

**MARKET MISPERCEPTIONS
AND
REGRETS ABOUT PAST BUSINESS DECISIONS**

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I. Introduction

The following short paper was prepared by Dr. Roy Shanker. It based in part on a written and oral statement that Dr. Shanker presented to the Pennsylvania Public Utility Commission in December 2008. Dr. Shanker has consulted to participants in the electric utility sector since 1973, and been an independent consultant since 1980.¹ He has been extensively involved in all aspects of the electric utility industry and has worked for regulators, independent power producers, integrated utilities, transmission owners, merchant transmission developers and financial institutions. Over the last 13 years Dr. Shanker has been extensively involved in the design and implementation of RTO markets, particularly in PJM and NYISO.

II. Executive Summary

In the debates over past regulatory decisions in several states, it is clear that some have confused and conflated two very different issues: (1) the effectiveness of the underlying market design in reflecting the “right” prices, and (2) the consequences, both positive and negative, of conscious business decisions made by participants in those markets, particularly buyers of power and/or those acting on behalf of buyers. Some buyers now call for radical market overhaul of wholesale markets and a reversion effectively to cost-based regulation. But these initiatives appear to be based more on regrets about past business decisions than on any analytical conclusions regarding the design of wholesale electricity markets and the associated energy and capacity pricing. As such these buyers and their comments are both misguided and myopic.

In particular, much of this criticism has originated with large industrial customers and municipal utilities or public power agencies. However, their current criticism of market design typically ignores the origin of their business position and decisions, and confuses the two. Under restructuring, large industrial customers often avoided paying full stranded costs and benefited in some cases for over a decade from capped electric rates. This typically was the result of direct negotiations and/or regulatory decisions regarding deregulation. Subsequently, during or after the freeze periods, whether or not these large, sophisticated customers decided to hedge² 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.

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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)

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 state regulatory commissions in their associated decision making related to restructuring. Often part of the regulatory balancing regarding rate freezes, the duration of freezes and levels and recovery of stranded costs directly incorporated expectations regarding the ability of divested or partitioned generation assets to earn market based income for their generation.

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, this debate 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 market pricing. I have witnessed this struggle repeatedly during the last 35 years during which the electric markets have gone through several business cycles of high and low marginal costs versus average 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 related to average costs. This basic conflict is what is at play 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 megawatt-hour (MWh) of electricity based on generator location and system conditions at the time it is produced. Worldwide, virtually all commodity markets, operate in a manner that reflects the so called “law of one price” with effectively a single clearing price adjusted for location, the same intent as PJM’s Locational Marginal Pricing mechanism. As PJM’s Independent Market Monitor emphasized at an October 2008 hearing, in Pennsylvania, PJM’s LMP

market is producing transparent, competitive marginal price bids. The heart of this process is a single clearing price mechanism. Similarly PJM's capacity mechanism, the Reliability Pricing Model (RPM) is producing capacity costs consistent with the recovery of long-term costs that are explicitly excluded from recovery in the energy markets. Notably as well, PJM's robust competitive wholesale market provides consumers and state regulators more procurement choices than ever. Prior to competition, there was only one choice: a long-term cost-plus regulated contract. Now we have numerous choices regarding term, pricing, products and risk allocation.

One thing must be remembered regarding the current cost implications of historic decisions: these wholesale procurement choices represent conscious business decisions by both customers and the regulatory commission, and the associated consequences (good or bad) of these decisions are independent of the underlying power 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 alternatives such as the "pay as bid" mechanisms that have been proposed by some industrial customers. Such an ill-advised move would subject consumers to tremendous downside risk with little potential upside.

In this paper, 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**

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

Worldwide, virtually all commodity markets, from corn to beans to aluminum, operate in a manner that reflects the so called "law of one price" with effectively a single clearing price adjusted for location. The same applies for power. A kilowatt-hour (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 (LMP) through which participants receive at least hourly price signals directly reflecting the cost of serving an incremental unit of electric demand at that location.

Indeed, each of us is familiar with and almost intuitively understands the appropriateness of this single clearing price concept from our own experience. Consider your home. 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 under locational single price clearing. 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. Under this pricing mechanism, the system has transparent recognition of the cheapest set of resources to meet overall requirements and constraints at each location, and recognizes the uniform value of power in meeting these requirements at each location. Each similarly situated party receives the same locational clearing price, none is subsidized, and each has an incentive to bid competitively at short-run marginal costs.

The overall structure is explicitly efficient and pro-competitive. In fact, 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, has emphasized, because single clearing price markets are very transparent with respect to the relationship between bids and marginal costs 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. Thus not only is the "right" price communicated, but this type of design is consistent with recognizing reasonable competitive incentives and behavior versus potential exercises of market power.

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. Historically, 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. In fact, prior to the establishment of the Regional Transmission Organization (RTO), PJM incorporated just this type of information to create the pool "running rate" that was used to direct generation dispatch and level of operation. This is the essence of LMP pricing and reflects standard practice for virtually

all utilities whether inside an RTO or not. In fact, my understanding is that virtually the same dispatch software was used to send pricing signals both before and after initial LMP implementation in PJM in 1998. 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 savings each year. These are benefits that accrue from getting wholesale power prices right under the RTO paradigm.

