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September 25, 2014

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER14-2940-000

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff") to revise certain elements of the Reliability Pricing Model[1] ("RPM") following a comprehensive independent review of RPM and an intensive stakeholder process to consider changes to RPM's auction parameters.

PJM requests that the enclosed revisions become effective on December 1, 2014, which is more than 60 days after the date of this filing.

I. INTRODUCTION AND SUMMARY

This filing fulfills an important RPM Tariff obligation under which PJM and its stakeholders perform a periodic review of the shape of the Variable Resource Requirement ("VRR") Curve[2] used to clear the RPM Auctions and key inputs to that curve, i.e., the Cost of New Entry ("CONE")[3] by a representative new power plant and the Net Energy and Ancillary Services Revenues[4] ("EAS") that plant would be expected to earn in the PJM markets. PJM retained an independent consultant, The Brattle Group ("Brattle") to assist with the triennial review. Brattle conducted two studies: (1) the Third Triennial Review of PJM's Variable Resource Requirement Curve ("2014 VRR

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1 All capitalized terms not otherwise defined in this filing have the meaning specified in the Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. or Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, as applicable.

2 Tariff, Attachment DD, sections 5.10(a)(i) – (iii). This is the last review that was required on a triennial basis; henceforth the reviews will be quadrennial.

3 *Id.*, section 5.10(a)(iv).

4 *Id.*, section 5.10(a)(v).

Report");[5] and (2) Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM ("2014 CONE Study").[6]

Brattle's 2014 VRR Report and 2014 CONE Study recommended changes to the VRR Curve shape, CONE values, and the net EAS revenue offset methodology. Based on the Brattle reports and PJM's own analysis, PJM staff on May 15, 2014 advised stakeholders of its recommendations concerning changes to RPM.

PJM and its stakeholders then devoted several months to intensive discussion of these issues. Based on the Brattle reports, PJM staff recommendations, and stakeholder input, the PJM Board of Managers ("PJM Board") determined to file the RPM changes set forth in this filing. In brief, by this filing, PJM proposes to:

- revise the shape of the VRR Curve to ensure that it will continue to help the PJM Region meet reliability objectives at a reasonable cost. Foremost among these is that the RPM auctions will, on average under a wide variety of conditions, procure sufficient capacity to allow the PJM Region to satisfy the reliability objective of a loss of load expectation ("LOLE") of no more than one event in ten years. At the same time, the VRR Curve should not frequently produce results with especially poor reliability, which could happen even if *average* performance meets the standard of one event in ten years. Attempting to guarantee against poor performance under *any* circumstances could lead to excessive capacity procurement costs, but the VRR Curve could properly be designed to bound the expected frequency of poor reliability performance (such as a significant risk of a loss of load expectation of one day in *five* years, or worse) if that can be done at a reasonable cost. This is not a change in the LOLE standard of 1 event in 10 years; rather, guarding against unacceptable frequency of a significantly worse LOLE is simply one of the multiple, sometimes competing, objectives that can properly be considered when evaluating a capacity demand curve. Here, PJM proposes a VRR Curve shape that satisfies the 1 day in 10 years standard on average, that limits the expected occurrence of an LOLE of 1 event in 5 years to about 7%, and that obtains this reliability protection at an expected long run increase in capacity costs of only about 1% compared to the current VRR Curve. With current and proposed air emissions regulations, uncertainty over the status of demand response resources in the capacity market, and other factors expected to influence a significant change in coming years in the composition of the portfolio of resources on which the PJM Region depends for reliability, the proposed VRR Curve strikes a prudent balance of cost and reliability;
- apply to constrained Locational Deliverability Areas ("LDAs") the same VRR Curve changes described above for the region-wide VRR Curve, just as is done today;

[5] *See* Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, L.L.C., (Attachment E) ("Newell/Spees Affidavit").

[6] *See* Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, L.L.C., (Attachment D) ("Newell/Ungate Affidavit").

- update the Cost of New Entry ("CONE") values largely per the estimates provided by the expert consultants retained for this review, i.e., The Brattle Group and Sargent & Lundy, Inc., but with one notable change identified in the stakeholder process. Per the recommendation of the Independent Marker Monitor for the PJM Region ("IMM"), and as favored by multiple stakeholders, PJM is adopting a lower estimate of construction labor costs as developed by the IMM's consultant. PJM has carefully reviewed the IMM's labor cost estimate, compared it with prior labor cost estimates and public data on labor costs, and is satisfied that it provides a reasonable alternative estimate for construction labor costs;
- make no change to the current PJM Tariff provision that defines the RPM Reference Resource as a combustion turbine ("CT") plant. While Brattle recommended that PJM consider changing the Reference Resource to an average of the estimated Net CONE for a combined cycle ("CC") and combustion turbine plant, PJM is retaining a CT as the Reference Resource. CT Net CONE, with lesser reliance on uncertain future energy revenues, can be estimated more accurately; CC and CT Net CONEs should be comparable; and the actual clearing levels in the RPM Auction ultimately will reflect the actual marginal resource, regardless of resource type, indicating that Net CONE requirements for needed capacity should converge.
- change the index that is used to adjust CONE values automatically for years between the comprehensive periodic review from the Handy-Whitman ("H-W") Index (a private subscription service) to a composite index composed of Bureau of Labor Statistics indices (a readily available government publication). This change is reasonable, given evidence that the H-W Index has overstated cost increases;
- retain the historical Net Energy and Ancillary Services Revenue Offset that is focused on the most recent three years of energy price and fuel cost data. While PJM and many stakeholders agree in principle with the potential promise of an EAS revenue offset based on futures markets, the present review and stakeholder process did not result in a specific proposal that sufficiently resolved concerns on such issues as futures market liquidity. Therefore, PJM proposes maintaining the status quo in this regard; and
- adopt certain changes to more closely align LDA Net CONE values with conditions in the LDA zone or zones.

II. TARIFF CHANGES RESULTING FROM THE TRIENNIAL REVIEW OF RPM.

A. Background.

The Tariff requires that for the 2018/2019 Delivery Year and "for every fourth Delivery Year thereafter," PJM "shall perform a review of the shape of the [VRR] Curve . . . based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis."[7] If, as a result of that review, PJM proposes that the VRR Curve shape be modified, it must present its proposal to PJM Members "on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied."[8] After the PJM Members review any such proposed change, they are required to vote "to endorse the proposed modification, to propose alternate modifications or to recommend no modification by August 31" of that year.[9] The PJM Board then will consider any proposed modification to the VRR Curve shape, and PJM must file any changes to the VRR Curve shape approved by the PJM Board with the Commission by October 1 of that year. [10]

The Tariff prescribes the same process, with the same deadlines, for review of, and consideration of possible changes to, the CONE values and the net EAS revenue offset methodology.[11]

PJM adhered to this prescribed process this year. Based on the Brattle analyses and PJM staff's analyses, PJM proposed Tariff changes to each of the three identified parameters, i.e., the VRR Curve shape, the CONE values, and the net EAS revenue offset methodology for implementation in connection with the May 2015 Base Residual Auction for the 2018/2019 Delivery Year.

PJM's recommendations, and alternative recommendations from the stakeholders, were discussed and developed at meetings of PJM's Capacity Senior Task Force. To meet the Tariff-prescribed August 31 deadline, the Members were asked to vote at the August 21, 2014 Markets and Reliability Committee ("MRC") meeting on the status quo (no Tariff changes for the triennial review), the PJM recommendations, and three stakeholder-developed alternatives.[12] None of the specific change proposals reached two-thirds sector-weighted support at the MRC; and the Members Committee voted to adopt the MRC voting results, confirming that lack of consensus.[13]

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7 Tariff, Attachment DD, section 5.10(a)(iii).

8 *Id.*, section 5.10(a)(iii)(A).

9 *Id.*, section 5.10(a)(iii)(C).

10 *Id.*, section 5.10(a)(iii)(D).

11 Tariff, Attachment DD, sections 5.10(a)(vii)(C) and (D).

12 While only two stakeholder proposals were advanced to the MRC, during the August 21, 2014, MRC meeting a stakeholder requested that a third proposal be considered.

13 The Members Committee ("MC") voted to adopt the results of the vote at the MRC. *See* PJM Interconnection, L.L.C., *Draft Minutes of August 21, 2014 Members Committee Meeting*, at 8-9 (last updated Sept. 11, 2014), http://www.pjm.com/~/media/committees-groups/committees/mc/20140918/20140918-item-02a-draft-20140821-meeting-minutes.ashx; PJM Interconnection, L.L.C., *Draft Minutes of August 21, 2014 Markets and Reliability Committee Meeting*, at 10 (last updated Sept. 11, 2014),

In accordance with the Tariff, the PJM Board met to consider the PJM Staff recommendations and stakeholder input, and determined to direct PJM Staff to file the Tariff changes set forth in this filing.

B. Change to VRR Curve Shape.

1. Background and Standards for Review of Capacity Demand Curves.

The VRR Curve is an administratively determined demand curve that is used, in combination with the supply curve formed from capacity supplier sell offers, to clear the RPM Auctions. The Tariff defines the VRR Curve as a set of lines connecting several price-quantity points that are stated as multiples or fractions of the Net Cost of New Entry ("Net CONE")[14](on the price axis) and the target Reliability Requirement[15] (on the megawatt quantity axis[16]). Higher prices (above Net CONE) are associated with capacity shortage conditions (generally below the target Reliability Requirement) and lower prices are associated with excess capacity conditions. The line segment of the current VRR Curve that produces the highest price is for any shortage condition in which capacity is three percentage points below the approved Installed Reserve Margin ("IRM") (or lower). The current effective Tariff sets that price as 1.5 times the Net CONE.[17]

The current VRR Curve is shown in simplified form on the graph below, with price on the vertical axis and quantity on the horizontal axis. The VRR Curve has four linear segments, each extending down and/or to the right from the point where the immediately preceding segment ends. First, the price cap forms a horizontal segment at 1.5 times Net CONE, applying whenever cleared capacity is three percent or more below the IRM target. The second line segment slopes down and to the right, ending at the point where price is Net CONE and the cleared quantity of capacity is at IRM plus 1%.

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http://www.pjm.com/~/media/committees-groups/committees/mrc/20140918/20140918-item-01-20140821-draft-meeting-minutes.ashx.

14 Net CONE is calculated by subtracting from CONE (the levelized capital costs and fixed operations and maintenance ("O&M") expenses of a new plant) the net EAS revenues (the net revenues such a plant could be expected to earn in the PJM energy and ancillary services markets). *See* Tariff, Attachment DD, section 2.42.

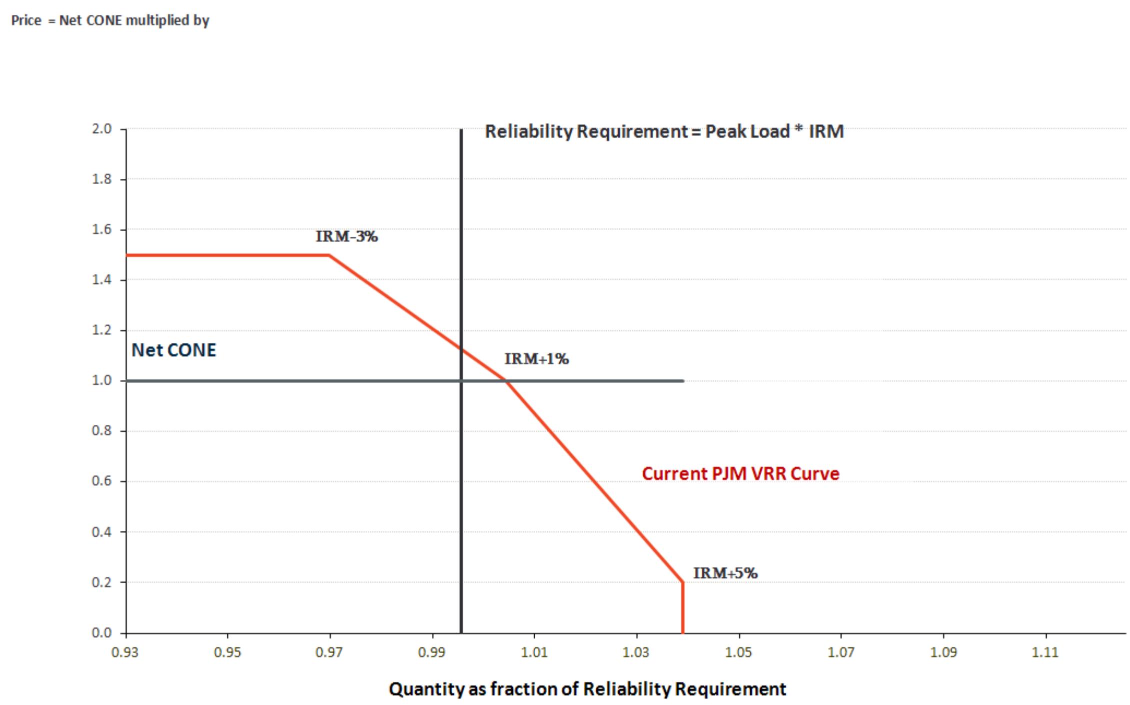
15 *Id.*, Attachment DD, section 2.55.

16 Capacity levels are on an "unforced capacity" basis, i.e., discounted for expected unforced outages.

17 To protect against a collapse in demand when the EAS revenue offset is high, the cap is set at Gross CONE if Gross CONE is greater than 1.5 times Net CONE. For simplicity of presentation, this contingency is not depicted in the demand curve graphs included in this transmittal. To be clear, however, this fall-back reliance on Gross CONE under very high EAS conditions will remain an attribute of the VRR Curve under PJM's proposal in this filing.

The third segment slopes down more steeply, ending at the point where price equals 0.2 times Net CONE and the cleared capacity exceeds the IRM by five percentage points. Last, a vertical segment where cleared capacity exceeds IRM by five percent drops to the point where price equals zero.

Figure 1
Current PJM VRR Curve



The Commission has now accepted downward-sloping, administratively determined demand curves for three regional capacity markets, covering a large portion of the country. The Commission has repeatedly cited the advantages of such a curve in capacity markets; for example, when the Commission first approved a VRR Curve for RPM in 2006, it found that a downward sloping curve was reasonably expected to:

- properly reflect the additional reliability benefits of incremental capacity above the Installed Reserve Margin target;[18]
- "reduce capacity price volatility and increase the stability of the capacity revenue stream over time" because "with a sloped demand curve, as capacity supplies vary over time, capacity prices would change gradually;"[19]
- "render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost;"[20] and

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18 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006), *order on reh'g*, 119 FERC ¶ 61,318 (1007).

19 *Id.* at P 75.

20 *Id.*

- "reduce the incentive for sellers to withhold capacity in order to exercise market power when aggregate supply is near the Installed Reserve Margin" because "withholding would result in a smaller increase in capacity prices" and thus would be less profitable."[21]

The Commission reaffirmed its support for RPM's sloped demand curve earlier this year, finding it "appropriate for Annual Resources to face a sloped demand curve and obtain the associated benefits,"[22] that the Commission has "seen . . . "from the use of a sloped demand curve, such as reduc[ed] price volatility and financing costs."[23]

As an administrative valuation of capacity at differing reserve levels, a capacity demand curve is inherently forward-looking. The essential question faced by any party designing such a curve is how well it will help the region meet its future reliability requirements at a reasonable cost. There is no single or simple answer to that predictive exercise; it necessarily requires balancing multiple, sometimes conflicting objectives, and usually entails complex modeling efforts to simulate, and reasonably estimate, how well a given curve will meet reliability and cost objectives under varying conditions.

The Commission highlighted the predictive, judgmental nature of demand curve design in the initial RPM proceeding when it assessed the competing VRR Curve proposals of PJM and a market participant, explaining that "[t]here may be a number of just and reasonable methods for determining the slope of the demand curve" and "[t]he derivation of the slope of the demand curve is at least in part subjective and cannot be reduced to simple metrics."[24] The Commission explained that in determining whether to accept a proposed capacity demand curve, "the Commission must rely on economic theory and evidence as to how rate designs will perform."[25]

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21 *Id.* at P 76 (footnote omitted). *See also N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, P 13 (2003) ("*NYISO*") (agreeing with the New York Independent System Operator ("NYISO") that demand curve proposal will "encourage greater investment in generation capacity;" "improve reliability, by reducing the volatility of ICAP revenues;" and "reduce the incentive for suppliers to withhold ICAP capacity from the market."); *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1240 (D.C. Cir. 2005) (affirming use of sloped demand curve for forward capacity auctions and finding that balancing of short-term costs against long-term benefits is within Commission's discretion).

22 *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,052, at P 66 (2014).

23 *Id.*

24 *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 111; *see also NYISO*, 103 FERC ¶ 61,201, at P 17 ("Determining the specific parameters . . . e.g., the slope and position of the Demand Curve . . . requires some measure of judgment, since there has been no experience with this new mechanism.").

25 *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 119.

Similarly, when it recently approved a downward-sloping demand curve for the ISO New England ("ISO-NE") capacity market, the Commission recognized the balancing effort inherent in demand curve design, finding that the proposed curve "reasonably balances the multiple considerations identified by Filing Parties, including reducing price volatility, susceptibility to the exercise of market power, frequency of low reliability events, and avoiding falling below a 1[event]-in-5 [years] [loss of load expectation ("LOLE")] in any individual time period."[26]

The Commission has shown some deference to the predictive market modeling efforts typically used to evaluate capacity demand curves. In the recent ISO-NE order, the Commission recognized that "in choosing a general methodology and the inputs into the model, judgments must be made and alternative methods and assumptions rejected."[27] The Commission's role is then "to determine whether these judgments and the resultant outcomes fall within a zone of reasonableness." Applying these principles, the Commission accepted a capacity demand curve proposed by ISO-NE based on "ISO-NE['s] demonstrat[ion] through its Monte Carlo simulation analysis that its proposed sloped demand curve can reasonably be expected to elicit sufficient capacity to meet its stated reliability objective of a 1-in-10 LOLE on average over time."[28]

The Commission took the same approach when it accepted the VRR Curve as a key element of the settlement that established RPM. Reviewing the market simulation analysis proffered by PJM and the other parties to the settlement in support of that curve design, the Commission found that "PJM and the Settling Parties in their Settlement have provided information showing that the Settlement Curve will attract sufficient generation to meet its capacity obligations at a just and reasonable price."[29] That, the Commission found, was sufficient for PJM and the Settling Parties "[to meet] the requirement of demonstrating that the Settlement is just and reasonable."[30]

2. PJM and Its Independent Consultants Followed the Same Approach the Commission Has Endorsed in the Past to Evaluate Possible Changes to the VRR Curve.

For this latest review and update to the VRR Curve, PJM followed the same type of approach that the Commission, as shown above, has previously accepted for PJM, the New York ISO, and ISO-New England. In their comprehensive independent review, Brattle:

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26 *ISO New England Inc.*, 147 FERC ¶ 61,173, at P 29 (2014) ("*ISO-NE*").

27 *Id.* at P 47.

28 *Id.* at P 30.

29 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 82.

30 *Id. See also NYISO*, 103 FERC ¶ 61,201, at P 36 (accepting capacity demand curve based on ISO's presentation of "information indicating that the proposed Demand Curve will yield the price signals to suppliers and their investors to build more capacity in constrained areas.").

- identified the objectives to be served by a VRR Curve to provide the foundation and metrics for an assessment of alternative curve designs;
- reviewed the existing VRR Curve on a qualitative basis, by carefully considering the components and features of the existing curve and their likely effectiveness in advancing the identified objectives;
- built on the prior market simulation analyses of demand curves by integrating data and experience from PJM's implementation of RPM for ten Delivery Years, including a locational clearing algorithm, supply curves shaped like those actually seen in the RPM auctions, various sized supply offers to reflect the capacity resource diversity actually seen in RPM, and plausible, historically-grounded variations in supply, demand, capacity import limits, and CONE estimates;
- applied the Monte Carlo simulation analysis to quantify the probability that the existing and proposed alternative VRR Curves will satisfy reliability objectives, and to estimate the cost of capacity that would be procured using such curves; and
- recommended changes to the PJM Region VRR Curve and locational VRR Curves based on its analyses and evaluations.

As discussed below, Brattle found that the current VRR Curve will not meet the fundamental reliability objectives. Brattle recommended changes to the VRR Curve to address these concerns, and PJM is adopting those changes. PJM also is adopting one further change to the VRR Curve shape, not recommended by Brattle but fully evaluated in Brattle's market simulation analyses, to strike a reasonable balance between reliability and cost. This is perfectly appropriate. PJM, as the responsible public utility and RTO, is the party that must balance the reliability and cost considerations in order to determine which VRR Curve design should be filed under FPA section 205 with the Commission. While the retained consultants can offer their suggestions on how to balance reliability and cost, PJM's Board properly exercised its independent judgment on that crucial policy question, resulting in the VRR Curve changes reflected in this filing. As shown below, there is ample evidence that the revised VRR Curve shape proposed her eby PJM is just and reasonable.

3. Brattle Carefully Reviewed and Identified the Relevant Objectives On Which the VRR Curve Must Be Judged.

In their review, Brattle delineates the objectives to be served by the RPM demand curve. First among these is "to procure enough resources to maintain resource adequacy."[31]

To meet this resource adequacy objective, the VRR Curve must satisfy a loss of load expectation ("LOLE") of no more than 1 event in ten years. Brattle explains that "[t]his does not mean the LOLE will be 0.1 in every year, but that it can be expected to achieve the 1-event-in-10 years LOLE target on average."[32] While that averaging

[31] 2014 VRR Report at 45.

[32] *Id.* at 46.

approach means some years will fall short of the 1 in 10 standard, "[v]ery low reserve margin outcomes should be realized from RPM auctions very infrequently."[33] As an example, Brattle recommends that "there should be a relatively small probability of clearing less than 'IRM – 1%,' the quantity at which PJM's Tariff stipulates that a Reliability Backstop Auction [be conducted] under certain conditions."[34]

Moreover, the VRR Curve's ability to meet these reliability objectives should "remain robust under a range of future market conditions, changes in administrative parameters and administrative estimation errors."[35] Recognizing, however, that PJM can file to change the VRR Curve parameters, the VRR Curve need not "substantially over-procure on an expected average basis just to ensure meeting these objectives under all conceivable future scenarios," because that approach "would incur excess costs."[36]

While the resource adequacy objective "must" be fulfilled, the VRR Curve design also should "aim[ ] to avoid excessive price volatility and susceptibility to market power abuse."[37] Brattle elaborates on both of these objectives in their report. As Brattle explains, because RPM is premised on new entry by merchant plants, auction clearing prices can be expected to approximate the Net CONE on a long-run average basis.[38] But while prices will vary around that long-run average as supply and demand conditions change, the VRR Curve also should, to support a well-functioning market, "reduce price volatility if possible."[39] More precisely, Brattle explains that the objective is to reduce the price impact from "small variations" in supply and demand.[40] This objective also serves to help mitigate susceptibility to the exercise of market power. As Brattle explains, "small changes in supply should not be allowed to produce large changes in price."[41]

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33 *Id.*

34 *Id.* at 46.

35 *Id.*

36 2014 VRR Report at 46.

37 *Id.* at 45.

38 A new plant that relies solely on PJM market revenues will base its capacity offer on the revenues it needs beyond those available from the PJM energy and ancillary services markets to support its project, i.e., it will base its offer on the Net CONE needed for its particular plant. Those offers from rational, profit-seeking developers of new plants will tend to drive the RPM clearing price to the market's view of Net CONE. By definition, and assuming rational market participants, even if clearing prices periodically vary from Net CONE, they will converge on Net CONE on a long-run average basis in a market that is attracting merchant energy.

39 2014 VRR Report at 46.

40 *Id.*

41 *Id.*

Adopting a flatter (i.e., less steep) VRR Curve serves both of the above objectives—that design both reduces price volatility and helps mitigate susceptibility to market power (because withholding supply will not move price as much as it would under a steeper curve).

Brattle cautions, however, against over-mitigating price volatility. Prices *should* reflect year-to-year changes in market conditions: the auction design should enable, and not suppress, that proper reflection of market conditions. Moreover, prices appropriately should increase faster as reserve margins decrease, because the increased threat of very low reliability outcomes demands a stronger price signal.[42]

Finally, as a general objective for all RPM market rules, including the VRR Curve, Brattle advises that a well-functioning market for resource adequacy, in which investors and other decision-makers can expect continuity and develop a long-term view, is best supported if those rules are "as rational, stable, and transparent as possible."[43]

4. Brattle Properly Engaged in a Thorough Qualitative Evaluation of the Current VRR Curve.

As discussed below, Brattle modeled the performance of the VRR Curve using Monte Carlo simulation, i.e., a quantitative analysis technique. In addition, Brattle assessed the curve on a qualitative basis in three different ways:

- Comparing the overall shape of the curve against estimates of the incremental value of reliability at different reserve margins;
- Carefully considering whether the curve should be more steep, or less steep, when the capacity auction clears short of the target reserve margin; and
- Reviewing the degree of variability in capacity supply and demand actually experienced in PJM, and assessing what that expected range in the supply-demand balance implies for price volatility under the current VRR Curve.

Each of these evaluations is discussed in turn below.

a. A Convex Curve Better Matches the Marginal Value of Capacity.

As seen above in Figure 1, PJM's current VRR Curve is concave:[44] the segment from the price cap to the quantity of IRM + 1 is less steep than the segment that extends

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42 2014 VRR Report at 46-47.

43 *Id.* at 47.

44 A curve is described as convex or concave from the perspective of the intersection of the "X" and "Y" axes: a bent line pointing toward the intersection is convex; a bent line pointing away from the intersection is concave.

from IRM + 1 to the point where the vertical segment starts. Brattle explains that this concave curve has "an important theoretical disadvantage," i.e., the curve shape does not match the *convex* shape of a curve that plots the incremental value of capacity in avoiding a failure to serve load.[45] Brattle illustrates this by showing the quantity of unserved energy that is *avoided* per MW of capacity at differing reserve levels.[46] For example, at a reserve margin of 14% (in installed capacity ("ICAP") terms) each added MW of capacity will allow PJM to avoid shedding 0.8 MWh of energy. But at a 17.7% ICAP reserve margin, each added MW of capacity allows PJM to avoid shedding only about 0.1 MWh of load. And at a 19.8% reserve margin, each added MW of capacity allows PJM to avoid shedding less than 0.03 MWh of load.[47] In other words, adding a unit of capacity at lower reserve margins provides more marginal benefit in avoiding load-shedding than adding that same unit of capacity at higher reserve margins, and that benefit diminishes as reserve margins increase. As shown in Figure 16 of the 2014 VRR Report, the curve of all such points is steeply sloped at low reserve margins and much less steep—approaching flat—at high reserve margins. Simply put, the marginal value of capacity as reserve margins increase is convex. The present concave VRR Curve, by contrast, assigns lesser value to marginal movements on the low-reserves part of the curve than it does to the same movement on the high-reserves part of the curve, because the curve to the right of the concave point at IRM + 1 is steeper than the curve to the left of that concave point.[48]

Based on these considerations, Brattle posits that the PJM Region may benefit from a convex-shaped VRR Curve, although they are careful not to overstate these benefits.[49] Brattle therefore includes convex curve alternatives in its quantitative modeling, as discussed in section II.B.7 below.

b. The Current Concave Curve Does Not Sufficiently Value the Risk of Reliability Degradation Under Low Reserve Margin Conditions.

Brattle explains that the "most important" region of the curve from a reliability perspective is the high-priced region at reserve margins below the 1-in-10 reliability standard. In that area, small reductions in the reserve margin can produce large increases in the LOLE. For example, decreasing the reserve margin from IRM to IRM – 1% increases LOLE from 1 event in 10 years to 1.8 events in 10 years, an increase of 0.8 event in ten years.[50] By contrast, increasing the reserve margin from IRM to IRM + 1%

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45 2014 VRR Report at 48-49.

46 For this purpose, Brattle relies on PJM's calculations of Loss of Load Events ("LOLE") at varying reserve levels.

47 2014 VRR Report at 49.

48 *Id.*

49 *Id.* at 49. *See also* Newell/Spees Affidavit at 11.

50 2014 VRR Report at 50.

decreases LOLE by only 0.4 events in ten years. Thus, a reserve margin *decrease* of one percent has twice the impact on reliability of a one percent *increase*, and "this asymmetry is even greater for larger deviations."[51]

However, under the current VRR Curve, price increases at low reserve margins lag well behind increases in the loss of load risk. For example, while the expected load loss events increase by nearly 80% from IRM to IRM – 1% (i.e., from 1.0 events in 10 years to 1.8 events in 10 years), the clearing price on the current VRR Curve increases by only 11% from IRM to IRM – 1% (i.e., from 1.125*Net CONE to 1.25*Net CONE). This disparity becomes worse as reserve margins drop. From IRM – 1% to the current price cap at IRM – 3%, expected load loss events increase 139 % (i.e., from 1.8 events in 10 years to 4.3 events in 10 years), while price increases only 20% (i.e., from 1.25*Net CONE to 1.5*Net CONE).

Brattle observes that this relatively flat shape of the VRR Curve in the low-reserve-margin area "puts the region at greater risk of low reliability events."[52] Indeed, even without detailed modeling, it is apparent that the flatter curve slope in this area, coupled with the cap of 1.5 X Net CONE, will produce "a relatively high frequency of relatively low reliability events" as a necessary consequence of averaging Net CONE over time.[53]

As an option for reducing the risk of low reliability events, Brattle suggests extending the VRR Curve's horizontal segment (at the 1.5 X Net CONE price cap) to the right, from the IRM – 3% shortage position (where it ends now) to the IRM – 1% position.[54] Allowing higher clearing prices in this low-reserves area of the curve will enhance the RPM Auctions' ability to attract supply offers and thus minimize very low reliability outcomes that are a substantial risk when the auctions are clearing in this low reserves area of the curve.

Moreover, this change will ensure that PJM exhausts all "in-market" avenues to obtain capacity before resorting to out-of-market options like the Reliability Backstop Auction in the current RPM market rules. The Tariff requires PJM to conduct a Reliability Backstop Auction if the PJM Region clears below IRM – 1% for three years

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[51] *Id.*

[52] *Id.*

[53] *Id.* This is so because averaging Net CONE over time would require numerous instances of clearing in the higher-priced area of the curve (to offset clearing in the lower-priced areas of the curve in other years), which is also the area of the curve with the most rapid degradation in reliability outcomes. Because price increases less steeply in this part of the curve (or does not increase at all, in the case of the horizontal segment to the left of IRM – 3%), it would require relatively *more* instances of clearing at these prices in order to achieve an average price of Net CONE.

[54] 2014 VRR Report at 50.

in a row.[55] The Tariff provides that if PJM conducts a Reliability Backstop Auction, the Tariff requires that the cost of capacity procured in the auction must be allocated to customers and recovered through uplift payments; the cost of that capacity is not reflected in the RPM Auction clearing results.[56]

Before resorting to that out-of-market uplift approach, however, PJM should try to secure the needed capacity through the RPM Auctions, where the cost of that capacity can be reflected in the resource clearing price. The current VRR Curve already allows clearing prices to rise as high as 1.5 X Net CONE, indicating that level is acceptable as an overall price cap. But under the current VRR Curve, which institutes the 1.5 X Net CONE price only at shortage conditions of IRM – 3% and worse, the auctions need only clear at IRM – 1% (in three consecutive years) before PJM declares a market shortfall and conducts an out-of-market Reliability Backstop Auction. Brattle therefore suggests moving the 1.5 X price to the IRM – 1% position on the curve.

As discussed in section II.B.7 below, Brattle also includes this suggested curve feature in the alternatives evaluated through its quantitative modeling.

c. The Part of the Current VRR Curve that Encompasses the Most Likely Range of PJM Region Supply and Demand Produces Relatively Volatile Prices.

For its independent review, Brattle catalogued the variations in capacity supply and demand in the PJM Region under RPM. Because supply and demand have both grown over that period (as the PJM RTO has grown in size), Brattle particularly focused on changes in the *difference* between supply and demand (i.e., in deviations from the trend). Brattle then calculated the standard deviation of the observed differences between supply and demand under RPM, to provide a statistical indication of the *range* of the difference between supply and demand that can reasonably be expected in future years. Brattle found that standard deviation to be 3%, or over 4,000 MWs when applied to the 2016/2017 Base Residual Auction.

Brattle then observed that these "relatively large year-to-year changes in net supply minus demand" are also "relatively large" when compared to the width of the VRR Curve.[57] For example, as can be seen on Figure 17 in the 2014 VRR Report, decreasing supply by the one standard deviation quantity would move the VRR Curve from the Reliability Requirement to the price cap at IRM – 3%, and would produce a very substantial clearing price increase—equal to over one-third of the Net CONE

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55 Tariff, Attachment DD, section 16.

56 *Id.*

57 2014 VRR Report at 52.

price.[58] Increasing supply by one standard deviation brings an even more dramatic *decrease* in price, equal to over *half* of Net CONE.[59]

These large price movements, associated with changes in net supply and demand that are reasonably expected for RPM, underscore that the current, relatively steeply sloped VRR Curve can produce considerable price volatility. Brattle concludes from this analysis that "it may be beneficial to increase the width of the VRR [Curve] to provide some additional volatility mitigation benefit, or to right-shift the curve to protect against very low future reliability outcomes."[60] Brattle acknowledges, however, that there are costs with either of these changes to the curve. While widening the curve would reduce *price* volatility, it would increase *quantity* uncertainty (because stretching the curve along the vertical axis means that smaller moves along the curve produce bigger changes in the clearing quantity).[61] And while right-shifting the curve would protect against low-reliability outcomes, it could also increase capacity procurement costs.[62]

Brattle therefore also assessed these alternatives in its quantitative modeling, as discussed in the following section.

5. Brattle Designed and Conducted a Comprehensive Monte Carlo Simulation of the Expected Reliability and Cost Performance of VRR Curves that Meets and Exceeds the Standards for Such Studies on Which the Commission Has Relied in the Past.

The PJM Tariff calls for a review of the VRR Curve shape "based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis."[63] In both the original RPM filing and settlement, and the periodic reviews of the VRR Curve, the independent consultants PJM has retained for analyses of demand curve designs have consistently used market simulation methods to assess the probabilities that various alternative curve designs will meet applicable reliability requirements.

The Monte Carlo method is a probabilistic analysis method "based on simulation by random variables and the construction of statistical estimators for the unknown

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58 *Id.*

59 *Id.*

60 *Id.* at 53.

61 2014 VRR Report at 53.

62 *Id.*

63 Tariff, Attachment DD, section 5.10(a)(iii).

quantities."[64] First developed by nuclear physicists at Los Alamos National Laboratory to help estimate the probable diffusion of sub-atomic particles in a nuclear reaction vessel,[65] Monte Carlo analysis tools have spread rapidly to many fields, including physics, biology, economics, political science, and finance, and the method is also frequently used as a decisional tool. As applied to VRR Curve analysis, the "random variables" are inputs like supply, demand, capacity import limits, and administrative Net CONE estimates, and the statistically estimated "unknown quantities" are the probabilistic measurements of reliability and cost outcomes. The Monte Carlo method aids understanding of expected outcomes by running hundreds or thousands of simulations or "draws," each with its own distinct combination of input variables, and showing how often particular outcomes, i.e, good reliability, poor reliability, low costs, high costs, arose when viewing those simulations as a whole.

For this modeling, the random input variables were generated based on a well-calibrated characterization of real-world variations in each parameter. Brattle made considerable enhancements to this year's version of the model to incorporate the distribution of outcomes that were actually observed from the RPM Base Residual Auction results for the 2007/2008 to the 2016/2017 Delivery Years. In particular, Brattle included in the model:

- Differing clearing results by location, reflecting RPM's locational features and similar to the locational clearing algorithm PJM uses to conduct the auctions in accordance with Tariff requirements;
- Varying supply curves based on those used to clear the markets in the 2009/2010 to the 2016/2017 Delivery Years;
- Diverse supply offer quantities, reflecting the diversity of resources—new generation, uprates, existing generation, and demand response—that have offered into RPM; and
- Varying levels of supply and demand based on the variances actually seen for those key inputs since RPM was implemented, plus realistic and representative variations in transmission constraints and Net CONE as informed by experience under RPM.

Brattle's report refers to these variances in supply and demand as "shocks," but that term should not be misinterpreted. These are not sudden or dramatic changes in supply or load. Rather, they are a realistic catalogue of varying levels of supply, demand, capacity import limits, and Net CONE estimates from which each Monte Carlo "draw" may randomly select to create one of a thousand or more different scenarios for which reliability and cost outcomes can be calculated. The results of those draws are then

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64 European Mathematical Society, Monte-Carlo method - Encyclopedia of Mathematics, available at http://www.encyclopediaofmath.org/index.php/Monte-Carlo_method.

65 Metropolis, N., "The beginning of the Monte Carlo method," *Los Alamos Science* (1987 Special Issue dedicated to Stanislaw Ulam): 125–130.

aggregated with the results of all of the other "draws" to support a probabilistic assessment of likely outcomes.

Brattle's simulations assume that the average price across all draws will converge to true Net CONE. This is consistent with the basic design premise of RPM often recognized by the Commission,[66] that the PJM energy, capacity, and ancillary service markets will provide sufficient net revenue to support new entry. In other words, supply offers into the market will reflect the new entry project developer's assessment of net revenues it requires from the capacity market, in light of the cost of its project and the revenues expected from the PJM energy and ancillary services markets. This assumption also is consistent with long-run equilibrium conditions in a restructured market that relies on merchant investment for resource adequacy. If prices were expected to be lower on average than the long-term equilibrium, merchant generation investment would diminish, raising prices; if prices were expected to be higher, investment would increase, lowering expected average prices back toward equilibrium.

6. Brattle Found that the Current VRR Curve Does Not Meet the Relevant Reliability Objectives

Based on its simulations, Brattle concludes that the current VRR Curve *does not* result in sufficient investment in capacity resources to meet the applicable reliability requirements. As described above, the key reliability objective is that the RPM Auctions will on average result in an LOLE of 1 event in 10 years. The current curve, however, substantially misses that goal, with an expectation that load will be lost *1.2* times in 10 years, as seen on Table 1 below.

Table 1
Comparison of Different Curves Ability to Meet Reliability Objectives

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Modeling Assumptions											
Vertical Curve	$331	$147	69%	0.175	-0.7%	1.4%	36%	24%	$19,980	$8,030	$31,531
Current VRR Curve	$331	$95	6%	0.121	0.6%	2.0%	35%	20%	$20,167	$12,672	$28,094
Brattle Recommended Curve	$331	$107	13%	0.100	0.8%	1.9%	29%	13%	$20,210	$12,379	$29,631
PJM Recommended Curve	$331	$107	13%	0.060	1.8%	1.9%	16%	7%	$20,383	$12,461	$29,859
ISO-NE Approved Curve	$331	$96	3%	0.039	2.8%	2.0%	10%	3%	$20,554	$13,327	$29,310
NYISO Approved Curve	$331	$69	0%	0.065	2.2%	2.4%	20%	9%	$20,456	$15,394	$26,490

Sources and Notes: Author and year references in the following refer to Brattle's VRR Curve report bibliography.
ISO-NE and NYISO curves reported using those markets' price and quantity definitions in most cases, but relative to PJM's estimate of 2016/17 Net CONE, Reliability Requirement, and 1-in-5 quantity point for the PJM system.

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66 *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at PP 3, 75, 89, 97 (2011) ("MOPR Rehearing Order"); *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 54 (2013).

For NYISO Curve, the ratio of reference price (i.e. the price at the reliability requirement) to Net CONE is equal to 1.185 consistent with the 2014 Summer NYCA curve, with cap at 150% of PJM's Gross CONE and a zero crossing point at 112% of PJM's requirement, see NYISO (2014a) and (2014b), Section 5.5.

ISO-NE Curve shows parameters proposed in April 2014 with cap quantity adjusted to 1-in-5 as estimated for PJM and cap at 160% of PJM's Net CONE, see Newell (2014b), pp 10-12.

PJM's current VRR Curve also produces a relatively high (20%) frequency of reliability outcomes below 1 event-in-5 years, confirming Brattle's qualitative assessment (discussed above) that the flat shape of the curve in the high-price region introduces greater risks of load loss not achieving the IRM target.

Brattle also finds that the current VRR Curve's reliability performance is especially degraded by a higher but still plausible estimate of the likely magnitude of "shocks," i.e., variances in the key auction parameters, especially supply variances. An increase of 33% in these "shocks" raises the LOLE to .186 events in 10 years—an increase of over 50%.[67]

The current VRR Curve's satisfaction of reliability objectives is even worse if Net CONE has been underestimated. If the Tariff's administrative Net CONE estimate understates true Net CONE by 20%, then the LOLE under the current VRR Curve jumps to 3.7 events in 10 years; the region will fall short of the 1 in 10 standard 69% of the time; and the region will even fall short of the 1 in 5 standard *half* the time.[68]

Brattle traces the current VRR Curve's relatively poor resilience in the face of Net CONE under-estimates to the curve's attributes in the low-reserve area of the graph, as described in the qualitative discussion in section II.B.4.b above. As explained there, reliability outcomes worsen on that part of the curve much more quickly than clearing prices can increase to incent new entry. Not surprisingly, the overall 1.5 X Net CONE price cap, which Brattle calls "relatively moderate," contributes to these adverse reliability outcomes when Net CONE is underestimated.

In short, based on a thorough review and a well-designed study of the type that the Commission has repeatedly accepted when considering changes to capacity demand curves, PJM's current VRR Curve *does not* enable the PJM Region to meet its established resource adequacy objectives. Changes to that curve are required, as discussed in the following section.

7. Identification and Assessment of Changes to the VRR Curve.

The qualitative assessment of the VRR Curve described in section II.B.4 above identified three possible changes that would be likely to improve reliability without undue additional cost:

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67 2014 VRR Report at Table 9.

68 *Id.* at Table 11.

1. Extending the horizontal segment of the curve (i.e., the 1.5 X Net CONE price cap) farther to the right, approximately to the IRM – 1% position;
2. Adjusting the curve so that it is convex, instead of concave; and
3. Right-shifting the entire curve as needed to provide additional reliability assurance, if that can be done at an acceptable cost.

To provide a sound basis for the selection of a new VRR Curve, Brattle modeled the reliability and cost performance of two alternatives: a curve that has the first two features listed above (the "Brattle Recommended Curve") and a curve that combines all three features, including a 1% rightward shift (the "PJM Recommended Curve"). The results of that Monte Carlo analysis are shown in Table 1 above.

As can be seen, the Brattle Recommended Curve exactly meets the 1-in-10 standard on average under "base" conditions. As previously explained, however, "average" reliability over time implies sub-par reliability in some years, and could include a significant number of years when reliability is particularly challenged, i.e., at or below a 1 event in 5 years level. A reasonable balancing of reliability objectives can properly take into account not only the average reliability but also the frequency with which reliability falls below this even more concerning 1-in-5 threshold.

As seen in Table 1 above, the Brattle Recommended Curve can be expected to fall short of the 1-in-5 level 13% of the time. By contrast, the PJM Recommended Curve cuts that incidence almost in half, falling short of the 1-in-5 standard only 7% of the time. According to Brattle's modeling, the PJM Recommended Curve "pays" for that increased reliability by increasing capacity procurement costs by approximately 1%.[69] The right-shifted curve is also considerably more resilient than the Brattle Recommended Curve in the face of underestimates of Net CONE, or increased "shocks." With a 33% increase in the level of the "shocks," the PJM Recommended Curve still just meets the 1-in-10 standard on average, while the Brattle-Recommended Curve increases the LOLE to 1.86 events per 10 years.[70] Similarly, if Net CONE is underestimated by 20%, the Brattle Recommended Curve increases the LOLE to 2.82 events in 10 years,[71] substantially worse than the increase to 1.82 events in 10 years with the PJM Recommended Curve. That underestimation scenario also causes the PJM Region to miss the 1-in-10 standard 59% of the time, and to miss the 1-in-5 standard 39% of the time, under the Brattle Recommended Curve; the PJM Recommended Curve performs significantly better in both of these metrics under these sensitivity tests.[72]

As the Commission has made clear, there is no single right answer to the choice of a capacity demand curve design. The choice requires balancing of multiple, sometimes competing, objectives, reliance on economic theory and market simulations,

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[69] 2014 VRR Report at 69 and Table 14.

[70] *Id.* at Table 16.

[71] *Id.*

[72] *Id.*

and ultimately calls for considerable exercise of judgment. The PJM Recommended Curve reflects a reasonable balance, is adequately supported, achieves reliability objectives at a reasonable cost, and is just and reasonable.

As shown above, the PJM Recommended Curve provides substantial improvements in protection against adverse reliability outcomes, compared to the Brattle Recommended Curve, both under "base" conditions and under the stressed conditions described in Brattle's sensitivity analyses. One possible criticism of the PJM Recommended Curve is that it achieves, on average, an LOLE of approximately 0.6 events in 10 years, and thus (some may assert) achieves a higher reliability standard than is required. But this criticism ignores that the LOLE calculation as used in the Monte Carlo model is an average of 1000 different scenarios. And that average could mask adverse (potentially very adverse) reliability outcomes in some of those scenarios (each of which could also be thought of as a distinct capacity Delivery Year). Given that, it is perfectly appropriate, and arguably essential, to consider not only the average but also how often the curve is expected to result in very poor reliability. That is exactly what PJM has done in this case. Notably, PJM has not required that there may be *no* expected failures to meet the 1-in-5 standard. Rather, PJM is simply saying that falling below 1-in-5 should be taken into account, even if the modeling satisfies the 1-in-10 on average, and that a market design that falls below the 1-in-5 standard 13% of the time (as does the Brattle Recommended Curve) presents a distinct reliability risk that should not be accepted if it can be mitigated at reasonable cost.

As detailed in the accompanying affidavit of Dr. Paul Sotkiewicz, PJM's judgment to minimize the frequency with which the region will fall below the 1-in-5 standard is informed by legitimate concerns about current and expected changes in the PJM Region resource base. Given the possibility for continuing significant variations in the supply offered into the RPM Auctions, it is prudent to adopt a VRR Curve that is more resilient in the face of supply shocks or other stresses.[73]

Finally, the reliability protections come at a relatively modest long-term cost. According to Brattle's modeling, the PJM Recommended Curve would increase power procurement costs by only about 1% compared to the Brattle Recommended Curve.

8. The PJM Recommended Curve Closely Compares To the Capacity Demand Curves the Commission Recently Approved for ISO-NE and NYISO.

Comparison of the PJM Recommended Curve against the capacity demand curves the Commission approved earlier this year for ISO-New England and the New York ISO makes clear that PJM's proposal is reasonable. Figure 2 below shows the current PJM VRR Curve, the PJM Recommended Curve, and the NYISO and ISO-NE curves (the latter two converted to PJM cost and quantity parameters), all overlaid on a single graph.

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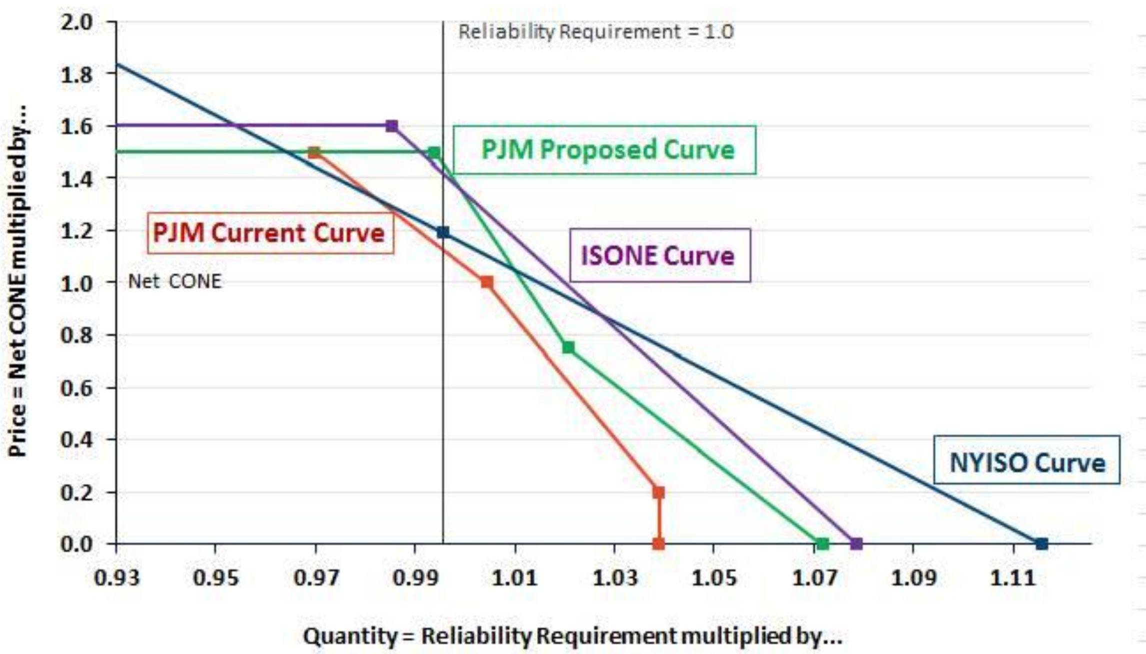
[73] *See* Affidavit of Dr. Paul M. Sotkiewicz on Behalf of PJM Interconnection, L.L.C., at ¶ 11 (Attachment C) ("Sotkiewicz Affidavit").

This graph therefore permits ready comparison between the *shape* of PJM's proposed curve and the shape of the other curves.

As can be seen, the current PJM VRR Curve is in almost all cases below and to the left of the other capacity demand curves, meaning that clearing prices in PJM will in almost every case (for a given supply curve) be below the prices set by the other curves. The PJM Recommended Curve, by contrast, more clearly overlaps with both the NYISO and ISO-NE curves. The current PJM VRR Curve also stands out as the only curve with a concave shape. The other curves, by contrast, are either convex or straight.

Figure 2
Comparison of PJM, New York, and New England Capacity Demand Curves



Moreover, the similarities between the PJM, NYISO, and ISO-NE curves go much deeper than their appearance. Brattle modeled the NYISO and ISO-NE curve shapes using PJM cost and quantity parameters (specifically those used for PJM's most recent Base Residual Auction), including the same "shocks" used by Brattle to assess the PJM VRR Curves. As can be seen, Brattle found that the reliability and cost metrics for the recently approved NYISO and ISO-NE curves are very similar to the same metrics for the PJM curve in that modeling.[74]

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[74] PJM notes that the reliability and cost results shown here for the NYISO and ISO-NE curves will differ from the results found by NYISO and ISO-NE when they modeled their own curves. The focus in this analysis is solely on those curve *shapes*, converted to PJM cost and quantity metrics, and using the same modeling assumptions and approaches that Brattle used to assess the PJM curves. Using the same parameters, metrics, and assumptions is essential to a meaningful comparison of possible alternative curve shapes. The end result is that if a market

Most notably, the incidence for those two approved capacity curves of falling below the 1 in 5 standard is below the 13% seen in the Brattle Recommended Curve. Indeed, the results for the other two ISOs on that metric comfortably bracket the PJM result: ISO-NE is at 3%, PJM is at 7%, and NYISO is at 9%. The same is true of the frequency below the Reliability Requirement: ISO-NE is at 10%, PJM is at 16%, and NYISO is at 20%; and the average LOLE: ISO-NE is at 0.39 events in 10 years, PJM is at 0.60, and NYISO is at 0.65. The PJM Recommended Curve's capacity procurement costs are very close to, but slightly less than, the ISO-NE and NYISO average and bottom quintile cost estimates, and slightly higher than the two ISOs' top quintile cost estimates.

The only metric on which the PJM curve notably departs from the other two is its greater frequency of clearing at the price cap. That result is a consequence of PJM's lower price cap of 1.5 X Net CONE, and the steeper slope of the curve in the high-price region. While PJM is extending that price cap to the right, it is not changing the level of the cap—PJM's maximum price remains the lowest of the three capacity market operators that use a demand curve.

Table 2
Comparison of PJM Recommended Curve against Commission-approved ISO-NE and NYISO Curves

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	($/MW-d)	(%)	(Ev/Yr)	(IRM + X%)	(% ICAP)	(%)	(%)	($mil)	($mil)	($mil)
Base Modeling Assumptions											
PJM Recommended Curve	$331	$107	13%	0.060	1.8%	1.9%	16%	7%	$20,383	$12,461	$29,859
ISO-NE Approved Curve	$331	$96	3%	0.039	2.8%	2.0%	10%	3%	$20,554	$13,327	$29,310
NYISO Approved Curve	$331	$69	0%	0.065	2.2%	2.4%	20%	9%	$20,456	$15,394	$26,490

9. The PJM Recommended Curve Is also a Just and Reasonable Curve for Use in Constrained Locational Deliverability Areas.

PJM's current Tariff makes no distinction between the VRR Curve shape for the PJM Region and the VRR Curve shape for the LDAs—they are the same. PJM is maintaining that approach in this filing. Thus, the PJM Recommended Curve will be used for the PJM Region and for any LDA that requires a VRR Curve.

The 2014 VRR Report recommended a different VRR Curve shape for use in constrained LDAs, to address Brattle's concern that location-specific reliability risks

participant were to ask PJM to consider adopting the ISO-NE curve shape, for example, the type of modeling comparison conducted by Brattle (including adapting the curve shape to PJM parameters and testing it using assumed PJM market conditions) would be a key element in evaluating that proposal.

(including greater susceptibility to shocks parent-LDA shortages, and under-estimates of Net CONE) warrant adoption of a VRR Curve shape that provides enhanced reliability protections. However, the PJM Recommended Curve, with its 1% rightward shift, provides an adequate alternative solution to the concerns Brattle identified. PJM bases this conclusion on the simulations Brattle performed on the PJM Recommended Curve in the relevant LDAs. The results of this modeling are shown in the affidavit of Drs. Newell and Spees, attached to this filing. As can be seen, the PJM Recommended Curve allows each of those LDAs to satisfy the 1 event in 25 years reliability standard for intra-PJM capacity transfers under base assumptions, and thus provides some protection against the concerns expressed by Brattle.

C. Updates to the Gross Cost of New Entry Values.

1. Background.

The CONE is an estimate of the total project capital cost and annual fixed operations and maintenance ("O&M") expenses of a new generating plant of a type likely to provide incremental capacity to the PJM Region in the forward Delivery Year addressed by the RPM auctions. The Tariff defines that representative new entry plant, or "Reference Resource," as a combustion turbine ("CT") power plant.[75]

From 2006 when RPM was first adopted until the present, CONE values in the Tariff have consistently been based on detailed, "bottom-up" estimates of the components of a representative new entry project.[76] Thus, capital costs include, for example, the turbine power package and other major materials, land, station equipment, buildings, necessary gas pipeline and electric transmission infrastructure, emissions control equipment, permitting costs, and any contingency. The ongoing fixed O&M expenses include, for example, labor, outside contractor costs for operations or maintenance, property taxes, insurance, overheads, and regulatory expenses. The CONE in each case was developed using a financial model that includes estimates of the likely debt cost, required internal rate of return, income taxes, and the project's economic life. Each CONE estimate has been provided by independent expert consultants, relying to the extent necessary on specialized expertise of other engineering or consulting firms with project management, O&M, permitting, environmental, or other experience.

The Tariff contains separate CONE estimates for each of five "CONE Areas" that are defined in terms of the transmission owner zones they encompass, as follows:

- CONE Area 1: Eastern MAAC (PS, JCP&L, AE, PECO, DPL, RECO);
- CONE Area 2: Southwestern MAAC (PEPCo, BG&E);

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75 Tariff, Attachment DD, section 2.58.

76 *See, e.g.*, *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 36 (2009) ("March 2009 RPM Order") ("PJM provided a detailed engineering study to support the CONE values contained in [its original] filing [and] [t]hat study also shows that the CONE values [ultimately proposed by PJM] are just and reasonable").

- CONE Area 3: Rest of RTO (AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC);
- CONE Area 4: Western MAAC (PPL, MetEd, Penelec); and
- CONE Area 5: Dominion.

The Tariff also includes a mechanism for automatic updates to the CONE values based on changes in the Handy-Whitman Index, a utility construction cost index.[77] This mechanism is intended to keep the CONE values up to date with the latest trends in electric plant construction costs in the years between PJM's submission of section 205 CONE changes.[78]

For this triennial review, PJM followed the same "bottom-up" approach that yielded CONE values previously accepted by the Commission as just and reasonable.[79] In addition to the 2014 VRR Report, Brattle prepared a detailed estimate of the Cost of New Entry for use in the VRR Curve. The results of Brattle's review and analysis are set forth in its 2014 CONE Study. A copy of that report is attached to the affidavit of Dr. Samuel A. Newell and Christopher D. Ungate. Dr. Newell is a Principal at Brattle and Mr. Ungate is a Senior Principal Management Consultant at Sargent & Lundy ("S&L"). As explained in their affidavit, Dr. Newell led the Brattle review of the CONE parameters together with Mr. Ungate and his team at S&L.

Therefore, the 2014 CONE Study, in its scope, approach, and level of detail, generally tracks the prior studies accepted by the Commission as adequate support for new RPM CONE values.

2. CONE Areas

PJM proposes to eliminate CONE Area 5: Dominion and combine it with CONE Area 3: Rest of RTO, primarily because there is no need for a separately-modeled Gross CONE value for Dominion. In the years since a separate CONE Area has been established for the Dominion zone, that zone has never been a modeled LDA and therefore the Gross CONE estimate for CONE Area 5 has never been used for

77 Tariff, Attachment DD, section 5.10(a)(iv)(B) ("the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index").

78 *See PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,090, at P 38 (2009)

79 *See* March 2009 PJM Order at P 36; *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,079, at P 70 (2013) (accepting settlement of CONE values in PJM's last triennial review that were supported by PJM's initial detailed CONE estimates and certain cost adjustments from the "detailed alternative estimates" provided by other parties in the case); *ISO New England Inc.*, 147 FERC ¶ 61,173, at PP 17, 29-35 (2014) (accepting stated CONE values for the ISO-NE forward capacity auction based on detailed "bottom up" CONE study conducted by Brattle and S&L).

determining a locational VRR Curve. Eliminating the never-used CONE Area 5 would reduce administrative cost and complexity of RPM.[80]

Moreover, part of the original rationale for establishing a separate CONE Area for the Dominion Zone was to ensure that the EAS revenue offset to calculate the Net CONE for Dominion would be based on energy prices in the Dominion Zone.[81] Under the rule then in effect, which PJM proposes to change through this filing, the EAS revenue offset for CONE Area 3 was calculated for a particular non-Dominion Zone in that CONE Area. That raised concerns for the Dominion Zone because energy prices in Dominion could differ significantly from the energy prices in that other CONE Area 3 Zone. By this filing, however, PJM proposes to calculate an EAS revenue offset for each Zone, which will then determine the Net CONE for any potential single-Zone LDAs, such as Dominion. Consequently, if the Dominion LDA *were* to price separate, the zonal EAS rule change proposed in this filing would ensure a more accurate Net CONE for Dominion, even without a separate gross CONE determination for the Dominion Zone.

As explained in the Newell/Spees Affidavit, the inclusion of Dominion in CONE Area 3 does not change the estimated Gross CONE value for CONE Area 3.[82] Because there are few reference projects in Dominion, Brattle "would not have used the region as one of the most representative locations in developing a Gross CONE estimate in the larger combined area."[83]

Accordingly, including Dominion in CONE Area 3: Rest of RTO is reasonable. PJM is not proposing any change to the scope of the other three CONE Areas.

To effectuate this change, PJM is revising section 5.10(a)(iv)(A) to remove the final row, which states "Dominion" and the CONE value for CONE Area 5, from the table stating the Gross CONE values for each CONE Area.

3. Updated CONE Values.

As explained by Dr. Newell, Brattle reviewed and updated the technical specifications of the "Reference Resource" for which CONE is to be estimated,[84] reference CT plant based primarily on the "revealed preference" of generation developers in the PJM Region and around the U.S. as reflected by recent installations of CT plants.[85]

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80 *See* 2014 VRR Report at 21-22; 2014 CONE Study at 4.

81 Revisions to the PJM Open Access Transmission Tariff and Reliability Assurance Agreement of PJM Interconnection, L.L.C., Docket No. ER10-366-000, at 2-8 (Dec. 1, 2009); *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER10-366-000 (Jan. 22, 2010).

82 *See* Newell/Spees Affidavit at 6.

83 *See id*. at 6.

84 See Tariff, Attachment DD, section 2.58.

85 *See* Newell/Ungate Affidavit at 7-10; 2014 CONE Study at 3.

Based on those considerations and discussions with S&L, Brattle based the CONE on a multi-turbine configuration employing the General Electric Frame 7FA turbine (i.e., the same plant design presently specified in the Tariff as the Reference Resource, and on which all prior RPM CONE estimates have been based).

Brattle identified an appropriate site within each CONE Area for construction of the Reference Resource based on considerations including proximity to electric transmission infrastructure, access to major natural gas pipelines, site attractiveness as indicated by recently built power plants, and availability of vacant industrial land.[86]

As this triennial review is required to address the CONE for the 2018-2019 Delivery Year, the CONE estimates assume a project entering service by June 1, 2018. The revenue requirements are calculated on a nominal levelized basis over the new entry plant's assumed twenty-year life. The estimated June 1, 2018 CONE figures for the CT plant in each CONE Area, as supported by the 2014 CONE Study and other evidence submitted with this filing, are as follows:

Table 3
Proposed Gross CONE values

CONE Area	CT Level-Nominal Gross CONE *($/MW-yr)*[87]
CONE Area 1	$132,200
CONE Area 2	$130,300
CONE Area 3	$128,900
CONE Area 4	$130,300

These CONE values represent a decrease for each of the four CONE Areas relative to those required by the current effective Tariff (which would apply the Handy-Whitman Index adjustment to the CONE values used in the May 2014 BRA).[88] The proposed CONE values are lower than those required by the current Tariff in large part due to the Tariff's present reliance on the Handy-Whitman index, which has risen significantly faster than actual plant costs.

86 *See* 2014 CONE Study at 3-7.

87 Brattle estimated the Gross CONE value for CONE Area 5 as $126,400/MW-yr. *See* Newell/Ungate Affidavit at 4.

88 *See* 2014 CONE Study at 41, Table 27. The 2018-19 Delivery Year Gross CONE values under the current Tariff provisions would likely be $161,600, $150,700, $148,000, $155,120, and $132,400, for CONE Areas 1, 2, 3, 4, and 5, respectively. 2014 CONE Study at Table 27. The final values required by the current Tariff would depend on a yet-to-be-published 2014 semi-annual update to the Handy-Whitman Index.

Brattle developed the CONE values using an after-tax weighted-average cost of capital ("ATWACC") of 8.0% to discount future cash flows into present values.[89] To arrive at this figure, Brattle analyzed all available reference points, including (i) updated estimates for publicly traded merchant generation companies, (ii) updated estimates of previously-traded merchant generation companies, (iii) fairness opinions for merchant generation divestitures, and (iv) analyst estimates.[90] As part of its analysis of each publicly traded company, Brattle estimated a return on equity using the Capital Asset Pricing Model, cost of debt, and debt/equity ratio and, from those values, determined each company's ATWACC.

Based on its analysis and the assumption that merchant generation faces higher risk than publicly-traded generation companies, Brattle concluded that an 8.0% ATWACC is the "most reasonable" value for estimating Gross CONE.[91] While the particular assumed component parts of the ATWACC, e.g., the debt rate and return on equity, do not significantly affect the CONE estimate, they are needed for certain steps in the calculation. To derive these from the estimated overall ATWACC of 8.0%, Brattle determined that a representative project could reasonably couple a 7% cost of debt with a 60/40 debt-equity capital structure, which, when considered in conjunction with the 8.0% ATWACC, results in a return on equity of 13.8%.[92]

An 8.0% ATWACC for developing the CONE estimates for PJM is identical to the value used for developing ISO-NE's recently-approved CONE values[93] and is less than the value the Commission accepted earlier this year for NYISO's estimate of the cost of adding a CT Frame-based power plant similar to PJM's Reference Resource.[94]

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[89] As Brattle explains, ATWACC "accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure." 2014 CONE Study at 34 n.26.

[90] 2014 CONE Study at 34-37, Table 25. Brattle noted that it did not include in its analysis either private equity investors or electric utilities in cost-of-service regulated businesses, as market data is not available for private equity investors, and regulated utilities face lower risks, and thus lower costs of capital, than merchant generation. *Id.* at 35 n.27.

[91] *Id.* at 37.

[92] *Id.*

[93] *ISO-NE*, 147 FERC ¶ 61,173, at P 40 (approving net CONE values); *see also* Tariff Filing of ISO New England Inc., Docket No. ER14-1639-000, Newell/Ungate Testimony, at 42-46 (Apr. 1, 2014).

[94] *N.Y. Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,043, at P 105 (2014). The Commission accepted a 9.75% pre-tax weighted-average cost of capital and applicable ATWACC values ranging from 8.16% to 8.36%, depending on the applicable taxes for each area. *Id.*; *see also* Tariff Revision re: ICAP Demand Curve Reset of New York Independent System Operator, Inc., Docket No. ER14-

4. PJM Modification to Brattle-recommended Gross CONE Values.

While PJM relies on 2014 CONE Study to support the CONE values filed in this proceeding, PJM has made one adjustment, not reflected in the 2014 CONE Study, to derive the proposed CONE values in this filing. PJM also departs from Brattle's recommendations on two other issues that affect CONE; however, in those two cases, Brattle included alternative calculations in the 2014 CONE Study showing the effect of adopting the PJM position on those issues. Each of these issues is discussed below.

a. Labor Inputs

During the stakeholder process following PJM's May 15, 2014 recommendation on CONE values, some stakeholders objected to the labor cost component of the Brattle/S&L estimate.[95] The Independent Market Monitor for the PJM Region lent some credence to these objections. The IMM advanced its own CONE estimate, based on the estimating work the IMM commissions each year in connection with its analyses in the State of the Market Report. The IMM's estimate departed from that in the 2014 CONE Study in a number of respects; the most prominent of these was in the labor costs.

At the request of stakeholders in the Capacity Senior Task Force, PJM met with the IMM and its consultant to see if there was a basis for common ground on the divergent CONE estimates. While PJM was not convinced to adopt other elements of the IMM CONE estimate, PJM is satisfied that the IMM's proposed labor cost estimates provide a reasonable alternative to the Brattle/S&L labor cost estimate. As Dr. Sotkiewicz explains in his attached affidavit, before adopting the IMM's labor cost estimates, PJM carefully considered publicly available data on wage rates, examined and benchmarked labor estimates from previous CONE studies, and consulted with S&L regarding the labor estimates used in the 2014 CONE Study.[96] Based on PJM's analysis, the PJM Board determined to reflect the IMM labor estimate in the CONE changes PJM is filing as a result of the triennial review.

For its analyses in the State of the Market report on whether PJM market revenues are sufficient to cover new plant costs, the IMM has for several years relied on Pasteris Energy, Inc. the same consultant PJM used to develop CONE estimates when RPM was first implemented. Pasteris Energy in turn relies on Stantec Consulting Services, Inc., a power plant project contractor, for the "plant proper" component of the cost estimate.

500-000, Attachment III, Exhibit B, at Table II-14 - Financing Assumptions (filed Nov. 27, 2014).

95 *See, e.g.*, PJM Interconnection, L.L.C., *Stakeholder Requests for Information and PJM Responses Posted for the June 25, 2014 CSTF Meeting*, Question No. 5 (June 30, 2014), http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20140630/20140630-stakeholder-requests-for-information-and-pjm-responses.ashx.

96 Sotkiewicz Affidavit at ¶¶ 41-46.

Stantec estimated labor hours and unit labor costs for the different CONE Areas. For example, Stantec estimated that constructing the CT Reference Resource in CONE Area 1: EMAAC would take approximately 360,000 labor hours, at $86/hour (in 2013 dollars), for a total labor cost of approximately $31.0 million. To determine the cost in 2018 dollars, Stantec escalated the costs at a rate of 3.75% per year[97] for a labor construction cost estimate for CONE Area 1 of $37.3 million.[98] Stantec's corresponding estimates of labor construction costs for CONE Areas 2, 3, 4, and 5, are $ 21.9 million, $ 20.4 million, $ 29.5 million, and $ 20.1 million, respectively.

To verify the reasonableness of the IMM labor cost estimates, Dr. Sotkiewicz compared them against the labor estimates for CONE AREA 1 provided in the 2011 CONE Study prepared by Brattle and CH2M Hill.[99] Dr. Sotkiewicz found that the IMM labor hours are comparable to construction labor hours estimated in the 2011 study. Dr. Sotkiewicz also found that the IMM's labor cost dollar estimate was comparable to (in fact slightly higher than) the corresponding labor cost estimate from the 2011 study, escalated to 2018 dollars to match the intended Delivery Year.[100]

Dr. Sotkiewicz also validated the reasonableness of the IMM estimates by examining the publicly available United States Bureau of Labor Statistics' ("BLS") Quarterly Census of Employment and Wages ("QCEW") for the North American Industrial Classification Standard (NAICS) 2371 Utility Construction Wages, as adjusted for inflation, fringe benefits, and labor productivity factors.[101] Dr. Sotkiewicz reviewed the publicly available labor wage data for 2013 (the last year for which such data is available) and, recognizing that wages constitute "approximately one-half of the total cost of labor" with so-called "fringe" costs of taxes, benefits, and workers' compensation comprising the other half,[102] Dr. Sotkiewicz, after consultation with S&L and reviewing

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97 This is the same escalation rate used by Brattle in the 2014 CONE Study, in which Brattle "estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials and labor" and "then added to the assumed inflation rate of 2.25% . . . to determine the nominal escalation rates." *See* 2014 CONE Study at 24.

98 Sotkiewicz Affidavit at ¶ 38 (citing Pasteris Energy, Inc., *Brattle CONE Combustion Turbine Revenue Requirements Review for Monitoring Analytics*, LLC (July 25, 2014), http://pjm.com/~/media/committees-groups/task-forces/cstf/20140725/20140725-brattle-vs-ma-som-cone-ct-revenue-requirements-comparison-final-report.ashx).

99 Kathleen Spees et al., *Cost of New Entry Estimates For Combustion Turbine and Combined Cycle Plants in PJM*, The Brattle Group et al., Appendix A.4 (August 24, 2011), http://pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx.

100 Sotkiewicz Affidavit at ¶¶ 28-39.

101 *Id.* at ¶ 37.

102 *Id* .at ¶ 42.

the 2011 CONE Study, determined the fringe costs relative to the wage rate to be 0.92 at the lower bound and 1.04 at the upper bound.[103]

Dr. Sotkiewicz then adjusted the fringe costs by a productivity factor. Following discussions with S&L and a review of the 2011 CONE Study, Dr. Sotkiewicz applied a productivity factor of 1.16 to the lower and upper bounds of the fringe costs to determine an overall estimated labor value for each CONE Area. The results of Dr. Sotkiewicz's analysis are shown in Table 4 below.

Table 4
Validating the IMM Construction Labor Values

	CONE Area 1 (EMAAC)	**CONE Area 2 (SWMAAC)**	**CONE Area 3 (EMAAC)**	**CONE Area 4 (WMAAC)**	**CONE Area 5 (Dominion)**
State	New Jersey	Maryland	Ohio	Pennsylvania	Virginia
Wage Rate (2013 $/hr)	$43.20	$27.28	$32.60	$36.95	$25.50
Wage Rate (2018 $/hr)	$48.47	$30.60	$36.58	$41.46	$28.61
Lower Bound w/Fringe(0.92)	$93.07	$58.76	$70.23	$79.60	$54.94
Upper Bound w/fringe(1.04)	$98.88	$62.43	$74.62	$84.58	$57.22
Total Construction Labor Costs ($millions 2018 dollars)					
Lower Bound	$38.9	$24.5	$29.3	$33.2	$22.9
Upper Bound	$41.3	$26.1	$31.2	$35.3	$23.9

The IMM construction labor cost estimates (stated per CONE Area earlier in this discussion) are close to the lower bound.

Given this data, Dr. Sotkiewicz concluded that the labor construction values provided by the IMM "closely track publicly available data"[104] and "can be nearly reproduced using publicly available data, and what PJM has learned over time from both current and past CONE studies for the CT Reference Resource."[105]

As Dr. Sotkiewicz explains, one adjustment was needed to ensure that reliance on the IMM estimate does not omit some labor costs. The IMM's CONE estimates included labor costs associated with dual fuel capability in a separate line item; they are not in the IMM's general estimate of construction labor costs. Simply removing the Brattle/S&L labor estimates and replacing them with the IMM numbers would also remove, but not

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103 *Id.* at ¶ 42; *see also id.* at Table 3.

104 Sotkiewicz Affidavit at ¶ 37.

105 *Id.* at ¶ 44.

replace the labor cost for dual fuel capability. PJM therefore has added back $1 million in "Other Labor" costs to ensure that dual fuel labor costs are include.[106]

Accordingly, PJM is adopting the estimated labor costs proposed by the IMM, as adjusted, and the Gross CONE values stated above are based on these labor values.[107]

b. Levelization Approach

In its other departure from Brattle's recommendations, PJM is not changing its Commission-accepted practice of using the "nominal levelized" financial model to determine the latest CONE values to the "real levelized" approach.[108] The Commission has previously accepted use of the nominal levelized approach in RPM as just and reasonable, and has rejected attempts to compel PJM to base generic CONE values (such as those used in the VRR Curve) on the real levelized basis.[109] The Commission has held that "the nominal levelized method is a just and reasonable method of modeling a competitive bid, in part because it is a reasonable method of modeling a competitive first-year offer based upon typical cash flow streams associated with financing" and is consistent with "the mortgage-like cash stream associated with project finance."[110]

Moreover, as explained by Dr. Paul M. Sotkiewicz in his affidavit, Brattle's assumption of a steady-state condition in which risk-neutral project developers confidently anticipate regular annual increases in their revenues at the inflation rate does not account for the real world risks and uncertainties that can cause project developers to hold back on their investments if they are not assured of a satisfactory revenue stream.[111] Simply put, the Commission correctly found that a real levelized approach is problematic in a generic CONE calculation, and the Brattle observations do not provide a compelling reason for the Commission to depart from prior precedent in this regard.

c. Dual Fuel Capability.

PJM also declines to adopt Brattle's recommendation that the CONE estimate for CONE Area 3: Rest of Market omit the costs of dual-fuel capability. The current Tariff

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106 *Id.* at ¶¶ 40, 42.

107 *See id.* at ¶¶ 36-44; Newell/Spees Affidavit at 7.

108 As explained by the Commission, the real levelized approach:

> produces lower numbers in the early years of a project's life and higher numbers in the later years [compared to nominal levelized], by assuming that plant revenue requirements will increase each year to reflect a 2.5 percent annual increase in operating expenses.

PJM Interconnection, L.L.C., 135 FERC ¶ 61,022, at P 34 n.28 (2011).

109 *Id.* at PP 49-51.

