UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.	))	**Docket No. ER14-504-000**

COMMENTS OF THE PJM POWER PROVIDERS GROUP

The PJM Power Providers Group ("P3")[1] hereby submit their comments in support of the November 29, 2013, filing ("PJM November 29 Filing") by PJM Interconnection, L.L.C. ("PJM") of proposed revisions to the PJM Open Access Transmission Tariff ("Tariff") and the Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA").[2] The revisions proposed in the November 29 Filing would correct the unintended adverse effects of earlier changes to the Reliability Pricing Model ("RPM") rules on the PJM Region's long-term ability to procure sufficient quantities of high-quality capacity needed to assure reliability.[3]

P3 respectfully submits these comments in support of the PJM November 29 Filing noting the following points which are further explained in the below comments:

- The existing PJM tariff provisions are not just or reasonable because they effectively eliminate the benefits of a sloped demand curve for PJM's most reliable capacity resources;

[1] P3 is a non-profit organization dedicated to advancing federal, state and regional policies that promote properly designed and well-functioning electricity markets in the PJM Interconnection, L.L.C. ("PJM") region. Combined, P3 members own over 87,000 MW of generation assets and over 51,000 miles of electric transmission lines in the PJM region, serve nearly 12.2 million customers, and employ over 55,000 people in the PJM region, representing 13 states and the District of Columbia. The comments contained in this filing represent the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue. For more information on P3, visit www.p3powergroup.com.

[2] On December 4, 2013, P3 filed a doc-less Motion to Intervene in the above-captioned proceeding.

[3] *PJM Interconnection, L.L.C.,* Docket No. ER14-504-000, November 29, 2013.

- PJM's revisions correct an unreasonable market flaw;
- While PJM's proposal is a positive step forward, additional issues associated with demand response must be addressed; and
- PJM's revision should be accepted and implemented in time to be effective for the May 2014 Base Residual Auction.

I. COMMENTS

A. The Existing PJM Tariff Provisions are Not Just or Reasonable Because They Effectively Eliminate the Benefits of a Sloped Demand Curve for PJM's Most Reliable Capacity Resources

The filing before the Commission in this proceeding is about fixing a mistake. This mistake, while unintentional, has led to perverse market outcomes, inaccurate price signals and an unnecessary further degradation of reliability in PJM below North American Electric Reliability Corporation ("NERC") and Reliability*First* Corporation ("RFC") standards.[4] P3 supports the changes proposed by PJM in this filing and urges the Commission to accept it.

PJM candidly acknowledges its mistake and unequivocally states the purpose of its filing is to correct a "mis-step" which is "now working at cross-purposes with one of RPM's most fundamental characteristics—a downward sloping demand curve."[5] The nature of the mistake is well explained by Dr. Roy J. Shanker, an expert retained by P3 for purposes of this proceeding, in the affidavit attached to these comments:

[4] As Dr. Shanker explains in footnote 6 of his affidavit, PJM is currently not procuring sufficient capacity to meet its RFC and NERC reliability standards. Affidavit of Roy J. Shanker Ph.D. n.6. ("Shanker Affidavit") While P3 is greatly concerned about this issue and hopes that PJM and the Commission will take the necessary steps to address it, P3 understand that approval of this filing will not completely remedy this reliability shortcoming in PJM. However, approval of this filing will bring PJM closer to the standard and should be viewed as material progress toward reaching the ultimate goal of compliance with the NERC and RFC standards.

[5] PJM November 29 Filing, pp.1-2.

> Approximately four years ago, PJM realized that it could not accept an unlimited amount of inferior reliability products into the RPM market. PJM conducted appropriate studies and analyses to determine the maximum amount of these products that could be accepted without unreasonably degrading reliability. Unfortunately, however, PJM did not appropriately represent these limits or caps in the RPM model structure…... Instead of acting consistently with its analytic conclusion and capping the lower reliability products, PJM modeled a "floor" for higher quality annual products. To be sure, a floor on superior reliability products would have precisely the same effect as a cap on inferior reliability products if RPM were a "zero-sum game" in which PJM procured a fixed amount of capacity. But with its downward-sloping demand curve, RPM is most decidedly not a "zero-sum game." Rather, it is a market under which PJM procures more or less capacity in response to price in order to control/moderate price volatility while sending the appropriate price signals. Importantly, the dynamics of this process were designed to capture significant benefits over the long-run from the interaction of product price and quantity with the downward sloping demand curve. The mechanism that adjusts this procurement, the demand curve, is essential for the long-term stability and efficient function of the capacity market. PJM's misstep has jeopardized RPM's ability to achieve these essential objectives.[6]

As recognized by PJM and explained by Dr. Shanker, the current rules present several problems. First, the current rules are leading to an over-procurement of Limited Demand Resources ("Limited DR") and Extended Summer Demand Resources ("Extended Summer DR"), which are indisputably inferior from a reliability point of view, at the expense of more reliable annual resources, both generation and unlimited demand response. The current market rules are structured in such a way that inferior demand response resources (Limited and Extended Summer DR, particularly Limited) are procured in greater quantities than they should be in comparison to the more valuable annual demand response product because of the effective "ceiling" that is placed on the annual products. As PJM explained in their filing, in the 2016/17

[6] Shanker Affidavit ¶¶ 5and 6.

Base Residual Auction ("BRA"), the Limited DR target for that BRA was exceeded by over 3,000 MW.[7] As a result, this inferior product, though acknowledged to have "saturated" reliability properties virtually eliminating any incremental value displaced superior reliability resources and prevented some annual resources from clearing the auction because of the lack of effective bounds on Limited DR.[8] This result provides an illogical advantage to those resources that are by very definition less reliable at the expense of resources that can provide more reliability to the grid.

Secondly, the current rules create an effective vertical demand curve for annual resources, thereby negating the benefits of a sloped demand curve. The current "ceiling" on higher reliability annual capacity resources that are available approximately 8,300 hours a year and the "floor" on Limited demand response resources that are available for as little as 60 hours per year effectively means that only the Limited reliability resources are "seeing" the slope of the demand curve while the higher reliability resources are priced on a vertical curve. As Dr. Shanker concludes, "The unambiguous result of PJM's error/oversight is the creation of a vertical curve for annual capacity resources."[9]

The use of a vertical demand curve to price the most reliable capacity resources in PJM is directly at odds with Commission precedent, PJM's stated policy intent and common sense. When approving a sloped demand curve in PJM in 2006, the Commission made it clear that "[a] downward-sloping demand curve would reduce capacity price volatility and increase the stability

[7] PJM November 29 Filing at 14.

[8] *Id.* at 14.

[9] Shanker Affidavit ¶ 51.

of the capacity revenue stream over time."[10] Since then, PJM has found the sloped demand curve to be a critical feature of its market that has led to more appropriate capacity pricing as opposed to the "boom-bust" capacity pricing that has been seen in RTOs without a sloped demand curve.[11] At no point did either PJM or the Commission intentionally decide to eliminate the demand curve for annual products.

Recently, FERC Staff reviewed the history and effectiveness of capacity markets and explained that PJM and the New York Independent System Operator, Inc. ("NYISO") adopted downward-sloping demand curves in response to concerns "that the prices resulting from the use of a vertical demand curve were too volatile, with prices at or near the deficiency charge when supply was not sufficient to meet the planning reserve margin, and prices near or at zero once the planning reserve margin was met."[12] In addition, FERC Staff observed that:

> PJM and NYISO no longer use a vertical demand curve due to concerns about volatile capacity prices. A vertical demand curve can create volatile – or even binary – prices from one commitment period to the next. Clearing prices can swing dramatically from near zero (or at the administrative price floor, if one is established) when there is excess supply to near the maximum when supply is insufficient. Capacity additions are often large and can be far larger than a current shortfall in installed capacity. Therefore, when a new resource enters the market, prices have the potential to drop significantly. For example, adding a 100 MW capacity resource when 50 MW are needed to meet the planning reserve margin target could result in capacity prices dropping from at or near the maximum price to at or near zero. This can inhibit efficient entry of new capacity resources even when supplies are below the planning reserve margin. While this 'lumpiness' problem exists when using a downward-sloping demand curve, it is particularly acute with a vertical demand curve."[13]

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[10] PJM Interconnection, L.L.C., 115 FERC ¶ 61,079, at P 104 (2006) ("*RPM* Settlement Order"), *order on reh'g*, 119 FERC ¶ 61, 318, *reh'g denied*, 121 FERC ¶ 61,173 (2007) *petition for review denied sub nom. Pub. Serv. Elec. &*Gas Co. v. FERC, No. 07-1336 (D.C. Cir., Mar. 17, 2009).

[11] http://www.ferc.gov/CalendarFiles/20130911144119-Ott%20Comments.pdf at 16.

[12] *Centralized Capacity Market Design Elements*, Commission Staff Report, AD13-7-000, August 23, 2013, p.5.

[13] *Id.* p. 9, citations omitted.

Under PJM's OATT, the demand curve (called the "VRR Curve") is used to establish the level of capacity resources that will provide an acceptable level of reliability.[14] As the Commission found, recent revisions to PJM's VRR Curve "strikes a reasonable balance between maintaining an incentive for resources to commit to providing capacity while not unduly burdening consumers with higher costs."[15] As opposed to the vertical demand curve, the sloped demand curve recognizes the relative amount of capacity on the system and prices it accordingly.[16] While the Commission has not mandated the use of a downward-sloping demand curve in all markets,[17] it is undeniably a core component of the PJM capacity construct.

Moreover, PJM's earlier mistake has also suppressed prices for more valuable capacity resources such as annual DR and generation. As Dr. Shanker observes:

> Prices for the more valuable annual products were inappropriately depressed, as additional increments of generation and other Annual Resources, including Annual Demand Resources ("Annual DR"), were treated as providing virtually no incremental reliability value beyond the MAR or MESR Requirement. The resulting distortion of the price signals RPM was intended to convey means that it is likely that a significant amount of generation was retired that should have been retained, that a significant amount of needed new entry was not pursued and that excess amounts of the least valuable product were procured. In short, all the desirable properties associated with a sloping demand curve, long recognized by the Commission, were inappropriately eliminated.[18]

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[14] PJM OATT, Attachment DD at section 5.10(a).

[15] PJM Interconnection, L.L.C., 138 FERC ¶ 61,062, at P 84 (2012).

[16] While P3, supports the sloped demand curve, the organization has expressed concerns about the characteristics of PJM's sloped demand curve including its steep slope.

[17] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,199, at P 245 (2012) (noting that the Commission has afforded system operators "substantial latitude in determining their reliability requirements and shaping their markets" and has approved downward-sloping demand curves for some markets (PJM and the NYISO) and a vertical demand curve for another market (ISO New England Inc. ("ISO-NE"))). Notably, ISO-NE has announced its intention to replace its vertical demand curve with a downward-sloping demand curve.

[18] Shanker Affidavit ¶ 9.

