Statement

Of

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on
"Current and Future Wholesale Electricity Markets"

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Statement

Introduction

Chairman Cawley, Vice Chairman Christy and Commissioners Pizzingrilli, Powelson and Gardner, I want to thank you and the Pennsylvania Public Utility Commission for inviting me to participate in this public hearing on Wholesale Electricity Markets. I also want to commend the PUC for undertaking this comprehensive series of hearings. You are addressing important issues, and I am glad to have the opportunity to offer my insights to the electric power markets to aid in your considerations.

Over the last 30 years, I have testified or provided written statements in matters involving the electricity industry over 180 times before Federal Energy Regulatory Commission ("FERC"), state and federal courts, and state public utilities commissions throughout the United States. Much of this experience has "tracked" through Pennsylvania, where I have a long personal and professional history. I attended undergraduate school at Swarthmore, and received my Masters and Doctorate degrees from Carnegie Mellon. Going back to the late 1970's I have worked for electric utilities, generation owners and developers, public entities, and industrial concerns located in Pennsylvania. Since the commencement of restructuring activity in 1995-96, I have been involved extensively in the development, implementation and continuing evolution of the PJM markets.[1]

Executive Summary

After reviewing the materials from these hearings, it is clear that some speakers have confused and conflated two very different issues: (1) the effectiveness of market design in reflecting the "right" prices, and (2) the consequences, both positive and negative, of conscious business decisions that were made. Some buyers call for radical market overhaul of wholesale markets and a reversion effectively to cost-based regulation. But this appears to based more on regrets about past business decisions than on any analytical conclusions regarding the PJM wholesale market design and pricing. As

[1] A full copy of my qualifications is available as part of a recent filing I prepared at the FERC Go to http//ferc.elibrary.gov. Document Submittal 20080711-5149 . In all public statements my comments represent my own opinions.

such they are misguided and myopic. Under restructuring, large industrial customers often avoided paying full stranded costs and benefited for over a decade from capped rates. Whether or not these large, sophisticated customers decided to hedge[2] their price risk in the face of rising commodity prices is unrelated to the question of whether the wholesale market is working properly. On the contrary, their complaints stem more from expiration of these favorable deals coupled with results of their deliberate business decisions than from any purported market design flaw. Similarly, the ability of sellers to achieve market pricing after the end of the restructuring "business deal" was a consequence fully anticipated and even relied upon by this Commission.

Fighting about the consequences of business decisions in a changing business environment isn't new. For that matter, neither are efforts to try and cloak this concern under the cover of flawed market design. Rather, the testimony presented over the course of these hearings, in particular the testimony on November 6th, reflects the historic tug of war between those seeking to support the use of average or marginal costs based on these changes in business conditions, and the related direct consequences to both buyers and sellers. The customers' claims of dysfunctional markets, however, do not reflect legitimate criticism regarding the PJM market pricing. I have witnessed this struggle repeatedly during my long career as the electric markets have gone through several business cycles of high and low marginal costs.

The underlying fundamental truth about pricing is, and always should be, the same: prices should be set at marginal cost to the extent possible. However, depending on circumstances, market participants seem to be selective about how they perceive this truth. When marginal costs exceeded average costs, sellers (including large industrials) have strong incentives to build new facilities and receive compensation at the related prices. Conversely, at the same time buyers will try to blunt market price signals and discourage marginal cost pricing, seeking instead the "protection" of average cost rate designs and regulatory schemes that discriminated between old "cheaper" power and new more "expensive" resources. When average costs exceed marginal, the positions reverse. Buyers suddenly support marginal cost pricing, while sellers seek compensation more

[2] A "hedge" refers to a business strategy to control exposure to cost variation or risk via contracting for term supplies of a needed good at a known price (for buyers) or term sales of production at a known price (for sellers).

related to average costs. This basic conflict is what is at play here today as marginal costs have been rapidly increasing. However, that fact should be irrelevant to the determination of the "right" wholesale market price for power.

To determine wholesale market design effectiveness, the key question should be: Does the market provide transparent and accurate price signals about short-run and long-run costs to enable the most efficient dispatch and expansion of the system? Competitive markets were never supposed to be a guarantee that the market price of electricity would, over time, stay the same or decline. No market, competitive or regulated, can ever provide that guarantee. Rather, the objective has been, and must be, the most efficient operation and allocation of resources.