110 MOPR Rehearing Order at P 32.

111 *See* Sotkiewicz Affidavit at ¶ 23.

expressly defines RPM's Reference Resource as including dual fuel capability in all five current CONE Areas. PJM is not amending that approved Tariff provision to eliminate dual fuel capability in CONE Area 3 or any other CONE Area. Such a change would not be just and reasonable at this time. As the PJM Region increases its reliance on gas-fired generation, capacity resources should develop and maintain the ability to deliver energy at PJM's dispatch even if natural gas fuel is not available at that moment. The cost of that capability properly should be reflected in the CONE that is used to determine capacity prices, regardless of whether individual project developers choose to take the risk of not installing that flexibility. Conversely, the alternative of removing dual fuel capability costs from the CONE that is used as a benchmark for setting capacity prices could act as a disincentive for developers of new entry projects to include that capability (and its attendant costs) in their projects.

d. Implementing Tariff Changes.

Accordingly, PJM is proposing to revise the Tariff, Attachment DD, section 5.10(a)(iv)(A) to adopt for the 2018/2019 Delivery Year the Gross CONE values set forth in Table 3 above.

5. Index Used for Annual Adjustment of Gross CONE Values.

a. Current process and need for change

The PJM Tariff calls for the CONE to be adjusted (up or down) each year in accordance with changes in the applicable Handy-Whitman Index.[112] To determine CONE values for a Delivery Year that is not the subject of a triennial review or other section 205 change, PJM applies to the CONE used in the Base Residual Auction for the prior Delivery Year a percentage change rate based on the most recent twelve-month rate of change in the applicable Handy-Whitman Index. PJM updates the CONE in each CONE Area using this Tariff-prescribed adjustment.

In the 2014 VRR Report, Brattle expressed concerns that the Handy-Whitman Index "has differed significantly from other measures of cost trends for electric generation plants."[113] As shown from Figure 3 below, taken from the 2014 VRR Report, the Handy-Whitman Index has escalated at a rate greater than recent CONE studies would suggest is warranted.

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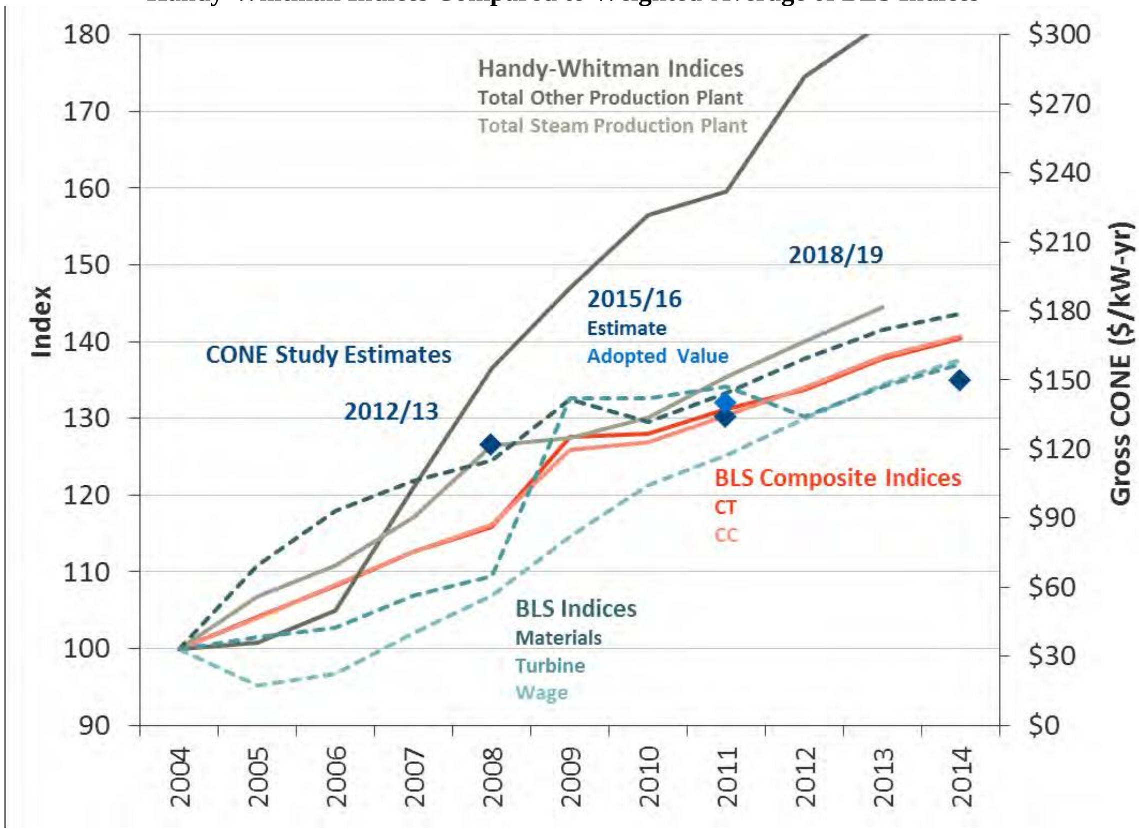
[112] Tariff, Attachment DD, section 5.10(a)(iv)(B). Specifically, PJM uses the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region to adjust CONE Areas 1, 2, and 4, Public Utility Construction Costs for the North Central Region to adjust CONE Area 3, and Public Utility Construction Costs for the South Atlantic Region to adjust CONE Area 5. Section 5.10(a)(iv)(B)(1). The Handy-Whitman Index is published as a commercial subscription service; market participants must purchase the service if they wish to know the changes in the indices.

[113] 2014 VRR Report at 11.

Figure 3
Handy-Whitman Indices Compared to Weighted-Average of BLS Indices[114]



Sources and Notes:

BLS indices retrieved in April 2014 from BLS (2014).

The composite BLS indices were calculated using the costs of labor, material and turbine as approximate percentages of total project costs, developed in Newell, *et al.* (2014a).

The "CONE Study Estimates" are those provided to PJM by the triennial review consultants for the current review and the two preceding reviews. Those study estimates do not necessarily reflect CONE values filed by PJM or approved by the Commission.

Handy-Whitman indices refer to the North Atlantic Region. See Whitman (2014).

Based on this evidence that the Handy-Whitman Index has likely overstated applicable industry costs, Brattle recommended in the 2014 VRR Report that PJM and its stakeholders consider replacing the Handy-Whitman Index with a weighted composite of wage, materials, and turbine cost indices published by the Bureau of Labor Statistics ("BLS"),[115] based on the appropriate subsets of the Producer Price Index ("PPI") and the Quarterly Census of Employment and Wages ("QCEW").

As explained in the 2014 VRR Report, the PPI measures the average change over time in domestic producers' received selling prices and "therefore reflect[s] the increase or decrease in construction costs for a [given] year."[116] The QCEW indices reflect a quarterly count of employment and wages reported by employers covering 98% of U.S.

114 *Id*. at 13.

115 *See id*. at iv, 11-12.

116 *Id*. at 11.

jobs, available at the county, state, and national levels by industry. Given that these reports are both detailed and readily available to the public, Brattle concluded that use of these indices provides a "more transparent" approach that is "more closely tied" to the approach Brattle used in developing the engineering costs estimates that support the Gross CONE values.[117]

PJM adopts this recommendation and accordingly is revising its tariff to reflect replacing the applicable Handy-Whitman Index with a weighted composite of BLS indices for wages, materials, and turbines.[118] PJM will use the same weighting among wages, materials and turbines in all CONE Areas and will state these weighting levels in the Tariff for further transparency. As explained by Dr. Sotkiewicz, PJM is proposing to comprise the BLS composite index of 20% for the applicable QCEW index on wages, 50% for the applicable PPI index on materials, and 30% for the applicable PPI index on turbines,[119] specifically:

- Materials: PPI Index- Commodities; Stage of Processing, Materials and components for construction;[120]
- Turbine: PPI Index- Commodities; Turbines and turbine generator sets;[121] and
- Wages: Quarterly Census of Employment and Wages; (corresponding to the applicable location), Utility system construction, Average annual pay.[122]

There was general stakeholder consensus favoring this change in the index.[123]

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117 2014 VRR Report at 12.

118 *See id*. at 12 n.24.

119 Sotkiewicz Affidavit at ¶ 48; *id.* at Table 4; Tariff, Attachment DD, proposed section 5.10(a)(ii).

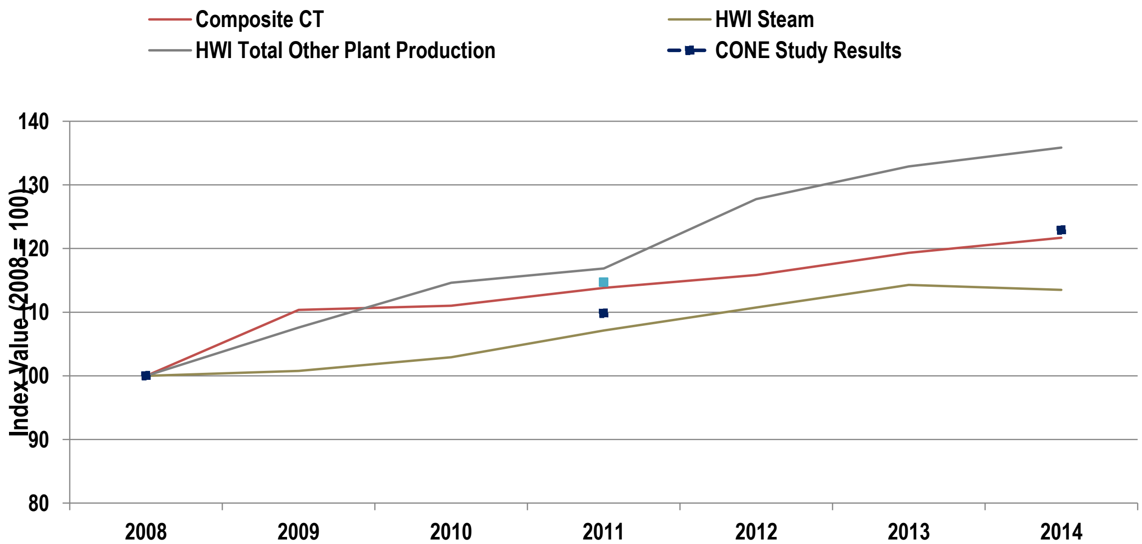
120 United States Department of Labor – Bureau of Labor Statistics, *PPI Index-Commodities – Materials and Components for Construction*, Series Id. No. WPUSOP2200 (last visited Sept. 25, 2014), http://data.bls.gov/timeseries/WPUSOP2200.

121 United States Department of Labor – Bureau of Labor Statistics, *PPI Index-Commodities – Turbine and Turbine Generator Sets*, Series Id. No. WPU1197 (last visited Sept. 25, 2014), http://data.bls.gov/timeseries/WPU1197?include_graphs=false&output_type=column&years_option=all_years.

122 *See* United States Department of Labor – Bureau of Labor Statistics, *Quarterly Census of Employment and Wages*, (last visited Sept. 25, 2014), http://www.bls.gov/cew/#databases: for CONE Area 1 New Jersey Statewide labor rates were used (Series Id. No. ENU340004052371); for CONE Area 2, Maryland Statewide labor rates were used (Series Id. No. ENU240004052371); for CONE Area 3, Ohio Statewide labor rates were used (Series Id. No. ENU390004052371); for CONE Area 4, Pennsylvania Statewide labor rates were used (Series Id. No. ENU420004052371); and for CONE Area 5, Virginia Statewide labor rates were used (Series Id. No. ENU510004052371).

Figure 4 below illustrates how well the proposed composite BLS index has tracked the changes to the CT Gross CONE estimates yielded by the 2008, 2011, and 2014 CONE studies as compared to the changes in the Handy-Whitman Indices for Steam and Total Other Plant Production during this past period.

Figure 4
Comparison of Proposed Composite BLS Index and Handy-Whitman Index to Gross CONE estimates made in 2008, 2011, and 2014



Thus, as Dr. Sotkiewicz concludes, "use of the BLS composite index is [] much more transparent," is "tailored to match the relative weights of the cost drivers to construct the Reference Resource," and "tracks much more closely with other independent credible estimates (from both EIA and the various triennial review consultants) of changes in the costs for building the CT Reference Resource than does the relevant Handy-Whitman index."[124]

As the Commission has recognized, "the choice of an escalation factor is essentially a judgment informed by an analysis of cost and inflation trends."[125] As the 2014 VRR Report and Dr. Sotkiewicz demonstrate, shifting from the applicable Handy-Whitman Index to a composite of applicable BLS indices will allow for the annual adjustments to the CONE values to better reflect changes in applicable industry costs.

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123 Replacing the Handy-Whitman Index with the BLS indices for CONE escalation was included in each of the proposals that were voted on by the CSTF and MRC during the stakeholder process. *See* PJM Interconnection, L.L.C., *Triennial Review Matrix of Proposed Packages* (Aug. 21, 2014), http://www.pjm.com/~/media/committees-groups/committees/mrc/20140821/20140821-item-03-triennial-review-matrix.ashx.

124 Sotkiewicz Affidavit at ¶ 52.

125 *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,064, at P 54 (2008).

Further, adoption of this change also is consistent with the Commission's recent acceptance of ISO-NE's proposal to adjust annually its Gross CONE values on the BLS indices.[126] However, unlike ISO-NE's methodology of updating the individual cost components and re-levelizing CONE each year, PJM is proposing a simpler alternative, as posited in the 2014 VRR Report, of using a composite of the three BLS indices that employs weightings, stated in the Tariff, that are roughly proportional to the capital costs associated with each component.

b. Proposed Tariff changes

To effectuate this change, PJM is revising section 5.10(A)(iv)(B) to replace all references to and descriptions of the applicable Handy-Whitman Index with references to and descriptions of the applicable BLS indices that comprise the BLS composite index.

6. Determination of PJM Region Gross CONE.

a. Current process and need for change

RPM requires a CONE value for the entire PJM Region so that PJM may construct a VRR Curve for the entire PJM Region. The region-wide VRR Curve is an integral part of the auction-clearing algorithm, because until any LDA price-separates from the PJM region, the PJM Region VRR Curve clears capacity for the entire PJM Region. Therefore, PJM should use a region-wide CONE value that is representative of the PJM Region as a whole for use in determining the region-wide VRR Curve.

The current Tariff states a region-wide Gross CONE value of $128,000 per MW-year for the 2015-2016 Delivery Year, and then provides for adjustment of that value using the Handy-Whitman Index for subsequent Delivery Years.[127] This value was determined on a "black box" basis as part of the negotiated settlement resolving PJM's most recent periodic review in Docket No. ER12-513.[128] However, the stated value of

126 *ISO-NE*, 147 FERC ¶ 61,173, at P 40; *see also* Tariff Filing of ISO New England Inc., Docket No. ER14-1639-000, Newell/Ungate Testimony, at 66-67 (Apr. 1, 2014).

127 *See* Tariff, Attachment DD section 5.10(a)(iv) ("the Cost of New Entry for the PJM Region shall be $128,000 per MW-year").

128 *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,079, at P 65 (2012) (accepting the region-wide Gross CONE value proposed in the Settlement Agreement); Settlement Agreement, Explanatory Statement at 14 ("The Gross CONE value for the PJM Region in the Settlement Agreement also was negotiated on a "black box" basis. That Gross CONE is a stated value of $128,000/MW-yr (for the 2015-16 Delivery Year); there is no agreement on a methodology for determining the PJM Region Gross CONE.").

$128,000/MW-year is close to the simple average of the five CONE values that the ER12-513 settlement established for the five CONE Areas.[129]

To determine the *Net* CONE for the PJM Region under the current Tariff, PJM subtracts from the PJM Region gross CONE the net EAS revenue offset for the PJM Region that is based on *system-average* Locational Marginal Prices ("LMP").[130]

Because RPM requires a VRR Curve and Net CONE for the entire region; because the region-wide CONE value should be reflective of the entire region; because the EAS revenue offset for the entire region (which PJM does not propose to change) is based on region-wide average energy prices; and because the region-wide CONE used in RPM the last two years is already very close to the average of the CONE Area CONE values, PJM proposes that the region-wide CONE should be set explicitly as the simple average of the CONE values for the CONE Areas (as those values are adjusted by the Tariff index methodology).[131] This approach is reasonable, as it would allow each CONE Area to affect the PJM Region Gross CONE value and thereby set a value more representative of region-wide conditions.

Using average Gross CONE also would allow the system VRR Curve to adjust with periodic changes to the CONE Area CONE values. As the CONE values for the different CONE Areas are adjusted annually based on the indices reflecting costs in those areas, the CONE Area values are not likely to change at the same rate. Accordingly, setting the CONE for the PJM Region at the average of the latest updated CONE Area values will allow the PJM Region VRR Curve, and the auction, to be representative of the PJM Region as a whole while reducing the impact of any CONE values that significantly diverge from the CONE values for the rest of the PJM Region.[132]

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129 The average of the five CONE Area CONE values stated in the Tariff, i.e., $140,000, $130,600, $127,500, $134,500, and $114,500, is $129,420. Tariff, Attachment DD section 5.10(a)(iv)(A).

130 Tariff, Attachment DD, section 5.10(a)(vi).

131 The 2014 CONE Study did not specify a CONE value for the PJM Region as a whole, recommending instead that the Gross CONE value for CONE Area 3 should be used to construct the system-wide VRR Curve. 2014 VRR Report at 20. PJM does not adopt this recommendation, because the CONE for CONE Area 3 is based on conditions and costs in *that* CONE Area; it is not designed to reflect conditions in *other* parts of PJM, to which the region-wide VRR Curve could often apply.

132 The Commission's action on PJM's region-wide Net CONE proposal in the 2011 triennial review proceeding does not change the result in this case. In that proceeding, PJM sought to set the PJM Region Net CONE value at the median the Net CONE determined for four of the five CONE Areas. The Commission rejected that proposed change as unsupported, because the Commission was not satisfied with PJM's explanation for excluding one of the CONE Areas from the calculation, nor was the Commission satisfied with PJM's support for changing

b. Proposed Tariff changes

To effectuate this change, PJM is eliminating the value currently referenced in Attachment DD, Section 5.10(a)(iv)(A) of the Tariff as the Gross CONE for the PJM Region and adding language that directs PJM to adopt as the PJM Region Gross CONE the average of the CONE values calculated for the CONE Areas (as adjusted by the applicable index provision).

7. Resource Type.

a. Current process and need for change

PJM's current Tariff defines the Reference Resource used for the CONE estimate as a combustion turbine ("CT") power plant "configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology . . . , dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh."[133] PJM does not propose to change that plant design in this proceeding.

While Brattle suggested PJM and its stakeholders "consider" changing the RPM Reference Resource to an average of the estimates for a combined cycle ("CC") and combustion turbine plant, Brattle recognized that "[o]ver the long-term, it should not matter which technology is selected [as between CC and CT] for determining Net CONE as long as the chosen technology is economically viable."[134] Indeed, the Net CONE values of both types of resource "would be identical and equal to the market price for capacity" as determined over long-term market equilibrium expectations.[135] Brattle also cautioned against "switching back and forth to the technology with the lowest Net CONE" because that approach "would understate the true cost of new entry for either technology."[136] Therefore, Brattle concluded that "maintaining a single reference technology over time can be expected to yield an accurate Net CONE value in expectation over time."[137]

PJM therefore is proposing no change to the current Tariff specification of a CT as the Reference Resource.

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the pre-existing Tariff which at that time required that the region-wide gross CONE be based on the *lowest* gross CONE of any CONE Area. *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062, at P 62 (2012). The current Tariff includes no such requirement, nor does PJM seek to base the region-wide CONE on fewer than all the CONE Areas in effect at the time the region wide CONE is determined.

133 *See* PJM Tariff, Attachment DD section 2.58 (defining Reference Resource).

134 2014 VRR Report at 27.

135 *Id*.

136 *Id*.

137 *Id*.

In addition to the above reasons for staying the course, and as the Commission has recognized,[138] a Net CONE based on a CT plant will have the lowest net EAS revenue offset of any resource type, and therefore would be the least affected by possible variance of actual energy market conditions from the conditions implicitly assumed in the net EAS estimate.[139] Thus, Net CONE values for CT resources can be estimated with greater accuracy and it is reasonable to retain a CT as the Reference Resource. Moreover, as Dr. Sotkiewicz explains, "[m]aintaining the CT as the Reference Resource also is appropriate given it is the marginal resource to serve load on the peak day in the peak hour" as "CTs are the highest running cost generation resource in the wholesale market, but are also the lowest capital cost generation resource."[140] Finally, use of a CT as the Reference Resource is consistent with the Commission's recent approval of NYISO's adoption of the CT as the reference resource for that region.[141]

b. Proposed Tariff changes

While not changing the specified CT plant design, PJM is making one conforming change in the Tariff's Reference Resource definition, to remove a reference to CONE Area 5, which PJM proposes to eliminate in this filing.

D. Retention of Historic Net EAS Revenue Offset Methodology.

The current Tariff directs PJM to estimate the energy revenues that the Reference Resource would receive based on actual LMPs and fuel prices for the most recent three calendar years, the heat rate of the Reference Resource, and an assumption that the resource would be dispatched for both the Day-ahead and Real-time Energy Markets on a Peak-Hour Dispatch[142] basis.

In the 2014 VRR Report, Brattle recommended that PJM and its stakeholders "evaluate options for incorporating future prices for fuel and electricity" into the net EAS revenue offset methodology,[143] based on shortcomings that Brattle identified in the current estimating approach that relies on historic data. Brattle offered a specific

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138 March 2009 RPM Order at P 39 ("combined cycle plants have more variable EAS revenues, and therefore, present significant estimating uncertainties").

139 By comparison, the gross CONE estimate is likely to be less variable, simply because plant construction costs are less volatile than energy prices. *See* Sotkiewicz Affidavit at ¶¶ 25-26, 27-35.

140 Sotkiewicz Affidavit at ¶ 31.

141 *N.Y. Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,043, *order on reh'g*, 147 FERC ¶ 61,148 (2014); Sotkiewicz Affidavit at ¶ 35.

142 *See* Tariff, Attachment DD, section 2.46 (defining Peak-Hour Dispatch).

143 2014 VRR Report at vi; *see also id.* at 16.

approach of developing a net EAS revenue offset using publicly-available futures prices.[144]

At the onset of the stakeholder process, PJM recommended developing a forward-looking net EAS revenue offset along the lines Brattle recommended, i.e., based on publicly-available futures prices. PJM worked with Brattle and the IMM to develop its proposed methodology. However, through the course of the stakeholder process, it became clear that while many stakeholders see theoretical value in a forward-looking EAS revenue methodology, no particular proposal (including PJM's proposal) found much support.

One recurring concern is whether forward markets, particularly three-year forward energy markets, have enough liquidity to permit their pricing results to be used with confidence in the manner contemplated here, i.e., as a key input to the VRR Curve that clears significant quantities of capacity at a cost of billions of dollars. PJM proposed a method that would adjust estimated energy revenues (calculated on a historic basis similar to today) using a forward heat rate, i.e., a ratio of forward energy prices to forward fuel prices. Even that simplified method depends on three-year forward energy prices in order to calculate the heat rate. Some market participants remain hesitant to adopt the results of those forwards markets for purposes of the administrative calculation of net EAS revenues at issue here, and PJM understands that caution.

Accordingly, PJM has decided not to change the Tariff by filing a forward-looking net EAS revenue offset methodology at this time. However, this retention of the historic method is not intended to foreclose any future attempts to develop forward-looking estimating methods that are shown to be transparent, reproducible, and reliably more accurate than current methods.

While PJM is retaining the historic EAS revenue estimating methodology, PJM proposes other changes in this filing to the net EAS revenue offset calculation and Net CONE determination that will more closely align the VRR Curves for each LDA to the actual conditions within the LDA, thereby sending more accurate price signals to the market on the need for capacity in each modeled LDA. These changes are described and supported in the next section of this letter.

E. Revisions to the Net Cost of New Entry determination for LDAs to better reflect the localized need for additional capacity.

The price signals sent for modeled LDAs under the current Tariff do not best reflect the localized need for capacity in that LDA, but rather reflect the need for capacity on a broader scale. To better send price signals that reflect the degree of need for additional capacity in each modeled LDA, PJM is proposing revisions to base the Net CONE for LDAs more closely on local conditions in those LDAs, as discussed below.

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144 *Id*. at 16.

1. Current process and need for change

Under the current Tariff, the Net CONE value for each LDA is based on the Zones that comprise that LDA and each Zone in the PJM Region is assigned to a CONE Area.[145] PJM calculates a Net CONE value for each of the identified CONE Areas for which a Gross CONE value is determined.[146] Such Net CONE values equal the Gross CONE for that CONE Area less the net EAS revenue offset calculated for that CONE Area. If an LDA is composed of Zones from more than one CONE Area, the lowest Net CONE value as between those CONE Areas is used for that LDA.[147]

a. The current approach generally does not use Net EAS revenue offsets that are representative of the economic conditions within the modeled LDA.

Brattle identified several problems with the current approach, most of which center on the issue that the net EAS revenue offsets are not representative of the economics within the modeled LDA.[148] As Dr. Newell and Dr. Spees explain, the current process results in "many single-zone LDAs hav[ing] a Net CONE parameter based on energy prices in a different (sometimes distant) location."[149] The Net CONE values of LDAs comprising multiple Zones should not be determined using only a single Zone's fuel and electricity conditions. Nor should the Net CONE values for an LDA be based on a Zone that is not in the LDA or that is not representative of the LDA as a whole. Of the 13 LDAs modeled for the last BRA,[150] Brattle concluded that the Net CONE values for

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145 Tariff, Attachment DD, section 5.10(a)(iv)(A).

146 *Id.*, Attachment DD, section 5.10(a)(v)(B).

147 *Id.*, Attachment DD, section 5.10(a)(iv)(A). For the last Base Residual Auction, PJM calculated a total of seven different Net CONE values: a PJM Region Net CONE value, a different Net CONE value for each of the five CONE Areas, and a Net CONE value for the Mid-Atlantic Area Council ("MAAC"), which is composed of CONE Areas 1 (Eastern MAAC), 2 (Southwestern MAAC), and 4 (Western MAAC) and is determined using the lowest Net CONE value of these three CONE Areas.

148 2014 VRR Report at 23.

149 Newell/Spees Affidavit at 7. Under the current rules, for example, PJM was required to use the net EAS revenue offset from southern New Jersey to calculate Net CONE for both the densely populated northern New Jersey suburbs of New York City and the sparsely populated Delmarva peninsula, despite the significant differences between expected revenues in those two LDAs. 2014 VRR Report at 22-23.

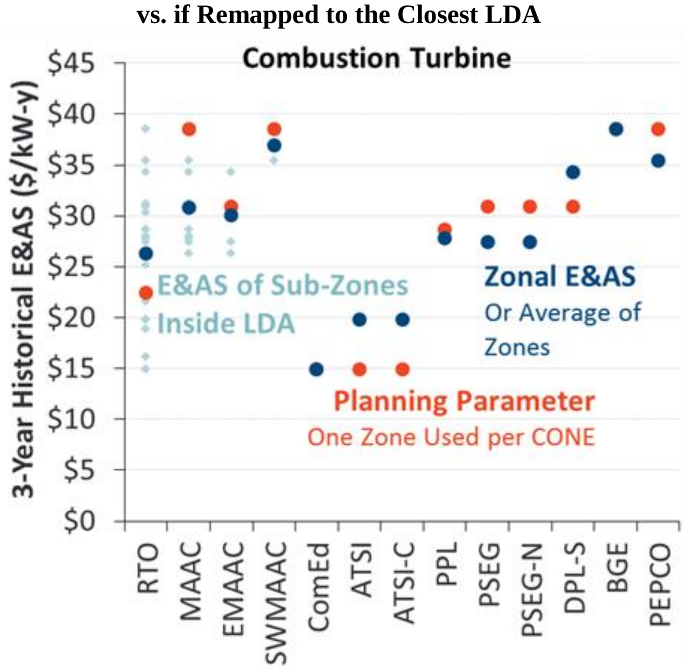
150 For the 2017/18 Delivery Year, PJM modeled LDAs for the PJM Region, ComEd, ATSI, Cleveland (a sub-region within ATSI), MAAC, and within MAAC, PJM modeled: PPL, SWMAAC, EMACC, BGE (within SWMAAC), PEPCO (within SWMAAC), DPL-South (within EMAAC), PSEG (within EMAAC), and PSEG-North (within PSEG and EMAAC).

ten of the LDAs were not based on net EAS revenue offset values estimated specifically for that location and therefore "there is potential for systematic discrepancies between the administratively-estimated and true developer Net CONE in these areas."[151]

To address these issues, Brattle recommended aligning the net EAS revenue offset, and thus, Net CONE, by using the energy conditions within the LDA. For LDAs that cover multiple Zones, Brattle recommended basing the net EAS revenue offset on either an injection-weighted generation bus average LMP across the LDA, or an average of zone-level EAS estimates weighted by the quantity of RPM generation offers from each Zone in the last Base Residual Auction.[152]

In Figure 5 below, Brattle "remapped" the Net CONE values for each modeled LDA that were determined for the last Base Residual Auction in May 2014. The blue points show the impact of more closely aligning the Net CONE for each LDA with the energy conditions within the LDA and the red points are the actual Net CONE values from the last Base Residual Auction in May 2014. To arrive at these revised values for LDAs composed of multiple Zones, Brattle used an average of net EAS revenue offset estimates calculated for each Zone, and for the sub-zonal LDAs composed of a single Zone, Brattle used the net EAS revenue offset for that Zone.[153]

Figure 5[154]
Three-Year Average E&AS Offset from 2017/18 Parameters vs. if Remapped to the Closest LDA



151 2014 VRR Report at 23.

152 *Id*. at 31-32.

153 *Id*. at 24 n.35.

154 *Id*. at 24. Figure 9 in the 2014 VRR Report also include a graphic depicting the changes in the EAS revenue offset for CC plants.

Sources and Notes:

All E&AS offset estimates reflect historical three-year averages of PJM estimates over calendar years 2011-13, as expressed on a $/kW-yr ICAP basis, and including the tariff-defined fixed A/S adder.

For RTO, "Planning Parameter E&AS" based on Average Zonal LMP, "Zonal E&AS" based on average E&AS of zones.

Historical E&AS offsets as used from 2017/18 Planning Parameters, see PJM (2014c.)

Other zones' estimated historical E&AS offset supplied by PJM staff.

This Figure 5 demonstrates that using an net EAS revenue offset calculated for each LDA based on the average energy prices within each LDA "result[s] in lower E&AS (higher Net CONEs) in seven of the thirteen LDAs according to 2017/18 parameters…."[155] That nearly all the remapped Net CONE values are different from those used in the last Base Residual Auction underscores that the current process is not adequately capturing the energy conditions within the LDA and thus the price signals sent to the market may not be fully reflective of the actual need for new capacity within that LDA.

b. To minimize the impact of underestimating Net CONE within a sub-LDA, the Net CONE of a parent LDA should establish a floor for the Net CONE of a sub-LDA.

Brattle also recommended that PJM adopt a market rule to prevent the Net CONE of a sub-LDA (i.e., an LDA wholly encompassed within a larger LDA) from falling below the Net CONE of its parent LDA. Brattle made this recommendation as a safeguard against underestimating locational Net CONE and the resulting under-procurement that could occur in the sub-LDAs. As Drs. Newell and Spees explain, "Net CONE estimation errors are more likely in sub- LDAs, such as Southwest MAAC, which may have idiosyncratic estimating uncertainties as well as small sample sizes for estimating gross CONE and calibrating E&AS estimates."[156] They also note that any capacity under-procurement resulting from Net CONE underestimates would have "disproportionately high reliability consequences in sub-LDAs as explained in our Third Triennial Review."[157]

While there are therefore "substantial reliability benefits from relying on the parent-minimum Net CONE to protect against Net CONE underestimates in sub-LDAs," Drs. Newell and Spees explain that "there is little harm from imposing the parent Net CONE as a minimum for the sub-LDA."[158] This is so, because if Net CONE is truly lower in the sub-LDA than in the parent LDA, then "developers considering locating somewhere in the parent LDA will preferentially site their new entry plants in the sub-

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155 The remapping shows the CT EAS dropping by $1,000-$8,000/MW-yr ICAP in most LDAs, but increase by $3,000-$5,000/MW-yr ICAP in areas where it goes up. 2014 VRR Report at 24.

156 Newell/Spees Affidavit at 8.

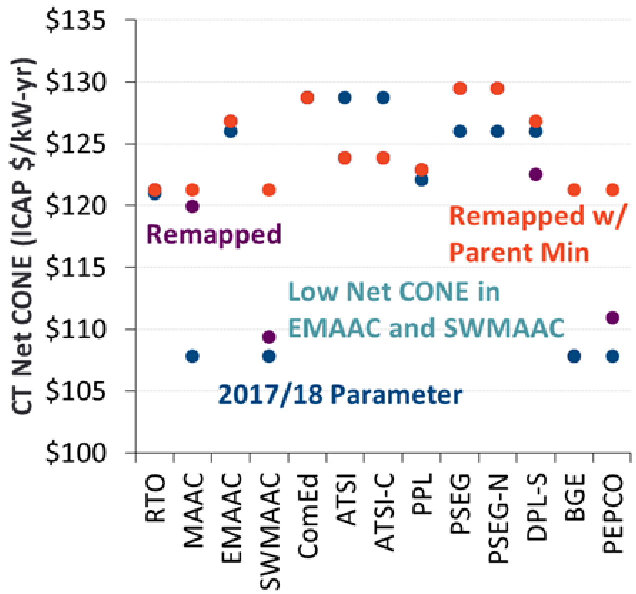
157 *Id*. (citing 2014 VRR Study at sections III.C.3, III.B.1, and VI.B.3).

158 *Id*.

LDA, given its lower net cost (and potential for higher capacity prices)."[159] Given that cost advantage, the sub-LDA would attract sufficient capacity that it would be unlikely to price-separate from the parent LDA in RPM auctions. If the sub-LDA does not price-separate, "then the theoretically lower Net CONE in the child LDA will never find any practical expression," and "the VRR Curve for the parent LDA will continue to set clearing prices in the sub-LDA."[160]

The Figure 6 below illustrates the impact of such a rule, while also taking into account Brattle's recommendation of using the energy conditions in the Zones covered by the LDA to determine Net CONE for each modeled LDA.

Figure 6[161]
Impact of Remapping Gross and Net CONE using 2017/18 Parameters
With and Without Imposing a Parent Minimum on LDA Net CONE



Sources and Notes:
Gross CONE, E&AS, and A/S values consistent with PJM 2017/18 Planning Period parameters, see PJM (2014c). Other E&AS values reflect historical three-year averages of PJM estimates over calendar years 2011-13, as expressed on a $/kW-yr ICAP basis, and including the tariff-defined fixed A/S adder.

The purple points show the impact of more closely aligning the Net CONE for each LDA with the energy conditions within the LDA and the blue points are the actual Net CONE value from the last Base Residual Auction in May 2014. The red points are remapped Net CONE values that illustrate the effect of using the parent LDA's Net CONE as a floor to the Net CONE value. Brattle found that the "parent minimum would be binding

159 *Id.*

160 Newell/Spees Affidavit at 8.

161 2014 VRR Report at 26.

in four locations" and the most substantial impact would be on the Net CONEs for SWMAAC and its sub-LDA PEPCO.[162]

2. Proposed tariff revisions

PJM generally adopts Brattle's recommendations for aligning Net CONE estimates more closely with the energy conditions in the LDAs. Specifically, instead of determining a Net CONE for each CONE Area and applying that Net CONE value for each LDA composed of Zones from that CONE Area, PJM is proposing to calculate a Net CONE *for each Zone* using the applicable Gross CONE value less the net EAS revenue offset estimate determined *for that Zone*.[163] For this purpose, PJM uses the average hourly LMP for that Zone and a posted fuel pricing point for that Zone or, if such a pricing point is not available for that Zone, a fuel transmission adder appropriate to that Zone from within the PJM Region.[164] The Net CONE values for each Zone will then be used to determine the Net CONE value for each LDA that contains such Zone. For LDAs composed of multiple Zones, PJM is proposing to use a simple average of the Net CONEs for all Zones in the LDA.[165] For Zonal or sub-zonal LDAs, PJM is proposing to use the Net CONE calculated for that Zone.

In addition, PJM is revising the Tariff to provide that the Net CONE for an LDA shall be no less than, the Net CONE determined for any other LDA in which the first LDA resides (whether "immediately or successively," i.e., including the parent LDA of a parent LDA, and the entire RTO).[166]

These changes to the methodology for determining Net CONE for LDAs are reasonable. By more closely aligning the Net CONE values for LDA with the actual conditions in that LDA, RPM will send price signals that more accurately reflect the need for investment in additional capacity in each modeled LDA.

F. All Changes Proposed in this Filing Are to Be Effective Starting With the 2018/2019 Delivery Year and Will Not Disturb the 2015/2016, 2016/2017, and 2017/2018 Delivery Years.

PJM is proposing to implement all the changes proposed in this filing starting with the 2018/2019 Delivery Year and for all subsequent Delivery Years. The current-effective Tariff rules related to the VRR Curve shape, adjustment of Gross CONE values, determination of Net CONE, and the net EAS revenue offset will all remain in effect through the end of the 2017/2018 Delivery Year, and will govern issues related to Delivery Years prior to the 2018/2019 Delivery Year, including any Incremental Auctions conducted for Delivery Years prior to the 2018/2019 Delivery Year. Thus, the

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162 *Id.*

163 Tariff, Attachment DD, proposed section 5.10(a)(ii).

164 *Id.*, Attachment DD, proposed section 5.10(a)(v)(B).

165 *Id.*, Attachment DD, proposed section 5.10(a)(ii).

166 *Id.*, Attachment DD, proposed section 5.10(a)(ii).

VRR Curves, Gross CONE values, net EAS revenue offsets, Net CONEs, and all other inputs and parameters determined for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years will continue in effect for the respective Delivery Years. The Tariff revisions PJM is proposing clearly specify this delineation and state that the changes proposed in this filing apply only beginning with the 2018/2019 Delivery Year and all subsequent Delivery Years.[167]

III. EFFECTIVE DATE.

PJM requests an effective date of December 1, 2014, which is more than 60 days after the date of this filing. It is important that the changes proposed in this filing are effective by that date to provide PJM time to develop and post the auction parameters by February 1, 2015 as PJM is required to do, in advance of the May 2015 Auction. Those parameters include the VRR Curves, the Cost of New Entry, and the Net EAS revenue offsets, all of which will be affected by the Tariff changes in this filing.

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167 *See, e.g.*, Tariff, Attachment DD proposed section 5.10(a)(i) ("For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be . . . ."); *id.*, Attachment DD, proposed section 5.10(a)(ii) ("The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year."); *id.*, Attachment DD, proposed section 5.10(a)(iv)(A) ("For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA.").

IV. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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V. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;

2. Revisions to the PJM Tariff (in redlined and non-redlined format (as Attachments A and B, respectively) and in electronic tariff filing format as required by Order No. 714);

3. Affidavit of Dr. Paul M. Sotkiewicz on behalf of PJM, as Attachment C;

4. Affidavit of Dr. Samuel A. Newell and Mr. Christopher Ungate on behalf of PJM, with attached resume and 2014 CONE, as Attachment D; and

5. Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of PJM, with attached resume and 2014 VRR Report, as Attachment E.

VI. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[168] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region[169] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

[168] *See* 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

[169] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

VII. CONCLUSION

Accordingly, PJM requests that the Commission accept the enclosed Tariff revisions effective December 1, 2014.

Respectfully submitted,

/s/ *Paul M. Flynn*

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September 25, 2014

Attachment A

Revisions to Sections of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of Annual Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource
"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for Delivery Years beginning June 1, 2017. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 [Reserved]

2.33 [Reserved]

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 [Reserved]

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for Delivery Years beginning June 1, 2017 for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016-2017 and subsequent Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction for the Zones comprising such Locational Deliverability Area for such Delivery Year.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction (as applicable) for such Delivery Year.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in all CONE Areas ~~1, 2, 3, and 4~~, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, ~~T~~the Variable Resource Requirement Curve for the PJM Region shall be plotted by ~~first~~ combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 0.2%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target.

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA; provided however, that the Net Cost of New Entry for an LDA may be greater than, but shall be no less than, the Net Cost of New Entry determined for any other LDA in which the first LDA resides (immediately or successively) including the Net Cost of New Entry for the RTO. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA. For the Delivery Year commencing on June 1, ~~2015~~2018, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B)~~$128,000 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used~~.

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	132,200~~140,000~~
BGE, PEPCO ("CONE Area 2")	130,300~~130,600~~
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion ("CONE Area 3")	128,900~~127,500~~
PPL, MetEd, Penelec ("CONE Area 4")	130,300~~134,500~~
~~Dominion ("CONE Area 5")~~	~~114,500~~

B) Beginning with the 2019/2020~~2016-2017~~ Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite~~H-W~~ Index, in accordance with the following:

(1) The Applicable ~~H-W~~ BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 30%), as each such index is further specified for each CONE Area in the PJM Manuals~~, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5~~.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable ~~H-W~~BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however

that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the ~~2015-2016~~2018/2019 Delivery Year to which the Applicable ~~H-W~~BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi~~i~~)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resourcce Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, ~~T~~the Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone~~sub-region of the PJM Region for which the Cost of New Entry is determined as identified above~~, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for ~~the~~ such Zone ~~in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals)~~ shall be used in place of the PJM Region average hourly LMPs; (2) if such ~~sub-region~~Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the ~~sub-region~~ Zone was integrated; and (3) a posted fuel pricing point in such ~~sub-region~~Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone~~each assumed Cost of New Entry location~~ from an appropriate PJM Region pricing point shall be used for each such ~~sub-region~~Zone.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall

file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for each Delivery Year beginning with the Delivery Year that commences June 1, 2017, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Attachment B

Revisions to Sections of the
PJM Open Access Transmission Tariff

(Clean Format)

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.6A Compliance Aggregation Area (CAA)

"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of Annual Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 [Reserved for Future Use]

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

“Extended Summer Demand Resource” shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

“Extended Summer Resource Price Adder” shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

“Sub-Annual Reliability Target” for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for Delivery Years beginning June 1, 2017. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation (“LOLE”) assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 [Reserved]

2.33 [Reserved]

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 [Reserved]

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for Delivery Years beginning June 1, 2017 for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016-2017 and subsequent Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction for the Zones comprising such Locational Deliverability Area for such Delivery Year.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction (as applicable) for such Delivery Year.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65B.01 Small Commercial Customer

"Small Commercial Customer," as used in Schedule 6 of the RAA and Attachment DD-1 of the Tariff, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 0.2%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target.

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA; provided however, that the Net Cost of New Entry for an LDA may be greater than, but shall be no less than, the Net Cost of New Entry determined for any other LDA in which the first LDA resides (immediately or successively) including the Net Cost of New Entry for the RTO. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA. For the Delivery Year commencing on June 1, 2018, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	132,200
BGE, PEPCO ("CONE Area 2")	130,300
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion ("CONE Area 3")	128,900
PPL, MetEd, Penelec ("CONE Area 4")	130,300

B) Beginning with the 2019/2020 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 30%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2018/2019 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resourcce Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the

Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for each Delivery Year beginning with the Delivery Year that commences June 1, 2017, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Attachment C

Affidavit of Dr. Paul M. Sotkiewicz on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER14-______

AFFIDAVIT OF DR. PAUL M. SOTKIEWICZ
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

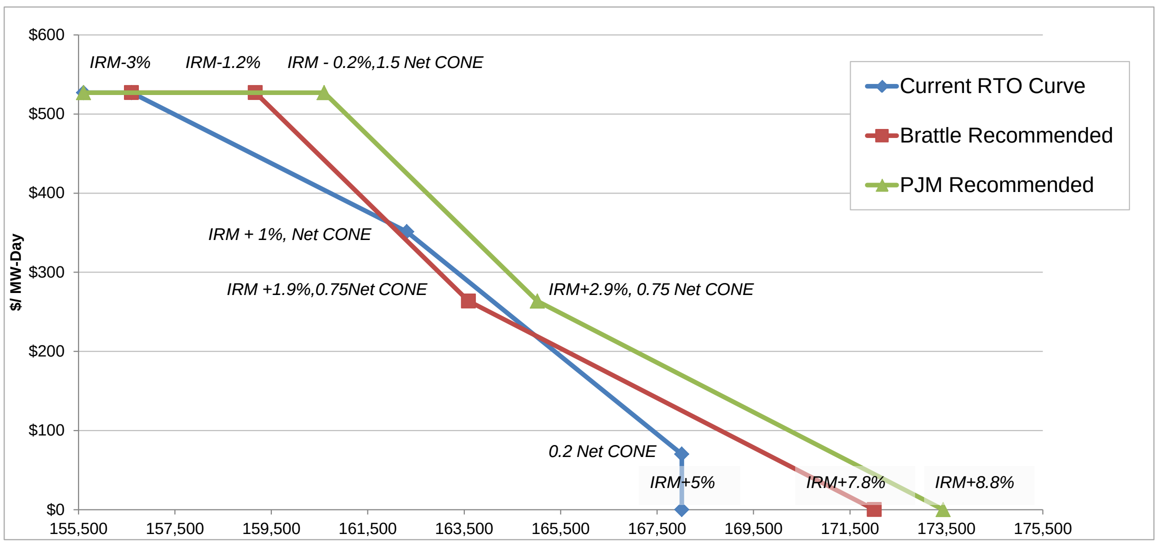
1. My name is Dr. Paul M. Sotkiewicz, and I am the Chief Economist in the Market Service Division at the PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit in support of five aspects of PJM's proposed changes related to PJM's capacity market, known as the Reliability Pricing Model ("RPM"): 1) adoption of The Brattle Group's ("Brattle") recommended VRR Curve shape right shifted by 1% of the Installed Reserve Margin ("IRM"); 2) continued use of a nominal levelized approach to calculating the estimated Cost of New Entry ("CONE") that is used in RPM's Variable Resource Requirement ("VRR") Curve; 3) retention of a combustion turbine ("CT") as the Reference Resource; 4) use of a composite of Bureau of Labor Statistics ("BLS") indices to adjust Gross CONE estimates in between periodic VRR parameter reviews; and 5) adoption of the labor estimates provided by the PJM Independent Market Monitor ("IMM") to determine Gross CONE values.

2. As the Chief Economist at PJM, I provide expert analysis, advice, and support for PJM initiatives related to market design changes in, and performance of, PJM's energy, ancillary service, and capacity markets. In particular, I have worked extensively on demand response mechanisms, the development of shortage pricing mechanisms to comply with the Commission's Order No. 719, the integration of intermittent renewable resources into PJM's markets, market power mitigation issues, and, as related to this proceeding, potential changes to RPM in conjunction with a review of RPM mandated by PJM's Open Access Transmission Tariff ("Tariff"). Additionally, I provide expert analysis on major policy issues facing PJM and have led research efforts that have resulted in whitepapers on the impact of potential climate change policies on PJM's energy markets, transmission cost allocation methods used here and abroad, and the effect of EPA's Cross State Air Pollution Rule and National Emissions Standards for Hazardous Air Pollutants on potential coal capacity retirements in the PJM region. Prior to joining PJM, I served as the Director of Energy Studies at the Public Utility Research Center, University of Florida and as an Economist at the United States Federal Energy Regulatory Commission. I have a B.A. in History and Economics from the University of Florida, and an M.A. and Ph.D. in Economics from the University of Minnesota.

I. Adoption of the Brattle Recommended VRR Curve Right Shifted by 1% of the Reserve Margin

3. Figure 1 below shows the VRR Curve currently in place in the RPM capacity market in blue, the Brattle recommended VRR Curve in red, and the PJM recommended VRR Curve in green. According to Brattle's analysis, the reliability results of which are reproduced in Table 1 below, the current VRR Curve does not achieve a loss of load expectation (LOLE) of one-day-in-ten years (0.1 days/year) but rather only achieves an LOLE of 0.121 days per year or slightly more than 1 day in 8 years .[1] Given that PJM is required by *Reliability*First Corporation ("RFC") and the North American Electric Reliability Council ("NERC"), to plan the bulk electric system to meet the 1-day-in-ten-year standard,[2] PJM arguably cannot retain the current VRR Curve and meet the RFC standard in expectation.

Figure 1: PJM Recommended VRR Curve Compared to Current and Brattle Recommended VRR Curve



4. In contrast, the Brattle recommended VRR Curve in Figure 1 exactly achieves the one-day-in-ten year standard as shown in Table 1, while the PJM recommended VRR Curve provides the greatest reliability on average with an LOLE of 0.06 days per year, as shown in Table 1, or approximately 1 day in 17 years.[3]

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[1] Brattle Group, Third Triennial Review of PJM's Variable Resource Requirement Curve, May 15, 2014 ("2014 VRR Report"), Figure 25 and Table 14 at 69. The report is available electronically at http://pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-vrr-curve-report.ashx.

[2] *See* Standard BAL-502-RFC-02 posted at http://www.nerc.com/files/BAL-502-RFC-02.pdf.

[3] *See* 2014 VRR Report, Table 14 at 69.

Table 1: VRR Curve Reliability Results[4]

	Reliability Measures				
Curve Shapes	Avg. LOLE (Events/yr)	Avg. Excess (Deficit) (IRM + X%)	Res. Margin Std. Dev (%ICAP)	Freq < IRM (%)	Freq < (1-in-5) (%)
Current	0.121	0.4%	2.0%	35%	20%
Brattle Recommended	0.100	0.7%	1.9%	29%	13%
PJM Recommended	0.060	1.7%	1.9%	16%	7%

5. The methodology Brattle has used to develop and test various VRR Curve shapes and placements is well understood, rigorous, and often used to simulate market and reliability outcomes in the power industry as well as other fields such as economics, engineering, and physics. Given that there are now seven Base Residual Auctions ("BRA") a full three years ahead of the Delivery Year (BRAs held for Delivery Year 2011/2012 through 2017/2018) from which to draw experience see how the supply and demand conditions may evolve from one BRA to the next, Brattle has been able to develop distributions of possible supply and demand shocks with known mean and variance from history, and to run Monte Carlo simulations with hundreds or thousands of draws from these distributions to see how various VRR Curves will perform. Time with RPM in place has now provided PJM with valuable experience on which to develop these models which were not available during previous reviews in 2008 and 2011.

6. But even more fundamentally, the distributions of supply and demand shocks and Monte Carlo simulation methods allow Brattle to test different VRR Curve shapes that may be more grounded in economic theory than the current VRR Curve which was a product of a settlement in litigation.

7. From an economic perspective, a convex shaped demand curve makes more sense. A convex shaped demand curve implies that as a consumer demands less of a good or service, the marginal benefit, an equivalent way of expressing demand, of consuming the last unit of the good or service is much higher that the marginal benefit of the last unit consumed when a consumer demands more of a good or service. Intuitively, think about somebody who is really thirsty: The first liter of water has a high marginal benefit as it contributes greatly to rehydration (high marginal benefit), but the tenth liter of water, after already consuming nine liters of water, contributes very little to rehydration and therefore has a lower marginal benefit. But this marginal benefit is decreasing at a decreasing rate. We can think of electric reliability in the form of resource adequacy in much the same way. That first MW of capacity beyond the peak load provides incrementally much greater reliability than does the 20,000th MW beyond the peak for

[4] *Id.*

exactly the same reason, but the marginal benefit of moving from the first MW to the $20{,}000^{th}$ MW is also decreasing at a decreasing rate.

8. In contrast, the concave shaped demand curve for capacity currently in place is counter intuitive in that the marginal benefit of additional capacity while decreasing, is doing so at an increasing rate. This has the effect of seeing capacity prices increasing *less sharply* when the system is below the Installed Reserve Margin ("IRM") target and increasing *more sharply* when the system is still long relative to the target IRM. Intuition and reliability would indicate that when the system starts going short relative to the IRM target, prices should rise steeply to incentivize new entry of resources.

9. The Brattle recommended VRR Curve in Figure 1 and Table 1 exhibits this feature that once the system begins going short relative to the IRM target, prices rise quickly so that the Brattle recommended curve is above the current VRR Curve when short of the IRM target, which helps maintain resource adequacy at the RFC standard in expectation. However, there is still a significant probability, 29% or nearly one-third of the time, where resource adequacy realizations are below the IRM target that meets the RFC standard as shown in Table 1. Furthermore, there is a 13% probability of being below the 1-in-5-year reliability level (an LOLE of more than 0.200 events per year) as shown in Table 1.

10. Indeed, Brattle analyzed its recommended curve right-shifted by 1% and its analysis shows the PJM recommended VRR Curve (The Brattle recommended VRR Curve right shifted by 1%) provides greater certainty in meeting the IRM target in that only 16% of the time would the PJM recommended VRR Curve fail to meet the IRM target defined by the LOLE standard, and only 7% of the time would the LOLE exceed 0.200 events per year as shown in Table 1. This additional reliability can be obtained in expectation for only a 0.8% increase in average procurement costs (an additional $173 million per year on average) according to Brattle's analysis.[5]

11. Given that PJM and the power industry as a whole are facing fast changing and uncertain market, policy and legal conditions, it is prudent to ensure the ability to minimize the probability of being unable to achieve the RFC resource adequacy standard. Examples of the changing conditions present today include the following: 1) approximately 26,000 MW of generation retirements from 2009 to 2016 due to the Mercury and Air Toxics Standards and the emergence of low-cost shale gas; 2) continued improvements in the efficiency and economies of scale in combined cycle gas technology; 3) the recent DC Circuit Court decision to vacate FERC Order No. 745 which creates uncertainty regarding the ability for Demand Resources ("DR") to continue to serve as Capacity Resources in PJM; and 4) uncertainty regarding the manner in which states will implement the United States Environmental Protection Agency ("EPA") proposed Clean Air Act Amendments Section 111(d) Greenhouse Gas Rule and the resulting changes in resource configuration. The full impact of these shocks could not be modeled by Brattle using the historic data, as most of these will affect the RPM capacity

[5] *Id.*

market in the future, and could potentially lead to an even greater range of supply and demand shocks to be considered.

12. As a sensitivity analysis, Brattle simulated a larger variance in supply and demand shocks, labeled 33% Higher Shock in Table 15 of the 2014 VRR Report.[6] One could reasonably view this sensitivity simulation as a proxy for the increasing changes and uncertainty that I discussed above, given that those items are significant *new* categories of resource uncertainty, and thus would not have been captured in the base level of supply "shocks" modeled by Brattle. Under this "33% Higher Shock" scenario, the PJM recommended VRR Curve is the only VRR Curve that achieves the one-day-in-ten-year LOLE standard set by RFC in expectation. As this is a challenging and volatile scenario, the PJM Recommended curve still would be below the target IRM 23% of the time, and would exceed an LOLE of 0.200 days per year 14% of the time.[7] The Brattle recommended curve achieves a 0.156 day per year LOLE which is approximately an LOLE of 1 day in 6 years. and would not achieve the IRM target 34% of the time. The current VRR Curve would see a relatively high LOLE of 0.186 days per year or nearly 1 day in 5 years while failing to achieve the IRM target 39% of the time.

13. In short the PJM recommended curve achieves the RFC resource adequacy standard and minimizes the probability of resource inadequacy outcomes below the RFC standard at an additional procurement cost of less than 1 percent of the cost under the Brattle recommended curve.

II. Cost of New Entry (" CONE").

14. The Cost of New Entry ("CONE") is an estimate of the capital costs and fixed operations and maintenance expenses of a reference resource – which in PJM is a new natural gas combustion turbine ("CT") plant. Dr. Samuel A. Newell of Brattle and Christopher D. Ungate of Sargent & Lundy, present Brattle's detailed, comprehensive estimate of CONE ("2014 CONE Study") with the affidavit they are submitting as part of PJM's filing in this proceeding. I will address four aspects of CONE to provide further support for PJM's proposal in this proceeding: (1) use of a nominal levelized financial modeling method to calculate CONE (instead of Brattle's recommendation to use real levelized); (2) continued use of the CT as the Reference Resource (instead of Brattle's recommendation to use a combination of CT and combined cycle plant ("CC") as the Reference Resource; (3) use of different labor costs than used by Brattle in developing the Gross CONE; and (4) additional support for Brattle's recommendation to use the Bureau of Labor Statistics indices for annual updates to Gross CONE.

[6] *Id*. at 71, Table 15

[7] *Id.*

A. Use of the Nominal Levelized Financial Modeling Method to Calculate CONE

15. Translating project investment and fixed operations and maintenance costs for new generation resources over the expected economic life of the resource into a levelized annual cost is standard practice in the utility industry. The levelized annual cost provides information to the project developer, regulators, and counterparties concerning the constant stream of revenues needed each year to cover the cost of the project including returns on capital. That constant stream of payments can be expressed in either "real" or "nominal" terms.

16. Expressing the constant stream of payments in nominal terms, ("nominal levelized"), means that the payment in each year is the same regardless of inflation. Under nominal levelized, the project developer would receive the same dollar amount (e.g. $120,000/MW-year) in each year over the life of the project regardless of the assumed rate of inflation over the life of the project.

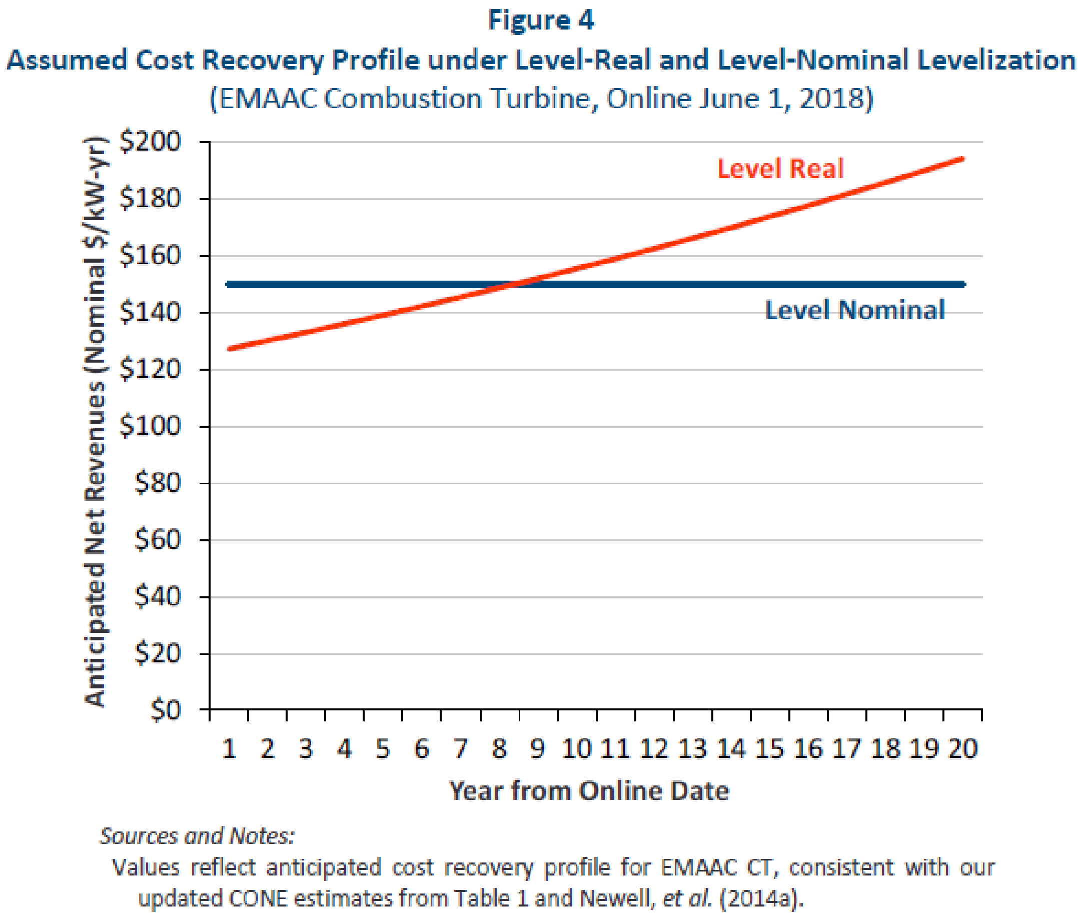
17. Expressing the constant stream of payments in real terms ("real levelized"), means that the payment each year, while the same on an inflation-adjusted basis, increases each year over the life of the project by the rate of inflation.

18. For any given assumed rate of inflation, the present value of the stream of payments under either nominal levelized or real levelized is exactly the same. What differs is the trajectory of the payments in nominal terms. Below I have reproduced Figure 4, and referenced as Figure 2 in my affidavit, from Brattle's 2014 VRR Report[8] (which is being submitted to the Commission with this filing) that shows the nominal levelized cost recovery as the flat line and the real levelized cost recovery as the line that increases over the life of the project.

19. Under nominal levelized cost recovery, the payments made in the early years are greater than the payments in the early years under real levelized cost recovery. However in the later years the nominal levelized payments are less than the real levelized payments. Figure 4 from the 2014 VRR Report shows nominal levelized payments recover more of the project cost in the early years and less of the project cost in later years. Conversely, Figure 4 shows real levelized payments recover less of the project cost in the early years and more of the project cost in the later years of the project.

[8] *Id.* at 10, Figure 4

Figure 2 Nominal Levelization vs. Real Levelization



20. In connection with preparation of its CONE estimate, Brattle has recommended that PJM and its stakeholders should consider transitioning from the nominal levelized method (which PJM has used to set CONE since RPM's inception) to a real levelized approach. Brattle's recommendation is based on the idea that the CONE will increase at the rate of inflation or more over time and that in the long run future net revenues accruing to merchant investment will be set by the CONE of future new entrants.[9] This conclusion is based upon the following two observations regarding the dynamics of new entry over time historically: 1) continuation of the CONE increasing at or faster than inflation; and 2) reduction in older turbines' net revenues due to relative outperformance by newer turbines if CONE is actually increasing at a rate greater than the inflation rate.[10]

21. To support its recommended movement toward real levelized CONE, Brattle only refers back to its 2011 RPM Performance Assessment, which relies only on the Handy-Whitman Index as the measure of CONE inflation (that Brattle has now disavowed as the

[9] *Id.*

[10] *Id.*

measure of CONE inflation in the 2014 VRR Report[11]) and the Consumer Price Index, and recognizes that its prior analysis is not conclusive as to cost recovery on a forward-looking basis.[12] From this, Brattle concludes that because CONE will rise by the rate of inflation based on historic evidence, project developers will expect the project's revenues to rise at the inflation rate, warranting PJM's adoption of the real levelized model that likewise assumes revenues will rise at an assumed inflation rate.

22. Brattle's assumption about project developers' expectations regarding future revenue increases highlights the central challenge with adopting a real levelized approach. The Commission addressed this very same issue for the PJM Region in 2011 in ER11-2875, when certain parties advocated using the real levelized approach for the CONE estimate that is used to screen capacity offers under RPM's Minimum Offer Price Rule. In that case, the Commission found that, even with a gross CONE escalation rate of only 2.5 percent under the real levelized method, the EAS offset and other factors would imply an effective inflation rate of 6.0 percent, which the Commission found to be an unreasonable expectation to ascribe to a developer.[13] By contrast, the Commission found that it would be reasonable for a developer to use a nominal levelized approach, since it matches the mortgage style financing that is typical for new generation projects.[14]

23. In my view, the issue here is not whether it is reasonable for Brattle to project that revenues based upon CONE will steadily increase every year at a particular inflation rate. The issue is whether it is *unreasonable* to expect that a *merchant developer* will want the assurance of a constant revenue stream (on a nominal levelized basis) in order to go forward with a new entry project. Brattle's analysis does not show that such an expectation is unreasonable. In fact, there are ample reasons to expect that a developer might be wary of the risks implicit in a real levelized model. In other words, a developer legitimately might decline to invest if it is at risk of not receiving the annual revenue increases on which the nominal levelized model depends.

24. Brattle's preference for a real levelized approach assumes that generation project developers are risk neutral rather than risk averse, especially with respect to adverse shocks that can reduce revenues for an extended period of time. But developer risk aversion is the heart of the matter, and must be confronted. It is reasonable to expect that project developers are risk averse for a host of reasons, including the inflation uncertainties and future revenue uncertainties attributable to various demand, supply, or policy shocks that are at best difficult to predict and to which I previously alluded. Project developers that are risk averse may prefer to receive a greater share of cost recovery in the early years of the project's life given that forecasts about future market

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[11] *Id.* at 11-13.

[12] *Id.* at 11.

[13] 135 FERC ¶ 61,022 at 50.

[14] *Id.* at 51.

conditions and policies affecting the industry 5, 10, 15, and 20 years forward grow ever more uncertain. Absent certainty about the future stream of payments, project developers likely would prefer to recover project investment costs in the early years of the project rather than in later years.

25. From a real options theory perspective, the choice of nominal levelized CONE reduces the value of waiting for more information about the effect of shocks to the wholesale energy and capacity markets before making a new investment. From a reliability (resource adequacy) perspective, providing greater certainty about revenues early in the project life through nominal levelization will be far more likely to attract new entry when it is actually needed than real levelization, precisely because merchant project developers are operating in an uncertain environment and are risk averse. If CONE were set at the real levelized value, risk averse generation developers would only enter at RPM prices above the real levelized Net CONE. This implies new entry would only take place when installed reserve margins are below the target installed reserve margin, resulting in an erosion of the ability of RPM to maintain resource adequacy reliability at the target installed reserve margin.

26. In sum, the nominal levelized modeling approach to calculating CONE remains reasonable, and Brattle's reasons for preferring a real levelized approach do not demonstrate that the nominal levelized approach is *un*reasonable. Indeed, Brattle recognizes that the reasonableness of each approach is dependent on which trajectory of net revenues and capacity revenues is expected by merchant investors in generation, as Brattle acknowledges in the 2014 VRR Report:

> We recognize that this analysis is not fully conclusive about the actual trajectory of cost recovery anticipated by generation developers on a forward-looking basis. One could make a case for attempting to determine projections of net revenues representing actual developers' likely views on energy prices, fuel prices, and capacity prices over the 20-year investment life. The entirety of this information is what ultimately determines the "true" value of CONE.[15]

Developers' views on the world are influenced by their perceptions of uncertainty and associated risk. One way in which to mitigate the risk associated with such uncertainty is to increase cash flows to the project in the early years of the 20-year investment life as the scope of uncertainty and risk grows further out in time. Finally, as a consequence, the nominal levelization then better ensures reliability to attract new investment when there is a need for new investment to meet the target IRM rather than waiting for the system to go short the IRM target to drive prices above Net CONE to attract new investment.

B. Retention of a Combustion Turbine (CT) as the Reference Resource

27. Brattle has recommended changing the Reference Resource from a combustion turbine ("CT") to an average of a CT Net CONE and a combined cycle ("CC") Net

[15] 2014 VRR Report at 11.

CONE.[16] This recommendation is predicated on the observation that of late very few CTs have been built in PJM and it has mostly been CCs that have been the new entrants into PJM. Brattle also cites the uncertainty as to whether it is really the case that CT technologies are no longer economic for merchant investment relative to CC technologies or whether this is a relatively temporary phenomenon.[17] Moreover, since both CTs and CCs have been built in PJM since 2008, an average Net CONE formulation recognizes that if both technologies are economic, then they should both converge in the long run to the same Net CONE.[18]

28. Brattle argues that consideration of a CC technology as part of an average of Net CONEs or as a stand-alone technology to define the Reference Resource can be supported on the basis of "revealed preference," and that in theory the Net Energy and Ancillary Service Offset (Net E&AS) can be easily computed when accompanied by a switch to a forward looking Net E&AS methodology where the peak period is 5 days a week, 16 hours per day ("5x16") and forward energy prices can be used to estimate a forward Net E&AS.[19]

29. While movement to the average Net CONE of a CC and CT can be supported, there are multiple reasons why retaining the CT technology as the Reference Resource makes sense: (1) If both technologies are truly economic, then staying with a CT is still consistent with the long-run Net CONE; (2) Consistency and stability of market design for investment; (3) Accuracy of the Net E&AS estimates with actuals for CTs than for CCs; and (4) less dependence on Net E&AS estimates relative to the CC technology.

30. Over the long-run with PJM exactly achieving the IRM target as a steady state, all new generation resources that enter the market (CT and CC) should converge to the same Net CONE even if there are times in which the Net CONEs of the two resources are not the same. And while today, there are more CC gas resources entering the market than CTs, there will reach a point where the market becomes saturated with CC resources and the CT Net CONE equalizes with the CC Net CONE. Given such a long run equilibrium outcome, consistency and stability for market participants dictates the retention of the CT as the Reference Resource.

31. Maintaining the CT as the Reference Resource also is appropriate given it is the marginal resource to serve load on the peak day in the peak hour. CTs are the highest running cost generation resource in the wholesale market, but are also the lowest capital cost generation resource. Moreover, a CT takes less time to permit and build than other generation resources. In theory a CT that is the marginal resource in the energy market

[16] *Id.* at 29.

[17] *Id.* at 26-27 and 2014 PJM CONE Study at 8-9.

[18] *Id*. at 29

[19] *Id.* at 28.

during the peak hour and will have low or zero net energy revenues over time, assuming it runs very little otherwise. So, by extension, if on a peak day, one could immediately build a new resource to meet the next increment of load if there were no other resources available, it makes economic sense to build the lowest capital cost resource, a CT, to meet the next increment of load since the purpose of the resource is to meet the "peak of the peak day" to achieve resource adequacy rather than building a resource that is more intermediate and base load.

32. Since the inception of RPM, the Reference Resource has been a CT. Decisions regarding the entry of new Capacity Resources, whether they are uprates to existing resources, new Combined Cycle ("CC") resources, or new CT resources through the 2017/2018 Base Residual Auction (BRA), have been predicated on the idea that the CT would remain the Reference Resource. Moreover, given the recent market changes with the emergence of low cost shale gas production, slow growing demand, and environmental regulations, decisions by existing capacity Resources to remain in service have also been predicated on the notion that the CT would remain the Reference Resource. In short, to maintain a sense of stability and consistency for market participants regarding past decisions and going forward decisions, retaining the CT as the Reference Resource will help best ensure resource adequacy over the long term.

33. Moreover, changing the Reference Resource to a Net CONE alternative blend of CT and CC resources could easily be perceived by market participants as being "opportunistic" in the sense of changing one of the most fundamental building blocks of RPM as the anchor to the VRR Curve as a way to reduce Net CONE in the short-run, even though in the long-term the Net CONEs should be equivalent, with the idea of capacity market prices or costs. When accompanied by recent fuel price and technology changes, such a change would be viewed by Capacity Resources as reason to forestall future new entry or lead to resource retirements that otherwise would not have taken place.

34. Brattle itself has shown that the CT Net E&AS estimates are far more accurately measured, and that the CC Net E&AS estimates are far higher than actual Net E&AS revenues collected by existing CC resources.[20] The implication would be to introduce a Net CONE value that is lower than the "true" Net CONE, if using the average of the CT and CC Net CONEs under the historic offset methodology being retained by PJM. Hence, retaining the CT as the Reference Resource avoids introducing this downward bias in Net CONE due to estimation error of the Net E&AS Offset, which would only exacerbate challenges to achieving resource adequacy over the long-run.

35. Finally, there is recent Commission precedent to indicate the retention of a CT as the Reference Resource remains just and reasonable. That is, the Commission approved the use of a CT as the Reference Resource for the NYISO capacity market and has consistently found the use of the CT as the Reference Resource as just and reasonable in multiple filings made by PJM with respect to the RPM capacity market.

[20] *Id*. at 14-15, Figure 6.

C. <u>PJM Adoption of the IMM Construction Labor Costs for Determining the CONE for the CT Reference Resource</u>

36. After careful consideration of publicly available data on wage rates, benchmarking construction labor hours from previous CONE studies, and consulting with Sargent & Lundy regarding labor productivity within the PJM Region, PJM has included the labor construction values presented by the PJM Independent Market Monitor ("IMM") that were derived by Pasteris Energy.[21]

37. As shown below, the labor construction values estimated by Pasteris Energy for the IMM closely track publicly available data from the United States Bureau of Labor Statistics ("BLS") Quarterly Census of Employment and Wages ("CEW") for the North American Industrial Classification Standard (NAICS) 2371 Utility Construction Wages, adjusted for inflation, fringe benefits and labor productivity factors. Moreover, the BLS CEW data is the same data source PJM proposes to use to adjust the labor portion of costs associated with constructing the CT Reference Resource as discussed in my affidavit below, and as such provides consistency in the data sources used to support construction labor and other cost increase between CONE reviews.

38. Pasteris Energy hired Stantec Consulting Services, Inc. ("Stantec") to develop the plant proper capital cost estimate.[22] For construction labor, Stantec estimated it would take 360,000 labor hours to construct the CT Reference Resource at an average labor rate of $86/hour in 2013 dollars for a labor construction cost of $31.0 million in CONE Area 1 for EMAAC.[23] Stantec then escalated the labor costs to 2018 dollars at a rate of 3.75% per year for a labor construction cost of $37.3 million in CONE Area 1 (EMAAC).[24]

39. The construction labor costs derived by Stantec for Pasteris Energy and the IMM are consistent with the labor hours and labor costs for CONE Area 1, EMAAC as derived in the 2011 CONE study by CH2M Hill for the Brattle Group and PJM.[25] In this study,

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[21] *See* Pasteris Energy, Brattle CONE Combustion Turbine Revenue Requirements Review for Monitoring Analytics, LLC, July 25, 2014, posted at http://pjm.com/~/media/committees-groups/task-forces/cstf/20140725/20140725-brattle-vs-ma-som-cone-ct-revenue-requirements-comparison-final-report.ashx.

[22] *Id*. at 2

[23] *Id.* at 7.

[24] *Id.* at 7

[25] *See* The Brattle Group, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants August 24, 2011, Appendix A.4, posted at http://pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx

CH2M Hill estimated 361,088 man hours of construction labor at a rate of $84.66/hour and total construction labor costs of $30.57 million in 2011 dollars.[26] To get an estimate of what the CH2M Hill construction labor cost would be in 2018 dollars, I inflated this by the expected rate of inflation as derived by the difference between 20 Year Treasury Bonds and 20 Year Treasury Inflation Protected Bonds from 2004 to the present, which is 2.39 percent per year.[27] This would give an equivalent construction labor value of $36.06 million in 2018 dollars for CONE Area 1, EMAAC, or just $1.2 million below the Pasteris/Stantec estimate.

40. During early August the IMM presented CONE values for the remaining CONE Areas with the corresponding construction labor costs. These construction labor costs are reproduced in Table 2. I have made one adjustment to ensure that reliance on the IMM estimate does not omit labor costs associated with the installation of dual fuel capability. The IMM's CONE estimates included labor costs associated with dual fuel capability in a line item separate construction labor costs. Table 2 includes the additional $1 million included in "Other Labor" costs to ensure that dual fuel labor costs are reflected in my discussion.