The incorrect modeling of Limited and Extended Summer DR and the resulting mis-pricing of those resources has displaced and under compensated annual products with greater reliability value and likely hastened the retirement of existing units capable of providing significantly greater reliability that should not have retired. This has also likely discouraged investments in new generation and new demand response technologies, leaving PJM with portfolio of resources that is less flexible in meeting capacity emergencies. As Dr. Shanker observes:

> the Annual Resources (including Annual DR) that provided the greatest reliability benefits were significantly undercompensated for three Delivery Years due to inappropriately depressed clearing prices. This means that signals for needed new entry and the retention of needed existing generation were substantially muted during a period of unprecedented generation retirements in PJM. Since the May 2011 auction, the first time that PJM included the incorrect modeling, approximately 9400 MWs of conventional generation has made retirement requests. While obviously there were a number of factors, particularly environmental costs, involved in these decisions, the inappropriate transfer of billions of dollars out of the capacity market, was undoubtedly a factor.[19]

While the current market rules have led to an unjust and unreasonable suppression of capacity prices, these same rules likely provoked higher energy prices than would have been seen had the capacity market rules been structured properly. Despite being able to offer capacity at relatively low prices, demand response enjoys a much higher offer cap than installed generation in PJM's energy markets and is not subject to the same bid mitigation rules. Indeed, DR can make unmitigated offers to the market at a price up to $1800 and most Limited DR is priced at this level.[20] Not surprisingly, as the level of demand response in PJM's market

[19] Shanker Affidavit ¶P48, citations omitted.

[20] As Dr. Shanker notes in Paragraph 50 of his affidavit, this summer prices in the ATSI zone set the energy price at $1800 for a two hour period because all of the available generation had been called which resulted in total energy costs of approximately $54 million over that period.

increases, the likelihood that these resources get called and set the clearing price increases. Because of this displacement of capacity resources with lower energy market costs, and overall reduced volatility from returning the demand curve to its proper representation, PJM estimates the energy market savings that could result from approval of this filing could rise to $3.4 billion depending on the surplus of resources.[21]

P3 is concerned that if existing rules are allowed to continue, reliability will be further jeopardized and costs to consumers could increase. The problems with the current market structured are well-explained by PJM, Dr. Hobbs and Dr. Shanker. Clearly, despite the best of intentions, a mistake was made, and PJM's existing Tariff is not just and reasonable in this regard.[22] PJM has recognized the mistake and is seeking to fix it. P3 urges the Commission to do the same.

B. PJM's Revisions Correct an Unreasonable Market Flaw

The solution put forth by PJM to address the problems articulated in the previous section is a just and reasonable response to the situation. Rather than continuing to subject the more reliable annual capacity products to a vertical demand curve, PJM has proposed a cap or "ceiling" on the limited or inferior demand response products that reflect the reliability degradation that PJM has deemed acceptable. P3 supports this solution and urges the Commission to accept the PJM November 29 Filing. Moreover, the instant filing is the product of a robust PJM stakeholder process that, while not producing a supermajority vote for any single

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[21] http://www.pjm.com/~/media/committees-groups/committees/mrc/20131113/20131114-item-03-clearing-limited-dr-pjm-comparison-of-proposals.ashx at 21.

[22] P3 notes that where a rate is found to be unjust and unreasonable, the Commission must act to establish a just and reasonable rate. *See Tennessee Gas Pipeline Co. v. FERC*, 860 F.2d 446, 454 (D.C. Cir. 1988) ("Once [the Commission determines a rate to be unjust and unreasonable], the Commission is required to reach a further determination: the just and reasonable rate to be fixed in place of either an unlawful proposed or existing rate.")

proposal, did feature a full vetting of the issues and the consideration of numerous proposals, counter-proposals and edits. During the six-month stakeholder process, most of which occurred at the Capacity Senior Task Force, outside experts delved deeply into the many reliability issues associated with the current market structure and ultimately produced a solution that helps to improve, while not completely fixing, the problems associated with inferior demand response products in the PJM market. Although no one single proposal received a stakeholder endorsement, P3 believes that the PJM Board acted appropriately within its discretion in making this 205 filing given that the existing Tariff is not just or reasonable with respect to its current treatment of annual resources as compared to Limited DR.

C. While PJM's Proposal is a Positive Step Forward, Additional Issues Associated with Demand Response Must be Addressed

1. PJM should transition to a single, annual DR product.

While P3 believes the instant filing is an important step for PJM's market that should be approved, there are other issues associated with demand response that must be addressed in order for demand response to play an appropriate and meaningful role in the market. As articulated in prior filings before this Commission,[23] P3 supports a single, clearly-defined, demand response capacity product, with attributes that are as closely aligned as possible with the attributes of the capacity product required from generation resources. The limited demand response products that currently exist in the PJM market and are the subject of this filing are an anathema to the market that need to be transitioned out of the market. As the PJM Independent Market Monitor has articulated many times, "Both the Limited and the Extended Summer DR products should be

[23] *See e.g., PJM Interconnection, L.L.C.,* Docket No. ER11-2288-000, Motion to Intervene and Protest of the PJM Power Providers Group (December 22, 2010) and *PJM Interconnection, L.L.C.,* Docket No. ER13-486-000, Motion to Intervene and Comments of the PJM Power Providers Group (December 20, 2012).

eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources."[24]

Dr. Shanker's affidavit details some of the many problems associated with inferior demand response products in the market. Specifically, by virtue of PJM's incorporation of these products in the market, PJM has effectively fallen below the 1 in 10 Loss of Load Expectancy (LOLE) standard by assuming that all capacity products are available all year long for purpose of calculating the installed reserve margin ("IRM") yet ultimately accepting inferior products without adjusting its IRM.[25] As a result, PJM is forced to quantify exactly how much degradation of this LOLE standard is acceptable when determining the limits for the Limited and Extended Summer demand response products. Despite the fact that approval of this filing would lessen the degradation of reliability below the standard, so long as limited demand response resources are allowed in the market, this problem will persist and by definition, PJM will be planning to a reliability standard in excess of 1.1 days in ten years if not higher.[26]

As P3 has previously stated, a single annual unlimited capacity product would permit competition by various capacity supply resources based on those resources' system reliability contributions, determined by a metric akin to the EFORd or EFORp metrics by which generator owners' offer volumes are currently determined.[27] A single product solution is consistent with PJM's long-term goal of greater participation by price responsive demand resources.

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[24] 2012 State of the Market Report at 11. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume2-sec1.pdf

[25] Shanker at ¶ 30.

[26] Shanker at n. 21.

[27] *PJM Interconnection, L.L.C.*, Docket No. ER11-2288-000, Motion to Intervene and Protest of the PJM Power Providers Group (December 22, 2010).

Furthermore, P3 remains concerned that multiple inferior DR products being compensated at similar levels as other capacity resources with more robust reliability capabilities results in a market structure that is prone to reliability issues and susceptible to market dysfunction**.**

2. The Short-term Resource Procurement or 2.5% "Holdback" should be eliminated.

Beyond the elimination of the inferior demand response products currently in PJM's capacity market, the 2.5% short term resource procurement target or "holdback" is contrary to a properly designed and well-functioning market in that it jeopardizes the reliability of PJM and should be eliminated.[28] By systematically under procuring capacity PJM distorts the price signals that are necessary to efficiently clear the market and ensure reliability, while also overtly discriminating between classes of capacity resources. The dramatic growth of demand response since the inception of RPM has made the reliability problems associated with the application of the holdback to minimum reserve requirements more troublesome and further calls into question the need for any reduction in cleared load. P3 has consistently supported and continues to support the complete elimination of the holdback.

3. Inequity issues associated with behind the meter generation must be addressed.

P3 has been consistent in its position that DR, especially DR that consists of behind the meter ("BTM") generation, as with any other energy-related service or source of generation, should not receive preferential treatment in the offering of its services into the wholesale energy or capacity markets. Generation should not be put at a disadvantage simply because it is located in front of the meter. To the extent that current rules regarding demand response are allowing

[28] In every base residual auction since the 2012/13 auction, PJM has removed 2.5% of the reliability requirement from the demand curve under the theory that shorter lead time resources can be added in incremental auctions. OATT Attachment DD § 2.65A.

generation assets to in essence "hide" on the system as demand response, market distortion will occur that ultimately will increase prices and degrade reliability. Generation assets should be treated similarly regardless of whether they are in front of the meter or behind the meter. The current PJM rules allow for discriminatory treatment of generation assets, and PJM, the PJM stakeholders and the Commission should address this growing problem.

The differences between the obligations of demand response to the market as compared to generation are well-documented and understood by the Commission. As capacity resources, demand response does not have a must offer obligation and is allowed to participate in Base Residual Auctions on a much more speculative basis than generation. In the energy market, demand response is allowed to submit offers above the $1000/MWh generation offer cap, does not have a must offer obligation, is not subject to the three pivotal supplier test, is not subject to energy offer price mitigation, and is not subject to the same measurement and verification protocols that generators are.

In a 2012 study by former Massachusetts commissioner Paul Hibbard, the following conclusions were reached: DR that is BTM Generation does not help system reliability -- it simply displaces other capacity resources that would contribute equally, if not more, to power system reliability than these DR resources; and secondly, the successful participation of BTM diesel generators participating in demand response programs in regional capacity markets likely increases emissions of CO_2, NO_x, SO_2, and mercury.[29]

Exacerbating the problem are environmental rules that allow pollution waivers for behind the meter diesel units that operate as demand response resources. EPA's recently approved 100-hour exemption for non-emergency generator units carries with it significant policy,

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[29] *Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets*, Paul J. Hibbard, Analysis Group, August 2012.

environmental and practical concerns, including the fact that such an exemption amounts to an unjustified preference for BTM generators that is not equally available for generating units located "in front of the meter," which are obligated to meet all federal and state air regulations.

P3 is especially concerned that the increased exemption confers a discriminatory preference against traditional generation and renewable sources. Waiving environmental regulations for certain generating resources within PJM is discriminatory and will result in further environmental harm. The fact that these DR units, but not other sources of generation, would receive such an extensive exemption from environmental regulations amounts to a discriminatory preference in favor of these resources.

Behind the meter diesel generation participating in the market as demand response comprises a very significant share of the demand response in the system. Recently, PJM reported that 21% of emergency DR is meeting its obligations with backup generation and 88% of the generators participating in PJM's emergency demand response programs are diesel fired.[30] These numbers are likely to grow and compound if the current rules are allowed to continue.

4. Price Responsive Demand is the ideal "end state" market.

Demand response in the capacity market, as it is currently constructed, may no longer be necessary if price responsive demand ("PRD") is integrated properly. P3 believes that PJM should focus now on the longer-term structure of demand response in the PJM capacity market in which a transition to PRD is the ultimate solution as demand response transition from a supply side capacity resource to a demand side energy resource – where it more appropriately belongs.

PJM's stated long-term vision of demand response in PJM was noted in the PJM Board's June 26, 2009 statement: "PJM's long-term vision is that 'Price Responsive Demand,' which

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[30] PJM 2013 Demand Response Operations Markets Activity Report: October (October 15, 2013), available at http://www.pjm.com/~/media/markets-ops/dsr/2013-dsr-activity-report-20131015.ashx

allows more customers to respond directly to market prices and to voluntarily reduce their consumption when wholesale prices rise, is the ultimate solution to demand participation." The current Tarriff, however, has moved the market in exactly the opposite direction by facilitating the expansion of a type of resource that is only called upon under emergency conditions.[31] A much better approach would be to develop a mechanism that would provide incentives for more DR facilities to become price responsive demand.

Regardless of whether some parties may argue that the issues raised in this section are beyond the scope of the proceeding, P3 raises them in the spirit of placing the instant proceeding in its proper context. Namely, there are numerous issues associated with the participation by demand response in PJM's capacity market that remain beyond the November 29 filing that can and should be addressed. P3 urges the Commission to recognize that these pressing issues remain and requests that PJM be instructed to commence a stakeholder process to produce tariff changes to rectify them.

