UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) **Dockets Nos. ER05-1410-000 & EL05-148-000**

AFFIDAVIT OF JONATHAN F. WALLACH
ON BEHALF OF
THE COALITION OF CONSUMERS FOR RELIABILITY

OCTOBER 19, 2005

I. Introduction and Qualifications

My name is Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

I have worked as a consultant to the electric-power industry for more than two decades. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-four years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; and energy-efficiency program design and planning.

I graduated Phi Beta Kappa from the University of California at Berkeley with a BA in political science with honors. My resume is included as Attachment 1 to this affidavit.

For the past six years, I have advised the Maryland Office of the People's Counsel ("OPC") on capacity-adequacy and system-reliability issues, particularly as those issues relate to the design and operation of both the installed-capacity and energy markets in the PJM Interconnnection ("PJM") and other regional transmission operators in the Northeast, Midwest, and California. I have represented the OPC throughout the stakeholder process concerning PJM's RPM proposal, as well as at meetings of predecessor working groups regarding capacity-market alternatives. I have also assisted OPC in the drafting of comments on these issues in a number of Commission proceedings, including comments on the Commission's Standard Market Design Notice of Proposed Rulemaking. Finally, I appeared on OPC's behalf at the Commission's technical conference on June 16, 2005 in Docket No. PL05-7.

II. Overview and Summary

As part of its Reliability Pricing Model proposal, PJM proposes to replace the market-based clearing mechanism currently employed in PJM's installed-capacity auctions with a mechanism based on an administratively determined demand curve or "Variable Resource Requirement" ("VRR"). In support of the proposed VRR, PJM relies on a "long-term" simulation analysis of the impacts of RPM on capacity and scarcity costs conducted by Dr. Benjamin Hobbs, as well as a modeling analysis of the impact of the VRR on energy costs under non-scarcity conditions conducted by Mr. Andrew Ott.

As I describe more fully in this affidavit, PJM has failed to show that the proposed VRR is a reasonable or superior alternative to the current clearing mechanism. A demand curve offers little advantage over the current clearing mechanism, since the current mechanism does not appear to suffer from the problems that the VRR is designed to rectify. On the other hand, PJM's proposed VRR is likely to significantly increase costs to consumers and windfall profits to generators, and perhaps lead to inefficient investments in generation capacity. In other words, the proposed VRR is likely to do more economic harm than good when applied to PJM's capacity market.

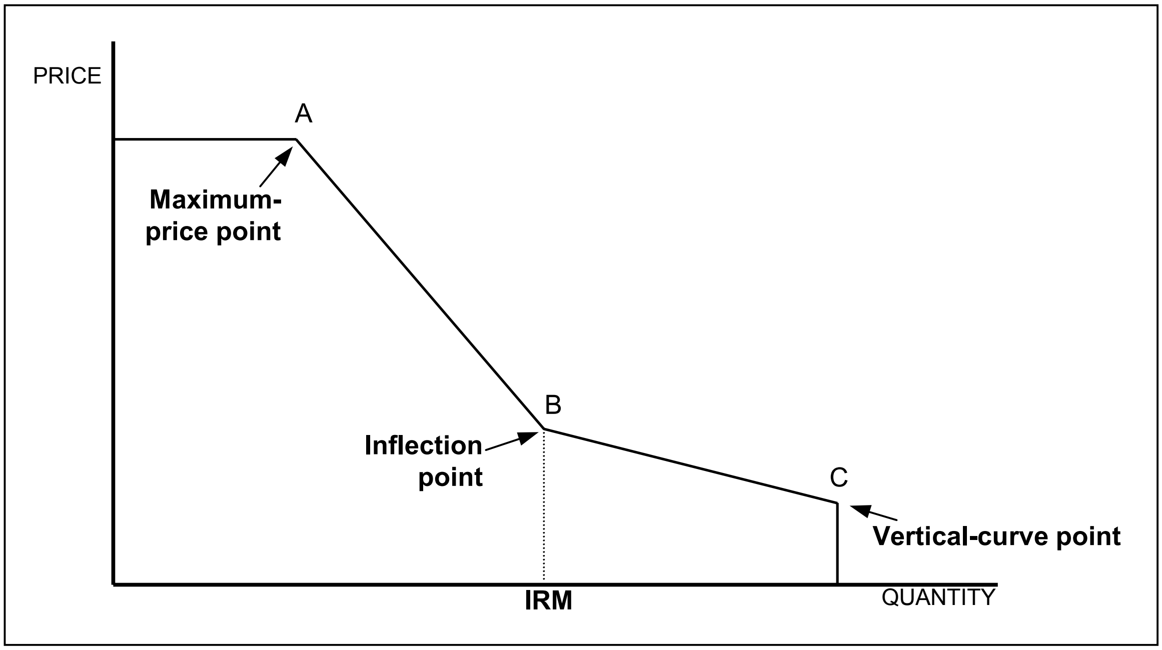
Neither Dr. Hobbs's nor Mr. Ott's modeling analyses offer compelling evidence to contradict the finding that the proposed VRR is likely to do more harm than good. Dr. Hobbs's analysis is marred by numerous problems that render it unreliable as the basis for determining the advantages of a VRR compared to the current clearing mechanism. These shortcomings include: (i) methodological flaws; (ii) unrealistic and unreasonable input data assumptions; and (iii) inadequate assessment of the impacts of market clearing in excess of reserve requirements.

Mr. Ott's estimate of reductions in energy costs from excess capacity purchases is also without merit. This simulation analysis is inconsistent with theoretical expectations and Dr. Hobbs's assumptions regarding market responses to increases in reserve requirements. Moreover, the analysis inconsistently accounts for reductions in energy costs, but not for increases in investment costs required to capture these energy-cost reductions.

III. PJM's Proposal for the Shape of the VRR

As illustrated in the following figure, the shape of PJM's proposed VRR is defined by three quantity points.

Figure 1: PJM Proposed Demand Curve



The "maximum-price point" (point "A" in Figure 1) is the quantity below which the price on the demand curve reaches a maximum of two-times the cost of new entry (net of operating profit.) The "inflection point" (point "B") is the quantity where the demand-curve price equals the net cost of new entry. Finally, the "vertical-curve point" (point "C") is the quantity where price on the demand curve drops to zero.

