UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Capacity Markets in the PJM Region	**)**	**Docket No. PL05-7-000**
	)	
PJM Interconnection, LLC	**)**	**Docket No. EL03-236-000 *et al.***
	)	
PJM Interconnection, LLC	**)**	**Docket No. ER04-539-000 *et al.***

PPL RESOURCE ADEQUACY MARKET PROPOSAL

COMMENTS OF THOMAS W. HYZINSKI

ON BEHALF OF PPL CORPORATION

June 16, 2005

PPL believes that an efficient, transparent and stable capacity market structure that allows investors to readily project potential future revenues will promote future investment and assure long term reliability. An active, liquid bilateral market is an important hedging tool, given that no market structure, including RPM, is free of volatility and completely predictable.

PPL believes RPM has several features (such as locational obligations and a Demand Curve) that, if properly implemented, can work. Locational obligations will encourage generation to locate in the proper locations. Implementing a Demand Curve should reduce volatility, mitigate market power, and provide a more predictable revenue stream. Proper implementation of a demand curve may even prove valid the claims of a better investment climate and lower long-term cost.

However, PPL also believes RPM has a fatal flaw – namely the forward auction that provides a one year commitment four years out. This RPM forward auction should be eliminated for the following reasons:

1. RPM is a non-market, administrative solution that would prevent formation of an active and liquid bilateral market where both load and generation can hedge. PPL's major concerns are: RPM preempts short-term markets, which increases the risk to doing long-term deals; RPM increases uncertainty associated with trading years five and beyond, which impedes doing long-term deals; and RPM poses significant credit issues (posting collateral for five years, limits counterparties, and increases cost).

2. RPM has limited pricing points – one base residual auction and up to three incremental auctions. All auction results would be ex post pricing. A liquid bilateral market would have continuous price discovery and provide ex ante pricing.
3. Under RPM, PJM would function as a market participant to some degree, rather than just a clearing market administrator. PJM becomes a sleeve for the huge capacity transaction that would take place in the Base Residual Auction. This potentially will expose the membership to credit risk that they would not have assumed themselves in bilateral contracts with counterparties.
4. RPM would not be conducive to new investment as claimed by supporters. Generation must have a signed Interconnection Service Agreement (ISA) in order to participate, possibly missing the deadline for the Base Residual Auction. The one year commitment four years out would not be meaningful to a new generator that needs to recover its costs over many years. In fact, because a generator needs to lock in year four's price today, RPM introduces uncertainty that should factor into a generator's offer, which ultimately may increase price. Further, a one-year binding financial commitment four years out is no more binding, and provides no more assurance, than a firm, liquidated damages provision in a bilateral contract.
5. RPM would create new seams issues because none of the contiguous ISO/RTOs have adopted this administrative forward auction concept.

This will discourage interregional capacity transactions, further reducing liquidity.

For these reasons, PPL proposes the following specific changes to RPM:

1. Improved Transparency Through Visible Website - Generation supply and load demand data, and information from the RTEP 5 year plan, including information about potential local reliability constraints should be assembled, just as it would have to be for RPM. The key difference is that this information would be made readily available to the market on an ongoing basis. PJM should display this information on a visible, transparent website that is accessible by all market participants. PPL proposes it be made available at least four years prior to the delivery year.
2. Set Obligations Forward - PJM should set capacity obligations and establish LDAs, based on the assembled information four years prior to the delivery year.
3. Move the Mandatory Auction To Allow for Robust Bilateral Markets - Generation and load would hedge themselves by contracting bilaterally up to and until PJM runs a mandatory auction just prior to the delivery year to satisfy any capacity obligations that have not been satisfied bilaterally. Firm, liquidated damages provisions in bilateral contracts negotiated between load and generation would be as financially binding as the results of the RPM auction.

Under PPL's proposal, generation and load would both play an active role in determining how the capacity obligations are met based on their respective market views. PJM would remain the operator of a clearing market and would not become a market participant.

Under PPL's proposal, price would be discovered continuously through bilateral contracting. Under RPM, most capacity would be ex post priced at the time of the base residual auction and there would not be any short-term liquidity aside from a few RPM incremental auctions.