A well-functioning market is designed to value each MWh of electricity based on generator location and system conditions at the time it is produced. Worldwide, virtually all commodity markets,[3] operate via a single clearing price market-adjusted for location, the same intent as PJM's Locational Marginal Pricing ("LMP") mechanism. As PJM's Independent Market Monitor emphasized at October's hearing, PJM's LMP market is producing transparent, competitive marginal price bids. Similarly the Reliability Pricing Model is producing capacity costs consistent with the recovery of long-term costs explicitly excluded from recovery in the energy markets. The bottom line is PJM's market is an efficient engine.

Notably as well, PJM's robust competitive wholesale market provides consumers and state regulators more procurement choices than ever. In the old days, before competition, we had but one choice: a long-term cost-plus regulated contract. Now we have numerous choices regarding term, pricing, products and risk allocation. Pennsylvania's recently passed Act 129 is a testament to the array of procurement choices provided by competition. Significantly, this Commission is uniquely poised to play a critical role in forging the future made possible by competition. But one thing must always be remembered: these wholesale procurement choices represent conscious business decisions by both customers and the Commission, and the associated consequences (good or bad) of these decisions are independent of the underlying power

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[3] For example, Alcoa, a presenter at the November 6th hearing, sells its products through single clearing price markets adjusted for location.

prices in the wholesale competitive market. Furthermore, it makes no sense to jettison a proven wholesale market design that is essentially working well and replace it with the untested, flawed market design proposed by some industrial customers. Such an ill-advised move would subject consumers to tremendous downside risk with little potential upside.

In my testimony, I will expand upon the following key points:

- **The PJM Single Clearing Price Energy Market Is Transparent, Competitive and Consistent with Bilateral Contracts**
- **Pay as Bid Is Inefficient, Lacks Transparency and Leads to Higher Prices**
- **PJM's Reliability Pricing Model ("RPM") is Helping to Keep the Lights On**
- **The Regulatory Restructuring Bargain Provided Many Benefits and Projected Comparable, If Not Higher, Capacity Prices**
- **Long Term Contracts Are Available in PJM at Fair Prices: Industrial Customers' Complaints Mainly Reflect Expiration of Their Favorable Deals and Their Failure to Hedge**
- **The Proposed Portland Cement Association Alternative Market Design is Unworkable.**

PJM's Single Clearing Price Energy Market Is Transparent, Competitive, and Consistent with Bilateral Contracts

A single clearing price market, with locational differentials is recognized worldwide as the most efficient and competitive way to sell almost all fungible commodities from corn and beans to aluminum. The same applies for power. A kWh of power produced at the same location, and at the same time, should clear at the same market price. PJM operates an open, single clearing price auction establishing Locational Marginal Prices, or "LMP", through which participants receive at least hourly price signals.

Indeed, each of us is familiar with the concept of a single clearing price from our own experience. Consider your house. Say you bought your house 30 years ago for

$100,000, whereas, your next-door neighbors bought their identical house 2 years ago for $800,000. Assume as well that in the last few months comparable houses have sold for only $750,000. If you want to sell your house and there are a number of willing potential buyers, you would rightfully object if others suggested you must sell yours for near its zero depreciated cost basis (i.e., cost based pricing). The notion that all buyers (but you) would be better off with this pricing would not likely change your mind. Likewise, although your next door neighbors who bought at $800,000 would be better off if we assured them recovery of their initial investment regardless of current prices, you similarly would be shocked at the notion of having to subsidize their $50,000 loss (i.e., recovery of stranded costs).

The same basic logic is guiding the wholesale power market. In PJM's LMP markets, suppliers have an incentive to offer energy at their short-run variable, or marginal, costs. By doing so, suppliers are best assured their facilities will be selected to run at any time it is profitable to do so. If, however, their offer is higher than marginal costs, they risk losing operating margins if the clearing price results in a value above their marginal cost, but below their bid price. Each party receives the clearing price, none is subsidized, and each has an incentive to bid competitively.