D. PJM's Revision Should be Accepted and Implemented in Time to be effective for the May 2014 Bas Residual Auction

As discussed throughout these comments it is very important that PJM's November 29 Filing be accepted be the Commission by January 31, 2014, as PJM requested so that it can be implemented in time for the May base residual auction. The integrity of the market as well as reliability in the PJM footprint depends on it.

[31] P3 supports the PJM Board's visions for price responsive demand in concept. Many P3 members, however, did oppose the PJM Staff's previous price responsive demand proposal, due to the lack of a comprehensive approach for addressing demand response, both as a reducer of energy demand and a seller of capacity.

III. CONCLUSION

For the foregoing reasons, P3 respectfully requests that the Commission consider its comments, and accept the PJM's Tariff and RAA revisions to be effective by January 31, 2014.

Respectfully submitted,

On behalf of the PJM Power Providers Group
By: */s/ Glen Thomas*____________

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Dated: December 20, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the Official Service List compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 20th day of December, 2013.

On behalf of the PJM Power Providers Group
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Attachment
Affidavit of Roy J. Shanker, Ph.D.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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PJM Interconnection, L.L.C.	)	Docket No. ER14-504-000
	)	

Affidavit
Of

Roy J. Shanker Ph. D.

Independent Consultant

December 19, 2013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. ER14-504-000
	)	

Affidavit
Of

Roy J. Shanker Ph. D.

1) My name is Roy J. Shanker. My address is P.O. Box 1480, Pebble Beach, CA. I am an independent consultant with almost 40 years of experience in energy markets, with most of that work dedicated to the electric utility industry, and for the past 18 years to the development of the market designs for independent system operators ("ISOs") and regional transmission organizations ("RTOs").

2) Most relevant in the context of this proceeding is my experience in the development and design of the PJM Interconnection, L.L.C. ("PJM") and New York Independent System Operator, Inc. ("NYISO") capacity markets, both of which employ downward-sloping demand curves. I worked on the initial design of these and other capacity markets and have been extensively involved with subsequent refinements since their initial operation. I was one of the sponsors of several of the basic design attributes of PJM's Reliability Pricing Model ("RPM"), and coined the term "missing money" to describe the underlying revenue adequacy concerns in organized markets with mandated reliability targets and price caps. I have been involved in a number general capacity market and RPM related dockets before the Commission. I have been an active participant in the PJM stakeholder processes, in

particular the Market Implementation Committee and the Capacity Senior Task Force (CSTF), where these issues in this proceeding were presented to the PJM stakeholder process. I have also participated in a number of related proceedings relating to the design of the ISO New England Inc. and Midcontinent Independent System Operator, Inc. capacity markets, and have been a frequent participant at the Federal Energy Regulatory Commission technical sessions on capacity market-related issues for approximately 15 years, including most recently, the technical conference on centralized capacity markets.[1] I also recently submitted an affidavit in another PJM RPA related stakeholder docket relating to planning parameters of the RPM auctions.[2] A summary of my background and regulatory experience is presented as Attachment A.

3) I have been retained by the PJM Power Providers Group ("P3") to review, and comment on, PJM's November 29, 2013 filing in this proceeding.[3] The analysis and conclusions contained in this affidavit are solely mine and do not necessarily represent the views of any P3 member with respect to any issue. In the following sections, I discuss my overall conclusions and recommendations.

Conclusion, Findings and Recommendation

4) Overall, I concur with PJM's findings and conclusions, and I support the changes proposed in the November 29 Filing. Through this filing, PJM would correct an error, whereby, in an earlier filing, it re-characterized demand response products and their associated reliability properties incorrectly in the Reliability Pricing Model. The net result was to put in place a vertical demand curve, with all of its

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[1] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, Docket No. AD13-7-000.

[2] *See* Motion to Intervene and Protest of NextEra Energy Resources, LLC, Attachment, Affidavit of Roy J. Shanker Ph. D. (filed Dec. 13, 2013).

[3] Tariff Filing, Docket No. ER14-504-000 (filed Nov. 29, 2013) (the "November 29 Filing").

associated problems, for the vast majority of the market, including those resources most needed for reliability.[4]

5) Approximately four years ago, PJM realized that it could not accept an unlimited amount of inferior reliability products into the RPM market. PJM conducted appropriate studies and analyses to determine the maximum amount of these products that could be accepted without unreasonably degrading reliability. Unfortunately, however, PJM did not appropriately represent these limits or caps in the RPM model structure. This occurred even though the limits on the quantities of the inferior products were determined by PJM's own analyses, and it was known that excessive amounts could only be accepted at the cost of degrading reliability and weakening the ability to meet adequacy requirements. Instead of acting consistently with its analytic conclusion and capping the lower reliability products, PJM modeled a "floor" for higher quality annual products.

6) To be sure, a floor on superior reliability products would have precisely the same effect as a cap on inferior reliability products if RPM were a "zero-sum game" in which PJM procured a fixed amount of capacity. But with its downward-sloping demand curve, RPM is most decidedly not a "zero-sum game." Rather, it is a market under which PJM procures more or less capacity in response to price in order to control/moderate price volatility while sending the appropriate price signals. Importantly, the dynamics of this process were designed to capture significant benefits over the long-run from the interaction of product price and quantity with the downward sloping demand curve. The mechanism that adjusts this procurement, the demand curve, is essential for the long-term stability and efficient

[4] As noted by P3 in its pleading, there are several other material issues related to the role of demand response in the RPM process, including the question of whether demand response products with limited calls should be allowed to participate in the RPM markets and the discriminatory practice of setting the demand curve to acquire only 97.5% of the needed capacity in the BRA. I agree with the P3 positions on these issues. However, in the context of this affidavit, I limit my comments to the specific issues raised by PJM in its submission.

function of the capacity market. PJM's misstep has jeopardized RPM's ability to achieve these essential objectives.

7) Products with superior reliability benefits, such as a generator that would provide over 8,000 hours of potential performance, will naturally tend to have higher costs than products with inferior reliability benefits, such as a Limited Demand Response Resource ("Limited DR") offering just 60 hours of potential performance. As a result, once the RPM optimization logic satisfied its floor requirements for what PJM describes in its November 29 Filing as "Annual Resources" and for Annual Resources plus Extended Summer Demand Resources ("Extended Summer DR"), the model immediately sought out cheaper Limited DR, regardless of the "saturation" level and the associated ability of additional increments of this product to contribute to reliability. That is, it bought the cheapest products even if they could not really offer any incremental value to reliability.

8) The upshot is that the most reliable (and the vast majority of) resources were effectively exposed to a vertical demand curve at the Minimum Annual Resource ("MAR") Requirement or the Minimum Extended Summer Resource ("MESR") Requirement, while only the least valuable (and possibly, from a reliability perspective, worthless) resources were "seeing" a key feature of the entire market design, the downward-sloping demand curve.

9) Not surprisingly, unintended consequences followed. Prices for the more valuable annual products were inappropriately depressed, as additional increments of generation and other Annual Resources, including Annual Demand Resources ("Annual DR"), were treated as providing virtually no incremental reliability value beyond the MAR or MESR Requirement. The resulting distortion of the price signals RPM was intended to convey means that it is likely that a significant amount of generation was retired that should have been retained, that a significant amount of needed new entry was not pursued and that excess amounts of the least valuable product were procured. In short, all the desirable properties associated with a

sloping demand curve, long recognized by the Commission,[5] were inappropriately eliminated.

10) I think that PJM has well justified the above findings. Further PJM and Professor Benjamin Hobbs make clear the nature of the mistake and the potential harms that have occurred and will continue to occur if their recommendation is not accepted. Thus I would recommend that the Commission approve the changes proposed in the November 29 Filing and appropriately establish caps on Limited DR resources and the combined quantity of Limited DR and Extended Summer DR resources in the fashion that PJM has proposed. These changes properly reflect the reliability characteristics of the Limited DR and Extended DR products identified in PJM's initial analyses approximately four years ago and will restore the downward-sloping demand curve for the Annual Resources that provide the greatest reliability benefit to the system.

11) In the following, I discuss my findings that support the conclusions and recommendations of PJM and Professor Hobbs. I also provide a background discussion about basic resource adequacy assumptions and PJM planning that I

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[5] As the Commission explained in approving the RPM construct:

> [A] downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market. Finally, as we discussed in orders in which a sloped demand curve was approved for NYISO, a sloped demand curve would reduce the incentive for sellers to withhold capacity in order to exercise market power when aggregate supply is near the Installed Reserve Margin.

PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 at P 76, *on reh'g*, 119 FERC ¶ 61,318 at P 99 (2007) (stating that the "sloping demand curve is designed to replicate a true market in which incremental amounts of capacity will have gradually declining, but positive, reliability benefits," while the "current vertical demand curve fails to reflect the value of incremental reliability"). *See also, e.g., New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 13 (2007) (finding that the NYISO's proposal to adopt a demand curve would "provide net benefits especially compared with the existing vertical demand curve"), *on reh'g*, 105 FERC ¶ 61,108 (2003).

believe make it more obvious why the current proposal is the correct and logical modeling representation for RPM, and why it always should have been represented in this fashion.[6]

Reliability Adequacy Basic Assumptions-Background

12) The key to understanding the nature of the modeling error that PJM made in characterizing less reliable products within the RPM/Base Residual Auction ("BRA") auction process lies in understanding two basic concepts in the overall planning process for reliability. The first relates to how PJM develops its basic underlying long-term reliability adequacy requirements to establish its installed reserve margin ("IRM") requirement that addresses its target adequacy objective of "one day in 10 years" LOLE. The second relates to how PJM calculates what level of inferior reliability products (Limited DR and Extended Summer DR) it can accommodate within the initial and primary calculation of IRM without reducing reliability further than it has deemed acceptable, in this case a reduction to something more than 1.1 days in 10 years (or approximately one day in nine years or less) LOLE.

13) Understanding these two steps in sequence and the explicit degradation effects due to the incorporation of inferior reliability products makes clear how Limited DR and Extended Summer DR should have been modeled in the first instance and support the correction that PJM has proposed in the November 29 Filing.

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[6] Although I fully support the changes proposed in the November 29 Filing, this discussion also highlights some issues of which the Commission should be aware with respect to with respect to the attainment of the reliability targets required under the PJM Reliability Assurance Agreement ("RAA") and associated reliability criteria of the North American Electric Reliability Corporation ("NERC") and the ReliabiltyFirst Corporation ("RFC"). Specifically, it appears that PJM is setting the RPM reliability targets at a loss of load expectation ("LOLE") of more than one occurrence in 10 years, *i.e.*, a lower level of reliability than suggested by the relevant NERC and RFC study standards (http://www.nerc.com/files/BAL-502-RFC-02.pdf). Further, the exact reliability target is unknown, other than it is worse than 1 in 10. As discussed we know that it is at least 1.1 in 10 based on the impact of Extended Summer DR, but the cumulative effect of this plus the less reliable Limited DR is unknown and no specific standard is stated other than in Manual 20, Section 1.4 (See footnote 10).

14) Typically, discussions of reliability partition the issue between security and adequacy. Security deals with the ability of the operating system to withstand a real time shock or disruption and recover. This is usually addressed in the context of operating resources, reserves, transmission operations and associated contingencies. Adequacy (the subject of RPM and this proceeding) addresses long-term sufficiency of generation resources to meet a target expectation that load will not exceed available supply. RPM, inclusive of the BRAs and Incremental Auctions ("IAs"), is thus just *one* part of the overall reliability adequacy construct in PJM. RPM represents the last step in terms of acquiring the level of reliability resources determined to be necessary via the overall adequacy planning process.

