between locations. These FTRs are the equivalent of perfectly tradeable firm transmission rights.[3]

IN MARKETS WITH CHOICES, PRICES MATTER

The new PJM locational pricing system was embraced after an experiment during 1997 with an alternative zonal pricing approach that proved to be fundamentally inconsistent with a competitive market and user flexibility.[4] The experiment made the point in a dramatic way.[5] The important issue is not the total cost of transmission congestion, which may be small on average if the system is used efficiently, and when the cost is often mistakenly dismissed as irrelevant. Rather, the point is the incentives at the margin when the system is constrained. In designing the rules for transmission access and pricing for a competitive market, it matters little how the rules perform when the system is unconstrained. The important question is how the rules deal with the market and participant choices when the system is constrained. The earlier zonal pricing system allowed market participants the flexibility to choose between bilateral transactions and spot purchases, but did not simultaneously present them with the costs of their choices. The circumstances created a false and artificial impression that savings of $10 per MWh or more could be achieved simply by converting a spot transaction into a bilateral schedule. Faced with this perverse pricing incentive, market participants responded naturally by scheduling more bilateral transactions than the transmission system could accommodate. In effect, using the wrong prices induced behavior which greatly increased the cost of congestion. Inevitably, in June 1997 the ISO had to intervene by restricting the market and constraining choice to preserve reliability. The PJM ISO was fully aware of the perverse incentives of zonal congestion pricing and the problems they created. But without the authority to change the pricing rules, the ISO had no alternative but to restrict the market.

Even if the total cost of congestion might be modest over a year, a gap of $10 per MWh between the true costs of transmission usage and what participants pay is more than sufficient to get the attention of market participants at the time when it matters most, when the system is constrained. Given the margins in this business, market participants will change their behavior for $1. And the changes in behavior can substantially affect system operations; in fact, the whole point of electricity restructuring is that changes in behavior can affect system operations and lead to different patterns of electricity use and investment.

By contrast, the locational pricing system avoids this perverse incentive. By construction, the locational prices equal system marginal costs. Every generator would be

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[3] An FTR is the same as a transmission congestion contract (TCC). For further details, see William W. Hogan, "Independent System Operator: Pricing and Flexibility in a Competitive Electricity Market," Center for Business and Government, Harvard University, February 1998, available on the author's web site.

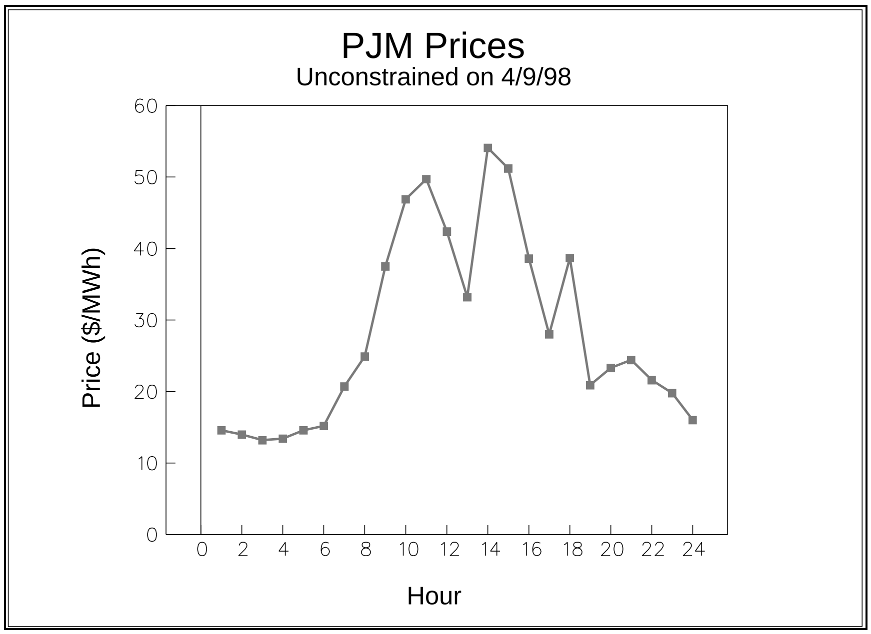
[4] Here the issue is pricing for transmission congestion. The recovery of embedded costs of transmission investment through access charges is a separate matter that is amenable to a zonal approach.