A major benefit of PJM's market design is that any anti-competitive bidding behavior is more readily apparent as the bid data clearly reveals the differences between the offer price and marginal costs. As Dr. Joseph Bowring, PJM's Independent Market Monitor emphasized, because single clearing price markets are very transparent as to marginal cost it is much easier to detect the exercise of market power. When transmission constraints limit potential suppliers, bids inconsistent with marginal price would be visible signs of the potential exercise of market power. Significantly as well, in his October testimony Dr. Bowring also stressed that the most direct measure of the competitiveness of markets is "mark-up", the difference between unit price and marginal costs. He demonstrated to the Commission that PJM's pricing mechanism was producing competitive prices as the observed bid margins in PJM (the difference between offer prices and marginal costs) were very low.[4]

[4] October 23, 2008 transcript at p. 71.

Locational pricing and integrated dispatch based on clearing price also reflects decades of real world operational practice of utilities designed to avoid overload of transmission facilities. When transmission constraints limited the ability to run the cheapest units, the utility would identify the generation on the other side of the transmission constraint, and then find the least cost combination of adjustments that complied with the transmission limits. Historically, PJM incorporated just this type of information to create the pool "running rate" that was used to direct generation prior to RTO operation. This is the essence of LMP pricing. In fact, my understanding is that virtually the same dispatch software was used to send pricing signals before and after initial LMP implementation.

Today, every five minutes PJM calculates LMP for over 1,200 generating units at over 8,000 pricing points to wring out all the efficiencies possible to ensure power is dispatched reliably at the lowest possible cost in compliance with all transmission constraints. Through its increased size and resources, PJM has developed new, and more robust dispatch and commitment tools that result in hundreds of millions of dollars of operational/production cost benefits each year. These are benefits that accrue from getting wholesale power prices right.

Moreover, PJM's market design is not biased against longer term bilateral contracting. On the contrary, the liquidity and transparency in PJM's LMP markets promotes bilateral agreements. As noted in the Independent Market Monitor's 2007 State of the Market ("SOM") Report for PJM, the majority of sales in PJM's market have underlying bilateral agreements and, on average, only about six percent of load clears through the real time or spot market.[5] My experience is the same. I encourage clients to formulate bilateral power purchase/sale agreements such as contracts for differences[6] because of the relative ease of contracting, the underlying transparency in the pricing, and

[5] PJM 2007 SOM report, Table 2-82.

[6] In contracts for differences arrangements, a strike or sales price is agreed to between a buyer and a seller. Typically, the buyer will pay a fixed price at a given location. In implementation, the participants just bid and offer "normally" into the single price auction market. If the price that the buyer pays in the clearing market is higher than the strike price, the seller pays the buyer the difference. If the price that the buyer pays is lower, the buyer pays the seller the difference. To an outside observer, both parties behavior appears to be that of "spot" participants in the market, with the underlying bilateral agreement not evident.

associated simplicity in other contract-related requirements such as assigning risks and responsibility for transmission or defining damages.[7]

Pay-As-Bid Market is Inefficient, Lacks Transparency And Results in Higher Prices

In stark contrast, however, a pay-as-bid market is inefficient, lacks transparency and results in higher prices. Under pay-as-bid, suppliers are encouraged not to offer their power at marginal cost, but to offer their power at what they project the clearing price will be. Empirical simulation has demonstrated that in a pay-as-bid auction structure, the participants very quickly adopt bidding strategies that result in higher clearing prices when compared to the single clearing price results.[8]

This pay-as-bid, "guess the clearing price" bidding behavior has the additional perverse effect of making the exercise of market power virtually impossible to detect as one cannot distinguish between a "bad guess" as to the likely market clearing price and economic withholding.[9] Dr. Bowring's previously referenced margin analysis, which confirmed the competitiveness of prices in PJM's LMP market, would be completely inapplicable in a pay-as-bid environment. It would be virtually impossible to make any such determination as to competitive offers. Furthermore, the lack of price transparency in a pay-as-bid structure makes the markets operate much less efficiently and makes bilateral contracting much more difficult than in a LMP market.

[7] As underscored by the recent dramatic drop in fuel prices, it is critically important for all market participants, both suppliers and buyers, to hedge their risks.

