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March 8, 2006

Mr. Thomas Kennedy
Director, Policy Program
Energy Division
Illinois Commerce Commission
527 East Capitol Street
Springfield, IL 62701

Dear Mr. Kennedy:

We have received copies of the comments made on the draft report "Evaluation of the Potential Impact of Transmission Constraints on the Operation of a Competitive Market in Illinois", dated April 2005. Comments from Ameren Electric, ComEd, Midwest Generation, Peabody Energy, and PJM have been received. Since there is a good deal of commonality in many of the comments, we will address them collectively.

As would be expected in this type of review, we agree with a number of the comments made and disagree with others. We are gratified that a number of the reviewers noted the caveats and qualifications we included in the report by quoting them in their comments. We believe this indicates that we have successfully conveyed our own thoughts about the bounds and limitations of the analysis.

The two most significant and common observations made by all the reviewers can be summarized by the following:

- The report does not reflect the current operating practices of the PJM/ MISO markets, and
- The data and information used in the report have been superseded.

While we concur with these observations for reasons related to the timing and resources allocated to the study, we must disagree with the conclusions drawn by some of the reviewers that the study has no relevance. We strongly agree with the comment from Ameren Electric that, "The most important finding of the study is the rigorous demonstration that the transmission system is a vital part of an energy market" and with the statement by PJM of "…the necessity for RTOs to continue to refine the independence of their transmission system operations, market designs, market rules and oversight of the RTO market by market monitors."
The following are our responses to these two major issues:

Current Operating Practices of the PJM and MISO Markets

At the time the study was initiated (June 2002), through the time of the first draft report (December 2003), and up to the submission of the second draft report (September 2004) neither PJM nor MISO were engaged in operating electricity markets in Illinois. As noted in the PJM comments, Illinois companies did not participate in these markets until April/May 2005. As was agreed to by ICC staff in one of our first meetings (see Working Paper #4 dated July 14, 2002), the structure that was used in the report was a reasonable first step in trying to understand how the electricity market might function. As such, the study's results should be interpreted as reflecting conditions in the absence of any regulatory or market monitoring oversight and without restrictions on generation company bidding practices. The intent was to see if competition alone would be able to control prices. In particular, the emphasis was on whether the transmission system could accommodate competition by allowing the cheapest power to be brought to where it was needed to meet loads.

We believe that the reviewers would concur with this qualification. However, we do not agree with some of the reviewers that this renders the results of no relevance to the current situation. On the contrary, the results clearly indicate that competitive forces alone, in the absence of any regulatory or market monitoring oversight, will not preclude the ability of a company to unilaterally raise prices, which is what we have defined here as "market power." The results demonstrate the importance of an ISO (PJM and MISO in this case) to maintain rigorous oversight of the market's operation. To further illustrate the significance of this, Attachment 1 shows some recent data from the PJM market. One set of information is generator bid data for July 26, 2005 taken from information published on the PJM Web site. These are actual bid data and not model results. The data clearly illustrate that some of the participants in the PJM market are bidding their capacity at well above production costs. The bids include prices approaching 1,000 $/MW. They also show the so-called "hockey stick" bidding of the last increment of capacity at a very high price. From the published PJM data, it is not possible to identify the specific companies in the PJM market that submitted these bids, nor is it possible to determine if the PJM market monitor took any action relative to these bids. Nevertheless, it illustrates that even in a tightly monitored market, such as PJM operates, there are participants that will bid strategically. Neither competitive forces nor market oversight and monitoring deterred this type of market activity. The findings of our study also illustrate this.

The data in the attachment also include the locational marginal prices (LMPs) for the PJM market for the same day, July 26, 2005. The spread of LMPs across the market (by a factor of two in the peak hours) clearly indicates the effects of transmission congestion. Even the ComEd zone, which had among the lowest LMPs in PJM, showed the effects of transmission congestion. Further, some of the PJM buses showed very high LMPs (some in excess of 900 $/MW) which reflects both the GenCo bids and the fact that transmission congestion prevents cheaper power from being brought to these points. Again, this is reflected in the findings of our study.

It should be noted that one of the tasks originally proposed for the study back in November 2001 was the evaluation of alternative market rules. This task would have allowed for the implementation of the PJM and MISO market rules into the model simulation to determine their effectiveness in mitigating the potential for market power. Resources for this phase of the work were not available.

Data and Information

There is no disagreement that the data used in the study have since been overtaken by new developments. As indicated above, the starting point of the work was in 2002 and resource limitations did not permit the dynamic update of the information, as would be done in on-going system analyses carried out by the power companies.

The most significant changes in data would likely be related to transmission capacity additions, generator additions/retirements, fuel prices, and loads.

- In modeling the transmission system, the NERC 2003 Summer Case was utilized. Additional information on planned transmission system upgrades that was provided by the companies was added to this. At that point in time, there was no better source of information available to us.