15) RPM is a market-based construct designed to meet reliability requirements that are based on the physical components, limits and forecasted demand for the PJM system. In order for RPM to achieve its goals, the products offered in RPM must be consistent with the products and related assumptions used to derive system resource adequacy requirements. If, in the underlying studies, it is determined that a products quantity/participation should be constrained due to its reliability performance *vis-à-vis* underlying assumptions, and thus its excess violates the underlying planning assumptions, then it similarly must be constrained in the RPM solution for consistency. Failure to do so results in a violation of the reliability planning assumptions. In this regard, I emphasize that it makes no sense to look at one element of the entire adequacy and long-term reliability construct in isolation, and doing so can result in misleading conclusions. The pieces must fit together, consistent with the underlying analytics. The error/oversight made by PJM in its initial modeling of DR products within RPM falls squarely into this lack of consistency "box."

16) The underlying planning constructs for resource adequacy establish the assumptions and associated properties for the resources eligible to participate in RPM and, similarly, the properties required to meet the necessary adequacy targets. They do not just come out of thin air. They are the product of an extensive series of

studies and analyses that together form the basis for the PJM reliability adequacy requirements.

17) The issue being presented to the Commission by PJM is a request to correct a now recognized inconsistency in the establishment of these properties. When PJM established the MAR and MESR floors, it was not proposing to abandon the Commission-approved downward-sloping demand curve or to adopt a vertical demand curve for Annual Resources, even if its approach had that unintended effect. This proceeding should not, therefore, be mischaracterized or misunderstood as an opportunity to revisit the Commission's previous decisions strongly supporting PJM's use of a downward-sloping demand curve.[7] Nor should PJM's simple, logical correction to this mistake in the RPM modeling constraints be misconstrued as opening the door for efforts to introduce elements of price discrimination into the RPM structure.

Reliability Planning Process: Summary of Basic Steps

18) To better understand the issue, a short description of the overall process for setting adequacy requirements is in order. The starting point in the PJM reliability planning process is the development of an IRM requirement. PJM begins by evaluating its entire system as if the resources were all "traditional"/conventional generating units, characterized by observable MW rating, availability metrics, and maintenance requirements.[8] It assumes no demand response resources or other non-traditional resources. It also assumes that there is infinite internal transmission and a 3,500 MW (equal to PJM's Capacity Benefit Margin ("CBM")) tie line linking PJM to the outside "world." Based on these internal assumptions, as well as analyses that indicate the potential diversity benefit from the outside "world" over the tie line, PJM establishes its IRM. The target reliability is the traditional

[7] See supra n.5.

[8] PJM uses the Probabilistic Reliability Index Study Model ("PRISM") to conduct these evaluations. Units are characterized by their size, availability, maintenance requirements, etc. The ability to schedule maintenance is also assumed.

industry standard one day in 10 years LOLE and conforms to RFC requirements.[9] [10] The supply side of this analysis is based entirely on annual generation resources.

19) In the next step, PJM accounts for the fact that that internal transmission is not, in fact, infinite. They do this by conducting evaluations of its internal transmission *and* generation to establish load deliverability targets, Capacity Emergency Transfer Objectives ("CETOs") for each Locational Deliverability Area ("LDA"). That is, it analyzes the ability to get generation into what might typically be referred to as "load pockets." To approximate the infinite internal transmission assumed in its initial reliability planning step, PJM establishes the CETO for a given LDA to reflect the chance of a one in 25 year probability of load exceeding generation (*i.e.*, a risk that load will be shed in the LDA due to an inability to import needed capacity assistance from the rest of PJM once in 25 years). Although this one in 25 year standard may appear stringent, implicit in using any finite limit at this stage is the fact that the assumption of less than infinite internal transmission, as was assumed in the first step, takes the actual reliability below one in 10 years. In other words, while one in 25 years may seem like a high standard for CETO, it is less demanding than the implied CETO of one in infinity that was assumed in the first planning

[9] The industry guidelines and standards for reliability are established by NERC and RFC. Specifically the applicable RFC Standard is BAL-502-RFC- 02. *See* PJM, PJM Manual 20: PJM Resource Adequacy Analysis, § 1.1 (Feb. 1, 2013) ("Manual 20"), available at http://www.pjm.com/~/media/documents/manuals/m20.ashx. See also http://www.nerc.com/files/BAL-502-RFC-02.pdf. Note that the standard for one in ten years is in terms of necessary studies, not a specific mandate; although PJM appears to adopt the standard based on Manual 20 Section 1.4.

[10] "The PJM Reserve Requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of 10 years, on average, per occurrence (loss of load expectation of one occurrence every 10 years) after emergency procedures to invoke load management. As indicated above, the PRISM program is the principal tool used to calculate the PJM Reserve Requirement. The PJM Reserve Requirement is calculated using a PRISM two-area model. PJM is modeled in Area #1 and a composite "World" representation consisting of parts of RFC, SERC Reliability Corporation, MISO and Northeast Power Coordinating Council, Inc. is modeled in Area #2. The PJM Installed Reserve Margin value is used in the determination of the Forecast Pool Requirement and demand response factor." See Manual 20, § 20 1.4. As noted above, in execution, because of the degradation of reliability from the Extended Summer and Limited DR products, the 1 in 10 standard is not met.

process step setting the IRM. Like the first, this second step is entirely based on conventional physical generation resource assessments.[11]

20) To gauge whether the CETO is met (and thus whether there is adequate transmission), PJM then conducts analyses of combinations of generation outages within an LDA to establish a Capacity Emergency Transfer Limit ("CETL") reflecting the available transmission capability that can allow generation from the rest of PJM into an LDA during an emergency.[12] These are location-specific generation and transmission studies that consider the ability to transfer resources into an LDA during emergency conditions, assuming potential outages of generation within the LDA under high load conditions (*i.e.*, their 90%/10% high non-coincident load forecast adjusted for demand response).

21) If the CETL is less than the CETO, there is a load deliverability reliability violation that triggers *mandatory* construction of physical transmission facilities in PJM's Regional Transmission Expansion Plan. By respecting the CETO/CETL ratio, PJM assures physical deliverability of necessary resources into LDAs. It is important to note that underlying performance here is based on unit specific conventional generation capacity resources. While there is a demand-side adjustment in the CETL calculation, no demand response resources are considered as supply resources.

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[11] Manual 20 explains:

> A fundamental assumption of the PJM Reserve Requirement Study is the absence of any transmission constraints within PJM that could result in "bottled" generation. This assumption is tested by Load Deliverability Analysis based on the Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) tests. These tests are applied to electrical areas (called Locational Deliverability Areas or LDAs in the RPM process) within the PJM RTO to ensure that the needed capacity resources are deliverable to load. The CETO is defined to be the import capability required by the area to comply with a Transmission Risk LOLE of one event, on average, in 25 Years.

Manual 20, § 4.1. *See also PJM Manual 14B: PJM Region Transmission Planning Process*, App. E (Oct. 24, 2013) ("Manual 14B") (same), *available at* http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

[12] *See* Manual 20, § 4.1; Manual 14B, App. E.

22) The load deliverability analysis described above is just one half of the location-specific evaluations that PJM conducts for capacity resources. The other half involves generation deliverability studies. The generation deliverability studies are not directly tied to the IRM, but rather serve to identify system upgrades necessary for a generation unit to participate in the capacity market (*i.e.*, RPM).[13] PJM discussed the multiple steps necessary to assure physical performance for deliverable capacity resources in detail in a recent filing.[14]

22) What should not be lost in this discussion is the underlying objective of the transmission evaluations conducted for the interconnection of a new generator, and how they complement the overall resource adequacy planning process. A new generator has the option of seeking to interconnect to the system as an energy-only resource or as a capacity resource. Interconnection as a capacity resource allows the generator to participate in RPM. The studies that PJM discussed in its recent filing related to the physical characterization and information required of new generation as capacity resource (*e.g.*, at minimum the completion of a System Impact Study) are conducted to assure that the new generation resource is deliverable to the bulk electric system and not "trapped" in a generation pocket. To the extent that new generation seeking recognition as a capacity resource might be limited by the "take-away" capability of the transmission system, transmission upgrades, the costs of which must be borne by the generator, are identified. These in turn create specific property rights, capacity interconnection rights, associated with the specific generator and potentially other transmission-related rights, such as capacity transmission interconnection rights and financial transmission rights.[15] In combination these processes address the need for generation to be useful and

[13] *See* Manual 14B, § 2.3.10.

[14] *See* Tariff Filing, Docket No. ER13-2108-000 (filed Aug. 2, 2013).

[15] See for example http://www.pjm.com/~/media/documents/reports/rtep-plan-documents/pjm-white-paper-capacity-interconnection-rights.ashx

access the bulk electric system, while the CETO/CETL evaluations assure deliverability from the bulk system to load.

DR Reliability Target Analyses within the Planning Process

24) It is also important to understand that in recent years, PJM has consciously degraded this reliability process target (*i.e.*, one day in 10 years LOLE) to a lower standard to accommodate less reliable demand response resources. PJM has done so by allowing less reliable demand response resources to participate in the RPM auctions while maintaining an IRM established under the assumption of utilizing only traditional generation resources as I have described above.

25) Within agreed limits, but explicitly with the understanding that reliability is degraded below the one day in ten years LOLE standard, PJM conducts analyses to determine how much Extended Summer and Limited DR resources it will accept. **<u>This makes it absolutely vital to understand just how these DR Reliability Target degradations are calculated in order to ultimately understand how the less reliable products should be modeled in RPM auctions, which is, the specific purpose of this proceeding</u>**. The following sections summarize the establishment of the Limited DR and Extended Summer DR Targets per PJM procedures.

Limited DR Reliability Target

26) The reliability degradation occurs in two basic ways, each associated with PJM addressing Limited DR and Extended Summer DR. As I will describe there is an interaction or hierarchy between the two. First, it is obvious that PJM needs to set a maximum target for Limited DR because the product is only available on an assured basis ten times a year for six hours or 60 hours total during the summer (June 1 to September 1 for evaluation). This is in contrast to the typical conventional Annual Resource that would be available approximately 95% of the time year round (approximately 8,300 hours) with coordinated outages taken with PJM's approval.

27) Several tests are utilized to establish which criterion may be most binding in terms of the amount of Limited DR allowed for the RTO and individual LDAs. PJM utilizes the most binding of the tests to set the saturation point for Limited DR.[16] First, PJM evaluates the likelihood that the Limited DR product may be called more than 10 times. This is a probabilistic evaluation that sets a reliability target based on the expectation that the 11th call would happen less than 10% of the time.[17] Second, PJM investigates the likelihood that the Limited DR product would be needed for more than six hours. Finally, it evaluates the likelihood that the new peak established outside of the event, *e.g.*, in the seventh hour (on either side of the triggering event), exceeds the values of load during the called events (inclusive of the demand response load impacts), effectively establishing a new higher peak than during the six-hour curtailment period.

28) Each test establishes a maximum acceptable amount at which point the Limited DR product fails to add any additional reliability value. For the RTO and the LDA, starting with the 2016/2017 Delivery Year, all three criteria are considered. As stated, the most binding is used. Empirically, this has currently resulted in a maximum Limited DR amount of 4.8% for the RTO. As discussed below, this is not an independent limit, but is a subset of the total amount of allowed demand response calculated for the Extended Summer DR limit. [18]

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[16] A more detailed discussion of these tests may found in Section 5 of Manual 20.