[8] Failing to understand adaptive behavior by counterparties is one of the most frequent and damaging errors in market design debates. Parties continually assume that they can adjust their own behavior or market designs to meet their own interests while failing to consider that others will directly adapt to the change in circumstances to either maintain or improve their own interests. Representative information of this type of experiment regarding pay-as-bid structures can be seen in the work of Dr. Tim Mount of Cornell University. *See* http://aem.cornell.edu/profiles/mount.htm; http://portal.acm.org/author_page.cfm?id=81331499635.

[9] Effectively, pay-as-bid encourages legitimate behavior to increase offer prices, but without extensive analyses and investigation regarding patterns of behavior, intent, etc., there is no objective way to distinguish between a legitimate, but bad, "guess" and economic withholding. Rational economic behavior and the exercise of market power appear virtually identical in these situations.

<u>PJM'S Reliability Pricing Model (RPM)</u>
<u>Capacity Market Helps to Keep the Lights On</u>

In reviewing the testimony and transcripts from the previous hearings, in particular November's, it is clear there are some major misconceptions concerning PJM's capacity market. Some historical perspective is helpful. In the early 2000s, PJM foresaw capacity shortfalls and system reliability problems, and recognized that in a market with mandated reserve requirements but capped energy bids, prices could not, over time, support the cost of new entry.[10] In 2006, FERC found that PJM's existing capacity market was unjust and unreasonable and could not assure long-term system reliability by retaining existing capacity and attracting new entry. In December of that year, FERC approved the settlement establishing RPM. The approved RPM settlement was the result of an over six year comprehensive process that allowed all stakeholders the opportunity to shape PJM's new reliability program. Notably, the parties negotiated the right to opt out of RPM auctions entirely if they believed they could meet their reliability requirement at lower costs through bilateral contracts or self supply.

In approving RPM, FERC's primary objective was to establish a market-based mechanism that would not only attract new supply and demand response resources, but also retain existing capacity needed to ensure long-term reliability. Given the extraordinarily high cost of maintaining, upgrading and building capital-intensive, long-lived generation assets, investors and suppliers require a high degree of regulatory certainty in the market structure, which in turn allows for the predictable and transparent

[10] This theoretical observation, has been empirically verified by the PJM Independent Market Monitor, Dr. Bowring, who testified before this Commission in October that no new entrant of any type would have made a profit, based on long-run marginal costs, for 8 of the first 9 years of the market (1999-2007), transcript page 84.

market prices necessary to evaluate the prospects for long-term recovery of their significant investments.

Continued regulatory uncertainty increases perceived investment risks and associated costs. This is particularly true with respect to repeated efforts to impose discriminatory pricing between existing and new generation capacity, which has occurred despite FERC's consistent rejection of this approach as inefficient and unworkable. As FERC has emphasized, there is no rational basis for distinguishing between "old" and "new" megawatts of capacity.[11] Nobody, for example, would contend that the trucker whose truck is paid for should receive less for hauling a load of goods to market than the trucker who just bought a new truck and continues to have monthly payments. Nor would Alcoa, which testified at your November hearing, agree to price its aluminum products differently based on the age or cost structure of its plants.[12]

Such discriminatory pricing proposals are only schemes to try to expropriate existing "sunk" property to avoid paying the appropriate market price. Basically, they are merely meant to offset buyers' decisions not to hedge price risk. Any such confiscation is doomed to failure as all new entrants will recognize that the day after they start operations they too become "old" and subject to the same adverse discriminatory treatment. Accordingly, such discriminatory pricing ultimately will undermine long-term

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[11] *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 at P 141 (2006), order on reh'g, *PJM Interconnection, L.L.C.*, 121 FERC ¶61,173 (2007). Past experience with "vintage" pricing in the context of natural gas ratemaking ultimately led to a national shortage in natural gas and prompted the passage of the Natural Gas Policy Act which deregulated natural gas supply.