[5] For details, see William W. Hogan, "FERC Policy on Independent System Operators: Supplemental Comments," Federal Energy Regulatory Commission, Docket No. PL98-5-000, Washington DC, May 1, 1998.

producing at its short-run profit maximizing output, given the prices. The market equilibrium would support the necessary dispatch in the presence of the transmission constraints. Spot-market transactions and bilateral schedules would be compatible. Flexibility would be allowed and reliability maintained consistent with the choices of the market participants.

Faced with this reality, the Federal Energy Regulatory Commission acted to approve the locational pricing system that became operational in PJM at the beginning of April of 1998. The developing experience with this full locational pricing of the use of scarce transmission capacity deserves close study by the Commission and all system operators.

TRANSMISSION CONGESTION AND LOCATIONAL PRICES



To put the problem in context, note that market clearing prices can vary substantially, even without transmission constraints.[6] The accompanying figure shows the prices in PJM over the day of April 9, 1998. This was not the most volatile day, and there were no transmission constraints during the day. However, the market clearing price varied from a low of $13 MWh to a high of $54. During June, the variation in unconstrained prices on the most expensive day increased by almost an order of magnitude to a high of $300, on June 26, 1998. As the summer continued, higher prices appeared even without internal transmission constraints in PJM. For example, on August 24 at 1400 and 1500 hours, the price reached the regulated maximum of $999. Clearly market participants must deal with substantial changes in prices, even without transmission congestion.[7]

Although these are the early days, the new locational pricing mechanism is working as anticipated by the ISO and the supporters of the approach, but apparently not as anticipated

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[6] The data used here were taken from the PJM web site at www.pjm.com.

[7] Prices outside of PJM reached even higher levels, reportedly as high as $7,000 per MWh in the Midwest; Wall Street Journal, June 29, 1998, p. C1. The apparent market disequilibrium between PJM and the Midwest is an important issue, but that is another story. The emphasis here is on the price implications for allocation of scarce transmission capacity within PJM.

by many who dismissed the importance of this issue. April and May are not typically highly constrained periods in PJM, and it would not have been impossible for the first days of locational pricing to have been boring. With no constraints, the locational prices, ignoring losses, would be identical at all locations. The cost of transmission between points--the difference in the locational prices--would have been zero. Nothing much might have happened until we approached the summer, when congestion would be more likely, as for the previous year in June.

In the event, the results were not boring. The system experienced transmission constraints, locational prices separated, and the opportunity cost of transmission was quite large. The lowest locational prices were sometimes negative, reflecting the value of counterflow in the system where it would be cheaper to pay participants to take power at some locations and so relieve transmission constraints. The highest locational prices were very large, much larger than the marginal cost of the most expensive plant, reflecting the need to simultaneously increase output from expensive plants and decrease output from cheap plants, just to meet an increment of load at a constrained location. Over all hours in April 1998, for example, the low price was -$45 at 1500 hours on April 18 at "JACK PS," and the highest price was $232 at 1100 hours on April 16 at "SADDLEBR," both locations being in the Public Service territory. Over the first six months with the locational pricing system, the maximum difference between the lowest and highest contemporaneous prices was $399, at 2000 hours on August 26, reflecting the difference between $437 at "ESAYRE" and $38 at "NYPP-W." This reached the same level as in the relatively unconstrained month of March before the prices were charged, when users could ignore the cost of congestion.[8]

The contemporaneous difference in locational prices, which is the price of transmission usage, has been large quite often. If we take the $1 per MWh standard as an arbitrary threshold, the range of highest to lowest price across locations exceeded the threshold for 119 hours in April, or approximately 17% of the time. As shown in the accompanying figure, the frequency distribution of the price range in constrained hours is skewed, with a median hourly price range at $33 and a mean of $49 in April. When the system is constrained and the market incentives matter the most, the marginal costs of transmission can be large indeed.