[17] These values are "inputs" by PJM and subjective. There are no supporting analyses of which I am aware that have explained why a 10% expectation in this specific type of degradation in reliability should be allowed.

[18] See October 16 Capacity Senior Task Force presentation on Item 4, at page 4. (http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20131016/20131016-item-04-limited-and-extended-summer-dr-targets.ashx.) (Note there are two similar but different values referred to in the Limited DR discussion. The Limited Reliability Target is 4.8% and based on the three tests just discussed. In a separate study to provide a rough feel for degradation associated with Limited DR on a standalone basis, PJM estimated that 4.9% penetration of Limited DR would decrease reliability by 10%. The similar values have been a source of confusion as in implementation, the Limited product cap is a subset of the total penetration allowed for Extended Summer DR.

Extended Summer DR Reliability Target

29) The Extended Summer DR product similarly provides markedly less reliability benefit than the conventional Annual Resources used to set the IRM. Extended Summer DR must be available for interruption from May-October of each Delivery Year for an unlimited number of interruptions of at least 10 hours in duration between 10:00 a.m. and 10:00 p.m. This translates into a resource that is available for a total of at most 1,840 hours during the extended summer period. While substantially better that the 60 hours from a Limited DR resource, this still falls well short of the approximately 8,300 hours of year-round availability that would be expected from a conventional generation resource, of the kind assumed in the IRM calculation.[19]

30) Consequently, PJM also performs an evaluation to determine how much Extended Summer DR can be accepted without unacceptable degradations in reliability. This is done by evaluating the program's unlimited 10-hour calls for the period between May 1 and October 31 (or June 1 to October 31 and May 1-May 31 of the same delivery year). In doing so PJM considers Extended Summer DR as if it were a 100% available product (which is obviously not true, given the 10:00 a.m.-10:00 p.m. restriction), and then approximates the impact of the less reliable product by effectively shifting load up to determine how much of the Extended Summer DR product can be accepted without degrading reliability by more than 10%.[20] In other words, PJM admittedly allows the reliability target to drop to 1.1 days in 10 years LOLE, or approximately one in nine years LOLE for the stand alone impact of the Extended Summer product.[21] [22] Empirically this has currently

[19] Indeed PJM's evaluations of the impact of the Extended Summer resource show not only a degradation of reliability, but also a shift of some portion of loss of load expectation from summer to winter due to the lack of any availability during the winter period and the associated loss of flexibility with respect to coordination of outages, as well as the simple reduction in available winter resources.

[20] *See* Manual 20, § 5.3.2.

[21] The actual drop is likely somewhat higher, because PJM has assumed that Extended DR is a 100% available product and operationally accepts that some portion of this amount may actually be the even less reliable Limited DR product. Though nowhere explicitly stated, the combined impact of the

resulted in a maximum allowed Extended Summer DR Reliability Target of approximately 10.5% of the target capacity procurement.

Interaction between the Two DR Reliability Targets

31) While PJM presents its discussion of the Limited DR and Extended Summer DR Reliability Targets in the above sequence in its manuals, the impact on overall system reliability planning and its implementation in RPM can be easier to understand by taking them in the reverse order: first establishing the Extended Summer DR Target and then setting the Limited DR Target as an allowed subset within the total quantity PJM has deemed acceptable for Extended Summer DR. This is how PJM has defined the product limits in implementation, because PJM has stated its intent to cap reliability degradation within the limits of the Extended Summer DR quantity, even though the Limited DR subset of that quantity further erodes reliability as discussed below.

32) Thinking about the exercise in this order is appropriate because PJM has no direct way within PRISM to represent the Limited DR product in its basic reliability/IRM planning and can only indirectly approximate the reliability

two less reliable products may lower reliability to a value approximating 1 day in 8 years versus the required one day in 10 years. See following discussion: http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20131016/20131016-item-04-limited-and-extended-summer-dr-targets.ashx

[22] It has always been puzzling to me that PJM has explicitly allowed a degradation of reliability below the one day in 10 years LOLE by these two demand response products rather increasing its IRM to compensate and maintain its reliability targets, because the entire exercise seems inconsistent with the NERC and PJM standards with which the RAA requires PJM to be consistent with. As noted, the one day in 10 years LOLE criterion is expressly adopted by RFC. *See supra* n.9. The standard serves as the basis by which PJM determines the capacity needs of the grid under the RAA. *See* RAA, § 1.75 (defining "Reliability Principles and Standards" as "the principles and standards established by NERC or an Applicable Regional Entity to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time"); *id.*, § 9.1 (continuing representation and warranty that each Party to the RAA "is in compliance with the Reliability Principles and Standards"); *id.*, Sch. 4 ("The Forecast Pool Requirement shall be determined for the specified Planning Periods to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards.").

degradation of the Extended Summer DR product.[23] Indeed, PJM has acknowledged that its characterization may understate the reduction in reliability associated with these Limited DR products. As a result, PJM has an explicit degradation of reliability for the Extended Summer DR (down to 1.1 days in 10 years LOLE), and then allows a subset of the 10.5% Extended Summer resource accommodation (4.8%) to be Limited DR, which further degrades overall reliability. While I have not identified the specific further incremental degradation metric, it is appears to be significantly higher.[24] In other words, PJM targets procurement of sufficient annual capacity resources to meet the industry standard one day in ten years LOLE, then permits 10.5% of that procurement to be filled by Extended Summer Resources (by definition resulting in a system LOLE less than the industry standard), then compounds the degradation by allowing nearly half of the Extended Summer tranche to be filled by Limited DR.

33) The overall effect of these two processes is to establish maximum acceptable quantities of inferior reliability products that drive the overall PJM LOLE to a level that, while below the RFC/NERC designated target study levels, is deemed acceptable by PJM. Any increased use of these products that may now or in the future result in the displacement of the superior annual products can only further reduce reliability. That is why it is so important to understand the adverse impacts of the specific error/oversight PJM made in its RPM modeling implementation of the constraints. By design, PJM already procures insufficient resource commitments to meet the industry standard LOLE to accommodate Extended Summer and Limited DR, and the PJM miscue likely exacerbates this problem. In addition, for Limited

[23] As noted above PJM can do a crude approximation that is quite non-conservative of Limited DR, but it really can only bound the adverse reliability impacts, noted as a free standing degradation of reliability by 10% at 4.9% Limited penetration.

[24] See for example http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20131016/20131016-item-04-limited-and-extended-summer-dr-targets-presentation.ashx at slide 3 and 4. October 16 presentation to PJM Capacity Senior Task Force. These results suggest that the LOLE may be degraded by up to a further 10%. Again note the conclusion that this exceeds the RFC/NERC planning study criterion. There are no analyses I am aware of that actually combine the two impacts, but they can be "eyeballed" from some of the referenced materials.

DR, the purpose of the saturation tests is really to establish the point at which additional increments of this product effectively cease to have any value at all.[25]

Consistent RPM/BRA Modeling Representation of the Computational Approaches to the DR Reliability Targets

34) If I were teaching students about how to model the preliminary analyses about DR saturation, at this point I would just state Q.E.D.[26] PJM has a model structure to obtain necessary resource adequacy products in an optimal fashion predicated in part on the use of a downward-sloping demand curve. PJM has also recognized that certain inferior products may be accepted into the market, but only in limited quantities. Thus the model must limit those products to the identified quantities in order to now modify the fundamental structure of the RPM design and its conformance with the integrated adequacy planning process.

35) Once these saturation points for inferior reliability products, *i.e.*, Limited DR and Extended Summer DR, have been identified, the only consistent representation of this information in a process designed to procure reliability products is to use the identified saturation points as explicit caps for the amount of those products to be procured through the auction. To do otherwise allows both greater quantities than desired to be procured, and the function of the downward-sloping demand curve to be thwarted. (This latter point is obviously key and is discussed further below.)

36) This is particularly obvious in the context of the nature of the testing that PJM does for both products. The saturation limits establish the point at which the Extended Summer DR exceeds a designated deemed acceptable level of LOLE

[25] The tests described above all have in common a recognition that at some point, additional increments of the Limited DR would probabilistically be expected to contribute nothing to reliability. This is strongly contrasted with annual products, where additional increments beyond a certain point may have lower marginal reliability value, but which never reach a point of saturation at which they would be expected to provide zero or near zero reliability value.

[26] Quod erat demonstrandum. The Latin phrase is typically used to summarize when the argument, in this case the previous several pages of discussion on the demonstration of how the saturation limits were established, is effectively the equivalent or demonstration of the conclusion.

degradation. For Limited DR, it is even more extreme as the product test process conducted by PJM is intended to demonstrate the point at which virtually no additional reliability benefits can be expected to be received. Thus, the right mathematical expression of the saturation points must be caps in the auction. PJM has always represented their analyses and results in just this fashion, with the level of Limited DR being a subset within the total saturation deemed acceptable for Extended Summer DR in order to control or limit overall reliability degradation (*i.e.*, the Limited DR product cannot exceed its saturation level, and the sum of the Limited DR and Extended Summer DR cannot exceed the Extended Summer DR Reliability target.)

37) As PJM has acknowledged, through error or oversight, these constraints were misrepresented as originally proposed in the RPM modeling process and constructed in a fashion to establish a floor on the minimum necessary Annual Resources (the MAR) and the sum of Annual Resources plus Extended Summer DR (the MESR). This was and is inconsistent with the underlying analyses and market design, and as discussed in the following portion of my testimony has likely already lead to material adverse results in the overall function of the RPM model *vis-à-vis* its original design criteria.

Impacts of the Incorrect Representation of Extended Summer and Limited DR

38) The goal of the optimization process for the BRA in very general terms is to meet PJM's stated overall and locational reliability requirements at lowest cost, while satisfying various constraints relating to transfer capability and specific product definitions. This is all achieved through a simultaneous solution optimization, but it is helpful to think about the solution as if it were sequential.

39) When PJM proposed the current menu of demand response products (Annual DR, Extended Summer DR and Limited DR), PJM also provided a set of constraints related to how much these products it could accept in the PJM region as a whole and

individual LDAs.[27] Despite all of the logical progression regarding the properties of these products discussed above, PJM took a misstep and established floors for the higher reliability value products, the Annual Resources (including Annual DR), rather than caps on the lower reliability values. In other words, rather than set a cap of 10.5% of the IRM on Limited DR and Extended Summer DR, PJM set a floor of 89.5% of the IRM on Annual Resources.[28] PJM also established a second higher floor of 95.2% (89.5% +10.5%-4.8%) of the IRM for Annual Resources plus Extended Summer DR.

40) It is logical to assume that the relative price of the various products will follow their reliability performance characteristics. For example, a resource that obligates itself to follow PJM commitment daily, has approximate availability 95% of the time (approximately 8,300 hours), and can schedule and move its maintenance activity would be expected to cost more and offer at higher prices in the auction process than a resource that only has to be available for 10 "events," none of which lasts more than six hours.

41) With this type of reliability/price ordering, the solution impacts of the types of "floor" equations (discussed two paragraphs above) become almost transparently obvious. The optimization will first attempt to satisfy the floor conditions, because these require the most expensive general types of products (assuming no locational constraints for our simple discussion). So the first "floor" type of constraint would be expected to be "filled" by the more expensive Annual Resources. But because these Annual Resources are more expensive, and the objective was to minimize costs, the optimization would "stop" this procurement as soon as the constraint limit was reached. Next, the optimization would move to satisfying the second floor condition regarding the sum of Annual Resources plus Extended Summer DR (all

[27] *See PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066 at PP 21-30 (2011) (accepting proposed demand response product definitions and discussing targets).