[12] Alcoa's aluminum prices are also set through a single clearing price market, but their plants have different cost structures. Yet, at the November hearing, Mr. David Ciarlone of Alcoa essentially complained about the ability of generation facilities to capture infra-marginal rents. Appling that illogical position to Alcoa's facilities, Alcoa's lower cost plants should be required to refund a portion of their profits, a result Mr. Ciarlone presumably would oppose.

reliability as it deters not only needed new entry, but also the continued investment required for maintenance and upkeep of efficient existing generation.

Testimony at the PUC's earlier hearings also revealed the mistaken view that before RPM capacity was somehow "free" and that capacity costs under RPM are unjust and unreasonable. Neither is true.

An independent report on RPM's performance to date by the Brattle Group confirmed that PJM is successfully ensuring long-term reliability at reasonable costs. Although the report recommended some enhancements to improve RPM's performance, it endorsed maintaining RPM's key components. The five auctions completed to date have locked in the most economic and competitive mix of new and existing capacity[13] needed to ensure system reliability through 2012, with over 14,500 MW of new capacity from diverse sources, including wind, solar, hydro repowering, nuclear uprates and almost 1,000 MW of base load coal. RPM has also resulted in an unprecedented amount of demand response, almost three times as much as before RPM. Furthermore, as you are aware, in August PJM also launched a stakeholder process to attempt to reach consensus on the recommended revisions. Although consensus was not reached, this week PJM filed with FERC a proposal to enhance RPM and a formal settlement process is underway. The bottom line is, RPM is essentially working as intended and through the ongoing stakeholder settlement process and an upcoming February technical conference at FERC, will continue to evolve.

[13] As underscored in the 2011-12 RPM auction in which approximately 2,900 MW of the full capacity of existing units and an additional 1700 MW of partial capacity of existing units (4600 MW total) didn't clear, contrary to the "no generator left behind" claims, clearly only the most economic generators receive these revenues. See The Brattle Group, "Review of PJM's Reliability Pricing Model," 6/30/08 at page 34 and Table 4 page 36.

Moreover, as detailed in the following section, the claim that capacity was essentially free before RPM is erroneous.

<u>The Regulatory Restructuring Bargain Provided Many Benefits and Forecasted Comparable, If Not Higher, Prices for Capacity</u>

As I noted at the outset, the distinction must be drawn between the results of conscious business decisions and the question whether market design is functioning properly. I will focus first on the "regulatory" side of the business decision using the PECO restructuring settlement to illustrate.[14]

Before restructuring, the regulatory bargain had been the exchange of guaranteed cost-based recovery of prudent and useful capital expense (both return on and return of capital) in exchange for the provision of energy at cost. Stated another way, in exchange for guaranteed recovery of capital expense, the purchaser (in this case the ratepayers of the regulated utility) paid market prices for energy but also received all the infra-marginal rents associated with energy produced by those capital goods.

The 1998 PECO restructuring settlement in part called for: specified rate reductions, transmission, distribution and generation rate caps and asset write downs, as well as partial recovery of stranded costs via transition charges and the transfer of generation assets to a separate unregulated entity. Basically, a regulatory tradeoff was made to capture the benefits of reduced and capped rates, and freedom from possibly higher stranded costs in an exchange for transferring ownership of the generation assets.

At the October 2008 hearing, one Commissioner expressed dissatisfaction with that regulatory bargain. In short, the Commissioner felt, looking back, that the plants were "sold" too cheaply and that market prices today are too high.[15] Although Pennsylvania's historic business decisions reflected in restructuring settlements are relevant to Pennsylvania, they are unrelated to the accuracy of current wholesale market power price signals and the effectiveness of market design. Both Dr. Bowring and Mr. Ott highlighted this point at that hearing, emphasizing that state-specific restructuring

[14] I chose the PECO settlement to review as it was among the first approved by the PUC.
[15] See 10/23/08 transcript, at pp. 110-111.

settlement terms cannot drive design of a workable, and sustainable regional wholesale market.