Thus, the price on the VRR

- is twice the net cost of new entry (net "CONE") for quantities below the maximum-price point;
- declines from two- to one-times the net CONE for quantities between the maximum-price point and the inflection point;

- declines from the net CONE to a fraction of the net CONE for quantities between the inflection point and the vertical-curve point;
- equals zero for quantities in excess of the vertical-curve point.

PJM evaluated three versions of this general curve that vary solely with respect to the quantity amount that sets the inflection point. The inflection point for each curve is: (1) IRM; (2) IRM plus one percentage point ("IRM+1%"); and (3) IRM plus four percentage points ("IRM+4%"). Based on this evaluation, PJM requests Commission approval of the IRM+1% curve.

IV. Economic Harm from the Demand Curve

PJM asserts that replacing the clearing mechanism in the current capacity construct with a downwardly sloping demand curve will result in "reduced risk and volatility, greater reliability, and lower consumer costs."[1]

PJM lacks a reasonable basis for these conclusions. PJM's assertions regarding the advantages of the VRR are based on a mischaracterization of the current construct and its impact on market prices. Moreover, when system capacity exceeds required margins, the proposed VRR arbitrarily and artificially forces auction prices to clear at levels that exceed marginal supply costs or even the marginal value of capacity to consumers. This attribute of the VRR not only needlessly increases costs to consumers and windfall profits to generators, but also reverses one of the few consumer benefits from restructuring by re-imposing the cost of uneconomic capacity on consumers.

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[1]Wright & Talisman, Transmittal letter to Honorable Magalie Roman Salas on behalf of PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000, August 31, 2005, p. 9.

A. The Current Construct Does Not Produce Extreme Price Volatility

Characterizing the current clearing mechanism as "similar" to a vertical demand curve, PJM claims that, under the current construct,

> prices are very high if there is a shortage of only a few megawatts below the IRM, but drop to zero if there is a surplus of only a few megawatts of excess capacity above the IRM level.[2]

PJM mischaracterizes both the nature and dynamics of the current clearing mechanism. Contrary to PJM's assertion, the current clearing mechanism for the monthly and multi-monthly auctions do not employ a vertical demand curve to clear supply offers.[3] Instead, the current mechanism clears supply offers against buy bids to determine the auction-clearing price.

The following table provides the range of buy bids in auctions for 12-month (planning year) capacity over the last six years.[4] The spread in buy bids for these auctions implies that offers were cleared against a sloped demand curve. In stark contrast with the administratively determined VRR, these demand curves represent market-buyers' determinations of the value of capacity.

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[2]Transmittal Letter, p. 8.

[3]Clearing dynamics in the daily market approximate that of a market with a vertical demand curve. However, the daily market represents only a small fraction of total market activity in PJM.

[4]Source: http://www.pjm.com/pub/capacity_credit_market/downloads/stat.csv. As indicated in the table, PJM may conduct multiple auctions prior to the start of a planning year for 12-month capacity covering the upcoming planning year. For example, as shown in the table, PJM conducted five auctions for 12-month term capacity covering the planning year June, 2004 through May, 2005.

Table 1: Buy Bids in Auctions for Planning-Year Capacity

Market Term	Clearing Price ($/MW-day)	Buy-Bid Price Range ($/MW-day)
Jun 1999-May 2000	79.90	5.00 – 85.15
Jun 2000-May 2001	—	5.00 – 60.58
Jun 2000-May 2001	69.49	1.00 – 125.00
Jun 2000-May 2001	—	20.00 – 62.00
Jun 2001-May 2002	165.00	1.33 – 169.14
Jun 2001-May 2002	180.00	0.00 – 180.01
Jun 2001-May 2002	170.00	0.00 – 200.58
Jun 2002-May 2003	35.00	2.00 – 40.00
Jun 2002-May 2003	35.00	10.00 – 40.00
Jun 2002-May 2003	42.00	5.00 – 60.00
Jun 2003-May 2004	26.50	10.00 – 27.95
Jun 2003-May 2004	22.99	10.00 – 30.01
Jun 2003-May 2004	23.00	1.00 – 30.00
Jun 2004-May 2005	28.68	2.00 – 30.51
Jun 2004-May 2005	23.05	5.53 – 27.50
Jun 2004-May 2005	20.00	5.53 – 28.00
Jun 2004-May 2005	20.75	10.28 – 50.00
Jun 2004-May 2005	20.00	9.00 – 50.00
Jun 2005-May 2006	5.25	0.01 – 15.00
Jun 2005-May 2006	4.73	3.00 – 12.00
Jun 2005-May 2006	10.74	2.00 – 16.00
Jun 2005-May 2006	14.50	0.00 – 35.00

PJM also mischaracterizes the impact of the current clearing mechanism on price volatility. Contrary to PJM's assertions, capacity-market prices over the last six years have not oscillated between the capacity deficiency rate and zero. Instead, with the exception of anomalous pricing in 2001, prices for 12-month capacity have declined steadily as supply margins have increased over time.[5] This price trend is shown in the following table.[6]

Table 2: Average Clearing Price for Auctions of Planning-Year Capacity

Market Term	Weighted Average Clearing Price ($/MW-day)
Jun 1999-May 2000	79.90
Jun 2000-May 2001	69.49
Jun 2001-May 2002	174.76
Jun 2002-May 2003	36.55
Jun 2003-May 2004	23.77
Jun 2004-May 2005	21.07
Jun 2005-May 2006	9.89

B. The VRR Does Not Reduce Capacity Costs

PJM makes an astounding claim regarding the benefits of the VRR: although the VRR may lead to purchases of capacity in excess of required reserves, the more you buy, the less you pay in total for capacity. According to PJM:

> When the VRR curve clears above the IRM, i.e., commits more capacity than the 15% margin, the *overall* cost of all capacity to the market (not simply the unit cost) is lower.[7]

Unfortunately, there is no free lunch under PJM's VRR. The total cost of purchases in excess of IRM is less than that for purchases at IRM only when such purchases are at the artificial price levels set by the demand curve. When compared

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[5]PJM's Market Monitoring Unit alleged that capacity-market prices were subject to manipulation in 2001. See PJM Interconnection, L.L.C., *PJM Interconnection State of the Market Report: 2001*, June, 2002.