Table 2: IMM Presented/PJM Adopted Construction Labor Values ($ millions 2018 dollars)

	CONE Area 1 (EMAAC)	CONE Area 1 (SWMAAC)	CONE Area 3 (EMAAC)	CONE Area 4 (WMAAC)	CONE Area 5 (Dominion)
IMM/Pasteris	$38.3	$22.9	$21.4	$30.5	$21.1

41. To validate the reasonableness of these construction labor estimates in Table 2, I examined publicly available BLS CEW Utility Construction Wages NAICS 2371 for different states corresponding to the respective CONE Areas presented in Tables 1 and 2.[28] The last full year for which the BLS CEW has published utility construction labor rates is 2013. The hourly wage rates in 2013 dollars in the second row of Table 3 below are derived from the published weekly rates and divided by 40 hours per week. These

[26] *Id.* at Appendix Page A-33.

[27] Federal Reserve Economic Database ("FRED") at http://research.stlouisfed.org/fred2/ and selecting data to graph and download at http://research.stlouisfed.org/fred2/graph/?id=DGS20,DFII20,# on September 23, 2014.

[28] United States Bureau of Labor Statistics (BLS) Quarterly Census of Employment and Wages (CEW) available at http://www.bls.gov/cew/#databases. For CONE Area 1 New Jersey Statewide labor rates were used (Series Id. ENU340004052371) For CONE Area 2, Maryland Statewide labor rates were used (Series Id. ENU240004052371). For CONE Area 3, Ohio Statewide labor rates were used (Series Id. ENU390004052371). For CONE Area 4, Pennsylvania Statewide labor rates were used (Series Id. ENU420004052371). For CONE Area 5, Virginia Statewide labor rates were used (Series Id. ENU510004052371).

values are then expressed in 2018 dollars in row 3 of Table 3 adjusted for expected inflation using an implied inflation rate of 2.32 percent per year based on the average difference in interest rates between the 20 Year Treasury Bond Constant Maturity and the 20 Year Treasury Inflation Protected Bond Constant Maturity from the beginning of 2012 to present.[29]

42. Actual wages paid to labor constitute only approximately one-half of the total cost of labor. Employers also are responsible for other labor related costs ("fringe") such as taxes, benefits, and workers' compensation. From the work CH2M Hill provided for Brattle and PJM in 2011, the implied fringe was 1.03 times the wage rate.[30] Discussions with Sargent & Lundy indicated a range of fringe from 0.92 times the wage rate to 1.04 times the wage rate. Rows 4 and 5 in Table 3 provide the lower bound and upper bound hourly wage rates in 2018 dollars accounting for fringe.

Table 3: Validating the IMM Construction Labor Values

	CONE Area 1 (EMAAC)	CONE Area 2 (SWMAAC)	CONE Area 3 (EMAAC)	CONE Area 4 (WMAAC)	CONE Area 5 (Dominion)
State	New Jersey	Maryland	Ohio	Pennsylvania	Virginia
Wage Rate (2013 $/hr)	$43.20	$27.28	$32.60	$36.95	$25.50
Wage Rate (2018 $/hr)	$48.47	$30.60	$36.58	$41.46	$28.61
Lower Bound w/Fringe(0.92)	$93.07	$58.76	$70.23	$79.60	$54.94
Upper Bound w/fringe(1.04)	$98.88	$62.43	$74.62	$84.58	$57.22
Total Construction Labor Costs ($millions 2018 dollars)					
Lower Bound	$38.9	$24.5	$29.3	$33.2	$22.9
Upper Bound	$41.3	$26.1	$31.2	$35.3	$23.9

[29] Federal Reserve Economic Database ("FRED") at http://research.stlouisfed.org/fred2/ and selecting data to graph and download at http://research.stlouisfed.org/fred2/graph/?id=DGS20,DFII20,# on September 23, 2014.

[30] The Brattle Group, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants August 24, 2011, Appendix A.4, page A-33 posted at http://pjm.com/~/media/committees-groups/committees/mrc/20110818/20110818-brattle-report-on-cost-of-new-entry-estimates-for-ct-and-cc-plants-in-pjm.ashx. The implied fringe was computed based on the New Jersey Utility Construction Wage Rate for 2011, inflated to 2015 dollars and then dividing the hourly rate of $84.66 by wage rate and subtracting 1.

43. Next, standard practice in estimating construction labor costs is to measure "labor productivity" by region relative to a benchmark area, usually the Gulf Coast of the United States which is given a productivity factor of 1. Labor productivity greater than one usually accounts for items such as regional practices that could increase the effective labor cost either through labor rates or labor hours required. Derivation of labor productivity factors is a judgment based on experience. Discussions with Sargent & Lundy indicate a range of productivity factors between 1.13 and 1.19. These values are consistent with labor productivity factors used by CH2M Hill in the previous CONE Study for Cone Areas 1, 3, and 4, but also higher than those assumed by CH2M Hill for Cone Areas 2 and 5 where productivity was assumed to be 1.[31]

44. Using a productivity factor of 1.16 (i.e., the average of the Sargent & Lundy values), applying this to the upper and lower bound on fringe, and multiplying by the 360,000 required labor hours, provides a range of total construction labor costs in the last two rows of Table 3. The construction labor costs in Table 3 are quite close too those derived by Stantec for Pasteris Energy and the IMM in Table 1. For example, for CONE Area 1 the difference is $1.6 to $4 million. In short, PJM has adopted the IMM construction labor costs because they can be nearly reproduced using publicly available data, and what PJM has learned over time from both current and past CONE studies for the CT Reference Resource.

D. Use of Bureau of Labor Statistics (BLS) Indices to Adjust Gross CONE between Comprehensive Periodic Reviews

45. Currently, PJM uses Handy-Whitman's "Total Other Production Plant" index for the appropriate location to update its Gross CONE values annually. There are several concerns relating to the continued use of this index. The Handy-Whitman index:

- is not specifically tailored to the construction of CTs or CCs;
- has escalated more quickly than the rate of cost increases found through CONE studies, and for costs associated with labor, materials, and turbine generator sets;
- is not transparent in its methodologies;
- is updated only twice each year;
- is available only through subscription and thus it is not publically available; and
- although it publishes a Total Production Plant index, it does not track well with other measures of cost inflation or match the changes in the Gross CONE that have been observed in PJM's three periodic CONE reviews.

From a market transparency perspective, an index that can be verified by market participants and monitored month by month can help anticipate yearly changes to Gross

[31] *Id.* at Appendix A, page A-9.

CONE. That more accurate reflection in actual changes in the Gross CONE over time would enhance the efficiency and cost-effectiveness of RPM in meeting its resource adequacy objectives in between CONE reviews.

46. BLS-based Indices are based on three inputs from the Producer Price Index (PPI) database for materials and turbines and the CEW for labor costs:

- Materials: PPI Index- Commodities; Stage of Processing, Materials and components for construction[32]
- Turbine: PPI Index- Commodities; Turbines and turbine generator sets[33]
- Wages: Quarterly Census of Employment and Wages; (Corresponding to the applicable location), Utility system construction, Average annual pay.[34]

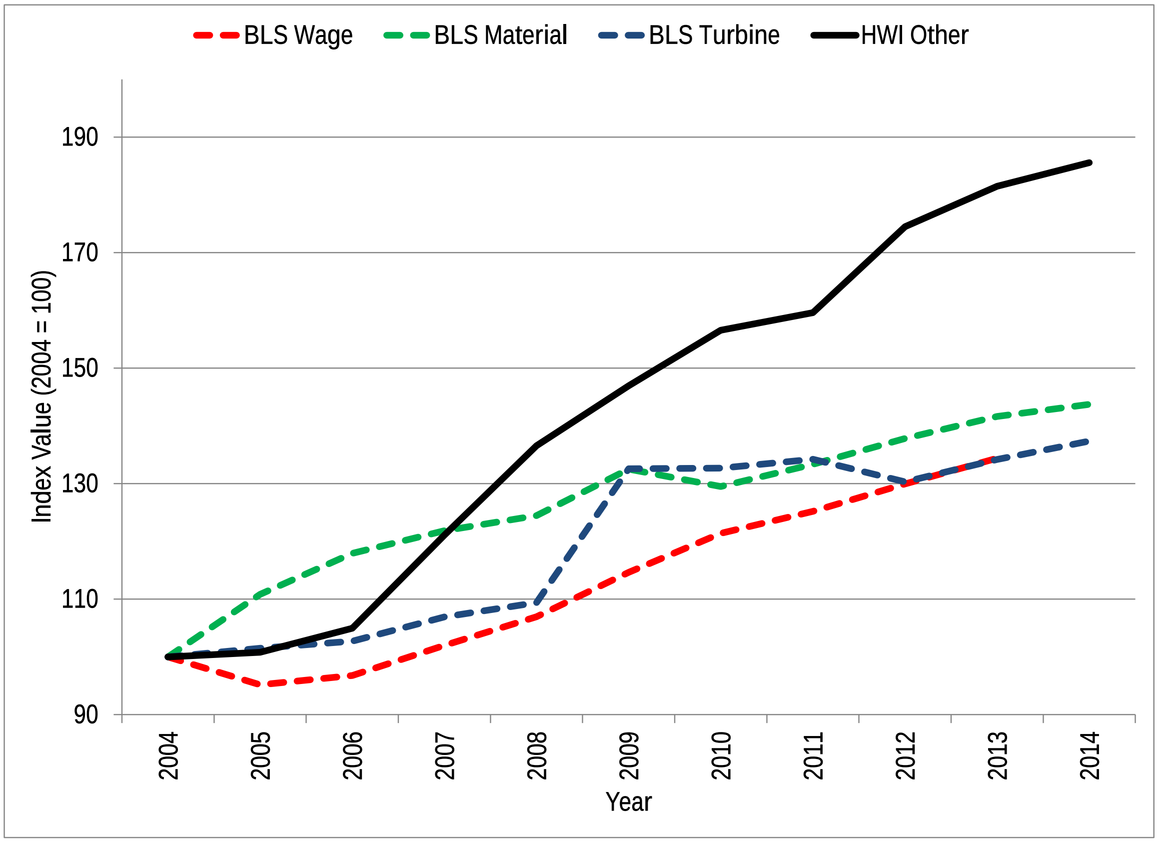
Figure 3 shows how the Handy-Whitman Index (HWI) Total Other Production Plant cost increases are far in excess of the price increases for utility construction wages, turbines, and construction materials from BLS. Figure 3 shows the HWI Other index has increased nearly 90 percent from 2004 to 2014 while wages, material, and turbine costs have not even increased 50 percent from 2004 to 2014. Moreover, unlike material and turbine costs, which saw a flattening or decline in prices during the recession and afterward, the HWI Other index continued to rise as if the recession did not occur. Such a trajectory calls into question the validity of the HWI Other index given that other costs reacted to the recession very differently.

[32] PPI Index- Commodities; Stage of Processing, Materials and components for construction | Series ID: WPUSOP2200 *http://data.bls.gov/timeseries/WPUSOP2200*

[33] PPI Index- Commodities; Turbine and Turbine generator sets | Series ID: WPU1197 *http://data.bls.gov/timeseries/WPU1197?include_graphs=false&output_type=column&years_option=all_years*

[34] *See supra* note 28.

Figure 3: BLS Wage, Turbine, and Material Costs vs. HWI Total Other Production Plant



47. PJM proposes to use a composite of price/cost indices from the BLS to adjust the Gross CONE to more accurately reflect yearly changes in Gross CONE. The BLS cost indices are related to three major cost categories associated with the construction of the CT Reference Resource: turbines, material, and labor. Figure 4 below shows the breakdown by specific cost category of the various line items sorted by Sargent & Lundy into the categories of turbine, materials, and labor costs.

48. Table 4 provides an approximate percentage weighting of turbine, material and labor costs to be used for the purposes of adjusting Gross CONE each year corresponding to the contribution to the Gross CONE, and the state from which the labor costs will be drawn by CONE Area. The states used for labor in the CONE Area are the same as discussed above in my affidavit validating the IMM construction labor costs adopted by PJM.

Table 4: Percentage of Cost for CONE

	CONE Area 1 (EMAAC)	CONE Area 2 (SWMAAC)	CONE Area 3 (EMAAC)	CONE Area 4 (WMAAC)	CONE Area 5 (Dominion)
State: Labor	New Jersey	Maryland	Ohio	Pennsylvania	Virginia
Labor	20%	20%	20%	20%	20%
Materials	50%	50%	50%	50%	50%
Turbines	30%	30%	30%	30%	30%

Figure 4: Categorization of Costs as Turbine, Materials, and Labor

Line Items from S&L	Cost Category
Gas Turbines	Turbine
HRSG / SCR	Material
(OFE) Sales Tax	Material
"Equipment Subtotal" *	Material
Construction Labor	Labor
Other Labor	Labor
Materials	Material
(EFC) Sales Tax	Material
EPC Contractor Fee	Material
EPC Contingency	Material
Project Development	Labor
Mobilization and Start-Up	Labor
Net Start-Up Fuel Costs	Material
Electrical Interconnection	Material
Gas Interconnection	Material
Land	Material
Fuel Inventories	Material
Non-Fuel Inventories	Material
Owner's Contingency	Material
Financing Fees	Material

* "Equipment Subtotal" includes the condenser, steam turbine and other equipment for the CC; for CT, it includes just the "Other Equipment"

49. Figure 5 shows the BLS composite index: BLS CT based on the weightings shown in Table 4 and the categorizations in Figure 4 compared to the Handy-Whitman Total Other Production Plant (HWI Other) index. Again, just as was seen in Figure 3, the HWI Other index rises much faster than the BLS CT index.

50. Figure 6 shows the BLS CT and HWI Other indices compared to the values of the previous PJM Region triennial review CONE study values. The data is shown for EMAAC, with 2008 as the base year. Figure 6 clearly shows the composite BLS index tracks more closely with the bottom-up CONE study values than does the HWI for Total Other Production Plant index. In fact, since 2008, the Gross CONE for a CT (according to the triennial review studies) has increased just over 20 percent, almost identical to the BLS CT index. In contrast, the HWI Other index has increased by approximately 35 percent over same period.

Figure 5: BLS CT Composite Index vs. HWI Other

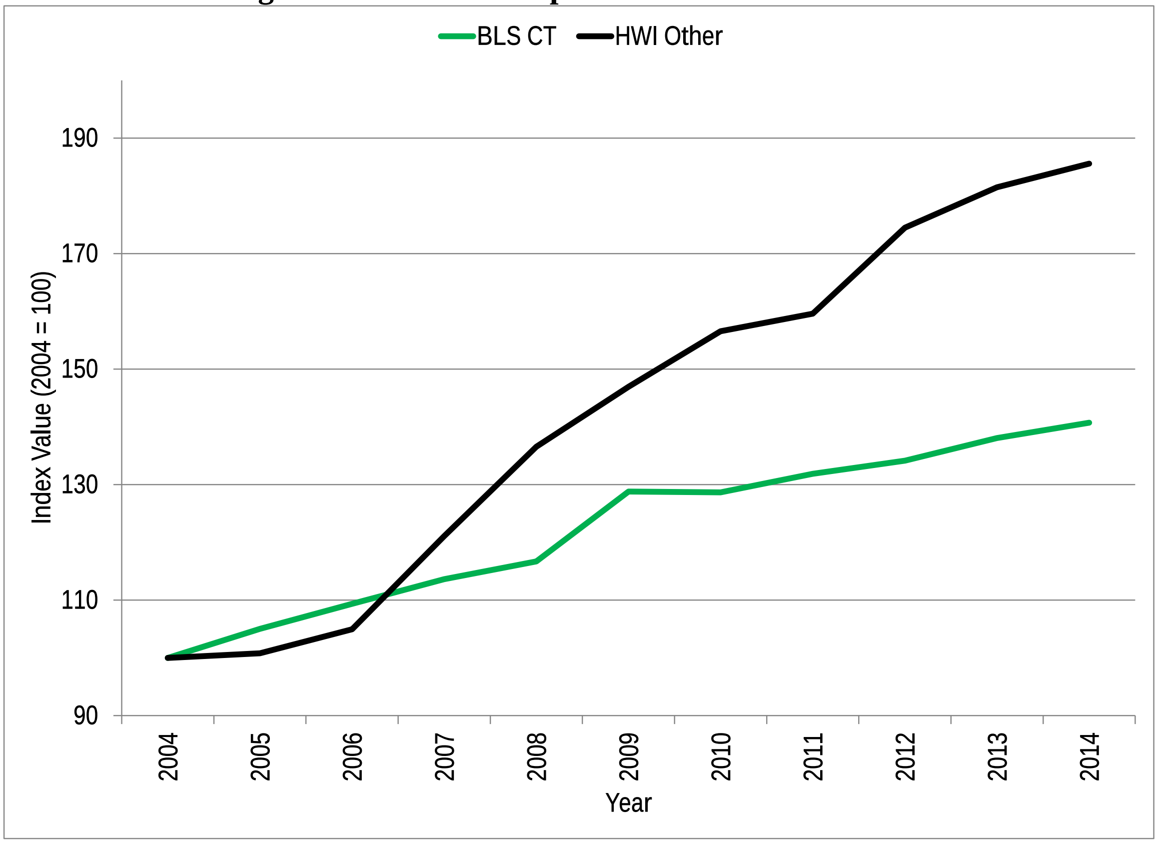
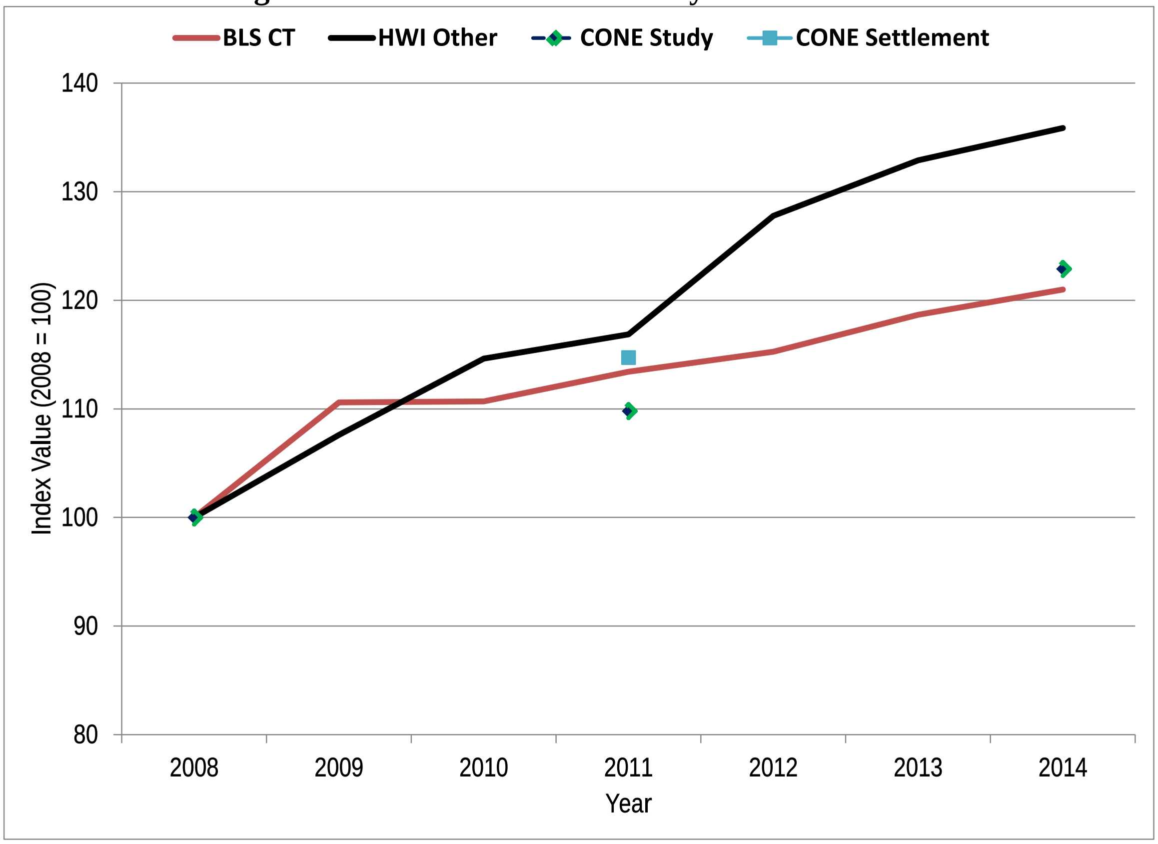


Figure 6: BLS CT vs. CONE Study and HWI Other



51. To further verify that the PJM proposed BLS CT index matches the actual increases in costs for new CT Reference Resources, Figure 7 shows the BLS CT index, and the HWI Other index compared to the costs of building the reference CT as published by the United States Energy Information Administration (EIA) studies on capital costs for new build generation resources. EIA completed two studies in 2010 and 2013 that estimate the cost of what is the equivalent of the CT Reference Resource.[35] Much like the PJM CONE studies, the evolution of costs for the CT Reference Resource more closely match the BLS CT index proposed by PJM than the HW Other index. In fact, the BLS CT index increased by 5 percent between 2010 and 2012, while the EIA estimates of CT costs increased by only 2 percent in nominal terms.[36]

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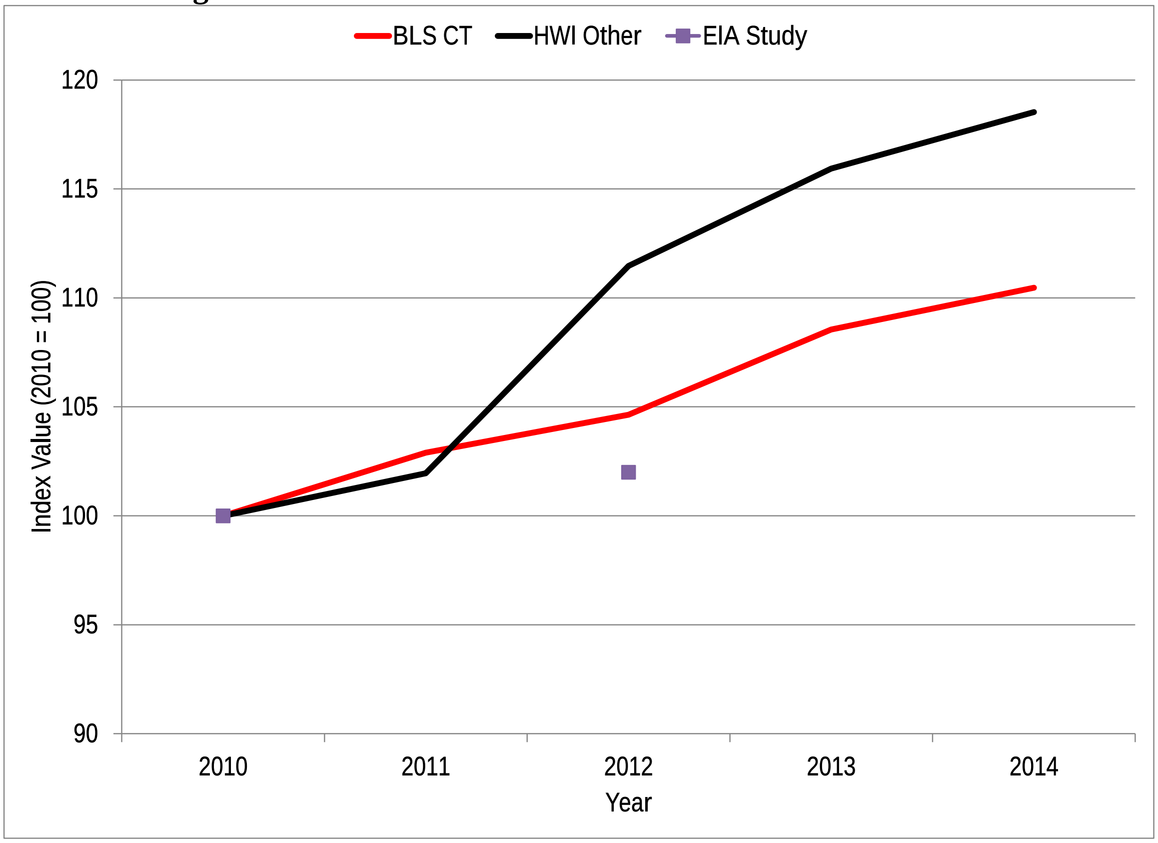
[35] *See* United States Energy Information Administration ("EIA"), Updated Capital Cost Estimates for Electricity Generating Plants, November 2010, pages 9-1 to 9-5, posted at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf and Updated Capital Cost Estimates for Utility Scale Generating Plants, April 2013, pages 9-1 to 9-3 and A-17, posted at http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf. The Capital cost estimates used are for New Jersey.

[36]In real terms, the cost of the CT Reference Resource has fallen in real terms by about 2 percent. *See* Updated Capital Cost Estimates for Utility Scale Generating Plants, April

Figure 7: BLS CT Index and HWI Other vs. EIA CT Studies



52. In summary, the use of the BLS composite index is (i) much more transparent to all market participants; (ii) tailored to match the relative weights of the cost drivers to construct the CT Reference Resource; and (iii) tracks much more closely with other independent credible estimates (from both EIA and the various triennial review consultants) of changes in the costs for building the CT Reference Resource than does the relevant Handy-Whitman index.

This concludes my affidavit.

2013 page 7 Table 2, posted at
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. ER14-___

AFFIDAVIT

STATE OF PENNSYLVANIA)
)
CITY OF NORRISTOWN)

DR. PAUL M. SOTKIEWICZ, being duly sworn, deposes and states: that the Affidavit of Dr. Paul M. Sotkiewicz on behalf of PJM Interconnection, L.L.C. was prepared by his or under his direct supervision, that the statements contained therein are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

DR. PAUL M. SOTKIEWICZ

Subscribed and sworn to before me this 25 day of September, 2014.

Sandra L Ritchie
Notary Public
My Commission Expires: Nov. 3, 2017

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
SANDRA L RITCHIE
Notary Public
LOWER PROVIDENCE TWP., MONTGOMERY CNTY
My Commission Expires Nov 3, 2017

{W0034793.1 }

Attachment D

Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER14-______

AFFIDAVIT OF DR. SAMUEL A. NEWELL
AND MR. CHRISTOPHER D. UNGATE
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

Our names are Dr. Samuel A. Newell and Mr. Christopher D. Ungate. We are employed by *The Brattle Group* ("Brattle"), as a Principal, and *Sargent & Lundy* ("S&L"), as a Senior Principal Management Consultant, respectively. We are submitting this affidavit in support of the proposal by PJM Interconnection, L.L.C. ("PJM") to adjust the administrative Cost of New Entry ("CONE") parameter, representing the cost of building a generation plant for use in PJM's capacity market (known as the Reliability Pricing Model or "RPM").

We both have extensive experience estimating CONE in capacity markets administered by Regional Transmission Organizations ("RTO"). For ISO-NE, we submitted joint testimony in April 2014 regarding the CONE for the ISO-NE Forward Capacity Market demand curve.[1] In December 2013, we sponsored testimony before the Commission to establish the ISO-NE Offer Review Trigger Prices based on our estimates of Net CONE values for various technologies.[2] Dr. Newell co-authored the 2011 PJM CONE study[3] and provided affidavits in ensuing litigation,[4] which informed the Net

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1 Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, *Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve*, April 1, 2014.

2 Before the Federal Energy Regulatory Commission Docket No. ER14-616-000, *Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England* and the accompanying "2013 Offer Review Trigger Prices Study," December 11, 2013.

Before the Federal Energy Regulatory Commission, Docket No. ER14-616-000, *Affidavit of Christopher D. Ungate on Behalf of ISO New England*, December 11, 2013.

3 Kathleen Spees, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, August 24, 2011. ("2011 PJM CONE Study") Available at http://www.pjm.com/documents/reports.aspx.

4 Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, *Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC,*

CONE values PJM used in its capacity auctions for the 2016/2017 and 2017/2018 delivery years. In addition, Dr. Newell's extensive related experience in market design for resource adequacy for ISO-NE, PJM, NYISO, MISO, and ERCOT has provided broad perspective on the capacity market context in which CONE is used. For NYISO, Mr. Ungate developed capital cost and fixed O&M cost estimates for the demand curve reset studies of 2007, 2010, and 2013.[5]

Our experience working for RTOs is also informed by our work for market participants building, buying, and contracting with generation plants. Dr. Newell has led numerous generation asset valuation studies and resource planning studies. Mr. Ungate has performed a number of utility planning studies, and he supports RTOs and utility clients with cost and performance estimates of new entrant technologies that are used in the development of administratively determined demand curves and power supply plans.

Dr. Newell is an economist and engineer with more than 16 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. Prior to joining The Brattle Group, he was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T.Kearney. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

Mr. Ungate has over thirty-five years of experience in electric utility operations, planning, and consulting. Prior to joining Sargent & Lundy, he was manager of generation resource planning at the Tennessee Valley Authority. He directed supply planning for 30,000 MW of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. He has a B.S. and M.S. in Civil Engineering from the Massachusetts Institute of Technology, and an M.B.A from the University of Tennessee at Knoxville. He is a registered professional engineer in the State of Tennessee.

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supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model, November 21, 2012.

5 NERA/Sargent & Lundy, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, April 15, 2007.

NERA/Sargent & Lundy, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, August 2, 2013.

New York Independent System Operator, Inc., *Proposed NYISO Installed Capacity Demand Curves for Capability Years 2011/2012, 2012/2013, 2013/2014* (Draft report for discussion purposes only) Final report prepared based on NERA/S&L's September 7, 2010 revised final study report, Issued 9/3/2010, Revised 9/7/2010, 10/30/2010.

Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes, attached to our affidavit.

In October of 2013, PJM retained Brattle to review the Cost of New Entry ("CONE") parameters of the Reliability Pricing Model ("RPM"), as required periodically under PJM's tariff. Dr. Newell led the Brattle review of CONE parameters, together with Mr. Ungate and his team at S&L as a sub-contractor. The Brattle team's role was to estimate CONE, starting by determining the configurations and locations of the reference plants, overseeing S&L estimates of the capital cost and fixed operation and maintenance ("O&M") costs, estimating certain components of capital costs (*e.g.*, gas and electric interconnection and land costs), estimating certain components of fixed O&M costs (*e.g.*, property taxes and firm gas contracts), analyzing the key financial assumptions (*e.g.*, cost of capital), and calculating the levelized costs. S&L's role was to contribute expertise in determining the configurations and locations of the reference plants and to provide detailed capital and fixed O&M cost estimates of the reference plants specified for each PJM CONE Area.

The results of the analysis completed by Brattle and S&L are set forth in a report entitled "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date" ("2014 CONE Study"). A copy of the 2014 CONE Study, which was prepared under our direction and supervision, is attached to our affidavit.

This affidavit summarizes the methodology and results of our study with PJM's requested modifications.

Our starting point for estimating CONE was to determine representative technical specifications and locations for the reference natural gas-fired combustion turbine ("CT") plant. To do so, we relied primarily on the "revealed preference" of developers in the PJM region and around the U.S., as reflected by recent and proposed CT plants. For CONE Areas where revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices.

We defined a representative reference plant based on two General Electric Frame 7FA.05 gas turbines with selective catalytic reduction ("SCR") technology and carbon monoxide ("CO") catalyst environmental controls to reduce air pollutant emissions, evaporative cooling for power augmentation, and dual-fuel capability. We found in our analysis that dual fuel has not been dominant in the Rest of RTO area for CT plants, but PJM requested that we calculate CONE in all areas assuming dual-fuel capability. The net summer installed capacity of such a plant is 383 to 396 MW depending on the ambient atmospheric conditions assumed in each location, with a net heat rate of approximately 10,300 Btu/kWh.

Based on this configuration, we estimated capital and fixed O&M costs for each CONE Area. More specifically, for each plant specified, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimated annual fixed operating and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. The 2014 CONE Study describes the bases for each of these estimates.

We then calculated the levelized CONE value using an after-tax weighted average cost of capital ("ATWACC") of 8.0% based on our review of various market reference points, as documented in the 2014 CONE study. We calculated levelized costs assuming 20 years of cash flows that are constant in real terms (*i.e.*, growing with inflation) and, alternatively, cash flows that are constant in nominal terms. Because PJM is filing CONE values based on the level-nominal assumption, we present only those results in this affidavit.

Following the release of the 2014 CONE Study, PJM conducted a stakeholder process to review the report and solicit input on the assumptions. As a result of those discussions, PJM chose to adopt, in lieu of the labor cost estimates provided in the 2014 CONE Study, an alternative labor cost estimate provided by the Independent Market Monitor for the PJM Region.[6] At PJM's request, we included these alternative labor costs in a recalculation of the CONE values from the 2014 CONE Study, and show those results in this affidavit.

The estimated CONE for the reference CT plant in each CONE Area with an online date of June 1, 2018, based on the 2014 CONE Study, including the level-nominal assumption and dual-fuel capability for all areas, as calculated as an alternative option in the 2014 CONE Study, plus the alternative labor cost estimate provided by PJM are as shown in Table 1.

Table 1
Reference CT Plant CONE Estimates

CONE Area	**CT CONE** *($/MW-year)*
CONE Area 1	$132,200
CONE Area 2	$130,300
CONE Area 3	$128,900
CONE Area 4	$130,300
CONE Area 5	$126,400

We note that while we include CONE estimates for CONE Area 5, Brattle has recommended, and PJM has agreed, to merge CONE Area 5 into CONE Area 3.

6 See Affidavit of Dr. Paul Sotkiewicz of PJM, which is being submitted concurrently with this affidavit

This concludes our affidavit.

SAMUEL A. NEWELL

Principal

Cambridge, MA | +1.617.234.5725 | Sam.Newell@brattle.com

Dr. Samuel Newell's expertise is in the analysis and modeling of electricity markets, the transmission system, and RTO rules. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation and development, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

Dr. Newell earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

AREAS OF EXPERTISE

- Electricity Wholesale Market Design
- Valuation of Generation Assets
- Energy Litigation
- Integrated Resource Planning
- Evaluation of Demand Response (DR)
- Transmission Planning and Modeling
- RTO Participation and Configuration
- Analysis of Market Power
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Wholesale Design

- **Third Triennial Review of PJM Capacity Market and CONE Study**. For PJM, conducted third tri-annual review of the Reliability Pricing Model. Addressed the shape of the demand curve, the Cost of New Entry (CONE) parameter, and the methodology for estimating the energy margins and ancillary services revenues in the Net CONE calculation.
- **ISO New England Capacity Demand Curve.** For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Also worked with

Sargent & Lundy and stakeholders to develop estimates for the Net Cost of New Entry (Net CONE) to which the prices in the demand curve are indexed. Submitted testimonies before FERC, with ongoing support to develop locational demand curves for individual capacity zones.

- **Market Development Vision**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **Economically Optimal Reserve Margins**. For the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO New England, developed offer review trigger prices for screening for uncompetitively low offers in the Forward Capacity Market. Collaborated with Sargent & Lundy to conduct a bottom-up analysis of the costs of building and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency, and demand response. For each technology, estimated the capacity payment needed to make the resource economically viable, given expected non-capacity revenues, a long-term market view, and a cost of capital. Recommendations were filed with and accepted by the Federal Energy Regulatory Commission (FERC).
- **Evaluation of Investment Incentives and Resource Adequacy in ERCOT**. For the Electric Reliability Council of Texas (ERCOT), led a team that (1) characterized the factors influencing generation investment decisions; (2) evaluated the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluated options to enhance long-term resource adequacy while maintaining market efficiency. Conducted the study by performing forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed

a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Findings and recommendations became a launching point for a PUCT Proceeding, in which I filed comments and presented at several workshops between June 2012 and July 2013.

- **Second Triennial Review of PJM Capacity Market and CONE Study**. For PJM, conducted second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty and safeguard future performance. Led a study of the Cost of New Entry (CONE), based on detailed engineering estimates developed by EPC contractor CH2M HILL, for use in PJM's setting of auction parameters. Served as PJM's witness in filing CONE values and a Settlement Agreement.
- **Evaluation of Reliability Pricing Model (RPM) Results and Design Elements**. For PJM, co-led a detailed review of the performance of its forward capacity market. Reviewed the results of the first five forward auctions for capacity. Concluded that the auctions were working and demonstrated success in attracting and retaining capacity, but made more than thirty design recommendations. Recommendations addressed ways to remove barriers to participation, ensuring adequate compensation/penalties, and improving the efficiency of the market. Resulting whitepaper was submitted to the FERC and presented to PJM stakeholders.
- **Evaluation of ISO-NE Forward Capacity Market (FCM) Results and Design Elements.** With the ISO-NE market monitoring unit, reviewed the performance of the first two forward auctions in ISO-NE's FCM. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor. Resulting whitepaper filed with the FERC and presented to ISO-NE stakeholders.
- **Evaluation of a Potential Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its existing short-term ICAP market structure with a proposed four-year forward capacity market (FCM) design. Evaluation based on stakeholder interviews, the experience of PJM and ISO-NE with their forward capacity markets, and review of the economic literature regarding forward capacity markets. Addressed the following attributes of FCM relative to the existing market: risks to buyers and suppliers, mitigation of market power, implementation costs, and long-run costs. Recommendations used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.

- **RTO Accommodation of Demand Response (DR) for Resource Adequacy**. For MISO, helped modify its tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying in detail the practices of other RTOs, and by characterizing the DR resources within the MISO footprint.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Integration of DR into MISO's Energy Markets**. For MISO, wrote a whitepaper evaluating the available approaches to incorporating economic DR in energy markets. Assessed the efficiency and the "realistic achievable potential" for each approach. Identified implementation barriers at the state and RTO levels. Recommended changes to business rules to efficiently accommodate curtailment service providers (CSPs).
- **MISO Capacity Market Enhancements**. Supported MISO in developing market design elements for its proposed annual locational capacity auctions.
- **Evaluation of MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its new resource adequacy construct. Identified several major successes and a series of recommendations for improvement in the areas of load forecasting, locational resource adequacy, and determination of the target level of reliability. The report incorporates extensive stakeholder input and review, and comparisons to other ISOs' capacity market designs. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements.
- **Evaluation of MISO's Demand Response Integration**. For MISO, conducted an independent assessment of its progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers to date. Assessed the likelihood of MISO's "ARC Proposal" to eliminate barriers to participation by curtailment service providers. Made recommendations for potential further improvements to market design elements.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, allowing reductions in installed capacity margins) on capacity costs, emergency procurement costs, capacity prices, and energy prices. Resulting whitepaper submitted by ISO-NE to the FERC in its filing on tie-benefits.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Also developed guidelines on the kinds of information ISO-NE should provide for major initiatives.

- **LMP Impacts on Contracts**. For a West Coast client, critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.
- **RTO Accommodation of Retail Access**. For MISO, made recommendations for improving business practices in order to facilitate retail access (and to enable auctions for the supply of regulated generation service). Analyzed the retail access programs in the three restructured states within MISO -- Illinois, Michigan, and Ohio. Performed a detailed study of retail accommodation practices in other RTOs, focusing on how they have modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Valuation of Generation Assets and Contracts

- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Analysis focused on projected market revenues, operating costs, and capital investments likely needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.

- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a major retail energy provider preparing to bid for a bundle of generation assets, provided energy and capacity price forecasts and reviewed their valuation methodology. Analyzed the supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the Dayzer model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan provided a market-based revenue forecast for energy and capacity. Identified gas and CO_2 allowance prices as the key drivers of revenue uncertainty, and evaluated the implications of several detailed scenarios around these variables.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogeneration plant in PJM, conducted an analysis of revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of plausible scenarios. Identified key uncertainties and risks in the acquisition of such assets.

Energy Litigation

- **Demand Response Arbitration**. Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony in arbitration before the American Arbitration Association (non-public).

- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.

- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.

- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages resulting from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's operating characteristics and costs. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Integrated Resource Planning (IRP)

- **IRP in Connecticut (for the 2008, 2009, 2010, 2012, and 2014 Plans)**. For the two major utilities in Connecticut and The Connecticut Department of Energy and Environmental Protection (DEEP), lead the analysis for five successive integrated resource plans. Plans included projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, and REC markets, and suppliers' likely investment/retirement decisions. Addressed policy questions regarding supply risks, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.

- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Serve (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Evaluation of Demand Response (DR)

- **ERCOT DR Potential Study**. For ERCOT, estimated the market potential for DR by end-user segment, based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented results to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.

- **Evaluation of DR Compensation Options**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **Wholesale Market Impacts of Price Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Present Value of DR Investments**. For Pepco Holdings, Inc., analyzed the net present value of its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated the reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Documented findings in a whitepaper submitted to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Transmission Planning and Modeling

- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of a Major Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects of the Project

on congestion, capacity markets, CO2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the congestion, production cost, and LMP impacts using the PROMOD model.

- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.

- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.

- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a "metric" indicating access and congestion-related benefits provided by its transmission investments and operations.

- **Analysis of Transmission Constraints and Solutions**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.

- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle effort to evaluate commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and Henwood LMP. Performed intensive in-house testing of each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability and ease to calibrate models with backcasts using actual RTO data.

RTO Participation and Configuration

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across regional transmission organization (RTO) seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a complaint proceeding before the FERC, assisted expert witness providing testimony regarding (1) the inadequacy of MISO and PJM's current efforts to improve inter-RTO coordination, and (2) the large net economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM in energy prices and in shadow prices of reciprocal coordinated flow gates. Analyzed results of MISO and PJM's market simulation models.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Analysis of Market Power

- **Buyer Market Power**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate various proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan potentially created incentives to exercise vertical wholesale market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **Market Monitoring and Market Power Mitigation**. For the PJM Interconnection, assessed their market mitigation practices and co-authored a whitepaper "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets" (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

Tariff and Rate Design

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility holding company, led the financial evaluation of a nascent venture to build and operate cogeneration facilities on customer sites. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with top executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Wrote RFPs and developed negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance their trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a large power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the potential value client could bring to each potential customer. Worked directly with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of an integrated utility, performed a market assessment of established and emerging DG technologies. Projected future market sizes across multiple market segments in the U.S. Concluded that DG presented little immediate threat to the client's traditional generation business, and that it presented few opportunities that the client was equipped to exploit.
- **Fuel Cells**. For a European fuel cell component manufacturer, acted as a technology and electricity advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Dr. Samuel A. Newell on behalf of Tri-State Generation and Transmission Association, Inc.," regarding an Analysis of Complaining Parties' Responses to Tri-State Generation and Transmission Association, Inc., September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on behalf of the Maine Office of the Public Advocate, regarding an Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. regarding a Forward Capacity Market Demand Curve," filed April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on behalf of ISO New England Inc. regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve," filed April 1, 2014.

Before the Federal Energy Regulatory Commission Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of ISO New England" and accompanying "2013 Offer Review Trigger Prices Study," December, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Texas Public Utility Commission, presented "ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates" on behalf of The Electric Reliability Council of Texas (ERCOT) at a workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, June 27, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 23, 2013.

Before the Federal Energy Regulatory Commission, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, Docket No. ER13-535-000, December 28, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model, filed November 21, 2012.

Before the Texas Legislature Committee on State Affairs, presented oral testimony: "The Resource Adequacy Challenge in ERCOT" on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Resource Adequacy in ERCOT: 'Composite' Policy Options" and "Estimate of DR Potential in ERCOT" on behalf of ERCOT at a workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, October 25, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Review of Resource Adequacy Proposals" on behalf of ERCOT at workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, September 6, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'" at workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22-25, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, D. Murphy, and J. Wharton, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

"Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism," report prepared for EnerNOC, Inc., August 2014 (with K. Spees).

"Third Triennial Review of PJM's Variable Resource Requirement Curve," report prepared from PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).

"Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pefiefenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).

"Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent." Foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).

"Estimating the Economically Optimal Reserve Margin in ERCOT," report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees and I. Karkatsouli).

"Resource Adequacy Requirements: Reliability and Economic Implications," September 2013 (with J. Pfeifenberger, K. Spees).

"Capacity Markets: Lessons Learned from the First Decade," Economics of Energy & Environmental Policy. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger, K. Spees).

"ERCOT Investment Incentives and Resource Adequacy," report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).

"Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" Public Utilities Fortnightly, December 2011 (with J. Pfeifenberger).

"Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15," report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Fostering economic demand response in the Midwest ISO," Energy 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).

"DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" Public Utilities Fortnightly, November 2010.

"Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," report prepared for MISO, January 2010 (with K. Spees and A. Hajos).

"Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," report prepared for MISO, January 2010 (with A. Hajos).

"Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market," whitepaper written for the NYISO and submitted to stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).

"Fostering Economic Demand Response in the Midwest ISO," whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).

"Review of PJM's Reliability Pricing Model (RPM)," report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).

"Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," Energy, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).

"Enhancing Midwest ISO's Market Rules to Advance Demand Response," report written for MISO, March 12, 2008 (with R. Earle).

"The Power of Five Percent," The Electricity Journal, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).

"Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes and others).

"Valuing Demand-Response Benefits in Eastern PJM," Public Utilities Fortnightly, March 2007 (with J. Pfeifenberger and F. Felder).

"Quantifying Demand Response Benefits in PJM," study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).

"Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," Energy, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).

"Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

"Effect of Cross Sound Cable," CERA Alert, October 24, 2003 (with H. Stauffer and G. Mukherjee).

PRESENTATIONS

"Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy" presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.

"EPA's Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d)," presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.

"Capacity Markets: Lessons for New England from the First Decade," presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.

"The State of Things: Resource Adequacy in ERCOT" presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.

"Resource Adequacy in ERCOT" presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.

"Electricity Supply Risks and Opportunities by Region" presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.

"Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented to the Cadwalader Energy Investor Conference, New York, February 7, 2013 (with K. Spees).

"The Resource Adequacy Challenge in ERCOT," presented to The Texas Public Policy Foundation's 11th Annual Policy Orientation for legislators, January 11, 2013.

"Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives," presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.

"Resource Adequacy in ERCOT," presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.

"Texas Resource Adequacy," presented to Power Across Texas, Austin, TX, September 21, 2012.

"Resource Adequacy and Demand Response in ERCOT," presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.

"Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'," presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

"Market-Based Approaches to Achieving Resource Adequacy," presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.

"Fundamentals of Western Markets: Panel Discussion," WSPP's Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with Jürgen Weiss).

"Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.

"Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.

Before the PJM Board of Directors and senior level representatives at PJM's General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

"Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

"Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, May 3, 2007 (with J. Pfeifenberger, presenter).

"Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

"Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.

"Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

"Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

September 23, 2014

CHRISTOPHER D. UNGATE
Senior Principal Management Consultant
Sargent & Lundy Consulting

EDUCATION

University of Tennessee, Master of Business Administration, 1984
Massachusetts Institute of Technology, M.S. Civil Engineering, 1974
Massachusetts Institute of Technology, B. S. Civil Engineering, 1973

REGISTRATIONS

Professional Engineer - Tennessee

EXPERTISE

Utility Planning
Technology Evaluation
Market Analysis
Asset Valuation
Condition Assessment
Due Diligence
Risk Analysis
Expert Witness

RESPONSIBILITIES

Mr. Ungate is accountable for Sargent & Lundy offerings in the Utility Planning business segment. He develops and evaluates integrated resource plans and associated analyses to identify and evaluate the optimum power supply options. He reviews and evaluates power supply planning and procurement options such as generation options (potential greenfield or plant expansion options), the viability of siting and permitting new gas, wind, solar, biomass, coal, nuclear or other alternatives, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. He also assesses the state of transmission planning and upgrade programs, and the fuel market and transportation capacities. He assures consistency with the Client's long-term plans and objectives and Client-specific economic factors.

Mr. Ungate supports ISOs and utility clients with cost and performance estimates of new entrant technologies. He develops analyses utilized in the assessment of power generation technologies, project development, asset transactions, operational reviews, and facility modifications and refurbishment projects. He evaluates and develops plans to optimize the utilization of renewable energy resources with thermal generating units and storage technologies. He also performs due diligence reviews of new technology development, new projects, modifications and refurbishment of existing facilities, asset transactions, and condition and operational assessments.

EXPERIENCE

Mr. Ungate has over 35 years of experience in engineering and planning for electric utilities. His most recent utility planning assignments since joining Sargent & Lundy in 2006 include:

- **Long Island Power Authority, 2014**
  - Sargent & Lundy is assisting the Long Island Power Authority (LIPA) in the evaluation and selection of bids for new generation, energy storage and demand response bids

submitted to LIPA under terms of a November 2013 Request for Proposals (RFP). The assignment includes development of an evaluation model; handling of bid administration; screening for responsiveness of bids to RFP requirements; a quantitative and qualitative assessment of responsive proposals to identify a short list; detailed quantitative and qualitative technical, economic and financial analyses of short listed bids; and formulation of recommendations for LIPA decision making.

- **PJM Interconnection, 2013-14**
  - Sargent & Lundy is supporting The Brattle Group's review of PJM's Variable Resource Requirement (VRR) curve, which is an administratively determined representation of a demand curve for capacity used in the PJM Reliability Pricing Model auction. S&L's role is to estimate (a) total gross overnight capital costs including most owner's costs, all owner-furnished equipment, and all engineering procurement and construction (EPC) balance of plant costs; (b) a capital drawdown schedule to be used in calculating interest during construction in the capital budgeting model; (c) first-year fixed operations and maintenance (FOM) costs including staffing, asset management, and other annual fixed costs; and (d) performance data relevant for calculating cost of new entry and net energy revenues including plant heat rate and summer capacity rating.

- **ISO New England, 2013-14**
  - Sargent & Lundy is supporting The Brattle Group's development of the ISO New England's capacity demand curve proposal. S&L is supporting the selection of a reference technology, identifying key assumptions required to estimate the cost and performance of the reference technology in New England, and develop cost and performance estimates for the reference technology in local regions of ISO New England as necessary.

- **NIPSCO, 2013**
  - Sargent & Lundy developed cost and performance estimates for gas, coal, nuclear, renewable, storage and distributed generation technology alternatives to be evaluated in NIPSCO's Integrated Resource Plan (IRP) for 2014. Sargent & Lundy prepared a Technical Assessment Report that outlines the methodology and results. The report will be included in NIPSCO's submittal of its IRP to the Indiana Public Service Commission.

- **ACES, 2013**
  - Sargent & Lundy developed cost and performance information for new build natural gas fired generation options for use by ACES in supporting development of mid- to long-term power supply strategies with its members and customers. In addition to developing assumptions and estimating the cost and performance of each option for an assumed Midwest U.S. location, S&L will develop an approach for ACES's use in translating the cost estimates to other sites where ACES' members and customers are located.

- **New York Independent System Operator, 2007- present**
  - Estimated the cost of new entrant peaking units used in the updating of demand curves for the NYISO capacity market in 2007, 2010 and 2013. Estimated going

forward costs of existing generation used in determining need for market power mitigation. Estimated cost of new entry for proposed projects used to determine need for buyer side mitigation. Assisted in development of technical assessment process supporting a determination of whether a generator could transfer interconnection service rights when proposing to repower a generating unit.

- **ISO New England, 2013**
  - Sargent & Lundy partnered with The Brattle Group to estimate the Offer Review Trigger Prices used by ISO New England as part of its market mitigation process. S&L's scope was to estimate capital and O&M costs for several technologies in the New England states, including natural gas-fired simple and combined cycle plants, biomass, onshore and offshore wind and solar photovoltaic technologies.
- **Confidential Client**
  - Sargent & Lundy supported The Brattle Group with an evaluation of the feasibility of supply options proposed in response to a Request for Proposals. The feasibility analysis identified supply options that could be placed in service for a stringent near term commercial operation date.
- **Ontario Power Authority, 2013**
  - Sargent & Lundy partnered with NERA to develop a cost and performance estimate for a simple cycle, natural gas fired frame combustion turbine unit in the Southwest Greater Toronto Area (GTA) in the province of Ontario, Canada.
- **Maui Electric Company, 2012-13**
  - Conducted a Generation Asset Assessment Study to review the condition of Maui Electric's generating facilities and the impact of the expected changes in usage resulting from increasing amounts of intermittent renewable resources. Each unit's remaining useful life and performance was assessed given the expected operational demands. Operational and maintenance adjustments were proposed to maximize the performance and useful life of the units.
- **GenOn Energy, 2012**
  - Estimated the cost of new entrant peaking and combined cycle units in two PJM zones to support GenOn's comments on PJM's CONE pricing proposal. Made presentation to and answered questions from participants in FERC Settlement Conference held to develop an agreement on the value of CONE.
- **Grand Haven Board of Light and Power, Zeeland Board of Public Works, 2011-12**
  - Prepared individual Integrated Resource Plans for two Michigan municipal utilities as part of a single study. Parts of the study related to their location in Ottawa County Michigan were common to both utilities. Potential resource options included existing and new non-renewable generation facilities, renewable energy resources, energy conservation and demand reduction programs, and long-term power purchase agreements or shared ownership options in large economies-of-scale facilities. Risk analysis was performed to evaluate how portfolio options performed under varying fuel and market prices, and environmental regulatory scenarios.

- **NV Energy, 2011-12**
  - Developed simple and combined cycle natural gas fired capacity expansion options at six brownfield sites in Clark County, NV, to support development of the Integrated Resource Plan. Factors considered in the development of options included emissions, water availability, transmission constraints, natural gas availability, and the shape and amount of space available at the site.

- **SaskPower, 2011-12**
  - Supervised a review of corporate resource planning processes. Processes and work products were compared to state-of-the-art utility industry examples and gaps identified. Recommendations for process improvements were prepared.

- **Confidential Client, 2011**
  - Led a due diligence study of a potential investment in temporary power services to countries with developing economies based on diesel engine technology.

- **Seven States Power Corporation, 2011**
  - Reviewed the performance history, environmental and regulatory requirements, contractual agreements, and operations and maintenance activities and plans for two natural gas fired combined cycle plants in support of a potential acquisition.

- **Confidential Client, 2011**
  - Reviewed the operating history, environmental and regulatory requirements, and contractual agreements, and identified potential operational limitations, plant upgrades, and expected operating life for four coal or natural gas fired cogeneration plants in support of a potential transaction.

- **Confidential Client, 2010-11**
  - Led the preparation of a business plan for a client considering whether to develop a fleet of generating plants based on small modular nuclear reactor technology.

- **Tennessee Valley Authority, 2010**
  - Supported preparation of the Need for Power and Alternatives sections of the Integrated Resource Plan. Developed Need for Power and Alternatives sections for Environmental Impact Statements for Sequoyah Nuclear Plant Relicensing and Bellefonte Nuclear Plant Unit 1 that were prepared concurrently.

- **South Mississippi Electric Power Association, 2009-10**
  - Reviewed renewable energy alternatives for this G&T cooperative in anticipation of future Renewable Portfolio Standard requirements. Directed the evaluation of responses to an RFP for renewable energy and capacity.

- **New England Power Generators Association, 2010**
  - Estimated the cost of new entrant peaking units in New England for a NEPGA proposal to revise the basis for capacity payments in ISO-NE.

- **PSEG, 2009-10**
  - Developed the need for power and energy alternatives analyses to satisfy the NUREG 1555 requirements for Environmental Reports associated with an Early Site

Permit Application for a new nuclear plant project. Responded to NRC questions on need for power and alternatives at the environmental site audit. Prepared responses to Requests for Additional Information.

Prior to joining Sargent & Lundy, Mr. Ungate had over 30 years of experience at the Tennessee Valley Authority in a variety of engineering and planning assignments. Examples of assignments include the following:

- Directed supply planning for 30,000 MWs of nuclear, coal, gas, renewable, and hydro generation, and determined peak season power purchase requirements. Directed the preparation of power supply plans, and the valuation of capacity additions, major projects, product offerings, and bulk power transactions.
- Led environmental controls optimization study to determine least cost approach to meeting CAIR/CAMR requirements for TVA's 15,000 MW coal generation portfolio. Alternatives included mothballing of units; increased allowance purchases; modified capital improvement programs; re-powering; and replacement with capacity and energy purchases from gas-fired units.
- Directed business planning for portfolio of 109 conventional hydropower units at 29 sites and four pumped storage units. Portfolio supplies 10-15% of company sales with 5000 MWs of capacity. Developed a five year business plan to increase resources to facilitate the transition to a process management maintenance strategy, and to integrate plant modernization and automation projects to change technology and workflow at the plants.
- Directed the first reassessment of the operating policies of Tennessee Valley Authority reservoirs since the system was designed in the 1930's. Directed the development of an operating scheme that preserved hydropower value while improving summer lake levels for recreation and increasing minimum flows for water quality.

TESTIMONY AND REGULATORY FILINGS

Before the Federal Energy Regulatory Commission, Docket No. ER14-500-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: answer to protests that challenged its November 29, 2013, filing of Proposed Tariff Revisions to Implement Revised ICAP Demand Curves and a New ICAP Demand Curve for Capability Years 2014/2015, 2015/2016 and 2016/2017, filed January 7, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-___-000, Affidavit of Christopher D. Ungate on Behalf of ISO New England, re: Revisions to Forward Capacity Market Offer Review Trigger Price Provisions, filed December 11, 2013.

Before the Federal Energy Regulatory Commission, FERC Docket No. ER12-513-000, presented oral testimony on behalf of GenOn Energy, Inc., re: comments and limited protest of PJM Interconnection, LLC's December 1, 2011 filing of modifications to the Reliability Pricing Model incorporated in Attachment DD of PJM's Open Access Transmission Tariff, April 18-19, 2012; May 21, 2012; and June 20, 2012

Before the Federal Energy Regulatory Commission, Docket No. ER11-2224-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: compliance with the Commission's January 28, 2011 Order on the NYISO's filing proposing updated Installed Capacity Demand Curves for Capability years 2011/2012, 2012/2013, and 2013/2014, filed March 29, 2011.

Before the Federal Energy Regulatory Commission, Docket No. ER11-2224-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: answer to protests that challenged its November 30, 2010, filing proposing revised ICAP Demand Curves, filed January 4, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER10-787-___, ER10-50-____ and ER10-57-___, Affidavit of Christopher D. Ungate on Behalf of New England Power Generators Association, Inc., re: Responses to Issues Addressed in the Commission's Hearing Order on Forward Capacity Market Revisions and Related Complaints, filed July 1, 2010.

Before the Federal Energy Regulatory Commission, Docket No. ER08-____-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: support for Tariff Revisions to Implement Revised ICAP Demand Curves for Capability Years 2008/2009, 2009/2010 and 2010/2011, filed November 29, 2007.

Before the Federal Energy Regulatory Commission, Docket No. EL07-39-000, Affidavit of Christopher D. Ungate on Behalf of New York Independent System Operator, re: revised market rules for NYC Installed Capacity to address buyer and seller market power concerns, filed October 2, 2007.

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2014 PJM Variable Resource Requirement Parameter Review

At PJM's direction and having successfully earned the bid to perform the work, The Brattle Group conducted a review of Variable Resource Requirement curve parameters. The review was completed in compliance with the Section 5.10a of the PJM Tariff, which requires a quadrennial review of the three key parameters in the Variable Resource Requirement curve: the shape of the VRR curve, the Cost of New Entry, and the Energy and Ancillary Services offset methodology.

Brattle's preliminary findings were shared with PJM stakeholders in an April 29 special meeting of the MRC and Brattle's final reports and recommendations to PJM are posted on pjm.com

PJM has reviewed Brattle's analysis and recommendations and subsequently, has developed preliminary PJM staff recommendations. These recommendations will be the basis for discussion by stakeholders in the Capacity Senior Task Force in which PJM will seek to achieve consensus on modifications to the shape of the VRR Curve, CONE and E&AS. PJM's preliminary recommendations are posted on pjm.com.

The deadline for stakeholder consensus on recommendations is August 31, 2014, with a FERC filing deadline of October 1, 2014.

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Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM

With June 1, 2018 Online Date

PREPARED FOR

PJM Interconnection, L.L.C.

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May 15, 2014

This report was prepared for PJM Interconnection, L.L.C. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or Sargent & Lundy, or their clients.

The authors would like to thank PJM staff for their cooperation and responsiveness to our many questions and requests. We would also like to thank the PJM Independent Market Monitor for helpful discussions.

Table of Contents

Executive Summary

PJM Interconnection, L.L.C (PJM) retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review the Cost of New Entry (CONE) parameters and other elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff.[1] This report presents our estimates of the CONE parameters for consideration by PJM and stakeholders in advance of their upcoming capacity auctions. Our review of the other elements of RPM is presented separately, in a concurrently-released report, the "Third Triennial Review of PJM's Variable Resource Requirement Curve" ("2014 VRR Report").

CONE represents the first-year total net revenue (net of variable operating costs) a new generation resource would need in order to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. It is the starting point for estimating the *Net* Cost of New Entry (Net CONE). Net CONE is defined as the operating margins that a new resource would need to earn in the capacity market, after netting margins earned in markets for energy and ancillary services (E&AS).

Accurate estimates of CONE, E&AS, and ultimately Net CONE are critical to RPM meeting its objectives because they provide the benchmark prices that define the administratively-determined demand curve for capacity (*i.e.*, the variable resource requirements, or VRR, curves). Without accurate Net CONE estimates, the VRR curves cannot be expected to procure the target amounts of capacity needed to satisfy PJM's resource adequacy requirements. Net CONE values are also used to establish offer price screens for market mitigation purposes under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[2]

We developed CONE estimates for gas-fired simple-cycle combustion turbine (CT) and combined-cycle (CC) power plants in each of the five administrative CONE Areas, with an assumed online date of June 1, 2018. Our estimates are based on complete plant designs reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. For both the CT and CC plants, we specify two GE 7FA turbines, with the CC equipped with a single heat recovery steam generator and steam turbine ("2×1 configuration"), cooling towers, and supplemental duct-firing capacity. All plants have selective catalytic reduction (SCR) for controlling NO_x. Most have dual-fuel capability except in the Rest of RTO Area, where actual projects have generally not been designed with dual-fuel capability (however, we also provide an alternative estimate with dual fuel at PJM's request following the gas delivery challenges experienced this past winter). CCs in the Southwestern Mid-Atlantic Area Council (SWMAAC) Area are also assumed not to have dual-fuel capability, consistent with projects in development and an assumption that they pay for firm gas transportation service instead. There

1 PJM Interconnection, L.L.C. (2014). Open Access Transmission Tariff, effective date 1/31/2014, ("PJM 2014 OATT"), accessed 5/1/2014 from http://www.pjm.com/~/media/documents/agreements/tariff.ashx, Section 5.10 a.

2 PJM 2014 OATT, Section 5.14 h.

are no other major differences in plant specifications among regions, although plant capacities and heat rates vary regionally with elevation and with ambient summer conditions.

For each plant specified, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimated annual fixed operating and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. We then translated the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to earn its required return on and of capital, assuming an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant investor, which we estimated based on various reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.8% at a 7% cost of debt and a 60/40 debt-to-equity capital structure.

Table 1 shows the resulting CONE values for CT plants in each CONE Area. We present the CONE estimates on both a "level-real" basis (a lower year-one cost recovery amount, assuming future contributions to cost recovery increase with inflation) and on a "level-nominal" basis (a higher year-one cost recovery requirement, assuming future contributions to cost recovery do *not* increase with inflation). As discussed in our 2014 VRR Report, we recommend that PJM transition from level-nominal to level-real CONE values. However, the following paragraphs discuss CONE in level-nominal terms to facilitate comparison to current parameter values.

Our CONE estimates vary by CONE Area due to differences in plant configuration and performance assumptions, labor rates, property tax laws, and other locational differences in capital and fixed O&M costs. The Eastern Mid-Atlantic Area Council (EMAAC) and SWMAAC Areas have the highest CT CONE estimates at $150,000/MW-year and $148,400/MW-year, respectively. Their higher CONE values reflect significantly higher labor costs in EMAAC and high property taxes in SWMAAC that are based on all property, not just land and buildings. The Western Mid-Atlantic Area Council (WMAAC) and Dominion Areas have the next highest CONE values of $143,500/MW-year and $141,200/MW-year, respectively. The Rest of RTO Area has the lowest CONE value of $138,000/MW-year due to the assumed absence of dual-fuel capability (consistent with observed development efforts) and lower labor costs. Under PJM's alternative assumption that future entrants there will invest in dual-fuel capability, the CT CONE value increases to $147,500.

Table 1 also compares these CT CONE estimates to two reference points: PJM's current parameters for the 2017/18 capacity auction and Brattle's prior estimates for the 2015/16 delivery year from its 2011 PJM CONE Study.[3] To produce a meaningful comparison, we show these reference points escalated to 2018 at 3% per year. As shown, our estimates are similar to the Brattle 2015/16 values, except in SWMAAC and Dominion where updated property tax calculations and labor costs contribute to increasing the CONE values by 9% and 15%, respectively. Our estimates in those

[3] Spees, Kathleen, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, (2011). *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM*, August 24, 2011, ("2011 PJM CONE Study"), available at http://www.pjm.com/documents/reports.aspx.

CONE Areas are closer to the PJM 2017/18 parameters (which are higher than the Brattle 2015/16 values largely because they were escalated from prior settlement values using a Handy-Whitman index that has risen significantly faster than actual plant costs, as noted in our 2014 VRR Report). In the other CONE Areas (EMAAC, Rest of RTO, and WMAAC), our estimates are lower than the 2017/18 parameters. Overall, our estimates are within -8% to +6% of PJM's current parameters, depending on the Area.

Table 1
Recommended CT CONE for 2018/19

		CONE Area				
		1 EMAAC	2 SWMAAC	3 RTO	4 WMAAC	5 Dominion
Gross Costs						
Overnight	*($m)*	$400	$373	$348	$372	$364
Installed	*($m)*	$420	$391	$364	$390	$382
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**
Unitized Costs						
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Table 2 shows the recommended CONE estimates for CC plants in each CONE Area, with comparisons to prior CONE values. EMAAC has the highest CONE estimates at $203,900/MW-year due to labor costs that are higher than the rest of PJM. SWMAAC and WMAAC have the next highest CC CONE estimates at $197,200/MW-year and $190,900/MW-year, respectively. The CONE

Areas with the lowest values are Rest of RTO (due to the lack of dual fuel) at $188,100/MW-year, and Dominion (as it has the lowest labor costs) at $182,400/MW-year. Under PJM's alternative assumption that future entrants will invest in dual-fuel capability in the Rest of RTO Area, the CC CONE value there increases to $193,700.

Compared to the Brattle 2015/16 values, the current CC CONE estimates are higher across all CONE Areas due to higher estimated costs of EPC contingency, owner's project development costs, and plant O&M costs. While the EPC contract costs increased in all Areas, the SWMAAC and Dominion values increased more due to higher estimated labor costs than in the previous analysis, as we found the prevailing wages in those regions include both union and non-union labor, whereas the previous analysis assumed strictly non-union labor.

Table 2
Recommended CC CONE for 2018/19

		CONE Area				
		1 EMAAC	2 SWMAAC	3 RTO	4 WMAAC	5 Dominion
Gross Costs						
Overnight	*($m)*	$808	$707	$709	$737	$708
Installed	*($m)*	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**668**	**664**	**651**	**649**	**660**
Unitized Costs						
Overnight	*($/kW)*	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	10%	18%	6%	7%	14%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

The updated CC CONE values have increased over the prior estimates more than the CT CONE values have, leading to a higher cost premium for CCs of $41,000–54,000/MW-year compared to $27,000-43,000/MW-year in our prior study. The most significant driver for the greater CC CONE increase is the relative difference in plant O&M costs estimated by S&L compared to the previous analysis. Fixed O&M costs decreased for CTs (with a larger fraction treated as variable costs) but increased for CCs. This difference explains approximately two-thirds of the increase in the CC premium over CTs. The rest of the difference is explained by higher labor rates and contingency and project development factors than in the prior study, which add more dollars to the cost of the more capital-intensive CC than the CT. In the Dominion CONE Area, the addition of the SCR to the CT largely offsets these differences.

The Brattle authors and Sargent & Lundy (S&L) collaborated in completing the CONE analysis and preparing this study. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M, and major maintenance costs and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

I. Introduction

A. Background and Objective

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which Variable Resource Requirement (VRR) curves set the "demand." The VRR curves are determined administratively based on a design objective to procure sufficient capacity for maintaining resource adequacy in all locations while also mitigating price volatility and susceptibility to market power abuse. To procure sufficient capacity, the VRR curves' price-quantity combinations are established to be consistent with the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at the Net Cost of New Entry (Net CONE). Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected energy and ancillary services margins) to recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. Thus, the sloped demand curve is assigned a price equal to Net CONE at approximately the point where the quantity equals the desired average reserve margin.[4] VRR curve prices are higher at lower reserve margins and lower at higher reserve margins, but all price points on the curve are indexed to Net CONE.

Just prior to each three-year forward auction, PJM determines Net CONE values for each of five CONE Areas, which are used to establish VRR curves for the system and for all Locational Deliverability Areas (LDAs). PJM calculates Net CONE for a defined "reference resource" by subtracting its estimated one-year energy and ancillary services (E&AS) net revenues from its estimated Cost of New Entry (CONE). CONE values are determined through triennial CONE studies (or litigated settlements), with escalation rates applied to the subsequent two auctions.[5] PJM separately estimates net E&AS revenue offsets annually for setting the Net CONE in each auction.

PJM has traditionally estimated CONE and Net CONE based on a gas-fired simple-cycle combustion turbine (CT) as the reference technology. However, as we explain in the concurrently-released 2014 VRR Report, we recommend defining the VRR curve based on the average Net CONE of a CT and a gas-fired combined-cycle gas turbine (CC).[6] If PJM and stakeholders accept this recommendation, they will need estimates for both a CT and a CC in setting the VRR curve. If they do not, PJM will still need both estimates for calculating offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[7]

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4 The exact quantity on the VRR curve where the price equals Net CONE is actually 1% above the IRM reliability requirement in order to reduce the likelihood of deficient outcomes. However, our concurrently-released VRR Curve report finds that even with this adjustment, the existing VRR curve is likely to fall short of reliability objectives. For more details, see 2014 VRR Report.

5 PJM 2014 OATT, Section 5.10 a.

6 2014 VRR Report.

7 PJM 2014 OATT, Section 5.14 h.

We were asked to assist PJM and stakeholders in this triennial review by developing CONE estimates for new CT and CC plants in each of the five CONE Areas. In this study, we define the CT and CC reference technologies and estimate their CONEs in the five CONE Areas.

B. Analytical Approach

Our analytical starting point for estimating CONE is a detailed characterization of the CC and CT plants in each CONE Area to reflect the technologies, plant configurations, and locations where developers are most likely to build. While the turbine technology for each plant is specified in the tariff (GE 7FA), we provide a review of the most recent gas-fired generation projects in PJM and the U.S. to determine whether this assumption is still relevant to the PJM market.[8] The key configuration variables we define for each plant include the number of gas and steam turbines, NO_x controls, duct firing and power augmentation, cooling systems, dual-fuel capability, and gas compression. We selected specific plant characteristics based on: our analysis of the predominant practices among recently-developed plants; our analysis of technologies, regulations, and infrastructure; and our experience with previous projects. Key site characteristics include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant locations and technical specifications for each CONE Area is presented in Section II.

We developed comprehensive, bottom-up estimates of the costs of building and maintaining the specified plants in Section III. S&L estimated *plant proper* capital costs—equipment, materials, labor, and EPC contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the *owner's* capital costs, including gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component.

We estimated annual fixed operations and maintenance (fixed O&M) costs, including labor, materials, property tax, insurance, asset management costs, and working capital. The results of this analysis are presented in Section IV.

Next, we translated these costs into the capital and fixed cost recovery the plant would have to earn in its first year, which we call the "Cost of New Entry" ("CONE"). CONE depends on the estimated capital and fixed O&M costs as well as the estimated cost of capital consistent with the project's risk and the assumed economic life of the asset. CONE also depends on developers' long-term market view and how it impacts the cost recovery path for the plant, specifically whether they can expect to earn as much in later years as in earlier years. We present our financial assumptions for calculating CONE in Section V.

Finally, in Section VI, we offer CONE calculations based on two different assumed cost recovery paths: one in which future revenues are assumed to remain constant in real-terms, which we recommend, as explained in our 2014 VRR Report; and one in which future revenues are assumed to

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[8] PJM, *PJM Manual 18: PJM Capacity Market*, Revision: 22, p. 21.

remain constant in nominal terms, which PJM has historically assumed. The level-real assumption results in lower CONE values.

The Brattle authors and Sargent & Lundy collaborated on completing this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

II. Determination of Reference Technologies

Similar to the 2011 PJM CONE Study, we determined the characteristics of the reference technology primarily based on a "revealed preferences" approach that relies on our review of the choices that actual developers found to be most feasible and economic. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional review of the underlying economics, regulations, and infrastructure, and S&L's experience. For selecting the reference technology location within each CONE Area, we modified our analysis from the 2011 PJM CONE Study to take into account a broader view of potential sites that can be considered feasible and favorable for new plant development. As the basis for determining most of the selected reference technology specifications, we updated our analysis from the 2011 study by examining CT and CC plants built in PJM and the U.S. since 2008, including plants currently under construction. We characterized these plants by size, plant configuration, turbine type, NO_x controls, CO catalyst, duct firing, dual-fuel capability, and cooling system.

A. Locational Screen

The Open Access Transmission Tariff (OATT) requires a separate CONE parameter in each of five CONE Areas as summarized in Table 3.[9]

Table 3
PJM CONE Areas

CONE Area	Transmission Zones	States
1 Eastern MAAC	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, DE
2 Southwest MAAC	BGE, PEPCO	MD, DC
3 Rest of RTO	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL	WV, VA, OH, IN, IL, KY, TN, MI
4 Western MAAC	MedEd, Penelec, PPL	PA
5 Dominion	Dominion	VA, NC

[9] PJM 2014 OATT, Section 5.10 a.

We conducted a locational screening analysis to identify feasible and favorable locations for each of the five CONE Areas. Our approach for identifying the representative locations within each CONE Area included three steps:

1. We identified candidate locations based on revealed preference of actual plants built since 2002 or recently proposed plants to identify the areas of primary development, putting more weight on recent projects.

2. We sharpened the definition of likely areas for future development, depending on the extent of information available from the first step. For CONE Areas where recent projects provide a clear signal of favored locations, we only excluded counties that would appear to be less attractive going forward, based on environmental constraints or economic costs (absent special offsetting factors we would not know about). For CONE Areas where revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices

3. This approach results in identifying a specified area that spans a wider range of counties than the previous CONE study. For this reason, we developed cost estimates for each CONE Area by taking the average of cost inputs (*e.g.*, labor rates) across the specified locations.

We describe next the results of the screening analysis that we used for determining the reference plant locations in each CONE Area. The locations chosen for each CONE Area are shown in Figure 1. To provide a more detailed description of the specified locations, we show the cities used for estimating labor rates in Table 4.

Our review of recent development in CONE Area 1 Eastern MAAC (EMAAC) resulted in identifying two areas where significant development has occurred since 2002. The first area is in northern New Jersey along the I-95 corridor, where four plants have been built since 2002, including the 2012 Kearny peaking facility, and three additional CC plants are in the planning phase. The second area includes Philadelphia and the southernmost New Jersey counties, where two CC plants have been built and three additional facilities are in the planning phase. With significant development in both areas and no reason for excluding either due to environmental or economic reasons, we include both as our reference locations.