I did my own research of the PECO settlement and came to materially different conclusions about that regulatory deal. Most notably, when the data is placed in context, the current market prices, particularly for capacity, not only are not very different, but in fact, have been lower than those which were forecasted in the restructuring proceeding, and upon which stranded cost decisions were based.[16]

In particular, I reviewed the actual values referenced in this hearing, and also some of the specifics in the PECO restructuring filing, for generation capital recovery, or capacity. For example, in this proceeding Commissioner Christy stated that a state-wide value of $318 per kW[17] was established for generation (after write downs and stranded costs). From this starting point one can then estimate the long-term rate-based capacity/capital charge that would have applied under traditional rate making even to the "low" written down amount. I did so by applying an 18% fixed charge rate to get an annual capital recovery for this rate-based amount equal to $57.24 per kW per year. Using a very conservative forced outage rate of 5%, much lower than the actual outage rate during that period, this translates to $60.25 per kW per year for unforced capacity. When converted to the same values as in the RPM auction, this is the equivalent of $165.08 per MW day.[18] Thus, even ignoring stranded costs, based on the written-down book value and under traditional regulation, the statewide value for generation to break even on capital charges each and every year would have been approximately $165.08 per MW day.[19] Comparing this to Table 3 in Dr. Bowring's testimony, [20] as well as with the $154.57 per MW day value PJM offered in its November 17th reply comments as the proper basis of comparison for RPM pricing, the conclusions are fairly obvious. Actual payments collectively both before and including RPM have produced cheaper results than

[16] Indeed as discussed subsequently, these low prices likely have discouraged long term contracts, which would be expected to price higher at the "correct" long-run marginal cost.
[17] See October 23, 2008 transcript, pages 110-111.
[18] None of the estimates I am providing include annual fixed O&M or other non capital "to go" costs, which would further increase the annual capital-related charges. Thus, these estimated equivalents are very conservative.
[19] I say at approximately as these values exclude such capacity-related charges as fixed O&M, which would be expected to be included in RPM pricing.
[20] See October 23, 2008 Testimony of Joseph Bowring, p. 11, attached hereto as Appendix A.

what was assumed for capacity at the time of restructuring, had such capacity been given cost-based treatment. [21]

Further, I identified a summary of market-based forecasts for capacity presented in the PECO restructuring including those submitted by the Philadelphia Area Industrial Energy Users Group ("PAIEUG").[22] In Appendix B, I have reproduced this PAIEUG's sponsored forecast, adjusted it for unforced capacity, and expressed it in $ per MW day. The Commission used this and other similar information to not only project the market value for capacity in the future, but also as a basis for estimating stranded costs. While not exactly apples-to-apples, a comparison with Dr. Bowring's historic data from his Table 3 is instructive, particularly as my understanding of PAIEUG's market estimates for capacity would be very comparable to the net Cost of New Entry values used in RPM. Several things are obvious from this table. First, that actual capacity rates have been lower than those forecast by the industrial customers. Second, had the actual rates been known, stranded costs and transition charges would have actually been higher; and third, given their access to such forecasts, the industrial customers' choice between negotiating long term hedges at those prices or "riding" the restructuring settlement and speculating on rates after the settlement had to be a conscious business decision.

The figures demonstrate convincingly that allegations of excessive capacity payments under RPM are unjustified. On the contrary, conservatively, the projections at the time of restructuring indicated that generators would need to make $165.08 per MW Day to break even. Yet prices in the last auction were only $110 per MW day and have averaged well below this target since the start of the market.

<u>Industrial Customers' Complaints Mainly Reflect the Expiration of Their Favorable Deals and Their Failure to Hedge</u>

Under restructuring in Pennsylvania, customers received the benefit of approximately 12 years of capped rates, by far the longest rate cap period I am aware of in the nation. Large industrial customers, particularly those with interruptible service or special contracts, and who generally escaped paying stranded costs on such service, have

[21] These numbers are based on written-down capital cost. Even if this written-down amount were used, absent the move to competition, equivalent rate-based payments for capacity would have been much higher than actual payments. Obviously without the writedown, the historic numbers under regulation would have been higher still.

[22] *See* PECO Statement No. 4-R, Exh. JFB-14, R-00973953, P-00971265.

had over a decade to anticipate and prepare for the expiration of rate caps. Many such customers, however, decided not to enter into long-term hedges because short run prices were lower than long-term marginal costs. The restructured capped rates were so attractive in comparison to market rates that these customers made conscious decisions not to enter into longer term transactions that would have effectively insulated them from charges at the market clearing price when rate caps expired. But this difference, in and of itself, does not make those market rates invalid.