Under PPL's proposal, the ability to forward contract would allow multiple years to be hedged at negotiated prices that reflected the dynamic nature of the RTEP and changing generation supply. RPM would only allow load and generation to hedge one year at an administratively set price.

RPM, as proposed, will make it impossible for a liquid bilateral market to develop. It only gives the illusion of providing the forward commitment from generation that PJM so desperately seeks so it can plan transmission adequately and avoid RMR contracts. The real solution to obtaining a forward commitment from generation is a robust market structure that will encourage investment in new generation and the retention of existing generation needed for reliability. PPL proposes the elimination of RPM's four-year forward auction in order to allow the market to work.

For further reference, attached to these comments is a Policy Analysis by Joseph Cavicchi and Joseph P. Kalt, Ph.D. entitled "*PJM's Proposed Four-Year Forward Capacity Market.*"

A Policy Analysis
of
PJM's Proposed Four-Year Forward Capacity Market

Joseph Cavicchi and Joseph P. Kalt, Ph.D.*

June 16, 2005

INTRODUCTION

Electricity industry and policy restructuring in the U.S. over the last decade has sought to use market-driven mechanisms to set power prices and induce investors to supply power generation capacity where and when it is needed. The restructuring revolution has meant a movement away from traditional coordinated planning by cost-of-service public utilities and their regulators for long-term, system-wide capacity adequacy. Not surprisingly in this setting, and in the aftermath of some memorable system breakdowns in the post-restructuring era, policymakers, consumer groups, and generators have been concerned about mechanisms for ensuring system reliability in the restructured environment. Specifically, the ability of restructuring's centerpiece – centrally operated short-term hourly wholesale electric energy markets – to provide the incentives for new electric generation capacity to be added in the places and with the timing that are needed is being questioned.

At their inception, newly formed wholesale electricity markets in the Northeastern and Mid-Atlantic regions of the U.S. included electricity generation capacity market structures that specified a minimum acceptable quantity of generation capacity necessary to maintain a level of reliability consistent with that which had been experienced prior to the introduction of new market structures. Although these original capacity market structures were thought to be sufficient to ensure adequate future investment in electricity generation capacity, it has become apparent that the original market structures, combined with what has become widely recognized as politically unattractive short-run electricity price volatility, are not systematically able to provide adequate assurance of

* Mr. Cavicchi is a Vice-President at Lexecon, an FTI Consulting Company. Dr. Kalt is the Ford Foundation Professor of International Political Economy, John F. Kennedy School of Government, Harvard University, and is a Senior Economist at Lexecon.

compensation for generation facilities needed to provide reliable service. This realization has led Northeastern and Mid-Atlantic wholesale electricity market operators to propose capacity market redesigns to overcome both current and expected problems compensating certain generating units that provide needed capacity.

In order to encourage and incent generation suppliers and investors to add needed capacity where and when it is needed, PJM has proposed a Reliability Pricing Model (RPM). Under the RPM, PJM would organize and operate a four-year forward market for claims on capacity. The idea would be for PJM to specify a schedule for demand four years hence, based to some degree on PJM's forecasts of electric power demand four years out from the year in which the market would take place. With a four-year forward demand schedule specified, the RPM would establish prices that load serving entities (LSEs) would pay for capacity in that fourth year out by soliciting bids from suppliers of capacity and clearing the market (i.e., setting the price of four-year forward capacity) based on the balancing of the demand schedule and the supply bid in to meet that demand.

The impulse behind PJM's RPM proposal is reasonable, and the attempt to improve capacity planning and investment via a market-driven process is admirable. However, the workability and efficacy of the RPM's four-year forward approach to capacity pricing is questionable. While a four-year ahead setting of capacity prices might provide some indication of whether capacity four years out is likely to be relatively tight or loose, the RPM's four-year forward anticipatory snapshot is inherently blurred. Pricing of capacity claims for a single year does not solve the fundamental problem of providing investors with reasonable assurances of reasonably stable and predictable base revenues over a period of multiple years; experience and logic suggest that only bilateral contracting between suppliers and demanders can plausibly and practically accomplish that. Moreover, relative to, say, one-year forward capacity pricing, four-year forward pricing is likely to produce a string of prices that can be expected to be plagued by relative unpredictability inherent in longer-term forecasting and infirmity as to whether prices struck on a four-year forward basis can be insulated from political intervention when they turn out to be out of step with actual market conditions as they come due. We believe that the underlying objectives of PJM's RPM proposal can be more reliably and efficaciously achieved with a more straightforward one-year ahead approach to capacity market pricing.