In CONE Area 2 Southwest MAAC (SWMAAC), four new projects are in various stages of development (three CCs and one CT) in the area around Waldorf, Maryland including portions of Charles and Prince George's counties. Despite the strong indication of developers' preferences to build in this area, limits on the existing gas infrastructure are expected to create gas supply challenges that will be addressed in the cost estimation section of this study. There is limited development in the rest of the region.

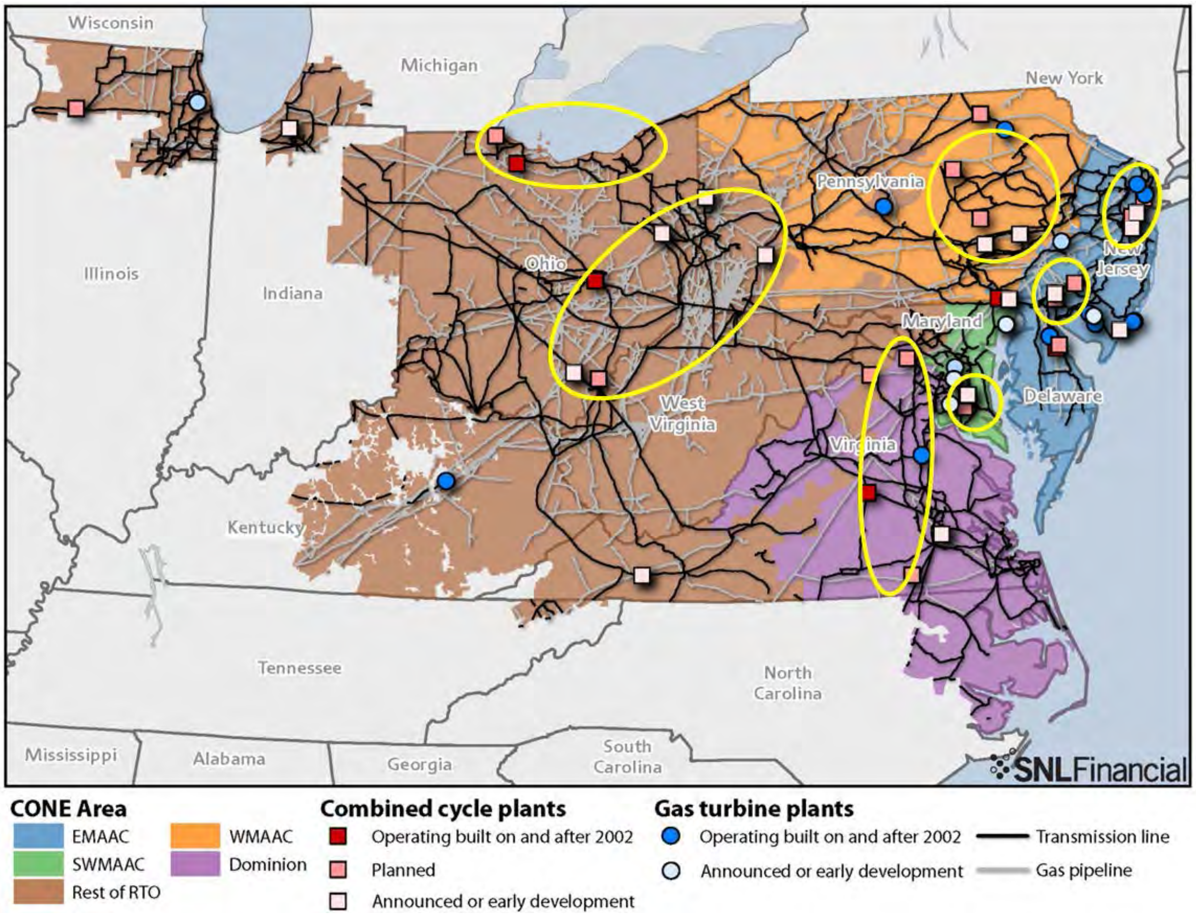
For the larger CONE Area 3 Rest of RTO CONE Area, the revealed preferences approach indicated three favored areas based on our review of recently built or in-development plants: northern Illinois, northwest Ohio, and the Pennsylvania, Ohio, and West Virginia portions of the Ohio River valley.

Further analysis resulted in excluding northern Illinois due to relatively low energy revenues and high labor costs, which disfavor this area relative to the others identified. For these reasons, we chose the counties in northwest Ohio and the Ohio River valley region for estimating costs in the Rest of RTO Area.

In CONE Area 4 **Western MAAC (WMAAC)**, developers have demonstrated a willingness to build primarily in mid-eastern Pennsylvania, including areas around Allentown, Scranton, and Lancaster. Projects include the Mehoopany peaking facilities added in 2013 and five CC facilities in different planning stages within this region. We found no reasons to narrow or expand the specified area further.

In CONE Area 5 **Dominion**, we identified two promising areas, one with several operating plants (in north-central Virginia) and the other with two proposed plants (south-central Virginia), both of which appear to meet developers' gas and electric infrastructure needs. We expanded the region considered to include both areas as well as the counties in between, which amounts to the counties along and just west of I-95 in Virginia.

Figure 1
Results of Locational Screening for each CONE Area



Source:
Map provided by SNL Financial
Data on operating and planned projects downloaded from SNL Financial between November 2013 and March 2014.

Table 4
CONE Area Labor Pools

CONE Area				
1 EMAAC	**2 SWMAAC**	**3 Rest of RTO**	**4 WMAAC**	**5 Dominion**
Jersey City, NJ	Washington, DC	Pittsburgh, PA	Reading, PA	Petersburg, VA
Newark, NJ	Annapolis, MD	New Castle, PA	Williamsport, PA	Richmond, VA
Camden, NJ	Alexandria, VA	Steubenville, OH	Wilkes-Barre, PA	Alexandria, VA
New Brunswick, NJ		Cleveland, OH		
Newark, DE		Lorain, OH		
Wilmington, DE		Toledo, OH		
Philadelphia, PA		Wheeling, WV		
		Parkersburg, WV		
		Huntington, WV		

We calculate the plant operating characteristics (*e.g.*, net capacity and heat rate) of the reference technologies using turbine vendors' performance estimation software for the combustion turbines output and GateCycle software for the remainder of the CC plant. For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[10] The assumed ambient conditions for each location are shown in Table 5.

Table 5
Assumed PJM CONE Area Ambient Conditions

CONE Area	Elevation (ft)	Max. Summer Temp (deg F)	Relative Humidity (%RH)
1 Eastern MAAC	110	94.0	44.2
2 Southwest MAAC	150	95.2	45.2
3 Rest of RTO	1,070	89.5	50.2
4 Western MAAC	1,200	91.0	46.0
5 Dominion	390	93.7	47.2

Source:
Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

B. Plant Size, Configuration and Turbine Model

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7FA as the turbine model), we provide a review of the most recent gas-fired generation projects in PJM and the U.S. to confirm this assumption.[11] We reviewed CT and CC projects built or currently proposed in PJM and across the U.S. to determine the configuration, size, and turbine types for the reference technologies.

10 The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition, Dordrecht, Holland: D. Reidel Publishing Company, 1981.

11 PJM 2014 OATT, Attachment DD, Section 2, see definition for Reference Resource.

For the CT, we found that frame-type CTs (GE 7FA and Siemens-501) have been the predominant turbine types built in PJM and throughout the U.S. since 2002, as shown in Table 6. We also found a recent trend toward aeroderivative turbines (GE LMS100 and LM6000). The total capacity of new aeroderivative turbines built in PJM since 2008 is approximately the same as frame-type turbines over the same time period.

Table 6
Turbine Model of CT Turbines Built and Under Construction in PJM and the U.S.

Turbine Model	Turbine Class	Online After 2002				Online After 2008			
		PJM		U.S.		PJM		U.S.	
		(count)	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*	*(count)*	*(MW)*
General Electric-7FA	Frame	31	4,807	105	16,132	3	481	16	2,518
General Electric-LM6000	Aeroderivative	11	1,615	27	4,088	7	317	80	3,669
General Electric-LMS100	Aeroderivative	15	1,165	135	10,057	3	273	28	2,606
Rolls Royce Corp-Trent 60	Aeroderivative	2	148	13	853	2	120	4	225
Siemens-501	Frame	22	949	198	8,784	0	0	0	0
Siemens-V84	Frame	3	273	29	2,688	0	0	0	0
General Electric-7EA	Small Frame	2	120	4	225	0	0	10	742
General Electric-MS6001	Small Frame	9	1,179	16	1,903	0	0	0	0

Source:
Data downloaded from Ventyx's *Energy Velocity Suite* between November 2013 and March 2014

We find that the frame-type GE 7FA turbine to be a reasonable choice for the PJM CT reference technology as it is the turbine model that has been built the most in PJM since 2008 and has a lower turbine cost per-kilowatt than the aeroderivative models. While we believe the turbine model should change if the market reveals such a preference, we do not find a basis to make a change in turbine model for PJM in the current study from the tariff specification. The reference CT plant configuration is assumed to have two turbines at one site (a "2×0") to capture savings from the economies of scale, which is also consistent with the tariff. We specify the CT reference technology capacity and heat rate in the CONE Areas based on the local conditions assumptions in Table 5, with the CT capacities ranging from 395 to 411 MW.

For the CC reference technology, the predominant size of recently developed CC plants is 500 to 700 MW (including duct firing capacity, if any), primarily in a 2×1 configuration, as shown in Table 7.

Table 7
PJM CC Under Construction or Built

(a) Since 2002

	< 300 *(MW)*	**300-500** *(MW)*	**500-700** *(MW)*	**700-900** *(MW)*	**> 900** *(MW)*	**Total** ***(MW)***
1 x 1	1,902	1,839	0	0	0	**3,741**
2 x 1	42	466	11,186	700	0	**12,394**
3 x 1	198	0	2,240	3,060	2,255	**7,754**
Total	**2,141**	**2,305**	**13,426**	**3,760**	**2,255**	**23,888**

(b) Since 2010

	< 300 *(MW)*	**300-500** *(MW)*	**500-700** *(MW)*	**700-900** *(MW)*	**> 900** *(MW)*	**Total** ***(MW)***
1 x 1	762	1,839	0	0	0	**2,601**
2 x 1	0	0	2,446	700	0	**3,146**
3 x 1	0	0	545	0	1,329	**1,874**
Total	**762**	**1,839**	**2,991**	**700**	**1,329**	**7,621**

Sources and Notes:

Data downloaded from Ventyx's Energy Velocity Suite between November 2013 and March 2014

The turbine model most often installed on recent CC plants is the GE 7FA, as shown in Table 8. The Siemens and GE turbines are similar designs that have both been competing for market share. While we find there are reasons to use either turbine manufacturer, we selected the GE 7FA for the PJM CONE due to its previous use in estimating CONE in PJM. Based on the local ambient condition assumptions in Table 5, we specify the 2×1 CC reference technology's summer capacity to range from 576–595 MW (prior to considering supplemental duct firing, as discussed in the next section).

Table 8
Turbine Model of CC Plants Built and Under Construction Combined Cycle Plants in PJM Online Since 2002

Turbine Model	Installed Capacity *(MW)*
General Electric 7FA	12,977
Siemens V84.2	2,240
Siemens SGT6-8000H	1,530
Siemens AG-501F	1,433
Mitsubishi M501GAC	1,329
Siemens SCC6-5000F	975
General Electric 7FB	758
Simens 501FD	559
General Electric Other	198
Other	1,889

Sources and Notes:
Data downloaded from Ventyx's Energy Velocity Suite between November 2013 and March 2014

We considered whether a flexible CC design, such as the GE Flex60, should be specified as the configuration of the CC reference technology. Our review of the performance of the conventional packages versus the flexibility package found that the benefits of the improved flexible design are largely offset by its incremental costs, such that the Net CONE calculation for the conventional and flexible designs would likely be similar. In addition, there is limited data available for accurately calculating either the capital costs or the E&AS revenues of the flexible design due to its recent introduction into the market. For these reasons, we assumed a conventional plant design for the CC. If the flexible design continues to be considered and built by developers in the next several years, PJM could consider using such a design in future CONE updates.

C. Detailed Technical Specifications

1. Combined Cycle Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and S&L recommendation. Our review of EIA-860 data found that all CC plants with a specified cooling system had a cooling tower installed, as shown in Table 9.

Table 9
Cooling System for CC Plants in PJM Under Construction or Built Since 2008

State	Once-Through *(MW)*	Cooling Tower *(MW)*	Dry Cooling *(MW)*	Unknown *(MW)*
Pennsylvania	0	545	0	126
Virginia	0	589	0	1,329
New Jersey	0	1,350	0	0
Delaware	0	309	0	62
Ohio	0	1,207	0	0
Illinois	0	0	0	573
Indiana	0	0	0	0
Total	**0**	**4,001**	**0**	**2,091**

Sources and Notes:

Based on 2012 Form EIA-860 Data; cooling tower includes recirculating with forced, induced and natural cooling towers.

We reviewed whether reclaimed water from municipal waste treatment centers would be available for use in the cooling systems to avoid environmental issues with withdrawing fresh water. Our review of the availability of reclaimed water indicated that EMAAC and SWMAAC have at least one treatment center per county, such that reclaimed water can be considered generally available. In WMAAC and Dominion, we found that reclaimed water can be available on a site-specific basis. Although not every county has such a facility, we assume reclaimed water is prevalent enough for the reference technology to use reclaimed water in each of these CONE Areas. For the Rest of RTO Area, municipal waste treatment facilities are much less common such that withdrawals from ground or surface water would be necessary. In addition to environmental drivers for using reclaimed water, building the piping and treatment facilities required for ground or surface water costs $500k to $1 million more than for reclaimed water, depending on the location.

2. Combined-Cycle Duct Firing

For the reference CC plant, supplemental firing of the steam generator, also known as "duct firing," increases steam production and hence increases the output of the steam turbine. Duct firing is common, although there is no standard optimized design. The decision to incorporate supplemental firing with the plant configuration and the amount of firing depends on the owner's preference and perceived economic value.

We assumed the reference CC plant would add duct firing sufficient to increase the net plant capacity by 73 MW, or 12%. This is close to the average of CC plants constructed since 2002 or in development in the U.S. but less than in PJM, as shown in Table 10. Due to the relatively small number of plants built in PJM since 2002, we chose to weigh the U.S. value more heavily.

Table 10
Duct-Firing Capability of CC Plants Constructed Since 2002 and In Development

	Installed Capacity *(MW)*	No. of Plants *(count)*	Avg. Plant Size *(MW)*	Avg. Duct Fired Capacity *(MW)*	Duct Fired Addition % *(%)*
PJM	2,020	3	673	93	16%
U.S.	35,865	56	640	77	14%

Sources and Notes:
Data on duct firing capacities for CC plants downloaded from Ventyx's Energy Velocity Suite in 2014

Including duct firing increases the net capacity of the plant but reduces efficiency due to the higher incremental heat rate of the supplemental firing (when operating in duct firing mode) and the reduced efficiency of steam turbine (when not operating at full output). The estimated heat rates and capacities take account for this effect.

3. Power Augmentation

Based on our analysis in the 2011 PJM CONE Study, we included evaporative coolers downstream of the filtration system to lower the combustion turbine inlet air temperature during warm weather operation. This increases turbine output and efficiency for only a small increase in capital cost. In addition, the combustion turbines in both simple- and combined-cycle arrangements are equipped with an inlet filtration system to protect from airborne dirt and particles. Evaporative coolers and associated equipment add $3 million per combustion turbine to the capital costs.

4. Emissions Controls

Emission control technology requirements for new major stationary sources are determined through the New Source Review (NSR) pre-construction permitting program. The NSR permitting program evaluates the quantity of regulated air pollutants the proposed facility has the potential-to-emit and determines the appropriate emission control technology/practice required for each air pollutant. The regulated air pollutants that will have the most impact on emission control technology requirements for new CTs and CCs are nitrogen oxides (NO_x) and carbon monoxide (CO).

NO_x and CO emissions from proposed gas-fired facilities located in PJM will be evaluated through two different types of NSR permitting requirements:

- Non-attainment NSR (NNSR) for NO_x emissions; and
- Prevention of Significant Deterioration (PSD) for CO emissions.

NO_x emissions are evaluated through the NNSR permitting requirements, because NO_x (a precursor to ozone) is treated as a non-attainment air pollutant for all areas within the Ozone Transport Region

(OTR) regardless of ozone attainment status.[12] Except for Rest of RTO, all of the CONE Areas in PJM are within OTR, and thus, emissions of NO_x from proposed facilities are treated as a non-attainment air pollutant and evaluated through non-attainment new source review (NNSR). The Rest of RTO is currently non-attainment for 8-hour ozone.

New CTs and CCs with no federally enforceable restrictions on operating hours are deemed a major source of NO_x emissions, and therefore, trigger a Lowest Achievable Emission Rates (LAER) analysis to evaluate NO_x emission control technologies. The NO_x emission control technology required by the LAER analysis is likely to be a selective catalytic reduction (SCR) system. SCR systems are widely recognized as viable technology on aeroderivative and smaller E-class frame combustion turbines and have more recently been demonstrated on F-class frame turbines. Our assumptions of an SCR on the F-class turbine is supported by the Commission's recent determination in approving the NYISO's assumption of F-class turbine with SCR as the proxy unit for its proposed Demand Curves that "the record of evidence presented in support of the frame unit with SCR is adequate in order to find that NYISO reasonably concluded that the F class frame with SCR is a viable technology."[13] In addition, we assume inlet air filters and dry low NO_x burners, which are also necessary to achieve the required emissions reductions.

CO emissions are evaluated through the PSD permitting requirements, because PJM is designated as an attainment area for CO. New combustion turbine facilities with no operating hour restrictions have the potential-to-emit CO in a quantity that exceeds the significant emission threshold for CO, and therefore, trigger a Best Available Control Technology (BACT) analysis to evaluate CO emission control technologies. The CO emission control technology required as a result of a BACT analysis is likely to be an oxidation catalyst (CO Catalyst) system.

For these reasons, we assume an SCR and a CO Catalyst system as the likely requirements resulting from the NSR permitting program for new gas-fired facilities proposed in all CONE Areas. The most significant change from the 2011 PJM CONE Study is assuming an SCR on the CT in Dominion, which is being added due to additional consideration of the regulatory requirements of being located in the Ozone Transport Region. The CO Catalyst system in all areas is expected to increase costs of emissions control equipment by $2.4 million (in 2014 dollars) over the 2011 CONE study.

5. Dual Fuel Capability, Firm Gas Contracts, and Gas Compression

We largely maintained our assumption from the 2011 PJM CONE Study that the reference CT and CC plants would install dual-fuel capability in all CONE Areas except for the Rest of RTO Area, based on a review of recent projects. The Rest of RTO Area is assumed to be single-fuel, although at PJM's request we also calculated CONE estimates for Rest of RTO with dual-fuel capability in Section VI).

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12 The Ozone Transport Region (OTR) includes all of New England as well as Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and portions of Virginia.

13 Federal Energy Regulatory Commission (2014). Order 146 FERC ¶ 61,043, Issued January 28, 2014, at paragraph 58. Docket No. ER14-500-000.

Our assumptions have changed only for CCs in SWMAAC, where we do not assume dual fuel, consistent with the CPV St. Charles project under development there.[14] Instead, we assume firm transportation service on the Dominion Cove Point (DCP) pipeline. We understand from shippers that the DCP pipeline is capacity-constrained and also has limited operational flexibility. Firm transportation avoids interruptions, although it may not provide additional operational flexibility. Firm transportation also largely eliminates the value of dual-fuel capability (except when the three major interstate pipelines to which the DCP pipeline is connected become constrained). However, we do not assume firm transportation for the reference CT plant since firm gas is unlikely to be economic for a plant that operates at a low capacity factor. We assume the CT will have dual-fuel capability.

To be capable of firing gaseous and liquid fuels, the plants are assumed to be equipped with enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability also requires the combustion turbines to have water injection nozzles to reduce NOx emissions while firing liquid fuel. These modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The incremental cost is approximately $22 million for the CC and $24 million for the CT (in 2014 dollars), including equipment, labor, and materials, indirect costs, and fuel inventory.[15] That contributes approximately $9,500/MW-year to the CONE for the CT and $5,600/MW-year for the CC (in 2018 dollars and in level-nominal terms). For CCs in SWMAAC, firm transportation avoids these costs, but the firm transportation itself costs about twice as much, as discussed in Section IV.A.5.

Based on our analysis in the 2011 PJM CONE Study, we determined gas compression would not be needed for new gas plants with frame-type combustion turbines located near and/or along the major gas pipelines selected in our study. The frame machines generally operate at lower gas pressures than the gas pipelines.

6. Black Start Capability

Based on our analysis in the 2011 PJM CONE Study, we did not include black start capability in either the CC or CT reference units because few recently built gas units have this capability.

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14 Environmental Consulting & Technology, Inc. (2011), Demonstration of Compliance with Air Quality Control Requirements and Request for Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Approvals: CPV St. Charles Project, 725-MW Combined Cycle Project, Prepared for Competitive Power Ventures Maryland, LLC (CPV), ECT No. 110122-0200, August 2011.

15 The incremental cost of dual-fuel capability is higher for the CT due to the cost of the demineralized water package that is already assumed to be installed for the CC for its steam cycle.

7. Electrical Interconnection

While all CONE Areas have a variety of transmission voltages, both lower and higher than 345 kV, we selected 345 kV as the typical voltage for new CT and CC plants to interconnect to the transmission grid in PJM. The switchyard is assumed to be within the plant boundary and is counted as an EPC cost under "Other Equipment," including generator circuit breakers, main power and auxiliary generator step-up transformers, and switchgear. All other electric interconnection equipment, including generator lead and network upgrades, is included separately under Owner's Costs, as presented in Section III.B.4.

D. Summary of Reference Technology Specifications

Based on the assumptions discussed above, the technical specifications for the CT and CC reference technology are shown in Table 11 and Table 12. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 5.

Table 11
Summary of CT Reference Technology Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7FA.05
Configuration	2 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	396 / 393 / 385 / 383 / 391 *
Net Heat Rate (HHV in Btu/kWh)	10,309 / 10,322 / 10,297 / 10,296 / 10,317 *
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Dual / Dual / Single / Dual / Dual *
Firm Gas Contract	No
Special Structural Req.	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes:
See Table 5 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* Power ratings and heat rates are for EMAAC, SWMAAC, Rest of RTO, WMAAC, and Dominion CONE Areas, respectively

Table 12
Summary of CC Reference Technology Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7FA.05
Configuration	2 x 1
Cooling System	Cooling Tower *
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
w/o Duct Firing	595 / 591 / 578 / 576 / 587 **
with Duct Firing	668 / 664 / 651 / 649 / 660 **
Net Heat Rate (HHV in Btu/kWh)	
w/o Duct Firing	6,800 / 6,811 / 6,791 / 6,792 / 6,808 **
with Duct Firing	7,028 / 7,041 / 7,026 / 7,027 / 7,039 **
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Dual / Single / Single / Dual / Dual **
Firm Transportation Service	No / Yes / No / No / No **
Special Structural Req.	No
Blackstart Capability	None
On-Site Gas Compression	None

Sources and Notes:
See Table 5 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* CONE Area 3 uses ground/surface water; all others use reclaimed water for cooling
** For EMAAC, SWMAAC, Rest of RTO, WMAAC, and Dominion CONE Areas, respectively

III. Capital Cost Estimates

Capital costs are those costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs, include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2014 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct simple and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost in 2018 dollars by escalating the 2014 cost data using reasonable escalation rates. The 2018 "installed cost" is the present value of the construction period cash flows as of the end of the construction period and is calculated using the monthly drawdown schedule and the cost of capital for the project.

A. Plant Proper Capital Costs

1. Plant Developer and Contractor Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

2. Equipment and Sales Tax

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. The major equipment includes "owner-furnished equipment" (OFE) that the owner purchases through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. A sales tax rate specific to each CONE Area is applied to the sum of major equipment and other equipment to account for the sales tax on all equipment.

3. Labor and Materials

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, and field engineering, start-up, and commissioning services. "Materials" include all construction material associated with the EPC scope of work, material freight costs, and consumables during construction.

The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, the labor rates have been developed by S&L through a survey of the prevalent wages in each region in 2014, including both union and non-union labor. This approach differs from the 2011 PJM CONE Study, in which a single assumption of the labor type was specified for each CONE Area. The change in determining wages and productivity rates results in higher labor costs in SWMAAC and Dominion, which were assumed to use strictly non-union labor in the 2011 study. The updated approach provides a better representation of the labor force that will include labor from both pools. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type.

4. EPC Contractor Fee and Contingency

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. Capital cost estimates include an EPC contractor fee of 10% and 12% of EPC costs for CT and CC facilities, respectively.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of EPC costs.

The EPC contractor fee and contingency rates are based on S&L's proprietary project cost database. The EPC contingency rate (10%) is higher than the value used in the 2011 PJM CONE study (4% contingency charged by the EPC, plus an additional 3% of EPC costs for change orders that was included as part of the Owner's Contingency) due to input received from stakeholders following the issuance of that study. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.6% of the pre-contingency overnight capital costs, compared to 6.4% in the 2011 study.

B. Owner's Capital Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

1. Project Development and Mobilization and Startup

Project development costs include items such as development costs, oversight, legal fees, and emissions reductions credits that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

2. Net Start-Up Fuel Costs During Testing

Before commencing full commercial operations, new generation plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas and ultra-lower sulfur diesel (ULSD) if dual fuel capability is specified. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas and fuel oil consumption, and will receive revenues for its energy production. We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume Transco Zone 6 Non-New York (Z6 NNY) prices apply for all CONE Areas; forecast Z6 NNY natural gas prices using traded futures on NYMEX (CME Group) until March 2015 and grow the basis differentials at the rate of inflation into 2018.
- **Fuel Oil:** rely on No. 2 fuel oil futures for New York harbor through January 2018; escalate fuel oil prices between January 2018 and an assumed fuel delivery date of March and April 2018 based on the escalation in Brent crude oil futures over the same date range.[16]
- **Electric Energy:** estimate prices based on PJM Eastern Hub for EMAAC, and PJM Western Hub for all other CONE Areas; calculate monthly 2015 market heat rates based on electricity and gas futures in each location and assume market heat rates remain constant to 2018; average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

[16] Data from Bloomberg, representing trade dates 12/22/2013 to 2/20/2014.

Table 13
Startup Production and Fuel Consumption During Testing

	Energy Production			Fuel Consumption						
	Energy Produced *(MWh)*	Energy Price *($/MWh)*	Energy Sales *($m)*	Natural Gas *(MMBtu)*	Natural Gas Price *($/MMBtu)*	NG Cost *($m)*	Fuel Oil *(MMBtu)*	Fuel Oil Price *($/MMBtu)*	Fuel Oil Cost *($m)*	Total Cost *($m)*
Gas CT										
1 Eastern MAAC	206,924	$42.3	$8.8	1,996,322	$5.49	$11.0	99,816	$17.9	$1.8	$4.0
2 Southwest MAAC	206,625	$38.7	$8.0	1,993,443	$5.49	$10.9	99,672	$17.9	$1.8	$4.7
3 Rest of RTO	190,360	$38.7	$7.4	1,928,726	$5.49	$10.6	n.a.	$17.9	$0.0	$3.2
4 Western MAAC	198,935	$38.7	$7.7	1,919,816	$5.49	$10.5	95,991	$17.9	$1.7	$4.6
5 Dominion	204,852	$38.7	$7.9	1,976,332	$5.49	$10.9	98,817	$17.9	$1.8	$4.7
Gas CC										
1 Eastern MAAC	691,621	$42.3	$29.3	3,958,589	$5.49	$21.7	197,929	$18.0	$3.6	-$4.0
2 Southwest MAAC	657,777	$38.7	$25.4	3,952,938	$5.49	$21.7	n.a.	$18.0	$0.0	-$3.7
3 Rest of RTO	639,138	$38.7	$24.7	3,824,235	$5.49	$21.0	n.a.	$18.0	$0.0	-$3.7
4 Western MAAC	668,436	$38.7	$25.8	3,806,568	$5.49	$20.9	190,328	$18.0	$3.4	-$1.5
5 Dominion	685,484	$38.7	$26.5	3,918,677	$5.49	$21.5	195,934	$18.0	$3.5	-$1.5

Sources and Notes:
Energy production and fuel consumption estimated by S&L
Energy and fuel prices are forecasted based on futures downloaded from Ventyx's Energy Velocity Suite in 2014

3. Gas Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 14. We identified appropriate lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs.[17]

We assume the gas interconnection will require a metering station and a five mile lateral connection, similar to 2011 PJM CONE Study. From this data, we estimate that gas interconnection costs will be $20.5 million (in 2014 dollars) for all plants, as we found no relationship between pipeline width and per-mile costs in the project cost data.

17 The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

Table 14
Gas Interconnection Costs

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(2014$)*	Pipeline Cost *($m/mile)*	Meter Station *(Y/N)*	Meter Station Cost *(2014m$)*
Delta Lateral Project	PA	2010	16	3.4	$9,944,085	$2.91	Y	$3.5
Carty Lateral Project	OR	2014	20	24.3	$52,032,000	$2.14	Y	$2.3
South Seattle Delivery Lateral Expansion	WA	2013	16	4.0	$13,788,201	$3.4	N	n.a.
Bayonne Delivery Lateral Project	NJ	2012	20	6.2	$13,891,136	$2.2	Y	$3.9
North Seattle Delivery Lateral Expansion	WA	2012	20	2.2	$11,792,028	$5.4	Y	$1.4
FGT Mobile Bay Lateral Expansion	AL	2011	24	8.8	$28,179,328	$3.2	Y	$2.6
Northeastern Tennessee Project	VA	2011	24	28.1	$133,734,240	$4.8	Y	$2.9
Hot Spring Lateral Project	TX,AR	2011	16	8.4	$34,261,849	$4.1	Y	$3.8
Average						**$3.5**		**$2.9**

Sources and Notes:

A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp)

4. Electric Interconnection

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs do not always occur, but are incurred when improvements, such as replacing substation transformers, are required.

In addition to the interconnection projects included in the 2011 PJM CONE study, we added projects recently constructed or under construction that are representative of interconnection costs for a new gas combined-cycle or combustion turbine. Table 15 summarizes the project costs used for estimating electric interconnection costs for this study. Based on the capacity-weighted average, electric interconnection cost is at approximately $12 million for CTs and $20 million for CCs, both expressed in 2014 dollars.

Table 15
Electric Interconnection Costs in PJM

Plant Size	Observations	Electrical Interconnection Cost Average	Electrical Interconnection Cost Average
	(count)	*(2014$m)*	*(2014$/kW)*
100-300 MW	5	$3.8	$26.7
300-500 MW	3	$11.3	$31.4
500-800 MW	13	$19.5	$30.9
Capacity Weighted Average	**21**	**$17.4**	**$30.0**

Sources and Notes:
Confidential project-specific cost data provided by PJM.

5. Land

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 20 acres for sale in each selected county. There is a wide range of prices within the same CONE Area as shown in Table 16, which means that land costs can vary significantly among plants.

Table 16
Current Land Asking Prices

CONE Area	Current Asking Prices Range	Current Asking Prices Observations
	(2013 $000/acre)	*(count)*
1 EMAAC	$10-$119	8
2 SWMAAC	$19-$150	10
3 RTO	$10-$100	22
4 WMAAC	$5-$100	14
5 Dominion	$13-$163	9

Sources and Notes:
We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

Table 17 shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location. We assume that 30 acres of land are needed for CT and 40 acres for CC.

Table 17
Cost of Land Purchased

CONE Area	Land Price (*$/acre*)	Plot Size		Cost	
		Gas CT (*acres*)	Gas CC (*acres*)	Gas CT (*$m*)	Gas CC (*$m*)
1 EMAAC	$66,300	30	40	$1.99	$2.65
2 SWMAAC	$73,900	30	40	$2.22	$2.96
3 RTO	$38,100	30	40	$1.14	$1.52
4 WMAAC	$41,600	30	40	$1.25	$1.66
5 Dominion	$54,300	30	40	$1.63	$2.17

Sources and Notes:
We assume land is bought in 2014, *i.e.*, 6 months to 1 year before the start of construction.

6. Fuel and Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel working capital is 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

We calculated the cost of the fuel inventory in areas with dual-fuel capability assuming a three day supply of ULSD fuel will be purchased prior to operation at a cost of $2.52/gallon, or $18/MMBtu (in 2018 dollars), based on current futures prices.[18]

7. Owner's Contingency

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* We assumed an owner's contingency of 9% of Owner's Costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

8. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are also part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs.[19]

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18 EIA, Electric Power Monthly, 2013.

19 As discussed in the Financial Assumptions section, we assume the plant is financed through a 60% debt and 40% equity capital structure.

C. Escalation to 2018 Installed Costs

1. Escalation

We escalated the 2014 estimates of overnight capital cost components forward to the construction period for a June 2018 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials and labor. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.25% (see Section V.A) to determine the nominal escalation rates, as shown in Table 18.

Table 18
Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.40%	2.65%
Labor	1.50%	3.75%

Sources and Notes:
Escalation rates on equipment and materials costs are derived from the relevant BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from 2014 overnight costs using the monthly capital drawdown schedule developed by Sargent & Lundy for an online date in June 2018.

However, we escalated several cost items in a different manner:

- **Land**: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2018 online date, the land is thus assumed to be purchased in late 2014 such that current estimates do not require any additional escalation.
- **Net Start-Up Fuel and Fuel Inventories**: no escalation was needed since we forecasted fuel and electricity prices in 2018 dollars.
- **Electric and Gas Interconnection**: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior completion, consistent with the 2011 CONE Study; the interconnection costs have been escalated specifically to these months.

2. Cost of Capital During Construction

S&L has developed monthly capital drawdown schedules over the project development period for each technology. The drawdown schedule is important for calculating debt and equity costs during construction to arrive at a complete "installed cost."

The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2018 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate.[20] By using the ATWACC to calculate the present value, the installed costs will include both the interest during construction from the debt financed portion of the project and the cost of equity for the equity financed portion.

[20] For CTs, the construction drawdown schedule occurs over 20 months with 80% of the costs incurred in the final 11 months prior to commercial operation. For CCs, the construction drawdown schedule occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation.

D. Capital Cost Summary

Based on the technical specifications for the reference CT and CC in Section II and the capital cost estimates in this section, a summary of the capital costs for an online date of June 1, 2018 is shown below in Table 19 and Table 20.

Table 19
Summary of Capital Costs for CT Reference Technology in Nominal $

	CONE Area				
	1	2	3	4	5
	EMAAC	SWMAAC	Rest of RTO	WMAAC	Dominion
Capital Costs (in $millions)	*396 MW*	*393 MW*	*385 MW*	*383 MW*	*391 MW*
Owner Furnished Equipment					
Gas Turbines	$98.8	$98.4	$94.0	$98.7	$98.6
SCR	$18.9	$18.7	$17.9	$18.8	$18.8
Sales Tax	$8.2	$7.0	$6.7	$7.1	$7.3
Total Owner Furnished Equipment	**$125.9**	**$124.1**	**$118.6**	**$124.6**	**$124.8**
EPC Costs					
Equipment	$30.9	$30.5	$25.5	$30.8	$30.7
Construction Labor	$71.7	$55.4	$55.3	$54.5	$48.2
Other Labor	$21.2	$19.6	$18.6	$19.6	$19.0
Materials	$9.7	$9.0	$8.6	$9.6	$9.4
Sales Tax	$2.8	$2.4	$2.0	$2.4	$2.5
EPC Contractor Fee	$26.2	$24.1	$22.9	$24.1	$23.5
EPC Contingency	$28.8	$26.5	$25.2	$26.6	$25.8
Total EPC Costs	**$191.4**	**$167.4**	**$158.1**	**$167.6**	**$159.2**
Non-EPC Costs					
Project Development	$15.9	$14.6	$13.8	$14.6	$14.2
Mobilization and Start-Up	$3.2	$2.9	$2.8	$2.9	$2.8
Net Start-Up Fuel Costs	$4.0	$4.7	$3.2	$4.6	$4.7
Electrical Interconnection	$13.0	$12.9	$12.7	$12.6	$12.9
Gas Interconnection	$22.6	$22.6	$22.6	$22.6	$22.6
Land	$2.0	$2.2	$1.1	$1.2	$1.6
Fuel Inventories	$5.3	$5.3	$0.0	$5.1	$5.2
Non-Fuel Inventories	$1.6	$1.5	$1.4	$1.5	$1.4
Owner's Contingency	$6.1	$6.0	$5.2	$5.9	$5.9
Financing Fees	$9.4	$8.7	$8.1	$8.7	$8.5
Total Non-EPC Costs	**$82.9**	**$81.4**	**$70.9**	**$79.6**	**$79.8**
Total Capital Costs	**$400.2**	**$372.9**	**$347.6**	**$371.8**	**$363.8**
Overnight Capital Costs ($million)	**$400**	**$373**	**$348**	**$372**	**$364**
Overnight Capital Costs ($/kW)	**$1,012**	**$948**	**$903**	**$971**	**$931**
Installed Cost ($/kW)	**$1,061**	**$994**	**$947**	**$1,018**	**$977**

Table 20
Summary of Capital Costs for CC Reference Technology in Nominal $

	CONE Area				
	1	**2**	**3**	**4**	**5**
	EMAAC	**SWMAAC**	**Rest of RTO**	**WMAAC**	**Dominion**
Capital Costs (in $millions)	*595 MW*	*591 MW*	*578 MW*	*576 MW*	*587 MW*
Owner Furnished Equipment					
Gas Turbines	$97.3	$92.6	$92.6	$97.2	$97.2
HRSG / SCR	$43.5	$43.5	$43.5	$43.5	$43.5
Sales Tax	$9.9	$8.2	$8.2	$8.4	$8.8
Total Owner Furnished Equipment	**$150.7**	**$144.3**	**$144.3**	**$149.1**	**$149.5**
EPC Costs					
Equipment					
Condenser	$4.2	$4.2	$4.2	$4.2	$4.2
Steam Turbines	$35.5	$35.5	$35.5	$35.5	$35.5
Other Equipment	$60.6	$55.9	$56.4	$60.4	$60.3
Construction Labor	$213.8	$162.1	$164.5	$168.2	$146.9
Other Labor	$45.1	$39.6	$39.9	$41.0	$39.1
Materials	$37.8	$37.8	$37.8	$37.8	$37.8
Sales Tax	$9.7	$8.0	$8.0	$8.3	$8.6
EPC Contractor Fee	$66.9	$58.5	$58.9	$60.6	$57.8
EPC Contingency	$62.4	$54.6	$54.9	$56.5	$54.0
Total EPC Costs	**$536.1**	**$456.2**	**$460.1**	**$472.5**	**$444.3**
Non-EPC Costs					
Project Development	$34.3	$30.0	$30.2	$31.1	$29.7
Mobilization and Start-Up	$6.9	$6.0	$6.0	$6.2	$5.9
Net Start-Up Fuel Costs	-$4.0	-$3.7	-$3.7	-$1.5	-$1.5
Electrical Interconnection	$22.0	$21.8	$21.4	$21.3	$21.7
Gas Interconnection	$22.6	$22.6	$22.6	$22.6	$22.6
Land	$2.7	$3.0	$1.5	$1.7	$2.2
Fuel Inventories	$6.1	$0.0	$0.0	$5.9	$6.0
Non-Fuel Inventories	$3.4	$3.0	$3.0	$3.1	$3.0
Owner's Contingency	$8.5	$7.4	$7.3	$8.1	$8.1
Financing Fees	$18.9	$16.6	$16.6	$17.3	$16.6
Total Non-EPC Costs	**$121.3**	**$106.7**	**$105.0**	**$115.8**	**$114.2**
Total Capital Costs	**$808.0**	**$707.2**	**$709.4**	**$737.4**	**$708.0**
Overnight Capital Costs ($million)	**$808**	**$707**	**$709**	**$737**	**$708**
Overnight Capital Costs ($/kW)	**$1,210**	**$1,065**	**$1,089**	**$1,137**	**$1,073**
Installed Cost ($/kW)	**$1,326**	**$1,168**	**$1,193**	**$1,245**	**$1,176**

IV. Operation and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed operations and maintenance (O&M) costs each year, including property tax, insurance, labor, consumables, minor maintenance, and asset management. Annual fixed O&M costs add to CONE. Separately, we also calculated *variable* operations and maintenance costs (including maintenance, consumables, and waste disposal costs) to inform PJM's future E&AS calculations.

A. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

1. Plant Operation and Maintenance

We estimated the labor, consumables, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including the Electric Power Research Institute (EPRI) State-of-the-Art Power Plant Combustion Turbine Workstation v 9.0 data for existing plants reported on FERC Form 1, confidential data from other operating plants, and vendor publications for equipment maintenance.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. We include monthly LTSA payments as fixed O&M since they are not based on the operation of the plant, and all other costs under the LTSA are considered variable O&M.

2. Insurance and Asset Management Costs

We calculated insurance costs as 0.60% of the overnight capital cost per year, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of CT and CC plants in operation.

3. Property Tax

To estimate property tax, we researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states. We estimated the property taxes through bottom-up cost estimates that separately evaluated taxes on real property (including land and structural improvements) and personal property (the remainder of the plant) in each location. In this study, we did not incorporate any assumed Payment in Lieu of Taxes (PILOT) agreements. Although PILOT agreements could be executed between an individual plant developer and a county, these agreements are individually negotiated and may not be available on a similar basis for all plants.

Real property is taxed in all states containing reference plant locations we selected for the CONE Area. Personal property is taxed only in SWMAAC (Maryland), Rest of RTO (the portion in Ohio), and Dominion (Virginia). For power plants, the value of personal property tends to be much higher than the value of real property, since equipment costs make up the majority of the total capital cost.

For this reason, property taxes for plants located in states that impose taxes on personal property will be significantly higher than plants located in states that do not.

To estimate real property taxes, we assumed the assessed value of land and structural improvements is the initial capital cost of these specific components. We determined assessment ratios and tax rates for each CONE Area by reviewing the publicly posted tax rates for several counties within the specified locations and by contacting county and state tax assessors (The tax rates assumed for each CONE Area is summarized in Table 21). We multiply the assessment ratio by the tax rate to determine the overall effective tax rate, and apply that rate to our estimate of assessed value. We assume that assessed value of real property will escalate in future years with inflation.

Personal property taxes in the states of Maryland, Ohio, and Virginia were estimated using a similar approach. As with real property, we multiply the local tax rate by the assessment ratio to determine the effective tax rate on assessed value. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years. For example, in Maryland, personal property is subject to straight-line depreciation of 3.3% per year down to a minimum of 25% of the original assessed value.[21]

[21] Maryland Depreciation Regulation Chapter 18, Subtitle 03, Chapter 01, Depreciation .02B(2). Phone conversation with Laura Kittel (410-767-1897) at State Department of Assessments & Taxation in June 2012.

Table 21
Property Tax Rate Estimates for Each CONE Area

		Real Property Tax			Personal Property Tax			
		Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Nominal Tax Rate	Assessment Ratio	Effective Tax Rate	Depreciation
CONE Area		[a]	[b]	[a] X [b]	[c]	[d]	[c] X [d]	[e]
State		*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	
1 EMAAC								
New Jersey	[1]	4.6%	75.2%	3.3%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.8%	50.0%	1.4%	straight-line at 3.3%/yr to 25% min.
3 RTO								
Ohio	[3]	5.6%	35.0%	1.9%	5.6%	24.0%	1.3%	follow annual report "SchC-NewProd (NG)"
Pennsylvania	[4]	3.7%	100.0%	3.7%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[4]	3.7%	100.0%	3.7%	n/a	n/a	n/a	n/a
5 Dominion								
Virginia	[5]	1.0%	95.5%	0.9%	1.0%	95.5%	0.9%	ceiling at 90%; floor at 25%

Sources and Notes:

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Middlesex and Camden Counties. For Middlesex County see: http://www.co.middlesex.nj.us/taxboard/rate-ratio.pdf; for Camden County see: http://www.camdencounty.com/sites/default/files/files/2013%20Rates.pdf and http://www.camdencounty.com/sites/default/files/files/2013%20%20Ratios.pdf.

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJSA § 54:4-1

[2a], [2c] Maryland tax rates estimated as the sum of county and state rates in Charles County and Prince George's County in 2013-2014. Data obtained from Maryland Department of Assessment & Taxation website: http://www.dat.state.md.us/sdatweb/taxrate.html

[2d] Md. Tax-Property Code Ann. 7-237

[2e] Maryland Depreciation Regulation Chapter 18, Subtitle 03, Chapter 01, Depreciation .02B(2). Phone conversation with State Department of Assessments & Taxation in June 2012.

[3a], [3c] Received "Rates of Taxation" from Morgan County auditor's office on Feb 27, 2014, which the auditor confirmed is applicable to both real and personal property; reviewed rates for Perry, Fairfield, and Athens counties, which range from 5–8%.

[3b], [3d] Assessment ratios for real property and electric companies' production personal property found on p. 91 and 95 of Ohio Department of Taxation 2012 Annual Report, http://www.tax.ohio.gov/portals/0/communications/publications/annual_reports/2012_annual_report/2012_AR_internet.pdf

[3e] Depreciation schedules for utility assets found in Form U-EL by Ohio Department of Taxation: http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2014/PU_EL_2014.xls

[4a] Berks county tax rates available at: http://www.co.berks.pa.us/Dept/Assessment/Documents/2014%20co%20twp%20%202013%20sch%20tax%20rate.pdf

[4b] Real properties assessed at 100% according to conversations with Chief Tax Assessor of Berks County.

[4c] - [4e]: According to *Pennsylvania Legislator's Municipal Deskbook*, only real estate tax assessed by local governments in Pennsylvania

[5a] Current real property rate in Fauquier County available at: http://www.fauquiercounty.gov/government/departments/commrev/index.cfm?action=rates. Reviewed property tax rates for Fairfax and Dinwiddie counties, which range from 0.8 – 1.1%.

[5b], [5d] Assessment ratio provided by Virginia State Corporation Commission Principal Utility Appraiser in March 2014.

[5c] Code of Virginia (§ 58.1-2606., Line C) states generating equipment shall not exceed the real estate rate applicable in the respective localities; we assume personal property tax rate equal to the real property tax rate in [5a].

[5e] Received depreciation for electric companies from Virginia State Corporation Commission by Principal Utility Appraiser via email; confirmed that depreciation ceiling of 90% and floor of 25% apply to personal property.

4. Working Capital

We estimated the cost of maintaining working capital requirements for the reference CT and CC by first estimating the working capital requirements (calculated as accounts receivable minus accounts payable) as a percent of gross profit for 3 merchant generation companies: NRG, Calpine, and Dynegy. The weighted average working capital requirement among these companies is 5.59% of gross profits.[22] Translated to the plant level, we estimate that the working capital requirement is approximately 0.7% of overnight costs in the first operating year (increasing with inflation thereafter). In the capital cost estimates, we do not include the working capital requirements but instead the cost of maintaining the working capital requirement based on the borrowing rate for short-term debt for BB rated companies 0.96%.[23]

5. Firm Transportation Service Contract in Southwest MAAC

The gas pipeline serving the part of SWMAAC we identified for the reference plants is the Dominion Cove Point (DCP) pipeline. We understand from shippers that they have had trouble obtaining gas on the DCP pipeline. Availability of interruptible service has been unreliable and inflexible with the pipeline being fully subscribed and also unable to absorb substantial swings in usage within a day. To at least partially address this problem, we assume new CC plants will sign up for firm transportation service on DCP. We assume that the new CT will not acquire firm service due to the relatively few hours such a plant is expected to operate.

To estimate the costs of acquiring firm transportation service on the DCP pipeline for a plant coming online in 2018, we assume the same transportation reservation rate on DCP as that filed for the proposed Dominion Cove LNG export project. That rate is $5.5260 per dekatherm per month for 2017,[24] which we escalate to 2018 dollars, resulting in a rate of $5.6503 per dekatherm.[25] We assume that the CC will reserve sufficient gas service to support baseload operation (without supplemental duct firing) as summarized in Table 22. This results in a $6.5 million annual cost, adding $11,100/MW-year to the CONE for CCs in SWMAAC.

Flexible, no-notice, non-ratable firm service would cost even more, but we do not have a basis for estimating such costs. Instead, we assume energy margin calculations would have to account for limited flexibility of gas service from the DCP (see Section III.B of the 2014 VRR Report).

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22 Gross profits are revenues minus cost of goods sold, including variable and fixed operation and maintenance costs.

23 15-day average 3-month bond yield as of February 14, 2014, BFV USD Composite (BB), from Bloomberg.

24 Application for Authority to Construct, Modify, and Operate Facilities Used for the Export of Natural Gas under Section 3 of the Natural Gas Act and Abbreviated Application for a Certificate of Public Convenience and Necessity under Section 7 of the Natural Gas Act, Volume 1 of III, Public, before the Federal Energy Regulatory Commission, in the matter of Dominion Cove Point LNG, LP, Cove Point Liquefaction Project, filed April 1, 2013. Docket No. CP13-___-000. Available at http://newsinteractive.post-gazette.com/20130401-5045(28233263).pdf.

25 This does not include variable charges, which should not be included in CONE but should be accounted for in estimating energy margins to calculate Net CONE.

Table 22
Estimated Cost of Procuring Firm Gas Service on DCP Pipeline

Component	Units	Gas CC
Plant Characteristics		
Summer ICAP (w/o duct-firing)	*(MW)*	591
Summer Heatrate at Baseload (HHV)	*(Btu/kWh)*	6,811
Gas Consumption at Baseload		
Maximum Hourly	*(MMBtu/hr)*	4,023
Maximum Daily	*(MMBtu/hr)*	96,563
Firm Gas Reservations		
Cost of Firm Gas Capacity per Month	*(2018$/Dth)*	$5.6503
Total Firm Gas Capacity Reservation	*(Dth)*	96,600
Total Cost of Firm Gas Reservations	***(2018$)***	**$6,550,000**
	(2018$/MW-year)	$11,100

Sources and Notes:
See footnote 24.
1 dekatherm (Dth) is equivalent to 1 MMBtu.

B. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they inform the E&AS revenue offset calculations performed annually by PJM. We provide an explanation of the costs here to clearly differentiate which O&M costs are considered fixed and which are variable.

- Major Maintenance: Over the long-term operating life of CT and CC plants, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the average variable O&M cost (in dollars per megawatt-hour, or $/MWh) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the plant capacity in megawatts. For starts-based major maintenance, the average variable O&M cost ($/factored start, per turbine) is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.
- Other Variable O&M: Other variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. These items are always expressed in $/MWh, regardless of whether the maintenance component is hours-based or starts-based.

C. Escalation to 2018

We escalated the components of the O&M cost estimates from 2014 to 2018 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 18) have been also used to escalate the O&M costs. The assumed real escalation rate for labor is 1.5% per year, while those for other O&M costs are 0.4%.

D. Summary of O&M Costs

Based on the technical specifications for the reference CT and CC in Section II and the O&M estimates in this section, a summary of the fixed and variable O&M for an online date of June 1, 2018 is shown below in Table 23 and Table 24.

Table 23
Summary of O&M Costs for CT Reference Technology

	CONE Area				
O&M Costs	**1** **EMAAC** *396 MW*	**2** **SWMAAC** *393 MW*	**3** **Rest of RTO** *385 MW*	**4** **WMAAC** *383 MW*	**5** **Dominion** *391 MW*
Fixed O&M (2018$ million)					
LTSA	$0.3	$0.3	$0.3	$0.3	$0.2
Labor	$1.5	$1.1	$1.2	$1.1	$1.0
Consumables	$0.2	$0.2	$0.2	$0.2	$0.2
Maintenance and Minor Repairs	$0.4	$0.4	$0.4	$0.4	$0.4
Administrative and General	$0.2	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.4	$0.4	$0.4	$0.4	$0.4
Property Taxes	$0.4	$5.3	$2.5	$0.4	$3.1
Insurance	$2.4	$2.2	$2.1	$2.2	$2.2
Firm Gas Contract	$0.0	$0.0	$0.0	$0.0	$0.0
Working Capital	$0.0	$0.0	$0.0	$0.0	$0.0
Total Fixed O&M (2018$ million)	**$5.9**	**$10.1**	**$7.2**	**$5.2**	**$7.7**
Levelized Fixed O&M (2018$/MW-yr)	**$15,000**	**$25,600**	**$18,800**	**$13,700**	**$19,600**
Variable O&M (2018$/MWh)					
Major Maintenance - Hours Based	2.40	2.39	2.39	2.39	2.36
Consumables, Waste Disposal, Other VOM	1.89	1.89	1.89	1.89	1.89
Total Variable O&M (2018$/MWh)	**4.29**	**4.27**	**4.27**	**4.27**	**4.25**

Table 24
Summary of O&M Costs for CC Reference Technology

O&M Costs	CONE Area 1 EMAAC *595 MW*	2 SWMAAC *591 MW*	3 Rest of RTO *578 MW*	4 WMAAC *576 MW*	5 Dominion *587 MW*
Fixed O&M (2018$ million)					
LTSA	$0.3	$0.3	$0.3	$0.3	$0.2
Labor	$4.6	$3.3	$3.6	$3.5	$3.0
Consumables	$0.3	$0.3	$0.3	$0.3	$0.3
Maintenance and Minor Repairs	$4.7	$4.1	$4.3	$4.2	$4.0
Administrative and General	$0.4	$0.3	$0.3	$0.3	$0.3
Asset Management	$0.7	$0.6	$0.7	$0.6	$0.6
Property Taxes	$1.4	$9.9	$5.5	$1.5	$6.0
Insurance	$4.8	$4.2	$4.3	$4.4	$4.2
Firm Gas Contract	$0.0	$6.6	$0.0	$0.0	$0.0
Working Capital	$0.1	$0.0	$0.0	$0.1	$0.0
Total Fixed O&M (2018$ million)	**$17.4**	**$29.7**	**$19.2**	**$15.1**	**$18.7**
Levelized Fixed O&M (2018$/MW-yr)	**$26,000**	**$44,800**	**$29,500**	**$23,300**	**$28,300**
Variable O&M (2018$/MWh)					
Major Maintenance - Hours Based	1.49	1.45	1.47	1.47	1.45
Consumables, Waste Disposal, Other VOM	1.14	1.14	1.14	1.14	1.14
Total Variable O&M (2018$/MWh)	**2.63**	**2.60**	**2.61**	**2.61**	**2.60**

V. Financial Assumptions

A. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[26] The appropriate ATWACC reflects the systemic financial market risks of the project's future cash flows as a merchant generating plant participating in the PJM markets. As a merchant project, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts and other hedges in place. This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

[26] The "after-tax weighted-average cost of capital" (ATWACC) is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

To estimate the cost of capital for such a project, we reviewed a broad range of reference points. As there is significant uncertainty in any single cost of capital estimate, we reviewed all of the available reference points and selected a level that is reasonable considering the wide range of values. The reference points that we are using include updated estimates for publicly-traded merchant generation companies (NRG, Calpine, and Dynegy), additional sources from previous analysis by Brattle, fairness opinions for merchant generation divestitures, and analyst estimates.[27] Supplementing our analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours. We derived each of the reference points as follows, with results summarized in Table 25.

- **Publicly Traded Companies**: we derived ATWACC estimates using the following standard techniques.
  - *Return on Equity:* We estimate the return on equity (ROE) using the Capital Asset Pricing Model (CAPM). The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta."[28] We calculated a risk-free rate of 3.4% using a 15-day average of 30-year U.S. treasuries as of February 2014.[29] We estimated the expected risk premium of the market to be 6.5% based on the long-term average of values provided by Credit Suisse and Ibbotson.[30] The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index. The resulting return on equity ranges from 7.1–11.9% for the companies included in the analysis, as shown in Table 25.[31]
  - *Cost of Debt*: We estimate the cost of debt (COD) by compiling the unsecured senior credit ratings for each merchant generation company and examining the bond yields associated with those credit ratings. In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments, with "AAA" being the highest rating and "D" being the lowest. Calpine and Dynegy's credit

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27 We do not include private equity investors in our sample because their cost of equity cannot be observed in market data. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses face lower risks and lower cost of capital than merchant generation.

28 Brealy, Richard, Stuart C. Myers, and Franklin Allen (2011). *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin.

29 Bloomberg, Bloomberg Professional Service (2014). Data downloaded February 21, 2014. (Bloomberg, 2014). Risk free rate calculated based on 30 year U.S. bond yields.

30 The Ibbotson market risk premium is 6.7% and the Credit Suisse market risk premium is 6.2%. Ibbotson (2013), *SBBI 2013 Valuation Yearbook*, Chicago: Morningstar, 2013. Dimson, Elroy, Paul Marsh, and Mike Stauton (2013). *Credit Suisse Global Investment Returns Sourcebook 2013,* Zurich: Credit Suisse Research Institute, February 2013.

31 Dynegy financial characteristics are currently significantly different from Calpine and NRG as it is in the final stages of emerging from bankruptcy. However, we believe that it still can provide a useful reference point for estimating the cost of capital for a merchant generator.

ratings are "B," with an associated cost of debt of 8.7%, while NRG's is "BB" with a 7.5% cost of debt.[32]

– *Debt/Equity Ratio*: We estimate the five-year average debt/equity ratio for each merchant generation company using company 10-Ks for the debt value and Bloomberg for the market value of equity.

- **April 2011 Brattle Estimates** were calculated using a similar approach and have been adjusted downward by 0.9 percentage points for the current analysis based on the difference in the risk-free rate between April 2011 (4.3%) and February 2014 (3.4%).
- **The other reference points** come from publicly available values used by financial advisors and analysts in valuations associated with mergers and divestitures. For example, the financial advisors for the acquisition of GenOn by NRG used discount rates of 7.0–8.5% for NRG and 8.5–9.5% for GenOn in their discounted cash flow analyses associated with the merger. While there are no details provided on how these ranges were developed, we find these values provide useful reference points for estimating the cost of capital. The values in Table 25 have been adjusted upward by 0.7 percentage points due to the change in risk-free rates since the original estimates were developed by the financial analysts in 2012.

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32 Data downloaded from Bloomberg in 2014.

Table 25
Summary of Cost of Capital Reference Points and Recommended ATWACC

	Brattle Updated ATWACC Estimates						Prior Estimates Adjusted to Feb 2014 Risk-Free Rate			
Company	**S&P Credit Rating** [1]	**Equity Beta** [2]	**Return on Equity** [3]	**Cost of Debt** [4]	**Debt/ Equity Ratio** [5]	**After Tax WACC** [6]	**July 2012 Financial Advisor Estimates for NRG-GenOn Merger** [7]	**Apr 2011 Brattle Estimates** [8]	**2011 Analyst Estimates** [9]	**2011 Fairness Opinions** [10]
Publicly Traded Companies										
Calpine	B	1.29	11.9%	8.7%	61/39	7.8%		6.7%	6.6%	
NRG	BB	1.04	10.4%	7.5%	73/27	6.1%	7.7 - 9.2%	6.3%	6.2%	
Dynegy	B	0.49	7.1%	8.7%	42/58	6.1%		7.4%	7.1 - 11.1%	
Acquired Companies (previously traded)										
GenOn Energy							9.2 - 10.2%	10.3%	7.6 - 9.6%	
Mirant								8.0%	7.6 - 8.6%	
Merchant Generation Divestitures										
FirstEnergy Merchant Generation										7.1 - 8.1%
Allgheny Merchant Generation										7.1 - 7.6%
Duke's Merchant Generation										7.3 - 8.3%
Recommendation			**13.8%**	**7.0%**	**60/40**	**8.0%**				

Sources and notes:
[1]: Bloomberg, 2014.
[2]: Brattle analysis.
[3] = Assumed risk-free rate (3.40%) + assumed market risk premium (6.50%) × [2].
[4]: Bloomberg, 2014.
[5]: Market structure calculated by Brattle using company 10-Ks for debt value and Bloomberg for market value of equity.
[6] = (% Debt) × [4] × (1 – [6]) + (% Equity) × [3]
[7] – [10]: 2011 and 2012 estimates have been adjusted based on changes in the risk-free rate. The risk-free rates were 4.3% in April 2011, 2.7% in July 2012, and 3.4% February 2014. (Bloomberg, 2014)
[7]: NRG Energy Inc. and GenOn Energy, *Joint Proxy Statement/Prospectus for Special Meeting of Stockholders to be Held on Friday, November 9, 2012*, October 5, 2012, pp. 63, 70, and 75.
[8] – [10]: 2011 PJM CONE Study contains original analysis for [8] and citations to original sources for [9] and [10].

Based on this set of reference points and our assumption of merchant entry risk that exceeds the average risk of the publicly-traded generation companies, we believe an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE. That value is above the cost of capital of Calpine and NRG, both of which have some long-term contracts and hedges in place, and it is near the mid-point of the range of the additional reference points.

Although the specific assumptions on capital structure, ROE, and COD corresponding to our ATWACC have almost no impact on the CONE calculation, we do need to assume specific values in order to quantify interest during construction and depreciable capital costs. We assumed a capital structure of 60/40 debt-equity ratio to reflect typical projects' capital structures and their associated ROE and COD. For a representative COD of 7.0% and a 60/40 debt-to-equity capital structure, the ATWACC of 8.0% translates to an ROE of 13.8%, as shown in Table 25. Note that the ATWACC applied to the five CONE Areas varies very slightly with applicable state income tax rates, as discussed in the following section.

B. OTHER FINANCIAL ASSUMPTIONS

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, and interest during construction.

Inflation rates affect our CONE estimates by forming the basis for projected increases in various FOM cost components over time. We also use the inflation rate as the cost escalation rate in our level-real CONE estimate. We estimated future twenty-year inflation rates based on bond market data, Federal Reserve estimates, and consensus U.S. economic projections. The implied inflation rate over twenty years from treasury yields is 2.2%, and the Cleveland Federal Reserve estimate of inflation expectations is 1.9% over twenty years.[33] The most forward looking forecast in the Blue Chip Economic Indicators report is 2.3%.[34] Based on these sources, we assumed for the Net CONE calculations an average long-term inflation rate of 2.25%.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal and state tax rates. The marginal federal corporate income tax rate for 2013 is 35%.[35] The state tax rates assumed for each CONE Area are shown in Table 26. Virginia's lower rate slightly reduces Dominion's CONE, although ATWACC there increases from 8.0% to 8.1% because the debt tax shield is less valuable.

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33 As stated on the Cleveland Federal Reserve website, "The Cleveland Fed's estimate of inflation expectations is based on a model that combines information from a number of sources to address the shortcomings of other, commonly used measures, such as the "break-even" rate derived from Treasury inflation protected securities (TIPS) or survey-based estimates. The Cleveland Fed model can produce estimates for many time horizons, and it isolates not only inflation expectations, but several other interesting variables, such as the real interest rate and the inflation risk premium." Federal Reserve Bank of Cleveland (2013), *Cleveland Fed Estimates of Inflation Expectations*, accessed July 16, 2013. Available at http://www.clevelandfed.org/research/data/inflation_expectations/.

34 Blue Chip Economic Indicators (2013), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, March 2013. We used the consensus ten-year average consumer price index (CPI) for all urban consumers.

35 Internal Revenue Service (2013), *2012 Instructions for Form 1120, U.S. Corporation Income Tax Return*, January 25, 2013. Available at http://www.irs.gov/pub/irs-pdf/i1120.pdf.

Table 26
State Corporate Income Tax Rates

CONE Area	Representative State	Corporate Income Tax Rate
1 Eastern MAAC	New Jersey	9.00%
2 Southwest MAAC	Maryland	8.25%
3 Rest of RTO	Pennsylvania	9.99%
4 Western MAAC	Pennsylvania	9.99%
5 Dominion	Virginia	6.00%

Sources and notes:
State tax rates retrieved from www.taxfoundation.org

We calculated depreciation based on the current federal tax code, which allows generating companies to use the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a CC plant and 15 years for a CT plant.[36]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 60% debt and 7.0% COD.

VI.Summary of CONE Estimates

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. "Level-nominal" cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real dollars, inflation adjusted terms) over the 20-year economic life of the plant. A "level-real" cost recovery path starts lower then increases at the rate of inflation (*i.e.*, constant in real dollar terms).[37] As discussed in the 2014 VRR Report, we recommend that PJM adopt the level-real value as it is more consistent with our expected trajectory of operating margins from future capacity and net E&AS revenues. All descriptions below refer to level-nominal values to facilitate consistent comparison with parameters PJM is currently using.

[36] Internal Revenue Service (2013), *Publication 946, How to Depreciate Property,* February 15, 2013. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

[37] Both cost recovery paths (level-real and level-nominal) are calculated such that the NPV of the project is zero over the 20-year economic life.

Table 27 and Table 28 show summaries of our capital costs, annual fixed costs, and levelized CONE estimates for the CT and CC reference plants for the 2018/19 delivery year. For comparison, the tables include the most recent 2017/18 PJM administrative CONE parameters and the results of the 2011 PJM CONE Study for the 2015/16 auction, with both escalated to a 2018/19 delivery year at 3% per year to reflect estimated historical escalation rates for generation.[38]

For the CT, our CONE estimates differ by CONE Area due to differences in plant configuration and performance assumptions, differences in labor rates, differences in property tax regulations, and other locational differences in capital and fixed O&M costs. EMAAC and SWMAAC have the highest CONE estimates at $150,000/MW-year and $148,400/MW-year, respectively, due to significantly higher labor costs in EMAAC and high property taxes in SWMAAC that are based on all property, not just land and buildings, as in some other areas. WMAAC and Dominion have the next highest CONE values of $143,500/MW-year and $141,200/MW-year, respectively. The Rest of RTO Area has the lowest CONE values of $138,000/MW-year due to the lack of dual-fuel capability and lower labor costs.

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[38] The 3% escalation rate is based on a component-weighted average of the escalation rates in Table 1818.

Table 27
Recommended CONE for CT Plants in 2018/2019

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$400	$373	$348	$372	$364
Installed	*($m)*	$420	$391	$364	$390	$382
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**
Unitized Costs						
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%

Sources and Notes:

Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Table 27 compares these CONE estimates to two reference points: PJM's current parameters for the 2017/18 capacity auction and Brattle's prior estimates for the 2015/16 delivery year from its 2011 PJM CONE Study. To produce a meaningful comparison, we show these reference points escalated to 2018 at 3% per year. As shown, our estimates are similar to the Brattle 2015/16 values, except in SWMAAC and Dominion where updated property tax calculations and labor costs contribute to increasing the CONE values by 9% and 15%, respectively. Our estimates in those CONE Areas are closer to the PJM 2017/18 parameters (which are higher than the Brattle 2015/16 values largely because they were escalated from prior settlement values using a Handy-Whitman index that has risen significantly faster than actual plant costs, as noted in our 2014 VRR Report). In the other CONE Areas (EMAAC, Rest of RTO, and WMAAC), our estimates are lower than the 2017/18 parameters. Overall, our estimates are within -8% to +6% of PJM's current parameters, depending on the Area.

Comparing the current CT CONE estimates to the Brattle 2015/16 estimates, the CT CONE values are either approximately equal in EMAAC, Rest of RTO and WMAAC or higher by 9% in SWMAAC and higher by 15% in Dominion. The SWMAAC and Dominion values are higher for several reasons. First, we assumed higher labor rates, based on the prevailing wages in those Areas, which include a mix of union and non-union labor. Second, increased property tax estimates that now consider taxes on personal property (*i.e.*, the plant equipment) in accordance with state tax laws in both of these regions also lead to higher CONE estimates. Third, the assumed addition of an SCR on the Dominion CT increased the CONE estimates there. Other components of the estimate also changed there and in all the CONE Areas, but with increases in some categories offsetting decreases in others. Assumptions that increased CONE included higher EPC contract costs (mostly due to labor costs), EPC contingency costs, and owner's project development costs. On the other hand, a lower ATWACC and lower plant O&M estimates reduced CONE.

For the CC, EMAAC has the highest CONE estimates at $203,900/MW-year due to labor costs that are higher than the rest of PJM. SWMAAC and WMAAC have the next highest CC CONE at $197,200/MW-year and $190,900/MW-year, respectively. The CONE Areas with the lowest values are Rest of RTO (due to the lack of dual fuel) at $188,100/MW-yr and Dominion (as it has the lowest labor costs) at $182,400/MW-year.

Table 28
Recommended CONE for CC Plants in 2018/2019

		CONE Area				
		1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs						
Overnight	*($m)*	$808	$707	$709	$737	$708
Installed	*($m)*	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**668**	**664**	**651**	**649**	**660**
Unitized Costs						
Overnight	*($/kW)*	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE						
Level-Real	***($/MW-yr)***	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates						
PJM 2017/18 Parameter*	*($/MW-yr)*	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates						
PJM 2017/18 Parameter	*($/MW-yr)*	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	10%	18%	6%	7%	14%

Sources and Notes:
Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at 3% annually, based on escalation rates for individual cost components.

Compared to the Brattle 2015/16 values, the current CC CONE estimates are higher across all CONE Areas due to higher estimated costs of EPC contingency, owner's project development costs, and plant O&M costs. While the EPC contract cost increased in all cases, the SWMAAC and Dominion values increased more due to higher estimated labor costs than in the previous analysis, as we found the prevailing wages in those regions include both union and non-union labor, whereas the previous analysis assumed strictly non-union labor.

The updated CC CONE values have increased over the prior estimates more than the CT CONE values have, leading to a higher cost premium for CCs of $41,000-54,000/MW-year compared to $27,000-43,000/MW-year in our prior study. The most significant driver for the greater CC CONE increase is the relative difference in plant O&M costs estimated by S&L compared to the previous analysis. As noted earlier in this report, the CT fixed O&M in the current analysis is less than the 2011 value, with a larger fraction treated as variable costs; however, the fixed CC plant O&M is greater than the previous value. Combined, this difference explains approximately two-thirds of the increase in the CC premium. The rest of the difference is explained primarily by higher labor rates, and contingency and project development factors than in the prior study, which add more dollars to the cost of the more capital-intensive CC than the CT. In the Dominion CONE Area, the addition of the SCR to the CT largely offsets these differences.

At PJM's request, we are also providing estimates for the Rest of RTO CONE Area with dual-fuel capabilities, as shown in Table 29. Adding dual-fuel capabilities to the plant specifications increases the level-nominal value of the CT CONE by $9,500/MW-year and the CC CONE by $5,600/MW-year.

Table 29
Rest of RTO CONE Estimates for Different Fuel Configurations

		Gas CT		Gas CC	
Rest of RTO		**Single Fuel**	**Dual Fuel**	**Single Fuel**	**Dual Fuel**
Gross Costs					
Overnight	*($m)*	$348	$373	$709	$733
Installed	*($m)*	$364	$391	$777	$802
First Year FOM	*($m/yr)*	$7	$8	$19	$20
Net Summer ICAP	***(MW)***	**385**	**385**	**651**	**651**
Unitized Costs					
Overnight	*($/kW)*	$903	$969	$1,089	$1,125
Installed	*($/kW)*	$947	$1,016	$1,193	$1,232
Levelized FOM	*($/MW-yr)*	$18,800	$19,700	$29,500	$29,900
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**
Levelized Gross CONE					
Level-Real	***($/MW-yr)***	**$117,100**	**$125,100**	**$159,700**	**$164,400**
Level-Nominal	***($/MW-yr)***	**$138,000**	**$147,500**	**$188,100**	**$193,700**

List of Acronyms

ATWACC	After-Tax Weighted-Average Cost of Capital
BACT	Best Available Control Technology
BLS	Bureau of Labor Statistics
CAPM	Capital Asset Pricing Model
CC	Combined Cycle
CO	Carbon Monoxide
COD	Cost of Debt
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CT	Combustion Turbine
DCP	Dominion Cove Point
DCR	Demand Curve Reset
E&AS	Energy and Ancillary Services
EIA	Energy Information Administration
EMAAC	Eastern Mid-Atlantic Area Council
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
HRSG	Heat Recovery Steam Generator
ICAP	Installed Capacity
IDC	Interest During Construction
ISO	Independent System Operator
LDA	Locational Deliverability Area
LAER	Lowest Achievable Emissions Rate
LTSA	Long-Term Service Agreement
m	Million
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System

MMBtu	One Million British Thermal Units
MOPR	Minimum Offer Price Rule
MW	Megawatt(s)
MWh	Megawatt-Hours
NNSR	Non-Attainment New Source Review
NNY	Non-New York
NO_x	Nitrogen Oxides
NSR	New Source Review
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFE	Owner-Furnished Equipment
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, LLC
PSD	Prevention of Significant Deterioration
ROE	Return on Equity
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SWMAAC	Southwestern Mid-Atlantic Area Council
ULSD	Ultra-Lower Sulfur Diesel
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
LONDON
MADRID
ROME

THE Brattle GROUP

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. ER14-___

AFFIDAVIT

STATE OF Massachusetts)
)
CITY OF Cambridge)

DR. SAMUEL A. NEWELL, being duly sworn, deposes and states: that the Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on behalf of PJM Interconnection, L.L.C. was prepared by his or under his direct supervision, that the statements contained therein and the Attachments attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

DR. SAMUEL A. NEWELL

Subscribed and sworn to before me this 23rd day of September, 2014.

Notary Public
My Commission Expires:

JENNIFER M. OSSEN
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 11, 2016

{W0034794.1 }

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. ER14-___

AFFIDAVIT

STATE OF TN.)
CITY OF Hamilton)

CHRISTOPHER D. UNGATE, being duly sworn, deposes and states: that the Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on behalf of PJM Interconnection, L.L.C. was prepared by his or under his direct supervision, that the statements contained therein and the Attachments attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

Christopher D. Ungate
CHRISTOPHER D. UNGATE

Subscribed and sworn to before me this 22 day of September, 2014.

Mary Beth Craven
Notary Public
My Commission Expires: 12·21·2014

MARY BETH CRAVEN
STATE OF TENNESSEE NOTARY PUBLIC
COUNTY OF HAMILTON

{W0034783.1 }

Attachment E

Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, LLC	**)**	**Docket No. ER14-_____-000**
	)	
	)	

AFFIDAVIT OF DR. SAMUEL A. NEWELL AND DR. KATHLEEN SPEES ON BEHALF OF PJM INTERCONNECTION, L.L.C. REGARDING PERIODIC REVIEW OF VARIABLE RESOURCE REQUIREMENT CURVE SHAPE AND KEY PARAMETERS

Our names are Dr. Samuel A. Newell and Dr. Kathleen Spees. We are employed by The Brattle Group, as Principal and Senior Associate, respectively. We submit this affidavit on behalf of PJM Interconnection, L.L.C. (PJM) to describe the analysis we conducted on the performance of PJM's Variable Resource Requirement curve (VRR Curve) for procuring capacity in its Reliability Pricing Model (RPM) capacity market. We conducted this analysis as part of PJM's tariff-mandated triennial review of the VRR Curve and its parameters, the results of which have informed PJM's proposed revisions to the VRR Curve in the present filing. The entirety of our review is contained in the attached report, *Third Triennial Review of PJM's Variable Resource Requirement Curve* ("Third Triennial Review").[1] That report was prepared under our supervision and direction.