The data for May through September reinforce this initial impression. In general, May saw both higher prices and more transmission congestion. The difference between the highest and lowest locational price in May exceeded the $1 threshold for 183 hours, or approximately 25% of the time. As shown in the accompanying figure, the frequency distribution of this congestion price shifted to higher costs. In May, the median of the hourly price ranges doubled to $66 and the mean increased to $75. June was less constrained, exceeding the $1 threshold for 95 hours or 13% of the time. The June median of the hourly price ranges was $57 and the mean was $64. During July, constraints appeared more often, as in May, with 151 constrained hours or about 20% of the time. July saw a median hourly price range of $39 and a mean of $46. By contrast, August showed locational constraints only for 48 hours or 7% of the time. The median

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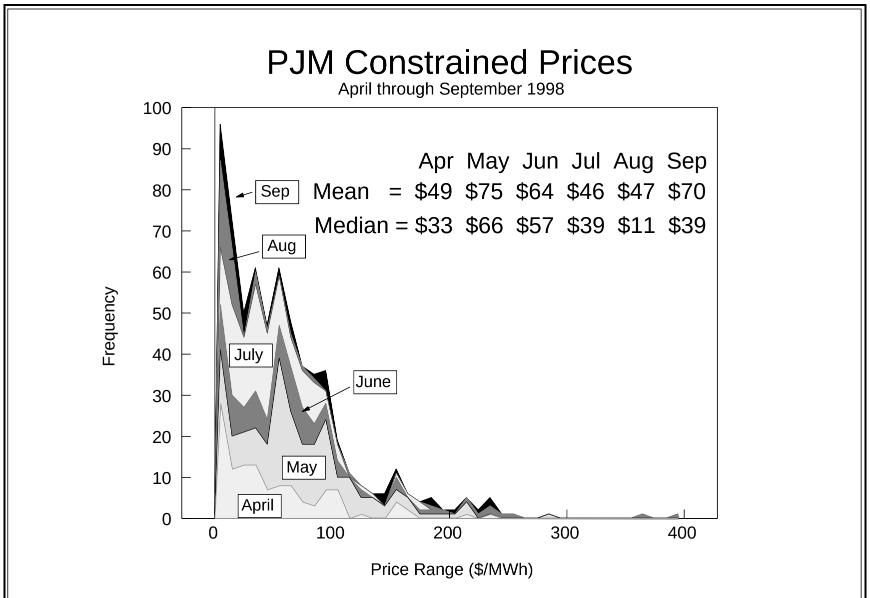
[8] On March 26, 1998, at 2200 hours, the difference between the highest to the lowest marginal cost was almost $400.



Maximum difference in locational prices for constrained hours.

hourly price range in August was $11 and the mean was $47, reflecting a few hours when the difference between the lowest to the highest price reached almost $400. September was like August, with 46 constrained hours or 6% of the time. However, the average price of congestion was high in September, with a mean of $70 and a median of $39.

The experience of higher unconstrained prices and fewer constrained hours in June August and September reminds us that the period of peak system load is not necessarily the time of greatest transmission congestion. Transmission congestion reflects an imbalance in the location of load and generation. At peak load, more generation comes on line and may relieve system congestion. In addition, the particular flow of power into the Midwest, reversing the usual direction, tended to unload the transmission constraints.

The evidence shows many things. For example, calculating and reporting the locational prices for each point on the grid are not especially complex tasks, at least for the system operator who has the necessary information available. The prices can be available every five minutes on the Internet. Faced with these prices, the market participants adjust their behavior, just as intended. The transition was not painless, especially for those who ignored many warnings and entered into "seller's choice" contracts that gave the seller the maximum theoretical financial advantage for relieving congestion. Presumably, this form of contract will disappear, or be properly priced in the future, and market participants will become more attuned to the use of fixed transmission rights to hedge much of the cost of congestion. But market participants who rely on the spot market, and are not prepared to pay for congestion hedges, will see price signals that align their incentives with the reality of system operations.