[28] For simplicity, I am ignoring the subtraction from all constraint targets of the 2.5% short term resource procurement target (the 2.5% holdback).

products except for Limited DR). Again, the next most expensive resources would be procured up to that floor value and then when satisfied, stop. Finally, relieved of all other constraints, the optimization would then move to procuring the cheapest resources available, presumably the Limited DR, and would continuing procuring Limited DR until the quantity intersects with the Variable Resource Requirement (VRR) demand curve.

42) As this verbal description should make clear, this type of clearing mechanism, in the face of price ordered reliability products ***looks exactly the same as a vertical demand curve for the two "floored" product groups***, *i.e.*, the Annual Resources and the sum of Annual and Extended Summer DR. This is exactly the conclusion that PJM itself has recognized. Visually, this interaction between the floors and the RPM optimization process is illustrated in Figure 1 of PJM's filing (reproduced below):

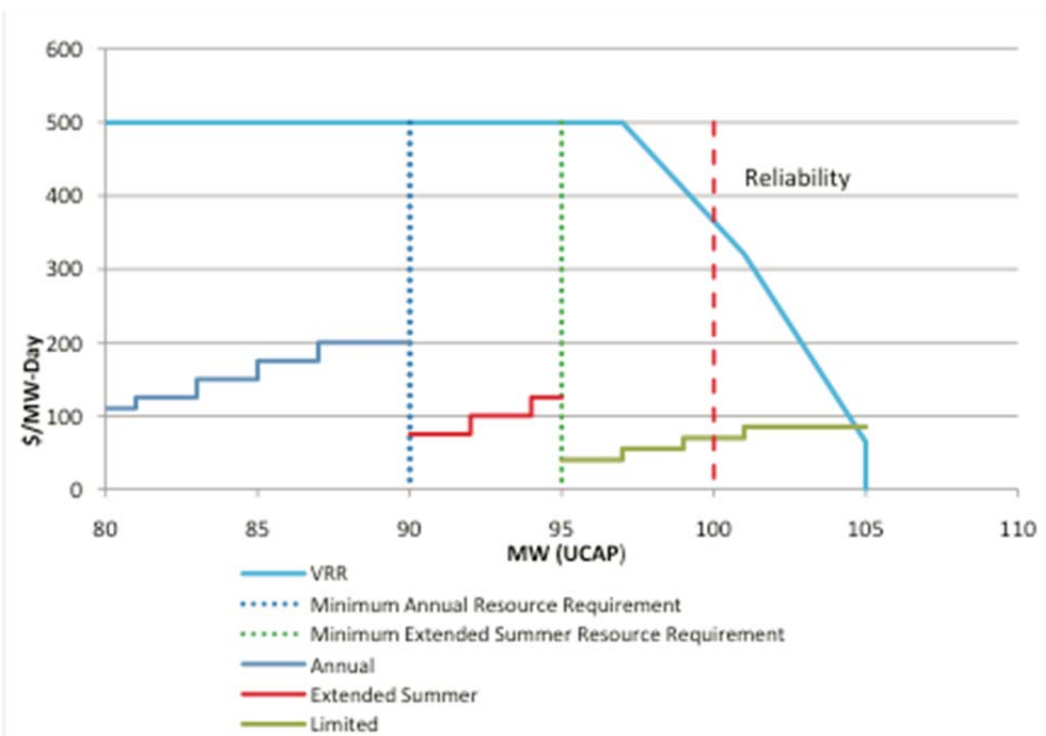

Figure 1 – PJM's Current Capacity Resource Clearing Process

43) This also is not just a hypothetical result. As PJM also demonstrated, the vertical curve impact was clearly visible in the BRA for the 2015/2016 Delivery Year, when the Annual Resources floor did not bind, but the combined Annual Resources plus and Extended Summer DR floor did. This is illustrated in PJM's Figure 2 (reproduced below):

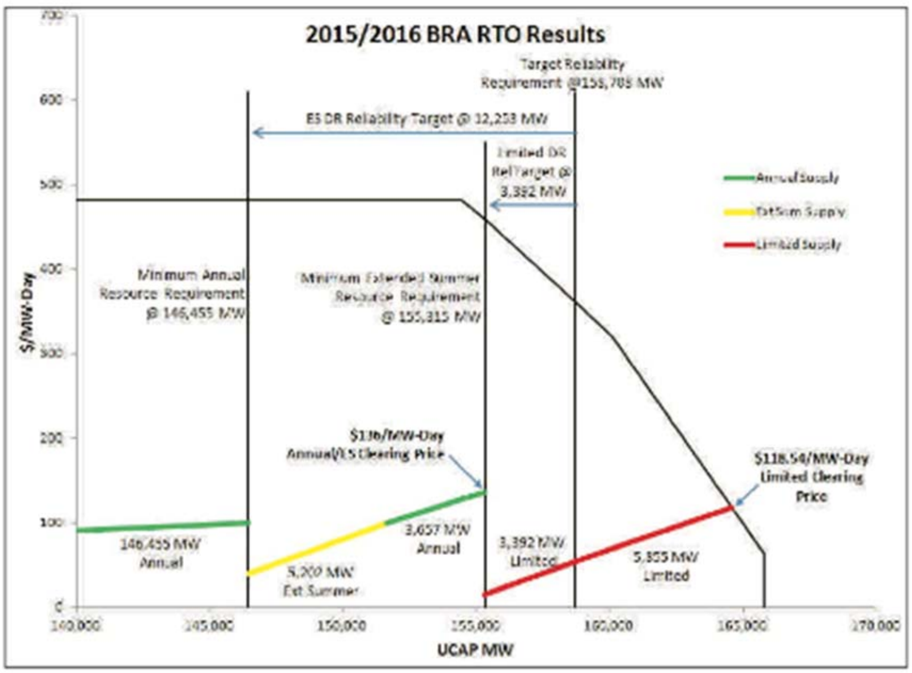

Figure 2 – 2015/2016 BRA Results Under Capacity Resource Clearing Process

44) Clearly, this was an unintended result. PJM strongly advocated the use of a downward-sloping demand curve in its initial RPM filing,[29] and the demand curve was a key feature of the resulting RPM settlement.[30] The Commission also recognized the desirability of a downward-sloping demand curve when it found PJM's prior market with a vertical demand curve to be unjust and unreasonable.[31]

[29] *See* Tariff Filing, Transmittal Letter at 11-13, Docket Nos. ER05-1410-000, *et al.* (filed Aug. 31, 2005) ("August 2005 Filing").

[30] *See* Settlement Agreement and Explanatory Statement of the Settling Parties, Tab 1, Explanatory Statement at 7-11, Docket Nos. ER05-1410-000, *et al.* (filed Sept. 29, 2006).

[31] *See PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 35 (2006) ("April 2006 Order") (finding the earlier deficiency charge mechanism, with what was, in effect, "a vertical demand curve," was unjust and unreasonable).

Similarly the Commission endorsed the benefits of the use of the VRR in its orders accepting RPM.[32] Yet by simply "inverting" the constraint representation in the model, PJM eliminated all of these VRR benefits for the entire fleet of annual products (approximately the most reliable 90% of generation supply existing in the market). Further, this also undid all of PJM's work to clearly recognize the inferior reliability characteristics of the Limited DR and Extended Summer DR products.

45) Even worse, because of this formulation, the saturation analysis for the Limited DR product becomes almost meaningless. While the exact values in the PJM figure 1 are notional, they are indicative of the approximate range of values possible using the historic 10.5% and 4.8% saturation limits (Extended Summer DR and Limited DR, respectively). As can be seen, because only the Limited DR product interacts with the demand curve, the ability to procure "out" to the demand curve only becomes meaningful for the Limited DR product. All other products are "blocked" and face a vertical curve. This is totally perverse. The higher reliability, higher cost products that were meant, and most needed, to interact with the demand curve do not do so. Thus this formulation has eliminated the benefits of having a demand curve. Moreover the current formulation of constraints encourages continued procurement of the Limited DR product at and beyond the point at which PJM has already found that additional increments of that product provide no reliability benefit due to the probability of either exceeding the number of calls, hours or inability to further reduce the peak load.[33]

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[32] PJM Interconnection, L.L.C., 115 FERC ¶ 61,079, at PP 6, 104 (2006) ("RPM Settlement Order"), order on reh'g, 119 FERC ¶ 61, 318, reh'g denied, 121 FERC ¶ 61,173 (2007) petition for review denied sub nom. Pub. Serv. Elec. & Gas Co. v. FERC, No. 07-1336 (D.C. Cir., Mar. 17, 2009) See also PJM filing letter in this proceeding at pages 6-7.

[33] PJM's shares my perspective. Our comments are congruent because they are observations of fundamental properties of the way in which the formulation should have occurred, versus what unintentionally did occur: "This is decidedly not how the sloped demand curve was intended to operate. Annual Resources, without the seasonal, frequency, or duration limits of Limited DR and Extended Summer DR, and representing approximately 90% of the PJM Region capacity resource base, are critical to the reliability of the PJM Region and must be properly valued. As shown, to realize the sloped curve's benefits of greater assurance of reliability at lower long-run cost, the curve must recognize the value of Annual Resources beyond the installed reserve margin. But when the curve

Empirical Impact Example from Capacity Senior Task Force Stakeholder Process

46) As part of the stakeholder process PJM ran simulations of the last several BRAs, using caps on Limited DR and the sum of Limited and Extended Summer DR, rather than floors on Annual Resources and the sum of Annual Resources plus Extended Summer DR. I present one such summary in Attachment B to my affidavit.

47) The results of this simulation of the 2016/2017 auction results,[34] if the modification proposed in the November 29 Filing were in effect, are very notable in several respects. First, the quantity of cleared annual resources increased by approximately 600 MW, most likely representing existing annual generation resources that were at high risk, and that may have actually retired after not clearing (although such information is not publically available). Second, clearing prices for Annual Resources in PJM RTO and LDAs increased, *e.g.*, for the RTO the clearing price for annual products increased from $59.37 to $85.15 and for MAAC it increased from $119.13 to $130. (Annual prices were virtually the same in PSEG and ATSI.). Perhaps most significant from a reliability perspective is the decrease in cleared Limited DR once the reliability constraints are properly represented. The cleared quantity of Limited DR fell from 9,849 MW to 3,462 MW, with most of the "exchange" occurring as a "swap" between increases in the more reliable Extended Summer DR product and reductions in the over saturated Limited DR product.

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selects lower-priced Limited DR or Extended Summer DR because the MAR Requirement has already been satisfied, then it is not valuing from a reliability perspective, Annual Resources beyond the established reserve margin (indeed, it is not valuing Annual Resources beyond the MAR Requirement). More importantly, the products with limited reliability value are displacing the annual products with greater reliability value. This has a long term impact of discouraging investment both in new generation and new annual demand response technologies and leaves PJM with a portfolio of resources that is less flexible in meeting capacity emergencies." PJM Filing at p.13-14.

[34] While this was a simulation based on what was then a working group proposal, my understanding is that this re-run of the auction is consistent with the filed PJM proposal and tariff language.