Our qualifications as experts derive from our extensive experience evaluating capacity markets and alternative market designs for resource adequacy. Our practice in capacity market design with RTOs across North America and internationally has given us a broad perspective on the practical implications of nuanced market design rules under a range of different economic and policy conditions.[2] In PJM, we have worked closely with PJM staff on this and prior assignments to understand RPM at a detailed level.[3] We have also

[1] Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, Ioanna Karkatsouli. *Third Triennial Review of PJM's Variable Resource Requirement Curve.* May 15, 2014.

[2] For example, we have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM Interconnection, ISO-New England (ISO-NE), New York, Alberta, California, Texas, Midcontinent ISO, Italy, Russia, and Western Australia. A comprehensive description of these engagements is shown in our resumes, which are provided as attachments to this affidavit.

[3] See our 2008 and 2011 triennial RPM reviews respectively, in Pfeifenberger, Johannes, Samuel Newell, Robert Earle, Attila Hajos, and Mariko Geronimo. *Review of PJM's Reliability Pricing Model (RPM).* June 30, 2008; and Pfeifenberger, Johannes, Samuel Newell, Kathleen Spees, Attila Hajos, and Kamen Madjarov. *Second Performance Assessment of PJM's Reliability Pricing Model.* August 26, 2011.

previously worked on a number of assignments with market participants from all sectors operating within the PJM footprint, which has provided us insights on how changes to the capacity market construct may impact the business decisions and other interests of suppliers, customers, utilities, and state regulators in PJM.

A subset of our market design work has focused on the development and improvement of capacity market demand curves designed around different sets of policy objectives. Our experience in capacity demand curve design includes: (1) prior PJM capacity market reviews in 2008 and 2011 to review market performance, including qualitative assessments and statistical simulations of the performance of the VRR Curve;[4] (2) support of ISO-NE in the development of the system demand curve for its capacity market, as filed with and approved by the Commission earlier this year, and of ISO-NE's ongoing development of locational curves, including simulation analyses of candidate curves' performance;[5] (3) Italian capacity demand curve and market design development in 2012, including developing a value-based locational demand curve reflecting the value of capacity to customers; and (4) a study on the economics of reliability for the Commission in 2013, including calculating a value-based capacity demand curve designed to procure an economically optimal quantity of capacity from a risk-neutral societal perspective.[6]

I, Dr. Newell, am an economist and engineer with more than 16 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and market rules. Prior to joining The Brattle Group, I was the Director of the Transmission Service at Cambridge Energy Research Associates and previously a Manager in the Utilities Practice at A.T. Kearney. I earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

I, Dr. Spees, am an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. I earned a Ph.D. in Engineering and Public Policy and an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University.

Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes, provided as attachments to this affidavit.

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4 See Sections IV and V of our 2008 and 2011 RPM reviews.

5 See the Newell/Spees Testimony in support of ISO New England's April 1, 2014 filing before the Federal Energy Regulatory Commission (FERC) in Docket ER14-1639-000 to implement a downward-sloping system demand curve in their Forward Capacity Market (FCM).

6 See Section IV.B for a derivation and discussion of a value-based capacity demand curve, from Pfeifenberger, Johannes P., Kathleen Spees, Kevin Carden, and Nick Wintermantel. *Resource Adequacy Requirements: Reliability and Economic Implications.* September 2013.

TABLE OF CONTENTS

I. SUMMARY

We were asked by PJM to evaluate the parameters and shape of the administrative VRR Curve used to procure capacity under RPM, as required periodically under the PJM Tariff.[7] Consistent with the review scope specified in PJM's Tariff, we evaluated three key elements of RPM: (1) the gross Cost of New Entry (CONE) parameter; (2) the methodology for determining the Net Energy and Ancillary Services (E&AS) Revenue Offset; and (3) the shape of the VRR Curve.

On the first of these, the CONE parameter, we conducted an engineering cost estimate as summarized in the concurrently-filed affidavit of Dr. Newell and Mr. Christopher Ungate of Sargent & Lundy (Newell/Ungate affidavit), and described in detail in the attached report, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* ("2014 CONE Study").[8] We also authored a second study, *Third Triennial Review of PJM's Variable Resource Requirement Curve* ("Third Triennial Review"), attached to this affidavit, to quantitatively and qualitatively evaluate all other parameters of the VRR Curve, and conduct a probabilistic simulation analysis of the curve's performance as required under the Tariff.[9]

This affidavit summarizes how the findings of this second report have informed PJM's proposed changes to the VRR Curve. With respect to the Net CONE parameter, our analysis informed PJM's proposals to: (a) eliminate the Dominion CONE Area, (b) revise the indices used for annual updates to gross CONE, (c) revise the mapping of CONE and E&AS offsets such that these components of administrative Net CONE will be aligned as closely as possible to each Locational Deliverability Area (LDA) modeled in RPM, and (d) apply a minimum on locational Net CONE values so that no sub-LDA will have a lower Net CONE than its parent LDA.

With respect to the shape of the VRR Curve, our qualitative assessment and probabilistic simulation analyses informed PJM's decision to propose the revised VRR Curve shape shown in Figure 1 in comparison with the current VRR Curve. This revised curve addresses three performance concerns that we identified in the current VRR Curve. First, point "a" in the current curve does not reach the price cap until a relatively low quantity that is below PJM's backstop procurement threshold. Second, we estimate that in the long-term after current capacity surpluses are exhausted, the current VRR Curve is not likely to procure enough capacity to achieve average reliability at the 1-day-in-10-years (1-in-10 or 0.1) loss

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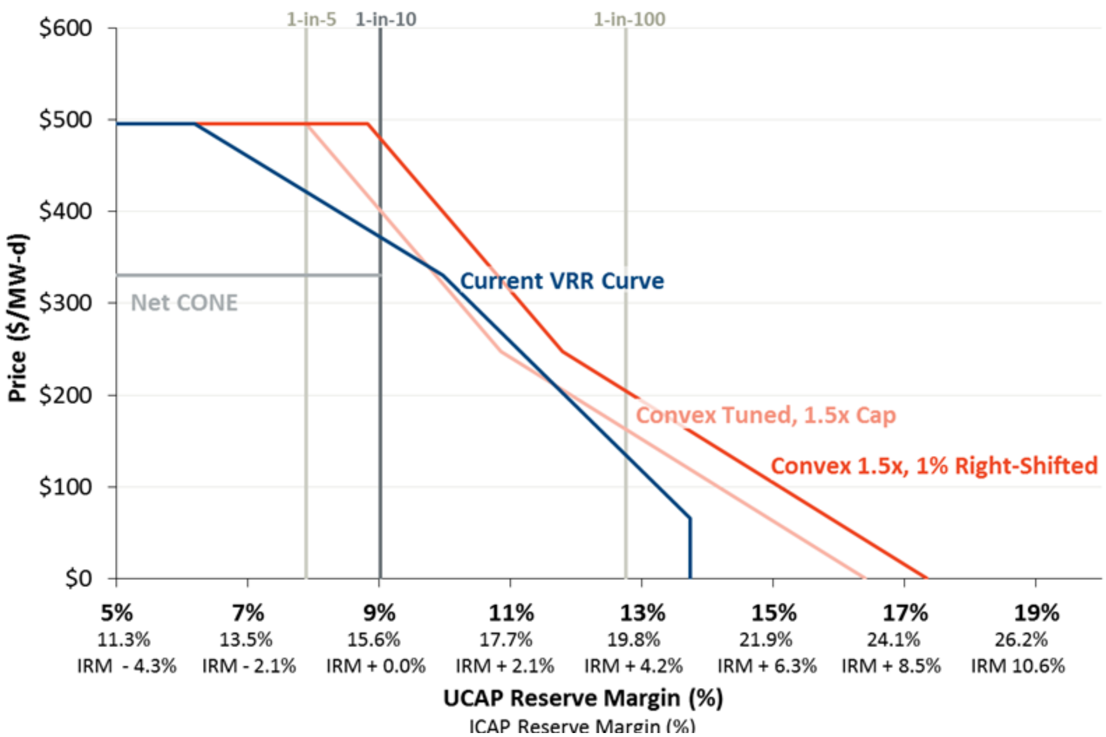
7 To date, PJM has required a triennial review of these parameters; in the future the review will be required only once every four years. See Section 5.10.a.iii of the *PJM Open Access Transmission Tariff*. Effective April 23, 2014. Retrieved from: http://www.pjm.com/~/media/documents/agreements/tariff.ashx

8 Newell, Samuel A., Michael Hagerty, Kathleen Spees, Johannes P. Pfeifenberger, Quincy Liao, Christopher D. Ungate, and John Wroble, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*, May 15, 2014.

9 See Pfeifenberger, Johannes P., Samuel A. Newell, Kathleen Spees, Ann Murray, and Ioanna Karkatsouli, *Third Triennial Review of PJM's Variable Resource Requirement Curve*, May 15, 2014.

of load event (LOLE) reliability standard of RPM. And third, the concave shape of the VRR Curve is less economically rational and more susceptible to reliability risks in the presence of administrative errors in Net CONE than the revised convex shape proposed by PJM.

Figure 1
PJM Proposed VRR Curve Compared to Current Curve



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, calculated relative to the full Reliability Requirement without applying the 2.5% holdback for short-term procurements. See "2016/2017 Planning Parameters," April 30, 2013, posted at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters.ashx.

Our findings are supported by probabilistic simulation analyses of RPM mechanics, and with parameters that are grounded in empirical data on supply curve shapes and supply/demand variations from the first ten Base Residual Auctions (BRAs) conducted under RPM. Our probabilistic market simulations are also grounded in the rational economic expectation that capacity prices must equal the long-run marginal cost of supply (or Net CONE) on a long-run average basis, and we adjust the amount of entry until this condition is satisfied. This approach reflects the fact that in PJM, as in other restructured markets, the system will meet resource adequacy needs only if the market can attract new investments made by merchant suppliers. Such private investors will only build new generation if they expect to earn a competitive return on investment through the capacity, energy, and ancillary service markets. In other words, capacity prices will converge to Net CONE in expectation. However, prices will not equal Net CONE in every year, but rather reflect a distribution around that expected value based on the shape of the VRR Curve and year-to-year variations in supply and demand. We estimate this distribution of realized price, quantity, and reliability outcomes that would be realized under long-run equilibrium conditions using a Monte Carlo simulation model that incorporates historical data on the magnitude of these variations.

Details on these other topics are available in the full body of our attached report.

II. NET COST OF NEW ENTRY (CONE) PARAMETER

Here we summarize our analysis and findings with respect to PJM's administrative Net CONE estimates, and how they have informed PJM's proposals to: (a) eliminate the Dominion CONE Area, (b) revise the indices used for annual updates to gross CONE, (c) revise the mapping of CONE and E&AS offsets such that these components of administrative Net CONE will be aligned as closely as possible to each Locational Deliverability Area (LDA) modeled in RPM, and (d) apply a minimum to locational Net CONE values so that no sub-LDA will have a lower Net CONE than its parent LDA.[10]

A. Elimination of Dominion CONE Area

Currently, PJM's Tariff defines five CONE Areas for which the gross CONE parameter must be separately estimated: (1) Eastern Mid-Atlantic Area Council (Eastern MAAC), (2) Southwest Mid-Atlantic Area Council (Southwest MAAC), (3) Rest of Regional Transmission Organization (Rest of RTO), (4) Western Mid-Atlantic Area Council (Western MAAC), and (5) Dominion. These five CONE estimates are then used in calculating the Net CONE parameter for each CONE Area and the Net CONE for use in any LDA for which PJM must establish a separate VRR Curve.

However, the CONE estimate for CONE Area 5: Dominion has not been used for developing any locational Net CONE parameters because Dominion has never been a modeled LDA within RPM. Therefore, we recommend that the Dominion CONE Area be combined into CONE Area 3: Rest of RTO, which is the broader region within which Dominion is modeled for the purposes of pricing and procurements in RPM. The remaining four CONE Areas will then be consistent with the four permanently-modeled regions in RPM auctions.[11]

Combining CONE Area 5: Dominion into CONE Area 3: Rest of RTO would not affect our estimate of gross CONE in Area 3 as summarized in the Newell/Ungate Affidavit. This is because, based on the relatively few reference projects in Dominion, we would not have used the Dominion zone as one of the most representative locations for developing a CONE estimate in the larger combined area. Further, the two estimates are relatively similar in any case, with the Dominion CONE estimate being 2% below the Rest of RTO estimate for a gas Combustion Turbine (CT).[12]

B. Adopting Different Indices for Annual CONE Escalation

PJM updates its gross CONE parameter annually for each year between the periodic CONE studies by applying the Handy-Whitman "Total Other Production Plant" index for the

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[10] See the more detailed discussion and analysis in our attached Third Triennial Review, Section III.

[11] A more detailed discussion of our review of how gross CONE is mapped between the CONE Areas into each LDA VRR curve is contained in Section III.C.1 of our attached Third Triennial Review.

[12] See Newell/Ungate affidavit.

appropriate location.[13] However, we found that this index has escalated more quickly than the rate of cost increases suggested by recent CONE studies.[14]

We therefore explored alternative updating methodologies, and we recommend that PJM adopt a revised annual escalation methodology based on a weighted average of three indices from the Bureau of Labor Statistics (BLS). These three indices track wages in utility system construction by location, construction materials costs, and turbine costs.[15] The weightings on each of the three indices would be equal to the relevant proportion of capital costs from the 2014 CONE Study.[16] As shown in the Third Triennial Review, we "backcasted" the resulting composite index over the 2004 to 2014 against the changes in CONE from the "bottom-up" comprehensive estimates of CONE studies, showing that the index more closely tracks the results of the CONE studies than does the Handy-Whitman Index.[17]

C. Single-Zone and Multi-Zone Calculation of Net CONE

Each modeled LDA must have a defined Net CONE parameter from which the price points on the locational VRR Curve is derived. Currently, PJM's Tariff specifies that Net CONE will be calculated for each CONE Area based on the gross CONE for that CONE Area, and the E&AS offset for a specific energy zone within that area. However, because the CONE Areas do not exactly align with the modeled LDAs, the Tariff also specifies how these Net CONE estimates are then mapped to each LDA.

The consequence of these mappings is that many single-zone LDAs have a Net CONE parameter based on the energy prices in a different (sometimes distant) location. In larger LDAs that cover many zones, the Net CONE reflects the energy prices in only one sub-zone and may not be reflective of other zones in the LDA.

To improve the accuracy of its Net CONE parameter, we recommend that PJM more closely align the Net CONE estimates to the LDAs as modeled in RPM. PJM's proposed Tariff revisions will accomplish that goal by calculating Net CONE individually for each

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13 See p. 27 of PJM's *Manual 18: PJM Capacity Market*. Revision 22, Effective April 24, 2014. Retrieved from: http://www.pjm.com/~/media/documents/manuals/m18.ashx

14 See Section III.A.3 of our Third Triennial Review.

15 The specific indices reflected in the composite index for the example of Eastern MAAC are: (1) BLS Quarterly Census of Employment and Wages: 2371 Utility System Construction for the appropriate state in each CONE Area; (2) BLS Producer Price Index Commodity Data: SOP Stage of Processing: 2200 Materials and Components for Construction; and (3) BLS Producer Price Index Commodity Data: 11 Machinery and Equipment: 97 Turbines and Turbine generator Sets. These indices weighted at 28%, 47%, and 25% for the CT, and 37%, 51% and 12% for the CC, consistent with our estimate of the relevant contribution to plant capital costs in each case, see Bureau of Labor Statistics. *Quarterly Census of Employment and Wages – Industry*. Available at http://data.bls.gov/cgi-bin/dsrv?en

16 We assign each capital cost line item to one of the three cost indices for calculating this ratio, even though in some cases these assignments are inexact.

17 See additional detail in the 2014 CONE Study, as well as in Section III.A.3 of our attached Third Triennial Review.

energy zone based on the energy prices for that zone. Each LDA's Net CONE will then be defined: (a) for LDAs that cover a single zone, as the Net CONE for that zone; and (b) for LDAs that cover multiple zones, as the average of the zonal Net CONEs for all zones in that LDA.[18]

D. Minimum Net CONE at Parent LDA Value

PJM also proposes to adopt our recommendation to prevent the Net CONE of a sub-LDA (*i.e.*, an LDA wholly encompassed within a larger LDA) from falling below the Net CONE of its parent LDA. We made this recommendation as a safeguard against under-estimating locational Net CONE and the consequential under-procurement that could occur in small LDAs. Net CONE estimation errors are more likely in small LDAs, such as Southwest MAAC, which may have idiosyncratic estimation uncertainties as well as small sample sizes for estimating gross CONE and calibrating E&AS estimates. Capacity under-procurement that can result from Net CONE underestimates would also have disproportionately high reliability consequences in small LDAs, as explained in our Third Triennial Review.[19] Consequently, there are substantial reliability benefits from subjecting sub-LDA Net CONE values to a minimum at the parent LDA's Net CONE value.

There is little cost from imposing the parent Net CONE as a minimum for the sub-LDA. If Net CONE is truly lower in the sub-LDA than in the parent LDA, developers considering locating somewhere in the parent LDA should preferentially site their new entry plants in the sub-LDA, given its lower net cost (and potential for higher capacity prices). That cost advantage indicates that the sub-LDA would attract sufficient capacity to avoid price-separating from the parent LDA in RPM auctions. If the sub-LDA does not price-separate, then the theoretically lower Net CONE in the sub-LDA will never find any practical expression. Even if a separate VRR Curve is established for the sub-LDA, the VRR Curve for the parent LDA will continue to set clearing prices in the sub-LDA.

In fact, the attractiveness of investing in locations with the lowest Net CONE is the reason that we would not expect Net CONE to be lower in a sub-LDA for any extended period of time. If we observe the opposite, with a location being persistently import-constrained and lacking investment despite a low administrative Net CONE estimate, then it seems likely that the low Net CONE estimate is a consequence of administrative estimation error rather than of developers failing to identify the low-cost, high-value investment opportunity.

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[18] See Section III.C.2 of our Third Triennial Review for a more detailed discussion of locational E&AS offset and Net CONE mapping.

[19] See our Third Triennial Review, Section III.C.3 for a more detailed conceptual discussion of this topic, Section III.B.1 for additional detail on Southwest MAAC, and Section VI.B.3 for simulation results illustrating the large reliability impacts from under-estimation errors in Net CONE in small LDAs.

III. DESCRIPTION OF PROBABILISTIC SIMULATION APPROACH USED TO EVALUATE VRR CURVE PERFORMANCE

One component of the Triennial review required by PJM's tariff is a probabilistic simulation analysis of the VRR Curve's performance. To conduct that probabilistic analysis, we developed a Monte Carlo simulation model that estimates the likely distribution of price, quantity, and reliability outcomes in PJM on both a system-wide and a locational basis under each analyzed demand curve. We present simulated results from 1,000 draws of potential market outcomes based on uncertainty distributions around year-to-year variations in: (a) total supply offers in the market and in each LDA, (b) different supply curve shapes, (c) the reliability requirement, (d) administrative Net CONE, and (e) capacity import limit parameters. For each variable, we developed estimates of the typical magnitude of such variations based on historical data.[20]

As we explained previously, the model assumes economically rational new entry, with new supply added infra-marginally until the long-term average price equals Net CONE. As such, our simulations reflect long-term equilibrium conditions in a market environment where prices must be high enough to support merchant investment.

Our simulation modeling approach is very similar to the one that we used when assisting ISO-NE in developing its downward-sloping demand curve, as recently approved by the Commission.[21] This approach also has a number of conceptual similarities to the model developed by Professor Benjamin Hobbs and previously used to evaluate the PJM VRR Curve.[22] Our approach differs from Professor Hobbs's approach primarily because we: (i) incorporate a substantial body of empirical data (covering ten BRAs) to develop estimates of realistic variations in supply, demand, and transmission for use in the Monte Carlo draws; (ii) assume a sloped capacity supply curve reflective of historical offer curve shapes; and (iii) apply RPM's locational auction clearing mechanism.

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[20] See Section IV and Appendix A of our Third Triennial Review for a detailed description of each uncertainty that we model and the underlying data we used to support our estimate of the magnitude of variations.

[21] See Newell, Samuel A. and Kathleen Spees. "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," Attachment to ISO New England and New England Power Pool submission before the Federal Energy Regulatory Commission, April 1, 2014. Docket ER14-1639-000.

[22] See Hobbs, Benjamin F. "Affidavit of Benjamin F. Hobbs on Behalf of PJM Interconnection, LLC," Filed before the Federal Energy Regulatory Commission, August 5, 2005. Docket Nos. ER05-1440-000, EL05-148-000; and Hobbs, Benjamin F., Ming-Che Hu, Javier G. Iñón, Steven E. Stoft, and Murty P. Bhavaraju, "A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model," IEEE Transactions on Power Systems, Vol. 22, No. 1. February 2007.

IV. REVIEW OF THE VARIABLE RESOURCE REQUIREMENT CURVE

We qualitatively and quantitatively evaluated the VRR Curve, to evaluate its likely performance and consistency with the RPM design objectives. The primary objective of the VRR Curve, and of RPM itself, is to achieve the 1-event-in-10-years (1-in-10) Loss of Load Expectation (LOLE) reliability standard on a long-term average basis (although not necessarily in every individual year). Other objectives include mitigating price volatility, reducing exposure to the exercise of market power, producing prices reflective of market conditions, minimizing complexity, and producing capacity prices that are reflective of reliability value (if possible). While not all of these objectives can be fully met simultaneously, a well-designed capacity demand curve will reflect a balance among these conflicting objectives.

In evaluating the current VRR Curve, we identified three performance concerns that PJM's revised curve would ameliorate: (1) the point "a" quantity at the VRR Curve cap is below PJM's backstop procurement trigger threshold, (2) based on our probabilistic market simulations we find that the current curve is not likely to achieve the 1-in-10 reliability standard on a long-run average basis, and (3) the concave shape of the curve is less economically rational than a convex curve and is more vulnerable to Net CONE estimation errors. In the following discussion, we qualitatively discuss how PJM's proposal to revise the shape of the VRR Curve addresses the first and third of these performance concerns. We then present a summary of our probabilistic analysis of PJM's proposed curve, showing that, unlike the current curve shape, the revised curve shape will meet or exceed the reliability standard at the PJM Region-wide level and in each modeled LDA under base assumptions.

A. Point "a" Quantity is Below Backstop Threshold

Point "a" on the current VRR Curve is where the curve reaches the price cap, at a quantity of Installed Reserve Margin (IRM) – 3%. Reliability is relatively poor at this point, corresponding to an average LOLE of 0.42 events/year (this LOLE can alternatively be described as a "reliability index" of 1 load loss event in 2.4 years). This point is also below PJM's defined backstop threshold of IRM – 1%, consistent with an LOLE of approximately 0.18 events/year (reliability index of 1-in-5.6). If procured quantities in the BRA fell below this threshold for three consecutive years, PJM would initiate a backstop procurement.[23]

To make the shape of the VRR Curve more consistent with design objectives, we recommended that PJM consider increasing the quantity at point "a" to a level equal to or greater than this IRM – 1% backstop procurement threshold. This change would: (a) reduce the likelihood of realizing very low reliability events in any one year, (b) produce stronger price signals more reflective of the low reliability conditions that would be realized at lower margins, and (c) ensure that PJM has exhausted all opportunities to procure capacity within the normal BRA structure before any backstop mechanism could be triggered. PJM's proposed VRR Curve incorporates this recommendation.

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[23] See additional discussion of the point "a" quantity and the backstop threshold in our Third Triennial Review, Section V.A.3.

B. Concave Shape is Less Economically Rational

Another, potentially less significant, limitation of the current VRR Curve is its concave shape that points away from the origin. Moving to a convex shape that points toward the origin would be more economically rational and somewhat more reflective of the incremental reliability and economic value of capacity. We therefore recommend that PJM consider adopting a convex curve, although we acknowledge that aligning the curve shape with marginal economic or reliability value is a secondary objective of the VRR Curve. We did not recommend developing a curve that is exactly reflective of marginal reliability value, because such a curve would be relatively steep compared to the current VRR Curve and therefore would not achieve the price volatility mitigation benefits of a more sloped curve.[24] PJM's proposed curve does reflect a slightly convex shape.

This revised convex shape also demonstrates more robust performance than the current concave shape in the stress scenario in which administrative Net CONE is systematically under-estimated. This is because the convex curve has a steeper shape in the high-price region, so an under-estimate of Net CONE will result in a relatively smaller reduction in average quantity and a relatively smaller degradation in reliability as compared to the current VRR Curve. In the case of an over-estimate of Net CONE, the convex curve will produce a relatively lower amount of over-procurement.[25]

C. Simulated System-Wide Performance of the Current and Proposed VRR Curves

Using the probabilistic simulation analysis described above, we evaluated the performance of the current VRR Curve as well as a variety of alternative curves under base case assumptions and a range of sensitivity assumptions.[26] We present in Figure 2 and Table 1 a comparison of the shapes and simulated performance of: (1) a vertical demand curve, (2) the current VRR Curve, (3) a convex-shaped curve tuned to exactly achieve the 0.1 LOLE standard, and (4) the convex curve right-shifted by 1%, consistent with PJM's proposal.

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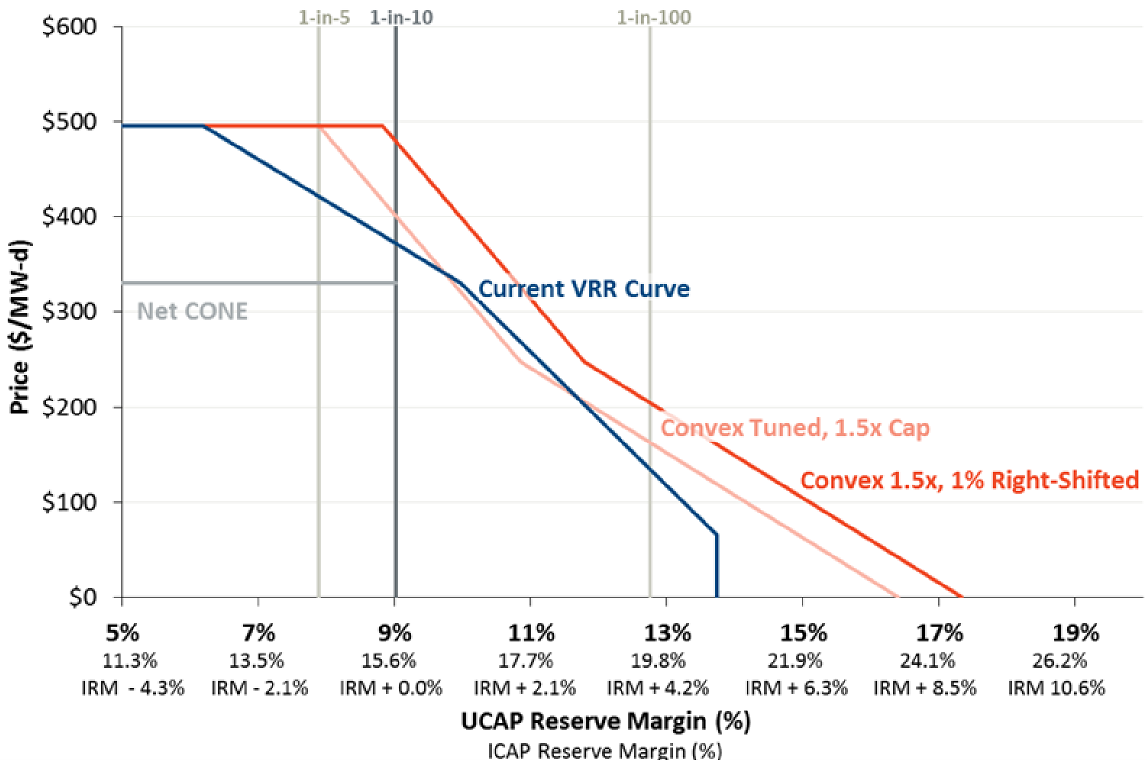
[24] See additional discussion of the VRR curve's concave shape and a convex alternative in our Third Triennial Review, Section V.A.2.

[25] See section V.C.4 of our Third Triennial Review for additional discussion of the robustness of each curve in our sensitivity analyses.

[26] See our Third Triennial Review, Sections V.B-C for a detailed description and the results of this analysis.

Figure 2
PJM Proposed VRR Curve Compared to Current Curve



Sources and Notes:

Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, calculated relative to the full Reliability Requirement without applying the 2.5% holdback for short-term procurements. See "2016/2017 Planning Parameters," April 30, 2013, posted at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters.ashx.

The most important result from our simulation analysis is that the current VRR Curve produces an average LOLE of 0.121 events/year, which does not achieve the primary RPM design objective. We also note that the curve produces a relatively high 20% frequency of events below the 1-in-5 (0.2 events/year) reliability level, which is approximately consistent with the IRM – 1% backstop threshold discussed in the prior section. These performance results are consistent with our qualitative observations that the quantity at the price cap is lower than desirable, and that the relatively flatter convex shape of the curve at low quantities contributes to these reliability concerns.

We tested a number of options for addressing these performance concerns in the VRR Curve, including developing a revised convex curve with the cap quantity at 1-in-5 and with the shape tuned such that the curve would exactly achieve the 0.1 LOLE standard on a long-term average basis. Our simulations demonstrate that this curve improves performance, meeting the 0.1 LOLE standard on average and reducing the frequency of falling below 0.2 LOLE to 13% of all years. However, this revised convex curve does not have uniformly superior performance in all dimensions, in that it produces somewhat higher price volatility (increasing from a standard deviation of $95/MW-day to $107/MW-day), and a higher frequency at the price cap (increasing from 6% to 13%). This somewhat higher price volatility is driven by the steeper shape of the curve in the high-price region, which is the region that has the greatest impact on price volatility due to the interaction with the steep portion of the upward-sloping capacity supply curve. Under the current VRR Curve, the flatter shape in the high price region mitigates this upside price volatility substantially, but at the expense of introducing more frequent and more severe shortage events.

PJM's proposed curve has the same convex shape, but is right-shifted by 1% IRM. Because PJM's proposed curve has the same shape and slope as the convex curve tuned to 0.1 LOLE, it produces the same price volatility results, but it supports 1% higher quantity in the market. The right-shifted curve therefore produces higher reliability with an LOLE of 0.060, and only 7% frequency below 1-in-5. The right-shifted curve also maintains the reliability standard under the stress scenario we analyzed where supply/demand fluctuations are 33% higher, whereas the non-shifted curve does not.[27] In a scenario where Net CONE is systematically underestimated by 20%, the right-shifted curve achieves an LOLE of 0.18 compared to 0.28 for the non-shifted curve.

However, the higher quantity that the right-shifted curve procures would come at a slight increase in long-term average capacity procurement costs. System-wide long-term average costs increase by about 1%, or approximately $170 million per year, relative to the similarly shaped curve that is not right-shifted. Note that this cost magnitude is indicative only, and does not account for the partially offsetting effects of higher reserve margins on net system costs and customer costs.[28]

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[27] In this scenario, the convex tuned curve produced an LOLE of 0.156, while PJM's proposed convex + 1% curve produced an LOLE of 0.099 events/year or nearly the reliability standard. See Section V.C.4 of our Third Triennial Review.

[28] This cost estimate accounts for only the difference in cleared capacity prices and quantities among 1,000 draws, assuming Net CONE remains the same. A more comprehensive cost-benefit analysis would account for a number of factors that we have not considered, that would change with a higher reserve margin including: lower energy prices, higher Net CONE, and fewer scarcity and other emergency event costs.

Table 1
System-Wide Performance of Vertical, Current, Convex Tuned, and PJM Proposed VRR Curves

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Vertical Curve	$331	$147	69%	0.175	-0.8%	1.4%	36%	24%	$19,980	$8,030	$31,531
Current VRR Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
Convex Tuned to 1-in-10	$331	$107	13%	0.100	0.7%	1.9%	29%	13%	$20,210	$12,379	$29,631
PJM Proposal (Convex + 1%)	**$331**	**$107**	**13%**	**0.060**	**1.7%**	**1.9%**	**16%**	**7%**	**$20,383**	**$12,461**	**$29,859**

Note: Capacity procurement costs account for price premiums in import-constrained sub-LDAs.

D. Simulated Performance at the Local Level

We also evaluated the performance of PJM's current and revised VRR Curves at the LDA level, evaluating the distribution of price, quantity, and reliability results under base and sensitivity assumptions.[29] When testing the performance of VRR Curves at the local level, we focused primarily on cases where each successive import-constrained sub-LDA has a Net CONE 5% higher than the parent LDA (with administrative Net CONE accurately reflecting true Net CONE on average in each location). This Net CONE assumption allows us to test the curve performance under a modest locational net cost differential, although the Net CONE values for most LDAs do not exactly match historical PJM Net CONE parameters.

In evaluating the locational performance of the current VRR Curve, we found even more reliability concerns in some LDAs than at the system level.[30] As shown in Table 2 summarizing our simulation results, four of the nine modeled LDAs experience poorer local reliability than the standard, at conditional LOLE values of 0.042 to 0.064 events/year compared to the 0.040 events/year (or 1-in-25) local reliability standard. Three of the LDAs also have a relatively high frequency of events below 1-in-15, at 11% to 17%.[31] We also found that the reliability performance of the VRR Curve in the LDAs is relatively vulnerable to sensitivity assumptions such as administrative under-estimates in Net CONE and an LDA having a Net CONE that is substantially above the parent Net CONE. The smallest and most import-dependent zones demonstrated the most vulnerability under these sensitivity tests.

PJM's proposed VRR Curve shape substantially mitigates these reliability concerns. Under the same assumptions, all LDAs meet or exceed the conditional 0.4 events/year LOLE

[29] See Third Triennial Review, Sections VI.B-C to review the entirety of this analysis of the VRR curve as implemented on a locational basis.

[30] One LDA shows LOLE further in excess of the standard than the system results, and several LDAs show greater vulnerability to low reliability events under similar sensitivity assumptions compared to the system.

[31] We use the 1-in-15 threshold as a measure of very poor reliability performance at the LDA level, similar to the 1-in-5 threshold that we used at the system level.

standard and no LDA shows a frequency below 1-in-15 above 9%. However, as at the system level, we observe a moderate increase in price volatility under the revised convex shape, and somewhat higher locational procurement costs associated with the right-shifted curve.

Table 2
Locational Performance of the Current and Proposed VRR Curves

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Current VRR Curve															
MAAC	$277	$89	12%	33%	0.053	0.160	1,389	2,356	102%	3%	27%	17%	$7,082	$4,257	$10,146
EMAAC	$291	$98	8%	25%	0.033	0.193	1,349	1,706	103%	4%	22%	15%	$3,903	$2,259	$5,683
SWMAAC	$291	$96	6%	17%	0.042	0.202	1,215	1,163	107%	7%	14%	8%	$1,621	$965	$2,328
ATSI	$277	$87	11%	18%	0.035	0.143	1,152	1,121	107%	7%	14%	11%	$1,451	$901	$2,046
PSEG	$305	$105	5%	15%	0.022	0.215	1,036	886	108%	7%	13%	9%	$1,281	$722	$1,859
PEPCO	$305	$104	25%	14%	0.064	0.266	1,099	923	112%	10%	11%	10%	$791	$462	$1,135
PS-N	$321	$116	31%	15%	0.023	0.238	503	442	108%	7%	12%	8%	$633	$352	$929
ATSI-C	$291	$95	10%	12%	0.059	0.202	906	694	115%	11%	9%	8%	$504	$311	$707
DPL-S	$305	$105	13%	15%	0.027	0.220	309	259	110%	8%	12%	7%	$289	$164	$421
Convex 1.5x, Right-Shifted															
MAAC	$277	$97	14%	31%	0.028	0.080	2,237	2,314	103%	3%	15%	9%	$7,167	$4,175	$10,602
EMAAC	$291	$107	13%	23%	0.020	0.100	1,879	1,694	105%	4%	14%	8%	$3,948	$2,200	$5,930
SWMAAC	$291	$104	8%	16%	0.024	0.105	1,460	1,159	108%	7%	8%	6%	$1,640	$935	$2,433
ATSI	$277	$95	9%	17%	0.022	0.074	1,373	1,118	108%	7%	10%	7%	$1,468	$884	$2,155
PSEG	$305	$114	8%	14%	0.014	0.114	1,218	885	109%	7%	9%	5%	$1,297	$700	$1,934
PEPCO	$305	$111	9%	14%	0.040	0.144	1,224	922	114%	10%	9%	7%	$801	$452	$1,187
PS-N	$321	$123	8%	14%	0.015	0.129	593	443	109%	7%	8%	5%	$640	$340	$962
ATSI-C	$291	$102	7%	11%	0.036	0.110	999	695	116%	11%	8%	6%	$510	$304	$744
DPL-S	$305	$113	7%	14%	0.018	0.118	351	259	111%	8%	7%	5%	$292	$161	$438

Notes:

Procurement cost estimates differ slightly from our Triennial Review, reflecting a more accurate allocation of customer costs in each LDA.
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

SAMUEL A. NEWELL

Principal

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Dr. Samuel Newell's expertise is in the analysis and modeling of electricity markets, the transmission system, and RTO rules. He supports clients in regulatory, litigation, and business strategy matters involving wholesale market design, contract disputes, generation asset valuation and development, benefit-cost analysis of transmission enhancements, the development of demand response programs, and integrated resource planning. He frequently provides testimony and expert reports to RTOs, state regulatory commissions, and the FERC and has testified before the American Arbitration Association.

Dr. Newell earned a Ph.D. in technology management and policy from the Massachusetts Institute of Technology, an M.S. in materials science and engineering from Stanford University, and a B.A. in chemistry and physics from Harvard College.

AREAS OF EXPERTISE

- Electricity Wholesale Market Design
- Valuation of Generation Assets
- Energy Litigation
- Integrated Resource Planning
- Evaluation of Demand Response (DR)
- Transmission Planning and Modeling
- RTO Participation and Configuration
- Analysis of Market Power
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Wholesale Design

- **Third Triennial Review of PJM Capacity Market and CONE Study**. For PJM, conducted third tri-annual review of the Reliability Pricing Model. Addressed the shape of the demand curve, the Cost of New Entry (CONE) parameter, and the methodology for estimating the energy margins and ancillary services revenues in the Net CONE calculation.
- **ISO New England Capacity Demand Curve.** For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Also worked with

Sargent & Lundy and stakeholders to develop estimates for the Net Cost of New Entry (Net CONE) to which the prices in the demand curve are indexed. Submitted testimonies before FERC, with ongoing support to develop locational demand curves for individual capacity zones.

- **Market Development Vision**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **Economically Optimal Reserve Margins**. For the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.
- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO New England, developed offer review trigger prices for screening for uncompetitively low offers in the Forward Capacity Market. Collaborated with Sargent & Lundy to conduct a bottom-up analysis of the costs of building and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency, and demand response. For each technology, estimated the capacity payment needed to make the resource economically viable, given expected non-capacity revenues, a long-term market view, and a cost of capital. Recommendations were filed with and accepted by the Federal Energy Regulatory Commission (FERC).
- **Evaluation of Investment Incentives and Resource Adequacy in ERCOT**. For the Electric Reliability Council of Texas (ERCOT), led a team that (1) characterized the factors influencing generation investment decisions; (2) evaluated the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluated options to enhance long-term resource adequacy while maintaining market efficiency. Conducted the study by performing forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed

a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Findings and recommendations became a launching point for a PUCT Proceeding, in which I filed comments and presented at several workshops between June 2012 and July 2013.

- **Second Triennial Review of PJM Capacity Market and CONE Study**. For PJM, conducted second tri-annual review of the Reliability Pricing Model. Analyzed capacity auction results and response to market fundamentals. Interviewed stakeholders and documented concerns. Addressed key market design elements and recommended improvements to reduce pricing uncertainty and safeguard future performance. Led a study of the Cost of New Entry (CONE), based on detailed engineering estimates developed by EPC contractor CH2M HILL, for use in PJM's setting of auction parameters. Served as PJM's witness in filing CONE values and a Settlement Agreement.
- **Evaluation of Reliability Pricing Model (RPM) Results and Design Elements**. For PJM, co-led a detailed review of the performance of its forward capacity market. Reviewed the results of the first five forward auctions for capacity. Concluded that the auctions were working and demonstrated success in attracting and retaining capacity, but made more than thirty design recommendations. Recommendations addressed ways to remove barriers to participation, ensuring adequate compensation/penalties, and improving the efficiency of the market. Resulting whitepaper was submitted to the FERC and presented to PJM stakeholders.
- **Evaluation of ISO-NE Forward Capacity Market (FCM) Results and Design Elements.** With the ISO-NE market monitoring unit, reviewed the performance of the first two forward auctions in ISO-NE's FCM. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor. Resulting whitepaper filed with the FERC and presented to ISO-NE stakeholders.
- **Evaluation of a Potential Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its existing short-term ICAP market structure with a proposed four-year forward capacity market (FCM) design. Evaluation based on stakeholder interviews, the experience of PJM and ISO-NE with their forward capacity markets, and review of the economic literature regarding forward capacity markets. Addressed the following attributes of FCM relative to the existing market: risks to buyers and suppliers, mitigation of market power, implementation costs, and long-run costs. Recommendations used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.

- **RTO Accommodation of Demand Response (DR) for Resource Adequacy**. For MISO, helped modify its tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying in detail the practices of other RTOs, and by characterizing the DR resources within the MISO footprint.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.
- **Integration of DR into MISO's Energy Markets**. For MISO, wrote a whitepaper evaluating the available approaches to incorporating economic DR in energy markets. Assessed the efficiency and the "realistic achievable potential" for each approach. Identified implementation barriers at the state and RTO levels. Recommended changes to business rules to efficiently accommodate curtailment service providers (CSPs).
- **MISO Capacity Market Enhancements**. Supported MISO in developing market design elements for its proposed annual locational capacity auctions.
- **Evaluation of MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its new resource adequacy construct. Identified several major successes and a series of recommendations for improvement in the areas of load forecasting, locational resource adequacy, and determination of the target level of reliability. The report incorporates extensive stakeholder input and review, and comparisons to other ISOs' capacity market designs. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements.
- **Evaluation of MISO's Demand Response Integration**. For MISO, conducted an independent assessment of its progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers to date. Assessed the likelihood of MISO's "ARC Proposal" to eliminate barriers to participation by curtailment service providers. Made recommendations for potential further improvements to market design elements.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, allowing reductions in installed capacity margins) on capacity costs, emergency procurement costs, capacity prices, and energy prices. Resulting whitepaper submitted by ISO-NE to the FERC in its filing on tie-benefits.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Also developed guidelines on the kinds of information ISO-NE should provide for major initiatives.

- **LMP Impacts on Contracts**. For a West Coast client, critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.
- **RTO Accommodation of Retail Access**. For MISO, made recommendations for improving business practices in order to facilitate retail access (and to enable auctions for the supply of regulated generation service). Analyzed the retail access programs in the three restructured states within MISO -- Illinois, Michigan, and Ohio. Performed a detailed study of retail accommodation practices in other RTOs, focusing on how they have modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Valuation of Generation Assets and Contracts

- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Analysis focused on projected market revenues, operating costs, and capital investments likely needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.

- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.
- **Valuation of Generation Asset Bundle in PJM**. For a major retail energy provider preparing to bid for a bundle of generation assets, provided energy and capacity price forecasts and reviewed their valuation methodology. Analyzed the supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the Dayzer model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan provided a market-based revenue forecast for energy and capacity. Identified gas and CO_2 allowance prices as the key drivers of revenue uncertainty, and evaluated the implications of several detailed scenarios around these variables.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogeneration plant in PJM, conducted an analysis of revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of plausible scenarios. Identified key uncertainties and risks in the acquisition of such assets.

Energy Litigation

- **Demand Response Arbitration**. Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony in arbitration before the American Arbitration Association (non-public).

- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.
- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages resulting from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's operating characteristics and costs. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Integrated Resource Planning (IRP)

- **IRP in Connecticut (for the 2008, 2009, 2010, 2012, and 2014 Plans)**. For the two major utilities in Connecticut and The Connecticut Department of Energy and Environmental Protection (DEEP), lead the analysis for five successive integrated resource plans. Plans included projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, and REC markets, and suppliers' likely investment/retirement decisions. Addressed policy questions regarding supply risks, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.

- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Serve (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs. Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Evaluation of Demand Response (DR)

- **ERCOT DR Potential Study**. For ERCOT, estimated the market potential for DR by end-user segment, based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented results to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the biggest, most cost-effective opportunities for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.

- **Evaluation of DR Compensation Options**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **Wholesale Market Impacts of Price Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Present Value of DR Investments**. For Pepco Holdings, Inc., analyzed the net present value of its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated the reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate the short-term energy market price impact and addressed the long-run equilibrium offsetting effects through several plausible supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Documented findings in a whitepaper submitted to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Transmission Planning and Modeling

- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of a Major Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects of the Project

on congestion, capacity markets, CO2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the congestion, production cost, and LMP impacts using the PROMOD model.

- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.

- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.

- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.

- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a "metric" indicating access and congestion-related benefits provided by its transmission investments and operations.

- **Analysis of Transmission Constraints and Solutions**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.

- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices in Connecticut and Long Island.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle effort to evaluate commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and Henwood LMP. Performed intensive in-house testing of each model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability and ease to calibrate models with backcasts using actual RTO data.

RTO Participation and Configuration

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across regional transmission organization (RTO) seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a complaint proceeding before the FERC, assisted expert witness providing testimony regarding (1) the inadequacy of MISO and PJM's current efforts to improve inter-RTO coordination, and (2) the large net economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM in energy prices and in shadow prices of reciprocal coordinated flow gates. Analyzed results of MISO and PJM's market simulation models.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Analysis of Market Power

- **Buyer Market Power**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate various proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan potentially created incentives to exercise vertical wholesale market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **Market Monitoring and Market Power Mitigation**. For the PJM Interconnection, assessed their market mitigation practices and co-authored a whitepaper "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets" (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes, and others).

Tariff and Rate Design

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility holding company, led the financial evaluation of a nascent venture to build and operate cogeneration facilities on customer sites. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with top executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Wrote RFPs and developed negotiating strategy. Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.
- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance their trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a large power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the potential value client could bring to each potential customer. Worked directly with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of an integrated utility, performed a market assessment of established and emerging DG technologies. Projected future market sizes across multiple market segments in the U.S. Concluded that DG presented little immediate threat to the client's traditional generation business, and that it presented few opportunities that the client was equipped to exploit.
- **Fuel Cells**. For a European fuel cell component manufacturer, acted as a technology and electricity advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Dr. Samuel A. Newell on behalf of Tri-State Generation and Transmission Association, Inc.," regarding an Analysis of Complaining Parties' Responses to Tri-State Generation and Transmission Association, Inc., September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on behalf of the Maine Office of the Public Advocate, regarding an Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. regarding a Forward Capacity Market Demand Curve," filed April 1, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on behalf of ISO New England Inc. regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve," filed April 1, 2014.

Before the Federal Energy Regulatory Commission Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of ISO New England" and accompanying "2013 Offer Review Trigger Prices Study," December, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Texas Public Utility Commission, presented "ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates" on behalf of The Electric Reliability Council of Texas (ERCOT) at a workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, June 27, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 23, 2013.

Before the Federal Energy Regulatory Commission, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, Docket No. ER13-535-000, December 28, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, supporting PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's Reliability Pricing Model, filed November 21, 2012.

Before the Texas Legislature Committee on State Affairs, presented oral testimony: "The Resource Adequacy Challenge in ERCOT" on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Resource Adequacy in ERCOT: 'Composite' Policy Options" and "Estimate of DR Potential in ERCOT" on behalf of ERCOT at a workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, October 25, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Review of Resource Adequacy Proposals" on behalf of ERCOT at workshop in Project 40480 Commission Proceeding Regarding Policy Options on Resource Adequacy, September 6, 2012.

Before the Texas Public Utility Commission, filed comments and presented "Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'" at workshop in Project 40000 Commission Proceeding to Ensure Resource Adequacy in Texas, July 27, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed January 13, 2012.

Before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the Federal Energy Regulatory Commission, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the Federal Energy Regulatory Commission, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 “Integrated Resource Plan for Connecticut,” report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

“Dynamic Pricing: Potential Wholesale Market Benefits in New York State,” lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as “Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure,” in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 “Integrated Resource Plan for Connecticut” (see below), June 30, 2009.

2009 “Integrated Resource Plan for Connecticut,” report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

“Informational Filing of the Internal Market Monitoring Unit’s Report Analyzing the Operations and Effectiveness of the Forward Capacity Market,” prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 “Integrated Resource Plan for Connecticut” and “Supplemental Reports” (see below), September 22-25, 2008.

“Integrated Resource Plan for Connecticut,” co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, D. Murphy, and J. Wharton, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

“Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI’s Proposed Demand-Side Management Programs,” whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, “Planning Analysis of the Paddock-Rockdale Project,” report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the Federal Energy Regulatory Commission, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

"Resource Adequacy in Western Australia — Alternatives to the Reserves Capacity Mechanism," report prepared for EnerNOC, Inc., August 2014 (with K. Spees).

"Third Triennial Review of PJM's Variable Resource Requirement Curve," report prepared from PJM Interconnection, LLC, May 15, 2014 (with J. Pfeifenberger, K. Spees, A. Murray, and I. Karkatsouli).

"Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," report prepared for PJM Interconnection, LLC, May 15, 2014 (with M. Hagerty, K. Spees, J. Pefiefenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).

"Developing a Market Vision for MISO: Supporting a Reliable and Efficient Electricity System in the Midcontinent." Foundational report prepared for Midcontinent Independent System Operator, Inc., January 27, 2014 (with K. Spees and N. Powers).

"Estimating the Economically Optimal Reserve Margin in ERCOT," report prepared for the Public Utilities Commission of Texas, January 2014 (with J. Pfeifenberger, K. Spees and I. Karkatsouli).

"Resource Adequacy Requirements: Reliability and Economic Implications," September 2013 (with J. Pfeifenberger, K. Spees).

"Capacity Markets: Lessons Learned from the First Decade," Economics of Energy & Environmental Policy. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger, K. Spees).

"ERCOT Investment Incentives and Resource Adequacy," report prepared for the Electric Reliability Council of Texas, June 1, 2012 (with K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton).

"Trusting Capacity Markets: does the lack of long-term pricing undermine the financing of new power plants?" Public Utilities Fortnightly, December 2011 (with J. Pfeifenberger).

"Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15," report prepared for PJM Interconnection LLC, August 26, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," report prepared for PJM Interconnection LLC, August 24, 2011 (with J. Pfeifenberger, K. Spees, and others).

"Fostering economic demand response in the Midwest ISO," Energy 35 (2010) 1544–1552 (with A. Faruqui, A. Hajos, and R.M. Hledik).

"DR Distortion: Are Subsidies the Best Way to Achieve Smart Grid Goals?" Public Utilities Fortnightly, November 2010.

"Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," report prepared for MISO, January 2010 (with K. Spees and A. Hajos).

"Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," report prepared for MISO, January 2010 (with A. Hajos).

"Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market," whitepaper written for the NYISO and submitted to stakeholders, June 15, 2009 (with A. Bhattacharyya and K. Madjarov).

"Fostering Economic Demand Response in the Midwest ISO," whitepaper written for MISO, December 30, 2008 (with R. Earle and A. Faruqui).

"Review of PJM's Reliability Pricing Model (RPM)," report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, June 30, 2008 (with J. Pfeifenberger and others).

"Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," Energy, Vol. 1, 2008, The Brattle Group (with M. Chupka and D. Murphy).

"Enhancing Midwest ISO's Market Rules to Advance Demand Response," report written for MISO, March 12, 2008 (with R. Earle).

"The Power of Five Percent," The Electricity Journal, October 2007 (with A. Faruqui, R. Hledik, and J. Pfeifenberger).

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper prepared for Pepco Holdings, Inc., September 21, 2007 (with A. Faruqui).

"Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," Report prepared for PJM Interconnection LLC, September 14, 2007 (with P. Fox-Penner, J. Pfeifenberger, J. Reitzes and others).

"Valuing Demand-Response Benefits in Eastern PJM," Public Utilities Fortnightly, March 2007 (with J. Pfeifenberger and F. Felder).

"Quantifying Demand Response Benefits in PJM," study report prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative, January 29, 2007 (with F. Felder).

"Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models," Energy, Vol. 2, 2006, The Brattle Group (with J. Pfeifenberger).

"Innovative Regulatory Models to Address Environmental Compliance Costs in the Utility Industry," October 2005 Newsletter, American Bar Association, Section on Environment, Energy, and Resources; Vol. 3 No. 1 (with J. Pfeifenberger).

"Effect of Cross Sound Cable," CERA Alert, October 24, 2003 (with H. Stauffer and G. Mukherjee).

PRESENTATIONS

"Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy" presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.

"EPA's Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d)," presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.

"Capacity Markets: Lessons for New England from the First Decade," presented to Restructuring Roundtable Capacity (and Energy) Market Design in New England, Boston, MA, February 28, 2014.

"The State of Things: Resource Adequacy in ERCOT" presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.

"Resource Adequacy in ERCOT" presented to FERC/NARUC Collaborative Winter Meeting in Washington, D.C., February 9, 2014.

"Electricity Supply Risks and Opportunities by Region" presentation and panel discussion at Power-Gen International 2013 Conference, Orlando, FL, November 13, 2013.

"Get Ready for Much Spikier Energy Prices—The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented to the Cadwalader Energy Investor Conference, New York, February 7, 2013 (with K. Spees).

"The Resource Adequacy Challenge in ERCOT," presented to The Texas Public Policy Foundation's 11th Annual Policy Orientation for legislators, January 11, 2013.

"Resource Adequacy in ERCOT: the Best Market Design Depends on Reliability Objectives," presented to the Harvard Electricity Policy Group conference, Washington, D.C., December 6, 2012.

"Resource Adequacy in ERCOT," presented to the Gulf Coast Power Association Fall Conference, Austin, TX, October 2, 2012.

"Texas Resource Adequacy," presented to Power Across Texas, Austin, TX, September 21, 2012.

"Resource Adequacy and Demand Response in ERCOT," presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.

"Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'," presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

"Market-Based Approaches to Achieving Resource Adequacy," presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.

"Fundamentals of Western Markets: Panel Discussion," WSPP's Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with Jürgen Weiss).

"Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.

"Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.

Before the PJM Board of Directors and senior level representatives at PJM's General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

"Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

"Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, May 3, 2007 (with J. Pfeifenberger, presenter).

"Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

"Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.

"Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

"Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

September 23, 2014

KATHLEEN SPEES

Senior Associate

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Dr. Kathleen Spees is a Senior Associate at *The Brattle Group* with expertise wholesale electric energy, capacity, and ancillary service market design and analysis. Dr. Spees has worked with market operators in PJM, MISO, Alberta, ERCOT, ISO-NE, and Italy to independently assess and improve their market designs for resource adequacy, increase efficiency of energy and capacity market seams, investigate market manipulation of virtual trading and FTR markets, evaluate system impacts from environmental coal retirements, evaluate the supply chain impacts of major simultaneous environmental retrofits, conduct engineering studies on the cost of building new generation facilities, develop capacity market demand curves, and refine wind integration rules for interconnection and dispatch. She has worked with market participants in these and other U.S. RTOs to support business strategy, investment decisions, asset transactions, contract negotiation, and damages litigation. Her experience includes modeling and analysis of demand response penetration impacts, client concerns or questions about capacity, energy, ancillary service, virtual trading, and FTR markets, impacts of environmental regulations on coal retirements, tariff mechanisms for accommodating merchant transmission upgrades, renewables integration approaches, utility and asset-specific strategy under carbon regulations, and market treatment of storage assets.

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center and her MS in Electrical and Computer Engineering from Carnegie Mellon University. She earned her BS in Physics and Mechanical Engineering from Iowa State University.

Publications posted: http://www.brattle.com/experts/kathleen-spees

REPRESENTATIVE EXPERIENCE

- **State Compliance Strategy under Clean Air Act 111(d).** For a regulated utility, evaluated options and feasibility of meeting state standards under 111(d) rate standards under a number of compliance scenarios. Developed an hourly dispatch model covering backcast and forecast years through the interim and final compliance timelines, accounting for impacts of load growth, renewables growth, coal-to-gas redispatch, coal minimum dispatch constraints, planned retirements, new generation development, and export commitments. Estimated the ability to meet the standard under various compliance strategies.
- **Western Australia Reserve Capacity Mechanism**. For EnerNOC, evaluated the characteristics of the Western Australia Reserve Capacity Mechanism in comparison with international best practices and made recommendations for improvements. Evaluated the advantages and disadvantages of a revised capacity market compared to adopting an energy-only market design in the region.
- **Review of Hydropower Industry Implications under Clean Air Act 111(d).** For the National Hydropower Association, provided members review of the implications for new and existing hydropower resources of proposed EPA Clean Power Plan under Clean Air Act Section

111(d). Analyzed impacts under a variety of potential revisions to the proposed rule, different potential state compliance options, differing plan regulatory statuses, mass-based vs. rate-based compliance, regulated planning vs. market-based compliance, and cooperative vs. stand-alone compliance.

- **Magnitude and Potential Impact of "Missing Efficiency" in PJM.** For the Natural Resources Defense Council, analyzed the potential magnitude of energy efficiency programs in PJM that are not accounted for on either demand side (through load forecast adjustments) or on the supply side (in the capacity market). Estimated potential energy and capacity market customer cost impacts in both the short-run and long-run if adjusting the load forecast to account for the missing efficiency.
- **ISO New England Capacity Demand Curve**. For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve shapes. Submitted Testimony before FERC supporting a proposed system-wide demand curve, with ongoing support to develop locational demand curves for individual capacity zones
- **MISO Market Development Vision.** For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **ERCOT Economically Optimal Reserve Margin.** For the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.
- **Economic Implications of Resource Adequacy Requirements.** For the Federal Energy Regulatory Commission (FERC), reviewed economic and reliability implications of resource

adequacy requirements based on traditional reliability criteria as well as alternative standards based on economic criteria. Evaluated total system costs, customer costs, supplier net revenues, and demand response implications under a range of reserve margins as well as under varying energy-only and capacity market designs.

- **MISO Wind Curtailment.** For MISO, evaluated the efficiency and equity implications of wind curtailment prioritization mechanisms and options for addressing stakeholder concerns, including interconnection agreement types, energy and capacity injection rights, ARR/FTR allocation mechanisms, energy market offers, and market participant hedging needs.
- **California Resource Adequacy Construct Review.** Sponsored by Calpine, evaluated and recommended efficiency improvements to California's resource adequacy construct mechanisms including long-term procurement, short-term local resource adequacy, and CAISO backstop mechanisms.
- **ERCOT Resource Adequacy Review.** For ERCOT, Evaluated wholesale market design in the context of its ability to attract sufficient investment for resource adequacy, when and where needed, including an evaluation of the implications of large simultaneous environmental retirements.
- **MISO Coal Retrofit Supply Chain Analysis.** For MISO, Examined the supply chain and outage scheduling implications of large simultaneous environmental retirements.
- **Italian Capacity Market Design.** For Italy's transmission system operator Terna, supported development of a locational capacity market design and locational capacity demand curves based on simulation modeling on the value of capacity to customers.
- **Survey of Energy Market Seams.** For the Alberta Electric System Operator (AESO), assessed the implications of energy market seams inefficiencies between power markets in Canada, the U.S., and Europe for the Alberta Electric System Operator. Evaluation of options for improving seams based on other markets' experiences with inter-regional transmission upgrades, energy market scheduling and dispatch, transmission rights models, and resource adequacy.
- **MISO Resource Adequacy Construct.** For MISO, conducted a review of the Midwest ISO's resource adequacy construct. Subsequent and ongoing assistance to MISO in enhancing the market design for resource adequacy related to market redesign, capacity market seams, and accommodation of both regulated and restructured states. Provided background presentations to stakeholders on the capacity market design provisions of NYISO, PJM, CAISO, and ISO-NE.
- **PJM Review of Resource Adequacy and Capacity Market Design: 2011 and 2014.** For PJM Interconnection, conducted a review of PJM's Reliability Pricing Model (RPM) on behalf of the market operator. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures,

and other market mechanisms. Related testimony submitted before the Maryland Public Service Commission.

- **Cost of New Entry Study to Determine PJM Auction Parameters: 2011 and 2014.** For PJM Interconnection, partnered with engineering, procurement, and construction firm to develop bottom-up cost estimates for building new gas combined cycles and combustion turbines. Affidavit before the Federal Energy Regulatory Commission and participation in ongoing settlement discussions on the same.
- **Alberta Energy-Only Market Review for Long-Term Sustainability: 2011 and 2013 Update.** For AESO, conducted a review of the ability of the energy-only market to attract and retain sufficient levels of capacity for long-term resource adequacy. Evaluation of the outlook for revenue sufficiency under forecasted carbon, gas, and electric prices, potential impact of environmentally-driven retirements, potential federal coal retirement mandate, and provincial energy policies.
- **Review of International Energy-Only, Capacity Market and Capacity Payment Mechanisms.** For PJM Interconnection, conducted a review of energy-only markets, capacity payment systems, and capacity markets on behalf of PJM market operator. Reviewed reliability, volatility, and overall investment outcomes related to details of market designs in bilateral, centralized, and forward commitment markets.
- **Russian Capacity and Natural Gas Market Liberalization.** On behalf of a market participant, conducted an assessment of market design, regulatory uncertainty, and liberalization success. Focus was on the efficiency of market design rules in the newly introduced system of capacity contracts combined with capacity payments, as well as on the impacts of gas price liberalization delays.
- **Tariff Design for Merchant Transmission Upgrades.** For a transmission developer, evaluated tariff design options for capturing market value of wind and transmission for a market participant proposing a large HVDC upgrade to enable wind developments.
- **PJM Capacity Market Price and Supply Adequacy Forecasting.** For multiple clients, capacity market price analysis, forecasting, and simulations for a number of clients to support investment decisions and bidding strategy. Equilibrium analysis based on projected energy prices and supply-demand fundamentals. Uncertainty analysis surrounding impacts from likely retirements, new builds, state supply contracts, transmission upgrades, demand response penetration potential, and seasonal demand response products.
- **ISO-NE Capacity Market Regulatory Analysis and Price Forecasting.** For multiple clients, capacity price forecasting assuming perfect-foresight retirement and new entry decisions by suppliers, based on going-forward economics including price floor expiration, required environmental upgrades, options to mothball, demand response supply curve, and energy margins.
- **Generation Asset Valuations in PJM, ISO-NE, MISO, and ERCOT.** For multiple clients, top-line operating cost and *revenues* estimation for clients in a number of different markets, to

support investment decision-making regarding asset purchases, sales, or contract negotiations. Evaluations for a number of different asset classes including gas combined cycles, gas- and oil-fired combustion turbines, gas cogeneration, wind, and waste-to-energy facilities. Forecasting locational fuel, emissions, capacity, energy, and ancillary services prices. Detailed plant dispatch modeling against forecasted hourly energy and ancillary price profiles including incorporation of dispatch constraints such as steam obligations, startup costs, maintenance contract provisions, and power purchase agreement terms. Producing back-casts for dispatch validation and forecasts for future operating margins estimates.

- **Wind and Storage.** For a developer of potential storage assets, simulation analysis modeling combined effects of gas dispatch, wind variability, load variability, and minimum generation conditions to determine the value of electric storage under various levels of wind penetration. Conducted portfolio analysis to determine the optimal level of storage on a systems level to minimize cost as a function of wind penetration levels.
- **Impact of Carbon Prices on Coal Generator Retirement.** For a PJM market participant, conducted a zone-level analysis of PJM market prices and used unit-level data to conduct a virtual dispatch of coal units under a series of long-term capacity, fuel, and carbon price scenarios. Modeled retirement decisions of plants by PJM zone and the effect of the carbon price on the location and aggregate size of these retirement decisions.
- **Southern Company Independent Auction Monitor.** Sponsored by Southern Company, developed auction monitoring capability and protocol development for daily and annual audits of internal company processes and data inputs related to load forecasting, purchases and sales, and outage declarations. Analysis of company data to develop monitoring protocols and automated tools. Coordinated implementation of data collection and aggregation system required for market oversight and for detailed internal company data audits.
- **FTR and Virtual Bidding Market Manipulation Litigation for PJM.** For PJM Interconnection, analyzed financial transmission rights, energy market, and virtual trading data for expert testimony regarding market manipulation behavior.

SELECTED PUBLICATIONS AND REPORTS

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2014 PJM Variable Resource Requirement Parameter Review

At PJM's direction and having successfully earned the bid to perform the work, The Brattle Group conducted a review of Variable Resource Requirement curve parameters. The review was completed in compliance with the Section 5.10a of the PJM Tariff, which requires a quadrennial review of the three key parameters in the Variable Resource Requirement curve: the shape of the VRR curve, the Cost of New Entry, and the Energy and Ancillary Services offset methodology.

Brattle's preliminary findings were shared with PJM stakeholders in an April 29 special meeting of the MRC and Brattle's final reports and recommendations to PJM are posted on pjm.com

PJM has reviewed Brattle's analysis and recommendations and subsequently, has developed preliminary PJM staff recommendations. These recommendations will be the basis for discussion by stakeholders in the Capacity Senior Task Force in which PJM will seek to achieve consensus on modifications to the shape of the VRR Curve, CONE and E&AS. PJM's preliminary recommendations are posted on pjm.com.

The deadline for stakeholder consensus on recommendations is August 31, 2014, with a FERC filing deadline of October 1, 2014.

Third Triennial Review of PJM's Variable Resource Requirement Curve

PREPARED FOR

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May 15, 2014

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Table of Contents

Executive Summary

The Brattle Group has been commissioned by PJM Interconnection, L.L.C. (PJM) to evaluate the parameters and shape of the administrative Variable Resource Requirement (VRR) curve used to procure capacity under the Reliability Pricing Model (RPM), as required periodically under the PJM Tariff.[1] Consistent with the review scope specified in PJM's Tariff, we evaluate three key elements of RPM: (1) the Cost of New Entry (CONE) parameter; (2) the methodology for determining the Net Energy and Ancillary Services (E&AS) Revenue Offset; and (3) the shape of the VRR curve. For each of these elements, we evaluate how well the current design supports RPM's resource adequacy and other design objectives, and provide recommendations on how this performance can be improved.

A. Cost of New Entry

The administrative Gross CONE value reflects the net revenues a new generation resource needs to earn to enter the market and recover its capital investment and annual fixed costs. Gross CONE is the starting point for estimating the *Net* CONE. Net CONE is defined as the operating margins that a new resource would need to earn in the capacity market, after netting margins earned in the E&AS markets. Accurate Net CONE estimates are critical to RPM performance because they provide the benchmark prices against which administratively-determined system and local VRR curves are defined. Over- or under-estimated Net CONE values would result in either over- or under-procuring capacity relative to the quantity needed to satisfy PJM's resource adequacy standard.

To develop updated CONE values applicable for the 2018/19 planning year, we partnered with the engineering services firm Sargent & Lundy. We recommended that PJM adopt these updated CONE values based on bottom-up engineering cost estimates for simple-cycle combustion turbine (CT) and combined cycle (CC) generation plants. We also review the methodology to calculate "levelized" annual costs, indices used to update CONE between CONE studies, and the choice of reference technology. Our principal recommendations regarding CONE for PJM's and stakeholders' further consideration are:

1. **Adopt updated CONE estimates**. Our updated level-nominal CONE estimates are within +/- 11% of PJM's 2017/2018 parameters (escalated by 3% to 2018 dollars), depending on CONE Area and technology. These estimates are based on plant specifications consistent with predominant industry practice and to conform to environmental requirements, infrastructure availability, and economic factors. Cost estimates incorporate current costs

[1] To date, PJM has required a triennial review of these parameters; in the future the review will be required only once every four years. See PJM (2014b), Section 5.10.a.iii.

of equipment, materials, and labor. Our levelized CONE calculation also incorporates an updated cost of capital estimate for merchant generation projects, which we estimate at 8.0% on an after-tax weighted average cost of capital (ATWACC) basis. While we present a summary of our updated CONE estimates in this report, full details are included in our separate, concurrently-released report, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date."

2. **Adopt level-real CONE values**. We recommend replacing PJM's level-nominal calculation (yielding annual CONE values that are assumed to stay constant for 20 years in actual, nominal dollars) with a level-real calculation (which would yield annual CONE values that are assumed to increase with inflation over time). This alternative level-real calculation is consistent with the approach used by New York Independent System Operator (NYISO) and ISO New England (ISO-NE), and we believe it is more representative of investors' expected recovery of capital and fixed costs over the long term. Level-real reflects a market view in which capital recovery remains constant in real (current) dollar terms as a result of two approximately offsetting factors: (a) the rate of technology cost escalation for new plants (a rate somewhat higher than inflation), and (b) the rate of performance improvement of future entrants that will tend to erode the future capacity market prices earned by today's entrants. Adopting this recommendation would reduce CONE values for the RPM delivery year by approximately 15%. For example, our updated CONE estimates for CTs and CCs in the Eastern Mid-Atlantic Area Council (Eastern MAAC or EMAAC) are $127,300/MW-yr and $173,100/MW-d in level-real terms, compared to our estimates of $150,000 and $203,900 in level-nominal terms.

3. **Consider replacing the Handy-Whitman Index (H-W) for annual updates**. To escalate CONE values annually between CONE studies, we recommend that PJM consider replacing the Handy-Whitman "Other" index with a weighted composite of wage, materials, and turbine cost indices from the Bureau of Labor Statistics (BLS). We believe such an approach would more accurately reflect industry cost trends that are the underlying drivers of changes to CONE.

4. **Consider adopting the average of CC and CT Net CONE values defining the VRR curve.** Rather than relying only on CT Net CONE estimates for defining the VRR curve, we recommend that PJM consider setting Net CONE based on the average of CC and CT Net CONE estimates. This would recognize that CC plants are the predominant technology under development by merchant generators (which increases the accuracy of Gross CONE estimates), while avoiding a complete switch away from the currently-defined CT reference technology. In the short term, the average of CC and CT Net CONE would be lower than a CT-based net CONE (if no other changes were made), or may be slightly higher or lower (if all of our recommended changes to the E&AS methodology are adopted). In the long-term our recommended approach will help stabilize Net CONE values under fluctuating market conditions and estimation errors that differently impacts CCs and CTs.

5. **Align CONE Areas more closely to modeled Locational Deliverability Areas (LDAs).**[2] We recommend that PJM consider revising the definitions of CONE Areas to more closely align with the modeled LDAs, by: (a) using the *CONE Area 3: Rest of PJM* estimate for the system-wide VRR curve (rather than the current fixed value adopted in settlement); (b) using the *CONE Area 4: Western MAAC* estimate for the MAAC VRR curve (rather than taking the minimum of sub-LDA numbers); and (c) combining *CONE Area 5: Dominion* into *CONE Area 3: Rest of PJM*, given that the Area 5 estimate has not been used to date. The result would be to develop a total of only four Gross CONE estimates in future studies, one for each of the four permanent LDAs.
6. **Consider introducing a test for a separate Gross CONE for small LDAs.** We also recommend that PJM introduce a test to determine whether smaller LDAs should have a separate Gross CONE estimate. In general, such a separate estimate would only be needed if the small LDA is persistently import-constrained, shows little evidence of potential for new entry, and shows evidence of structurally higher entry costs (*e.g.*, because the reference technology cannot be built there).

B. NET ENERGY AND ANCILLARY SERVICE REVENUE OFFSET

As noted above, the E&AS revenue offset is intended to estimate the net revenues (or operating margins) the reference resource would earn from energy and ancillary services markets. The E&AS offset is subtracted from the estimated Gross CONE value, yielding the Net CONE parameter used for setting VRR curve prices. We evaluate PJM's historical E&AS offset estimates by comparing against the actual E&AS margins earned by generation units similar to the reference resources, and find that PJM's historical estimates are over-estimated for CCs in all locations and over-estimated for CTs in the Southwestern Mid-Atlantic Area Council (SWMAAC). We also compare the historical three-year average E&AS estimate, from which PJM's current Net CONE parameter is estimated, to an indicative forward-looking E&AS estimate based on futures prices for the RPM delivery year and find them to be very different for the CC. Finally, we find that the locations used for estimating E&AS margins are not well aligned with the LDAs for which VRR curves are defined. As a result, our principal recommendations for further consideration by PJM and its stakeholders are:

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[2] Note that the current CONE Areas include the following load zones: (1) EMAAC includes Atlantic City Electric Company (AECO), Delmarva Power and Light (DPL), Jersey Central Power and Light Company (JCPL), PECO Energy Company (PECO), Public Service Enterprise Group (PSEG), and Rockland Electric Company (RECO); (2) SWMAAC includes Baltimore Gas and Electric Company (BGE) and Potomac Electric Power Company (PepCo); (3) Rest of RTO includes American Electric Power (AEP), Allegheny Power System (APS), American Transmission Systems, Inc (ATSI), Commonwealth Edison (ComEd), Dayton Power and Light Company (Dayton), Duke Energy Ohio/Kentucky (DEOK), and Duquesne Lighting Company (Duquesne); (4) WMAAC includes Metropolitan Edison Company (MetEd), Pennsylvania Electric Company (PenElec), and Pennsylvania Power and Light Company (PPL). LDA detailed definitions and structure in PJM (2014a).

1. **Calibrate historical E&AS estimates to reflect plant actuals.** We recommend further investigating why PJM's simulated historical E&AS estimates exceed actual margins of CCs in all areas by roughly $40,000/MW-yr and by roughly $25,000/MW-yr for CTs in SWMAAC. Given the large discrepancies, we recommend that PJM compile a more detailed set of plant-specific cost and revenue data for representative units that can be used for such a calibration, and then adjust its historical simulation approach to develop E&AS numbers that are as reflective as possible of these actual plant data in each location. This adjustment would require identifying and accounting for factors that may be depressing actual net revenues below simulated levels, such as operational constraints, heat rate issues, differences in variable and commitment costs, or fuel availability. This analysis would inform how to develop more realistic simulations of E&AS margins, and avoid overstating E&AS offsets and understating Net CONE values, which risks procuring less capacity than needed to meet PJM's resource adequacy objectives. To allow flexibility in this calibration exercise, we also recommend that PJM consider eliminating Tariff language specifying an exact ancillary service (A/S) adder and variable operations and maintenance (VOM) cost assumption.

2. **Develop a forward-looking estimate of Net E&AS revenues.** An E&AS offset based on three years of historical prices can be easily distorted by anomalous market conditions that are not representative of what market participants expect in the future RPM delivery year. The threat of significant distortions due to unusual historical market conditions has increased with PJM's new shortage pricing rules that will magnify the impact of shortages. For example, unusual weather or fuel market conditions can cause prices to spike, increasing E&AS revenues beyond what a generation developer would expect to earn in the future under more typical weather conditions. Historical prices are also 4 to 6 years out of date relative to delivery period corresponding to a three-year forward Base Residual Auction (BRA) and, therefore, may not be a good indicator of future market conditions. For these reasons, we recommend that PJM evaluate options for incorporating futures prices for fuel and electricity into this analysis, similar to the stakeholder-supported approach proposed to the Federal Energy Regulatory Commission (FERC) by ISO-NE. Currently, such a forward-looking E&AS approach would likely produce results similar to three-year historical approach for the CT, but substantially below the historical approach for the CC (resulting in a similar CT Net CONE, but an increased CC Net CONE).