The full market response to all these changes is not known because the data are not all in the public domain. However, one information source is a sampling of trader activity reported in the Wall Street Journal.[9] According to these data, the immediate response of the market was to reduce reported spot trading in April. However, by mid May reported transactions

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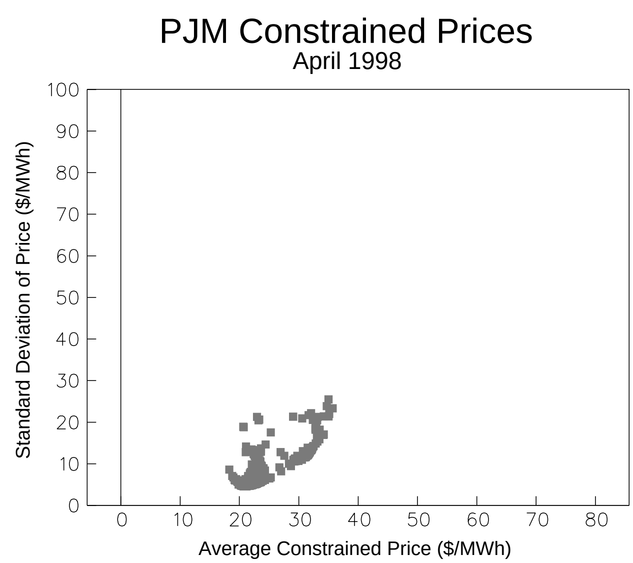
[9] For example, see "DJ Electricity Price Indexes," Wall Street Journal, June 3, 1998, p. C19.

had returned to volumes comparable to those seen just before the new locational pricing system went into effect. Hence, at least from this one source, the market appears to have adjusted to the new environment within a framework that supports transactions with consistent prices.

FULL LOCATIONAL PRICING IS THE TRULY SIMPLE APPROACH

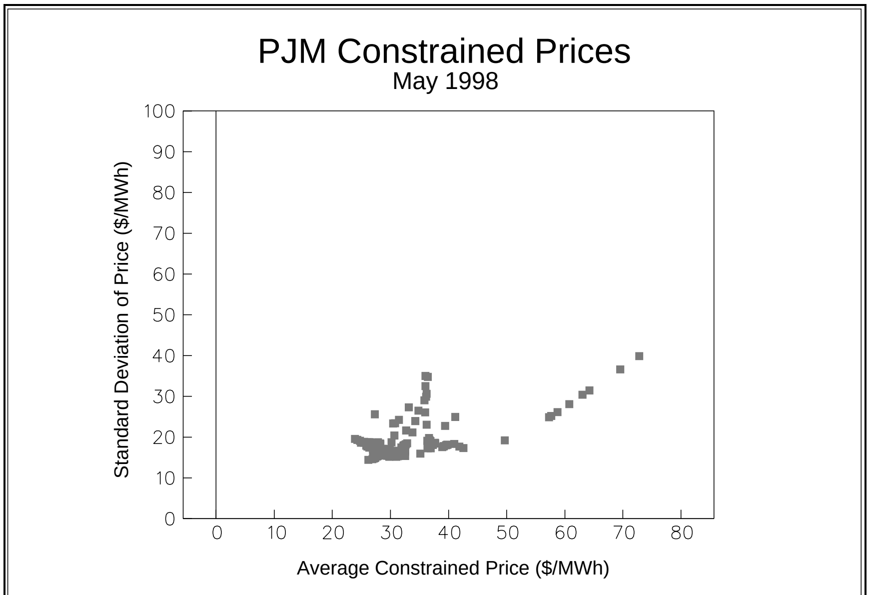
What about aggregating PJM into a few zones, if not just one? The PJM ISO is reporting prices for approximately 2000 locations. This is a convenient way to represent the information, because it is how the data are organized for actual system operations. However, some of these locations are really just multiple units at the same point on the grid, and would necessarily have the same prices in most circumstances. For other points on the grid, the zonal argument is that the locational differences would be minor, and could be represented by a relatively few zones. This view has been subjected to a test over the first months of operation.



Mean and standard deviation over 119 constrained hours at different locations.