- With regard to generator additions, units that were permitted by the Illinois EPA and under construction with an on-line date by 2007 were included. We did not include units that were announced but not yet permitted or under construction since history has shown that many such units are not actually built. Again, we used the best data available at the time.

- The fuel prices were based on Energy Information Administration projections for 2007. Clearly the natural gas prices have since risen well beyond the values we used. Since natural-gas-fired units serve as the marginal producers during peak load periods, higher gas prices would likely increase overall electricity prices even beyond what is in the study.

- With regard to loads, it can be noted, for example, that the peak load reported by ComEd in 2005 was 21,635 MW. The study used a 2007 peak load of 24,200 MW for the ComEd area.

Overall, it is not possible to definitively state how the updated information would affect the results. It should be noted that, from the beginning, the intent of this work was not to treat this study as a one-time-only analysis. Rather, the plan was to turn the EMCAS model and the supporting database over to ICC staff, train them in its use, and allow them to update the analysis in-house as any new information became available. An offer was made to have the ICC staff participate in an EMCAS training course in the spring of 2005, but scheduling conflicts did not permit it. The offer for training and model transfer is still open. Our next 2-week intensive, hands-on training course on EMCAS is scheduled for June 5-16, 2006.

In addition to these two major issues, a number of more specific issues were identified in the reviewers' comments. These are addressed in Attachment 2. To avoid repetition, comments related to the PJM/MISO market rules and to the currency of the data not addressed in that Attachment.

We are pleased that this study has resulted in constructive discussions. We are always open to further interaction, exchange of opinions, and further analysis to shed more light on this important issue. We are more than willing to share any of our information with interested parties in an effort to better understand the issues, improve the analyses, and provide decision makers with clear and objective information upon which to base their actions. We look forward to future opportunities to continue this important work.

Sincerely,

Richard R. Cirillo

Richard R. Cirillo
Decision and Information Sciences Division

ATTACHMENT 1
EXAMPLES FROM THE PJM MARKET

The data displayed in this attachment is taken from information published for the month of July 2005 on the PJM Web site. Generation companies (GenCos) and individual generator units are identified only by codes, not by name. They are located in various parts of the PJM system. The published information does not identify the location of each generator unit.

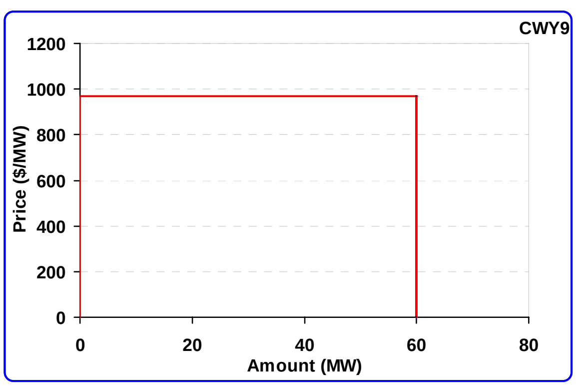
According to PJM bidding procedures, a GenCo may submit bids for either individual generator units or for a portfolio of units. It is not always possible to determine from the published information whether a bid is for an individual unit or a portfolio of units. The term “unit” as used below refers to whatever was in the GenCo’s bid. It is not possible to determine from the published information if a particular bid was accepted or rejected by the market.

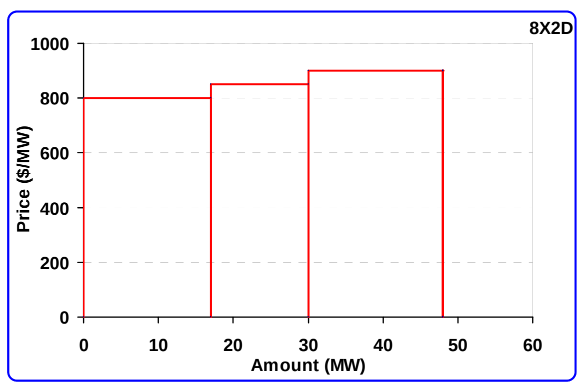
All of the bid data presented here are for the day-ahead energy market. PJM rules require that bids into the day-ahead market be identical for each hour of the day.

All data are for July 26, 2005 on which the peak load in the PJM system reached approximately 134,000 MW.