3. **Align E&AS offset and Net CONE calculations more closely to modeled LDAs**. The current approach calculates E&AS offsets based on prices in a single tariff-designated energy zone for each CONE Area. As a result, the E&AS offset that is applied to a specific LDA may not be calculated based on prices in that LDA, but on prices in the parent LDA, a sub-LDA, or an adjacent LDA, none of which would provide an accurate E&AS estimate for the LDA and thus may cause under- or over-stated Net CONE values. We recommend that each LDA's E&AS offset be estimated based on prices within that LDA. For large LDAs that cover many zones, such as the Regional Transmission Organization (RTO) and Mid-Atlantic Area Council (MAAC), the E&AS offset could be based on an

injection-weighted generation bus average locational marginal price (LMP) across the LDA, or an average of zone-level E&AS estimates weighted by the quantity of RPM generation offers from each zone in the last BRA. This more accurate approach would increase CONE for CT plants in PSEG, PSEG North, PepCo, and MAAC, while decreasing it in American Transmission Systems, Inc. (ATSI), ATSI-Cleveland (ATSI-C), and Delmarva Power and Light-South (DPL-South), by roughly $4,000-6,000/MW-yr based on 2017/2018 RPM parameters.

4. **Consider imposing the parent-LDA Net CONE value as a minimum for sub-LDA Net CONE values**. We recommend that PJM consider imposing a minimum Net CONE for sub-LDAs at the parent-LDA Net CONE value, either for all LDAs or at least for medium-sized or small LDAs (*i.e.*, for all LDAs smaller than MAAC or EMAAC). This recommendation would safeguard against errors and associated under-procurement in small LDAs. Such errors are more likely to occur in small LDAs, such as SWMAAC, which may have idiosyncratic conditions and small sample sizes for calibrating CONE and E&AS estimates, and where under-procurement has disproportionately high reliability consequences. Even if Net CONE were truly lower in a small LDA, imposing a "parent-minimum" constraint would avoid down-shifting the VRR curve and offsetting the locational investment signals created by E&AS prices. This recommendation could increase Net CONE in some modeled LDAs (*e.g.*, by approximately $13,000/MW-yr in SWMAAC and PepCo under 2017/18 parameters) but likely would have no incremental effect if our other E&AS recommendations were adopted. If PJM and stakeholders decide not to pursue this recommendation, it would at least be necessary to carefully investigate E&AS and CONE estimates whenever Net CONE values in import-constrained LDAs are substantially below the Net CONE estimates of the parent LDA, such as in SWMAAC where low historical Net CONE estimates were caused by inaccurately high E&AS estimates.

C. THE VARIABLE RESOURCE REQUIREMENT CURVE

In our review of the VRR curve, we rely heavily on probabilistic simulations of RPM auction outcomes using a Monte Carlo simulation model that estimates the distribution of capacity market price and quantity outcomes under a particular demand curve shape. We use these results to determine whether the existing VRR curves could meet PJM's resource adequacy and other RPM design objectives. Our probabilistic simulation model differs from the model iterations used to support the development and prior evaluations of the VRR curve in that it: (a) simulates RPM auctions at both the RTO and LDA levels; (b) incorporates realistic supply curve shapes developed from historical BRA offer data; and (c) relies on realistic "shocks" to supply, demand, and transmission informed by and calibrated based on actual historical market conditions and auction outcomes.

We base our probabilistic simulations on long-term equilibrium market conditions (not current or near-term market conditions) under which total supply adjusts until the long-term average price over all draws equals Net CONE. We estimate a distribution of price and quantity outcomes by applying realistically-sized "shocks" to supply, demand, administrative Net CONE, and transmission parameters, around the expected value. We translate the resulting distributions of clearing prices and quantities into a set of metrics for evaluating RPM performance against four objectives. These objectives, determined in consultation with PJM staff, are:

(1) Achieve an average Loss-of-Load Event (LOLE) of one event in ten years for the system, and a 1-in-25 conditional LOLE in all LDAs (LOLEs are calculated as a function of cleared quantities, based on the results of PJM's reliability studies);

(2) Rarely fall below 1-in-5 LOLE, which is approximately 1% below PJM's Installed Reserve Margin (IRM) target, the point at which PJM is authorized to conduct backstop procurement auctions under certain conditions;

(3) Be resilient to changes in market conditions, administrative parameters, and uncertainties, but without relying on costly over-procurement to eliminate all potential risks; and

(4) Mitigate price volatility and susceptibility to the exercise of market power.

We find that the existing VRR curve would not satisfy these performance objectives and fail to achieve resource adequacy objectives at both the system-level and the local level on a long-term average basis. For example, we estimate that the average LOLE across all years would be 0.12 (*i.e.,* 0.12 events per year or 1.2 events in 10 years) at the system level, with reliability falling below 1-in-5 LOLE in 20% of all years. These results vary across a range of modeling assumptions, RPM parameter values, and economic shocks that might reasonably be encountered, with objectives being met in some scenarios but widely missed in others. These findings differ from RPM market experience to date because we model long-term equilibrium conditions under which existing surplus resources and low-cost sources of new capacity are exhausted. To improve RPM performance, we recommend the following VRR Curve revisions:

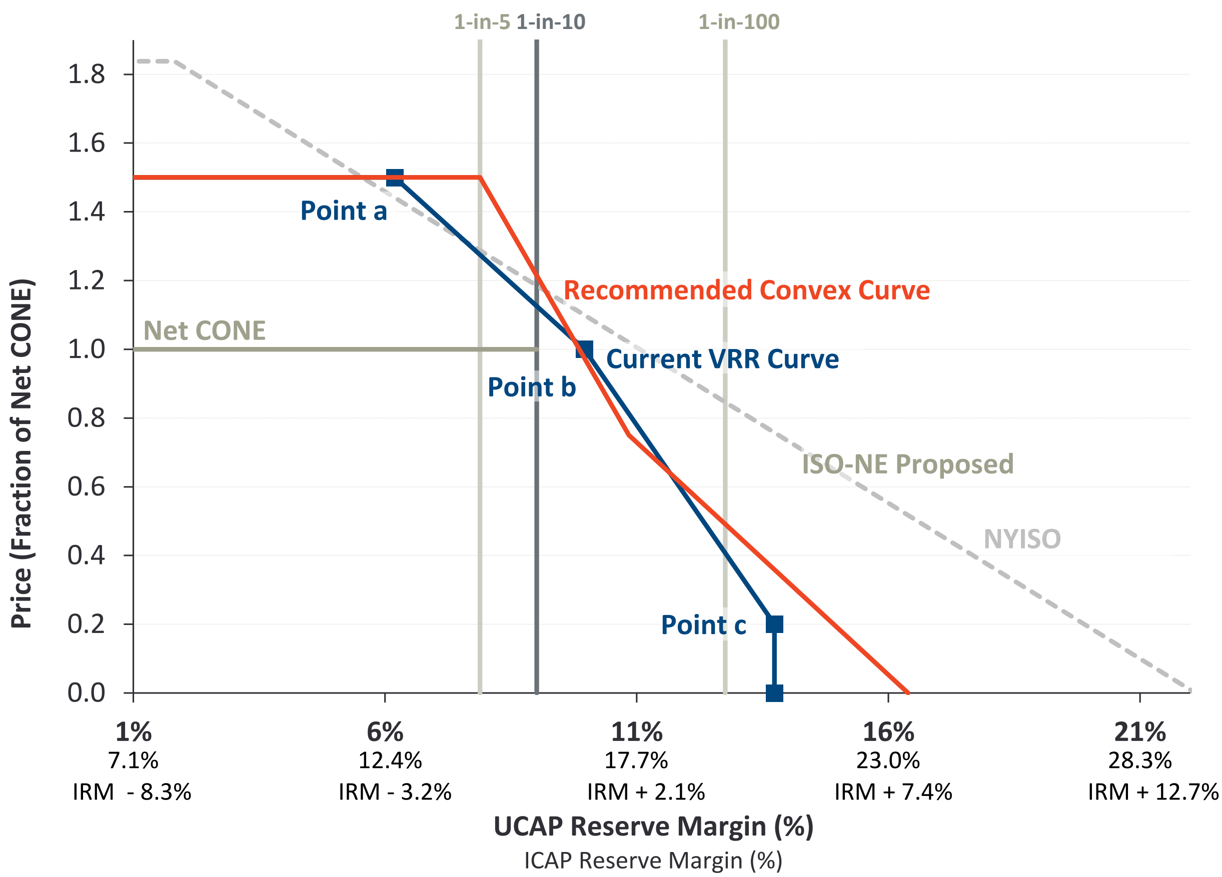
1. **Right-shift point "a".** We recommend that PJM right-shift point "a" (the highest-quantity point at the price cap) to a quantity at 1-in-5 LOLE (at approximately IRM-1%). This change would significantly improve reliability outcomes by providing stronger price signals when supplies become scarce, without right-shifting the entire distribution of expected reserve margins. This change would not increase long-term average prices, which would be determined by the market, based on the true Net CONE developers incur to develop new resources. Right-shifting point "a" would also make the VRR curve more consistent with PJM's current reliability backstop auction trigger at IRM-1%, such that PJM would procure all available resources through the BRA before any such backstop auction could be triggered.

2. **Stretch the VRR Curve into a convex shape.** We recommend that PJM consider adopting the convex shape (*i.e.*, less steep at higher reserve margins) as illustrated in Figure ES-1, with its parameters tuned such that the curve will meet the 1-in-10 reliability standard on average under our base modeling assumptions. This convex shape is more consistent

with a gradual decline of reliability at higher reserve margins and helps to reduce price volatility under such market conditions. Similar to the prior recommended change, this revision also would not affect long-term average prices. However, because the recommended convex VRR curve would increase the expected total procured quantity, PJM-wide capacity procurement costs would increase by approximately 0.2%.

The combined effect of these changes is reflected in our recommended convex curve in Figure ES-1. We estimate that adopting these recommendations would result in meeting the 1-in-10 LOLE objective on average, and would reduce the frequency of years below 1-in-5 LOLE to 13% under base modeling assumptions, while also significantly improving VRR curve performance under stress scenarios. The figure also shows NYISO's capacity market demand curve and ISO-NE's proposed curve for comparison.

Figure ES-1
VRR Curve Recommendation



Sources and Notes:

ISO-NE and NYISO curves reported using those markets' price and quantity definitions in most cases, but relative to PJM's estimate of 2016/17 Net CONE, Reliability Requirement, and 1-in-5 quantity point for the PJM system.

Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, calculated relative to the full Reliability Requirement without applying the 2.5% holdback for short-term procurements, see PJM (2013a).

For NYISO Curve the ratio of reference price to Net CONE is equal to 1.185 and is consistent with the 2014 Summer NYCA curve, see NYISO (2014a) and (2014b), Section 5.5.

ISO-NE Curve shows parameters proposed in April 2014 with cap quantity adjusted to 1-in-5 as estimated for PJM, see Newell (2014b), pp 10-12.

Regarding the local VRR curves that apply to individual LDAs, we find that the current curves result in even greater expected reliability shortfalls than at the system level. Maintaining resource adequacy in LDAs is more challenging because typical fluctuations in supply and demand have a relatively larger impact in small LDAs, and additional uncertainty is introduced by fluctuations in LDA import constraints, as defined by the Capacity Emergency Transfer Limit (CETL) parameters. A single typical change to CETL or the entry or retirement of a single power plant can exceed the width of the entire VRR curve. Consequently, the LDAs are exposed to significantly wider distributions of reserve margin outcomes as a percentage of the local Reliability Requirement. The lower-reliability end of the distributions can bring the average conditional LOLE well below its 1-in-25 target level in many LDAs, particularly in our stress scenarios with higher shocks or with systematic Net CONE estimation error. Moreover, the likelihood of Net CONE estimation error is higher in small LDAs due to idiosyncratic factors (*e.g.*, siting, environmental, or infrastructure related) that may not be incorporated in CONE studies, even if our recommendations related to gross and net CONE are implemented. The small LDAs may offer sparse data on actual projects' costs, and E&AS margins are harder to calibrate if there are few comparable plants.

To improve performance, we recommend that PJM and its stakeholders also apply our system-wide VRR Curve recommendations at the LDA level, and also consider two additional recommended revisions. We estimate that these additional recommendations will result in achieving at least the 1-in-25 conditional LOLE objective on average across all LDAs in a non-stress scenario, while also improving outcomes under the stress scenarios.

1. **Increase the LDA price cap to 1.7× Net CONE**. We find that a higher cap substantially improves simulated outcomes in LDAs because stronger price signals when supplies become scarce. The prospect of higher prices during low reliability outcomes provides greater incentives for suppliers to locate there rather than in the parent LDA. This would reduce the frequency of price separation from parent zones, but increase the magnitude of those price separation events when they do occur. Similar to all of our other recommendations, long-term average capacity prices would not be affected.

2. **Impose a minimum curve width equal to 25% of CETL**. We find that raising the LDA price cap to 1.7× Net CONE would not by itself achieve the local reliability objective in a non-stress scenario, with even larger gaps under stress scenarios. Performance is worst in the smallest, most import-dependent zones. To address this performance gap, we find that applying a minimum curve width based on CETL to be a targeted and effective way to improve performance. Under year 2016/17 parameters, applying a minimum width (from point "a" to point "c") of 25% of CETL would not affect the MAAC or EMAAC VRR curves, but would increase the width in SWMAAC (from 1,351 MW to 1,785 MW), ATSI (from 1,268 to 1,814 MW), PSEG (from 1,004 to 1,560 MW), PepCo (from 703 to 1,433 MW), PSEG-N (from 502 to 683 MW), and ATSI-C (from 481 to 1,273 MW), and DPL-S (from 246 to 459 MW). While this recommendation would not increase long-term average *prices*, it would increase total procurement costs (although by less than 2.3%

depending on the LDA) by increasing the fraction of total capacity procured locally within the LDAs. Moreover, it would likely increase prices in the short term, moving prices in import constrained LDAs from below long-term-equilibrium levels toward equilibrium pricing more quickly.

These results and VRR curve recommendations are based on the assumption that there is no systematic bias in the load forecast, Reliability Requirements, or the Net CONE estimate. However, as noted above, we do find both positive and negative biases in various components of current Net CONE estimates. Hence, our simulation results of VRR curve performance and our associated recommendations assume that these biases will be corrected. We therefore encourage PJM and stakeholders to consider our entire package of recommendations rather than a subset that might bias the results in one direction or the other.

We also note that we took as given the PJM resource adequacy standards that define the "objectives" in our study. Although we discussed resource adequacy standards in our prior RPM reviews, evaluating these standards is not within the defined scope of this present engagement. Other RPM-related topics beyond the scope of this study include: reliability challenges such as winter fuel availability; load forecasting; forward procurement periods and delivery durations; Incremental Auction (IA) design; the 2.5% holdback; participation rules and penalties (*e.g.*, for Demand Response (DR), imports, and new generation); Minimum Offer Price Rules (MOPR) and other mitigation measures.

D. Other Recommendations

Through our analyses of the interactions between CONE, E&AS offsets, and VRR curve performance, we also identified some potential improvements to closely-related market design elements that may reduce RPM price volatility or better rationalize prices with locational reliability value. While these following recommendations are not strictly within the defined scope of our study, they are related and would lead to performance improvements that could not be achieved through changes to the VRR curve alone. We therefore offer these additional recommendations for consideration by PJM and its stakeholders:

1. **Consider defining local reliability objectives in terms of normalized unserved energy.** We recommend that PJM evaluate options for revising the definition of local reliability objective, currently set at a 1-in-25 conditional LOLE standard. Instead, PJM could explore options for an alternative standard based on normalized expected unserved energy (EUE), which is the expected outage rate as a percentage of total load. We also recommend exploring this alternative standard based on a multi-area reliability model that simultaneously estimates the location-specific EUE among different PJM system and sub-regions. The result would be a reliability standard that better accounts for the level of correlation between system-wide and local generation outages, and a more uniform level of reliability for LDAs of different sizes and import dependence.

2. **Consider alternatives to the "nested" LDA structure.** We recommend that PJM consider generalizing its approach to modeling locational constraints in RPM beyond import-constrained, nested LDAs with a single import limit. As the number of modeled LDAs increases and the system reserve margin decreases, we see the potential for different types of constraints emerging that do not correspond to a strictly nested model. A more generalized "meshed" LDA model (with simultaneous clearing during the auction) would explicitly allow for the possibility that some locations may be export-constrained, that some LDAs may have multiple transmission import paths, and some may have the possibility of being either import- or export-constrained, depending on RPM auction outcomes.

3. **Evaluate options for increasing stability of Capacity Emergency Transfer Limits (CETL).** We recommend that PJM continue to review its options for increasing the predictability and stability of its CETL estimates. Based on our simulation results, we find that reducing CETL uncertainty could significantly reduce capacity price volatility in LDAs. Physical changes to the transmission system would need to continue to be reflected as changes in CETL, but reducing uncertainty would provide substantial benefits in reducing price volatility. We have provided more detailed suggestions on options to evaluate for mitigating volatility in CETL in our 2011 RPM Review.[3]

4. **Consider revising the RPM auction clearing mechanics within LDAs based on delivered reliability value.** As another option for enhancing locational capacity price stability and overall efficiency, we recommend that PJM consider revising its auction clearing mechanics to produce prices that are more proportional to the marginal reliability value of incremental resources in each LDA. Such a mechanism would determine the lowest-cost resources for achieving local reliability objectives by selecting either: (a) a greater quantity of lower-cost imports from outside the LDA, but recognizing the lower reliability of imported resources (due to added transmission import capability risk and lost diversity benefits as an LDA becomes more import-dependent); or (b) a smaller quantity of locally-sourced resources with greater reliability value (*i.e.*, without the additional transmission availability risk). This approach would also stabilize LDA pricing by allowing for more gradual price separation as an LDA becomes more import-dependent (rather than price-separating only once the administratively-set import constraints bind).

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[3] See Pfeifenberger, *et al.* (2011).

II. Background

This study provides an assessment of the parameters and shape of PJM Interconnection, LLC's Variable Resource Requirement (VRR) curve, used to procure capacity under the Reliability Pricing Model (RPM). As background to this analysis, we provide here a brief overview of the structure of RPM and the VRR curve, along with references to more detailed documentation as available in PJM's Tariff and manuals.[4]

A. Study Purpose and Scope

We have been commissioned by PJM to evaluate the parameters and shape of the administrative VRR curve used to procure capacity under RPM, as required periodically under the PJM tariff.[5] The purpose of this evaluation is to evaluate the effectiveness of the VRR curve in supporting the primary RPM design objective of maintaining resource adequacy at the system and local levels, as well as other performance objectives such as mitigating price volatility and susceptibility to the exercise of market power. Our study scope includes: (1) estimating the Cost of New Entry for each Locational Deliverability Area; (2) reviewing the methodology for determining the Net Energy and Ancillary Services Revenue Offset; and (3) evaluating the shape of the VRR curve. This report documents our analysis and findings under all three topic areas, although the full supporting details for our updated CONE estimates are contained in a separate detailed report.[6]

Under the previous two triennial reviews, we assessed the overall effectiveness of RPM in encouraging and sustaining infrastructure investments, reviewed auction results over the first eight Base Residual Auctions (BRAs) and first seven Incremental Auctions (IAs), analyzed the effectiveness of individual market design elements, and presented a number of recommendations for consideration by PJM and its stakeholders. The results of these prior assessments are presented in our August 2011 and June 2008 reports reviewing RPM's performance ("2011 RPM Report" and "2008 RPM Report").[7] The scope of this study is more narrowly focused than our prior RPM reviews. It does not include a review and summary of RPM auction results, solicitation of stakeholder input, the 2.5% Short-Term Resource Procurement Target (STRPT), the Limited and Sub-Annual Resource Constraints, or an evaluation of other RPM parameters beyond CONE, the E&AS offset, and the VRR curve.

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4 As the authoritative sources documenting the structure of RPM, see Attachment DD of PJM's Tariff, and Manual 18, PJM (2014 a-b).

5 See PJM (2014b, Attachment DD, Sections 5.10.a.iii and 5.10.a.vi.C-D).

6 See Newell (2014a).

7 See Pfeifenberger (2008, 2011).

B. Overview of the Reliability Pricing Model

The purpose of RPM is to attract and retain sufficient resources to reliably meet the needs of consumers at all locations within PJM, through a well-functioning market. It has been doing so since its inception in 2007/08. RPM is now entering its eleventh delivery year of experience, with the next auction scheduled for May 2014 to procure capacity for the 2017/18 delivery year.

RPM is a centralized market for procuring capacity on behalf of all load, with most capacity procured through BRAs conducted three years prior to delivery, and a remaining 2.5% procured through shorter-term IAs. The costs of these capacity procurements are allocated to load serving entities (LSE) throughout the actual delivery year. “Demand” in PJM’s auctions is described by the VRR curve, a segmented downward-sloping curve that is designed to procure enough capacity to meet resource adequacy objectives while avoiding the extreme price volatility that a vertical curve might produce. Recognizing transmission constraints, each of several nested LDAs has its own VRR curve that may set higher prices locally if transmission constraints bind in the auction.

On the supply side, a diversity of existing and new resources compete to sell capacity under RPM, including traditional and renewable generation, demand response, energy efficiency, storage, qualified transmission projects, and imports. Existing resources are required to submit an offer, subject to market monitoring and mitigation; some types of new resources are also monitored to ensure they are being introduced at competitive levels that do not artificially suppress prices. All resources are subject to performance requirements and penalties for non-performance during the delivery year.

RPM also allows for self-supply arrangements, whereby entities with load-serving obligations can sell supply into the auction and earn prices that cancel the load’s price exposure on the demand side. RPM also has an opt-out mechanism in which self-supply utilities can meet a Fixed Resource Requirement (FRR) instead of a variable requirement.

Attachment DD of PJM’s Open Access Transmission Tariff (OATT) and PJM’s Manual 18 describe these and other features of the RPM market design in greater detail.[8] Additional documentation on the parameters and performance of PJM’s RPM include: (a) PJM’s planning period parameters and auction results; (b) our 2008 and 2011 RPM performance reviews; and (c) performance assessments of PJM’s Independent Market Monitor (IMM), as documented in annual State of the Market Reports, assessments of individual auctions’ results, and other issue-specific reports.[9]

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8 See PJM (2014 a,b).

9 See PJM (2007, 2009a,b,c, 2010, 2011, 2012, 2013a, 2014c), Pfeifenberger (2008, 2011). For PJM State of the Market and periodic reports on RPM, see Monitoring Analytics (2014a-b).

C. Description of the Variable Resource Requirement Curve

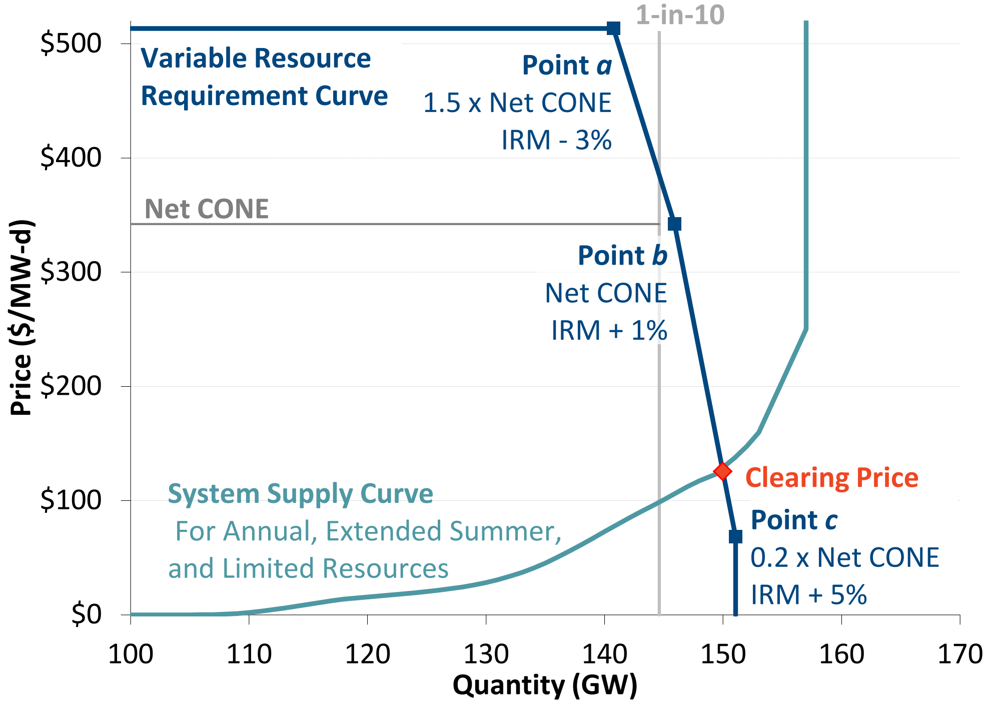
The VRR curve is a downward sloping demand curve illustrated in Figure 1 that is anchored at point "b" at a price of Net CONE and quantity at one percentage point above the installed reserve margin needed to satisfy the system-wide Reliability Requirement. Net CONE is determined as the estimated annualized fixed costs of new entry, or Gross CONE, of a combustion turbine *net* of estimated E&AS margins. The Reliability Requirement is the quantity needed to meet the 1 event in 10 years, or 1-in-10, loss of load event standard.

Gross CONE is estimated administratively as the levelized net revenues that a new entrant needs to earn from the wholesale energy, ancillary, and capacity markets to recover its investment costs. The PJM Tariff stipulates that the parameter be updated through bottom-up engineering cost estimates once every four years, and annual index-based adjustments in other years. The E&AS offset is an administrative estimate of the net revenues that a new entrant with the reference technology would earn from the sale of energy and ancillary services (minus variable costs). Under current RPM rules, the E&AS offset is calculated as a trailing three-year average of estimated historical net energy revenues plus an assumed value for ancillary services revenues ($/MW-yr) as set forth in the Tariff.[10] Net CONE is then calculated as Gross CONE minus the E&AS offset, and reflects the amount of annual capacity market revenue that the new entrant needs for profitable entry.

The VRR curve is designed to yield auction clearing prices higher than Net CONE when the amount of cleared capacity falls below the target reserve margin, and below Net CONE when cleared capacity exceeds the target. Figure 1 compares the PJM-wide capacity supply curve, VRR curve, and auction clearing price and quantity for the 2014/15 BRA.

[10] See PJM (2014b), Section 5.10.a.v.

Figure 1
Capacity Supply and Demand in RPM
(Example: 2014/15 Base Residual Auction)



Sources and Notes:
VRR Curve reflects the system VRR curve in the 2014/2015 PJM Planning Parameters. See PJM (2011.)
Supply curve reflects all supply offers for Annual, Extended Summer, and Limited Resources, stacked in order of offer price and smoothed for illustrative purposes.

By definition, the VRR curve yields a capacity price equal to Net CONE at point "b", at the target reserve margin plus 1 percentage point, or IRM+1%. For lower supply levels to the left of point "b", capacity prices increase linearly until the quantity drops to IRM - 3% at point "a", where the capacity price is capped at the greater of: (1) 150% of Net CONE, or (2) 100% of Gross CONE. At higher reserve margins to the right of point "b", capacity prices decline linearly until IRM + 5% at point "c", where capacity price is equal to 20% of Net CONE. At even higher reserve margins, the capacity price drops to zero.[11]

As was noted in the Federal Energy Regulatory Commission order approving the RPM design,[12] compared to a system that simply attempts to procure capacity to satisfy a target reserve margin (*i.e.*, a vertical demand curve), the downward-sloping demand curve is designed to provide the following advantages:

- The downward-sloping VRR curve reduces capacity price volatility by allowing capacity prices to change gradually with changes to supply and demand. The lower

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11 Formulas for calculating each VRR curve point are from PJM's Manual 18, Section 3.4. See PJM (2014a).

12 December 2006 RPM Order, see FERC (2006), pp. 43-46.

volatility due to a sloped demand curve should render capacity investment less risky, thereby encouraging greater investment at a lower cost.

- The sloped demand curve provides a better indication of the incremental and decremental value of capacity at different planning reserve margins. The sloping VRR curve recognizes that incremental capacity above the target reserve margin provides additional reliability benefit, albeit at a declining rate.

The sloped VRR curve also mitigates the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin. Withholding capacity is less profitable under a sloped demand curve close to the target reserve requirements than under a vertical curve because withholding would result in a smaller increase in capacity prices.

At the local level, individual VRR curves are applied to each LDA based on the local Reliability Requirement and locally estimated Net CONE. Modeled LDAs are sub-regions of PJM with limited import capability due to transmission constraints. If an LDA is import-constrained in an RPM auction, locational capacity prices will exceed the capacity price in the unconstrained part of PJM. Currently there are 27 LDAs defined in RPM, although only 12 LDAs are modeled such that capacity auctions could yield different clearing prices as of the 2017/18 delivery year.[13] Figure 2 is a map of these modeled LDAs, while Figure 3 shows the nested LDA structure as modeled in RPM with sub-LDAs having equal or greater price than all parent-level LDAs.

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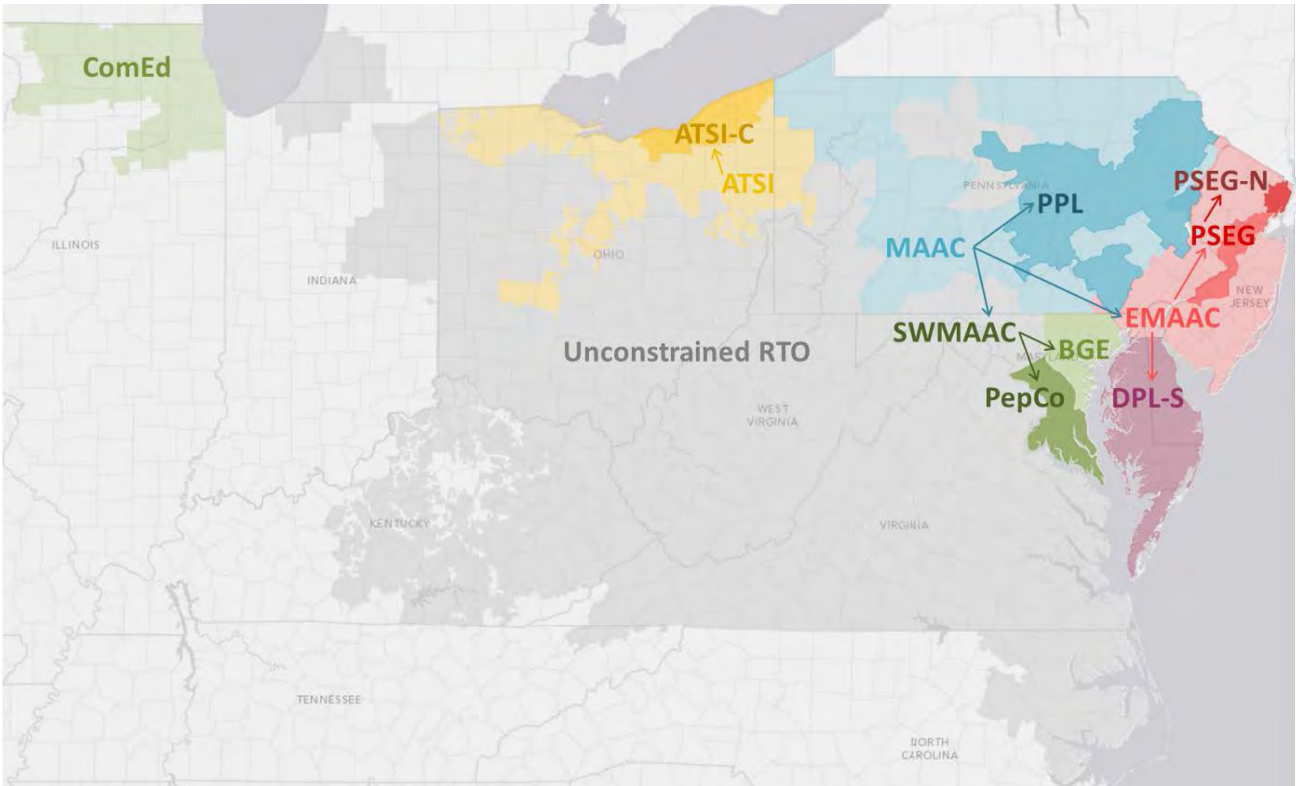
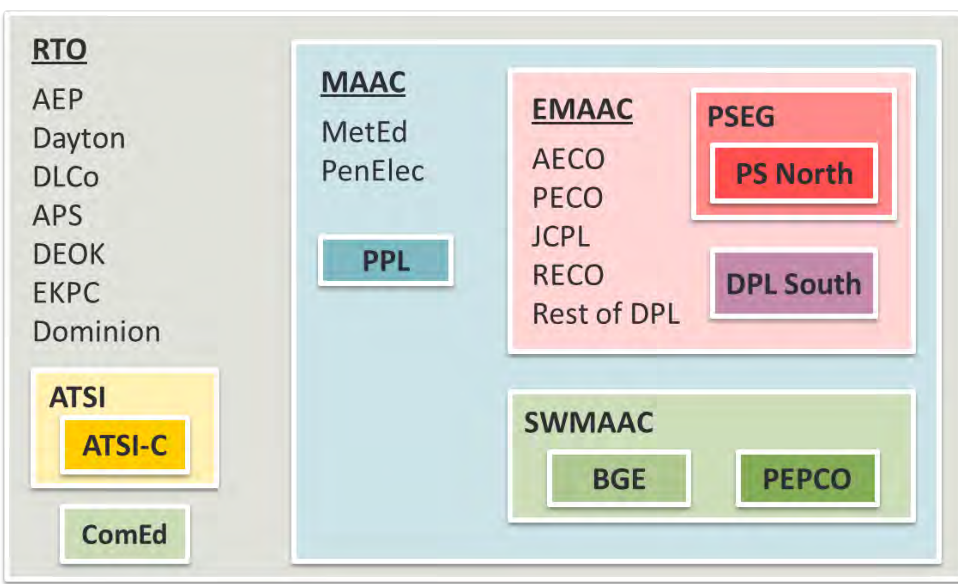
[13] Note that there are a total of 13 internal locational prices, considering the 12 LDAs and the unconstrained RTO, plus border prices for each of PJM's defined import prices, and in each internal region there may also be price separation between Annual resources, sub-annual resources, and call-limited resources. For additional detail, see PJM (2014a).

Figure 2
Map of Modeled Locational Deliverability Areas



Sources and Notes:
Map created with SNL Energy (2014); map reflects modeled LDAs as of 2017/18, PJM (2014c).

Figure 3
Schematic of Nested Structure for Modeled Locational Deliverability Areas and Load Zones



Sources and Notes:
Each rectangle and bold label represent an LDA modeled in 2017/18 BRA; individual load zones that are not modeled in RPM auctions are not bold, see PJM (2014c).

III. Net Cost of New Entry Parameter

The prices and quantities of the VRR curve are premised on the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at Net CONE. Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected E&AS margins) to fully recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. Thus, in order to achieve the desired reserve margin, the VRR curve is assigned a price equal to Net CONE at approximately the point where the quantity equals the desired average reserve margin.[14] Prices decline as reserve margins increase and rise as reserve margins decrease, but all price points on the curve are indexed to Net CONE.

The VRR curve's performance depends on estimating Net CONE as accurately as possible, and especially not understating it significantly. This is because, the purpose of the VRR curve is to achieve PJM's resource adequacy objectives assuming that the estimated Net CONE value accurately represents the true value that new entrants would need to enter the market. Overstating Net CONE would result in procuring more capacity than needed, causing a modest increase in procurement costs; understating it would result in under-procuring capacity with significantly diminished system reliability. (Long-term average prices would be set by true Net CONE in both cases.) We further examine the magnitude, cost and reliability implications of such over- or under-estimated Net CONE values in Sections V and VI below.

This section of our report analyzes the accuracy and robustness of the administrative Net Cost of New Entry estimate from that perspective. Section III.A addresses Gross CONE, providing updated CONE estimates for the 2018/19 delivery year and recommending a revised cost indexing approach for PJM to apply for the following years' annual updates. Section I.B analyzes the E&AS offset, which PJM subtracts from Gross CONE to produce administrative Net CONE values for each auction. We examine the accuracy of the administratively-determined historical E&AS offset compared to the E&AS margins actually earned by generating units similar to the reference technology. We also recommend that the E&AS methodology be: (1) calibrated to actually-earned E&AS margins of plants similar to the reference technology, and (2) modified to estimate a forward-looking offset. In Section III.C we evaluate possible revisions to the locational definitions of the Gross CONE, E&AS, and Net CONE estimates, and finally, in Section III.D we evaluate options for changing the reference technology, including our recommendation to adopt an average of CC and CT Net CONE estimates.

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[14] The exact quantity at Net CONE in the current VRR curve is at IRM + 1%, or slightly higher than the Reliability Requirement, to achieve adequate average performance in spite of likely shocks and uncertainties.

A. GROSS COST OF NEW ENTRY

We provide here a summary of updated engineering cost estimates for PJM's Gross CONE parameters for reference gas CC and gas CT plants, with full supporting detail provided in our concurrently-prepared 2014 CONE Report.[15] These updated CONE estimates would be applicable for adoption in RPM in the 2018/19 delivery year. For the following three years, PJM will update the administrative CONE values using annual index adjustments, currently based on the Handy-Whitman index. We also describe an alternative annual indexing approach that would tie annual updates more closely to underlying cost drivers.

1. Revised Gross CONE Estimates

Updated CONE estimates are needed periodically to ensure that the administrative Net CONE parameter reflects current cost and technology trends. Historically, these estimates have been updated once every three years, and in the future will be updated once every four years.[16] The new CONE estimates, if adopted, would be used as a key parameter defining the VRR curve and as inputs to mitigation thresholds under the MOPR.

As in the 2011 triennial RPM review, we have developed Gross CONE estimates for the current review. We partnered with the engineering services company Sargent & Lundy to provide detailed engineering-based cost estimate that we used to calculate CONE. Table 1 summarizes our recommended CONE estimates for gas CT and CC plants in each of the five PJM CONE Areas for the 2018/19 delivery year. Detailed documentation of these CONE estimates and our study approach is provided in our separate report and associated data files, *2014 Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* (2014 CONE Report).[17] The installed and annualized cost estimates for these reference CT and CC plants presented in Table 1 are in 2018 dollars. The table also compares our results with the 2011 CONE Study and most recent auction parameters, both adjusted to 2018/19 dollars.

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15 See Newell, *et al.* (2014a).

16 See PJM (2014b).

17 See Newell (2014a).

Table 1
Updated CONE Estimates for Gas Simple Cycle and Combined Cycle Plants

		Simple Cycle					Combined Cycle				
		1	2	3	4	5	1	2	3	4	5
		EMAAC	SWMAAC	RTO	WMAAC	Dominion	EMAAC	SWMAAC	RTO	WMAAC	Dominion
Gross Costs											
Overnight	*($m)*	$400	$373	$348	$372	$364	$808	$707	$709	$737	$708
Installed	*($m)*	$420	$391	$364	$390	$382	$885	$775	$777	$808	$776
First Year FOM	*($m/yr)*	$6	$10	$7	$5	$8	$17	$30	$19	$15	$19
Net Summer ICAP	***(MW)***	**396**	**393**	**385**	**383**	**391**	**668**	**664**	**651**	**649**	**660**
Unitized Costs											
Overnight	*($/kW)*	$1,012	$948	$903	$971	$931	$1,210	$1,065	$1,089	$1,137	$1,073
Installed	*($/kW)*	$1,061	$994	$947	$1,018	$977	$1,326	$1,168	$1,193	$1,245	$1,176
Levelized FOM	*($/MW-yr)*	$15,000	$25,600	$18,800	$13,700	$19,600	$26,000	$44,800	$29,500	$23,300	$28,300
After-Tax WACC	***(%)***	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**	**8.0%**	**8.0%**	**8.0%**	**8.0%**	**8.1%**
Levelized Gross CONE											
Level-Real	***($/MW-yr)***	**$127,300**	**$126,000**	**$117,100**	**$121,800**	**$119,900**	**$173,100**	**$167,400**	**$159,700**	**$162,000**	**$154,800**
Level-Nominal	***($/MW-yr)***	**$150,000**	**$148,400**	**$138,000**	**$143,500**	**$141,200**	**$203,900**	**$197,200**	**$188,100**	**$190,900**	**$182,400**
Prior CONE Estimates											
PJM 2017/18 Parameter*	*($/MW-yr)*	$161,600	$150,700	$148,000	$155,200	$132,400	$199,900	$176,300	$192,900	$191,800	$170,100
Brattle 2015/16 Estimate*	*($/MW-yr)*	$145,700	$134,400	$134,200	$141,400	$120,600	$183,700	$161,000	$177,100	$176,700	$157,000
Increase (Decrease) Above Prior CONE Estimates											
PJM 2017/18 Parameter	*($/MW-yr)*	($11,600)	($2,300)	($10,000)	($11,700)	$8,800	$4,100	$20,900	($4,700)	($900)	$12,200
Brattle 2015/16 Estimate	*($/MW-yr)*	$4,300	$14,000	$3,800	$2,000	$20,600	$20,300	$36,200	$11,100	$14,200	$25,400
PJM 2017/18 Parameter	*(%)*	-8%	-2%	-7%	-8%	6%	2%	11%	-3%	0%	7%
Brattle 2015/16 Estimate	*(%)*	3%	9%	3%	1%	15%	10%	18%	6%	7%	14%

Sources and Notes:

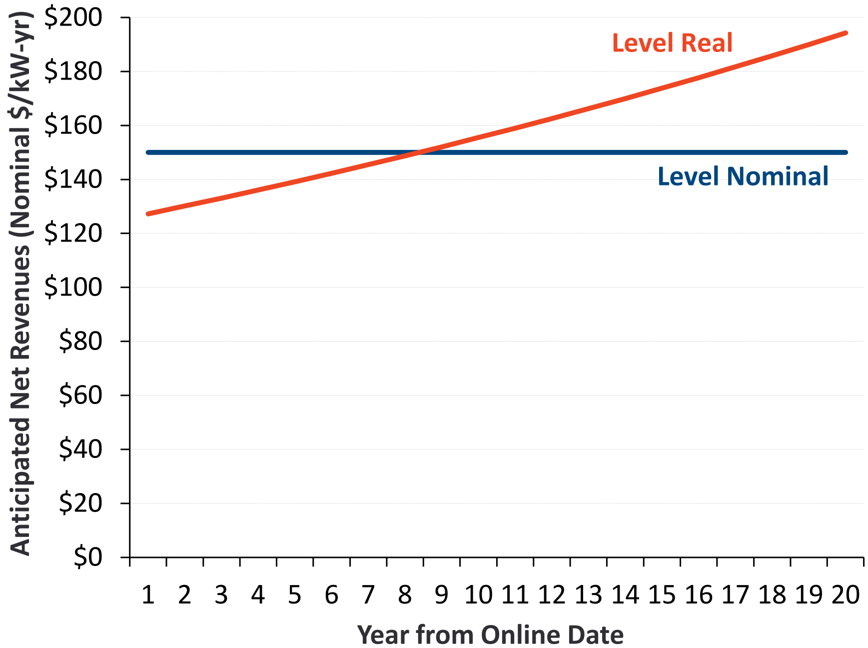
All values are expressed in 2018 dollars, except "overnight" costs, which are in nominal dollars in the year in which they are incurred, see detailed cost estimation in Newell, *et al.* (2014a).

*Brattle 2015/16 estimates and PJM 2017/18 parameters escalated to 2018/19 at approximately 3% annually, based on escalation rates for individual cost components.

2. Level-Real vs. Level-Nominal

Table 1 above reports two sets of levelized CONE estimates, one based on "level-nominal" and the other based on "level-real" cost recovery, with a comparison of the two cost recovery trajectories illustrated in Figure 4. Level-nominal cost recovery reflects an assumed 20-year cost recovery trajectory under which the plants' combined net revenues from the E&AS and capacity markets would remain constant over time in nominal dollar terms, and would not increase over time with factors such as inflation. In contrast, a level-real cost recovery reflects a cost recovery trajectory under which the plants' operating margin would increase over time at an assumed 2.25% rate of inflation, and so would remain constant in inflation-adjusted real terms. Because the reported CONE value refers to just the *first* year of the assumed cost-recovery trajectory, the level-nominal CONE value is higher with their more pessimistic view of future levels of cost recovery. Under either assumed cost profile, the Net Present Value (NPV) of projected future net E&AS and capacity revenues is the same, such that the investor would recover all capital and fixed costs of the investment, including the cost of capital.

Figure 4
Assumed Cost Recovery Profile under Level-Real and Level-Nominal Levelization
(EMAAC Combustion Turbine, Online June 1, 2018)



Sources and Notes:
Values reflect anticipated cost recovery profile for EMAAC CT, consistent with our updated CONE estimates from Table 1 and Newell, *et al.* (2014a).

Which approach is more reasonable depends on which trajectory of total net E&AS and capacity revenues is most likely. However, under a well-functioning market that relies on merchant investments, we expect that total future net revenues will be set by the CONE of future entrants. If technology remained unchanged and its costs would be expected to increase with inflation, a level-real cost recovery trajectory (with constant cost recovery in real, inflation-adjusted dollar terms) would be mostly likely.

As we discussed in our 2011 RPM Review, we believe we are not precisely in this world, but one very similar to it.[18] For example, historical costs of combustion turbines have actually risen faster than inflation. If that trend were to continue, CONE values would increase at a rate faster than inflation, which would make near-term cost recovery needs even lower than the level-real CONE value because future cost recovery values would increase faster than the rate of inflation. However, newer turbine technologies have progressively outperformed their older competitors in thermal efficiency. This reduces the older technology's net revenues at a rate that partially offsets the increase in capacity revenues to the extent that their rate of increase exceeded the rate of inflation. As we have shown in our prior RPM review report, the net effect of these two factors results in a

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[18] See Pfeifenberger, *et al.* (2011).

cost recovery trajectory that increases approximately at the rate of inflation, *i.e.*, is approximately level-real.[19]

We recognize that this analysis is not fully conclusive about the actual trajectory of cost recovery anticipated by generation developers on a forward-looking basis. One could make a case for attempting to determine projections of future revenues representing actual developers' likely views on energy prices, fuel prices, and capacity prices over the 20-year investment life. The entirety of this information is what ultimately determines the "true" value of CONE. On balance, however, we believe level-real is most reasonable for use in RPM, reflecting an assumption that the trajectory of future operating margins will grow with inflation as the net cost of new plants increases over time. We also note that NYISO and ISO-NE use the level-real approach to estimate CONE for the purpose of setting both their demand curves and MOPR.[20]

In sum, we conclude that the level-nominal approach currently used by PJM, likely overstates the true value of CONE, which could yield an upward biased VRR curve and could cause RPM to over-procure—assuming administratively-estimated E&AS offsets are not overstated, as they may be. Thus, we recommend that PJM and its stakeholders consider switching to level-real estimates of CONE, but do so in combination with our other recommendations.

3. Annual Updates According to Cost Indices

PJM's tariff specifies that CONE will be updated annually for each year between the periodic CONE studies by applying the Handy-Whitman "Total Other Production Plant" index for the appropriate location.[21] However, we are concerned that this index has differed significantly from other measures of cost trends for electricity generation plants. Specifically, as shown in Figure 5, this index has escalated more quickly than the rate of cost increases suggested in recent CONE studies.

Aware of this discrepancy, we recently developed an alternative gross capital cost indexing approach for ISO-NE, which it has recently proposed to adopt in is annual Net CONE updating methodology.[22] Under this alternative approach, different indices are used for each line item of the cost analysis. These indices are based on the appropriate subsets of the Producer Price Index (PPI) and the Quarterly Census of Employment and Wages (QCEW) datasets published by the Bureau of Labor Statistics. The PPI indices measure the average change over time in the selling prices received by domestic producers for their outputs, and therefore reflect the increase or decrease in construction costs for a different commercial online year. The QCEW indices are developed from a quarterly count of employment and wages reported by employers covering 98% of U.S. jobs, available at the

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19 For a comprehensive discussion of this topic and supporting analysis, see Section IV.A.3 of Pfeifenberger, *et al.* (2011).

20 For example, see Newell, *et al.* (2014c), p. 7 and NERA (2013), p. 55.

21 See PJM (2014a), p. 27.

22 See Newell, *et al.* (2014c), pp. 66-67.

county, state, and national levels by industry. We believe this approach is more transparent and more closely tied to the approach we use in our engineering cost estimates than is the Handy-Whitman Index.

However, the ISO-NE approach is also somewhat more complex, because it involves updating individual cost components and re-levelizing CONE each year.[23] A simpler alternative that could be adopted in PJM would be to update Gross CONE annually using the weighted average of three BLS indices, with the weights of the three indices equal to the relevant proportion of capital costs.[24] A resulting composite index is shown in Figure 5, consistent with an appropriate cost index for *CONE Area 1: EMAAC*.

We recommend that PJM and its stakeholders consider adopting this indexing approach. Alternatively, we recommend to at least consider changing from the H-W "Total Other Production Plant" index to the H-W "Total Steam Production Plant" index, which better matches the composite index approach as well as the escalation in successive CONE Studies, as illustrated in Figure 5.

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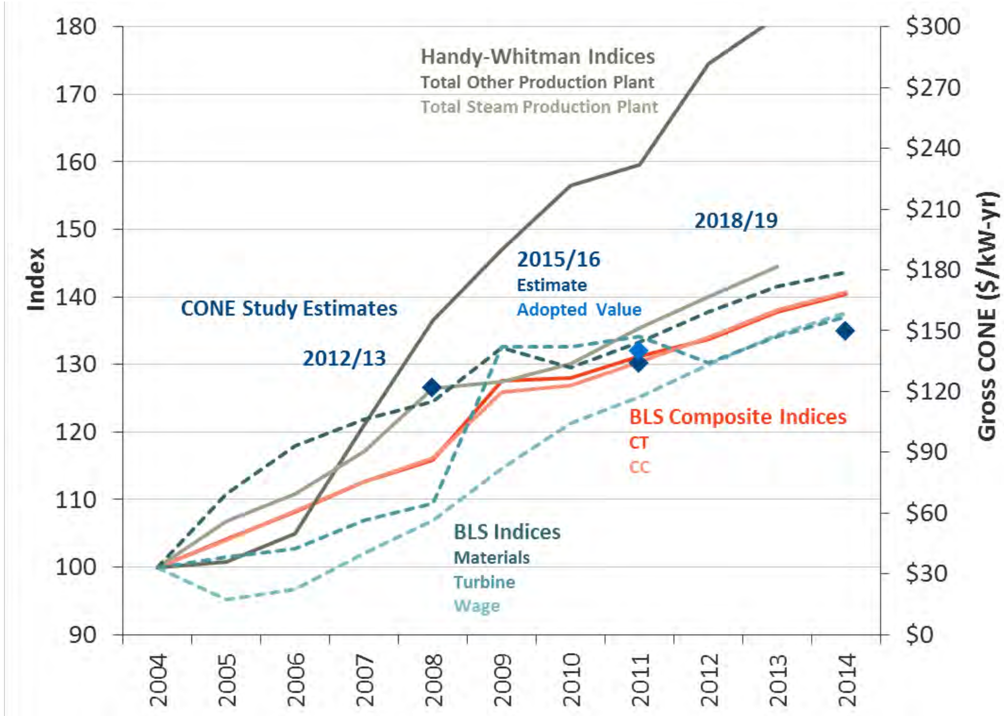
23 See Newell, *et al.* (2014c), pp. 66-67.

24 The specific indices reflected in the composite index for the example of EMAAC are: (1) BLS Quarterly Census of Employment and Wages: 2371 Utility System Construction: New Jersey – Statewide; (2) BLS Producer Price Index Commodity Data: SOP Stage of Processing: 2200 Materials and Components for Construction; and (3) BLS Producer Price Index Commodity Data: 11 Machinery and Equipment: 97 Turbines and Turbine generator Sets. These indices weighted at 28%, 47%, and 25% for the CT, and 37%, 51% and 12% for the CC, consistent with our estimate of the relevant contribution to plant capital costs in each case, see BLS (2014).

Figure 5
Handy-Whitman Indices Compared to Weighted-Average of BLS Indices



Sources and Notes:

BLS indices retrieved in April 2014 from BLS (2014).

The composite BLS indices were calculated using the costs of labor, material and turbine as approximate percentages of total project costs, developed in Newell, *et al.* (2014a).

Handy-Whitman indices refer to the North Atlantic Region. See Whitman (2014).

B. NET ENERGY AND ANCILLARY SERVICES REVENUE OFFSET

PJM determines administrative Net CONE values for each CONE Area just before each three-year forward auction. The Gross CONE value is based on CONE studies previously conducted once every three years and to be conducted once every four years in the future, with escalation applied annually for years between these periodic studies. Net CONE is calculated as Gross CONE minus E&AS margins, which PJM calculates annually by conducting a virtual dispatch analysis of the reference resource against electricity and gas prices over the prior three years.

In this section, we analyze how accurately PJM's E&AS calculations reflect the value developers can reasonably expect to earn. We focus on: (1) the accuracy of PJM's historical analysis; and (2) the applicability of the historical data to the future delivery period. We find that the historical analysis appears to accurately represent actual units' E&AS margins for CTs in most locations, but overstates CT margins in SWMAAC and substantially overstates CC margins in all locations. Regarding applicability, we explain how the historical data may not represent future E&AS margins due to anomalous historical events as well as evolving market conditions and rules. The result may result in bias or volatility PJM's Net CONE estimates, potentially threatening RPM performance. Hence, we present recommendations for avoiding such errors and developing a more accurate forward-looking E&AS estimation approach.

1. Accuracy of Historical Simulation Estimates

To assess the accuracy of PJM's historical simulation estimates of the reference resources' E&AS margins, we compare these historical estimates to the actual E&AS margins of similar existing units earned over the same period. Historical simulation estimates were provided by PJM staff for each PJM energy zone in each historical year.[25] Actual unit-specific E&AS margins were provided by the Independent Market Monitor, reflecting the IMM's estimate of total energy, ancillary, and make-whole revenues minus fuel, variable operations and maintenance, and other costs. To ensure a relevant comparison, we compare actual E&AS margins only for units that we identify to be similar to each of the reference resources, based on fuel type, unit type, online date, and unit size.

While we conducted this comparison on a zone-specific, yearly basis, we report a more aggregated summary comparison by CONE Area in Figure 6 to protect confidential data. The chart shows average actual E&AS margins on the x-axis, and the E&AS simulation error (actual minus simulated E&AS) on the y-axis. We also qualify the conclusions we report here by explaining that: (a) a comprehensive detailed comparison is not possible in some zones without existing units similar to the reference units; (b) we observe a wide range of actual E&AS margins, some of which we attribute to poor data quality or uniquely-situated units that we exclude from our sample; and (c) our analysis here covers only annual net E&AS data. More detailed monthly data on revenues, output, and costs would likely provide a more comprehensive basis from which to conduct a more thorough comparison or calibration exercise.

These charts, along with our more detailed zonal comparison of PJM's estimates to actual E&AS margins, suggest that the E&AS estimate for CTs is accurate on average over multiple years in most locations. However, PJM's E&AS estimate for CTs appears to be substantially overstated for SWMAAC (although data for that location are not displayed in the chart). For the CC, we find that PJM's simulated E&AS estimate is systematically over-stated by approximately $40,000/MW-yr on average across locations and years.

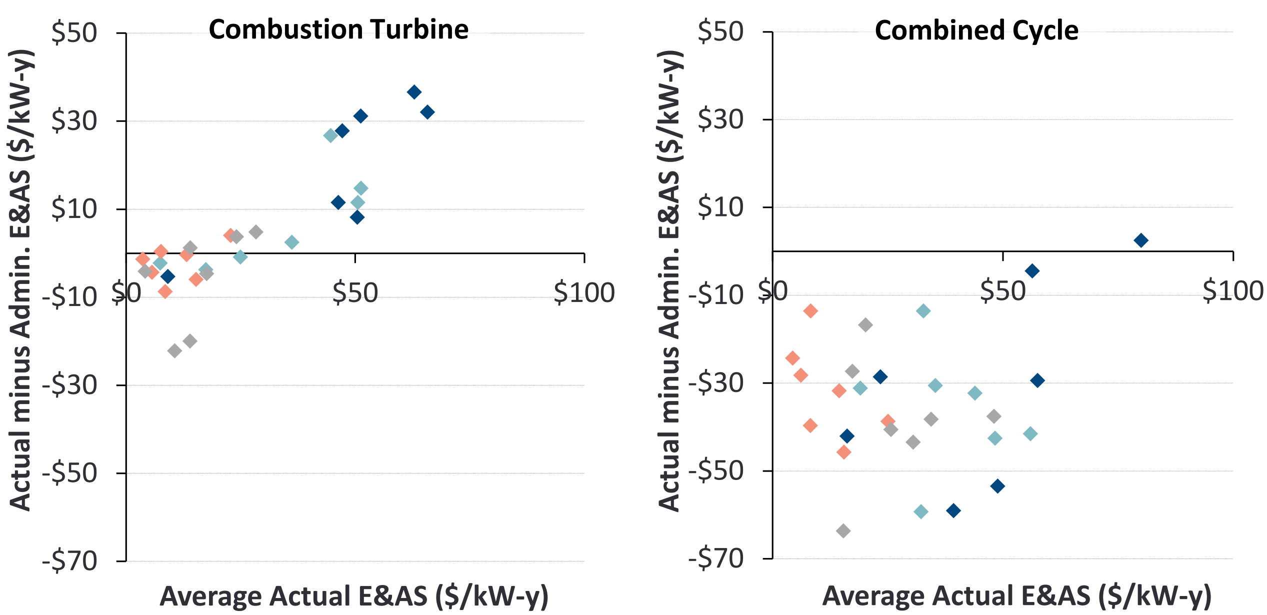
In SWMAAC, this comparison is a particular challenge because there are no installed CT or CC units similar to the reference unit, and so we report a comparison with older and smaller CTs and no comparison for CCs. While acknowledging these comparisons are challenging, we believe that the data show that PJM's simulation estimates systematically exceeded actuals in that location, and by more than in other regions of PJM (although possibly by a bit less than the $25,000/MW-yr found by our calculations, given the comparison against older and smaller units). This discrepancy appears to be attributable to unavailability of non-firm natural gas or inflexible gas scheduling capabilities in

[25] A subset of these same historical estimates are used to calculate PJM's historical E&AS in the BRA planning parameters.

the SWMAAC region, causing actual units to generate rarely and to more often rely on expensive oil when they do run. The current historical simulation calculations do not account for the higher costs associated with these challenges, causing an overestimation of the E&AS offset and, consequently, an underestimated Net CONE value.

To avoid these inaccuracies and biases, we recommend that PJM more comprehensively analyze the source of overstated E&AS estimates and then calibrating simulated E&AS margins against actual plants' operational or net revenue data (including gas deliverability issues) for CCs in all locations, and for CTs in SWMAAC specifically. This analysis and calibration could involve an analysis of an expanded set of monthly output, fuel consumption, cost, and revenue data for actual plants, using the expanded dataset to provide more insight into potential causes of any discrepancies. For locations in which no units similar to the reference CC or CT are available, PJM may need to validate its method compared to units dissimilar to the reference unit or based on similar units in nearby locations.

Figure 6
Actual Minus Simulated E&AS Margins over 2007-2013



Sources and Notes:
SWMAAC data not shown due to lack of CCs similar to the reference unit and CTs dissimilar from the reference unit.
Reflects CTs > 140 MW and online since 2000; reflects CCs > 500 MW, online since 2000, not cogen.

2. Backward- versus Forward-Looking E&AS Offset

PJM uses a three-year historical average of simulated values to estimate E&AS margins, as required by the Tariff since the inception of RPM.[26] The primary advantage of this historical approach is its relative simplicity and transparency in comparison to the greater complexity of forecast-based

[26] See PJM (2014b), Section 5.10.a.v.

approaches. Moreover, it should provide an unbiased estimate that should result in an accurate Net CONE on a long-term average basis, even if the values are not accurate in any particular year.

However, as we explained in our past RPM reviews, this historical E&AS approach based on the last three years of spot market prices for energy and ancillary services is quite volatile. The current historical approach may yield E&AS margins that reflect neither normal nor expected future market conditions. For example, a single year with a substantial number of shortage pricing events or major changes in fuel prices can substantially distort Net CONE from reasonable forward-looking estimate, which increases the volatility of capacity prices.

The fact that these administrative estimates can differ substantially from market expectations at any particular time also creates RPM performance concerns. For example, three years of historical data can be highly affected by anomalous market conditions that are not likely to be repeated. Resulting distortions may become especially pronounced under PJM's new shortage pricing mechanisms, which allow extreme weather or fuel market conditions to produce very high E&AS margins. With a four- to six-year delay between the historical years and the delivery year, the historical average may not be representative of evolving market conditions. This could result in significantly under-estimated Net CONE values (and an under-procurement of capacity) for the three delivery years that are affected by the anomalous high-price historical year.

To address these concerns, we recommend that PJM consider developing and adopting a forward-looking E&AS estimation approach. We recognize that developing a fundamentals-based estimate would be difficult to conduct with enough simplicity, transparency, and objectivity to gain widespread stakeholder support. Instead, we recommend developing an estimate of E&AS margins based on publicly-available futures prices, an approach that ISO-NE has recently adopted with full stakeholder support.[27] Futures prices will average out extreme weather years and also reflect market participants' expected changes in fundamentals.

We illustrate this concept in Figure 7, showing the average of EMAAC zonal values for: (a) PJM's historical E&AS simulation estimates (blue for CC, red for CT); and (b) a three-year average of PJM's historical estimate, after a three-year delay consistent with the relevant RPM delivery year (blue dotted for CC, red dotted for CT). We then compare these values against a simplified illustrative back-cast and forecast of E&AS margins using monthly data for fuel prices, on-peak power, and off-peak power.[28] We conduct a simplified CC and CT dispatch on a monthly basis using the reference

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27 See Newell, *et al.* (2014c), Section VIII.

28 The monthly prices reflected in this analysis are: (a) historical gas prices at Transco Zone 6 Non-New York; (b) futures gas prices at Henry Hub, plus a basis swap to Transco Zone 6 Non-New York, assuming that the basis differential increases with inflation in years beyond the horizon of data availability; (c) historical on-peak and off-peak electric prices based on day-ahead monthly average prices, calculated as the average price across all energy zones within EMAAC; and (d) energy futures prices based on the forward curve at PJM West Hub, with the basis differential between PJM West Hub and the EMAAC

Continued on next page

unit's heat rate and typically operating costs that increases with inflation.[29] We attempted to match historical simulation values (not actuals) in this illustrative calculation.

Based in this illustrative calculation, current forward curves indicate $20,000/MW-yr lower E&AS margins for CCs compared to the historical 3-yr estimate in EMAAC. This discrepancy between the margins means that PJM's administrative Net CONE estimate for year 2017/18 may be overstated compared to the revenues anticipated by a typical new CC developer. This would not translate into a reliability concern if CC CONE is only used for MOPR purposes, but would be a bigger concern if CC Net CONE were also used in the VRR curve.

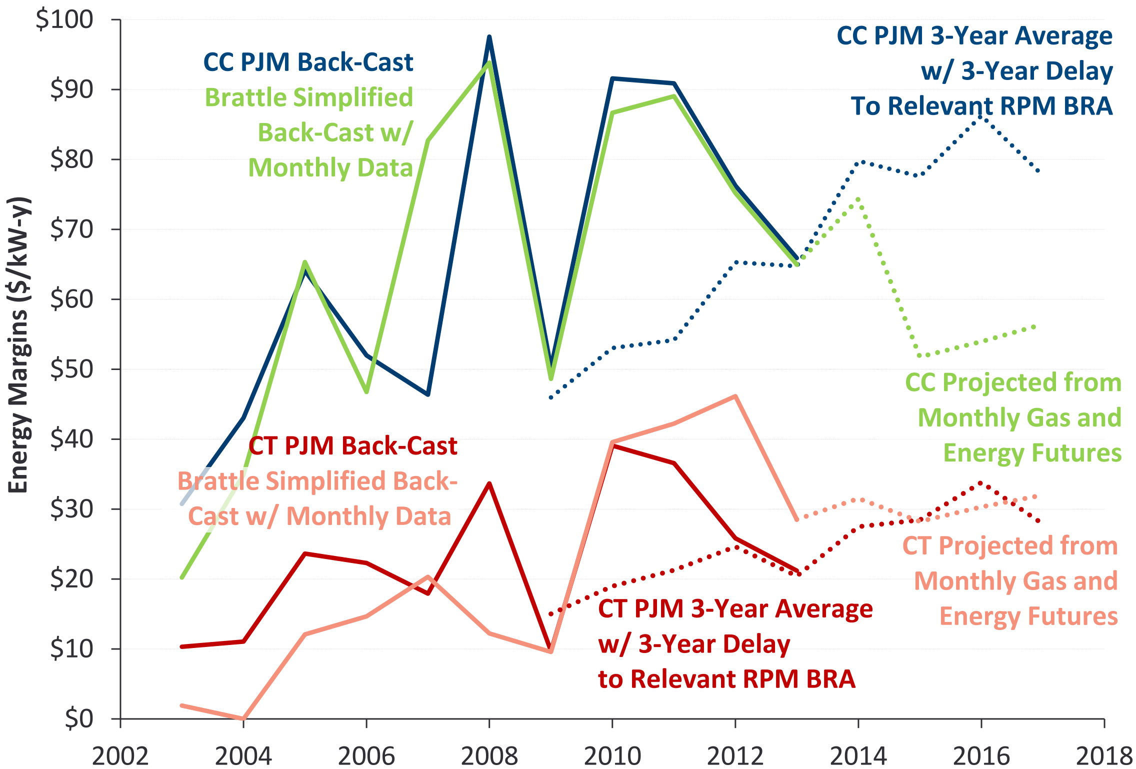
For CTs, which is the reference technology currently used as the basis for Net CONE in the VRR curve, estimated E&AS revenues are similar in EMAAC for the illustrative backward and forward-looking approaches. However, we note that we would not expect such consistency to persist through changing market conditions. Rather, we anticipate periodic discrepancies similar to what we currently observe for CC plants. We also note that a futures-based E&AS approach is likely to be more accurate for a CC than for a CT, because the 5x16 on-peak hour period associated with on-peak futures approximately coincides with the dispatch period of a CC. In contrast, E&AS margins for CT plants are determined by a much smaller number of super-peak hours.

Continued from previous page

average calculated as the average of the Rounds 1, 2, and 3 2014/17 Long-Term FTR Auction implied congestion differentials for the 2014 through 2017 delivery years (adjusted to a monthly series based on the difference between the average annual differential and average differential in each month over the last five historic years), plus the 3-year average of losses differentials, with both losses and congestion costs assumed to increase with inflation for years beyond data availability. See PJM (2014b, 2014c, and 2014d.), Bloomberg (2014), Ventyx (2014), and SNL (2014).

29 This simplified calculation reflects the net E&AS revenues of a unit that turns off or on for all on-peak hours of the month (and separately turns off or on for all off-peak hours),if the unit has no start costs, no changes to heatrate over the year, no dispatch constraints, no ancillary revenues, and is always available. These illustrative calculations assume CC and CT heatrates of 10,094 Btu/kWh and 6,722 Btu/kWh respectively, as calculated in our prior CONE study, see Spees, *et al.* (2011). We adjust the assumed VOM for both the CC and CT until the resulting E&AS back-cast approximately match PJM's historical simulations, resulting in $6/MWh and $0/MWh for the CC and CT respectively in 2013$.

Figure 7
Comparison of Historical and Forward-Looking E&AS Estimates



Sources and Notes:

Simplified historical and futures calculation use monthly data for gas and electric prices to calculate net revenues for a plant dispatched across an entire month of on- or off-peak hours. Gas prices are at Transco Z6 NNY, electric prices are zonal based on energy futures at West Hub plus a basis differential. The basis differential is derived from annual long-term FTR auctions (with a monthly shape adjustment consistent with historical energy price differentials), plus a losses factor proportional to the West Hub energy price.

As with historical recommendations above, it would be important to carefully calibrate this forward-looking approach against historical actuals to the extent that they are available in each location. Monthly calibration data would likely provide a sufficiently comprehensive data set from which to test the accuracy of the historical calculation under range of realized gas and electric price conditions. It may be possible to match historical actual data using small adjustments to this simplified approach, or it may be necessary to consider additional refinements, *e.g.*, to incorporate extrinsic value, or unit commitment inefficiencies.

C. Locational Net CONE Approach

PJM is a large multi-state region covering a large number of energy zones with sometimes substantially different energy prices and with very different going-forward costs for investing in new generation. As such, Net CONE may be quite different across the footprint, introducing a challenge for estimating an appropriate administrative Net CONE in each location. In this section, we review PJM's approach for selecting the appropriate locations for which to estimate Gross CONE, the E&AS

offset, and finally Net CONE, and then how these parameters are assigned to each LDA for the purposes of calculating the local VRR curve.

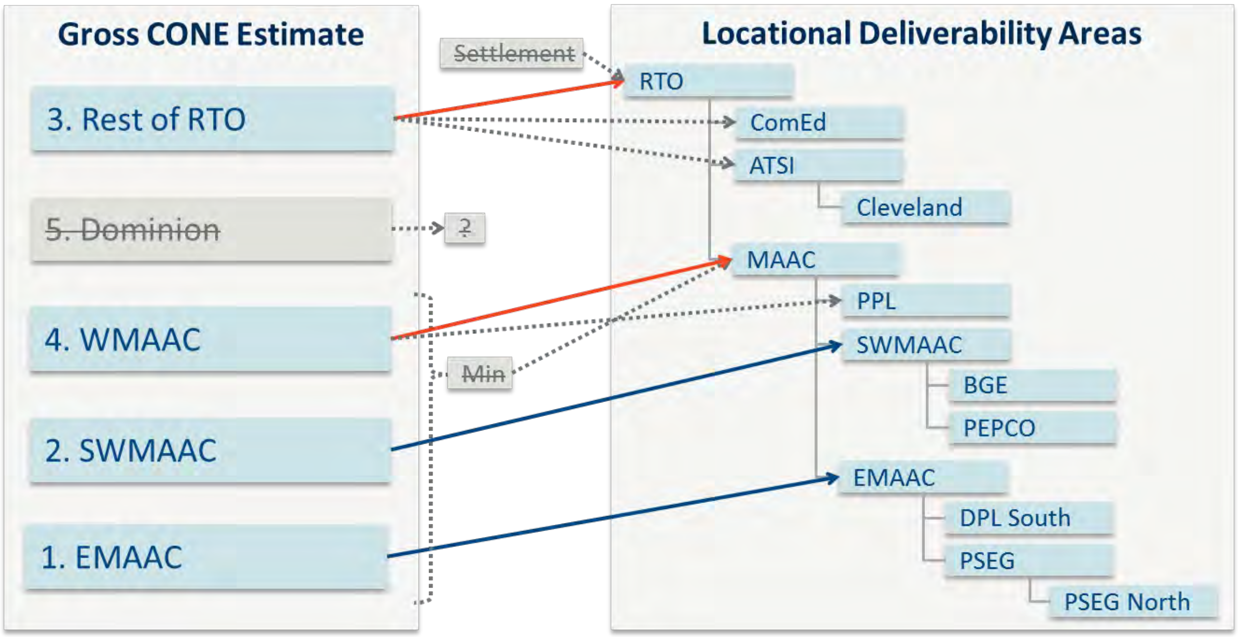
In general, we follow a guideline that the Gross CONE and E&AS parameters should be broadly representative of the economics within each modeled LDA, with the parameters matched as closely as possible to the boundaries of the particular LDA. We also recognize in this review that there are some realistic bounds to the level of accuracy possible in estimating Net CONE, given the range of unique circumstances faced by developers and some unavoidable level of error in these administrative estimates.

1. Mapping of Locational Gross CONE Estimates

Currently, PJM's Tariff specifies five different CONE Areas for which administrative Gross CONE estimates must be developed once every three years historically, and once every four years going forward; it also specifies a sixth CONE value to be used in the system-wide VRR curve.[30] The CONE estimates are then mapped into individual LDAs for the purposes of calculating the locational Net CONE estimates and locational VRR curves. In reviewing these locational considerations, we identified a series of potential revisions that may be made to: (a) better align the geographic definitions of the Gross CONE estimates and the LDAs that those estimates are assigned to; (b) reduce the number of administrative CONE estimates to reduce administrative complexity, while maintaining distinct CONE estimates where needed; and (c) recognize the possibility that additional CONE estimates might be needed in the future. We summarize these possible revisions in Figure 8 and Table 2.

30 See PJM (2014b), Section 5.10.a.iv.

Figure 8
Potential Revisions to Gross CONE Mapping



Sources and Notes:

Current mapping from PJM's Tariff and 2017/18 Planning Parameters, see PJM (2014b-c).

Blue and gray dotted lines reflect current mapping of CONE estimates to LDAs; crossouts represent existing elements that we recommend eliminating; red lines represent our recommended revised mapping.

To better align CONE Areas to individual LDAs, we make two recommendations. First, we recommend adopting the *CONE Area 3: Rest of RTO* estimate for the system-wide VRR curve, rather than continuing to use the fixed tariff value that was adopted as part of a settlement process after the most recent CONE study.[31] This change would allow the system curve to adjust with periodic CONE study estimates, as with other locations in the system. Second, we recommend adopting the *CONE Area 4: Western MAAC* estimate for the MAAC VRR curve rather than adopting the minimum of sub-LDA Net CONE values.[32] This revised mapping would: (a) be more consistent with the expected result that the most import-constrained sub-LDAs of MAAC should have higher Gross CONE estimates (although we acknowledge that this has not always been the case historically, it is true in the present CONE estimates and we anticipate that it will continue to be true in the future); (b) result in a more stable and accurate Net CONE estimate for MAAC; and (c) avoid incorporating downward bias into the MAAC Net CONE estimate, which can be introduced by taking the minimum of three estimates (for Western MAAC, Eastern MAAC, and Southwest MAAC) each of which has some administrative error.

31 See PJM (2014b), Section 5.10.a.iv

32 We also note that the Tariff wording is relatively unclear and may leave ambiguity regarding whether it refers to the minimum of sub-LDA Gross CONE or Net CONE values. Note that this provision does not apply to any LDA other than MAAC, and has consistently resulted in SWMAAC Net CONE values being used for MAAC. See PJM (2014b).

To reduce the number of CONE estimates, we identify only one recommended change: to eliminate *CONE Area 5: Dominion* and combine it with *CONE Area 3: Rest of RTO*. We recommend this change because Dominion has never been a modeled LDA and so that location's CONE estimate has never been used for determining a locational VRR curve. Eliminating this CONE estimate will somewhat reduce administrative complexity and cost. The remaining four CONE estimates would remain as applicable for the four permanent LDAs that PJM has determined will always be modeled in RPM: Eastern MAAC, Southwest MAAC, MAAC, and Rest of RTO.