BACKGROUND

A number of independently operated, federally regulated, hourly wholesale electricity markets have been established in the U.S. during the present era of industry and regulatory restructuring. Driven by the U.S. Federal Energy Regulatory Commission's (FERC's) landmark 1996 regulatory order providing open access to the U.S. high voltage transmission network, various regions readily embraced the opportunity to form sophisticated, internet-based trading platforms that produce transparent hourly spot prices for wholesale electricity supplies. Concomitantly, in most regions where such markets were introduced, significant investment in new, high-efficiency, low-emission electricity generators occurred. Although the liquid short-term markets prompted investment and indeed even (what, after the fact, has turned out to be) overinvestment in capacity, the underlying market structures in some regions did not provide sufficient revenues to generators whose resources were required to maintain system reliability. As a result, policymakers and system operators (such as PJM) have recognized the need to address the problem, and numerous FERC proceedings have come to focus on resolving the problem before a capacity crisis ensues.

At the time restructuring was initiated, it was understood that future investment was an important issue, and simply formulated capacity markets were expected to maintain adequate investment in generation. Although much investment occurred at the onset of restructuring in many parts of the U.S., expectations associated with how the markets would function often were not realized. This has become a pronounced problem during the current period of excess supply in many regions where although there may be sufficient total generation capacity, it is in some instances not in the appropriate location, or even if in the right location, is undervalued by the market in the sense that capacity prices are not sustainable at levels needed to compensate investors for the plants needed to ensure system reliability in the event of unusually tight supply and demand conditions. In short, early markets under restructuring dealt with the very short-term challenge of pricing electrical energy and have not provided optimal price signals for capacity reliability. Unfortunately, the time when more generation capacity will be required is here now or is within the planning horizon in many geographic sub-regions of the electricity grid. This drives the urgency to modify existing wholesale market structures.

Without delving into the myriad details associated with short-term wholesale electricity market design in the U.S., it is well understood that the combination of bid mitigation (*sic*, capping) systems, designed to thwart the potential exercise of market power or other possible causes of politically unacceptable price spikes, and so-called reliability must-run contracts results in electricity market-clearing prices that interfere with the price-signaling capabilities of the single-price clearing market. Price capping and related distortions of price signals emanating from the short-term energy markets tend to leave electricity generation capacity undervalued in certain geographic regions.

Usually, price capping occurs in response to electric energy prices perceived to be unacceptably high, and particularly high prices tend occur in particular geographic sub-regions where transmission constraints limit imports and indigenous capacity is particularly tight relative to demand.[1] In fact, PJM is well-known for short-term, hourly markets that yield higher prices in tight sub-regions. It is within these sub-regions that the under-compensation, price-signaling problem is most pronounced. Where we would expect the market system to reveal the value of generating capacity to investors, it does not (or is prevented from doing so), requiring the market operator to scramble to either support aged and/or financially challenged resources, or to jaw-bone for or command the acquisition of new resources needed to maintain system security and reliability. This observed approach to maintaining short-term system security, and ensuring long-term generating capacity adequacy, was not envisioned when these markets were put in place.[2]

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1 For example, in New England the independent system operator (ISO-NE) has identified Southwest Connecticut as a problematic sub-region. In New York, both New York City and Long Island are considered separate geographic locations to ensure adequate capacity is available to meet demand. All these sub-regions are characterized by limited import capability, and in some instances are areas where siting new generation or transmission facilities is complicated both environmentally and technically.

2 Although we understand that in some instances transmission system additions may resolve these observed problems, there nonetheless continues to be a fundamental problem with the current market structures when capacity shortages do not result in increased compensation to generating facility owners.