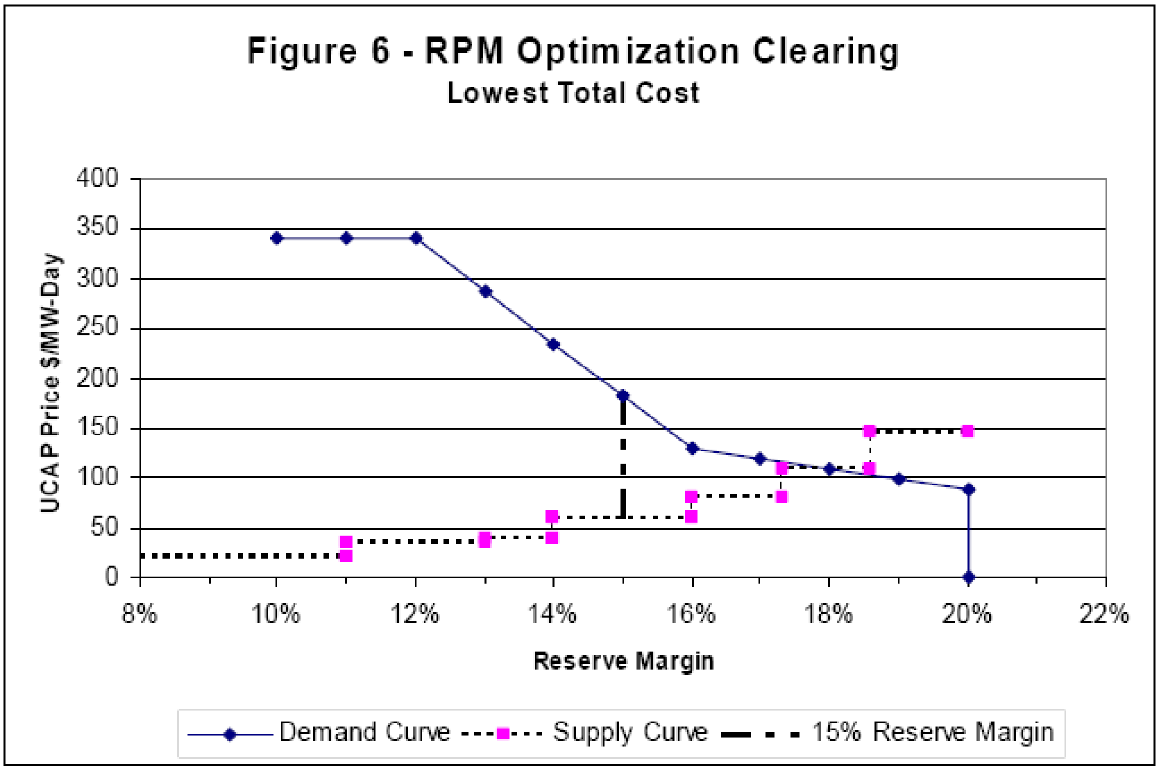
[6]Prices shown for each planning year are the weighted average of clearing prices for all auctions for 12-month capacity covering that planning year. For example, as shown in Table 1, there were four auctions conducted for capacity with a 12-month term covering the planning year from June, 2005 through May, 2006, with prices ranging from $4.73-$14.50/MW-day.

[7]Transmittal Letter, p. 11.

to the cost of purchases at IRM under the current construct, the total cost of purchases in excess of IRM under the VRR is significantly higher.

The relationship between capacity costs under the current construct and under the VRR is illustrated in the following figure, which reproduces Figure 6 in the affidavit of Andrew Ott of PJM.[8]

Figure 2: Figure 6 from Affidavit of Andrew Ott



Assuming a system peak of 1000 MW, Mr. Ott calculates that, with prices set by the demand curve, the total cost would be about $209 thousand per day when purchasing capacity equivalent to at an IRM of 15% and about $129 thousand per day when purchasing capacity equivalent to an 18% reserve margin. Thus, when prices

[8]Affidavit of Andrew L. Ott, on behalf of PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000, August 31, 2005, p. 11.

are set by the VRR, total costs are reduced in this example by about $80 thousand per day as a result of purchasing capacity three percentage points in excess of IRM.

While excess purchases under the VRR may appear to be a bargain against purchases at IRM under the VRR, they are clearly a bad deal when compared against purchases at IRM under the current construct. Under the current construct, purchases at IRM will clear at the marginal supply offer price at IRM. Using the illustrative supply curve in Figure 6 of Mr. Ott's affidavit, the marginal offer price at IRM is about $60/MW-day. The total cost of a purchase at IRM under the current construct, again assuming a system peak of 1,000 MW, would then be $69 thousand per day, or roughly half that for a purchase at 18% reserve margin under the VRR.

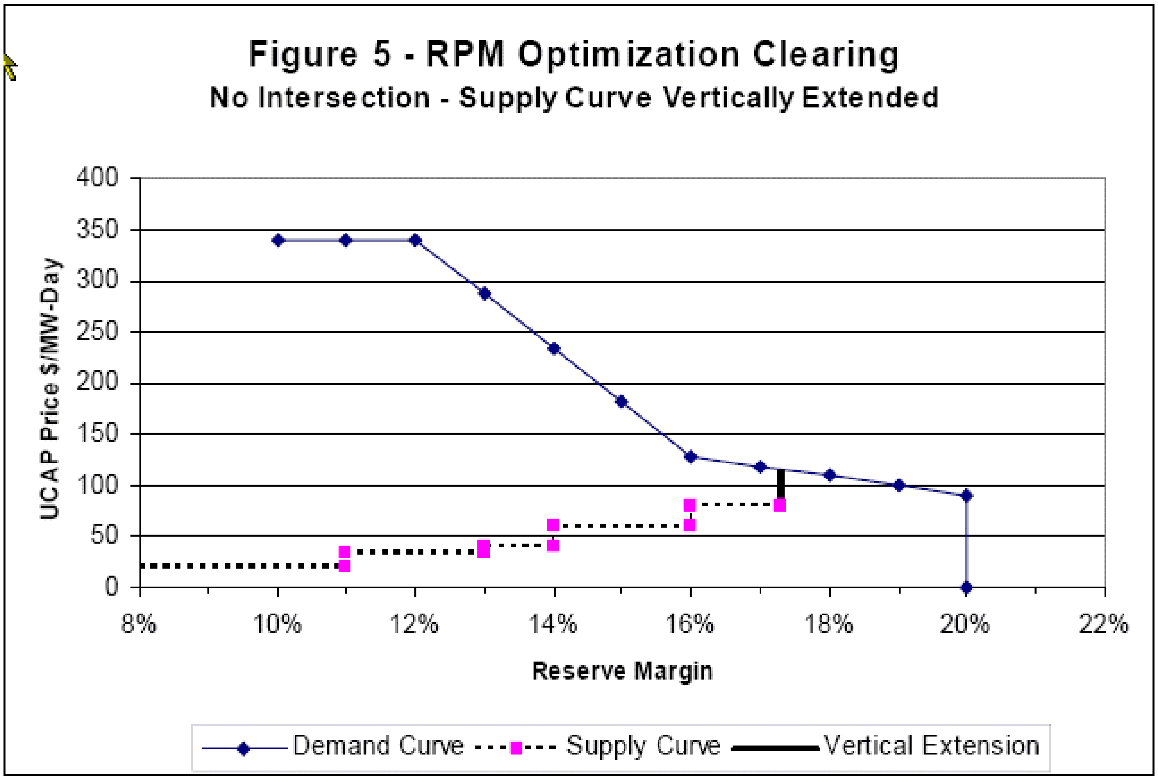
In other words, with Mr. Ott's illustrative example, it would cost twice as much to purchase capacity equivalent to 18% reserves under the VRR than it would to purchase capacity equivalent to IRM under the current construct. When viewed in relation to the current construct, the requirement to purchase excess capacity under the VRR will significantly increase, not decrease, total costs to consumers and windfall profits to generators.