It is also possible that the number of CONE estimates could be further reduced, given that in many cases the locational CONE estimates have not resulted in large variations by region beyond the range of administrative error. While we find this option appealing, we recommend against it primarily because it would still be necessary to evaluate in the periodic CONE studies whether the locational differentials are likely large enough that separate CONE estimates would be needed in the future. Such a determination is hard to make without following through with a full locational CONE estimate or gathering a sufficient number of locational cost indicators, reintroducing some complexity and cost. Ultimately, the change may not result in substantial improvement unless two CONE Areas can be shown to be consistently similar such that they can be permanently combined, which does not appear to be true at the present time.

Finally, we recommend that PJM introduce a test or test(s) to identify cases where additional CONE estimates may be needed in the future. The particular case of concern could materialize if there is an import-constrained sub-LDA that is smaller than any of the CONE Areas that has a structurally and permanently higher Gross CONE and Net CONE than in surrounding areas, and within which it may not be possible to sustain resource adequacy.

Table 2
Summary of Possible Revisions to Locational Gross CONE Approach

Potential Change	Rationale
Use RTO CONE Estimate for RTO VRR Curve *(Rather than Fixed Settlement Number)*	• Legacy of most recent settlement agreement that currently the RTO Gross CONE number is not based on the periodic CONE study estimates, but rather set at a fixed value agreed in settlement (updated with Handy-Whitman) • Revert to a standard approach consistent with other Areas' Gross CONE updates
USE WMAAC CONE for MAAC VRR Curve *(Rather than Minimum of Sub-Areas)*	• Currently, Tariff states that LDAs spanning multiple CONE Areas will use the minimum CONE of sub-LDAs, historically always SWMAAC • Revised approach is more consistent with underlying theory that the most import-constrained areas should have the highest Gross CONE and Net CONE
Eliminate CONE Area 5: Dominion	• Dominion CONE estimate is not used in setting VRR curves as Dominion has never been a modeled LDA
Add Test to Trigger a Separate Gross CONE Estimate for Small LDAs	• Current approach always estimates Gross CONE for the permanent, large LDAs (RTO, MAAC, SWMAAC, & EMAAC) • But in some LDAs, it is possible there could be a circumstance where the reference technology would not be feasible to build, or would be far more expensive to build in some difficult sub-areas. If Net CONE in that sub-zone is close to 1.5× Net CONE of the parent, then RPM would not be able to achieve resource adequacy in that subzone • The test might consider whether the LDA is persistently import-constrained, shows little evidence of new entry, and shows evidence of structurally higher entry costs (*e.g.*, if the reference technology cannot be built there)

2. Mapping of Energy and Ancillary Services Offsets

Currently, PJM estimates E&AS offsets for each CONE estimate based on the specified location of the original reference unit at the time that the tariff language was written.[33] These E&AS offsets are used to develop seven different Net CONE estimates used in the VRR curves in different locations in PJM: (a) one for use the system-wide VRR curve, based on the RTO-wide average LMP; (b) one for each of the five CONE Areas, and the resulting Net CONE values are applied to all LDAs within each CONE Area; and (c) the MAAC Net CONE, which is equal to the lowest Net CONE value of the three CONE Areas within MAAC, which are WMAAC, EMAAC, and SWMAAC.[34]

[33] Note that subsequent CONE studies have specified different reference unit locations but these revised locations were not incorporated into the tariff. See PJM (2014b), Section 5.10.a.iv and PJM (2013a.)

[34] Note that these mappings are slightly different from the mappings used for MOPR, which include only five values consistent with the five CONE Areas, see PJM (2014d).

The result of this mapping process is that the E&AS offset incorporated into individual LDAs' Net CONE and VRR curve is usually developed based on energy prices from a different location, as summarized in Table 3 for the 2017/18 delivery year. In fact, only the RTO-wide, Commonwealth Edison (ComEd), and Baltimore Gas and Electric Company (BGE) Net CONE values are based on E&AS offset values estimated specifically for that location. The other ten modeled LDAs are not mapped as closely as possible, meaning that there is potential for systematic discrepancies between the administratively-estimated and true developer Net CONE in these areas.

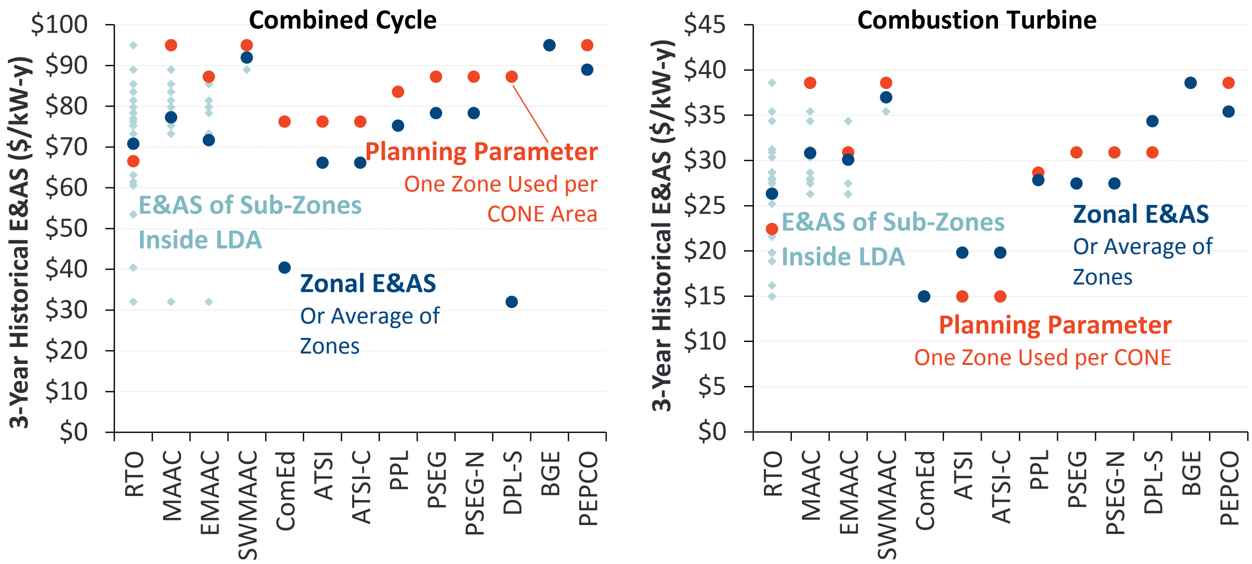
Table 3
Summary of Possible Revisions to Locational Gross CONE Approach

LDA	E&AS Zone	Relationship
RTO	PJM Average	Self
ComEd	ComEd	Self
ATSI	ComEd	Peer
Cleveland	ComEd	Parent's Peer
MAAC	BGE	Sub-Sub-LDA
PPL	MetEd	Peer
SWMAAC	BGE	Sub-LDA
BGE	BGE	Self
PepCo	BGE	Peer
EMAAC	AECO	Sub-Zone
DPL South	AECO	Peer
PSEG	AECO	Peer
PSEG North	AECO	Parent's Peer

Sources:
Current mapping from PJM's Tariff and 2017/18 Planning Parameters. See PJM (2014b-c).

To address this potential mismatch, we recommend that PJM expand the number of Net CONE estimates and calculate a separate number for each of the modeled LDAs. In each case, the E&AS offset would be calculated using energy prices that match as closely as possible the energy prices applicable in each LDA. Figure 9 illustrates the impact of remapping E&AS parameters in this way using the 2017/18 Planning Parameters, and PJM's administrative E&AS estimate based on zonal average energy prices in each location.[35] This remapping on the reference CT would result in a lower E&AS (higher Net CONE) in seven of the thirteen LDAs according to 2017/18 parameters, with the CT E&AS dropping by $1,000-$8,000/MW-yr ICAP in most LDAs, but increasing by $3,000-$5,000/MW-yr ICAP in the areas where it goes up. The CC E&AS parameters as used for MOPR would follow similar patterns, although the mapping used for MOPR is somewhat different.[36]

Figure 9
Three-Year Average E&AS Offset from 2017/18 Parameters vs. if Remapped to the Closest LDA



Sources and Notes:

All E&AS offset estimates reflect historical three-year averages of PJM estimates over calendar years 2011-13, as expressed on a $/kW-yr ICAP basis, and including the tariff-defined fixed A/S adder.

For RTO, "Planning Parameter E&AS" based on Average Zonal LMP, "Zonal E&AS" based on average E&AS of zones.

Historical E&AS offsets as used from 2017/18 Planning Parameters, see PJM (2014c.)

Other zones' estimated historical E&AS offset supplied by PJM staff.

3. Option to Impose a Minimum Net CONE at the Parent LDA Level

One concern that we observe is that in some cases the locational Net CONE estimates result in small LDAs having administrative Net CONE below the parent LDA's Net CONE. This is particularly true in Southwest MAAC, which has historically had high energy prices and E&AS offset resulting in a Net CONE estimate substantially below the other LDAs. This low Net CONE in Southwest MAAC has then also propagated up to MAAC based on the minimum Net CONE rule that we recommend eliminating as explained above.

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35 For LDAs that cover multiple zones we use a simple average of E&AS estimates, and for sub-zonal LDAs we use the E&AS offset as estimated for the entire zone. Additional accuracy could be achieved by estimating E&AS offsets based on the injection-weighted average LMP across all generation buses contained within a particular LDA.

36 The MOPR estimates include only five values consistent with the five CONE Areas, see PJM (2014d).

First, we note that it is not necessarily a concern for administrative Net CONE to be lower in sub-LDAs, as long as the administrative Net CONE is accurate and equal to the true developer Net CONE. In this case we would expect developers to identify this low cost (or high energy revenue) location as an attractive opportunity for building. In fact, whenever the parent LDA is in need of capacity, suppliers would choose to site in the sub-LDA, with the likely result that the sub-LDA would never price separate according to its own VRR curve and maintain more than sufficient capacity to meet its Reliability Requirement. The local VRR curve would then be a non-binding constraint, and the sub-LDA would eventually cease to be a modeled LDA unless it were one of the four permanent LDAs.

In fact, the attractiveness of investing in locations with the lowest Net CONE is the reason that we would not expect Net CONE to be lower for any extended period of time. In general, would expect load pockets to be persistently import-constrained from a resource adequacy perspective only if there are structurally higher going-forward costs associated with developing assets in that location. For example, a load pocket may be persistently import-constrained if there are substantial siting difficulties, environmental restrictions, or lack of available infrastructure that make it more costly to build. Lower energy revenues may also be a driver of higher Net CONE in sub-regions, for example if gas availability substantially restricts dispatch and reduces potential energy margins.

In cases where administrative Net CONE deviates from this expectation (showing lower Net CONE in persistently import-constrained sub-regions), it may be caused by errors in the administrative estimate. We believe this to be the case in Southwest MAAC, where high local energy prices have driven administrative Net CONE substantially below other areas (with the results propagating up to the larger MAAC LDA). However, despite the apparently more attractive investment opportunity, we observe relatively less investment activity in that location compared to the much greater levels of investment in other locations including other locations with lower capacity prices.[37]

Some of this disconnect may be resolved by a close calibration of E&AS estimate to actual plants' net revenues as discussed in Section III.B.1, it may be further addressed by making note of potential siting and investment cost concerns as we discuss in our CONE study.[38] However, the potential to refine these estimates consistent with true costs and revenues, will be limited in locations where there are no plant similar to the reference resource and limited development activity. The limited ability to more accurately capture locational costs is also more difficult in small LDAs, for which there is no location-specific CONE estimate. These locations are the most at risk for under-estimated Net CONE, since there may be localized siting, permitting, or infrastructure concerns that prevent the reference resource from being built even if there are no such concerns in the broader CONE Area.

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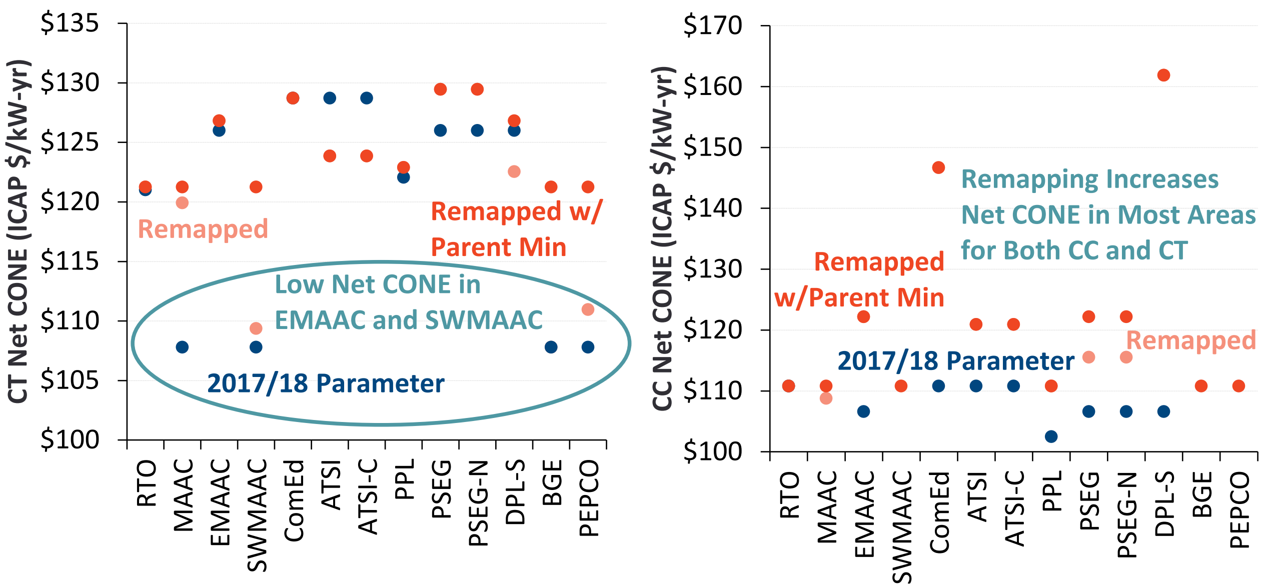
37 Based on analysis of new plants cleared in RPM and under construction in SWMAAC compared to other regions of PJM, using data obtained from Ventyx (2014) and news reports from SNL Energy (2014).

38 See Newell, *et al.* (2014a).

For these reasons, we recommend that PJM consider imposing a minimum on LDAs' Net CONE that would prevent import-constrained sub-LDAs from having Net CONE below the parent LDA value. We would recommend applying this rule to all LDAs, but particularly for the smallest, non-permanent LDAs for which there is no CONE estimate. Figure 10 shows the combined impact of imposing this minimum and remapping Net CONE as discussed in prior sections, using PJM's 2017/18 Planning Parameters. As the charts show, remapping would cause Net CONE to increase in most locations for both the CC and CT. The parent minimum would be binding in four locations for the CT and one location for the CC, with the most substantial effect being to increase Net CONE in SWMAAC and its sub-LDA PepCo.

Figure 10
Impact of Remapping Gross and Net CONE using 2017/18 Parameters
With and Without Imposing a Parent Minimum on LDA Net CONE



Sources and Notes:
Gross CONE, E&AS, and A/S values consistent with PJM 2017/18 Planning Period parameters, see PJM (2014c).
Other E&AS values reflect historical three-year averages of PJM estimates over calendar years 2011-13, as expressed on a $/kW-yr ICAP basis, and including the tariff-defined fixed A/S adder.

D. Reference Technology as Combined Cycle or Combustion Turbine

As noted earlier, PJM has been utilizing a frame-type combustion turbine plant as its reference technology for the purpose of defining Net CONE for the VRR curve. However, as summarized in our concurrently-published CONE study, very few such plants have recently been built or are being built in PJM today.[39] This is particularly true for merchant generators, who have been developing primarily combined cycle plants. This current lack of merchant CT development in PJM raises the question of whether CTs may become less suitable as a reference technology to estimate Net CONE

39 See Newell (2014a) Section II.B.

for VRR curve purposes, because it: (a) results in sparse availability of data on the technical specifications and cost drivers on the reference CT technology; and (b) may indicate that technology and market developments are trending such that CT plants are no longer economic for merchant investment compared to CC technology. It is also possible, however, that the current preference for merchant CC development reflects only a temporary disequilibrium due to currently-projected market conditions that make higher-efficiency, intermediate-load CC plants more economic.

Over the long-term, it should not matter which technology is selected for determining Net CONE as long as the chosen technology is economically viable. This is because in long-term market equilibrium expectations, the Net CONE value of all economically-viable generating technologies for new plants would be identical and equal to the market price for capacity. However, it would not be uncommon to find most markets in at least some level of disequilibrium at a given snapshot in time. In fact, changing market conditions will tend to introduce short- to intermediate-term deviations from long-term equilibrium in terms of total resource level and resource mix, such that prevailing market conditions temporarily make one technology more economic than other, with a lower Net CONE. Over time, however, these relative fluctuations in Net CONE values should average out and be the same for all technologies that are economically viable in the long-run.

It is important to recognize that CC and CT Net CONE estimates may fluctuate around the same long-term equilibrium value when selecting the reference technology for the VRR curve. First, because both CCs and CTs will sometimes have Net CONE values temporarily below their long-run average, it is important to avoid switching back and forth to the technology with the lowest Net CONE. Such an approach would understate the true cost of new entry for either technology when evaluated individually, and would result in the under-procurement of resources relative to the reliability target. Further, fluctuating Net CONE estimates may reflect not only temporary changes in market fundamental but also estimation errors, meaning that switching to technologies with the biggest downward errors would almost guarantee under-procurement. For similar reasons, it does not make sense to always switch to the technology with the highest Net CONE estimate.

For these reasons, maintaining a single reference technology over time can be expected to yield an accurate Net CONE value in expectation over time. However, doing so might lead to temporary over-procurement when the chosen technology becomes less viable for merchant entry because another technology has a lower Net CONE. A less obvious but more worrisome problem is that maintaining a single reference technology could lead to under-procurement when the reference technology yields Net CONE estimates that are substantially below its equilibrium value due to unusual market conditions or estimation errors. Thus, under temporary market conditions characterized by oscillations around long-term equilibrium market conditions, the technology with the temporarily-lowest Net CONE value might still need a capacity price above its administratively-estimated Net CONE value before entry is economically viable.

To account for these dynamics, it may be preferable to set Net CONE at an *average* of the Net CONE values of technologies that are most likely viable for merchant investments. Such an average would help stabilize capacity prices and resource adequacy through periodic short-term deviations from long-run equilibrium and diversify the risk of estimation error associated with any single technology. If the averaging approach stay the same over time and incorporates multiple technologies that are both economically viable and have similar susceptibility to estimation error, then we would expect administrative Net CONE estimates to be more accurate and reflective of equilibrium conditions on average.

PJM can choose to move ahead with any of three reference technology options: (1) maintaining the current gas CT; (2) adopting a gas CC; or (3) adopting an average of the two. We summarize the advantages of each approach in Table 4, in each case considering that the reference technology should be one that: (a) is technically feasible to build; (b) is economically viable on a merchant basis; (c) has a relatively standard set of characteristics and costs, such that large quantities of similar units could be built (*e.g.*, which would exclude some low-cost unique opportunities such as DR and cogeneration); (d) has net costs that can be estimated with relatively small administrative estimation errors; and (e) is likely to remain a viable reference technology for many years.

Some of these considerations would support continuing to rely on the currently-used reference CT, including maintaining continuity in the market design. This avoids switching to other technologies that may temporarily have lower Net CONE values, and has the advantage that the smaller value of net E&AS revenues makes Net CONE values for CTs less dependent to E&AS-related estimation errors.

There are also important considerations that suggest that CC plants may be a more appropriate reference technology. First, natural-gas-fired CCs are being proposed and built in large numbers in PJM and elsewhere in the U.S. In contrast, very few CTs are being developed by merchant generators. Based on these "revealed preferences," a CC plant would be the most logical choice of reference technology if there were no pre-existing approach and only one technology could be selected. Second, a switch to CCs as the reference technology may be justified because the lack of merchant CT development also creates doubt about whether the technology is well-suited for merchant investment. Third, because more CC plants are being developed, we have more and better information on the costs and characteristics of a new CC plants. And finally, if PJM and stakeholders decided to pursue and implement our recommendations to switch to a forward-looking E&AS offset, it would be easier to estimate that parameter accurately for CC than for CT plants. This is the case because available 5x16 forward prices are better-aligned with gas CC dispatch profiles, making it easier to determine forward-looking estimates for E&AS revenues.

Table 4
Selecting the Reference Technology to Estimate Net CONE for VRR Curve Purposes

Arguments for Gas CT	… for Gas CC	… for Average of CC and CT
• Existing reference technology (as prescribed by PJM tariff) • Continuity of market design will minimize price changes due to changes in administrative parameters • Frequent switching based on each year's lowest Net CONE would under-procure if relative economics of technologies are switching • Lower absolute E&AS means its estimation error has lower impact	• Predominant new build in PJM & US • Current 7FA CT may look good on paper (and recently accepted by FERC as feasible w/ SCR in NYISO), but why is no one building them? • Is there room for gas CTs going forward or do a combination of CCs and DR make them uneconomic? • More standardize technology and better cost information for estimating CONE • Easier to calculate forward-looking CC E&AS offset from 5x16 futures • E&AS not as widely varying among actual plants for idiosyncratic reasons	• In the long run, all economic resource types should have the same Net CONE; makes sense to average if they are all economic for merchant entry • Averaging results in a closer-to-equilibrium estimate, as any one technology likely will be out of the money for temporary periods • Prevents problems from switching and reduces impact of administrative error of estimates • Will help mitigate impacts of volatile or uncertain E&AS estimates • Averaging for the next 4 years would provide continuity and time to observe whether predominance of CC builds is temporary or reflects a permanent change

Evaluating the advantages and disadvantages to choosing either a CC or a CT as the reference technology, we recommend that PJM consider adopting an approach that estimates Net CONE as the average of the CC and CT Net CONE estimates. As long as both technologies are economically viable, we believe that this averaging approach will provide a more stable and more accurate estimate of Net CONE by reducing the impact of CONE and E&AS revenue estimation errors and disequilibrium market conditions. However, we also acknowledge that it remains an open question whether the frame gas CT is an economically viable part of the resource mix, and so recommend re-evaluating this determination in the next CONE study four years from now. If additional market evidence becomes available showing that the CT will not be a viable technology for merchant entry over that period, then the two-technology average could be treated as a transitional step to relying exclusively on CCs as the reference technology. In that future evaluation, we would recommend considering the same factors that we have evaluated here and similarly avoid changing the approach unless it is clearly supported by market evidence.

E. Recommendations for Net Cost of New Entry

Although PJM's administrative Net CONE estimates have likely been within a reasonable error band of the true value in most locations, recommend a series of modifications that could improve the accuracy and stability of these estimates in the future. We anticipate that the overall impact of these modifications would be largely offsetting, with some increasing and others decreasing Net CONE in individual locations. However, we believe implementation of our recommended modifications would result in a greater level of accuracy and stability of Net CONE estimates as market conditions change over time.

1. **Adopt updated Gross CONE estimates.** We recommend updating the levelized Gross CONE to the numbers reported in Section III.A.1 for delivery year 2018/19, based on our concurrently-published study of the costs of building new gas CC and CT plants in PJM.[40]
2. **Adopt level-real Gross CONE values.** We recommend that PJM consider adopting a "level-real" (rather than the current "level-nominal") approach to levelizing gross plant capital costs. As we explained in our 2011 review and reiterate now, we view a level-real capital cost recovery more consistent with the time profile over which most developers anticipate recovering their investment costs. This recommendation is contingent, however, on combining it with our recommendation to improve VRR curve's anticipated reliability performance as discussed below.
3. **Consider replacing the Handy-Whitman Index for annual CONE updates.** To escalate Gross CONE values annually between CONE studies, we recommend that PJM consider replacing the Handy-Whitman "Other" index with a weighted composite of wage, materials, and turbine cost indices from the Bureau of Labor Statistics. We believe such an approach would more accurately reflect industry cost trends that are the underlying drivers of changes to CONE.
4. **Calibrate historical E&AS simulations against plant actuals.** We recommend further investigating why PJM's simulated historical E&AS estimates exceed actual margins of CCs in all areas by roughly \$40,000/MW-yr and by roughly \$30,000/MW-yr for CTs in SWMAAC. Given the large discrepancies, we recommend that PJM compile a more detailed set of plant-specific cost and revenue data for representative units that can be used for such a calibration, and then adjust its historical simulation approach to develop E&AS numbers that are as reflective as possible of these actual plant data in each location. This adjustment would require identifying and accounting for factors that may be depressing actual net revenues below simulated levels, such as operational constraints, heat rate issues, differences in variable and commitment costs, or fuel availability. This analysis would inform how to develop more realistic simulations of E&AS margins, and avoid overstating E&AS offsets and understating Net CONE values, which risks procuring less capacity than needed to meet PJM's resource adequacy objectives. To allow flexibility in this calibration exercise, we also

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40 See Newell (2014a).

recommend that PJM consider eliminating Tariff language specifying an exact ancillary service adder and variable operations and maintenance cost assumption, instead adopting assumptions that result estimates that are well-calibrated to plant actuals.

5. **Develop a forward-looking estimate of Net E&AS revenues.** An E&AS offset based on three years of historical prices can be easily distorted by anomalous market conditions that are not representative of what market participants' expect in the future RPM delivery year. The threat of significant distortions due to unusual historical market conditions has increased with PJM's new shortage pricing rules that will magnify the impact of shortages. For example, unusual weather or fuel market conditions can cause prices to spike, increasing E&AS revenues beyond what a generation developer would expect to earn in the future under more typical weather conditions. Historical prices are also 4 to 6 years out of date relative to a delivery period corresponding to a three-year forward Base Residual Auction and, therefore, may not be a good indicator of future market conditions. For these reasons, we recommend that PJM evaluate options for incorporating futures prices for fuel and electricity into this analysis, similar to the stakeholder-supported approach proposed to FERC by ISO-NE. Currently, such a forward-looking E&AS approach would likely produce results similar to three-year historical approach for the CT, but substantially below the historical approach for the CC (resulting in a similar CT Net CONE, but an increased CC Net CONE).
6. **Align CONE Areas more closely to modeled LDAs.** We recommend that PJM consider revising the definitions of CONE Areas to more closely align with the modeled LDAs, by: (a) using the *CONE Area 3: Rest of RTO* estimate for the system-wide VRR curve (rather than the current fixed value adopted in settlement); (b) using the *CONE Area 4: Western MAAC* estimate for the MAAC VRR curve (rather than taking the minimum of sub-LDA numbers); and (c) combining *CONE Area 5: Dominion* into *CONE Area 3: Rest of RTO*, given that the Area 5 estimate has not been used to date. The result would be to develop a total of only four Gross CONE estimates in future studies, one for each of the four permanent LDAs.
7. **Consider introducing a test for a separate Gross CONE for small LDAs.** We also recommend that PJM introduce a test to determine whether smaller LDAs should have a separate Gross CONE estimate. In general, such a separate estimate would only be needed if the small LDA is persistently import-constrained, shows little evidence of potential for new entry, and shows evidence of structurally higher entry costs (*e.g.*, because the reference technology cannot be built there).
8. **Align E&AS offset and Net CONE more closely to modeled LDAs.** The current approach calculates E&AS offsets based on prices in a single tariff-designated energy zone for each CONE Area. As a result, the E&AS offset that is applied to a specific LDA may not be calculated based on prices in that LDA, but on prices in the parent LDA, a sub-LDA, or an adjacent LDA, none of which would provide an accurate E&AS estimate for the LDA and thus may cause under- or over-stated Net CONE values. We recommend that each LDA's E&AS offset be estimated based on prices within that LDA. For large LDAs that cover many zones, such as RTO and MAAC, the E&AS offset could be based on an injection-weighted generation bus average locational marginal price across the LDA, or an average of zone-level

E&AS estimates weighted by the quantity of RPM generation offers from each zone in the last BRA.

9. **Consider imposing the parent-LDA Net CONE value as a minimum for sub-LDA Net CONE values.** We recommend that PJM consider imposing a minimum Net CONE for sub-LDAs at the parent-LDA Net CONE value, either for all LDAs or at least for medium-sized or small LDAs (*i.e.*, for all LDAs smaller than MAAC or EMAAC). This recommendation would safeguard against errors and associated under-procurement in small LDAs. Such errors are more likely to occur in small LDAs, such as SWMAAC, which may have idiosyncratic conditions and small sample sizes for calibrating CONE and E&AS estimates, and where under-procurement has disproportionately high reliability consequences. Even if Net CONE were truly lower in a small LDA, imposing a "parent-minimum" constraint would avoid down-shifting the VRR curve and offsetting the locational investment signals created by E&AS prices. If PJM and stakeholders decide not to pursue this recommendation, it would at least be necessary to carefully investigate E&AS and CONE estimates whenever Net CONE values in import-constrained LDAs are substantially below the Net CONE estimates of the parent LDA, such as in SWMAAC where low historical Net CONE estimates were caused by inaccurately high E&AS estimates.

10. **Consider adopting the average of CC and CT Net CONE values for defining the VRR Curve.** Rather than relying only on CT Net CONE estimates for defining the VRR curve, we recommend that PJM consider setting Net CONE based on the average of CC and CT Net CONE estimates. This would recognize that CC plants are the predominant technology under development by merchant generators (which increases the accuracy of Gross CONE estimates), while avoiding a complete switch away from the currently-defined CT reference technology.

IV. Monte Carlo Simulation Modeling Approach

The position, slope, and shape of PJM's VRR curve have important consequences for the performance of the capacity market in terms of realized reliability levels and price volatility. Revising the shape and slope of the curve would change the expected distribution of price and quantity outcomes from the market, but the magnitude of these effects is not obvious on inspection or with only a few years of historical experience. We, therefore, use a Monte Carlo model to simulate a distribution of price, quantity, and reliability outcomes that might be realized over many years under the current VRR curve or alternative curves. In this Section, we describe the primary components of this model, including our characterization of supply, demand, transmission, reliability, and locational auction clearing. We present simulation results under the current VRR curve and alternative curves under several scenarios in Sections V and VI below.

A. Overview of Model Structure

To evaluate the performance of the VRR curve and alternative curves over the long term, we conduct a Monte Carlo simulation of 1,000 capacity market outcomes. This analysis allows us to estimate a distribution of price, quantity, and reliability outcomes under a particular curve, and review these outcomes in light of the performance objectives of the VRR curve and RPM as discussed in Sections V.A.1 and VI.A.1 below.

The Monte Carlo simulation model we developed for this analysis builds on the simulation model we developed to assist ISO-NE design a sloped demand curve and is similar to the model, originally developed by Professor Benjamin Hobbs, that was previously used to evaluate VRR curve performance.[41] The model developed for this analysis adds important features to make the simulations more realistic and more applicable to RPM. We now simulate RPM performance within individual LDAs, while the previously-used Hobbs model was only a system-wide model not able to simulate reliability outcomes within individual LDAs. The current model also employs a realistic sloped supply curve that is calibrated to observed RPM outcomes and reflects the wide range of capacity resources bidding into the RPM market—such as retrofits to existing units, imports, demand response, and different types of new units. In contrast, the previously-used Hobbs model did not utilize a sloped supply curve and relied on CTs as the only technology that would ever be added to the market. Equally important, the size and standard deviation of "shocks" to supply and demand conditions utilized in our Monte Carlo simulations are calibrated to the size and standard deviations of shocks observed in PJM, both at the system and individual LDA level.

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41 See discussion of the Hobbs simulation model in our 2008 and 2011 RPM Reports, Pfeifenberger (2008, 2011).

We use the planning parameters for delivery year 2016/17 as the basis for our modeling assumptions, combined with a historically-grounded locational supply curve to determine locational clearing prices and quantities. We then use historical market data to develop realistic shocks to supply, demand, and transmission in each draw. A stylized depiction of the price and quantity distributions driven by supply and demand shocks is shown in Figure 11, with the intersection of supply and demand determining price and quantity distributions. The shape of these distributions will change with the shape of the demand curve.

We assume economically rational new entry, with new supply added infra-marginally until the long-term average price equals Net CONE.[42] As such, our simulations reflect long-term conditions at economic equilibrium on average, and do not reflect a forecast of outcomes over the next several years or any other particular year. In our base case analysis, we model each draw from the model independently of the others, but we also conduct a sensitivity analysis incorporating time-sequential supply investments and auto-correlated loads.

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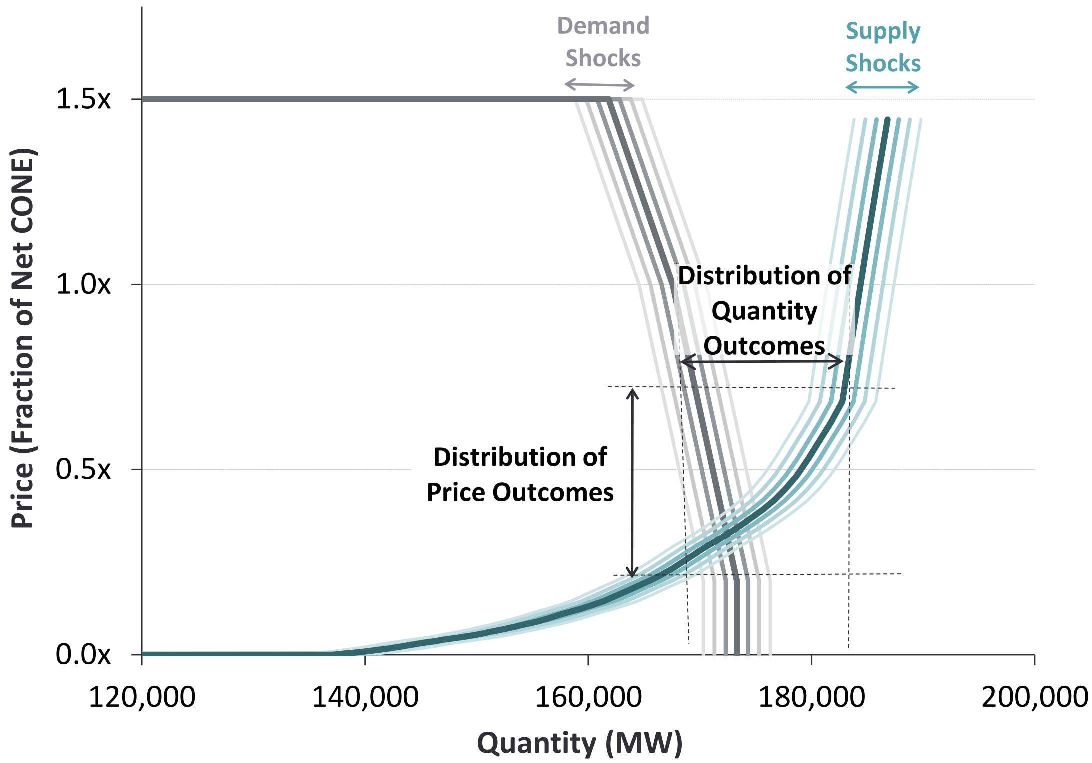
42 An alternative approach would have been to model new supply as a long, flat shelf on the supply curve set at Net CONE, but that would be inconsistent with the range of offers we have observed for actual new entrants, and it would artificially eliminate price volatility. Our modeling approach reflects the fact that short-run capacity supply curves are steep, resulting in structurally volatile prices, while long-run prices converge to long-run marginal costs, or Net CONE.

Figure 11
Stylized Depiction of Supply and Demand Shocks in the Monte Carlo Analysis



Note:
Illustrative shocks are not intended to reflect exact shock magnitudes or locational clearing results.

Finally, we note three important simplifications to our modeling approach that reflect the scope of our assignment with PJM: (1) we analyze only the likely results of the three-year forward Base Residual Auctions (BRAs) and do not examine the short-term Incremental Auctions in terms of supply and demand changes that may occur between the BRA and IAs; (2) we do not evaluate the reliability or price implications of the 2.5% Short-Term Resource Procurement Target (STRPT), implicitly assuming that PJM will acquire exactly the targeted quantity in subsequent auctions; and (3) we do not evaluate the reliability implications or price interactions with PJM's multiple demand response (DR) product types. While these aspects of RPM, do have material importance for the performance of the curve in combination with the rest of the market design, these issues are not within the scope of the present analysis.

B. Locational Supply and Demand Modeling

In each simulation draw, we generate locational supply curves, locational demand curves, and transmission parameters. We then apply an optimal auction clearing algorithm to determine the cleared price and quantity in each location for that draw. The cleared quantity in each location then also determines the realized reliability outcome for each location. We describe here how we used historical market data to develop realistic representations of each of these components, consistent with the 2016/17 delivery year.

1. System and Local Supply Curves

The supply curve shape is an important driver of volatility in cleared price and quantity in our modeling, as in real capacity markets. A gradually-increasing, elastic supply curve will result in relatively stable prices and quantities near the Reliability Requirement even in the presence of shocks to supply and demand, while a steep supply curve will result in greater volatility.

We use historical PJM offer prices and quantities to create eight realistic supply curve shapes, consistent with the supply curve shapes from the PJM BRAs conducted over 2009/10 to 2016/17.[43] To develop comparable supply curve shapes consistent with the 2016/17 delivery year, we escalate all offer prices to the 2016/17 delivery year and normalize the quantity of each curve by the quantity of offers below $330 MW-d. Smoothed versions of the resulting supply curve shapes are presented in Figure 12, showing a range of shapes from the steepest curve in 2013/14 to the flattest or most elastic curves in 2014/15 and 2015/16, when many existing units offered at higher levels reflective of the expense of environmental retrofits.[44] However, in all years the supply curve becomes quite steep at high prices above $300/MW-d, a fact that underpins the structural volatility of capacity markets in the real world as well as in our modeling.

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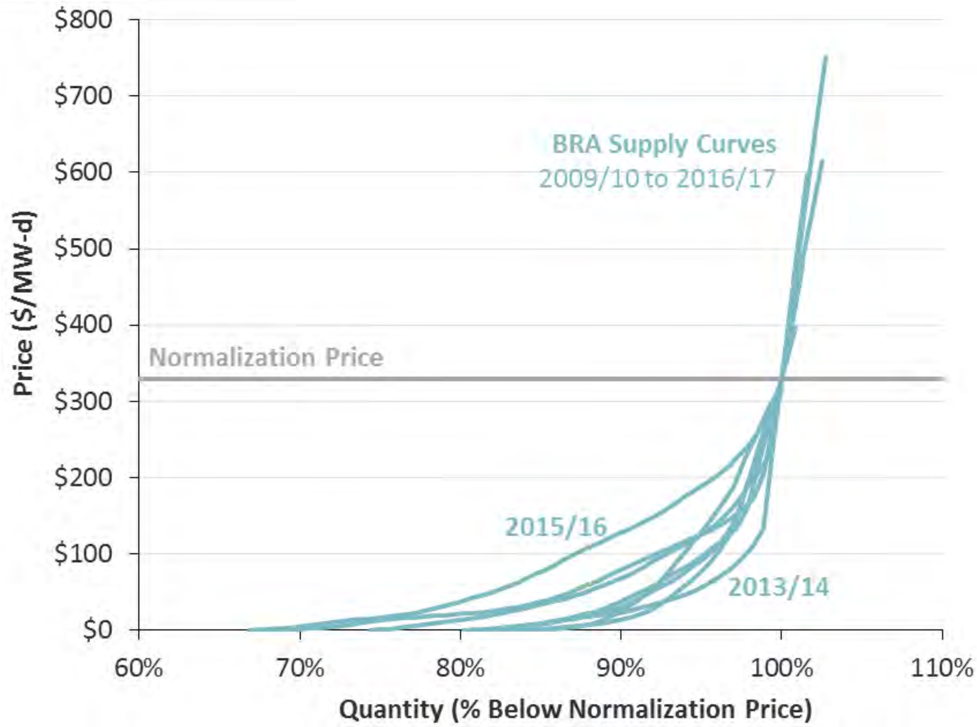
43 Developed from auction supply curve data provided by PJM staff. We exclude data from the initial two BRAs, because those auctions were conducted on a shorter forward period and therefore exhibited a steeper supply curve shape that we expect in typical BRAs. The curves reflect the aggregate resource supply curve that would be available to meet the VRR curve, and so contingent bids for different DR products are collapsed into a single offer for the maximum quantity available from each resource.

44 Those environmental retrofits were required by the Mercury and Air Toxics Standard (MATS) which induced retire-or-retrofit decisions on a substantial portion of PJM's coal fleet beginning with the 2014/15 BRA. See additional discussion of the impacts of this rule in Section II.A.3 of Pfeifenberger (2011).

Figure 12
Individual Supply Curve Shapes used in Monte Carlo Analysis



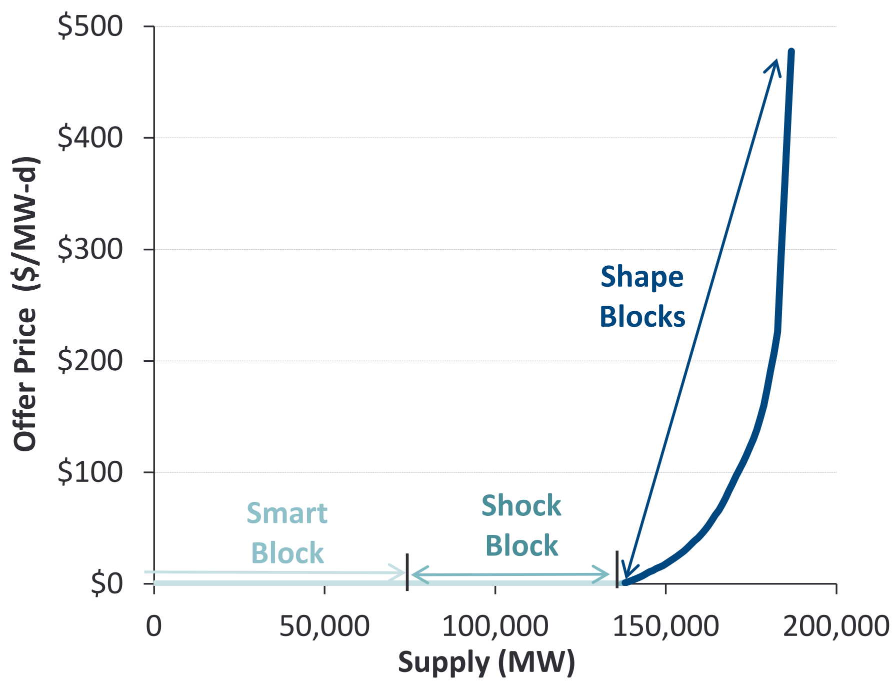
Sources and Notes:
Smoothed supply offer curves developed from raw data provided by PJM staff.
Offer curves normalized by quantities offered below $330/MW-d and inflated to 2016/17 dollars.

We reflect the lumpy nature of investments by simulating each supply curve as a collection of discrete sized offer blocks. Simply modeling a smooth offer curve, like one of the individual smoothed curves shown in Figure 12, would somewhat understate realized volatility in price and quantity outcomes, especially in small LDAs that are more greatly affected by lumpy investments. To derive realistically-sized offer blocks in each location, we randomly select from actual offers in that location from the 2016/17 BRA but re-price those offers consistent with the selected smooth supply curve shape.

To simulate rational economic entry, we increase or decrease the quantity of zero-priced supply so that the average clearing price over all draws is equal to Net CONE. The result is that average prices will always equal Net CONE under all different demand curves, although differently-shaped demand curves will result in a different average cleared quantities. This normalization allows us to examine the performance of the VRR curve in a long-term equilibrium state. Too much zero-priced supply would result in an average price below Net CONE, while too little supply would result in a price above Net CONE.

We provide a stylized depiction of these supply curve components in Figure 13. The block of zero-priced supply used for normalization is shown as the "Smart Block," and is held constant across the 1,000 individual draws we report, but is slightly different between demand curves.[45] For example, with a right-shifted demand curve, more supply would be included in the smart block (if the same smart block were used to model both curves, then clearing prices with the right-shifted curve would be higher than with our proposed curve). In contrast to the smart block, the quantity of the shock block varies with each draw to generate shocks to the supply curve, as described in Section IV.C below. Finally, the "Shape Blocks" are the collection of offers at above-zero prices generated using historical BRA offer data as described above.

Figure 13
Stylized Depiction of Simulated Supply Curve Components



Sources and Notes:
Smart block and shock blocks both represent quantities of supply that are offered at zero-price, and are used as adjustable parameters in our model.
Shape blocks represent the supply that is offered at non-zero prices, and is based on historically observed supply as shown in Figure 12.

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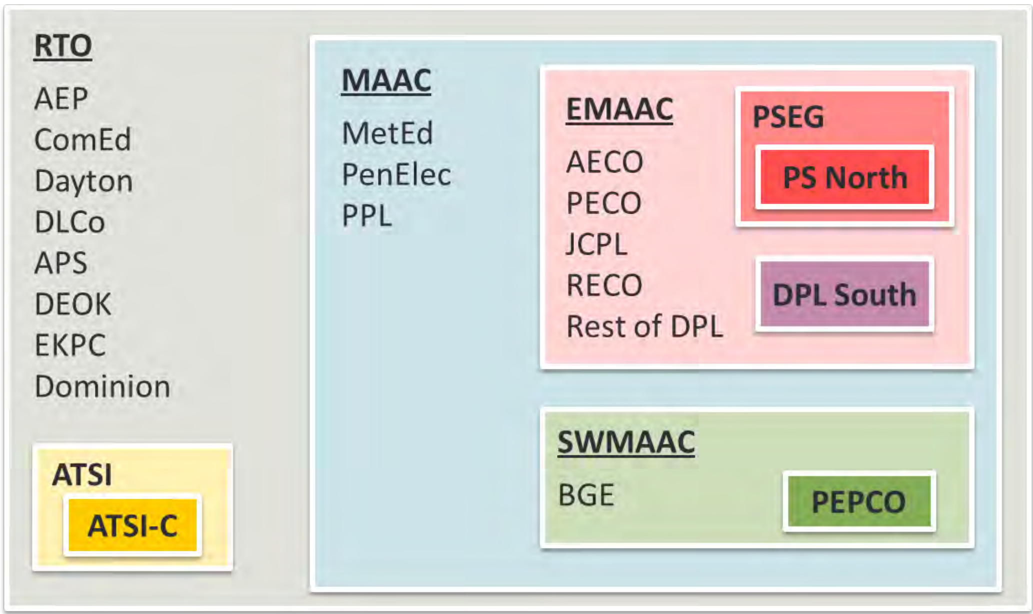
45 We refer to it as the "Smart Block" because it reflects rational entry or exit from the market in response to market signals, this differs from the "Shock Block" which reflects random deviations that are not driven by rational economic decision-making. We calculate the appropriate "Smart Block" in each location under each demand curve by first running a convergence algorithm over 9,000 draws to determine the quantity that will result in long-run prices equal to Net CONE, we then run a final 1,000 draws with the converged fixed smart block size and report only these draws in this report.

2. Administrative Demand, Transmission, and Auction Clearing

We reflect administrative demand curves at both a system and local levels in a locational clearing algorithm that minimizes capacity procurement costs subject to transmission constraints. We reflect the nested zonal structure of PJM's capacity market, consistent with the planning parameters for the 2016/17 delivery year, as shown schematically in Figure 14.

Figure 14
Nested Zonal Structure Consistent with 2016/17 BRA



Source:

Each rectangle and bold label represent an LDA modeled in 2016/17 BRA; individual load zones that are not modeled in RPM auctions are not bold, see PJM (2013a) and (2014a).

Note that the chart is slightly different from Figure 3 above because the prior figure reflects the subsequent delivery year after which three additional LDAs are modeled.

3. Reliability Outcomes

We calculate reliability outcomes for each Monte Carlo simulation draw based on locational and system-wide reliability simulations conducted by PJM staff. We use the same simulation results that PJM used to calculate the system and local Reliability Requirements for delivery year 2016/17, and as described in their reliability studies.[46] In that simulation analysis, PJM estimates the relationship between the supply quantity and LOLE, with system-wide Reliability Requirement set at the quantity needed to meet an LOLE of 0.1 Events/Yr (or 1-in-10) and local Reliability Requirements set at an LOLE of 0.04 Events/Yr (or 1-in-25).[47]

Figure 15 shows the relationship between the system reserve margin and LOLE. This relationship is asymmetrical, with reliability outcomes deteriorating sharply at reserve margins below the Reliability Requirement but improving only gradually at reserve margins above the Reliability Requirement. An important implication of this asymmetry is that a demand curve that results in a distribution of clearing outcomes centered on the target with equal variance above and below the target, will fall short of the 0.1 LOLE target on an average basis.[48]

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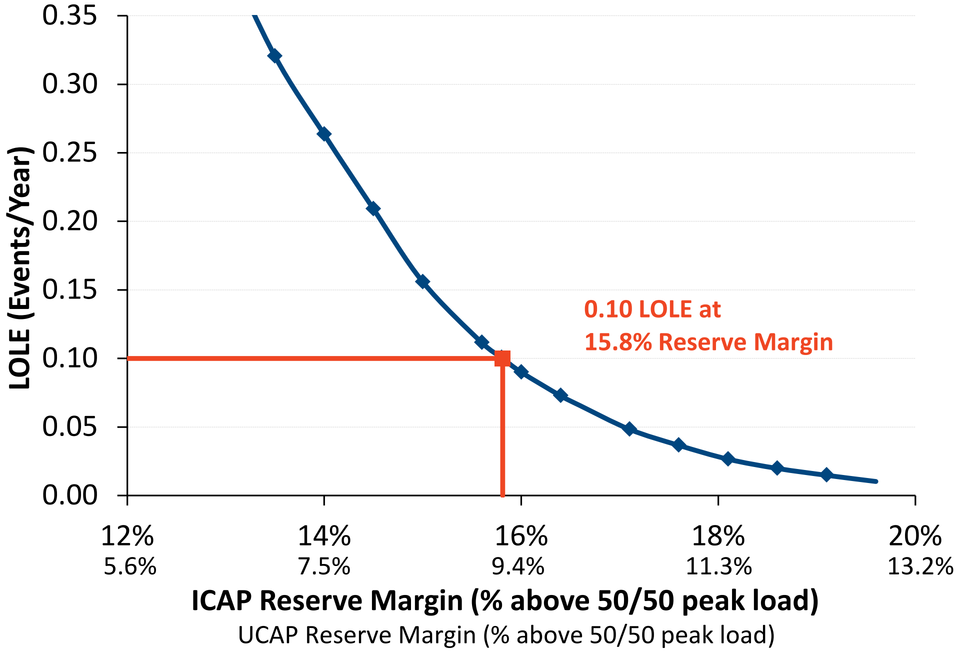
46 See PJM (2013f).

47 Note that the local requirement of 1-in-25 actually reflects lower total reliability, because the location is subject to not only local shortages but also system-wide shortages.

48 In our analyses, the average LOLE reported for a given demand curve is calculated as the average of the LOLE at the cleared reserve margin in each individual draw, rather than the LOLE at the average cleared reserve margin across all draws.

Figure 15
LOLE vs. Reserve Margin



Sources and Notes:
LOLE data provided by PJM staff, with interpolation between discrete points.

C. Shocks to Supply, Demand, and Transmission

To simulate a realistic distribution of price, quantity, and reliability outcomes, we introduce upward and downward shocks to supply, demand, administrative Net CONE, and transmission, with the magnitude of the shocks based on historical observation. Because the magnitude of these shocks is an important driver of the performance of the VRR curve, we also report the sensitivity of the VRR curve's performance to each type of shock and conduct a sensitivity analysis regarding overall shock sizes in Sections V.B.2 and VI.B.4 below. We briefly describe here our approach to estimating shocks reflective of historical market data, and provide additional detail supporting these estimates in Appendix A. We also compare our resulting shock estimates to historically-observed values in Table 5 below.

- **Supply Offer Quantity**: We estimate shocks to supply offer quantities using the total quantity of supply offers in each location in each historical BRA, estimating the standard deviation in supply offers between years as a function of LDA size. See detail in Appendix A1.
- **Demand**: We model demand shocks in two components: (1) shocks to the load forecast, estimated at a standard deviation of 0.8% of the peak load forecast for the RTO, with each LDA having an RTO-correlated shock in addition to an uncorrelated load forecast shock; and (2) shocks to the Reliability Requirement as a percentage of system or local peak load. See detail in Appendix A2.

- **Administrative Net CONE**: We assume that administrative Net CONE is equal to true Net CONE on average under base case assumptions, but that administrative Net CONE is subject to random error around this expected value. We estimate the shock to administrative net CONE in each simulation considering: (a) shocks to Gross CONE, based on historical variation in the Handy Whitman index, and (b) shocks to one-year historical E&AS estimates, and (3) overall shocks to administrative Net CONE calculated as Gross CONE minus a three-year average of historical E&AS estimates. See detail in Appendix A3.
- **Capacity Emergency Transfer Limit**: We simulate shocks to CETL as normally distributed with a standard deviation of 12% of the expected CETL value based on the 2016/17 parameter, with the standard deviation estimated based on historical auction data across all locations and years. See detail in Appendix A4.

The aggregate impact of these individual shocks is illustrated in Table 5, where we compare historical shocks to supply, demand, and transmission (top two panels) against our simulated shocks (bottom panel). The most important comparison in this table is in "net supply," calculated as supply plus CETL minus reliability requirement. This net supply comparison is the most important driver of price and quantity results in our modeling as well as in historical market results. Net supply is also the most important comparison, because it accounts for correlations between supply and demand that may exist, for example, because: (a) supply and demand are both increasing over time; (b) the total scope of RPM has expanded over time because of territory expansions and incorporation of FRR entities into RPM; and (c) suppliers may anticipate market conditions and pro-actively increase (decrease) offer quantities when there is anticipated increase (decrease) in demand.[49]

We report historical shocks in two ways: (1) as a simple standard deviation of the actual historically observed values, and (2) as a standard deviation of the differences between the absolute observed values and a simple linear time trend over time. The first method produces larger shocks than the second, because removing the time trend reduces the variability of the distributions. We believe that both reference points provide a relevant basis for comparison, for example, because the absolute-value approach may over-estimate shocks for components with a substantial time trend (*e.g.*, in load forecast and total supply), while the deviation-from-trend approach may under-estimate shocks for components that we would not expect to change substantially over time (*e.g.*, CETL and net supply minus demand). For these reasons, we base our modeling on simulated net supply shocks that fall between these two methods, but also test the sensitivity of our results to a reasonable uncertainty range.

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[49] These correlations between supply and demand shocks, particularly related to FRR integration and RTO expansions, are the reason that gross supply and demand shocks are so much larger than the net supply shocks calculated historically. While these FRR integrations and expansions <u>do</u> introduce some amount of additional volatility in net supply, it is far less than if the same magnitude of supply and demand shocks were introduced on a non-correlated basis.

Table 5
Net Supply minus Demand Shocks

LDA	Standard Deviation Supply (MW) [1]	CETL (MW) [2]	Reliability Requirement (MW) [3]	Net Supply (MW) [4]	Standard Deviation as % of 2016/17 LDA Size Supply (%) [5]	CETL (%) [6]	Reliability Requirement (%) [7]	Net Supply (%) [8]
Historical Absolute Value								
RTO	20,040	n/a	14,783	5,894	12.1%	n/a	8.9%	3.5%
MAAC	3,549	811	931	3,480	4.9%	1.1%	1.3%	4.8%
EMAAC	1,900	721	645	2,451	4.8%	1.8%	1.6%	6.2%
SWMAAC	907	910	335	1,652	5.2%	5.3%	1.9%	9.5%
PS	820	352	288	832	6.4%	2.7%	2.2%	6.5%
PS NORTH	534	252	101	585	8.3%	3.9%	1.6%	9.1%
DPL SOUTH	112	206	57	282	3.5%	6.5%	1.8%	8.9%
PEPCO	423	1,060	233	1,673	4.7%	11.8%	2.6%	18.6%
ATSI	717	1,742	38	2,421	4.4%	10.7%	0.2%	14.9%
ATSI-Cleveland	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Historical Deviation from Trend								
RTO	4,816	n/a	4,850	2,147	2.9%	n/a	2.9%	1.3%
MAAC	1,229	808	792	2,208	1.7%	1.1%	1.1%	3.1%
EMAAC	1,102	717	578	2,091	2.8%	1.8%	1.5%	5.3%
SWMAAC	409	378	283	792	2.4%	2.2%	1.6%	4.6%
PS	657	329	96	759	5.1%	2.6%	0.7%	5.9%
PS NORTH	338	222	84	401	5.3%	3.4%	1.3%	6.2%
DPL SOUTH	70	172	48	193	2.2%	5.4%	1.5%	6.1%
PEPCO	234	236	166	585	2.6%	2.6%	1.8%	6.5%
ATSI	557	n/a	n/a	n/a	3.4%	n/a	n/a	n/a
ATSI-Cleveland	473	n/a	n/a	n/a	7.7%	n/a	n/a	n/a
Simulation Shocks								
RTO	4,054	n/a	1,499	4,277	2.4%	n/a	0.9%	2.6%
MAAC	2,767	794	794	2,984	3.8%	1.1%	1.1%	4.1%
EMAAC	1,591	1,090	492	1,954	4.0%	2.7%	1.2%	4.9%
SWMAAC	644	1,074	279	1,214	3.7%	6.2%	1.6%	7.0%
PS	363	804	215	908	2.8%	6.2%	1.7%	7.1%
PS NORTH	226	359	131	446	3.5%	5.6%	2.0%	6.9%
DPL SOUTH	97	232	76	259	3.1%	7.4%	2.4%	8.2%
PEPCO	328	837	220	935	3.6%	9.3%	2.4%	10.4%
ATSI	663	963	259	1,186	4.1%	5.9%	1.6%	7.3%
ATSI-Cleveland	157	641	164	699	2.5%	10.4%	2.7%	11.3%

Sources and Notes:

All values calculated over 2009/10 through 2016/17 delivery years, where data were available.

[1]: Historical standard deviations calculated from annual BRA Supply Offers, see Appendix A1.

[2]: Historical standard deviations calculated from CETL values in the PJM Planning Parameters., see Appendix A4.

[3]: Historical standard deviations from Reliability Requirement values in the PJM Planning Parameters, see Appendix A2.

[4]: All standard deviations are calculated based on Net Supply, where Net Supply equals [1] + [2] – [3].

[5] – [8]: Equal to columns [1] – [4], divided by the LDA's 2016/17 Reliability Requirement.

D. Summary of Base Case Parameters and Input Assumptions

Table 6 summarizes the base case input assumptions that we apply in our Monte Carlo simulation exercise. We adopt the Reliability Requirement, CETL, and Net CONE parameters from the administrative parameters from the 2016/17 BRA, and assume that the true developer Net CONE is equal to the administratively-estimated Net CONE. We also report the standard deviation of shocks to each of these parameters as generated across 1,000 simulation draws.

Table 6
Base Case Parameters and Input Assumptions

Parameter		RTO	ATSI	ATSI-C	MAAC	EMAAC	SWMAAC	PSEG	DPL-S	PS-N	PEPCO
Average Parameter Value											
Administrative Net CONE	*($/MW-d)*	$331	$363	$363	$277	$330	$277	$330	$330	$330	$277
True Net CONE	*($/MW-d)*	$331	$363	$363	$277	$330	$277	$330	$330	$330	$277
CETL	*(MW)*	n/a	7,881	5,245	6,495	8,916	8,786	6,581	1,901	2,936	6,846
Reliability Requirement	*(MW)*	166,128	16,255	6,164	72,299	39,694	17,316	12,870	3,160	6,440	9,012
Standard Deviation of Simulated Shocks											
Administrative Net CONE	*($/MW-d)*	$26	$23	$23	$37	$34	$37	$34	$34	$34	$37
Reliability Requirement	*(MW)*	1,499	259	164	794	492	279	215	76	131	220
Reliability Requirement	*(% of RR)*	0.9%	1.6%	2.7%	1.1%	1.2%	1.6%	1.7%	2.4%	2.0%	2.4%
CETL	*(MW)*	n/a	965	662	771	1,055	1,008	793	230	364	844
Supply Excluding Sub-LDAs	*(MW)*	624	507	157	532	1,132	315	136	97	226	328
Supply Including Sub-LDAs	*(MW)*	4,054	663	157	2,767	1,591	644	363	97	226	328
Net Supply	*(MW)*	4,277	1,186	699	2,984	1,954	1,214	908	259	446	935

Sources and Notes:
Average Parameter Values are from 2016/17 PJM Planning Parameters, see PJM 2013a.
Details on Standard Deviation of Simulated Shocks are provided in Appendix A.

V. System-Wide Variable Resource Requirement Curve

The PJM VRR curve is an administrative representation of demand for capacity, supporting the primary RPM design objective of attracting and retaining sufficient supplies to meet the 1-in-10 reliability standard. The curve also supports other objectives such as mitigating price volatility, susceptibility to the exercise of market power, and rationalizing prices according to the diminishing value of reliability. In this Section of the report, we evaluate the VRR curve by: (1) laying out the VRR curve design objectives against which we evaluate the curve; (2) qualitatively reviewing its likely performance, as indicated by the curve shape, quantity at the price cap, and width; and (3) estimating the distribution of price, quantity, and reliability outcomes under the curve. This evaluation is focused on the performance of the system-wide VRR curve, while we evaluate the VRR curve at the locational level in the following Section VI.

Based on this evaluation, we identify potential performance concerns including a relatively high frequency of low-reliability events and realized reliability below the 1-in-10 standard on a long-term average basis. To address these concerns, we recommend revising the VRR curve by adopting a revised convex VRR curve shape that would address these performance concerns, with parameters that are tuned to meet the 1-in-10 standard.

A. Qualitative Review of the Current System Curve

We begin our evaluation of the system VRR curve by laying out an explicit set of design objectives, with the primary objective being to achieve the 1-in-10 reliability standard on a long-term average basis. We then qualitatively assess the likely performance of the VRR curve by examining the curve shape, reliability at the price cap, and VRR curve width compared to the likely size of year-to-year shocks in supply and demand.

1. System-Wide Design Objectives

The primary design objective of the system-wide VRR curve is to procure enough resources to maintain resource adequacy, including through merchant entry when needed. This objective must be fulfilled while also aiming to avoid excessive price volatility and susceptibility to market power abuse. These objectives can be at odds, with a vertical curve providing greater assurance of procuring the target quantity, but producing prices that are maximally sensitive to small shifts in supply and demand; in the other extreme, a horizontal curve provides total certainty in price but provides no certainty in the quantity that will be procured or consequently in realized reliability levels. Tradeoffs between quantity uncertainty and price uncertainty reflect the classic "prices vs. quantities" problem in regulatory economics.[50]

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[50] See Weitzman (1974).

In order to inform these tradeoffs and determine whether the VRR curve provides a satisfactory balance, it is helpful to sharpen the definition of both the quantity-related and price-related objectives. We have established the following specifications in collaboration with PJM staff, consistent with PJM's Tariff, practices, and prior statements:

- **Resource Adequacy (Quantities).** Recognizing that procurement can be increased by shifting the curve up or to the right, but cleared quantities will vary as supply and demand conditions shift, our analysis assumes the VRR curve should meet the following objectives:
  - The expected LOLE should be 0.1 events per year. This does not mean the LOLE will be 0.1 in every year, but that it can be expected to achieve the 1-event-in-10 years LOLE target on average.
  - Very low reserve margin outcomes should be realized from RPM auctions very infrequently. For example, there should be a relatively small probability of clearing less than "IRM – 1%," the quantity at which PJM's Tariff stipulates that a Reliability Backstop Auction under certain conditions.[51]
  - The curve should meet these objectives in expectation and remain robust under a range of future market conditions, changes in administrative parameters and administrative estimation errors. However, considering that future VRR curve reviews and CONE studies can adjust for major changes, it is unnecessary to substantially over-procure on an expected average basis just to ensure meeting these objectives under all conceivable future scenarios, as that would incur excess costs.
- **Prices.** Consistent with relying on merchant entry, prices can be expected to equal Net CONE on a long-run average basis (no matter what the shape of the VRR curve). But prices will vary as supply and demand conditions shift, depending on the elasticity of the supply and VRR curves. To support a well-functioning market, the VRR curve should meet the following price-volatility-related objectives:
  - The curve should reduce price volatility if possible. That means reducing the impact from small variations in supply and demand, including administrative parameters, rule changes, lumpy investment decisions, demand forecast changes, and transmission parameters.
  - To mitigate susceptibility to the exercise of market power, small changes in supply should not be allowed to produce large changes in price. Mitigating susceptibility to market power and price volatility are both served by adopting a flatter VRR curve. Relatedly, concerns about market power are also

51 Specifically, if the BRA clears a quantity less than IRM-1% for three consecutive years. See PJM (2014b), Section 16.3.

supported by having a moderate price cap that limits the price impact of withholding.

 - On the other hand, price volatility should not be over-mitigated. Prices should be allowed to vary sufficiently to reflect year-to-year changes in market conditions. It is also preferred for prices to rise increasingly steeply as reserve margins decrease in order to provide a stronger price signal when needed to avoid very low reliability outcomes. Such a convex VRR shape would also make prices more proportional to the marginal reliability value, a desirable attribute for a "demand curve" for resource adequacy.[52]

 - As noted above, the VRR curve needs a price cap, but it is important that the price cap binds infrequently, to prevent prices from departing too substantially from supply fundamentals.

- **Other Design Objectives.** The VRR curve forms the basis for a multi-billion dollar market, and yet it is an administratively-determined construct. To support a well-functioning market for resource adequacy in which investors and other decision-makers can expect continuity and develop a long-term view, this administrative construct should be as rational, stable, and transparent as possible.

  - The curve can be deemed "rational" if it consistently meets the design objectives outlined above, with well-reasoned and balanced choices about tradeoffs among objectives.

  - To provide stability, the curve (and RPM as a whole) should have stable market rules and administrative estimates, although adjustments may be necessary to accommodate changes in market and system conditions.

  - To support stability and transparency, the VRR curve should also be simple in its definition and in how parameters are updated over time. This can also avoid stakeholder contentiousness and litigation, which would increase regulatory risk for investors.

Several of these design objectives are inherently difficult to satisfy, and in many cases we must weigh tradeoffs among competing design objectives. For example, capacity markets can produce structurally volatile capacity prices due to steep supply and demand curves, meaning that relatively small changes in supply or demand can cause large changes in price. Introducing a sloped demand curve will mitigate some of this price volatility, with flatter curves resulting in more stable capacity prices. However, a very flat demand curve will introduce greater quantity uncertainty and greater risk of low-reliability outcomes. We further explain the tradeoffs among these design objectives as we evaluate the performance of the VRR curve and potential changes to the curve.

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52 Since the VRR curve is designed to meet the engineering-based standard of 0.1 LOLE rather than an economics-based reserve margin, the curve can only be designed to be proportional to marginal reliability value rather than equal to the marginal economic value.

We also note that we evaluate the curve against the primary RPM design objective of achieving 1-in-10 LOLE on average over many years. While we and others have separately evaluated the 1-in-10 standard itself from reliability and economic perspectives, this is not within the scope of our present analysis.[53]

2. Shape of the VRR Curve

PJM's VRR curve has a concave shape (*i.e.*, pointing away from the intersection of the x- and y-axis) defined by three points as described in Section II.C above. The overall price and quantity placement of the VRR curve are consistent with PJM's design objectives, with prices above Net CONE when the system would be below the resource adequacy requirement and prices below Net CONE when the system exceeds the resource adequacy requirement by more than IRM+1%. This price and quantity relationship should work to attract new capacity investments when the system is short, and postpone such investments when the system is long. The downward-sloping shape of the curve will also work to mitigate against price volatility and the exercise of market power, consistent with the design objectives. However, the concave shape of the VRR curve may not meet PJM's design objectives as well as alternative shapes such as straight-line or convex curves, a topic that we evaluate qualitatively here and quantitatively in subsequent sections.

An important theoretical disadvantage of the existing concave curve is that it is not consistent with the incremental reliability and economic value of capacity, as illustrated in Figure 16. The figure shows the VRR curve superimposed over the marginal avoided expected unserved energy (EUE), which measures the amount of incremental load shedding that can be avoided by adding more capacity. The avoided EUE line, therefore, illustrates the estimated reliability value of increasing the reserve margin, which has a steeper slope at low reserve margins and gradually declines at higher reserve margins. This *convex* shape will also reflect the economic value of adding capacity at varying reserve margins, although the total economic value of capacity also includes components other than avoided EUE, such as other avoided emergency events, avoided DR dispatch, and avoided dispatch of high-cost resources.[54]

For these reasons, moving from a concave to a convex shape would move toward one of PJM's secondary objectives of rationalizing prices according to incremental reliability value. However, we note that attempting to make the curve exactly proportional to this avoided EUE line is not advisable from a price volatility perspective, because this curve is much steeper than the current VRR curve and would not reflect the volatility-mitigation benefit of a more sloped curve.

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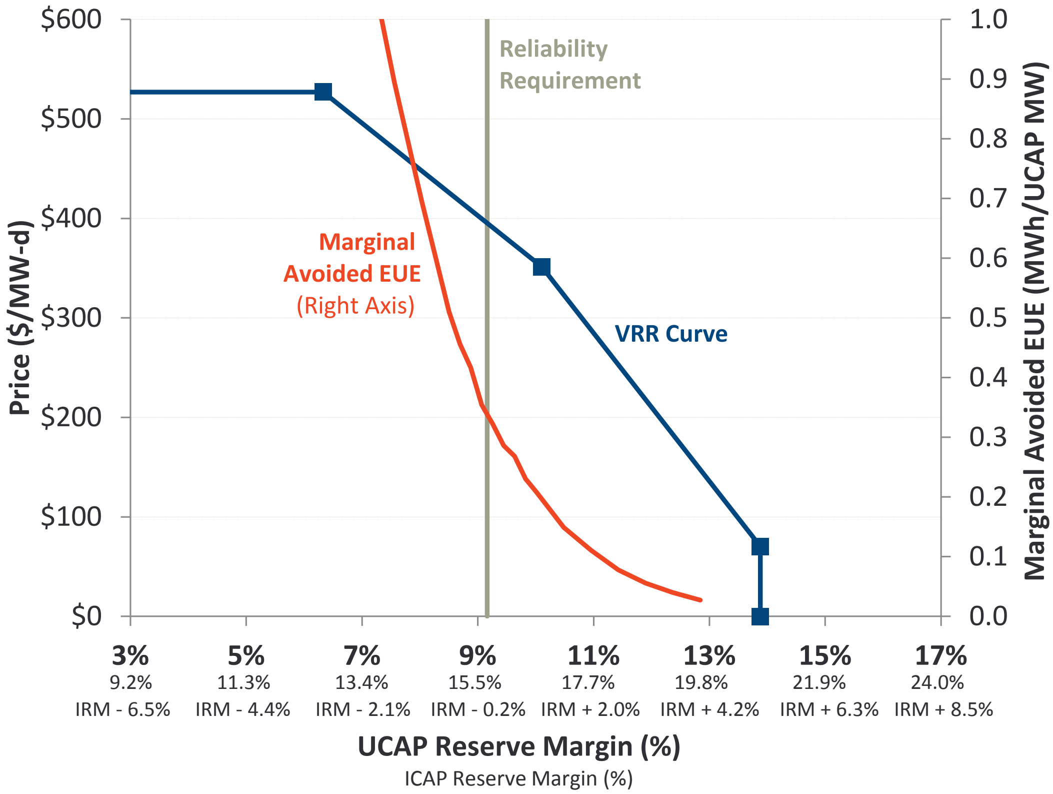
[53] For example, see Pfeifenberger (2013).

[54] See Pfeifenberger (2013).

Figure 16
2017/18 RTO VRR Curve Compared to Marginal Avoided EUE



Sources and Notes:
Current VRR Curve reflects the system VRR curve in the 2016/2017 Planning Parameters, PJM (2013a.)
Marginal Avoided EUE equal to LOLH times 1 MW.

A convex-shaped curve would also tend to produce a distribution of market prices that would be more consistent with those of other commodity markets, with a fatter tail on the high-price side. Perhaps most importantly, a convex curve is more robust from a quantity perspective, with changes to Net CONE or errors in Net CONE producing smaller reliability deviations from the resource adequacy target than straight-line or concave curves. However, as we illustrate quantitatively in the following sections, we find that convex curves also lead to slightly more price volatility than would a straight-line curve or concave curve due the steeper shape in the high-price region of the demand curve, which is magnified by steep supply curves. Additionally, combining a convex curve with PJM's relatively low price cap of 1.5× Net CONE can have the undesirable consequence of increasing the frequency of price-cap events unless the curve is relatively flat.

3. Reliability at the Price Cap

The curve can also be evaluated in terms of its reliability implications at varying reserve margins by comparing the VRR curve to system LOLE at varying reserve margins. The most important region of the curve from a reliability perspective is the high-priced region at reserve margins below the 1-in-10 Reliability Requirement. This is because LOLE and other reliability metrics increase very quickly at low reserve margins, with small deviations below the requirement having a disproportionately large impact in degrading reliability while similarly-sized increases above the requirement result in relatively modest reliability improvements. For example, increasing the reserve margin from IRM to IRM+1% changes LOLE from 0.10 to 0.06 events per year, while decreasing the reserve margin to IRM-1% changes LOLE from 0.10 to 0.18 events per year. A 1 percentage point decrease of reserve margin thus has an impact on reliability that is twice as large as the impact of a 1 percentage point increase, and this asymmetry is even greater for larger deviations.

By comparison, the current VRR curve is *less* steep below the Reliability Requirement, with prices increasing by only $41.32/MW-d or 7% between IRM and IRM-1%, although anticipated outage events increase by 79% over that range. The reliability impact becomes even greater at lower reserve margins, with LOLE increasing to 0.43 events per year, or a reliability index of 1 event in 3.37 years by the time prices reach the maximum value at point "a". This indicates that the flat shape of the current VRR curve at low reserve margins puts the region at a greater risk of low reliability events. In fact, to produce prices equal to Net CONE on average, and with a cap at the moderate level of 1.5× Net CONE, we would expect a relatively high frequency of relatively low reliability events (an expectation that we confirm through simulation estimates in Section V.B below).

To reduce the frequency of such low reliability events, we recommend that PJM consider right-shifting the quantity at point "a" as well as also possibly increasing the price cap. In terms of quantity, we recommend that PJM revise this parameter consistent with its administrative reliability backstop practices, such that PJM would attempt to procure all available resources through capacity market auctions before triggering any backstop auctions or out-of-market procurement. The only such practice that is currently codified in the Tariff is PJM's Reliability Backstop Auction trigger, which states that PJM must conduct a backstop procurement if the BRA should ever clear below a quantity of IRM-1% for three consecutive years.[55] This IRM-1% threshold is consistent with a reliability index of 1-in-5.6, as summarized in Table 7 in comparison with other quantity points. This suggests that the appropriate quantity at the price cap should be at least IRM-1%. Specifically, we recommend increasing point "a" to the quantity that produces a reliability index of 1-in-5 (rather than a fixed distance from IRM) to ensure that the reliability implications of this point are robust to changes in system conditions.

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55 See PJM (2014b).

