

**Statement
of
ROBERT A. WEISHAAR, JR.
on behalf of the
PJM INDUSTRIAL CUSTOMER COALITION
for the
PENNSYLVANIA PUBLIC UTILITY COMMISSION'S
En Banc Second Public Hearing on
"Current and Future Wholesale Electricity Markets"**

November 6, 2008

The PJM Industrial Customer Coalition (PJMICC) appreciates the opportunity to participate in the Pennsylvania Public Utility Commission's (PA PUC) second *en banc* public hearing regarding the "Current and Future Wholesale Electricity Markets." I am Bob Weishaar of McNees Wallace & Nurick, LLC. McNees has the privilege of serving as counsel to PJMICC.

PJMICC is a coalition of 31 industrial and institutional customers of electricity. Many of the PJMICC companies own and operate significant electricity-consuming facilities here in Pennsylvania. PJMICC was organized in 1996 and has been active in the PJM stakeholder process, in proceedings before the Federal Energy Regulatory Commission (FERC), and, beginning recently and out of necessity, before the US Congress on all matters that affect wholesale electricity prices in PJM.

Industrial Customers' Concerns

PJMICC members are extremely frustrated with the performance of organized markets and with FERC's performance relative to organized markets. PJMICC companies in deregulated states that have already removed rate caps have closed facilities. PJMICC companies in deregulated states that have not yet removed rate caps are earnestly attempting to inject rationality and practicality in wholesale electricity markets before those rate caps expire. PJMICC companies in still-regulated jurisdictions have focused their attention on shielding their plants from PJM market prices.

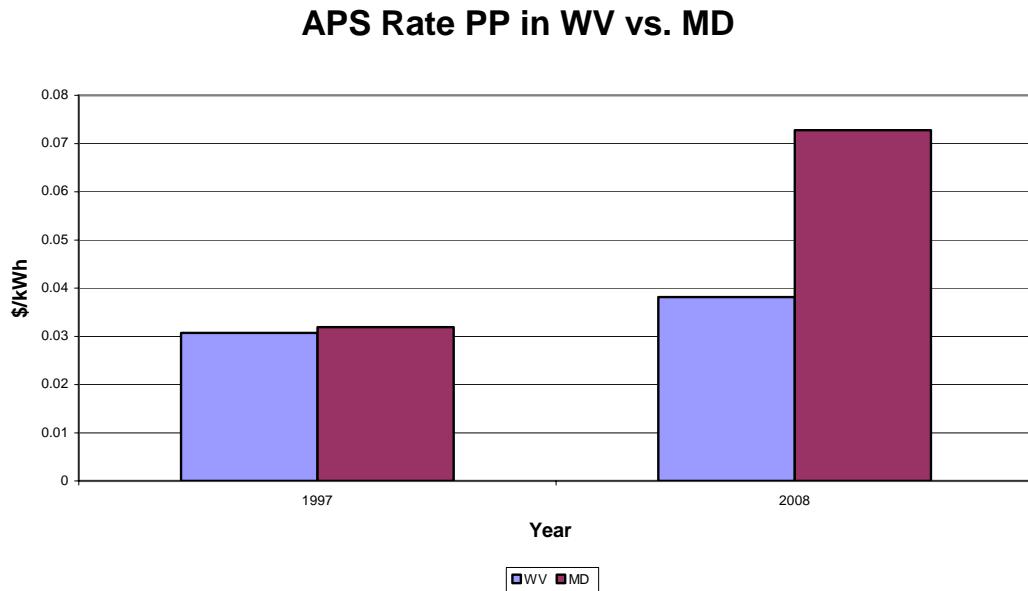
The Federal Power Act was designed to protect customers. Given the Federal Power Act's overarching mandate, FERC should be listening closely to sophisticated customers that are active in highly competitive global markets. They are not. And when customers of all types and sizes, from all areas in which organized markets exist, pleaded with FERC to take a hard look at organized markets, we hoped FERC would listen. They did not. FERC's recently issued Final Rule on Organized Markets takes us back a step, by passing up an excellent opportunity to begin to get things right. FERC's Final Rule on Organized Markets adds to customers' frustration.