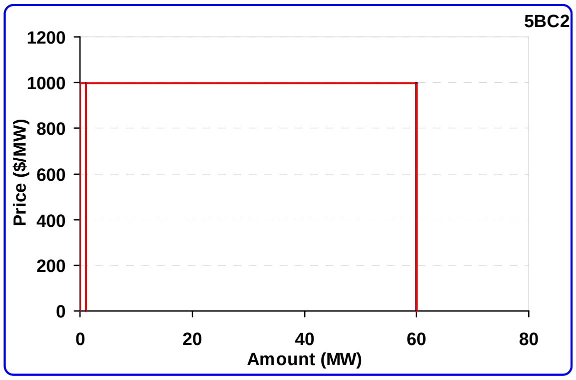
Examples of High Price Bids

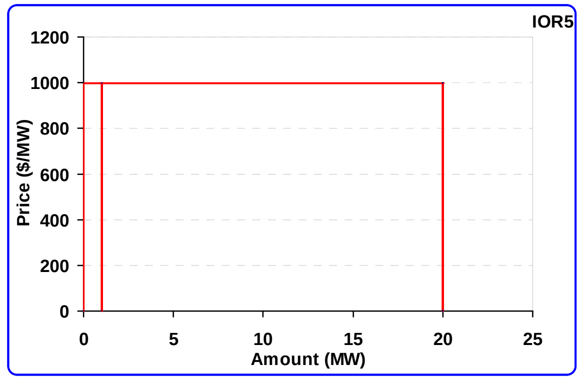
Bidding all of a generator’s capacity at very high prices may make it unlikely to be accepted in the market. This could be interpreted as effectively withholding the unit from the market.

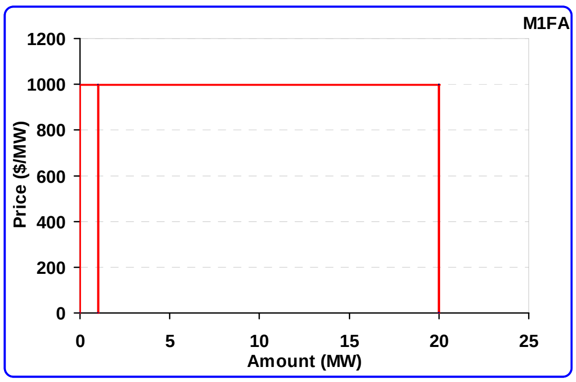




GenCo 9O bid two units (CWY9 and 8X2D) of 60 and 48 MW respectively
at 969 $/MWh and at 800-900 $/MWh respectively



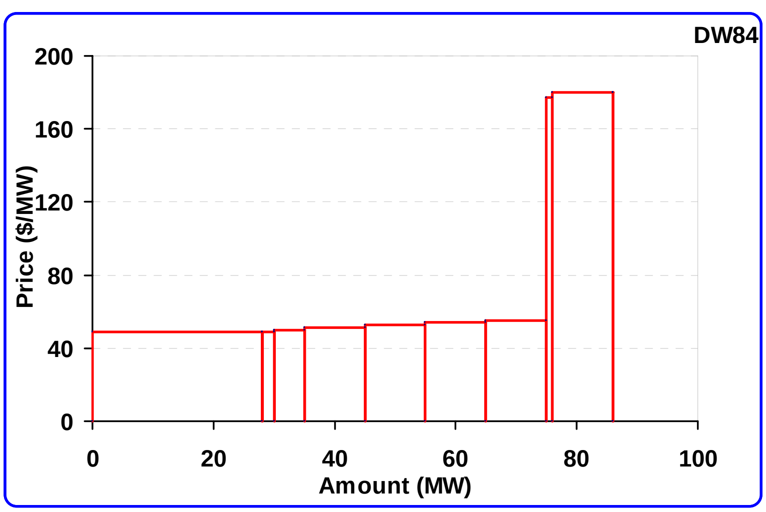




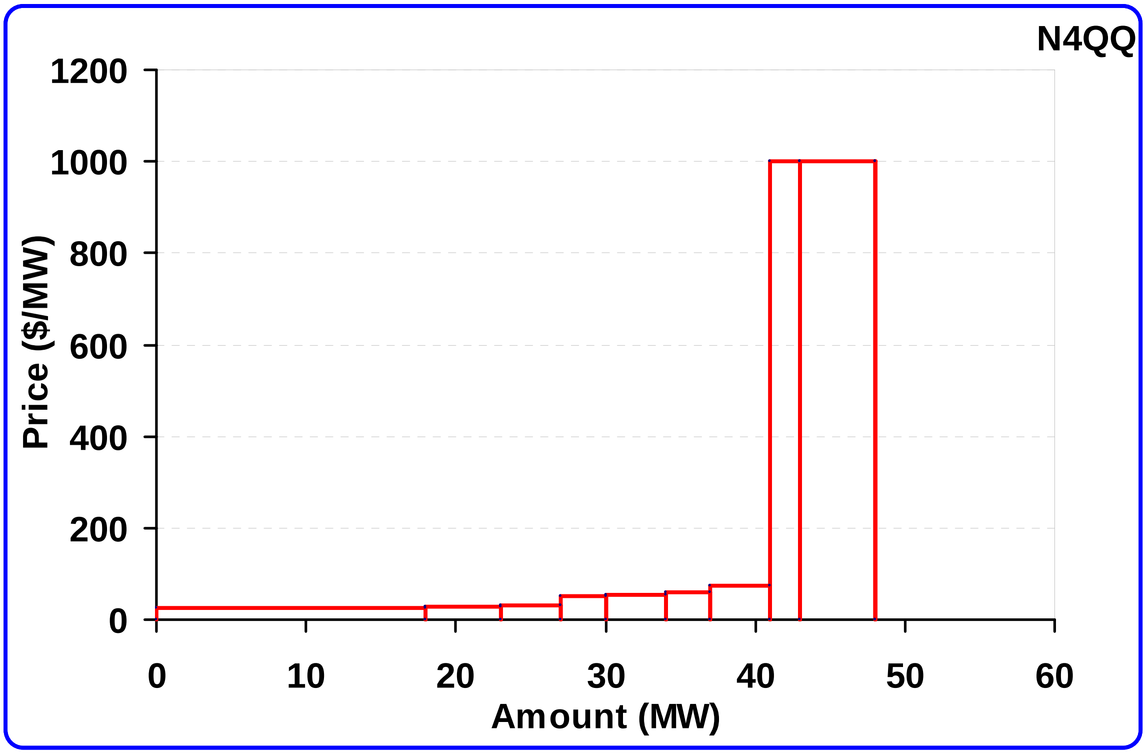
GenCo 2C bid three units (5BC2 – 60 MW; IOR5 – 20 MW; and M1FA - 20 MW) at 999 $/MWh.