At the same time energy prices have been suppressed, initially constituted capacity markets[3] have been based on "vertical" demand curves specified by market operators. This has proven to be a poor approach to pricing capacity. The vertical demand curve specifies an absolute amount of capacity that is needed, regardless of price. This is a vestige of the traditional, pre-restructuring approach to defining a reliability standard: the amount of generation capacity available to the system should be adequate to ensure that only one major outage occurs every ten years.[4] This approach results in absolute minimum quantities of needed capacity. Typically, a capacity quantity is set at some percentage above measured or forecasted peak demand (typically 12-18% above), and this amount is defined as the total amount of generation capacity demanded throughout a region. Wholesale system buyers responsible for serving consumers are required to purchase an amount of capacity based on resulting peak obligations plus the established reserve percentage and face financial penalties if they do not purchase enough. This defines demand. To meet this mandated demand, generation suppliers sell capacity bilaterally or receive revenues from auctions administered by system operators who ensure system buyers meet their obligations.

The vertical demand curve for capacity has at least three distinctly undesirable characteristics. First, auction prices are volatile: Whenever system capacity is above or below the set quantity, prices either shoot up to penalty levels, or decline to nearly zero. And second, when capacity is in, or near to being in, short supply, there can be increased incentives for sellers to withhold supply and potentially drive up prices. Third, the combination of total region-wide system excess supply and sub-regions where capacity is in short supply creates opportunities for buyers in some instances to realize preferential pricing by free-riding on the system.[5] Coupled with suppressed energy pricing under

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3 At the time when independent system operators began administering wholesale electricity markets in the U.S., New York's, New England's, and Pennsylvania/New Jersey/Maryland's (PJM) ISOs each included capacity markets that were based on vertical demand curves. New York replaced its initial capacity market in 2003, New England is in the process of replacing its capacity market, and PJM is actively debating the so-called reliability pricing model to replace its capacity market.

4 This refers to the bulk transmission and generation system as opposed to the lower voltage distribution system that will often experience weather-induced outages.

5 Initially constituted capacity markets had attributes that resulted in capacity being akin to a public good when it was in excess supply. Thus, consistent with the classic characteristic of a public good – non-exclusivity – buyers in all locations were able to take advantage of excess supply wherever it was

which higher prices are lopped off by capping or other "mitigation," unworkable capacity markets have resulted in observably inadequate remuneration for various generation facilities.

The resolution of these problems will not be simple. The market operator cannot force the construction of generating capacity where needed[6]; and buyers of generating capacity generally and understandably seek to limit their expenditures for reliability, particularly when the costs to improve reliability are difficult to allocate equitably and efficiently across system users, and the costs of system breakdown typically are shared across buyers regardless of whether particular buyers have disproportionately contributed adding generating capacity. Moreover, generating capacity can often provide reliability and security services over fairly wide geographic regions, while consumers are in many instances served by several utilities that are not subject to consistent regulatory frameworks, further complicating cost allocation issues. The urgency of implementing solutions to these problems must not be underemphasized.

PJM's RPM APPROACH TO THE CAPACITY MARKET PROBLEM

PJM has been diligently engaged in developing a generating capacity adequacy market design that could beneficially supplant its current capacity market. Not unlike other Northeastern Independent System Operators (ISOs), PJM has acknowledged that it cannot assure reliability with a capacity market construct that does not differentiate resources' values based on their location, and whose design results in volatile pricing due to its reliance on a vertical demand curve.[7] At the heart of PJM's current efforts is the goal of a new capacity market design that will yield longer-term, locationally differentiated capacity pricing signals which will assist in incenting (along with locational energy prices) investment in appropriate locations and on appropriate time

located on the system. This problem has arisen because generators have been required to offer their capacity in order to be eligible for capacity payments.

6 Of course, it is possible for the market operator to solicit supplies and make contractual obligations to buy such supplies, although taking a position in the market is completely contrary to the idea that market operators shall be independent and only provide a means for buyers and sellers to meet and transact anonymously.

7 PJM, *Whitepaper on Future PJM Capacity Adequacy Construct, The Reliability Pricing Model*, Version 4.0, PJM Interconnection, November 2004.

profiles. To achieve its primary objectives, PJM has proposed the so-called Reliability Pricing Model.

In describing the RPM, PJM states that: "The concept behind the Reliability Pricing approach is to coordinate the price paid to generation capacity with overall system reliability requirements."[8] In its *Whitepaper on Future PJM Capacity Adequacy Construct*, PJM explains that its current capacity market structure relies on a fungible product that does not take account of generator location or operational characteristics, and relies on a vertical demand curve that generates volatile price signals.[9] The RPM alternative is intended to be a locational installed capacity (LICAP) market design similar in some respects to that which has been implemented, or is being considered, in New York and New England.