C. The Demand Curve Artificially Forces Prices to Clear Above Marginal Supply Costs

The VRR may not only force purchases of capacity in excess of IRM, at significant cost to consumers as discussed above. It may also force purchase of excess capacity at artificial price levels that exceed marginal supply costs, thereby further enriching both infra-marginal and marginal capacity resources.

The demand curve will force prices above marginal supply costs whenever the supply curve does not intersect the demand curve, i.e., when all supply offer prices are less than prices on the VRR. This scenario is illustrated in the following figure, which reproduces Figure 5 in Mr. Ott's affidavit.[9]

Figure 3: Figure 5 from Affidavit of Andrew Ott



According to Mr. Ott, the most-expensive capacity resource at the end of the illustrative supply curve shown in the figure has a marginal cost of about $80/MW-day. Since the supply curve does not cross the demand curve before reaching the end of the supply curve, the price in this instance will be determined by the intersection of the demand curve with a vertical line extending up from the end of the supply curve. According to Mr. Ott, the clearing price in the example shown in this figure will be about $115/MW-day, or more than 40% higher than the cost of the most-expensive capacity resource.

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[9]Ott Affidavit, p. 10.

This is more than a hypothetical concern. As discussed below in Section V, PJM conducted numerous simulations of near-term RPM cost impacts during the stakeholder process. These simulations of auction clearing under the VRR consistently resulted in the purchase of all available excess capacity in local areas, with prices clearing above the cost of the most-expensive local capacity resource. It appears then, that the near-term impact of the VRR will be to not only require consumers to pay for the purchase of excess capacity, but to do so at a price that is artificially set at levels that exceed the cost of that excess capacity.

There are no apparent benefits from a pricing mechanism that forces prices above marginal cost when there is excess capacity on the system. Unlike when the system is short, there is no need to ration scarce resources with above-cost prices. Nor is there a need to push prices to the cost of new capacity to signal the need for and value of new investment in reserve capacity. Indeed, setting prices at artificially high levels may distort investment signals and spur the type of over-investment that PJM finds so problematic under the current construct.

D. Demand-Curve Prices for Excess Supply Exceed the Marginal Value to Consumers

Procurement of capacity in excess of minimum requirements is not necessarily an undesirable outcome. Consumers benefit from such purchases so long as the value to consumers of such purchases exceeds the cost. This is not the case for purchases of excess capacity under PJM's preferred demand curve, which arbitrarily sets prices at levels that exceed consumer value for all quantities in excess of IRM.

PJM's initial conception of a demand curve did not suffer from this defect. In the early stages of the stakeholder process, PJM proposed a demand curve that pegged prices to estimates of the value of lost load ("VOLL"). While PJM's estimates of VOLL appeared overstated, the proposal to pay no more than marginal value for excess capacity was conceptually sound.

Inexplicably, PJM subsequently abandoned the value-based curve in favor of a curve designed to ensure "revenue adequacy" to generators. In accordance with this new design standard, PJM derived a curve that set prices high enough to ensure prices that on average would clear at the cost of new capacity. For quantities in excess of IRM, prices on this revenue-adequacy-based curve exceed those on the VOLL-based curve. As a consequence, the revenue-adequacy-based curve generates prices that are considerably higher than the value to consumers for quantities in excess of IRM.

Thus, as long as there is excess capacity on the PJM system, PJM's preferred demand curve will procure excess supply at prices that exceed the marginal value of that excess capacity. These above-value payments lead to inefficiencies in resource allocation, retaining excess capacity that should be either sold into higher-value markets outside PJM, written down, sold off at a loss, or shut down.

Moreover, these above-value payments represent a reversal of one of the few benefits from restructuring that have flowed to consumers. Restructuring promised to transfer the risk of uneconomic excess capacity from consumers to generators. Under PJM's proposed VRR, consumers will once again be required to pay more than its worth for more capacity than is needed to meet reliability requirements.

V. Shortcomings of the Hobbs Analysis

In support of its proposal to implement a VRR, PJM retained Professor Benjamin Hobbs of Johns Hopkins University to develop a spreadsheet model for simulating the impact under RPM of different demand curves on generator profits, consumer costs, and control-area reserve margins over a 100-year planning horizon. Dr. Hobbs evaluated capacity constructs on the basis of 100-year average results, as well as volatility around those averages as measured by the standard deviation over the 100-year horizon.

Dr. Hobbs evaluated five different versions of a demand curve: a vertical demand curve, a VRR based on consumer value of lost load, and, as discussed above in Section III, three versions of a VRR based on the net cost of new entry. PJM concludes that Dr. Hobbs's analysis "provides compelling support" that "use of a demand curve, in principle, is a just and reasonable improvement over…PJM's current approach."[10]

There is simply no merit to this finding. Dr. Hobbs's simulation of the vertical demand curve is not representative of market clearing under the current capacity construct, and thus provides no useful information regarding the likely long-term impacts of the current construct. PJM mischaracterizes the current clearing process with its assertion that "…PJM's current capacity mechanism already uses an administratively determined vertical demand curve."[11] In fact, as discussed above in Section IV.A, the current construct allows for buy bids and thus market clearing against a market-based, sloped demand curve.[12]

Moreover, as discussed in detail below, the Hobbs analysis suffers from a number of defects, including:

- Methodological flaws;
- Unrealistic and unreasonable input data assumptions; and
- Incomplete evaluation of the impacts of alternative demand curves.