Examples of "Hockey Stick" Bidding

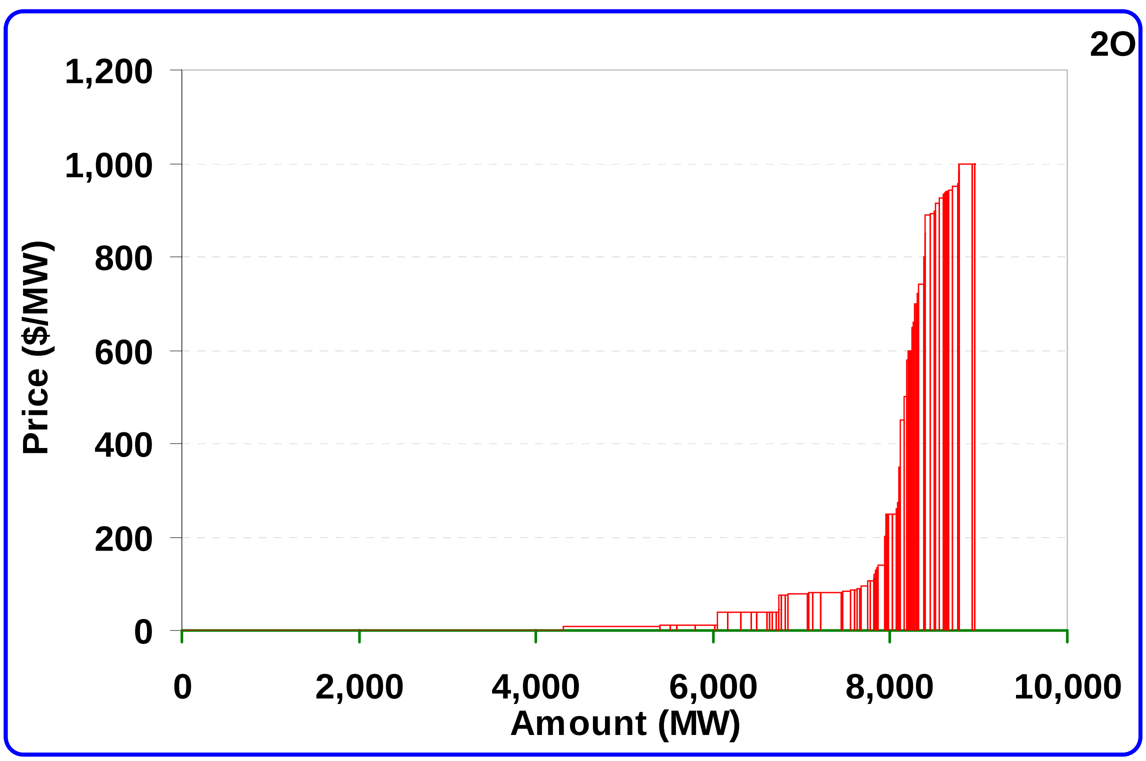
The following bids demonstrate "hockey stick" bidding in which the last increments of capacity are bid at significantly higher prices than the majority of the power.



GenCo Z5 bid unit DW84 at 48-55 $/MW for the first 75 MW and at 177-180 $/MWh for the last 11 MW.



GenCo D1 bid unit N4QQ at 27-75 $MW for the first 41 MW and at 1000 $/MW for the last 7 MW.