The current single clearing price wholesale designs have also been criticized as being inconsistent with or discouraging of bilateral contracting. This simply isn't the case. Again considering the PJM market, there is no indication of this whatsoever. 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 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.³ My experience is the same; transparent markets facilitate contracting. I encourage clients to formulate bilateral power purchase/sale agreements such as contracts for differences⁴ because of the relative ease of contracting, the underlying transparency in the pricing, and associated simplicity in other contract-related requirements such as assigning risks and responsibility for transmission or defining damages.⁵

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

In stark contrast, however, a pay-as-bid market where each successful supplier is paid their offer price, is inefficient, lacks transparency and should result 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 will be the clearing price or the level of marginal costs for an offer to be accepted. Empirical simulation has demonstrated that in a pay-as-bid auction structure, the participants very quickly adopt bidding strategies that often (not

³ PJM 2007 SOM report, Table 2-82.

⁴ 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.

⁵ 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.

always) result in higher clearing prices when compared to the single clearing price results.⁶

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.⁷ Dr. Bowring in his State of the Market publication analyzed the offer margins or mark ups for suppliers in a single clearing price market and confirmed the competitiveness of prices in PJM’s LMP market. The ability to reach such a conclusion is vital not only to both actual competitiveness and mitigation of market power, but also to the confidence of market participants.

No such conclusion would be possible or applicable in a pay-as-bid environment. It would be virtually impossible to make any such determination as to competitive offers. This occurs because there is no standard of behavior to compare a supplier’s offer to. The “right” behavior under pay as bid is to “guess” the level of the marginally accepted price. This guess has no relationship to the supplier’s costs, so it is impossible to distinguish between a “bad guess” and the exercise of market power via economic withholding or other potentially manipulative bidding behavior. 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 single clearing price LMP market by obscuring information about what the “right” price is at any location.

V. PJM’S Reliability Pricing Model (RPM) Capacity Market Helps to Keep the Lights On

Clearly 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. A similar independent conclusion was reached by the Market Monitor. 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

⁶ 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.

⁷ 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.

new entry. In December of that year, FERC approved the settlement establishing RPM. The approved RPM settlement was the result of a longer than 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 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 the Federal Energy Regulatory Commission'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.⁸

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 a commodity producer such as a large electrical consumer like Alcoa agree to price its aluminum products differently based on the age or cost structure of its plants. Alcoa's aluminum prices are also set through a global, locational, single clearing price market, but each of their plants have different cost structures. Yet, at a November 2008 Pennsylvania Public Utility Commission hearing, Alcoa essentially complained about the ability of generation facilities to capture infra-marginal rents (i.e. the ability of lower cost facilities to earn higher margins when prices were set by the operation of higher costs production units or by scarcity). Applying that illogical position to Alcoa's facilities, Alcoa's lower cost plants should be required to refund a portion of their profits, a result Alcoa and any other competitive supplier in a single clearing price market presumably would oppose.

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 an indirect means to attempt to offset buyers' business decisions not to hedge price risk. Effectively they are the same as trying to confiscate ownership in the infra-marginal facility, by taking away a portion of the income private owners would otherwise receive. 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

⁸ *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.

discriminatory treatment. Accordingly, such discriminatory pricing ultimately will undermine long-term reliability as it deters not only needed new entry, but also the continued investment required for maintenance and upkeep of efficient existing generation. This is an unfortunate complement to the mistaken view that before RPM capacity was somehow “free” and that capacity costs under RPM are unjust and unreasonable. Neither is true. As detailed in the following section, the claim that capacity was essentially free before RPM is erroneous.

VI. The Regulatory Restructuring Bargain Provided Many Benefits and Forecasted Comparable, If Not Higher, Prices for Capacity Than Resulted From the RPM Design

The distinction must be drawn between the results of conscious business decisions and the question whether market design is functioning properly. To focus on the “regulatory” side of the business decision, the PECO restructuring settlement is a useful example to illustrate.⁹

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 whose costs they guaranteed. Effectively the guarantee of fixed price recovery was the same as a contract for the output of the generation at the generator specific marginal cost.¹⁰

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.

Many parties have expressed dissatisfaction with that regulatory bargain, and with the benefit of hindsight look back and conclude that the plants were “sold” too cheaply and that market prices today are too high. However, although Pennsylvania’s historic business decisions reflected in restructuring settlements are relevant to Pennsylvania and its consumers, they are unrelated to the accuracy of current wholesale market power price signals and the effectiveness of market design. State-specific restructuring settlement terms are nothing more than historic business arrangements, and cannot and should not be used as justification in any fashion to drive the design of a workable, and sustainable regional wholesale market. However, much of the current criticism of the current single

⁹ This paper was originally presented to an En Banc proceeding of the Pennsylvania Public Utility Commission. I chose the PECO settlement to review as it was among the first approved by the Pa PUC.

¹⁰ Obviously it is just this business agreement that was terminated by restructuring.

clearing markets rests on the commingling of this dissatisfaction with historic business/regulatory decisions and the resulting price consequences of the decisions with the actual operation of the market design.