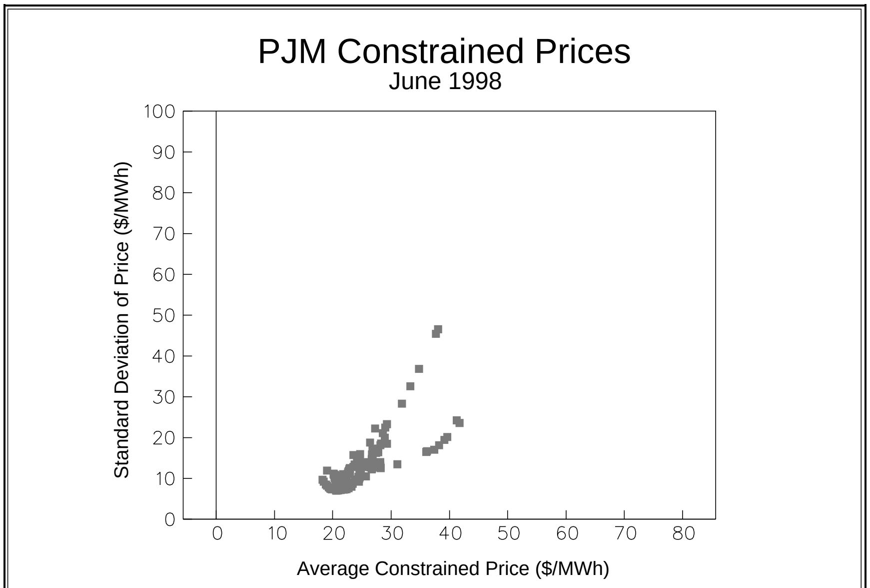
The period April through at least early June could have been relatively unconstrained, presenting a low hurdle for the zonal approach. The choice of the appropriate zones would not be an easy matter, and there is some ambiguity in clustering criteria. However, one simple way to summarize the data would be to examine both the average and the variation of prices at different locations during constrained hours. If two locations always have the same prices, then the two average prices would be the same and the two standard deviations of the prices would be the same. These conditions would be necessary, but not sufficient, for the prices to be the same at the two locations. Hence, this straightforward calculation gives a lower bound on the number of different locations with sometimes unique prices.

The accompanying figure for April plots the data on average price and standard deviation of price across 119 constrained hours in April for all the locations reported by the PJM ISO. There are 2000 points in the graph, one for each location. Were it true that there were only a few zones, the graph would show a few clusters of locations where the average prices were the same and the standard deviations were the same. In fact, there is substantial dispersion.[10] After the first month of operation, there were 766 locations within PJM where the price points did not overlap and were different by this lower bound test. The corresponding data for May show a similar dispersion and higher costs of congestion. The accompanying figure plots the locational means and standard deviations for May, for which there were 789 different locations by this lower bound test. There were not as many limiting constraints, but even one constraint can produce a substantial range of prices.



Mean and standard deviation over 183 constrained hours at different locations.

In June there was a similar dispersion of prices. As shown in the corresponding figure for June, there were 689 locations with unique prices according to the lower bound test of having different averages or different standard deviations. The data for July in the subsequent figure show more congested hours and more locations, with a total of 785 different points much like in May. By contrast, August revealed relatively fewer congested hours. Nonetheless, even in August the data indicate 693 different locations. September showed greater price dispersion with 825 different locations appearing in the price data.



Mean and standard deviation over 95 constrained hours at different locations.