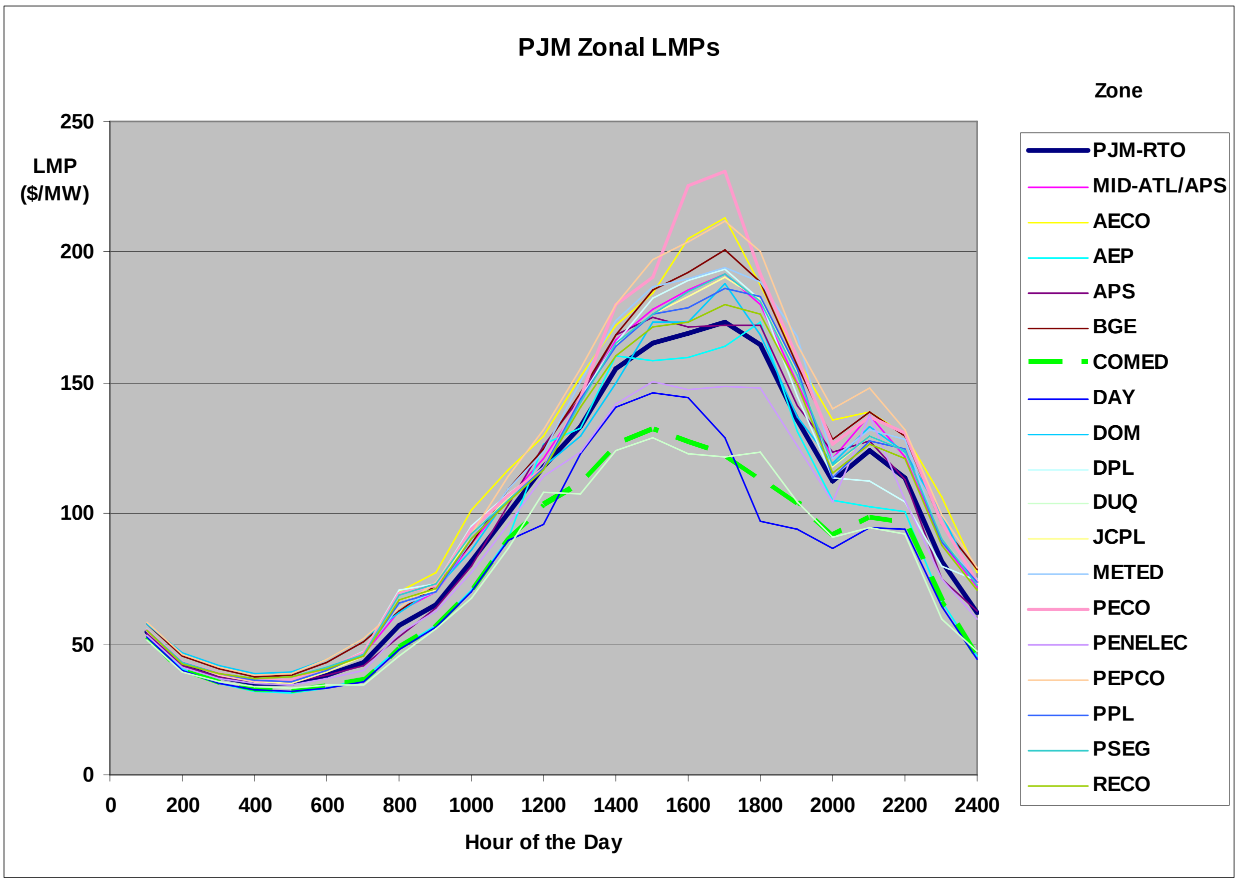


On a companywide basis, GenCo 2O bid almost 9,000 MW made up of 55 units into the market. Each unit was divided into several bid blocks. Approximately the last 1,000 MW of the company's capacity were bid at prices greater than 600 $/MW.