[10]Transmittal Letter, p. 60.

[11]Transmittal Letter, p. 24.

[12]Individual buy bids, and thus a market-based demand curve, are not feasible under RPM's centralized procurement, where PJM procures capacity on behalf of all load. Centralized procurement requires PJM to clear the market using an administratively determined demand curve, either vertical or sloped.

It is thus unreasonable to rely on the results of Dr. Hobbs's analysis as the basis for replacing the current construct with the proposed RPM.

A. PJM Relies on an Unsupported and Undocumented "Long-Term" Simulation Analysis

PJM has not assessed the merits of its proposed VRR on the basis of an estimate of near-term impacts. Instead, PJM relies on the results of an untested simulation of market conditions over a 100-year study period. Judging the reasonableness of a market construct based on forecasts of impact 100 years in the future is unprecedented, and an analysis period of 100 years is well outside the bounds of what is generally accepted as a reasonable planning horizon for forecasting exercises.

PJM apparently does not give any weight to near-term cost impacts in its long-term evaluation of the VRR. During the stakeholder process on RPM, Dr. Hobbs indicated that he simulated impacts over a 110-year period, but only reported the results for the 100-year period starting in Year 11. Hence, the modeling results reported by Dr. Hobbs and relied on by PJM to support the reasonableness of the proposed VRR apparently do not account for likely cost increases over the next decade.

PJM's failure to report on near-term impacts is particularly troubling, since PJM devoted significant effort and resources during the stakeholder process engaged in just such a simulation effort. This near-term simulation work was carried out in parallel with, and served as an important complement to Dr. Hobbs's long-term analysis. Without explanation, PJM has apparently abandoned this critically important near-term simulation analysis.

Finally, PJM has not provided the Commission or other parties a working version of the dynamic model or any model results on an annual basis and in sufficient detail to determine: (i) whether the model reasonably simulates near-term system conditions in PJM, particularly with respect to the current state of excess supply; or (ii) how many years before long-term benefits outweigh near-term cost increases. This latter shortcoming is especially problematic, since the reasonableness of the RPM proposal may hinge on benefits that don't start accruing until several decades in the future.[13]

B. Demand-Curve Benefits Are Overstated Due To Unrealistic Input Assumptions

Even without the benefit of sufficiently detailed supporting data, it is abundantly clear that Dr. Hobbs's simulation of a vertical demand curve artificially imposes extreme volatility in prices and investment cycles by assuming that both existing and new resources would irrationally bid capacity at a zero price:

> For the base cases, it is assumed that all capacity is bid in at $0/MW/yr; that is generators are assumed to commit to maintaining or building certain quantities of capacity, and then bid in a vertical supply curve, which makes them price takers for the price of ICAP.[14]

An assumption of zero-price bidding in the simulation of the vertical demand curve forces market prices to clear at one of two extremes: (1) zero, when there is supply in excess of reserve requirements; or (2) the assumed capacity deficiency rate, when supply falls short of required reserves.[15] This artificial price volatility, in turn, results in extreme fluctuations in generator profits, investment cycles, and thus installed reserves. The bottom-line impact of this unrealistic bidding assumption is

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[13]PJM does not even provide such basic, yet critical information as to whether the 100-year average cost figures reported for Dr. Hobbs's simulations are expressed in discounted dollars–as would be appropriate to reflect the time value of money–or are simple averages of annual real or nominal dollar results.

[14]Affidavit of Benjamin F. Hobbs, on behalf of PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000, August 31, 2005, p. 29.

[15]This outcome is illustrated in Figure 8 of Dr. Hobbs's affidavit.

a dramatic over-estimate of expected costs to consumers and profits to generators, and substantial understatement of average system adequacy under a vertical demand curve.

Dr. Hobbs's base-case assumption of zero-price bidding is contrary to economic theory regarding competitive bidding and contrary to experience in PJM's capacity markets.[16] The theory regarding rational bidding strategy is discussed by PJM's Market Monitor in his affidavit in the instant filing in the context of PJM's proposal regarding offer caps:

> Market seller offer caps are intended to reflect competitive offers for capacity resources, recognizing that capacity in the RPM construct is fundamentally an annual product. At the most basic level, a competitive offer for an annual offer of capacity is the annual avoidable cost of the unit, less net revenues from other PJM markets, including the bilateral sale of any product from the unit. This is a competitive offer because it reflects the incremental cost of capacity for a year…. In a competitive market, this incremental cost is the competitive offer.[17]

Indeed, under a uniform-price clearing mechanism, such as that employed in PJM's capacity markets and proposed for RPM, bidders have a strong incentive to bid no less than their true incremental cost and certainly not at zero as assumed by Dr. Hobbs. As Alfred Kahn and other economists stated in a report on uniform pricing in energy markets:

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[16]This assumption of zero-price bidding is apparently also contrary to Dr. Hobbs's own conception of bidding and clearing dynamics, as indicated by his discussion of Figure 5 (p. 30) of his affidavit. In that figure, Dr. Hobbs illustrates clearing dynamics of a demand curve against positively priced supply offers. Dr. Hobbs does not provide any rationale for the discrepancy between this generic description and his actual modeling assumption of zero-priced offers.

[17]Affidavit of Joseph E. Bowring, on behalf of PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000, August 31, 2005, p. 19.