Industrial customers' frustrations are driven not only by higher and more volatile electricity prices – although both are causes for concern. Industrial customers understand (as well as anyone understands) that high and volatile fuel prices do contribute, in part, to high and volatile electricity prices. What is frustrating, though, is that the rate of increase is noticeably higher in states exposed to organized markets than it is in other states, notwithstanding the original intent of restructuring to close the gap between high-cost states and low-cost states.

As Mr. Hughes from ELCON also testifies today, one of the best measures of regulated versus deregulated prices is a comparison that isolates nearly all variables except the customer's exposure to organized market prices. Consider the following real-life example. A customer has two plants, with nearly identical operating characteristics, one in an area of Maryland in which customers are directly exposed to PJM market prices and one in West Virginia, where rates are still regulated based on actual costs. Both plants are customers of the same utility – Allegheny Power System (APS). The only difference is that one plant has the good fortune of being located in West Virginia and the other has the burden of being located in Maryland where customers are

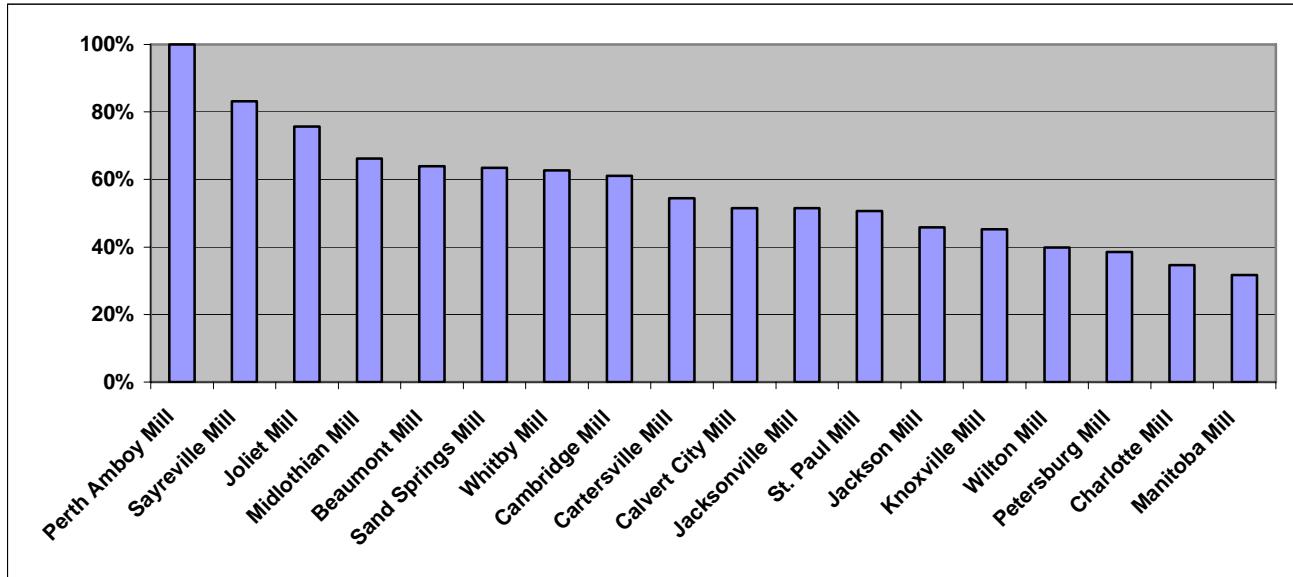
directly exposed to PJM prices. In 1997, the two plants paid nearly identical prices – just over 3 cents per kWh. However, as of August 2008, a very large rate differential has developed between the 2 plants. The West Virginia plant now pays just under 4 cents per kWh, an increase of less than 33% over the 9-year period. The Maryland plant, in sharp contrast, now pays more than 7 cents per kWh, an increase in excess of 100% over the same 9-year period. When all variables are isolated except for exposure to organized market prices, it becomes clear that customers are not benefitting from the PJM market design and many are being seriously harmed.