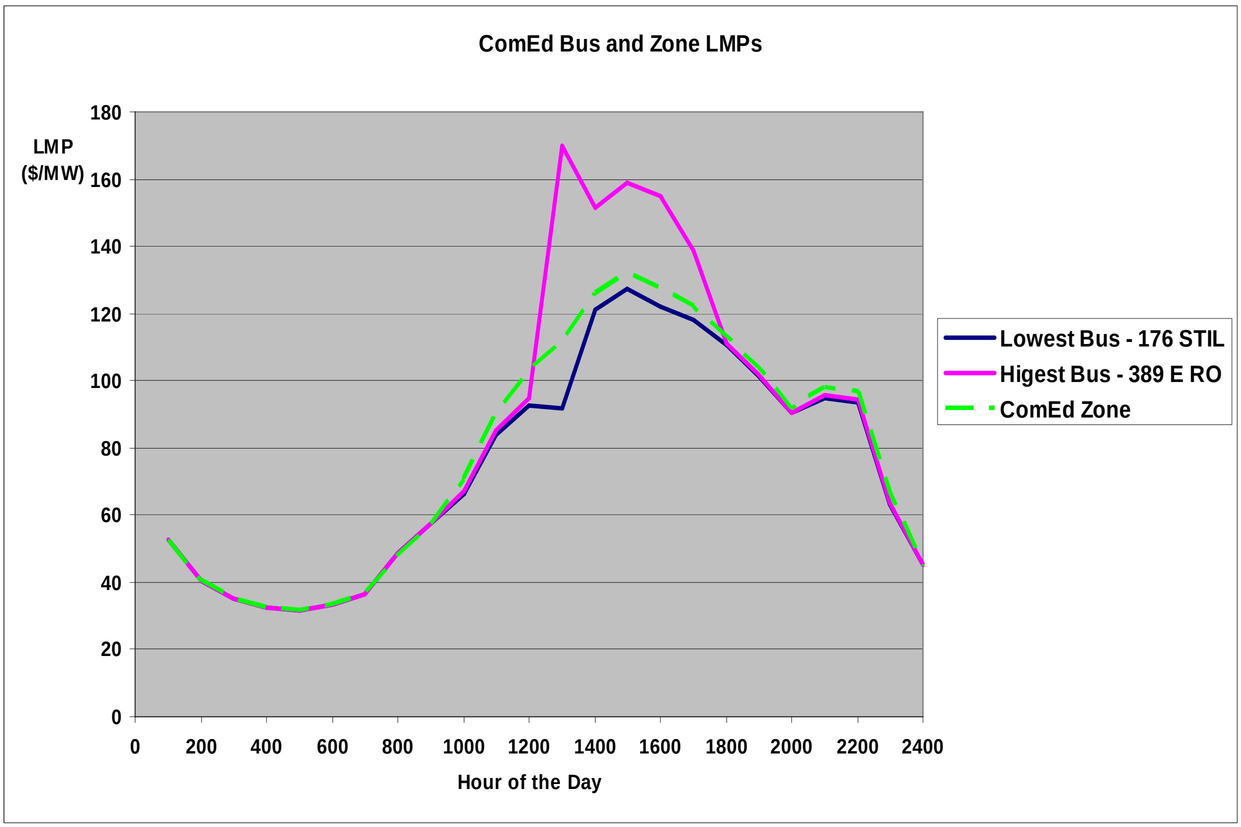
Examples of the Effect of GenCo Bids and Transmission Congestion on LMPs

PJM publishes daily locational marginal prices (LMPs) at each of 7460 buses in its network. In addition, it publishes LMPs for 19 zones, which are aggregations of buses. The following LMPs are for July 26, 2005, the same day as the above examples of GenCo bids. From the published information, it is not possible to identify specifically which of the GenCo bids affected the LMPs in which zones.

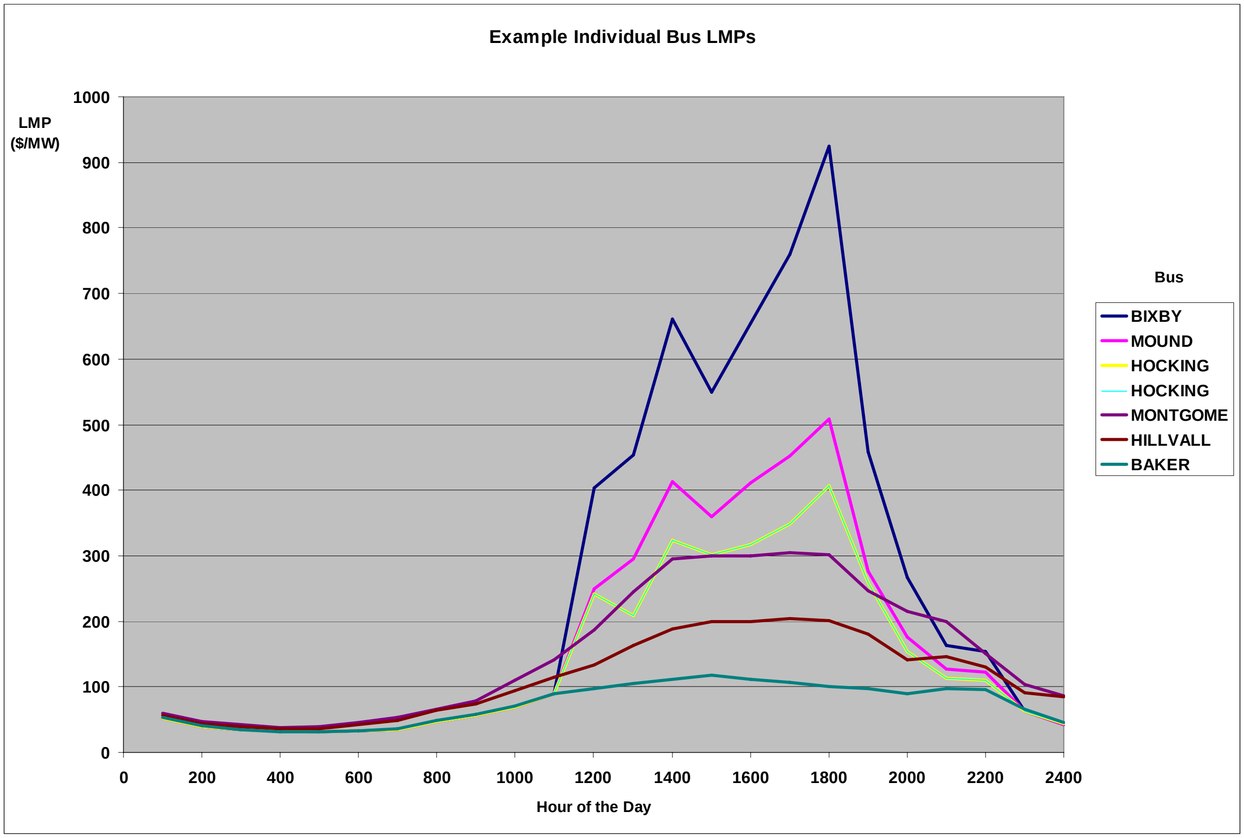
In the absence of transmission congestion, all LMPs would have been identical. The spread in LMPs reflects the effects of congestion. The magnitude of the LMPs reflects the GenCo bids. During the peak hour, 1700, the highest zone LMP is almost double the lowest zone LMP.