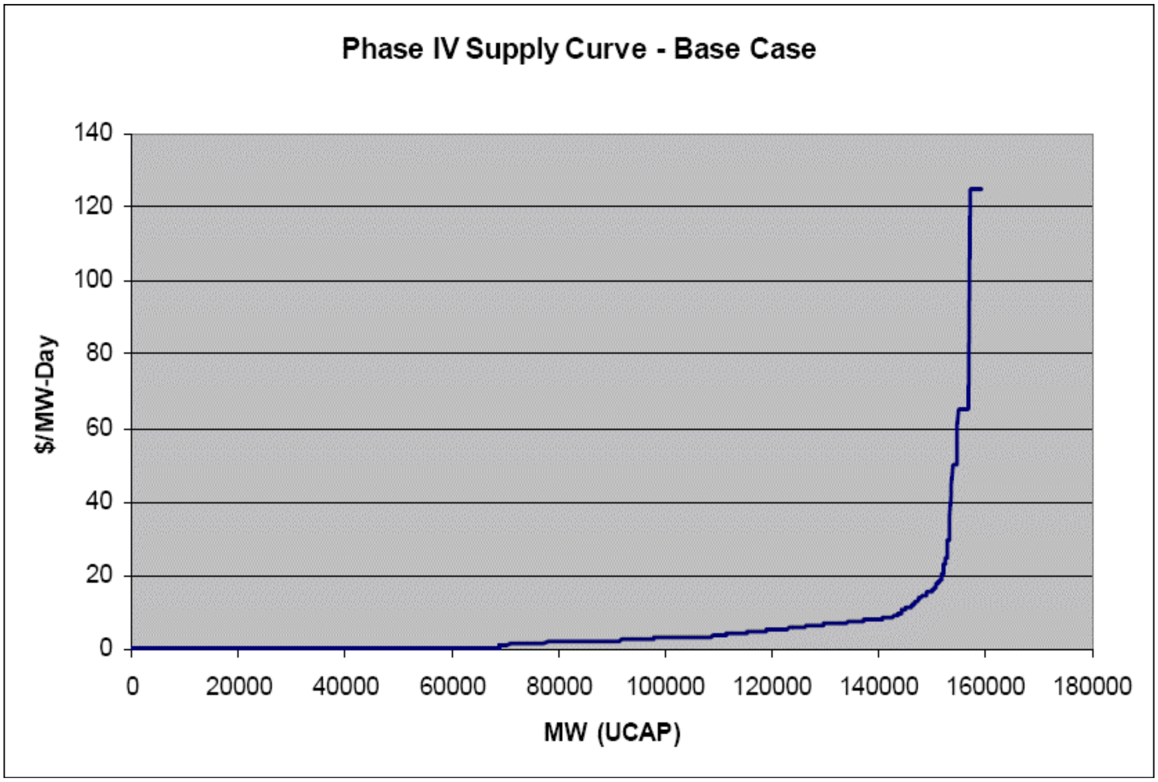
> Under the present uniform-pricing rules, suppliers in an effectively competitive market have every reason to bid approximately their marginal opportunity costs for energy in each of the blocks of power that they offer. They know that if any of those bids is rejected because there are sufficient lower bids to satisfy the demand, they will be better off, because they will not have committed themselves to sales at prices that fail to cover their avoidable costs.[18]

In contrast to Dr. Hobbs's modeling effort, PJM, during the course of the stakeholder process, simulated the impacts of RPM based on an assumption of bids at incremental cost. As shown below, PJM assumed an offer supply curve for its RPM simulations that ranged in price from less than $10/MW-day for existing nuclear and fossil-steam units up to $120/MW-day for new peaking capacity:[19]

[18]Alfred Kahn, et al, "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?", study commissioned by the California Power Exchange, January 23, 2001, p. 3.

[19]Source: http://www.pjm.com/committees/working-groups/pjmramwg/downloads/rpm-simulations-aggregate-supply-curves.pdf. PJM's estimates of incremental costs depicted in this supply curve do not include any risk adders associated with the 4-year forward commitment of capacity under RPM. In the instant filing, PJM's Market Monitor proposes to increase offer caps above incremental costs to incorporate both a general risk adder of 10% on incremental costs and a separate EFORd risk adder (priced at the cost of new peaking capacity.) See Bowring affidavit, pp. 19–23.

Figure 4: Supply Curve for PJM RPM Simulation Analysis



The base-case assumption of zero-price bidding is also contrary to experience in PJM's capacity markets over the last six years. As indicated in the following table, the range on actual supply offers for 12-month (planning year) capacity is generally consistent with PJM's incremental-cost assumptions shown above.[20]

[20]Source: http://www.pjm.com/pub/capacity_credit_market/downloads/stat.csv.

Table 3: Sell Offers in Auctions for Planning-Year Capacity

Market Term	Clearing Price ($/MW-day)	Sell-Offer Price Range ($/MW-day)
Jun 1999-May 2000	79.90	79.90 – 176.00
Jun 2000-May 2001	—	75.00 – 120.00
Jun 2000-May 2001	69.49	54.00 – 130.00
Jun 2000-May 2001	—	75.42 – 200.00
Jun 2001-May 2002	165.00	165.00 – 165.00
Jun 2001-May 2002	180.00	165.00 – 325.50
Jun 2001-May 2002	170.00	123.43 – 170.00
Jun 2002-May 2003	35.00	33.00 – 176.50
Jun 2002-May 2003	35.00	34.00 – 177.00
Jun 2002-May 2003	42.00	40.00 – 125.98
Jun 2003-May 2004	26.50	26.00 – 90.00
Jun 2003-May 2004	22.99	19.99 – 100.00
Jun 2003-May 2004	23.00	20.00 – 170.00
Jun 2004-May 2005	28.68	22.00 – 110.50
Jun 2004-May 2005	23.05	21.00 – 87.00
Jun 2004-May 2005	20.00	18.00 – 40.00
Jun 2004-May 2005	20.75	15.24 – 125.00
Jun 2004-May 2005	20.00	18.50 – 100.00
Jun 2005-May 2006	5.25	1.00 – 100.00
Jun 2005-May 2006	4.73	4.43 – 100.00
Jun 2005-May 2006	10.74	5.00 – 125.00
Jun 2005-May 2006	14.50	10.00 – 125.00

Capacity-price volatility would have been substantially reduced in the modeling of the vertical demand curve if Dr. Hobbs had substituted a bid curve based on incremental cost for his base-case assumption of zero-price bidding. The extent of this reduction in volatility is indicated by the results of a sensitivity case analyzed by Dr. Hobbs, which assumed bids of $20/kW-yr for existing capacity and $44/kW-yr for new investments.[21] As Dr. Hobbs notes, this more-realistic bidding assumption significantly reduces price volatility:

[21]This sensitivity only partially captures the benefit of realistic bidding assumptions, since it assumes a single value for existing-capacity bids, rather than the more-continuous offer curve