48) Also notable is the increase in total payments to all suppliers. The total went from $15.1 billion to $17.9 billion. No doubt this will give rise to claims that PJM's November 29 Filing will unnecessarily increase prices. But the reality is exactly the opposite. In fact, the Annual Resources (including Annual DR) that provided the greatest reliability benefits were significantly undercompensated for three Delivery Years due to inappropriately depressed clearing prices. This means that signals for needed new entry and the retention of needed existing generation were substantially muted during a period of unprecedented generation retirements in PJM. Since the May 2011 auction, the first time that PJM included the incorrect modeling, approximately 9400 MWs of conventional generation has made retirement requests.[35] While obviously there were a number of factors, particularly environmental costs, involved in these decisions, the inappropriate transfer of billions of dollars out of the capacity market, was undoubtedly a factor.

49) Further, as PJM noted in its analyses, there would be likely very high additional energy savings associated with the corrected solutions, as additional annual resources could contribute more energy that would not be available from DR resources which typically offer very near the scarcity price cap of $1800 per MWh. At the November 14, 2013 Markets and Reliability Committee meeting, summary materials provided indicated that depending on the ultimate level of additional annual resources, energy savings could be as much as $3.4 billion depending on the level of surplus.[36]

50) In fact the actual result in terms of energy pricing could be more pronounced should the Limited DR set price frequently, which might be the long-term result of

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[35] http://www.pjm.com/~/media/planning/gen-retire/generator-deactivations.ashx

[36] http://www.pjm.com/~/media/committees-groups/committees/mrc/20131113/20131114-item-03-clearing-limited-dr-pjm-comparison-of-proposals.ashx at 21.Note that PJM also observed that excess DR would not be expected to supply such energy savings.

price suppression for other resources and the underlying modeling error. Indeed in the recent situation where Limited DR did set price in the ATSI Zone this past summer, the LMP was $1800 per MWh (based on DR offers, not scarcity). Annual resources would have been subject to cost based offer price mitigation in a similar situation.[37]

Adverse Impacts of the Removal of the Demand Curve for Annual Resources

51) The unambiguous result of PJM's error/oversight is the creation of a vertical curve for annual capacity resources. PJM itself has been straightforward in its own statements recognizing this result and the associated problem.[38] The foregoing discussion should reinforce PJM's conclusions. To its credit PJM has also been forthcoming about the adverse impacts that they this result will have over the long run, and potentially may have had already.

52) When PJM first proposed the RPM construct in August 2005, it went to great lengths to justify the need for a downward-sloping demand curve.[39] The existing system at that time had a vertical curve that charged a relatively high deficiency if any party were short capacity, and valued incremental annual capacity resources at zero. As noted above, the Commission agreed that the associated deficiencies of a vertical demand curve such as the then status quo, versus the benefits of a downward-sloping demand curve rendered the status quo unjust and unreasonable, explaining:

> [T]he current capacity construct effectively creates a vertical demand curve for capacity. When aggregate supply is less than the IRM, LSEs will be willing to pay a price equal to the deficiency charge for

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[37] For the ATSI zone with a resource target of approximately 15,000 MW, the $1800 price translates to a total load payment of approximately $54 million for just one two hour minimum run period. On an RTO wide basis it would be 10 times that. For a situation where this occurred for 60 hours, it would be approximately $1.6 billion in energy payments. Cost capped payments from conventional resources would be expected to be a fraction of that amount.

[38] *See, e.g.,* November 29 Filing, Transmittal Letter at 11-14.

[39] *See supra* n.29.

> capacity in order to avoid the deficiency charge penalty; but when aggregate supply is even slightly greater than IRM, so that all LSEs can find capacity to meet their requirement, the price of capacity will fall to zero. Such volatility and risk increases the cost of financing needed generation investments.[40]

53) PJM's initial conclusions regarding the benefits of a downward-sloping demand curve were clear. Both Mr. Andrew Ott and Professor Hobbs discussed the benefits of the downward-sloping demand curve versus a vertical curve.[41] The proposed initial 2005 VRR curve was found by the Commission to be a just and reasonable resolution of the problems PJM identified.[42] It would remove extreme volatility and associated risk premiums from the market costs of new entry. It would also, over time serve as a form of control system for the capacity needs of PJM, encouraging rapid entry to the market when supplies were short, and allowing a slower and organized exit from the market during times of surplus. It also would tend to mitigate the potential exercise of market power.[43]

54) It would be a tragic mistake if, after all the effort devoted to developing and implementing the RPM construction, an unintended error on the part of PJM was allowed to effectively eliminate one of its core design elements. But that is precisely what will occur should the Commission fail to approve PJM's proposal.

55) PJM itself has recognized that its miscue might have these types of repercussions and properly asked Professor Hobbs, who "provided critical theoretical support at the initiation of RPM," to evaluate both the modeling

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[40] April 2006 Order, 115 FERC ¶ 61,079 at P 35.

[41] *See* August 2005 Filing, Tab E, Affidavit of Andrew L. Ott on Behalf of PJM Interconnection, L.L.C. at 15-17; *id.*, Tab H, Affidavit of Benjamin F. Hobbs on Behalf of PJM Interconnection, L.L.C. at 11-13 ("2005 Hobbs Affidavit").

[42] *See* April 2006 Order, 115 FERC ¶ 61,079 at P 104 (finding the use of a downward-sloping demand curve to be a "just and reasonable option for acquiring capacity").

[43] *See* 2005 Hobbs Affidavit at 12.

error/oversight and the implications of the mistake.[44] Dr. Hobbs reached the same conclusions that I did: under the price/reliability ordering assumptions that are likely to exist, PJM's current modeling leads to a vertical demand curve for Annual Resources;[45] he similarly noted that the value of having a downward-sloping demand curve was critical, and that the absent such a curve, the market reliability performance would degrade and overall costs to consumers would be expected to increase. I agree with his findings, which he summarized as follows:

> The imposition of a fixed Minimum Annual Resource ("MAR") Requirement, together with a large quantity of lower priced offers from Demand Resources (as defined by PJM) with limited availability, has resulted in a demand curve for Annual Resources that is, in effect, vertical. As a result, Annual Resources have lost the price stabilization, reliability and consumer cost benefits of the sloped demand curve that I described in my 2005 and 2006 RPM affidavits. To restore those benefits for Annual Resources, which have the highest level of reliability due to their absence of seasonal or response limitations, a slope can be introduced in their effective demand curve.[46]

56) Dr. Hobbs cited "two undesirable implications" of this accidental reversion to an effectively vertical demand curve:

> a. Under this approach and these conditions, the Annual Resources offered are, in effect, cleared against a vertical demand curve defined by the MAR Requirement. Further, the sloped demand curve beyond the MAR Requirement has no impact on the cleared quantities and clearing prices of the Annual Resources that provide PJM with the highest level of reliability due to their absence of seasonal or response limitations. In this situation, the price received by Annual Resources is determined by the intersection of their overall offer (supply) curve with the MAR Requirement, which, as a fixed quantity, acts as a vertical demand curve with a price cap. Consequently, Annual Resources no longer derive the benefits of price stabilization provided by a sloped demand curve as identified in my 2005 and 2006 analysis and recognized by the Commission. This effective vertical curve is analogous to PJM's ICAP market structure before RPM which assessed a penalty on load serving entities that failed to demonstrate capacity equal to or in excess of expected peak loads plus a stated reserve margin. Just as the fixed-reserve and penalty approach failed to recognize the value of capacity

[44] November 29 Filing, Transmittal Letter at 3.

[45] *Id.*, Attachment A, Affidavit of Benjamin F. Hobbs on Behalf of PJM Interconnection, L.L.C. at ¶ 14.

[46] *Id.* at ¶ 10.

procured beyond the fixed reserve level, PJM's present approach is not adequately recognizing the value of Annual Resources procured beyond the MAR Requirement and results in less stable prices than a sloped curve.

b. The sloped portion of the demand curve beyond the target reliability requirements (MAR and MESR Requirements) is utilized only to clear additional quantities and determine the clearing price of the capacity resource types having the lowest availability and response requirements (lowest reliability value). The long-run reliability and cost benefits provided by a sloped demand curve relative to a vertical demand curve are, in effect, unavailable to the capacity resource type having no seasonal or response limitations and highest reliability value (i.e., Annual Resources) and instead maintained for capacity resource types having the lowest availability and response requirements and lowest reliability value (i.e., Limited DR and Extended Summer DR). [47]

57) In order to test the impact of the incorrect modeling of Limited DR and Extended Summer DR, Dr. Hobbs basically replicated his 2005 analyses, but adjusted it to examine the effects of the vertical demand curve at the MAR. He found that as before, a downward-sloping demand curve performs far better than a vertical demand curve in maintaining reliability and minimizing total cost to consumers over time.[48]

58) From the perspective of reliability and cost, Dr. Hobbs reached two conclusions that echo his original findings about the disadvantages of a vertical demand curve and the advantages of a downward-sloping demand curve. The first addresses the underlying degradation of reliability that will occur if PJM does not "fix" the underlying error in its original modifications for DR products. Dr. Hobbs finds that restoring a downward-sloping demand curve should result in the Annual Resources requirement (*i.e.*, the MAR requirement) being met or exceeded in 96% of the years, versus just 42% with the effective vertical demand curve resulting from the modeling errors.[49]

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[47] *Id.* at ¶ 15.

[48] *Id.* at ¶ 11.

[49] *Id.* at ¶ 24.

59) Professor Hobbs's second conclusion that is most pertinent is that with the restoration of a functioning downward-sloping demand curve, total costs to consumers would be expected to decline versus the erroneous status quo in terms of costs over time. Specifically, his model "shows that the revenue required by the risk-averse generators in order to invest decreases by $50/MW-Day under the sloped demand curve . . ."[50] This conclusion about long-term cost savings is important to bear in mind in considering the short-term cost increases that may result from allowing PJM to implement the correction proposed in the November 29 Filing.

60) This concludes my affidavit.

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[50] *Id.* ¶ 26.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. ER14-504-000
	)	

AFFIDAVIT

I, Roy J. Shanker, do hereby swear and affirm under penalty of law that the statements in the foregoing Affidavit of Roy J. Shanker, Ph. D. are true to the best of my knowledge, information and belief.

Executed this 19th day of December, 2013.

Roy J. Shanker

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Roy J. Shanker

Attachment A

ATTACHMENT RJS-A

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 60450 Potomac MD 20854 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc. 1901 L Street, N.W.

Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2013

224-Federal Energy Regulatory Commission. Docket No. ER14-456. On behalf of NextEra Energy to analyze a proposed modification to the PJM Tariff allowing for "easily resolved constraints" to be address by transmission upgrades without any analyses of benefits.

223-Federal Energy Regulatory Commission. Docket No. ER14-504.Affidavit on behalf of PJM Power Producers addressing the interaction between the PJM adequacy planning processes and the formulation of saturation constraints on Limited and Extended Summer Demand Response products.

222-Federal Energy Regulatory Commission. Docket AD13-7. Invited speaker on the Commission's technical session regarding capacity markets in RTO's. Comments addressed basic principles of market design, market features, and consequences of market failures and deviations from design principles.

221-Federal Energy Regulatory Commission. Docket No. EL13-62 on behalf of TC Ravenswood LLC. Two affidavits addressing the treatment of reliability support services agreements and associated capacity in the NYISO capacity market design.

2012

220-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of First Energy Services Company. An affidavit and testimony addressing the appropriateness of the application of a proposed new MISO tariff provision after the fact to a withdrawing MISO member.

219-Federal Energy Regulatory Commission. Docket ER13-335. On behalf of Hydro Quebec U.S. Affidavit addressing appropriate application of ISO-NE Market Rule 1/ Tariff with respect to the qualification of new external capacity to participate in the Forward Capacity Market.