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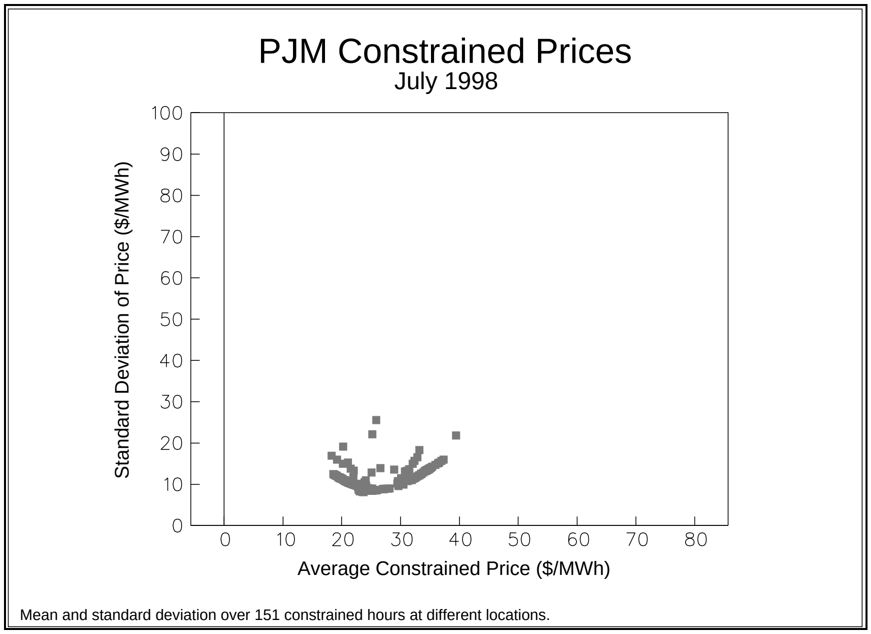
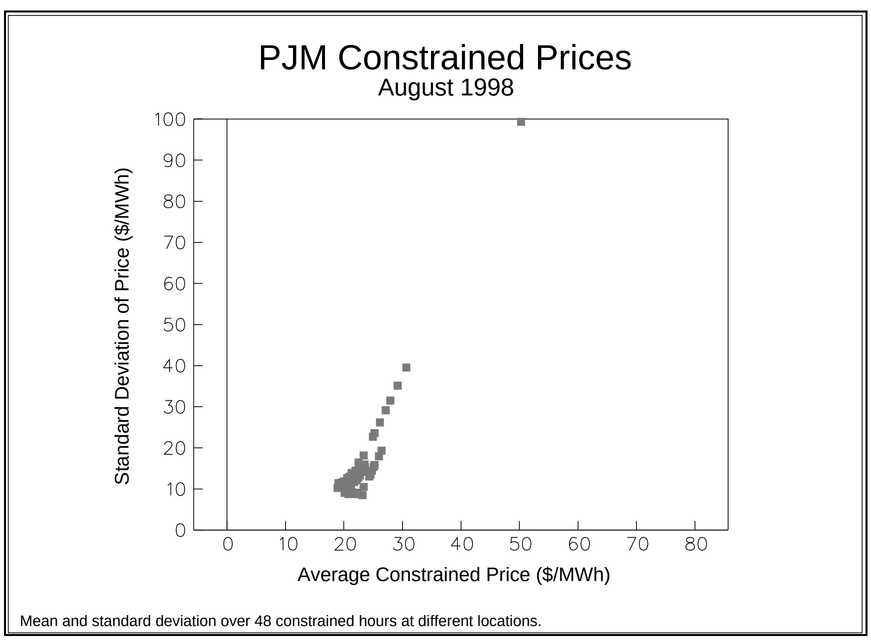
[10] The large scale in the graphic allows for consistent comparison with later months, when the price dispersion is even greater.



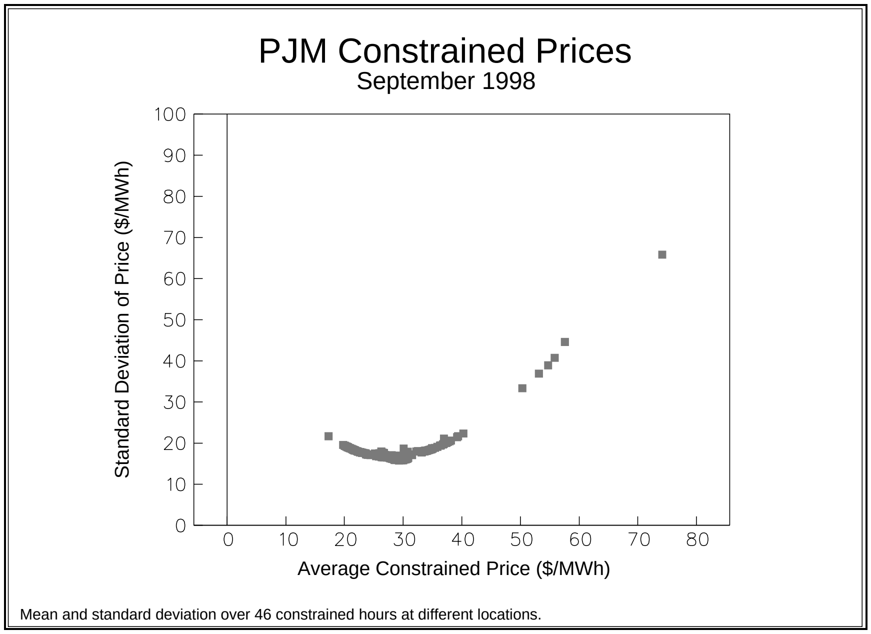
Mean and standard deviation over 151 constrained hours at different locations.