Figure 1: 2008 Comparison of APS Rates: Regulated vs. Deregulated



The following chart (shown as Figure 2) also helps illustrate the problem. This is a bar chart of Gerdau Ameristeel, a steel manufacturer with 18 facilities across the United States – all but one are located in the Eastern Interconnection. Notably, of the 18 total facilities, the 4 plants with the highest electricity prices are all located in single-clearing price markets. The 3 highest-priced plants are all located in PJM; the 4th highest is located in the ERCOT area of Texas, which also has a single-clearing price market, albeit not yet with a locational aspect. What is not shown in the bar chart, but what I know from experience with this company, is that the rate of increase is also higher in the single-clearing price markets than it is in regulated jurisdictions or under other market designs. Also noteworthy is that, the plants in Whitby and Cambridge are located in Ontario, and were much farther to the left on the chart when Ontario exposed customers to single-clearing prices. Because the Independent Electricity System Operator (IESO), working with stakeholders, has recently taken significant steps to implement a more practical and rational approach to new resource procurement, those two mills have become competitive again relative to the other mills. To its credit, the IESO and its key stakeholders are moving away from reliance on single-clearing price markets to accomplish the reliability objectives that single-clearing price markets were not designed to cost-effectively accomplish.

Figure 2: Relative comparison of electricity rates across mills – Gerdau Ameristeel



The Fundamental Problem

The single-clearing price mechanism, while generally supported in most economic circles, has been shown to have significant shortcomings when confronted with the real-world realities of structural market power, substantial mitigation, demand inelasticity, and an overarching societal preference for reliable power. In the face of these realities, FERC has taken an approach toward market design that layers revenue streams (from energy, ancillary service, and capacity markets) until all units needed for reliability have **at least** enough revenue to cover their revenue requirements. The most expensive unit needed for reliability receives enough revenue to remain financially viable and, because all lower-cost units also receive revenue based on those prices, most units in the PJM generation stack are receiving far more than their actual revenue requirements.

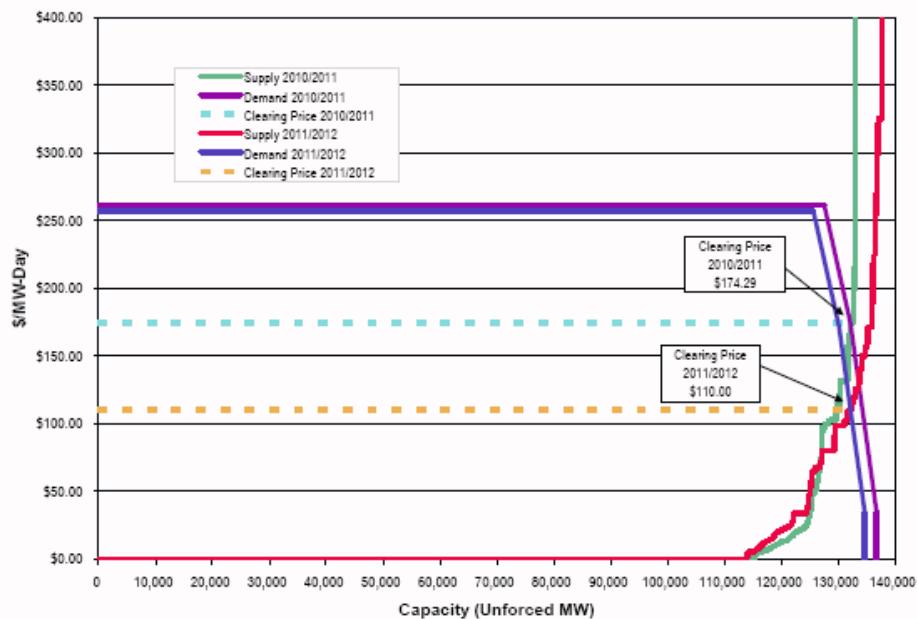
As evident from the comparisons of retail rates in regulated versus deregulated states, the claimed benefits of lower outage rates, increased operational efficiency, and shifting investment risk from ratepayers to shareholders are being dwarfed by the price run-ups resulting from a single clearing price mechanism. The disconnect occurs because the current FERC-approved market designs ignore completely the state commissions' rate decisions issued over a period of decades. The FERC-approved market designs start from the assumption (as they must for the theory to work) that all generation units are new units and that the capital costs and operating costs are meaningful determinants of the efficiency and competitiveness of all units. Of course, that is not the case. And, as a consequence of this mistaken threshold assumption, the left side of the supply curve, particularly in the capacity market, is loaded with units that have low costs simply because ratepayers have already picked up depreciation tabs and stranded cost tabs for a long period of time. Yet, the differential between the clearing price and those low actual costs

never benefits ratepayers – the differential (known in economic parlance as inframarginal revenue) goes directly to the shareholders owning the units.