As this favorable restructuring deal is about to expire and the historic regulatory hedge will no longer be available, both short run and long run marginal costs have increased. The obvious result of this series of business decisions is exposure, after 12 years of regulatory "protection," to higher prices. This is a business result, not a pricing failure. Those same customers who demanded restructuring and chose not to hedge now claim the wholesale market design is flawed and rates are unreasonable. Yet the reality is that long-term contract rates since the start of restructuring are legitimately higher than their 12 year old favorable restructuring deal. This fact doesn't make the long-term rates invalid. The reality is simply that long-term marginal costs are above both spot and restructured capped rates. This is not a cause to change wholesale pricing.

As I noted before, PJM wholesale market design supports long-term contracts. As FERC emphasized in its October 16, 2008 Final Rule on market performance, such contracts are available and at a fair price that reflects long run marginal costs. This Commission also has recognized that a fair long term contract rate is equal to long-run marginal costs. [23] Dr. Bowring's net revenue, or breakeven analyses effectively are the equivalent of a current year estimate of long run marginal costs for base load, cycling and peaking generation. They reflect a long run carrying cost for capacity. This is an excellent proxy for the long run marginal cost one would expect to see in the bilateral long-term contracts that the industrial and municipal customers in this proceeding claim to want.

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[23] Opinion and Order R-00973953, P-00971265 at 29, January 15, 1998. It is interesting to note that this Commission also was cognizant that its own regulatory intervention into retail pricing would have the potential to skew new entry of generation. Specifically, the Commission noted that if shopping credits were below the long-run marginal cost, no one would enter into long term agreements and/or build new generation. This is a direct corollary to the complaints in front of the Commission today. Sellers will not enter into long-term contracts for compensation that is less than the fair long-run marginal cost.

Dr. Bowring's Net Revenue Analysis further shows that a contract price set approximately at long run marginal costs would exceed the cost of buying the same energy and capacity under current market prices. Dr. Bowring calculates whether the profit (infra-marginal rents) from any of these plants is positive when compared to the amount such a plant could earn in the PJM energy and capacity market. When Dr. Bowring concludes that in eight of the last nine years, generators in PJM have not covered their fixed costs, he is demonstrating that a contract price legitimately set at long run marginal costs would exceed the costs of buying the same energy and capacity under the current spot market prices. Faced with this reality, in not entering such contracts, it appears that the industrial customers chose to speculate on the market at the end of the rate cap period. However, again, that says nothing about the accuracy of the market pricing they faced, simply something about their business decisions.

Accordingly, complaints that long run contract prices are too high and unavailable due to PJM's market design are specious. On the contrary, such contracts are available, and at a fair price. The false concern here is the failure to recognize that the fair price for these contracts has legitimately been in excess of the cheaper spot market prices. The disconnect is that apparently the industrial customers don't want to pay this fair price but would prefer, after receiving the upside of over ten years of capped rates, to unwind the regulatory bargain and impose a cost-plus agreement from existing, depreciated power plants they don't own. That simply isn't the business deal they struck. At the expiration of the restructuring rate caps, this Commission explicitly anticipated that the owners of the existing power plants would be free to sell their energy and capacity at market, and actually relied on this capability to justify the final level of stranded costs and duration of the rate caps.

Portland Cement Association's Alternative Market Design Proposal is Unworkable

As detailed in previous sections, the wholesale energy and capacity markets essentially are working properly and FERC and PJM remain focused on incremental enhancements to further improve the markets' performance. As such, it makes no sense to make radical changes and effectively "start from scratch," especially by implementing the unworkable, fundamentally flawed alternative market design ("AMD") proposal championed by the Portland Cement Association ("PCA") and endorsed by Robert Weishaar in his testimony at the PUC's November 6th hearing.[24]