Furthermore, the differences were not the same across the months. The publicly available data for June through September cannot be merged easily with the previous months due to changes in the names and number of locations. However, using pooled data that calculates the averages and standard deviations for each location across both April and May, there were 821 different locations where either the average price or the standard deviation differed from other locations. Presumably as more experience develops and different constraints appear, this number will grow. Recall that in a sufficiently interconnected network, a single thermal limit on a transmission line could create different prices at every location, sometimes very different prices. This is contrary to the intuition that arises from the misleading analogy to a simple radial transmission connection without any network interactions, where a single constraint results in only two prices. But the network interactions and the many different prices are quite real and no surprise to the system operators.



Mean and standard deviation over 48 constrained hours at different locations.

The criterion of no difference in prices may be too strict, and we might be willing to declare two locations as the same if they are close enough. Defining the standard for close enough would be contentious, but it may be moot. If we accept the $1 per MWh threshold above and ask how many separate zones would be necessary to cover all the points in the figures, the answer is 94 zones in April, 83 zones in May, 75 zones in June, 57 zones in July, 52 zones in August, and 64 zones in September.[11]



Again, these are not the same zones in each month. If we pool the months of April and May and apply the consistent threshold of $0.50 per MWh average difference over two months, we find 132 different zones needed to capture the variability in locational prices, so far. This is many more than the few zones predicted, and there is no reason to believe that we are finished adding to the list. Furthermore, as is obvious, the effect of locational pricing for "natural" zones would be to produce the same price for all such locations. Hence, aggregating to zones where prices are almost the same would result in many zones and no apparent simplification with any meaning. We might as well do the simpler thing of using the locational prices at each location. Aggregating across the many real locations to a few zones, by contrast, necessarily means combining like with unlike, thereby recreating in microcosm the perverse incentives of the failed experiment with a single zone, leading to a breakdown of the non-discriminatory market and administrative restrictions on choice.

The interaction between reliability (with its inescapable physical realities) and economics will limit the acceptable ISO access and pricing rules for allocating scarce transmission capacity. It would be desirable to offer market participants flexibility in their own decisions. A great deal of flexibility in combining a range of bilateral schedules and spot transactions would be possible. However, the more varied and flexible the options for the market participants, the more important it will be to get the prices right, meaning consistent with the marginal impacts on the system. The whole point of the turn to greater reliance on competition is that the market participants will respond to incentives. As we have seen, if prices don't provide the right incentives, consistent with the impacts on the system, the participants will respond in their own interests without concern for the system effects, and the ISO will be driven inexorably to intervene in the market and restrict choice. With locational pricing, participant

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[11] Starting with separate zones for the ten service territories and sorting on the average and then the standard deviation. If we do not require the individual service territories to be separate zones, the number of distinct price zones is 60 in April. The corresponding figures for a $5 per MWh threshold would be 28 and 10 zones in April, with and without separating service territories.

incentives are aligned. Buyers and sellers can buy and sell as they choose through the spot market at the locational prices. Or they can schedule bilateral transactions and pay the difference in locational prices as the charge for transmission usage. The result is flexible, non-discriminatory, and compatible with the mandates of reliability.

CONCLUSION

The experience of the first months in PJM illustrates the importance of using, or at least reporting the real locational marginal costs. The network effects can be surprising for virtually everyone other than experienced system operators. Our intuition about these impacts and their market implications is poorly informed and often wrong. Much of the policy argument on this point is misinformed. However, only the ISO would have the information needed to calculate and post real locational prices, as in PJM. The computations are easy for a given dispatch, but only the ISO has all the information about the dispatch. Given the striking gap between the previous claims that congestion is insignificant and the observed reality of true locational pricing in the first real implementation in the United States, the Federal Energy Regulatory Commission should have a strong interest in prescribing that the real locational marginal costs--considering the real network interactions, and not just simplified zonal aggregations--be made available on a regular basis.

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