ComEd has among the lowest LMPs in PJM. There is, however, evidence of transmission congestion in the ComEd zone as shown below. During the peak hour in the ComEd area, 1300, the highest bus LMP is about double the lowest. During the off-peak hours, the bus LMPs across the ComEd zone are virtually identical thus indicating no congestion during these periods.



During peak hours, the LMPs at individual buses can reach very high levels as a result of the combined effect of GenCo bids and transmission congestion. The figure below shows the LMPs at selected buses in the PJM system.



The distribution of bus LMPs during the 1800 hour is as follows:

Hour 1800 LMP Range ($/MW)	Number of PJM Buses with LMP in the Range
<100	438
100-200	6618
200-300	296
300-400	50
400-500	26
>500	32
Total	7460

A number of buses experience very high LMPs due to the combination of generator bids and transmission congestion. The manner in which these high LMPs factor into the prices charged to consumers and prices paid to GenCos is a function of PJM settlement rules.

ATTACHMENT 2
RESPONSE TO SPECIFIC COMMENTS
(Comments related to PJM and MISO market rules or data validity not included here. See transmittal letter for response to these comments.)

Comment: Physical withholding of capacity is not realistic
(ComEd comments p 3-4; Ameren comments p 5-7)

The cases of physical withholding of generator units evaluated in the study were designed to determine if such a strategy was attractive from the perspective of increasing company profitability. Experiences during the California electricity crisis indicated that some generation companies did appear to intentionally take units off line, thus causing higher prices and the need for rolling blackouts. The cases studied here were designed only to see if, in the absence of any intervention on the part of market monitors or regulators, such a strategy could result in higher company profits. The study did show that taking units off one at a time was not, in fact, beneficial to company profits. Only a more complicated strategy of multiple units at selected times would increase profitability. The fact that such cases were found was not intended to imply that any company would do so, nor was it intended to evaluate the effectiveness of market monitoring in preventing such events. The results do, however, reinforce the need for regulators to be aware of such possibilities and to ensure that mechanisms were in place to deal with them.

Comment: Economic withholding of capacity is not realistic
(ComEd comments p 4,5)

Analogous to the physical withholding cases, the economic withholding cases included in the study were designed to determine their attractiveness from the perspective of increasing company profitability. The actual bid data published by PJM (see Attachment 1) illustrates that, even with the current market monitoring mechanisms, very high priced bids are being submitted. The cases included in the study were an initial attempt to determine how such strategies might be effective. They also reinforce the need for regulators to be aware of the conditions that could lead to this.

Comment: The bid assumptions are unrealistic
(ComEd comments p 7)
The point is made that bid prices used in the Case Study Assumptions cases that incorporate fixed operating and maintenance costs is unrealistic. We agree that the conventional approach is to consider the marginal cost of production to include only fuel and variable operating costs. In a set of early results (June 2003) that developed bids on this basis and which were discussed with ICC staff, it was recognized that this approach to bidding resulted in most generation companies in the State operating at a significant annual loss, which was clearly not a sustainable situation. We agreed with ICC staff recommendations to add costs into the bids to reflect what might actually be expected. The ComEd comments indicated that "Economists typically model offers at variable cost, or at some increment higher than variable costs to reflect such costs as startup costs." We concur with this approach and elected to use, with the concurrence of ICC staff, a prorated portion of fixed operating and maintenance costs to represent this increment. It should be noted that even with this addition, most of the generation companies still showed operating losses over the year. The Conservative Assumptions cases were even worse in this regard. We do not feel that the Case Study Assumptions,

coupled with including cases using the Conservative Assumptions, is an unreasonable way to understand this issue. Further, as was shown in Attachment 1, the bids that are currently being offered to the market clearly are not based solely on marginal production cost.

Comment: The HHI analysis is invalid
(ComEd comments p 8, Ameren comments p 4)
The comment was made that, in computing the HHI, a geographic area beyond the State of Illinois should have been used. While this may be appropriate for a study of the larger eastern interconnection, the focus of the study was on Illinois. Given that, at the time of the analysis the integration with PJM and MISO was not implemented, using the Illinois boundary was a reasonable approach.