An unvarnished review of the PECO settlement provides insight into how these issues have been erroneously mixed, and produces materially different conclusions about that regulatory deal and the associated business, not market design, decisions and decision making. Most notably, when the data is placed in context, the current market prices for capacity not only are not very different than forecasted over a decade ago, but in fact, have been lower than those which were forecasted in the restructuring proceeding, and upon which associated stranded cost decisions were based.

Understanding the role of such capacity price forecasts is an important part of the puzzle in seeing the current criticisms for what they are: regrets about old business decisions, not valid market design criticisms. As a key part of that restructuring proceeding, various parties offered their forecasts of what they believed future energy and capacity prices would be. *All* parties assumed a single clearing price market in the future, and calculated expected profits or operating margins for existing generation based on these forecasts, and in turn, the implied stranded costs of the existing generation. This was done by comparing the present value of such income to the book value of the assets. Thus the higher the forecast future prices, the lower the stranded costs. From the perspective of consumers, higher future market prices were perceived, at least in the restructuring process, as a good thing. This was because higher future market prices increased the value of the potential assets that would be divested or transferred from vertical utility ownership into private or non-regulated affiliate hands. In turn, this reduced the stranded cost exposure of customers. Thus consumers would be the direct recipients of this increased value, and therefore argued in favor of higher forecasts of future prices.

A summary of market-based forecasts for capacity presented in the PECO restructuring was presented in the proceeding, and it included those submitted by the Philadelphia Area Industrial Energy Users Group (“PAIEUG”). Reproducing PAIEUG’s sponsored forecast, adjusted for unforced capacity, and expressed in \$ per MW day (See Attachment 1) demonstrates convincingly that allegations of excessive capacity payments under RPM are unjustified. On the contrary, the projections by consumers such as the PAIEUG at the time of restructuring for the 2011-12 period were approximately \$200 per MW day. Yet prices in the last RPM auction for the same period were only \$110 per MW day. A full comparison shows that actual PJM capacity prices have been well below those forecasted during restructuring. The PJM capacity prices during that period also are presented in Attachment 2.

The key observation here is that consumers and their representatives in restructuring not only forecasted capacity prices higher than have actually occurred, but perceived this as being to their benefit when they advocated the use of such forecasts. What is at issue today is principally how they acted or failed to act based on the very information they themselves put forward.

VII. Industrial Customers' Complaints Mainly Reflect the Expiration of Their Favorable Deals and Their Failure to Hedge

Under restructuring in Pennsylvania, customers received the benefit of approximately 12 years of capped rates, by far one of the longest rate cap periods 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 had over a decade to anticipate and prepare for the expiration of rate caps. Many such customers, however, apparently decided not to enter into long-term hedges because short run prices were lower than long-term marginal costs (or they didn't believe their own forecasts submitted to regulators). The restructured capped rates were so attractive in comparison to market rates for long-term capacity and energy 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 market pricing failure. Those same customers who encouraged restructuring to escape what they perceived as large stranded costs, and then chose not to hedge against price risk, now despite the logical disconnect 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 and the associated frozen rates. This fact doesn't make either the spot market rates for energy and capacity or the long-term contract 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.

Further, there is no indication that the historic prices in PJM for energy or capacity are out of line with legitimate costs, and in fact have been lower than the long-run marginal costs that one would have expected to be seen in long-term hedge contracts. Steady state, one would expect that market prices would have to support the cost of a new entrant, otherwise no new capacity would be built. PJM's Market Monitor recognizes this fundamental fact, and uses it as one measure to effectively "take the temperature" of the market. He does so by calculating the net earnings potential new entrants would receive from the capacity, energy and ancillary services markets and comparing it to the average carrying costs of new generation. This is the so-called "Net Revenue Analyses" presented in the annual State of the Market reports. Dr. Bowring's Net Revenue Analysis show 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. When Dr. Bowring concludes in the PJM State of the Market report that in eight of the last nine years, new entrant generators in PJM have not recovered 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.

Two facts become obvious here. First, market pricing for energy and capacity can hardly be seen as excessive, and second, faced with this reality, in not entering into such long-term hedge contracts and not hedging their price risk, it appears that the industrial customers chose to speculate on the market at the end of the rate cap period. There is nothing wrong with making such a business decision; however, again, that says nothing about the accuracy of the market pricing they faced. Rather, it simply states something about those 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 price freeze levels as well as 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 10 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, state regulators 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. Clearly, regulators depended on just this fact to justify their decisions regarding the value of existing generation, and associated benefits and liabilities assigned to the various participants in the utility restructuring. It would be at best inequitable at this point to suddenly decide, after 12 years of benefits, to unwind the bargain and attempt to reclaim assets whose value depended in large part, on potential earnings after the rate freeze period.

Attachment 1

FORECASTED PECO GENERATION MARKET PRICE FOR CAPACITY (PAIEUG, 1997)

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

Attachment 2

PJM HISTORIC CAPACITY PRICES

Capacity prices: 1999 through May 31, 2012

(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				