So, we are left with a design that is premised upon a "no generator left behind" pricing policy. Instead of targeting customer payments to the actual revenue requirements of each unit in the fleet, we are now ignoring revenue requirements altogether except for the revenue requirement of the most expensive unit needed to reliably serve load. We then pay all generators as if they, too, carried that most expensive revenue requirement.

The supply curves from the two most recent RPM Base Residual Auctions (shown below in Figure 3) paint a vivid picture.

Figure 3: Supply and Demand Curves From Most Recent RPM Base Auctions



Because of the pervasive structural market power that exists in the PJM capacity market, all bids from existing units are mitigated to the unit's "Net Avoidable Cost Rate." That calculation, in a nutshell, determines what fixed going-forward costs the unit must recover to remain in operation, and then nets from that number the profit earned by the unit in the energy and ancillary services markets. What you can see from the supply curves in Figure 3 is that 115,000 MWs of the roughly 135,000 MWs that cleared the Base Residual Auction (approximately 85% of the total cleared MWs) have a mitigated bid of \$0/MW-day. In other words, 85% of total capacity needs no money to cover its avoidable costs, after you consider the energy market profits received by this capacity. Yet, the way RPM is designed, these units (again, representing 85% of total cleared capacity) receive the full RPM clearing price which in one year was \$1,174.29/MW-day and then in the next year was \$110.00/MW-day. That phenomenon alone is a significant contributor to the expected increases that will occur in Pennsylvania when rate caps expire. A

similar phenomenon occurs in each hourly clearing of PJM's day-ahead and real-time energy markets.

A Potential Solution

When FERC proposed a rulemaking to fix the organized markets, we were cautiously optimistic. Based on that cautious optimism, PJMICC joined with the Portland Cement Association and other industrial groups to file with FERC an Alternative Market Design Proposal ("AMDP" or "Design").

The Design proposes the use of competition and market forces, but only where those dynamics can be used to drive efficiency and reduce customer costs. The Design stops short, though, of carrying economic theory to illogical extremes. Like cost-of-service models, the Design ensures that capital recovery payments by customers entitle those customers to paying only actual unit-specific variable costs, not the bid submitted by the least efficient unit. The combined effect of this capacity and energy payment structure is to provide generation owners with a reasonable opportunity to collect revenues consistent with the revenue requirement of their units, while ensuring that consumers receive some value for their capacity payments, in the form of fuel diversity and improved supply system efficiencies. This structure for capacity and energy pricing, with the potential for zonal differences based on real transmission constraints, also reflects the electrical topology of the system.

This Design attempts to create reasonable economic opportunities for both buyers (e.g., LSEs and large customers) and suppliers to negotiate long-term bilateral contracts that would, over time, expose consumers to prices that more closely reflect long-run marginal costs, rather than to prices that reflect the recurring recalculation of short-term marginal costs.

In order to support new entry and investment, however, the Design retains the existing function of some RTOs as a default aggregator of load in order to reduce counterparty risk for generation developers and to enhance the efficiency of the overall system by integrating the transmission planning process into the generation supply auctions over a broad geographic area. The Design depends, as it must, on transparent integrated resource planning of the entire system and integrating transmission planning with the generation procurement process.

The Design, if properly implemented and administered by PJM, would provide consumers a lower all-in delivered cost than available today from the organized markets. The ultimate goal is to equilibrate revenue opportunities for owners of existing depreciated assets and owners of new generation assets, by injecting competition in the selection of generation resources (both new and existing) and in the dispatch of generation for energy imbalance service across broad geographic areas, while restoring the consumer benefits of generation asset depreciation, fuel diversity, and improved operational efficiencies. In short, the goal is an improved balance between the needs of investors and consumers than what is provided by the current market design of single-clearing price energy and capacity markets. If this Design is successful, we would expect all states to begin turning toward regional markets and RTO processes for solutions to their long-term needs, instead of retreating to, or fiercely defending, individual state approaches.