Another comment was made that a high HHI or 20% of generation level in the State may not be bad if some of the power is exported. This may be the case but the judgments made in the study were not focused on whether or not market concentration was "good" or "bad." Rather, the objective was limited to determining how companies might be able to function in the market.

Comment: The transmission system analysis is based on faulty assumptions
(ComEd comments p 9-12, Ameren comments p 4)
Most of the comments in this regard relate to more recent information on the transmission system. This issue has already been discussed with respect to the use of data that has since been updated. The points about the lack of inclusion of transmission reinforcements, generation added without transmission upgrades, and lack of inclusion of system operating steps must all be regarded in light of the study using the best data available at the time. Data on these issues was requested from the companies. The data that was provided was incorporated into the analysis. Further, it can be seen from the current spread in LMPs (see PJM data in Attachment 1) that transmission congestion persists even with the system reinforcements that have been implemented.

Comment: There is no simulation of a Real Time Market
(Ameren comments p 1)
This is a correct observation. The simulation includes the Day Ahead market but not the Real Time market. We feel that this does not materially change the results as the Real Time market generally satisfies a much smaller portion of the system needs than does the Day Ahead market. Further, experience has shown that real time market prices are generally higher than day ahead prices. Including this market in the simulation would have resulted in prices even higher than those seen in the study.

Comment: The study did not include bilateral contracts
(Ameren comments p 2,7)
This is a correct observation. With the agreement of ICC staff, the decision was made early on that since there was no information available on bilateral contracts that would be in place after December 2006, the analysis would be conducted without any. The EMCAS simulation tool allows for bilateral contracts, but this feature was not implemented.

Comment: The EMCAS projection did not consider transmission outages or contingencies
(Ameren comments p2)

This is a correct observation. However, the companion PowerWorld analysis did include consideration of 1,360 contingencies. (See Appendix E, Section E.2.2)

Comment: The analysis did not account for Firm Transmission Rights
(Ameren comments p2)
This is a correct observation.

Comment: The EMCAS model aggregates tie lines.
(Ameren comments p3)
This is not entirely correct. The tie lines that cross state boundaries are modeled individually. It is the out-of-state lines that are effectively aggregated.

Comment: The study does not address capital recovery; economic sustainability needs to be addressed
(Ameren comments p 3)
The observation is correct. In fact, the study points out that some of the conditions (e.g., Case Study Assumptions with production cost bidding) result in many companies sustaining operating losses. Adding consideration of capital recovery requirements would make this situation even worse from a profit/loss consideration. This is clearly not a sustainable condition. The implication is that there is considerable incentive for generation companies to seek higher electricity prices in the market, if for no other reason than to remain financially solvent.

Comment: The study overstates the level of market concentration
(Ameren comments p 3-4)
The comment is made that the HHI analysis in the study overstates the level of market concentration. Reference is made to p55 of the PJM 2004 State of the Market Report. In looking at the referenced report, it is noted that PJM comments "Calculations for installed and hourly HHI indicate that the ComEd Control Area's Energy Market during Phase 2 of 2004, was highly concentrated." In those calculations the HHI values ranged from 2600 to 7746, which are even higher than found in the study. Care must be taken to avoid taking these results out of context. The PJM calculations were done for what is called Phase 2 of the implementation of their market. During this phase, the ComEd Control Area was treated as a separate market when the "Pathway" connecting it to the remainder of the PJM system was at its limit. (See p52 of the PJM report.) In fact, this condition is very similar to the assumptions used in our study's simulation. Thus, it can be argued that the study's results confirm high levels of market concentration, as measured by the HHI index, when compared to actual PJM results under conditions that are similar to the study's assumptions.

Comment: The study should have investigated a range of natural gas prices. The low gas price used mutes the possible transmission congestion costs.
(Peabody comments p 2)
The evaluation of alternative scenarios, including a range of fuel prices, was proposed as a follow-on phase to the study. Resources were not available to pursue this. It is agreed that higher gas prices would probably result in higher cost attributable to transmission congestion since natural-gas-fired units frequently set the marginal price during high load periods.

Comment: The question was raised as to whether congestion would change dependent on the

bidding strategies employed.
(Peabody comments p 4)
During the course of the study it became very clear that the level of congestion is affected by the bidding strategies employed by market participants. It is not possible to generalize that it increases or decreases with a particular strategy. In fact, it is highly dependent on which participant employs which strategy at what times. The benefit of this type of analysis is that it allows for a wide variety of strategies to be evaluated.

Comment: The study appears to assume demand inelasticity
(Peabody comments p 4)
This is correct as explained on p 27 of the report. Demand elasticity is an included feature of the EMCAS model but it was not implemented during this study.

Comment: Multiples of incremental costs are somewhat misleading
(Peabody comments p 4)
The comment points out that using multiples of production cost can result in widely varying absolute costs because of the variability in the level of production cost across different types of generators. This is correct. To address this issue, the results shown on p 159-163 of the study are displayed in absolute costs.