218-Federal Energy Regulatory Commission. Docket IN12-4. On behalf of 220-Deutsche Bank Energy Trading. Affidavit regarding a review of specific transactions, related congestion revenue rights, and deficiencies in CAISO tariff implementation during periods when market software produces multiple feasible pricing solutions.

217-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of FirstEnergy Services Company. Affidavit regarding implementation of the MISO Tariff with respect to the determination of appropriate exit fees and charges related to certain transmission facilities.

216-Federal Energy Regulatory Commission. Docket No. IN12-11. On behalf of Rumford Paper Company. Affidavit regarding free riding behavior in the design of demand response programs, and its relationship to accusations of market manipulation.

215-Federal Energy Regulatory Commission. Docket No. IN12-10. On behalf of Lincoln Paper and Tissue LLC. Affidavit regarding relationship of demand response behavior and value established in Order 745 to claimed market impacts associated with accusations of market manipulation.

214-Federal Energy Regulatory Commission. Docket No. AD12-16-000. On behalf of PJM Power Providers, testimony regarding deliverability of capacity between the MISO and PJM RTO's and associated basic adequacy planning concepts.

213-United States Court Of Appeals, District of Columbia Circuit. Electric Power Supply Asociation, et al (Petitioners) v. Federal Energy Regulatory Commission et al (Respondents) Nos. 11-1486. Amici Curiae brief regarding the appropriate pricing of demand reduction services in wholesale markets vis a vis the FERC determinations in Order 745.

212-United States Supreme Court. Metropolitan Edison Company and Pennsyvalnia electric Company (Petitioners), Pennsylvania Public Utility Commission (Respondent) (No. 12-4) Amici Curiae brief regarding the nature of physical losses in electric transmission and relationship to proper marginal cost pricing of electric power and the marginal cost of transmission service.

2011

211-Federal Energy Regulatory Commission Docket No. ER12-513-000. On behalf of PJM Power Providers, testimony regarding the establishment of system wide values for the net cost of new entry related to modifications of the Reliability Planning Model.

210-Federal Energy Regulatory Commission Docket No. EL11-56-000, on behalf of First Energy Services. Affidavit regarding the appropriateness of proposed transmission cost allocation of Multi-Value Projects to an exiting member of the Midwest Independent System Operator.

209-Federal Energy Regulatory Commission Docket No. ER11-4081-000, on behalf of “Capacity Suppliers”. Affidavit addressing correct market design elements for Midwest Independent System Operator proposed resource adequacy market.

208-Public Utility Commission of Ohio, Case Nos. 11-346-EL-SSO,11-348-EL-SSO,Nos. 11-349-EL-AAM, 11-350-EL-AAM, on behalf of First Energy Services. Testimony regarding the interaction between the capacity default rates for retail access under the PJM Fixed Resource Requirement and the PJM Reliability Planning Model valuations.

207-Federal Energy Regulatory Commission Dockets No. ER11-2875, EL11-20, Staff Technical Conference on behalf of PJM Power Providers, addressing self supply and the Fixed Resource Requirement elements of PJM’s capacity market design.

206-New Jersey Board of Public Utilities, Docket Number EO11050309 on behalf of PSEG Companies. Affidavit addressing the implications of markets and market design elements, and regulatory actions on the relative risk and trade-offs between capital versus energy intensive generation investments.

205-Federal Energy Regulatory Commission Docket No. ER11-2875. Affidavit and supplemental statement on behalf of PJM Power Providers addressing flaws in the PJM tariff’s Minimum Offer Price Rule regarding new capacity entry and recommendations for tariff revisions.

204-Federal Energy Regulatory Commission Docket No. EL11-20. Affidavit on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry.

203-Federal Energy Regulatory Commission Docket Nos. ER04-449. Affidavit and supplemental statement on behalf of New York Suppliers addressing the appropriate criteria for the establishment of a new capacity zone in the NYISO markets.

2010

202-New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381

201-Federal Energy Reglatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

200-Federal Energy Regulatory Commission. Docket ER11-2059Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed "exit charges" for transmission owners leaving the MISO RTO related to long term transmission rights.

199-Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

198-Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

197-Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

196-Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

195-Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

194-PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

193-Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

192-Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

191-Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

190-Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

189-American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

188-Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

187-Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

186-American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

185-Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

184-Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

183-Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

182-Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

181-Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

180-Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

179-Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

178-Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

177-FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

176-FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

175-FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

174-FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

173-United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

172-FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

171-FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

170-FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

169-FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

168-FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

167-FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

166-FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

165-American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

164-Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

163-Federal Energy Regulatory Commission. Docket No. Docket No. EL03-236-003 Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

162-Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

161-Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

160-Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

159-Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

158-Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

157-Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

156-Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

155-Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

154-Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

153-American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cineregy Solutions regarding an energy services agreement related to a cogeneration facility.

152-Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

151-Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

150-Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

149-Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

148-Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

147-Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

146-Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

145-Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

144-Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

143-Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

142-United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

141-Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

140-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

139-Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

138-Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

137-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

136-Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

135-Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

134-Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

133-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

132-Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

131-Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

130-Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

129-United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

128-Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

127-New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

126-Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

125-American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

124-Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

123-Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

122-Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

121-Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

120-Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

119-New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

118-JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

117-Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

116-Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

115-Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

114-Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

113-U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

112-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

111-Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

110-United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

109-United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

108-Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

107-Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

106-Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

105-Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

104-American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

103-Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

102-New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

101-Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

100-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

99-Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

98-New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

97-State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

96-United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

95-United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

94-American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

93-Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

92-Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

91-New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

90-Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

89-Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

88-American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

87-United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

86-Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

85-Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

84-New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

83-Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

82-New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

81-New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

80-American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

79-U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

78-State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

77-Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

76-Federal Energy Regulatory Commission. Docket EL93-45-000; Docket QF83-248-002. Analyses related to the qualifying status of cogeneration facility.

75-Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

74-Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

73-State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

72-State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

71-Pennsylvania Public Utility Commission. Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

1992

70-Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

69-Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

68-Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

67-Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

66-State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

65-State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

64-State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

63-Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

62-Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

61-Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

60-Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

59-State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

58-District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

57-State Corporation Commission, Virginia. Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

56-State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

55-Public Service Commission of Maryland. Case Number 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

54-State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

53-Federal Energy Regulatory Commission. Northeast Utilities Service Company Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000,ER90-145-000 and El90-9-000. Analyses of the implications of Northeast Utilities and Public Service Company of New Hampshire merger on electric supply and pricing.

52-Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

51-Puerto Rico Electric Power Authority, Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing QF's.

50-State Corporation Commission, Virginia. Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989

49-Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

48-Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

47-Federal Energy Regulatory Commission. Docket RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

46-Circuit Court of the Fifth Judicial Circuit, Dade County, Florida. Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

45-Florida Public Service Commission. Docket 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988

44-Virginia State Corporation Commission. Case No. PUE870081. Testimony on the implementation of the differential revenue requirements avoided costmethodology recommended by the SCC Task Force.

43-Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

42-Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

41-Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

40-Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

39-Florida Public Service Commission. Docket No.8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

38-Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

37-Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factorapplication and relationship to avoided costs.

36-District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

35-Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

34-Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

33-Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

32-Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

31-Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

30-U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

29-Public Utility Commission, New Hampshire Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and QFs. (Settlement Negotiations)

28-Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of standby rates for qualifying facilities.

27-Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

26-Virginia State Corporation Commission. Commonwealth Gas Pipeline Corporation. Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

25-Bonneville Power Administration. Case No. VI86. Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

24-Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

23-Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

22-Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

21-Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

20-Connecticut Light and Power. Docket No. 85-08-08.
Assist in the development of testimony for industrial natural gas transportation rates.

19-Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

18-Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

17-Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

16-Virginia Electric and Power Company. Fuel Factor Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

15-New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

14-Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

13-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-serviceprocedures, class rate of return and rate design.

12-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

11-Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

10-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

9-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

8-Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

7-Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

6-BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

5-Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

4-Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

3-PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

2-PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

1-Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia
Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration

Attachment B

Parameter Description	RTO	MAAC	EMAAC	SWMAAC	PSEG	PS-NORTH	DPL-SOUTH	PEPCO	ATSI	ATSI-CLEVELAND
Reliability Requirement	161,974.3	70,634.3	38,786.4	16,932.0	12,581.1	6,299.9	3,093.5	8,826.7	15,892.6	6,039.7
Min Ext Summer Resource Requirement	158,512.2	62,179.2	28,559.2	7,503.3	5,483.4	3,113.3	1,114.3	1,712.9	7,668.1	676.8
Min Annual Resource Requirement	149,469.1	58,109.3	24,606.9	6,183.2	4,214.2	2,503.1	903.5	750.0	6,200.8	0.0
Max Limited DR Constraint	3,462.1	1,960.1	1,311.2	642.8	516.7	250.6	78.3	267.8	343.6	117.9
Max ES DR Constraint	12,505.2	6,030.0	5,263.5	1,962.8	1,785.9	860.8	289.0	1,230.6	1,810.8	1,115.4
Import Limit (CETL)	NA	6,495.0	8,916.0	8,786.0	6,581.0	2,936.0	1,901.0	6,846.0	7,881.0	5,245.0

Resource Credits

Scenario Description	Cleared Quantities	TOTAL	RTO	MAAC	PSEG	ATSI
Actual BRA Results	Cleared Annual MW (Rest Of)	156,840.2	88,742.7	55,542.3	5,686.4	6,868.8
	Cleared Ext Summer MW (Rest Of)	2,470.0	617.3	991.6	61.8	799.3
	Cleared Limited MW (Rest Of)	9,849.5	4,581.1	3,713.9	550.4	1,004.1
	Clearing Prices					
	RCP (Annual)	na	$59.37	$119.13	$219.00	$114.23
	RCP (Extended Summer)	na	$59.37	$119.13	$219.00	$114.23
	RCP (Limited)	na	$59.37	$119.13	$219.00	$94.45
	Resource Credits					
	Annual Resource Credits	$ 13,915,353	$ 5,268,654	$ 6,616,754	$ 1,245,322	$ 784,623
	Ext Summer Resource Credits	$ 259,617	$ 36,649	$ 118,129	$ 13,534	$ 91,304
	Limited Resource Credits	$ 929,792	$ 271,980	$ 442,437	$ 120,538	$ 94,837
	Total Resource Credits	$ 15,104,761	$ 5,577,283	$ 7,177,320	$ 1,379,393	$ 970,764

Scenario Description	Cleared Quantities	TOTAL	RTO	MAAC	PSEG	ATSI
PJM Proposal	Cleared Annual MW (Rest Of)	157,451.8	88,799.7	55,882.4	5,697.6	7,072.1
	Cleared Ext Summer MW (Rest Of)	7,831.4	3,031.2	3,278.6	305.0	1,216.6
	Cleared Limited MW (Rest Of)	3,462.1	1,859.4	963.1	296.0	343.6
	Clearing Prices					
	RCP (Annual)	na	$85.15	$130.07	$219.00	$115.00
	RCP (Extended Summer)	na	$85.15	$130.07	$219.00	$115.00
	RCP (Limited)	na	$16.44	$61.36	$150.29	$27.40
	Resource Credits					
	Annual Resource Credits	$ 16,890,982	$ 7,561,294	$ 7,268,624	$ 1,247,769	$ 813,295
	Ext Summer Resource Credits	$ 891,258	$ 258,107	$ 426,448	$ 66,795	$ 139,909
	Limited Resource Credits	$ 143,565	$ 30,569	$ 59,096	$ 44,486	$ 9,415
	Total Resource Credits	$ 17,925,805	$ 7,849,970	$ 7,754,167	$ 1,359,050	$ 962,619