PJM's proposed RPM market design addresses a number of primary issues that have been identified as preventing capacity markets from producing stable price signals. Thus, for example, it would establish capacity prices that could vary with sub-regional location. Moreover, it would substitute a demand curve that is not vertical, but instead allows the price the market is "willing"[10] to pay for additional capacity to decline as the volume of installed capacity increases. The RPM, however, would adopt a complex four-year forward auction mechanism to establish four-year forward capacity prices at the time of an annual auction of four-year ahead capacity commitments. These prices would define generator capacity-based revenues and load costs for a future year four years before the year of the establishment of the capacity prices.

PJM's proposed RPM auction process[11] would, first, set locational demand levels (as obligations of LSEs) by March 31 four years ahead of the scheduled initial delivery.

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8 *Ibid*. at 4.

9 *Ibid*. at 1-2.

10 This demand curve is not, however, the product of bidding or other demand revelation by actual buyers. Rather, it is an administrative construct intended to avoid system breakdowns due to inadequate capacity.

11 PJM's Reliability Pricing Model DRAFT Business Rules, Document #271800, Version 7.0, February 24, 2005, outline the various details described herein. A graphical summary of the auction process is available from the PJM RAM Working Group website, http://www.pjm.com/committees/working-groups/pjmramwg/pjmramwg.html, Scope of RPM Auctions, PJM RAM Stakeholder WG, Terri Esterly, October 7, 2004.

Thus, for example, PJM, by March 31, 2006, would set the obligation for planning year June 2010-May 2011 (i.e., the 2010/2011 planning year). Then, in May of the year four years prior (2006 in this example), PJM would run a base auction that would set the price for zonal (locational) capacity that would be paid by LSEs that purchase capacity in the auction. Based on this price, PJM would commit buyers and sellers four years forward to either pay, or be paid, for that one planning year (2010/2011) using the reported results of the base auction.

Thereafter, PJM proposes to run three incremental auctions. The first incremental auction would be run two years prior to the 2010/2011 planning year and would have as its sole objective allowing resource replacement as necessary to allow for changes in expected available resources that have occurred since the date of the base auction. A second incremental auction would be run fourteen months prior to the 2010/2011 planning year, and its sole objective would be to adjust the forward obligation if a capacity resource shortage of greater than 100 MW results due to a higher load forecast. The second incremental auction would only be held if the shortage condition test is met, otherwise it is not held. Finally, there would be a third incremental auction eight months prior to the 2010/2011 planning year, the objective being the same as the first incremental auction.

ASSESSMENT OF PJM's RPM APPROACH TO CAPACITY PRICING

Notwithstanding its other strengths and the diligence of PJM's efforts, the RPM design for capacity pricing is flawed in its embracing of a four-year forward auction as the "solution" to discovering the prices upon which investors might rely in making their decisions. The failure of the first generation of capacity markets highlights what is important to future investors in generation capacity. In particular, investors in the very expensive and long-lived plant, equipment, and sites that make up a power plant fundamentally require reasonable certainty that their investments will garner a stream of relatively stable payments over multiple years. This perspective is driven especially by the demands of lenders for surety of debt service: The presence or absence of such assurance is commonly the make-or-break determinant of whether a planned facility actually gets built.

The kinds of organized capacity markets that ISOs or similar quasi-public parties can feasibly operate do not and cannot of themselves solve the problem of generating multiple years of reasonably stable and secure revenues for power plant developers. That is the job of long-term bilateral contracting between wholesale buyers and power plant developers. The feasible roles for organized ISO and ISO-like capacity markets are to ensure immediate avoidance of capacity shortages that result in system service disruption and to assist in discovering prices that accurately signal relative tightness or looseness of capacity in a market area.