The standard deviation of ICAP payments in Curve 1 [the vertical curve] is more than halved (from $57/kW/yr to $15/kW/yr), because ICAP prices now occur frequently at intermediate values where bids intercept the demand curves rather than just the extremes of $0 and $124.7/kW/yr [with zero-price bids.][22]

The reduction in capacity-price volatility, in turn, substantially improves reserve margins while dramatically reducing consumer payments and generator profits.[23] As indicated in following table, the percentage of forecast years where reserve meets or exceeds IRM increases from 39% to 96% when more-realistic bidding assumptions are used in the simulation of the vertical demand curve.[24] In addition, more-realistic bidding assumptions reduce average consumer costs by over 30% and reduce average generator profits by almost 60%.[25]

Table 4: Summary of Results for Vertical Demand Curve

	Percent of Years ≥ IRM	**Generation Profit** ($/kW-yr)	**Total Consumer Payments** ($/kW-yr)
Base Case with Zero-Price Bidding	39%	66	129
Realistic-Bidding Sensitivity Case	96%	29	89

experienced in PJM's capacity markets. Volatility in price and reserve margins would be further reduced if the model assumed more than two bid levels.

[22]Hobbs affidavit, p. 63.

[23]In contrast, the results of the VRR simulations are largely invariant with the use of more-realistic bidding assumptions.

[24]Hobbs affidavit, Tables 1 and 3. Dr. Hobbs' affidavit reports the value for this statistic for the realistic-bidding sensitivity as four percent. In a letter to William Fields of the Maryland Office of People's Counsel, dated October 17, 2005, PJM's counsel corrected this value to 96 percent.

[25]Hobbs affidavit, Tables 1 and 3.

C. Dr. Hobbs Did Not Fully Evaluate a Vertical Curve Under Realistic Bidding Assumptions

Despite the dramatic improvement in results for the vertical demand curve when using more-realistic bidding assumptions, Dr. Hobbs asserts that "under no assumptions is the 'no demand curve' case found to be preferable, in terms of reserve margins or consumer payments, to the sloped curves."[26] Dr. Hobbs's analysis does not provide a reasonable basis for this conclusion, since it did not include sensitivity analysis on a base-case model that incorporated realistic bidding assumptions.[27]

Given the dramatic impacts from using more-realistic bidding assumptions, which more closely comport with economic theory and practice, it would have been reasonable for Dr. Hobbs to have repeated his sensitivity analyses on a base case that incorporated these assumptions. In addition, it would have been reasonable for Dr. Hobbs to have evaluated alternative versions of the vertical demand curve, just as he had done for the VRR. Two feasible alternatives would be: (1) a vertical curve at IRM+1%, similar to the IRM+1% VRR curve; and (2) a curve that is vertical at IRM, and that slopes up from the net cost of new entry to the capacity deficiency rate for quantities below IRM (as discussed below.)

D. Purchases of Excess Supply Do Not Appear to Provide Incremental Benefits

As discussed above, Dr. Hobbs evaluated three alternative shapes for the VRR based on net CONE that varied with respect to quantity used to set the inflection point

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[26]Hobbs affidavit, p. 62.

[27]During the stakeholder process, members of the Coalition of Consumers for Reliability highlighted the fact that Dr. Hobbs's assumption of zero-price bidding was unrealistic and exacerbated volatility under the vertical demand curve. At that time, PJM appeared to acknowledge the reasonableness of this critique and agreed to re-run Dr. Hobbs's model with more-realistic bid assumptions. PJM does not explain in the instant filing why it continues to rely on a base case that assumes zero-price bidding.

(point B in Figure 1): (1) IRM; (2) IRM + 1%; and (3) IRM + 4%. For each of these curves, Dr. Hobbs ran three cases that varied the vertical-curve point—i.e., the quantity in excess of IRM where price on the demand curve dropped to zero.[28] These cases were IRM plus (1) five percentage points; (2) ten percentage points; and (3) 13–17 percentage points, depending on the curve.

In all cases, changing the vertical-curve point has little or no impact on long-term consumer costs, generator profits, or reserve adequacy. For example, with PJM's preferred IRM+1% curve, reducing the vertical-curve point from IRM plus fourteen percent to IRM plus ten percent has no impact on consumer payments or generator profits, and only slight impact on average reserve margins. The same holds true when the vertical-curve point is reduced from IRM plus ten percent to IRM plus five percent.

This result begs the question as to whether the Dr. Hobbs's simulation would yield comparable results if the vertical-curve point were reduced all the way down to the inflection point for the various curves, at which point the "sloped" demand curve would be non-vertical only for quantities below the inflection point. If so, then Dr. Hobbs's model would be showing that there is no apparent long-term value to clearing of capacity in excess of IRM (or IRM+1%), since costs and performance are comparable whether the vertical-curve point is at IRM or IRM plus five or ten percentage points.[29]

In other words, the model results could be indicating that the long-term benefit under RPM of a sloped demand curve case relative to a vertical curve is solely or

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[28]This is point C in Figure 1.

[29] In contrast, consumers benefit in the near term by moving the vertical-curve point closer to IRM. As discussed above in Section IV.B, purchases of excess capacity at demand-curve prices are more costly than purchases at IRM at the marginal cost of supply per the current clearing mechanism.

largely attributable to the sloped portion below IRM (or IRM+1%). Unfortunately, Dr. Hobbs apparently did not investigate whether this is the case. As a result, the Commission and other parties lack critical data to determine whether there is any incremental long-term benefit under RPM associated with the clearing of quantities in excess of IRM, or whether consumers would benefit in both the near- and long-term from a curve that is vertical at IRM, but that slopes up to the capacity deficiency rate for quantities below IRM.

VI. Flawed Estimate of Energy-Cost Savings

PJM asserts that procurement through a VRR of capacity in excess of IRM will produce energy-cost savings beyond the scarcity-cost savings estimated by Dr. Hobbs, arguing that "the commitment of capacity at a higher reserve level will tend to decrease energy market prices."[30] In support of this claim, Mr. Ott conducted a simulation of energy-production costs under varying reserve margins. According to this modeling analysis, an increase in reserve margins from 15% to 18% reduces annual energy costs to consumers by approximately $940 million.[31]

PJM's simulation of VRR impacts on energy costs under non-scarcity conditions is fundamentally flawed and inconsistent with Dr. Hobbs's formulation of VRR impacts. As recognized by Dr. Hobbs, increasing the amount of installed reserves above IRM is unlikely to have a material impact on energy costs under non-

[30]Ott affidavit, p. 23.