Alternative Market Design Proposal Outline

This Alternative Market Design Proposal begins with the premise that RTOs deliver value to customers by performing, independently and more transparently, certain functions that were previously performed by monopoly transmission owners. RTOs should continue to perform these functions. The essential RTO functions, as identified in the American Public Power Association's (APPA) "Consumers in Peril: Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates," are as follows:

- Ensure non-discriminatory access to the grid through independent administration of a regional Open Access Transmission Tariff (OATT) and provision of transmission service, including needed ancillary services.
- Develop and administer a regional transmission rate design that eliminates rate pancaking and assures the recovery of the cost of transmission facilities for all transmission facility owners that wish to participate in the RTO, regardless of their form of ownership.
- Operate a single regional open access same-time information system (OASIS) and independently calculate available transmission capacity (ATC).
- Conduct independent and collaborative regional transmission and generation interconnection facilities planning, with the full inclusion of affected stakeholders.
- Carry out wide-area system security and reliability-related activities, ensuring that transmission facilities are operated in compliance with relevant North American Electric Reliability Corp. and regional reliability entity criteria.
- Operate an energy imbalance market to enable transmission customers to manage their imbalances and to allow generators (including intermittent renewable generators) to sell excess generation not committed under bilateral contract arrangements.
- Ensure adequate generation reserves through implementation of appropriate regional resource adequacy requirements.

The Design expands on the last two bullet-points on the APPA list (i.e., procuring an efficient mix of generation resources and operating a cost-effective energy imbalance market).

1) Load Forecasting and System Modeling

- a) RTOs/ISOs, in coordination and cooperation with state planning and state siting authorities pursuant to a transparent process, shall have primary responsibility for developing integrated transmission and generation modeling/planning.
 - i) Modeling/planning results should be released annually.
 - ii) States, wholesale customers, and industrial customers should have the ability to demonstrate to RTOs/ISOs that they have adequately self-supplied resources to satisfy resource adequacy requirements.
- b) Load forecast procedures for future Regional Transmission Planning Processes ("RTEPP") and for the Competitive Procurement Process discussed below should:
 - i) Account for changes in peak load, energy volumes, load duration, and others factors critical to long-term planning.
 - ii) Use the same set of assumptions for an integrated approach to generation, transmission, and demand resource planning.

- iii) Consider state commission and other stakeholder input regarding planning parameters, including the renewable portfolio requirements and other constraints on the procurement of resources.
- iv) Determine local deliverability requirements based on transmission transfer limits and generation characteristics under peak system load conditions.
- v) Utilize existing RTO/ISO Security Constrained Unit Commitment ("SCUC") dispatch models.
- c) Through this planning process, the RTO/ISO will identify the region's needs for generation capacity and long-term demand response resources, and any reliability-based operating or locational characteristics that are necessary for these resources.

2) Competitive Procurement Process

- a) The Competitive Procurement Process will apply to all load for which LSEs have not demonstrated, to the RTO/ISO, long-term arrangements for delivering energy to meet load levels during the peak period.
- b) The first Competitive Procurement Process would be held soon after implementation of the new market design, and Competitive Procurement Processes would be held every 2 years thereafter, unless the RTO determines that a Process must occur more frequently.
- c) The number of years before obligations are imposed on units procured through the Competitive Procurement Process shall be determined by the RTO based on actual performance in the industry, based on, among other things, the type of generation that is procured (i.e., baseload, intermediate, and peaking).
For example:
 - i) Obligations on peaking units incurred through Competitive Procurement Process could take effect no earlier than 3 years after the Competitive Procurement Process is conducted.
 - ii) Obligations on intermediate units incurred through Competitive Procurement Process could take effect no earlier than 5 years after the Competitive Procurement Process is conducted.
 - iii) Obligations on baseload units incurred through Competitive Procurement Process could take effect no earlier than 7 years after the Competitive Procurement Process is conducted.
- d) Selected units receive revenue recovery assurances over the long-term (10-20 years) via a FERC tariff, consistent with their remaining useful lives, as reflected in their capacity offers.
- e) The Competitive Procurement Process for each forward year would procure the needs identified by the planning process discussed above, but would procure less than the full reserve requirement, to account for the margin of error inherent in extended load forecasts and the attendant pricing implications of shifting that risk to customers; the difference between the initial procurement of generation and demand response resources for a given delivery year and the full reserve requirement for that delivery year would be procured over time by "Incremental Residual Auctions" (IRAs) closer in proximity to the delivery year.
- f) Generation that is not receiving compensation pursuant to bilateral or state arrangements for long-term capacity obligations would be subject to a must-offer requirement into the