The former role is most effectively performed by clearing capacity markets (i.e., setting price so as to balance supply and demand) on the near horizon in which the vast majority of capacity is already online. The latter role is played by striking prices that can be reasonably relied upon by investors and wholesale power buyers as they form their expectations as to the longer-term future tightness or looseness of power markets. Ideally, this formation of expectations is of the following archetype: A wholesale buyer combines the information contained in, say, high[12] prices in an ISO's organized capacity auction with all of the other information available to the buyer regarding future supply and demand conditions over multi-year horizons and concludes that: "I face the prospect of a stream of extraordinarily high annual capacity prices set in the ISO's auction. I think I'll go out on the bilateral market and see if I can do better with a five-year, ten-year, or longer (as appropriate) direct commitment from a developer." On the developers' side, the presence of demand from such buyers and those buyers' concomitant willingness to agree to multiple-year contracts with relatively secure and knowable payment streams attracts supply when bilateral offers come in at price streams at least sufficient to reasonably provide for the coverage of a new plant's total costs.

Simply due to the fact that the RPM's single forward price provides but a single year of revenue "certainty"[13] *four years hence*, the RPM's price discovery system is less

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[12] "High," here, has a fairly precise meaning: A "high" capacity price is a price that, if sustained, would fully compensate developers for adding new capacity.

[13] Note that the prospect of three "adjustment" auctions as the original fourth year out approaches indicates that the "certainty" of the original auction results is problematic. Moreover, the subsequent "adjustment" auctions do not imply a full reckoning of expected supply and demand conditions as the fourth year out approaches: Once the original price is established, PJM's proposed auction structure

reliable – and, thus, less valuable as a source of information and as incentive to investment – than an auction for capacity in the immediately coming year. It is a basic axiom of forecasting that the farther out into the future a forecast is made, the wider are the bounds of prospective error (i.e., the wider are the confidence bounds). It is easier to forecast a year ahead than four years ahead. In the present context, it would seem to be inherent in the complicated process of electric power planning, siting, financing, regulation, and commissioning that the farther out into the future a current commitment is made, the greater the likelihood that that commitment will not stick – and for myriad blameless and blameworthy possible reasons.

The implication is that, under PJM's RPM proposal, it would reasonably be expected that, as the year of commitment approaches, commitments struck up to four years earlier would not uncommonly fail to be executable; that the proposal's three layers of adjustment auctions would have to be invoked; and that the prices struck up to four years earlier would be out of step with actual, extant market conditions (perhaps thereby bringing further pressure for private or regulatory breach of those pricing terms). This is not to say that a capacity auction for one-year forward supply would not have errors and tensions vis-à-vis market conditions at the time of performance, but only that such problems would be expected to be less severe and less frequent than under the RPM's four-year forward approach. To be sure, bilateral long-term contracting for capacity implies reliance on the long-term forecasts and risk assessments of individual market participants. From a public policy perspective (i.e., aimed at assessing the broad public's interest), the advantage of such reliance on bilateral contracting is that the market-wide outcome in terms of contracting, investment decisions, purchase commitments, and the like is that that market outcome is an amalgam of the forecasts and risk assessments of the many market participants – from developers and their financial backers, to wholesale customers and ultimate consumers, to siting officials and equipment manufacturers. Relative to putting all or a great deal of a system's eggs in the basket of, say, the ISO and its demand/need projections, reliance on bilateral contracting creates a beneficial

provides little or no opportunity for it to vary in response to changes in market participants' expectations of future supply/demand conditions.

portfolio effect in which multiple outlooks and forecasts are brought to bear on market outcomes.

These economics of market-driven and market-determined capacity additions argue against the RPM's complex four-year forward capacity market and in favor of a year-forward approach when it comes to setting capacity prices. Setting capacity prices one year forward does not preclude the ISO from playing a useful role in monitoring long-term developments and needs, and in injecting information into the market regarding reliability-driven capacity needs prior to establishment of capacity prices. Thus, for example, the ISO might well announce obligations of LSEs in advance of a year-forward capacity auction that sets capacity prices – announcing obligations, say, four years in advance with possible revisions based on load shifts leading up to an auction. Knowing targets in advance would encourage LSEs to remove uncertainty vis-à-vis ultimate auction outcomes by meeting their commitments via bilateral contracting with suppliers and/or by building their own additions to capacity. The year-ahead capacity auction would then play the valuable role of filling out any remaining unmet obligations.