[31]PJM does not explain why it focuses on the savings resulting from an increase in reserves of three percentage points, when Dr. Hobbs's analysis shows that PJM's preferred VRR (IRM + 1%) increases reserves on average by only 1.8 percentage points.

scarcity conditions.[32] The Commission should therefore give no weight to PJM's estimate of non-scarcity cost savings in its assessment of PJM's proposal for a VRR.

In order to estimate energy costs under varying reserve margins, Mr. Ott started with a production-cost model of the existing PJM system for 2007.[33] He then removed from the modeled system, in order of installation date, increasing amounts of existing capacity resources in order to reduce the reserve margin to particular levels. Since a reduction in reserve margin from 18% to 15% increased estimated energy costs for 2007 by $940 million, PJM asserts that an increase in committed reserves from 15% to 18% due to a VRR will reduce energy costs under non-scarcity conditions by $940 million per year.

Mr. Ott's approach simulates the impact of a VRR as if incremental capacity would be provided by non-peaking plant. In order to reduce reserve margins in the modeled system, Mr. Ott removes capacity starting with oldest units on the system and continuing in order of installation date. The earlier-vintage plants in the PJM system are predominantly fossil-steam units that are relatively cheap to operate and therefore likely to be economically dispatched as infra-marginal baseload or cycling capacity. As confirmed by Mr. Ott's modeling, removing such units from the bid

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[32]This assumes that reserve additions are met with peaking plant. While incremental capacity could be provided by baseload or cycling technologies that reduce energy costs, such technologies are significantly more expensive to build than peaking plant. The energy-cost reductions from non-peaking technologies would be largely offset by the additional capital investment.

[33]In order to avoid double-counting of scarcity costs, PJM would have to ensure that the model dispatches enough generation to meet load in every hour of the simulated year. Otherwise, in any shortage hour the model would presumably set the price at $1,000/MWh (as assumed by Dr. Hobbs in his simulation of scarcity costs) or perhaps at a higher level based on the value of lost load. If that were the case, PJM's estimate of energy costs under non-scarcity conditions would inappropriately include energy costs incurred in scarcity hours.

stack increases market prices and consequently energy costs.[34] Mr. Ott then treats this estimated cost increase associated with removal of non-peaking capacity as representative of the cost savings attributable to the addition of committed reserves under a VRR.

PJM's estimate is contrary to theoretical expectations–as supported by Dr. Hobbs's findings–that increases in installed reserves will not materially reduce energy costs under non-scarcity conditions. In contrast to Mr. Ott's approach, Dr. Hobbs's analysis assumes that "incremental capacity is provided by benchmark combustion turbine (CT) capacity."[35] Dr. Hobbs cites previous modeling analyses of PJM's ICAP market in support of this modeling assumption:

> I have also conducted simulations of long-run equilibrium entry of coal plants, combined cycle facilities, and peaking plants for the PJM system. Justifying my present focus on turbine investments, it turns out that those simulations show that the amount and mix of non-peaking capacity is not affected by the required reserve margin or the price of ICAP. Only the amount of peaking capacity is affected.[36]

Adding peaking capacity will not materially affect energy prices during non-scarcity hours. Peaking units are likely to operate at the margin, setting the market price at their offer price. Consequently, an increment of peaking capacity is unlikely to reduce market price by displacing a more-expensive marginal unit.[37] Thus, Dr. Hobbs appropriately assumed for his long-term simulation analysis that "other pay-

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[34]When this infra-marginal capacity is removed from the bid stack, the production-cost model replaces it with the next-most expensive capacity after the marginal resource. The result is an increase in market price, as set by this replacement capacity at the margin.

[35]Hobbs affidavit, p. 22.

[36]Ibid.

[37]In contrast, additional peaking capacity will likely reduce the frequency of scarcity. In those hours where the additional peaking capacity alleviates scarcity, the market price will decline

ments by consumers (including, e.g., energy produced during nonscarcity periods…) are unaffected by the ICAP curve."[38]

As Dr. Hobbs recognizes, under certain conditions, capacity additions may be based on non-peaking baseload or cycling technologies that reduce energy costs. However, investment costs for these technologies are significantly greater than for peaking capacity, and this additional capital will largely offset any energy-cost reductions. Mr. Ott's analysis captures the energy-cost reductions associated with the addition of such non-peaking technologies, but fails to account for the offsetting additional capital costs. This analysis thus inappropriately assumes that non-peaking energy-cost savings can be achieved with peaking-plant investments.

PJM's approach to estimating VRR impacts on energy costs under non-scarcity conditions is misguided. No weight should therefore be given to PJM's estimate of savings from implementation of a VRR.

This concludes my affidavit.

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from the scarcity price to the offer price of the additional peaking capacity. Dr. Hobbs captures this impact on scarcity costs in his simulation analysis, assuming a scarcity price of $1,000/MWh.

[38]Hobbs affidavit, p. 31. Dr. Hobbs (p. 24) did assume an additional payment of $10/kW-yr to peaking capacity to account for revenue "that is earned in ancillary service markets that I do not model or which results from margins earned when more expensive plants are on the margin."

AFFIDAVIT OF JONATHAN F. WALLACH

Jonathan F. Wallach, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Jonathan F. Wallach on behalf of the Coalition of Consumers for Reliability, that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information, and belief.

/s/ ______________________

Jonathan F. Wallach

Subscribed and sworn to before me this 18th day of October, 2005.

/s/ ______________________

Notary Public

My Commission Expires
October 31, 2008

My commission expires: ______________

Attachment 1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

“The Future of Utility Resource planning: Delivering Energy Efficiency through Distributed Utilities” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

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“Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer’s Energy Cooperative” (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

“Good Money After Bad” (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

“Maryland Office of People’s Counsel’s Comments on Staff Restructuring Report: Case No. 8738.” 1997. Filed by the Maryland Office of People’s Counsel in PSC Case No. 8738.

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“Profitability Assessment of Packaged Cogeneration Systems in the New York City Area.” 1989. Principal investigator.

“Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions.” 1989.

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“Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility.” 1985. ESRG Study No. 85-22/2.

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"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

1996 **New Orleans City Council** Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

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2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

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2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

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Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

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Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.