Among other things, this proposal would implement centrally-managed procurement of less than the full reserve requirement with 10- to 20-year contracts for energy and capacity linked to a 20-year planning horizon. It is perplexing that representatives of large, sophisticated industrial customers competing in global markets would advocate repeating the very inefficient market design that failed ten years ago. Furthermore, the framework incorporates explicit price discrimination designed to undervalue existing generation and pay market prices only to new entry. Pricing existing capacity differently from new capacity leads to numerous problems and undermines the competitive process. The mandated must offer requirement for all existing generators, coupled with staged procurement of less than full requirements creates an artificial surplus that supports discriminatory pricing. Suppliers of the identical product will likely be paid two different prices, exactly the results repeatedly rejected by FERC on solid economic grounds. As referenced earlier, FERC has noted: "In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants, commodity markets clear at prices based on location and timings of delivery, not the vintage of the … plants used to produce the commodity."[25]

Additionally, the PCA AMD proposes to combine this discriminatory pricing design with pay-as-bid clearing mechanisms, in particular pay-as-bid market-based offers for capacity coupled with cost-based and pay-as-bid energy supplies. As highlighted previously, this creates an incentive for inefficient bids at a premium. It also will likely dilute the right price signals for consumers regarding efficient demand response by hiding the true marginal cost of energy, and in turn reducing the level of price responsive conservation. For, as detailed earlier, in a pay-as-bid auction those making offers are have an incentive not to bid their true costs, but to bid "guesses" at the level of prices they can offer and still clear in the auction. Therefore, the PCA AMD creates something of a

[24] Wholesale Competition in Regions With Organized Electric Markets, RM07-19, AD07-7-000 Consumers' Supplemental Comments and Proposed Alternative Market Model, January 10, 2008.
[25] *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 at P 141 (2006), order on reh'g, *PJM Interconnection, L.L.C.*, 121 FERC ¶61,173 (2007).

lose/lose proposition with the adverse impacts of both discriminatory pricing coupled with incentives for inefficient and higher bids and associated costs for consumers. Finally, the use of pay-as-bid mechanisms creates an almost insurmountable barrier to rational market monitoring by making it impossible to distinguish between legitimate bids seeking to capture market-based margins and artificially high bids reflecting economic withholding.

Conclusion

Again, I thank the Commission for inviting me to testify in this hearing and commend you for your focus on these critically important market issues. This is an exciting time of tremendous opportunity. Thanks to the ongoing development of robust competitive wholesale markets, rather than having to strike another regulatory deal, all Pennsylvanians, including this Commission, now have more viable options than ever in deciding how best to fulfill their future electricity needs.

APPENDIX A

Table 3 Capacity prices: 1999 through May 31, 2012[26]

(Values in $/MW Day)

	Market Weight	RTO	EMAAC	SWMAAC	MAAC APS	DPL SOUTH
1999	$52.24					
2000	$60.55					
2001	$95.34					
2002	$33.40					
2003	$17.51					
2004	$17.74					
2005	$6.12					
2006	$5.73					
Jan 07 - May 07		$3.21				
Jun 07 - May 08		$40.80	$197.67	$188.54		
Jun 08 - May 09		$111.92	$148.80	$210.11		
Jun 09 - May 10		$102.04		$237.33	$191.32	
Jun 10 - May 11		$174.29				$178.27
Jun 11 - May 12		$110.00				

[26] From the Testimony of Joseph Bowring October 23, 2008, Monitoring Analytics. Table 3, p. 11.

APPENDIX B

PECO GENERATION MARKET PRICE FOR CAPACITY (PAIEUG, 1997)[27]

YEAR	$/KW YEAR	$/KW YEAR UNFORCED (5%)	**$/MW DAY UNFORCED**
1999	24.3	25.47	**69.79**
2000	30.8	32.42	**88.82**
2001	46.5	48.95	**134.10**
2002	49.0	51.58	**141.41**
2003	53.4	56.21	**154.00**
2004	58.2	61.26	**167.84**
2005	60.0	63.16	**173.04**
2006	61.2	64.42	**176.50**
2007	61.3	64.53	**176.78**
2008	64.4	67.79	**185.72**
2009	64.6	68.00	**186.30**
2010	67.4	70.95	**194.38**
2011	68.5	72.11	**197.55**
2012	69.7	73.37	**201.01**
2013	73.6	77.47	**212.26**
2014	77.3	81.37	**222.93**
2015	80.0	84.21	**230.71**

[27] See PECO Statement No. 4-R, Exh. JFB-14, R-00973953, P-00971265.