As has been widely discussed in recent years, the establishment of a simple, efficient, transparent and stable capacity market system that allows buyers to more reliably form long-term expectations on the price of capacity and that allows investors to more reliably project potential future revenues is critical for reducing uncertainty, promoting long-term planning, allowing multi-year contracting, and promoting future investment. This is especially so in price-mitigated electricity markets where energy price volatility is politically unacceptable and subject to intervention that (whatever its social and political benefits in the short run) distorts signals for long-term investment and purchase behavior.[14] A stable regulatory structure that provides for workable capacity markets that generate accurate price signals will enhance the prospect of well-timed,

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[14] See, for example, Cross-Answering testimony of Thomas Boland on behalf of Capacity Suppliers, Exhibit CS-51, filed in Federal Energy Regulatory Commission Docket No. ER03-563-030, January 10, 2005, at 10-11. Although Mr. Boland notes that certain aspects of the LICAP design can reduce its effectiveness, he indicates how generators will require stable returns in order to ensure reliability, which is the primary objective of the LICAP demand-curve-based market designs.

well-placed, and well-sized investment and buyer commitments. This, in turn, directly promotes system reliability.

CONCLUSION AND RECOMMENDATIONS

PJM's effort to redesign its capacity market is consistent with what has been observed in other locational capacity proceedings (namely New York and New England). The PJM RPM proposal provides useful approaches to avoiding the problems associated with the use of so-called vertical demand curves in ISO-organized capacity adequacy auctions. PJM's proposed RPM design, however, is uniquely differentiable from other locational capacity markets as a result of its proposed forward auction system.[15] Instead of setting prices in a one-year forward capacity market with various monthly balancing markets during the ensuing year, PJM is proposing to set binding capacity prices at a single time for four years forward.

Importantly, relative to allowing market participants to manage their capacity market positions themselves in response to the new locational capacity market structure, PJM's system will only provide limited price discovery and puts PJM in the position of forcing potentially costly forward-purchase commitments with elevated risk as a result of the demand that parties make commitments relatively far in the future. Even though we understand that PJM intends for this system to allow better coordination between generation and transmission planning, the principles embraced by PJM actually argue for a PJM capacity market operated over a shorter time horizon. The PJM approach, in fact, raises risk, and risk is a cost. Risk-related costs would manifest themselves as distorted and inefficient investment decisions. Introducing a system that can lead to inefficient investment is undesirable. Absent convincing evidence that PJM's proposed four-year forward pricing will result in better incentives to investors, it should not be adopted.

The risks most readily apparent under the RPM approach include: 1) PJM's four-year forward zonal obligation (demand) forecast could be too high, resulting in

[15] Each location capacity market system in use, or considered thus far, has various unique details, although they all value capacity by location using a price-quantity schedule for setting prices. The discussion herein does not delve into these various details – such as PJM's use of a "Variable Resource Requirement Curve" for its demand curve and its planned approach to optimizing price determination – but instead focuses on a primary aspect that is unique to PJM.

commitments to build unneeded generation resources; 2) LSEs would be forced to take on purchase obligations four years ahead even if those purchases were inconsistent with their own views of future supply/demand conditions and created debt obligations that impacted access to capital; 3) LSEs would face uncertain final prices for capacity obtained through the auction process (i.e., uncertainty as to whether and how supplementary adjustment auctions would affect capacity prices); and, 4) considerable opportunities would likely exist for proposed capacity "committed" in the base four-years ahead auction to drop out, requiring unexpected additional procurement costs. All of these risks can be reduced without compromising reliability by eliminating the four-year forward auction and substituting for it a one-year forward auction system (e.g., 8-14 months prior to planning year), perhaps with ISO establishment of target commitments well prior to the auction. This approach would allow market participants to plan multi-year forward procurement under the locational capacity market structure, with relatively more reliable price signals able to emerge from year-ahead market price setting.

Finally, although there may not be uniform clarity on what the appropriate role for ISOs is with respect to planning generation and transmission investments, the intention should be to rely on market participants to make forward-looking investment and purchase decisions, with ISOs operating competitive marketplaces and aiding system reliability by producing reliable price signals. Using a year-ahead auction design for the capacity markets maintains the ISO's role of assuring that balancing markets are run in a timely fashion. In this instance, using a not-vertical demand curve will produce relatively stable price signals that can be acted upon via bilateral contracting sufficiently in advance of the need for capacity to be put in place.