Competitive Procurement Process, in the form of market-based capacity bids with cost-based energy bids (i.e., \$/MW-day with a cost-based strike price of \$/MWh); market-based capacity bids should reflect a commitment length consistent with the remaining useful life of the unit; cost-based energy bids must show unit heat rate and unit operational characteristics.

- g) The objective function of both the Competitive Procurement Process and IRAs is to procure supply at the lowest cost to consumers for the planning period.
- h) A long-term, unit-specific approach to procurement and pricing should reduce the need for mitigation due to a more level playing field for new entry, but some areas with concentrated generation ownership and limited ability for new entry will require that capacity offers reflect the actual cost of existing units (including appropriate amortization of actual fixed costs) if, and for as long as, those units are needed for system reliability, as determined by a properly structured Market Monitor.

3) Clearing Process and Payments to Suppliers

- a) Consistent with the objective functions above, the Competitive Procurement Process, the IRAs, and unit dispatch would produce the overall lowest cost supply to customers.
 - i) The unit selection process/algorithm will consider and select units based on the combination of capacity and energy prices that will result in the overall lowest cost to customers over the relevant planning horizon.
 - ii) Optimization and unit selection in the procurement process must be synergized with transmission planning objectives.
- b) Units selected in the Competitive Procurement Process receive unit-specific capacity payments and unit-specific "cost plus" energy payments with indexing to account for changes in fuel and variable O&M costs.
- c) Units receiving capacity payments would be subject to liquidated damages (LDs) for non-performance of energy delivery when dispatched (e.g., LDs equal to LMP replacement cost).
- d) Balancing markets (Day-Ahead and Real-Time) would continue on a very limited basis for residual energy, and would be dispatched at LMP; however, only those units not receiving a capacity payment would actually collect LMP on a clearing price basis. Any unit receiving capacity payments would collect only its actual fuel and variable O&M costs associated with the dispatch of their rated capacity.
 - i) Any energy production beyond the contracted capacity of a unit would also receive LMP on a clearing price basis.
- e) Equal access to the transmission system would exist for new and existing units; deliverability would be determined by offers and transfer limits

4) Load Costs

- a) Customers would pay MW-weighted zonal prices for capacity and MWh-weighted zonal prices for energy because energy and capacity would mostly be paid "as bid".
- b) Customers would not pay the LMPs produced in the Day-Ahead and Real-Time energy markets for **all** energy consumed from those markets because the LMPs would be paid only to units that are not receiving capacity payments.

5) Performance Metrics

As part of approving any market design, including the AMDP, FERC should adopt metrics for determining whether markets are delivering their intended benefits. This recommendation is consistent with the recommendations included in a recent Government Accountability Office ("GAO") report on RTO performance. The success of markets should be measured relative to the impact on customer prices, consistent with the Federal Power Act's objective of advancing the public's interest in enjoying cheap and plentiful electricity.

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A cure to the fundamental problems underlying unacceptably high electricity prices will not come easily. To achieve the best results, the current market design must be changed by FERC. For FERC to change those designs, FERC must be convinced that its market design choices are working against the public interest. Also, incumbent suppliers must be forced to accept the fact that extraordinarily high margins on wholesale power sales are not an acceptable norm. This Commission, and similarly situated state commissions must coalesce around an acceptable alternative. While PJMICC has joined others in proposing AMDP, the group welcomes all ideas and improvements that begin moving outcomes in a more customer-friendly direction.

PJMICC applauds the Commission's initiative in scheduling hearings to examine the problems of current wholesale electricity market designs and the pressures those designs place on retail customers' prices. PJMICC appreciates the opportunity to address the Commission directly, and I look forward to your questions. Thank you.