Table 7
Reliability at VRR Curve Quantity Points and Backstop Trigger

Quantity Point	LOLE *(Ev/Yr)*	Reliability Index *(1-in-X)*
Point "a" at IRM - 3%	0.42	1-in-2.4
Backstop Trigger at IRM - 1%	0.18	1-in-5.6
Reliability Requirement at IRM	0.10	1-in-10.0
Point "b" at IRM + 1%	0.06	1-in-17.9

Notes:

Loss of Load Event (LOLE) shows the corresponding reliability for each quantity outcome shown, based on an exponential fit of LOLE and quantity as a percentage of Reliability Requirement.

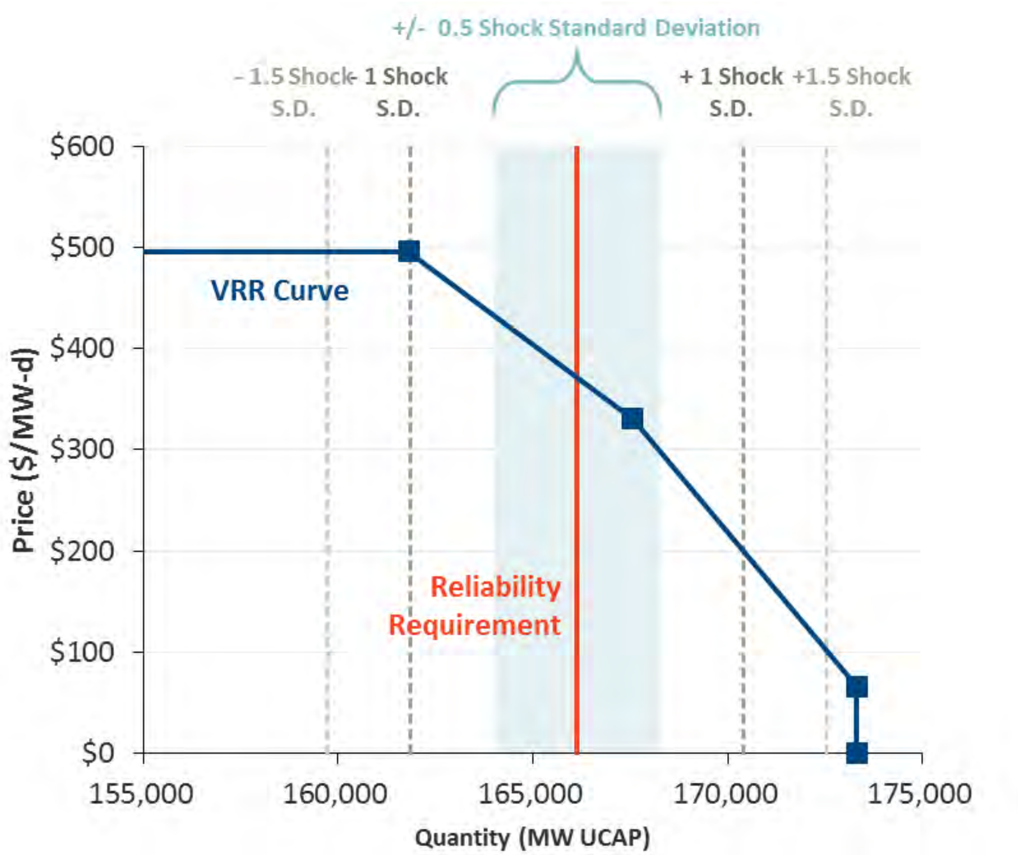
Reliability Index is the reciprocal of LOLE.

4. VRR Curve Width Compared to Net Supply Shock Sizes

Another important driver of the curve's performance is the width of the curve compared to year-to-year shifts in supply and demand. Capacity markets are structurally volatile, primarily because the supply curve is quite steep at high prices. (In contrast, the flat slope of the supply curve provides meaningful volatility mitigation benefits in the low price range). This is why, with a vertical demand curve, a capacity market would be subject to extreme price volatility with even small changes to supply or demand causing large changes in price. To mitigate this structural price volatility, the VRR curve must be flat enough (or "wide" enough) to moderate the magnitude of price changes in the face of reasonably expected shocks to supply and demand.

Figure 17 shows the VRR curve width compared to typical expected net supply shocks as estimated in Section IV.C above. We find that the net supply minus demand balance can be expected to change by a relatively substantial quantity each year, with a standard deviation of 3% of the Reliability Requirement or 4,277 MW total using 2016/17 parameters. These relatively large shocks to supply and demand have been driven by a number of different factors over the years, with a subset of examples including: (a) changes to supply economics, with individual years sometimes experiencing a wave of new offers from demand resources, imports, or new generation; (b) regulatory changes, with the most important example being the 2014/15 MATS regulation which introduced a substantial number of retirements over a small number of years; (c) rule changes, that have resulted in increased or decreased offer quantities from categories of resources such as demand response and imports; (d) the economic recession that began in Year, resulting in a substantial reduction in demand forecasts over the subsequent years; and (e) incorporation of supply and demand from FRR entities and territory expansions, which have tended to increase both supply and demand by similar but not exactly offsetting magnitudes, thereby introducing a net supply shock into the market.

Figure 17
VRR Curve Width Compared to Expected Net Supply Shocks

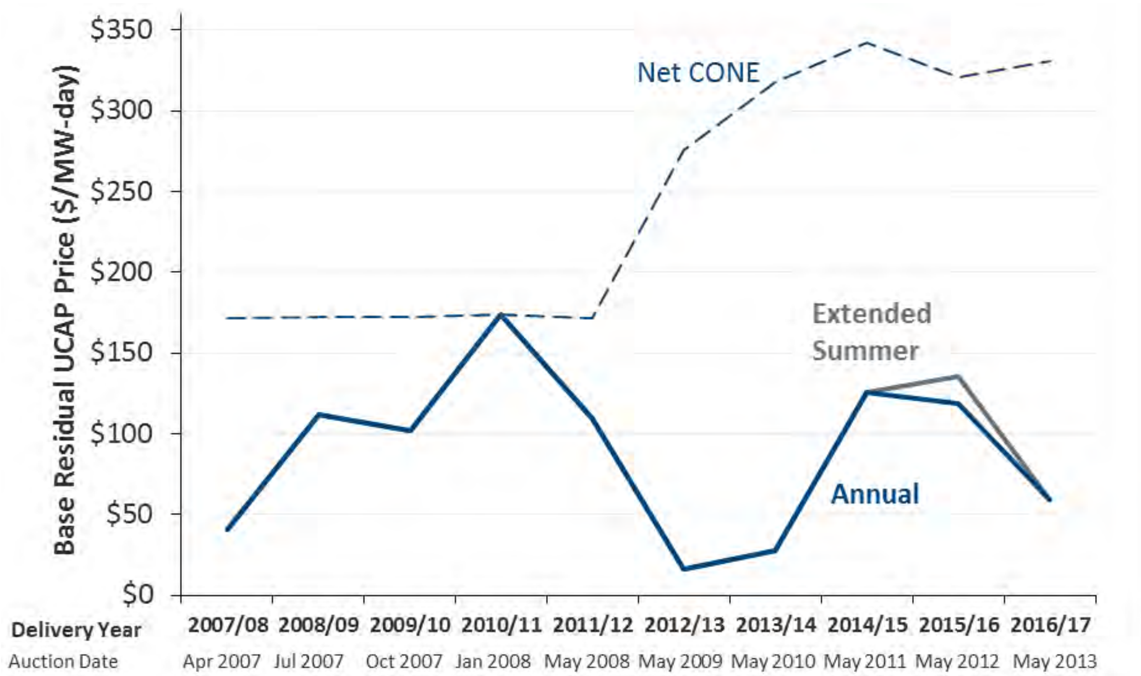


Sources and Notes:
The range of expected net supply shocks are based on simulated outcomes of supply minus demand shocks for the system. As reported in Table 5, the standard deviation of simulated shocks is 4,277 MW.

These relatively large year-to-year changes in net supply minus demand balance are relatively large compared to the width of the VRR curve. As Figure 17 shows, if starting at the Reliability Requirement, losing one standard deviation of supply would increase prices to the cap, or by a delta of $123/MW-d or 37% of Net CONE; while adding one standard deviation of supply would decrease prices by $172/MW-d or 52% of Net CONE. The magnitude of expected shifts to net supply balance also has important implications for reliability. For example, if prices need to be at Net CONE on average in long-run equilibrium, then assuming a normal distribution in net supply shocks, we would expect quantities at IRM-1% (reliability index 1-in-5.6) approximately once every 2.7 years and at IRM-3% (reliability index 1-in-2.4) approximately once every 6.4 years.

The consequence of these relatively large deviations in net supply and demand balance, combined with the current VRR curve, is that RPM has produced relatively volatile price outcomes, as shown in Figure 18. These volatile price outcomes have been the source of substantial concern to market participants, introducing substantial uncertainty into business decisions. However, supply shocks have not historically resulted in low realized reserve margins, largely because RPM was initiated at a time of relative supply excess and is only now approaching (but has not reached) long-run equilibrium reserve margins.

Figure 18
Historical BRA Capacity Prices for Rest of RTO



Sources and Notes:
PJM Base Residual Auction Reports and Planning Parameters. See PJM (2007 – 2013a.)

Together, these factors suggest that it may be beneficial to increase the width of the VRR to provide some additional volatility mitigation benefit, or to right-shift the curve to protect against very low future reliability outcomes. However, both of these potential revisions would come at a cost. Widening or flattening the curve would reduce price volatility, with a tradeoff of increasing quantity uncertainty. Right-shifting the curve would increase realized reserve margins and reliability, but at the expense of increased capacity procurement costs. We more fully examine these options and quantify their tradeoffs using probabilistic simulations of these various outcomes in the following sections.

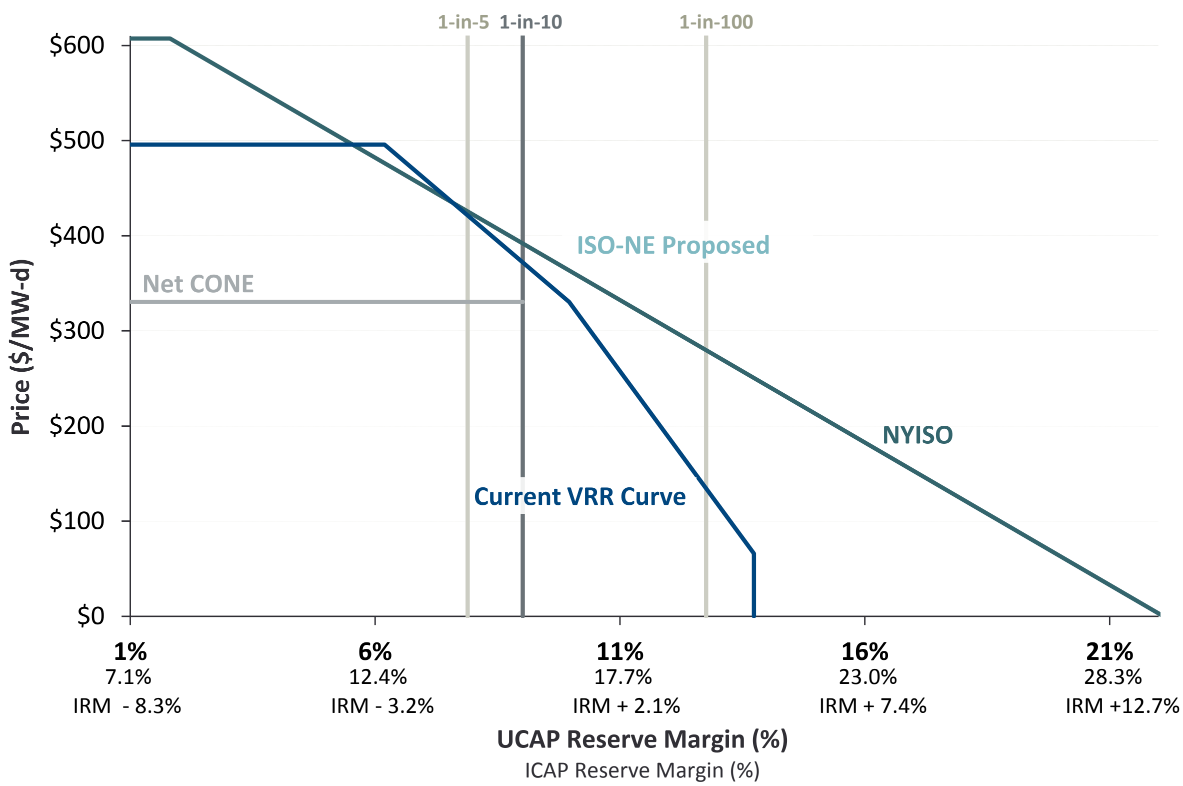
B. Simulated Performance of the Current System Curve

In this Section, we use the probabilistic modeling approach described in Section 10 above to estimate the likely distribution of price, quantity, and reliability outcomes that the current VRR curve will achieve. We also conduct a sensitivity analysis evaluating the performance of the curve under different modeling assumptions, higher and lower Net CONE values, and in the presence of administrative errors in the Net CONE estimate. All analyses reflect long-term equilibrium conditions in which annual outcomes fluctuate but the long-term average price equals (true) Net CONE. These long-term analyses are not intended to reflect current or near-term market conditions.

1. Performance of VRR Curve Compared to other Pre-Defined Curves

We start by presenting summary statistics describing the distribution of price, quantity, and reliability outcomes that we simulate under Base Case assumptions for PJM's current VRR Curve. To provide benchmark reference points to compare to, we also compare these results to three other curves as shown in Figure 19: (1) a vertical curve with the same price cap; (2) NYISO's ICAP demand curve; and (3) ISO-NE's recently-proposed capacity demand curve that is currently bending before FERC.

Figure 19
PJM's Current VRR Curve Compared to Other Pre-Defined Curves



Sources and Notes:

ISO-NE and NYISO curves reported using those markets' price and quantity definitions in most cases, but relative to PJM's estimate of 2016/17 Net CONE, Reliability Requirement, and 1-in-5 quantity point for the PJM system.

Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, calculated relative to the full Reliability Requirement without applying the 2.5% holdback for short-term procurements, PJM (2013a).

For NYISO Curve the ratio of reference price to Net CONE is equal to 1.185 and is consistent with the 2014 Summer NYCA curve, see NYISO (2014a) and (2014b), Section 5.5.

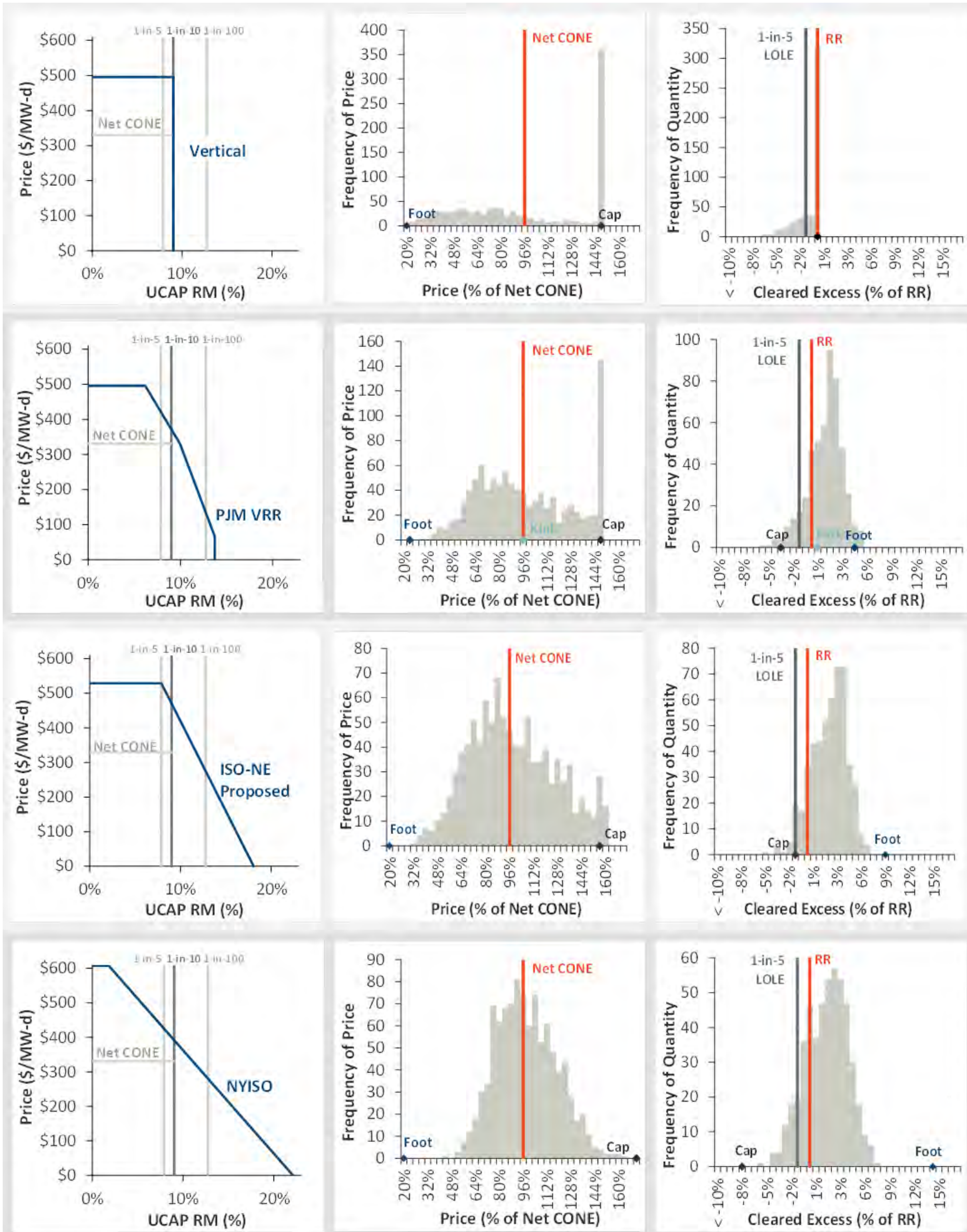
ISO-NE Curve shows parameters proposed in April 2014 with cap quantity adjusted to 1-in-5 as estimated for PJM, see Newell (2014b), pp 10-12.

We compare the distribution of price and quantity outcomes under each of these curves as histograms in Figure 10, and present summary statistics comparing these curves in the following Table 8. These distributions show the expected result that the steepest vertical curve has the most price volatility and most quantity certainty, while the flattest NYISO curve shows the most price stability and the widest range of realized quantities.

In each of the three cases, prices are distributed above and below Net CONE, with prices equal to Net CONE on average. This result follows from our assumption that new supply would rationally enter (or not) whenever long-run average prices are above (below) Net CONE. However, the distribution of price outcomes around Net CONE is very different across the curves, with the vertical curve producing volatile bi-modal prices while NYISO's flatter curve produces a relatively stable distribution of prices around Net CONE.

PJM's curve substantially reduces price volatility compared to the vertical curve, with a standard deviations of $95/MW-d (29% of Net CONE) and $147/MW-d (44% of Net CONE) respectively. However, the curve does not mitigate price volatility as much as the flatter curve of NYISO, which has a standard deviation of $69/MW-d (21% of Net CONE).

Figure 20
Simulated Price and Quantity Outcomes with Current VRR Curve and Other Pre-Defined Curves



Sources and Notes:
Price distribution charts summarize the outcomes of our simulation modeling results for each curve over 1,000 draws.

In terms of quantity outcomes, the vertical curve shows the most quantity certainty, while the NYISO curve produces the widest distribution of realized quantities. This distribution of quantity outcomes can be translated into realized reliability levels, by calculating the LOLE from each draw and estimating the average LOLE over many draws. In general, a wider distribution of quantity outcomes (if they are distributed around the same average quantity) will result in lower reliability, because excursions far below the reliability impact have a disproportionately large impact on average reliability.

Averaging these realized reliability outcomes across draws shows that PJM's current VRR curve does not meet the reliability objectives, with the distribution of quantity outcomes corresponding to an average of 0.121 LOLE over many years, compared to 0.1 LOLE at the 1-in-10-year target. The curve also produces a relatively high 20% frequency of reliability outcomes below 1-in-5, a result consistent with our qualitative finding from Section V.A.3 that the flat shape of the curve in the high-price region introduces greater risks of such shortage events. Assuming Net CONE correctly reflects the net cost of new entry (*i.e.*, is not upward biased), both of these results indicate that some or all of PJM's curve would need to be shifted rightward or upward in order to achieve the 1-in-10 reliability objective on a long-run average basis.

Table 8
Performance of Proposed Curve and Other Pre-Defined Curves[56]

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Modeling Assumptions											
Vertical Curve	$331	$147	69%	0.175	-0.8%	1.4%	36%	24%	$19,980	$8,030	$31,531
Current VRR Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
ISO-NE Proposed Curve	$331	$96	3%	0.039	2.7%	2.1%	10%	3%	$20,554	$13,327	$29,310
NYISO Curve	$331	$69	0%	0.065	2.0%	2.4%	20%	9%	$20,456	$15,394	$26,490

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

56 We note that this table and all similar tables through the remainder of the report may be affected by a small convergence error in Net CONE. As explained in Section IV above, we adjust the total quantity of "Smart Block" supply in each location until prices equal Net CONE on average, and then re-run our Monte Carlo simulation across 1,000 draws with a fixed Smart Block in each location. The resulting model outputs are therefore subject to some convergence error such that realized prices deviate somewhat from Net CONE, typically by +/- 0.2% of Net CONE. To correct for this error we adjust average price and cost results proportionally, but report this as an indicator of the level of model error that should be assumed.

2. Sensitivity to Primary Modeling Uncertainties

We test the robustness of our conclusions and identify the primary drivers of our results using a sensitivity analysis on our modeling assumptions, as summarized in Table 9. We first test the sensitivity to individual shocks, by eliminating one type of shock at a time and then testing our results if all shocks are 33% larger or 33% smaller, while remaining symmetrically distributed around the same average values. As expected, eliminating or reducing any type of shock will reduce the distribution of price and quantity outcomes and also improve reliability performance. Among the sources of volatility that we examined, our results are most sensitive to supply shocks, followed by the much smaller impacts from shocks to demand and, finally, to non-systematic administrative Net CONE estimation errors.

Comparing higher and lower shocks cases, we note the substantial asymmetry in reliability results. Decreasing shocks by 33% reduces LOLE by 0.032 (from 0.0121 to 0.089) events per year, while increasing shocks by 33% increases LOLE by 0.065 (from 0.121 to 0.186) events per year or twice as much. This asymmetry is caused by the relatively steep shape of the LOLE curve at low reserve margins. The higher shocks case increases the frequency of low reserve margin outcomes that contribute a disproportionately large number of reliability events, while the greater number of very high reserve margin outcomes have a relatively smaller reliability benefit due to the flatter slope of the LOLE curve in that region.

Table 9
Performance under Base and Sensitivity Case Assumptions

	Price			Reliability					Procurement Costs		
	Average *($/MW-d)*	Standard Deviation *($/MW-d)*	Freq. at Cap *(%)*	Average LOLE *(Ev/Yr)*	Average Excess (Deficit) *(IRM + X%)*	Reserve Margin St. Dev. *(% ICAP)*	Freq. Below Rel. Req. *(%)*	Freq. Below 1-in-5 *(%)*	Average *($mil)*	Average of Bottom 20% *($mil)*	Average of Top 20% *($mil)*
Current VRR Curve											
Current VRR Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
Zero Out Supply Shocks	$331	$50	0%	0.074	0.8%	1.0%	22%	4%	$20,283	$16,364	$24,824
Zero Out Demand Shocks	$331	$91	4%	0.115	0.5%	1.9%	35%	19%	$20,170	$12,831	$27,617
Zero Out Net CONE Shocks	$331	$93	5%	0.120	0.5%	2.0%	35%	20%	$20,170	$12,603	$27,749
All Shocks 33% Higher	$331	$115	12%	0.186	0.2%	2.7%	39%	26%	$20,087	$10,923	$29,638
All Shocks 33% Lower	$331	$70	1%	0.089	0.7%	1.4%	29%	11%	$20,227	$14,826	$26,227

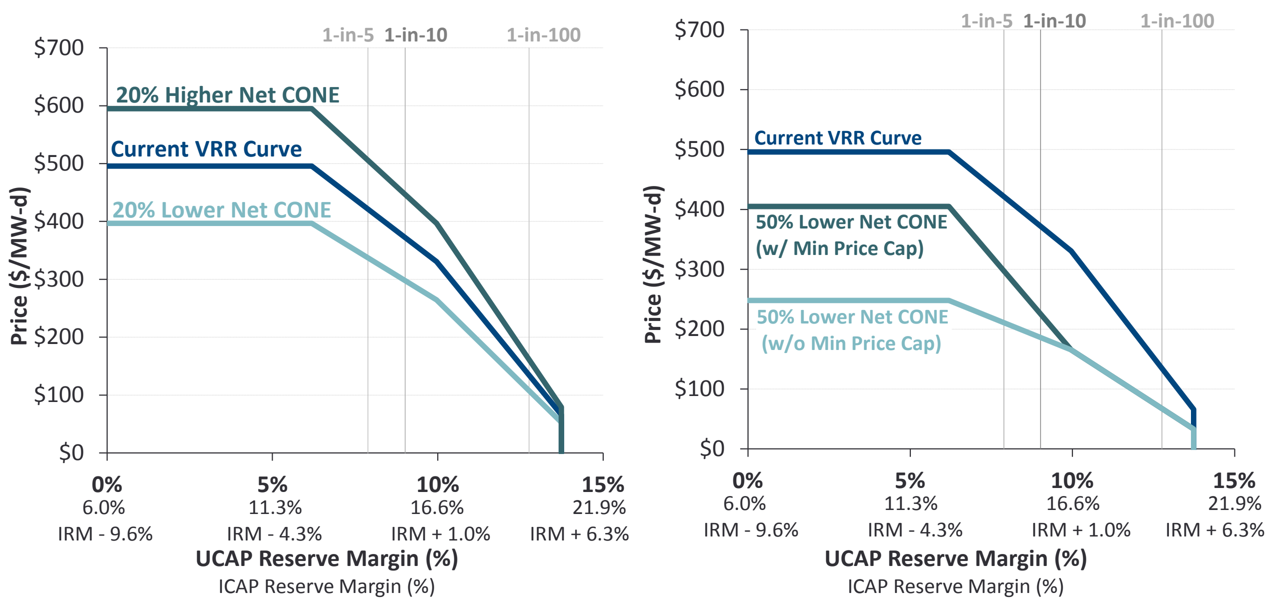
Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Performance with Higher or Lower Net CONE

Ideally, a curve should perform well not only under today's system conditions, but also under very different conditions, such as changes in Net CONE. We do anticipate at least some performance robustness to system conditions, because the VRR curve is indexed to Net CONE and will therefore adjust as Net CONE changes over time. If energy prices decrease and the energy market provides a smaller proportion of the incentives necessary to invest, then the administrative Net CONE and VRR curve will increase even if Gross CONE stays the same. Similarly, when energy prices increase, the demand curve will decrease, providing approximately the same investment incentives overall.

We examine the performance of the VRR curve under +/-20% changes to Net CONE, as well as under a 50% reduction in Net CONE. We test more extreme decreases than increases because the currently low E&AS offset has more upside than downside, and also in order to evaluate the impact of the price cap minimum at Gross CONE.[57] We illustrate the resulting demand curves under these cases in Figure 26 and present simulation results in Table 7. Note that these sensitivities reflect changes in Net CONE under the assumption of no estimation error; sensitivities to estimation error are presented in the following section.

Figure 21
PJM's VRR Curve with +/-20% Net CONE (Left) and Low Net CONE w/ Cap at Minimum (Right)



Sources and Notes:

Current VRR Curve shows the VRR curve as specified in the 2016/17 PJM Planning Parameters, see PJM (2013a.)

In the 20% Higher Net CONE, 20% Lower Net CONE, and 50% Lower Net CONE (w/o Min Price Cap) curves, points "a", "b", and "c" are each 20% higher, 20% lower, and 50% lower than the current VRR curve, respectively.

The 50% Lower Net CONE (w/Min Price Cap) curve has point "a" set to 2016/17 Gross CONE.

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57 Specifically, the price at point "a" is calculated as the maximum of 1.5× Net CONE or 1× Gross CONE, so the cap can never fall below Gross CONE. See Manual 18, PJM (2014a), Section 3.4.

We find that the curve performs similarly under modest changes of 20%, with reliability declining by 0.009 events per year under the 20% Net CONE increase or improving by 0.007 events per year in the 20% Net CONE decrease. The intuition behind the improved reliability levels is that at lower Net CONE values, the VRR curve is compressed to a lower price range within which the supply curve is more elastic (less steep). The higher supply elasticity mitigates the reliability effects of supply and demand shocks. We find that the curve performs similarly under modest changes of 20%, with reliability declining by 0.009 events per year under the 20% Net CONE increase or improving by 0.007 events per year in the 20% Net CONE decrease. The intuition behind the improved reliability levels is that reducing Net CONE values compresses the demand curve to a lower price range within which the supply curve is less steep. The higher supply elasticity mitigates the reliability effects of supply and demand shocks.

However, for a much larger 50% decrease in Net CONE, the impact on reliability depends on whether the price cap minimum at Gross CONE is observed. Without the price cap minimum, reliability degrades to LOLE of 0.150 events per year, with the increased low-reliability events primarily related to administrative error in Net CONE. At these low levels with the entire VRR curve shifted down, administrative uncertainty is a greater as a percentage of Net CONE due to the higher proportion of E&AS offset as a fraction of Gross CONE. This makes it more likely that that the auction will clear in the low and very low reserve margin region.

Observing the price cap minimum at 1× Gross CONE protects against this outcome, with reliability that is improved beyond target levels at LOLE of 0.076 events per year. The price cap minimum also protects against any downward bias in Net CONE estimation, which could conceivably be a much larger fraction of Net CONE at high E&AS offset levels corresponding to a lower Net CONE. Such under-estimates could precipitously compromise reliability, as discussed further in the following Section.

Table 10
Performance of VRR Curve with Higher and Lower Net CONE

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
<u>With</u> Price Cap Minimum at Gross CONE											
20% Higher Net CONE	$397	$120	7%	0.130	0.4%	2.2%	37%	22%	$24,180	$14,831	$34,187
Base Case	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
20% Lower Net CONE	$264	$73	5%	0.114	0.5%	2.0%	33%	17%	$16,144	$10,285	$22,189
50% Lower Net CONE	$165	$57	0%	0.076	1.0%	1.6%	25%	7%	$10,141	$5,888	$15,298
<u>Without</u> Price Cap Minimum at Gross CONE											
50% Lower Net CONE	$165	$50	7%	0.150	0.1%	2.5%	39%	22%	$10,074	$6,205	$14,610

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity to Administrative Errors in Net CONE

In the analyses presented up to this point, we assume that the administrative Net CONE estimate accurately represents the true Net CONE that developers need to earn in order to enter. However, estimation error is inevitable even in a careful analysis due to uncertainties in every component of Net CONE estimate, for example in: (a) the identification of an appropriate reference technology; (b) estimation of the capital and fixed operation and maintenance (FOM) costs; (c) translation of those costs into an appropriately levelized value consistent with developers' cost of capital, long-term views about the market, and assumed economic life; and (d) estimation of E&AS margins.

If the administrative estimate of Net CONE understates true Net CONE, the demand curve would be lower than needed to meet the reliability objectives, as shown in an example in Figure 22. Supply would still enter and set prices at the true Net CONE in the long term, but the cleared quantity and reliability would be below target.[58] Conversely, overstated Net CONE would attract excess supply as suppliers continued entering until average prices equal the true Net CONE. Customers would not have to pay higher prices in the long term, but they would have to buy a greater quantity that has diminishing value.

We test the robustness of the VRR curve's performance to administrative Net CONE estimation errors of +/-20%, as summarized in Table 11. In both cases, we hold true Net CONE at the base value of $331/MW-d, always adjusting supply until the long-term average price across simulation draws equals to that value no matter what the demand curve, as shown in Figure 22.[59]

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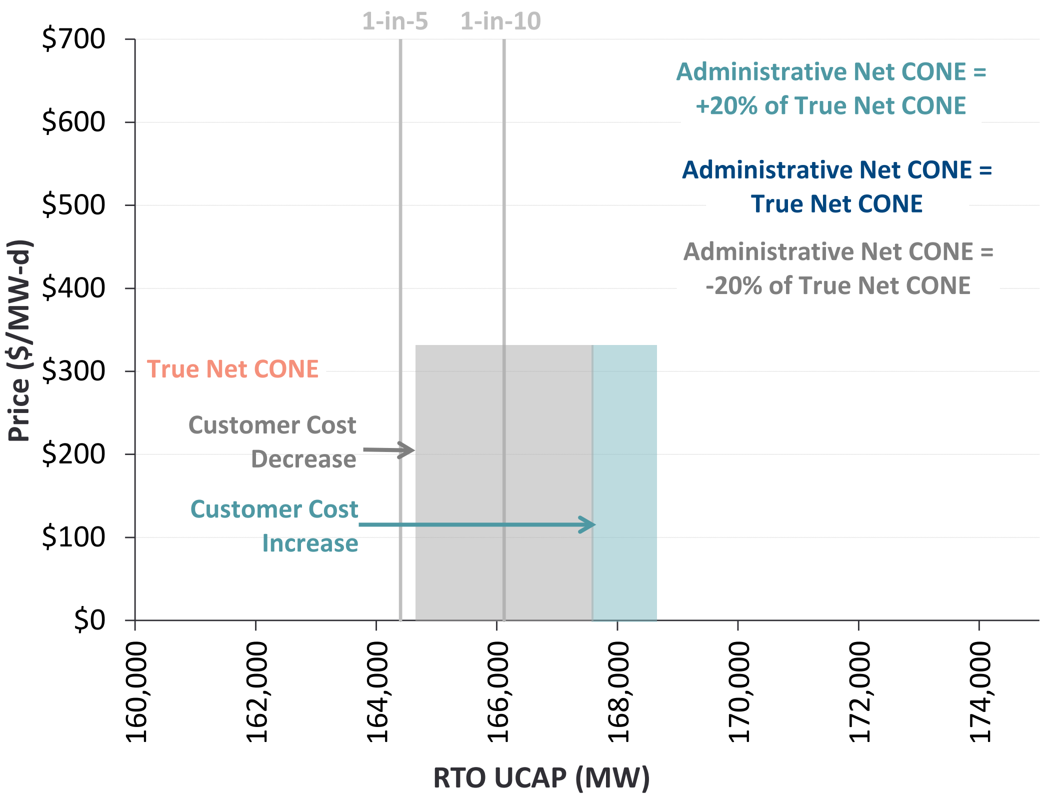
58 In the short term (*i.e.*, in any one year) an over-estimate or under-estimate in Net CONE would in increase or decrease prices respectively, since in a particular auction the demand curve is cleared against a relatively fixed short-term supply curve with the majority of the resource base not making entry or exit decisions in any one auction. The point we make here is that prices will not stay persistently above or below Net CONE in the long term, because this *would* result enough resources entering or exiting to move long-term average prices back to true Net CONE.

59 We specify the sensitivities by fixing true Net CONE rather than fixing administrative Net CONE so that cost outcomes would be comparable.

Figure 22
VRR Curve Performance with 20% Over- or Under-Estimate in Net CONE
Assuming True Net CONE Equals the Base Case Value of $331/MW-d



Sources and Notes:
The curve with Administrative Net CONE = True Net CONE shows the VRR curve as specified in the 2016/17 PJM Planning Parameters. In the other two curves, points “a”, “b”, and “c” are each 20% higher or 20% lower than the base curve. In call cases, however, True Net CONE is equal to the 2016/17 Net CONE from the PJM Planning Parameters. See PJM (2013a.)

The most important observation from these tests is that Net CONE estimation errors can have a substantial impact on reliability outcomes. Reliability impacts of estimation errors are asymmetric with respect to positive and negative estimation errors because shortage frequencies rise increasingly steeply as reserve margins fall below target (see the shape of the LOLE curve in Section IV.B.3 above). A 20% underestimate worsens LOLE by 0.249 (to 0.370 events/yr), whereas an overestimate improves it by only 0.057 (to 0.064 events/yr).

In both cases, impacts on long-term average customer capacity procurement costs are small because average market clearing prices depend on suppliers’ true Net CONE, not on administrative estimates or errors thereof. Capacity procurement costs change only because cleared quantities change, causing customers to buy a little more or less capacity. We show these customer cost increases or decreases schematically in as the blue and gray squares, respectively in Figure 22. For example, if true Net CONE is $331/MW-d, overestimating Net CONE by 20% would increase capacity procurement costs by $185 million per year, or only 0.9% of total capacity procurement costs; underestimating Net CONE by 20% would reduce costs by a larger $350 million per year, or about

1.7%.[60] Note that these capacity procurement cost impacts do not account for all of the energy costs or reliability-related costs that would change as reserve margins change, such as those we have described in a recent analysis conducted for FERC.[61]

Table 11
Performance of Current VRR Curve with Administrative Error in Net CONE

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Case											
Accurate Net CONE	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
20% Over-Estimate	$331	$114	1%	0.064	1.5%	1.8%	18%	8%	$20,352	$11,568	$30,579
20% Under-Estimate	$331	$64	26%	0.370	-1.7%	2.5%	69%	50%	$19,817	$14,757	$24,543

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

These observations point to three key insights important for reducing vulnerability to low reliability outcomes. The first and most obvious insight is that the administratively-determined Net CONE must be estimated as accurately as possible for the demand curve to achieve its resource adequacy objectives. It is particularly important to avoid underestimating Net CONE, to avoid the asymmetrically high reliability risks.

The second insight is that applying a minimum of 1× Gross CONE to the price cap substantially reduces the risk of under-procuring when high E&AS revenues and low Net CONE would otherwise collapse the demand curve. However, the fact that the VRR curve kink at point "b" continues to drop even if the cap is at its minimum quantity, helps to prevent over-procurement under those conditions.

The third insight is that most of the reliability risks derive from the flatness of the top part of the demand curve, combined with the moderate price cap at only 1.5× Net CONE. This flat portion of the curve and the moderate price cap help to substantially mitigate price volatility and market power concerns, but at the tradeoff of introducing substantial reliability risks in the event of a under-

60 Understating Net CONE decreases customer capacity costs more than overstating Net CONE increases them because the cleared quantities are asymmetrically lower due to the kink in the curve at the cap. The price stops increasing once it reaches the cap, so the distribution of outcomes must shift leftward to achieve a greater frequency of low-quantity price cap events and maintain average prices at true Net CONE. The relative proportion in cost increases or decreases is shown as the area in the blue or gray boxes in Figure 22 respectively.

61 See Pfeifenberger (2013).

estimate of Net CONE. Making the curve steeper in this region or increasing the cap would substantially reduce these risks, but would also increase price volatility.

C. Options for Improving the VRR Curve's Performance

The prior two Sections describe reliability risks under the existing VRR curve. Namely, we find that the VRR curve would not achieve the target LOLE of 0.1 on average under Base Case assumptions, and performance would deteriorate substantially further if Net CONE were systematically under-estimated. In this Section, we evaluate three approaches to improving reliability outcomes:

1. Adjusting the price and quantity at point "a" (the price cap point) to sharpen price signals when reserve margins decline;
2. Adjusting the shape of the curve in various other ways; and
3. Right-shifting the entire curve to avoid low reliability outcomes by procuring more on average and protecting against supply-demand shocks and Net CONE estimation error.

Each approach can improve reliability outcomes but may have tradeoffs regarding price volatility or over-procurement. We estimate here the impact of each potential change on reliability, price, and cost criteria under base case and stress scenarios.

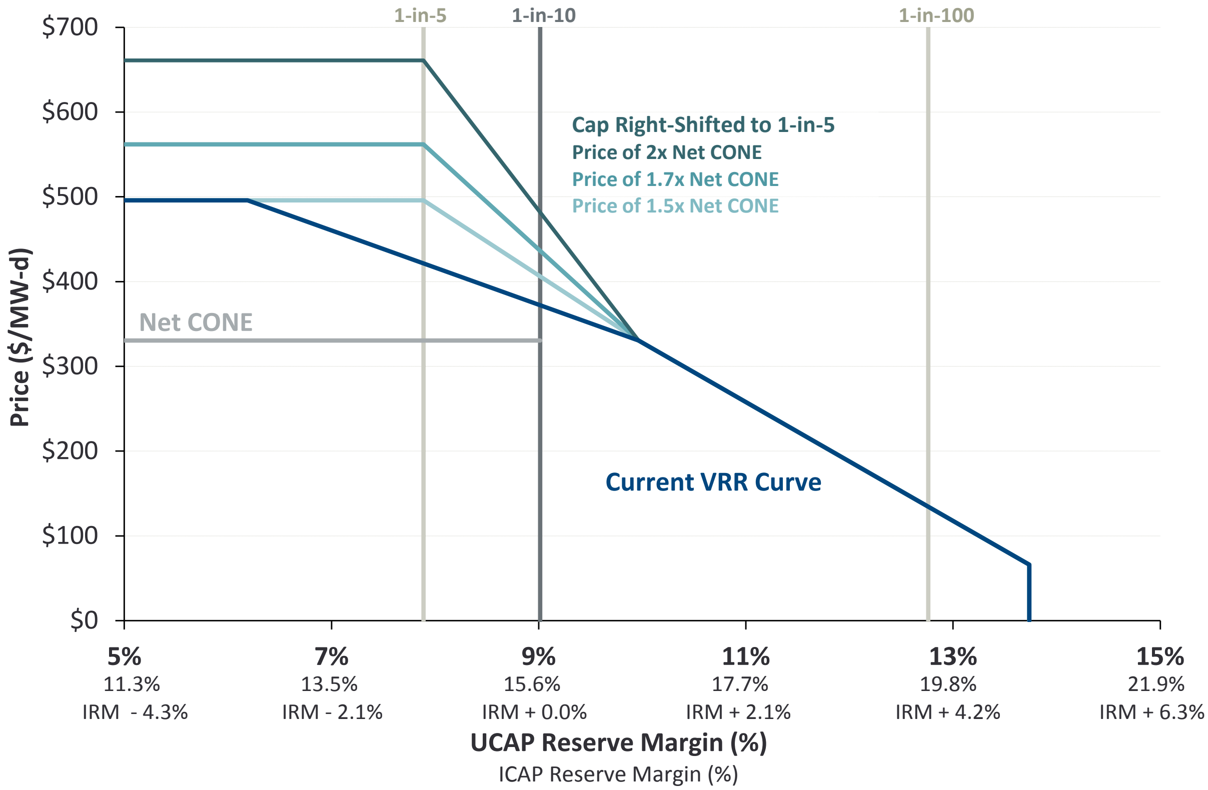
1. Adjusting the Cap at Point "a" to Reduce Low-Reliability Events

The existing VRR curve has a price cap of 1.5× Net CONE (with a minimum value of 1.0× CONE), at a quantity equal to IRM-3%.[62] As discussed in Sections V.A.2 and V.A.3, this makes the upper section of the curve less steep than the lower section, so price signals increase at a relatively low rate as reserve margins fall into the very low reliability region. Increasing prices in the low-reliability section of the curve would produce stronger price signals during shortage conditions and result in procuring additional resources when they are most needed for reliability. Increasing the price cap would also protect against systematic under-procurement if Net CONE were underestimated.

We test two types of adjustments to the VRR curve's price cap point "a": (1) right-shifting point "a" to a quantity corresponding to a 1-in-5 LOLE, or IRM-1.2%; and (2) right-shift point "a" and then also increasing the cap price from 1.5× Net CONE to 1.7× or 2× Net CONE. These alternatives are depicted in Figure 23.

62 See PJM (2013a.)

Figure 23
PJM's Current VRR Curve after Right-Shifting and Increasing the Price Cap



Sources and Notes:
Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters, see PJM (2013a).

Simulation analyses of these alternative candidate curves show that modest changes substantially reduce the frequency of low reliability events, as summarized in Table 12. Under Base assumptions, right-shifting the cap reduces the frequency of low reserve margins (*i.e.*, below the level corresponding to 1-in-5 LOLE) from 20% to 12%; then raising the cap price reduces that frequency further to 9% with a 1.7× cap and 7% with a 2.0× cap. The improvement is even greater under the scenario in which administrative Net CONE is 20% below true Net CONE. However, increasing the cap increases overall price volatility, as shown by the standard deviation of simulated prices.

Table 12
Performance of VRR Curve if Right-Shifting and Increasing the Price Cap at Point "a"

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Modeling Assumptions											
Current Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
Cap at 1-in-5, 1.5x	$331	$107	12%	0.096	0.8%	1.9%	28%	12%	$20,224	$12,071	$29,579
Cap at 1-in-5, 1.7x	$331	$124	9%	0.079	1.1%	1.7%	23%	9%	$20,267	$11,438	$32,019
Cap at 1-in-5, 2x	$331	$145	7%	0.065	1.3%	1.6%	18%	7%	$20,305	$10,863	$35,033
20% Under-Estimated Net CONE											
Current Curve	$331	$64	26%	0.370	-1.7%	2.5%	69%	50%	$19,817	$14,757	$24,543
Cap at 1-in-5, 1.5x	$331	$73	38%	0.272	-1.0%	2.4%	57%	38%	$19,928	$13,784	$25,250
Cap at 1-in-5, 1.7x	$331	$97	25%	0.166	-0.2%	2.0%	45%	25%	$20,053	$12,449	$27,912
Cap at 1-in-5, 2x	$331	$124	14%	0.112	0.3%	1.8%	33%	14%	$20,145	$11,323	$31,341

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

Right-shifting point "a" helps reliability not only by procuring more in the auctions when incremental supply is most needed (*i.e.*, when supply-demand shocks are greatest), but also by increasing the procured quantity on an average basis across all simulation draws. The fact that average reserve margins increase by 0.4% under Base assumptions and 0.7% if Net CONE is underestimated suggests that the improved reliability derives partly from adding money to the market, inducing entry, and shifting the whole distribution of outcomes to the right. This observation can be explained as follows: because the supply curves in our simulations are not very elastic at high prices, increasing the price cap causes prices to rise more than cleared quantities during short-supply years. However, supply is more elastic in the long-term. The prospect of reaching the price cap more quickly if supplies tighten (even if rarely) supports increased entry. This explains why right-shifting and increasing the cap results in such substantial reliability improvements, including improving reliability somewhat beyond the 1-in-10 objective.

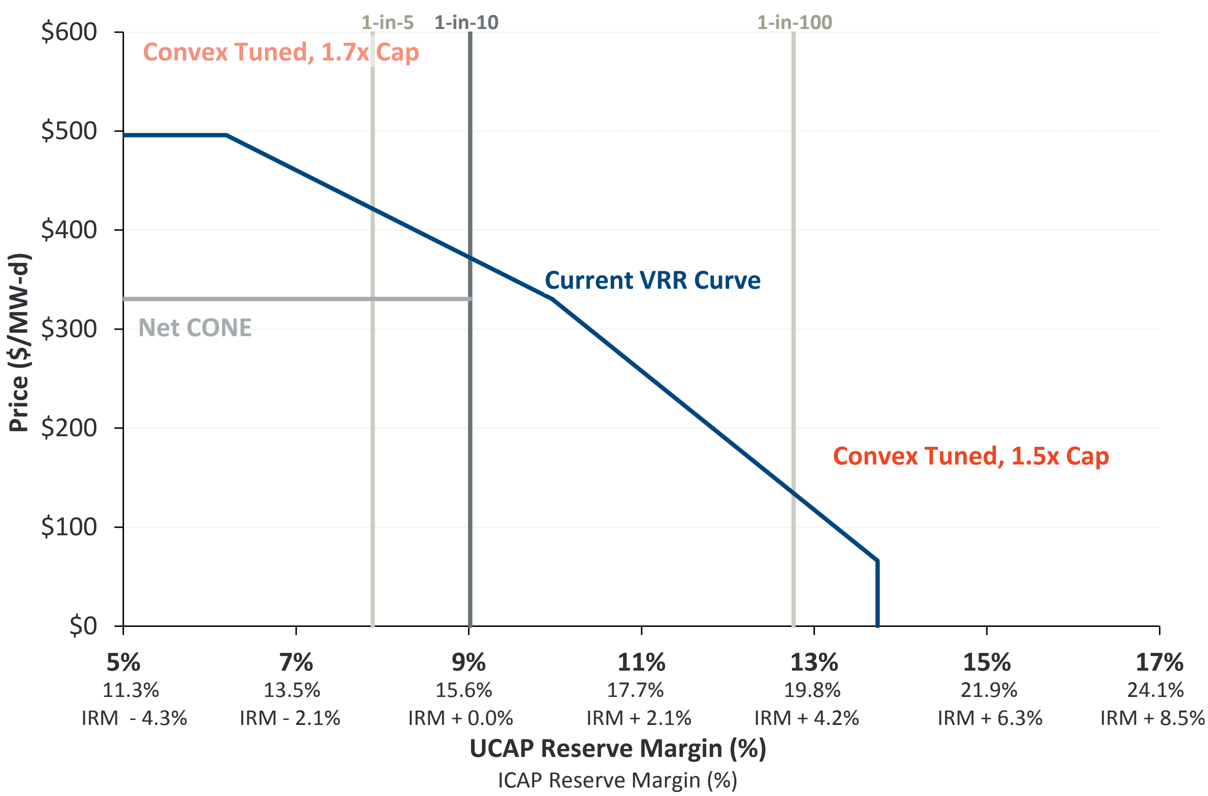
By contrast, moving the lower part of the demand curve up or to the right would interact with a lower part of the supply curve where price elasticity is greater, leading to a larger change in cleared quantities and smaller change in prices in any particular auction when supply-demand shocks are in the surplus direction. Unfortunately, increasing cleared quantities in outcomes where reserve margins were already quite high adds little to average reliability. Nevertheless, in the following two sections, we evaluate shifting other parts of the curve to avoid the price volatility implications of only raising or right-shifting the cap.

2. Options for Steeper and Flatter Convex VRR Curves Tuned to 1-in-10

Adjusting point "a" as described above improves reliability performance by allowing prices to rise more steeply when reserve margins are low. However, if the cap is not increased above the current 1.5× Net CONE, the curve would be nearly a straight line. As discussed in Section V.A.2, a more convex curve shape has several theoretical advantages, by providing stronger price signals as the system approaches short supply conditions and more nearly reflecting the relationship between LOLE and reserve margin.

To evaluate the performance of a reshaped convex VRR curve, we tested two alternative curves: (1) a convex curve with a price cap at 1.5× Net CONE; and (2) a convex curve with a price cap at 1.7× Net CONE. Both curves set the point "a" quantity at the cap at the same 1-in-5 point as described in the prior section, with the other curve parameters adjusted until the simulated average LOLE meets the objective of 0.1 events per year. These two, convex tuned curves are depicted in Figure 24.

Figure 24
PJM's Current VRR Curve Compared to Convex Curves Tuned to 1-in-10



Sources and Notes:
Current VRR Curve reflects the system VRR curve in the 2016/2017 PJM Planning Parameters. See PJM (2013a.)

Our simulation analysis shows that both curves provide substantially better reliability than the current VRR curve as shown in Table 13. However, the curve with a 1.5× cap appears better overall because it has substantially lower price volatility and the flatter shape would provide better protection against potential exercise of market power. The convex 1.7× curve shows better performance in terms of both frequency at the cap and frequency below 1-in-5 but this improvement is relatively small compared to the substantially greater price volatility.

Comparing Table 13 to Table 12 shows that the performance of the Convex Tuned 1.5× Cap curve is very similar in all respects to that of the curve in which only point "a" is right-shifted to 1-in-5. This is because the two curves are very similar everywhere except the right-most sections, where the convex curve is higher and flatter. Even though the convex curve does not exhibit substantial performance differences in our simulations, we believe it would marginally improve RPM. It sets prices more nearly proportionally to marginal reliability value, and would reduce price volatility and susceptibility to market power abuse in the flatter half of the curve. Finally, it avoids the anomalous "cliff" that the current VRR curve has at point "c."

Table 13
Performance of Current VRR Curve Compared to Convex Curves Tuned to 1-in-10

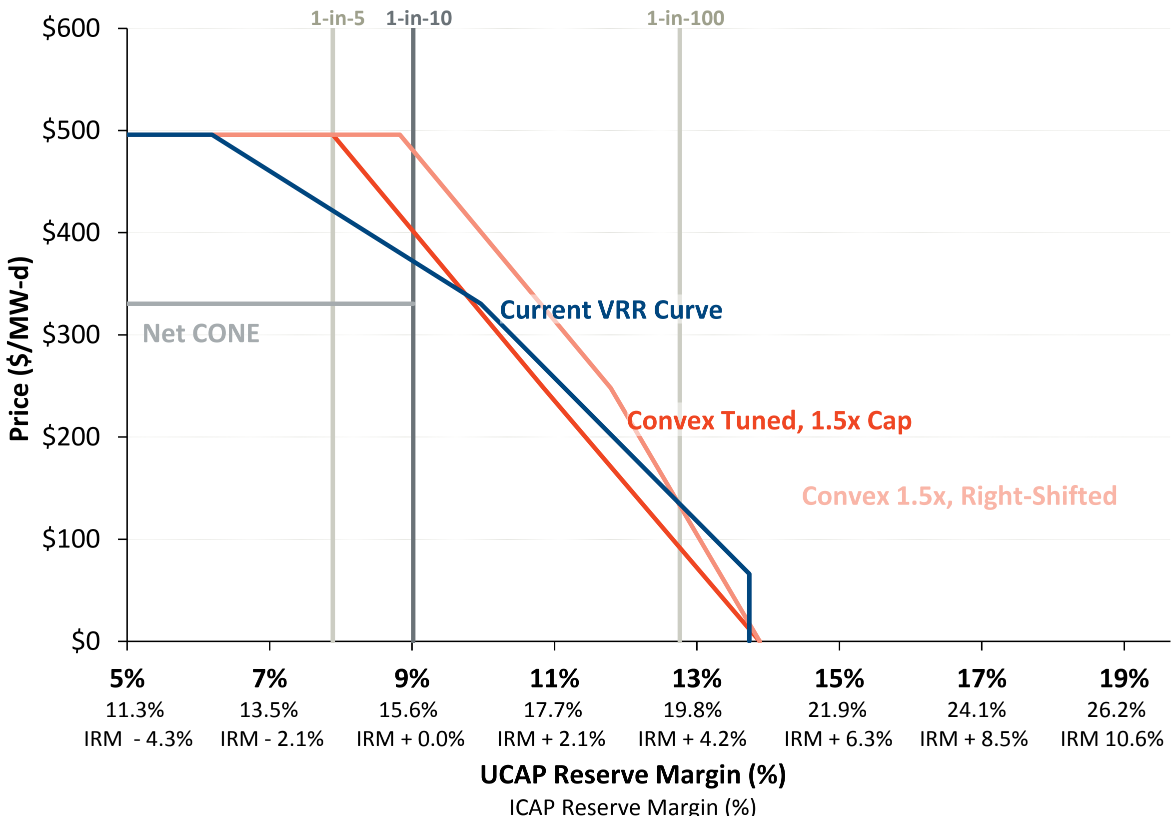
	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Modeling Assumptions											
Current VRR Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
Convex Tuned, 1.5x Cap	$331	$107	13%	0.100	0.7%	1.9%	29%	13%	$20,210	$12,379	$29,631
Convex Tuned, 1.7x Cap	$331	$134	12%	0.100	0.5%	1.7%	29%	12%	$20,171	$10,987	$32,648

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Option for a Right-Shifted Curve to Mitigate Low-Reliability Events

Although the convex curve presented above performs better than the current VRR curve, it still produces reserve margins below the 1-in-5 level (at about IRM-1%) approximately 13% of the time under Base modeling assumptions. The curve could also under-procure capacity if either shocks or Net CONE are underestimated, as shown in Table 15 in the following section. Therefore, we also evaluate the option shifting the entire curve to the right as a sort of insurance against these risks. We test the performance impacts of this change by right-shifting each point on the 1.5× convex curve by 1% IRM, as shown in Figure 25.

Figure 25
PJM's Current VRR Curve Compared to Alternative VRR Curve Shapes



Sources and Notes:
Current VRR Curve reflects the system VRR curve in the 2016/17 PJM Planning Parameters. See PJM (2013a).

Our simulations show that the right-shifted curve improves reliability, with reserve margins falling below the Reliability Requirement only 16% of the time and below the 1-in-5 level only 7% of the time. The improvement is even greater under the stress scenarios shown in the next section. However, this increased security comes at a slight cost, with procurement costs slightly less than 1% higher corresponding to the 1% higher average reserve margin.

Table 14
Performance of Current VRR Curve, Convex Curve, and Right-Shifted Convex Curve

	Price			Reliability					Procurement Costs		
	Average	Standard Deviation	Freq. at Cap	Average LOLE	Average Excess (Deficit)	Reserve Margin St. Dev.	Freq. Below Rel. Req.	Freq. Below 1-in-5	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(Ev/Yr)*	*(IRM + X%)*	*(% ICAP)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Modeling Assumptions											
Current VRR Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
Convex Tuned, 1.5x Cap	$331	$107	13%	0.100	0.7%	1.9%	29%	13%	$20,210	$12,379	$29,631
Convex 1.5x, Right-Shifted	$331	$107	13%	0.060	1.7%	1.9%	16%	7%	$20,383	$12,461	$29,859

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity of Alternative Curves' Performance

In addition to testing the performance of the current VRR curve to alternative curves under Base modeling assumptions, we also compare the robustness of each curve under alternative assumptions as summarized in Table 15. All of the alternative curves improve reliability performance under our Base modeling assumptions. Under stress scenarios with greater supply-demand shocks and Net CONE underestimation, the improvement is even greater. As we have explained earlier, the current VRR curve is susceptible to rapid deterioration from a reliability perspective, especially in the case of under-estimated Net CONE, because of the moderate price cap and relatively flat shape in the low-reliability region of the curve.

We observe that the convex-shaped curves appear much more robust from a reliability perspective than the current concave shape. The higher price cap in the 1.7× cap curve provides the most protection against reliability degradation under stress scenarios, with the higher cap protecting against low-reliability events of all types but particularly against under-estimates of Net CONE. The steeper shape of this curve also reduces the magnitude of over-procurement caused by over-estimating Net CONE compared to the other curves. However, as we have discussed previously the 1.7× cap curve has greater price volatility and provide less protection against exercise of market power. The right-shifted curve shows the best reliability performance across all scenarios, related to the higher average procurement quantities across all scenarios. This protection against plausible stress scenarios would increase capacity procurement costs by approximately 1.0%-1.4% depending on the scenario.

Considering each of these factors, we recommend that PJM and stakeholders consider adopting the 1.5× convex curve for use in RPM. Adopting this curve would substantially reduce the likelihood of low-reliability events, achieve the 1-in-10 objective in expectation, and provide better performance under stress scenarios. Adopting this curve would come at the expense of a modest increase in price volatility and an approximately 0.2% increase in capacity procurement costs.

While the 1.7× cap curve and right-shifted 1.5× curve provide superior protection against low reliability scenarios and generally good performance in other dimensions, we do not adopt either of these options as our primary recommendation because of the greater price volatility (in the former case) and somewhat higher procurement costs (in the latter case). However, we do recommend that options, such as increasing the price cap or refining the curve shape, be considered as options in future triennial VRR curve reviews and CONE studies to ensure that the curve can be adjusted for major challenges as they arise.

Table 15
Performance of VRR Curve and Alternative Curves under Sensitivity Assumptions

	Price			Reliability					Procurement Costs		
	Average ($/MW-d)	Standard Deviation ($/MW-d)	Freq. at Cap (%)	Average LOLE (Ev/Yr)	Average Excess (Deficit) (IRM + X%)	Reserve Margin St. Dev. (% ICAP)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-5 (%)	Average ($mil)	Average of Bottom 20% ($mil)	Average of Top 20% ($mil)
Base Modeling Assumptions											
Current VRR Curve	$331	$95	6%	0.121	0.4%	2.0%	35%	20%	$20,167	$12,672	$28,094
Convex Tuned, 1.5x Cap	$331	$107	13%	0.100	0.7%	1.9%	29%	13%	$20,210	$12,379	$29,631
Convex Tuned, 1.7x Cap	$331	$134	12%	0.100	0.5%	1.7%	29%	12%	$20,171	$10,987	$32,648
Convex 1.5x, Right-Shifted	$331	$107	13%	0.060	1.7%	1.9%	16%	7%	$20,383	$12,461	$29,859
20% <u>Under</u>-Estimate in Net CONE											
Current VRR Curve	$331	$64	26%	0.370	-1.7%	2.5%	69%	50%	$19,817	$14,757	$24,543
Convex Tuned, 1.5x Cap	$331	$73	39%	0.282	-1.1%	2.4%	59%	39%	$19,912	$13,628	$25,267
Convex Tuned, 1.7x Cap	$331	$103	28%	0.194	-0.6%	2.0%	50%	28%	$19,984	$11,702	$28,071
Convex 1.5x, Right-Shifted	$331	$74	39%	0.182	-0.1%	2.4%	42%	28%	$20,086	$13,742	$25,489
20% <u>Over</u>-Estimate in Net CONE											
Current VRR Curve	$331	$114	1%	0.064	1.5%	1.8%	18%	8%	$20,352	$11,568	$30,579
Convex Tuned, 1.5x Cap	$331	$123	5%	0.056	1.7%	1.8%	15%	5%	$20,377	$11,956	$32,451
Convex Tuned, 1.7x Cap	$331	$151	7%	0.066	1.2%	1.5%	17%	7%	$20,288	$10,614	$35,714
Convex 1.5x, Right-Shifted	$331	$123	5%	0.033	2.7%	1.8%	7%	2%	$20,552	$12,049	$32,794
33% Higher Shocks											
Current VRR Curve	$331	$115	12%	0.186	0.2%	2.7%	39%	26%	$20,087	$10,923	$29,638
Convex Tuned, 1.5x Cap	$331	$124	21%	0.156	0.5%	2.7%	34%	21%	$20,134	$10,928	$30,885
Convex Tuned, 1.7x Cap	$331	$155	19%	0.141	0.3%	2.3%	33%	19%	$20,106	$9,330	$33,974
Convex 1.5x, Right-Shifted	$331	$124	21%	0.099	1.5%	2.7%	23%	14%	$20,310	$11,011	$31,162
33% Lower Shocks											
Current VRR Curve	$331	$70	1%	0.089	0.7%	1.4%	29%	11%	$20,227	$14,826	$26,227
Convex Tuned, 1.5x Cap	$331	$84	5%	0.075	0.8%	1.3%	23%	5%	$20,256	$14,147	$28,064
Convex Tuned, 1.7x Cap	$331	$105	5%	0.080	0.6%	1.0%	24%	5%	$20,215	$12,945	$30,406
Convex 1.5x, Right-Shifted	$331	$84	5%	0.043	1.8%	1.3%	6%	2%	$20,430	$14,249	$28,338

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

D. Recommendations for System-Wide Curve

We find that the existing VRR curve would not satisfy PJM's primary system-wide reliability objectives on a long-term average basis. For example, we estimate that the average LOLE across all years would be 0.12 (*i.e.,* 0.12 events per year or 1.2 events in 10 years) at the system level, with reliability falling below 1-in-5 LOLE in 20% of all years. These results vary across a range of modeling assumptions, RPM parameter values, and economic shocks that might reasonably be encountered, with objectives being met in some scenarios but widely missed in others. These findings differ from RPM market experience to date because we model long-term equilibrium conditions under which existing surplus resources and low-cost sources of new capacity are exhausted.

To improve RPM performance, we recommend the following VRR Curve revisions. We estimate that adopting these recommendations would result in meeting the 1-in-10 LOLE objective on average, and would reduce the frequency of years below 1-in-5 LOLE to 13% under base modeling assumptions, while also significantly improving VRR curve performance under stress scenarios. The combined effect of these changes is reflected in our recommended convex curve in Figure 24 in Section V.C.2 above. Our specific recommendations are:

1. **Right-shift point "a".** We recommend that PJM right-shift point "a" (the highest-quantity point at the price cap) to a quantity at 1-in-5 LOLE (at approximately IRM-1%). This change would significantly improve reliability outcomes by providing stronger price signals when supplies become scarce, without right-shifting the entire distribution of expected reserve margins. Right-shifting point "a" would also make the VRR curve more consistent with PJM's current reliability backstop auction trigger at IRM-1%, such that PJM would procure all available resources through the BRA before any such backstop auction could be triggered.
2. **Stretch the VRR Curve into a convex shape.** We recommend that PJM consider adopting the convex shape (*i.e.*, less steep at higher reserve margins) as illustrated in Figure ES-1, with its parameters tuned such that the curve will meet the 1-in-10 reliability standard on average under our base modeling assumptions. This convex shape is more consistent with a gradual decline of reliability at higher reserve margins and helps to reduce price volatility under such market conditions.

VI. Locational Variable Resource Requirement Curves

Reliability challenges at the local level are greater than at the system level. The LDAs are qualitatively different from the system in some ways. For example, their reliability also depends on transmission import limits defined by CETL, which tend to fluctuate and introduce additional volatility in prices and quantities. Moreover, LDAs are small relative to realistic fluctuations in supply, demand, and CETL. In the smallest LDA DPL-South, a 700 MW plant is more than three times the width of the VRR curve (from point "a" to point "c"). And highly import-dependent LDAs are most sensitive to CETL shocks. For example, in PepCo, CETL would represent more than 76% of the Reliability Requirement if the LDA were import-constrained, using 2016/17 parameters. A 12% reduction in CETL (one standard deviation) would correspond to an 822 MW drop in total supply, or more than 130% of the width of the entire VRR curve.

The large size of shocks relative to the VRR curve width causes greater upside volatility in prices, although downside and total price volatility are mitigated on the downside by the "soft floor" on prices created by parent LDAs. If ignoring this multi-area effect, one generating unit or CETL shock could move from the top to the bottom of the curve, eliminating any price premium from the parent area. Indeed, CETL changes have historically driven much of the price volatility in LDAs, where prices have been more price spikes than at the system level.[63]

The large relative size of shocks also makes LDAs vulnerable to low reliability outcomes. Shock-driven distributions are very wide as a percentage of local Reliability Requirements, and the low reserve margin part of the distributions bring the average conditional LOLE below target.

Further threatening resource adequacy, the likelihood of Net CONE estimation error is higher in small LDAs, and the reliability impacts are greater than at the system level. Estimation error is more likely due to idiosyncratic siting and environmental factors, which may not be discovered in CONE studies due to sparse data on actual projects' costs (and if the LDA is not its own CONE area), and because E&AS margins are harder to calibrate if there are few comparable plants. Developers may avoid building efficient-scale plants to prevent collapsing the price premium for many years. Simulations show that underestimation degrades reliability, particularly in LDAs.

A. Qualitative Review of Locational Curves

In this Section, we qualitatively evaluate the VRR curve as applied at the local level, to develop intuition around the likely performance concerns and locational price efficiency, before estimating its performance quantitatively in subsequent Sections. In developing this evaluation, we: (1) review

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63 See 2011 RPM Review, Table 2 Summary of Major BRA Price Shifts and Causes, Pfeifenberger, *et al.* (2011), p. 15.

the design objectives at the local level; (2) discuss the definition of the locational Reliability Requirement at a 1-in-25 conditional LOLE; (3) review reliability at the price cap, both before and after right-shifting the cap point, as recommended for the system in Section V.C.1 above; (4) compare the width of the curves to anticipated shocks to supply and demand; and (5) evaluate a locational clearing approach with prices more gradually separating at the local level in proportion to reliability value.

1. Locational Design Evaluation Criteria

Locational VRR curves serve similar objectives to the system-wide VRR curve (See Section V.A.1), as applied to the Locational Deliverability Areas. However, there are some important differences regarding both reliability and pricing. Regarding reliability, PJM has always defined local targets as a 0.04 *conditional* LOLE (reliability index of 1-in-25), conditioned on the assumption that imports into the LDA are fully available (while the LDA is also subject to loss of load in the event of system-wide shortages). Although we discuss alternatives to this target in the following section, we evaluate local VRR curves in Section VI.B under the assumption that this traditional standard must be met on average across all LDAs under non-stressed modeling scenarios. As at the system level, it is also preferred to develop a curve that is robust to stress scenarios, including somewhat different types of stresses that can occur at the local level.

Regarding pricing, the primary objectives of mitigating price volatility and susceptibility to the exercise of market power remain the same. However, an essential difference from the system-wide market is that the realized price in the LDAs depends on either the system-wide VRR curve or the local VRR curve, depending on whether the transmission constraint is binding. Our simulation modeling results show that most LDAs can be expected to price separate a minority of the time once the system grows out of its current capacity surplus. Thus, the local curves cannot be analyzed in isolation, and any evaluation of pricing performance must recognize the prices that resources would receive and that loads would pay.

2. Definition of Locational Reliability Requirement

As noted above, PJM's local Reliability Requirements are set based on a 1-in-25 or 0.04 *conditional* LOLE standard. It reflects the total amount of local supply plus imports that would be needed to meet 0.04 LOLE under the conditional assumption that imports are fully available at the CETL import limit.[64] Taken at face value, the local standard would appear to suggest that an import-constrained LDA would have higher reliability than the system as a whole, with local load shed events only once every 25 years compared to once every 10 years at the system level. This is not the case, however, because the local 1-in-25 reliability standard does not include all of the reliability events that an LDA would be expected to experience. Instead, the local 1-in-25 is a conditional

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[64] See PJM (2014a), Section 2.2.

LOLE standard, measuring local reliability events that would occur if the LDA could always import up to the CETL limit (i.e., assuming no outages at the system level or parent LDA level.)

An additional complexity in the local standard is that the realized reliability at the LDA level depends on the level of overlap between the local outage events and the system-wide and parent LDA outage events. For a first-level LDA, the realized LOLE could be as low as 0.10 or as high as 0.14, if the events occur at exactly the same time or at entirely different times from the system-wide outage events. For a fourth-level LDA, realized LOLE could be as low as 0.1 or as high as 0.26 in the unlikely event that all outage events occur at different times, as well as in its parent LDAs and RTO. Thus, the reliability standard as currently implemented could result in very different LOLE at different locations within PJM's footprint, with the estimated reliability not reported after considering this additive effect.

Beyond these potential discrepancies in LOLE by LDA, there may be larger discrepancies in realized reliability among LDAs based on the definition of LOLE itself. While LOLE is a widely-used metric for determining reliability standards, it is relatively less meaningful than some alternatives. Because LOLE counts only load shed events, but not their depth or duration, it will treat a small, short event and a large, widespread event with equal importance. The metric may also have very different meanings at different LDA levels, since the magnitude of outages is not normalized by the LDA size.

To resolve this relative lack of transparency in realized reliability and also make apply a more uniform reliability standard across the region, we recommend that PJM consider revising the definition of the locational reliability requirements. One option would be to adopt a standard based on normalized EUE, which is the expected outage rate as a percentage of total load. This metric has been used in various international markets, and we believe it to be a more robust metric since its meaning is more uniform across different system sizes and load profiles.[65] Although we recognize that the reliability standards themselves are not within the triennial review scope, they are related to the scope. We believe it would be more meaningful to compare the consistency in the VRR curve reliability implications and to rationalize VRR curve prices across LDAs if locational reliability were measured using this more uniform metric across LDAs of different sizes and at different nested levels.

3. Reliability at the Price Cap

Similar to the system-level comparison of reliability metrics and the VRR curve from Section V.A.3, we compare the local VRR curves to the LDA conditional LOLE curves as shown in Figure 26. Again, we place particular emphasis on the shape of the curve at quantities below the Reliability

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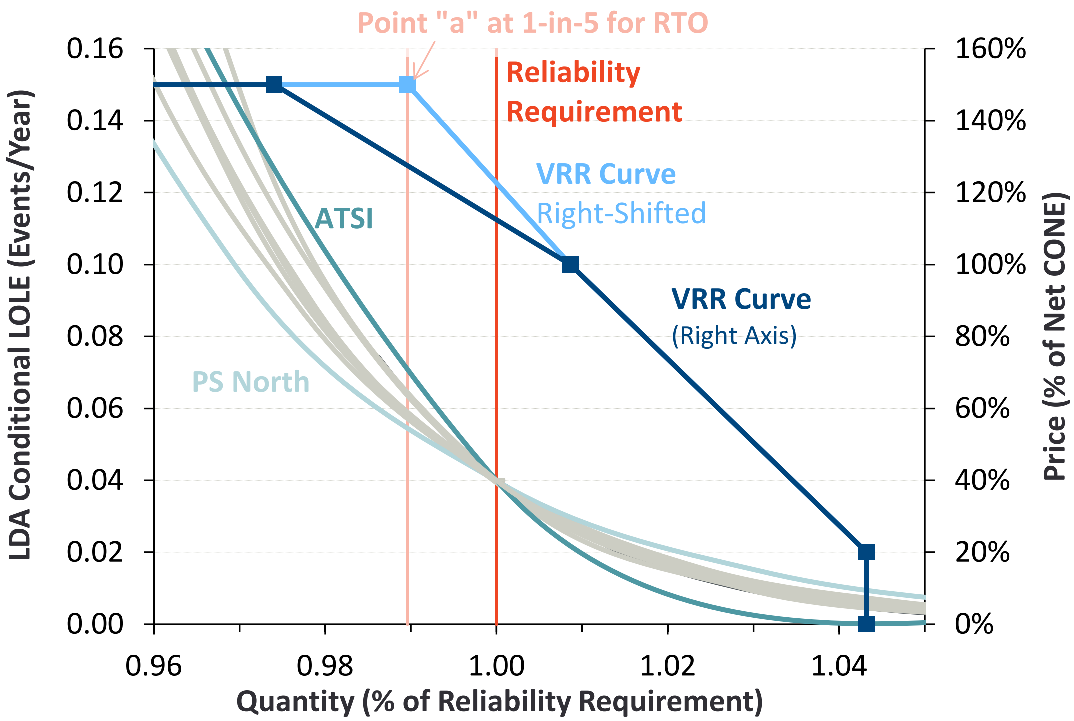
65 Examples of metrics equivalent to Normalized EUE that are used in international markets include: (a) a 0.001% LOLP standard in Scandinavia; and (b) a 0.002% USE standard in Australia's National Energy Market (NEM) and South West Interconnected System (SWIS). See Nordel (2009), p. 5; AEMC (2007), pp. 29-30, (2010), p. viii.

Requirement, and similarly observe that rapidly increasing LOLE could result in very low reliability outcomes at moderate price levels. Based on the current VRR curve, prices would not reach the cap until reliability has substantially degraded to conditional LOLE values of approximately 0.086 to 0.138 (reliability index of 1-in-12to 1-in-7, compared to a standard of 1-in-25) depending on the LDA.

These concerns could be similarly resolved by right-shifting the price cap. If PJM adopts our recommendation to right-shift the system curve cap to 1-in-5, then the same shift applied locally would result in substantially improved LOLE of approximately 0.051 to 0.068 (reliability index of 1-in-20 to 1-in-15) depending on the LDA.

Figure 26
Local VRR Curve Compared to Conditional Loss of Load Event
(Without Adding Parent-LDA or System-Wide LOLE Events)



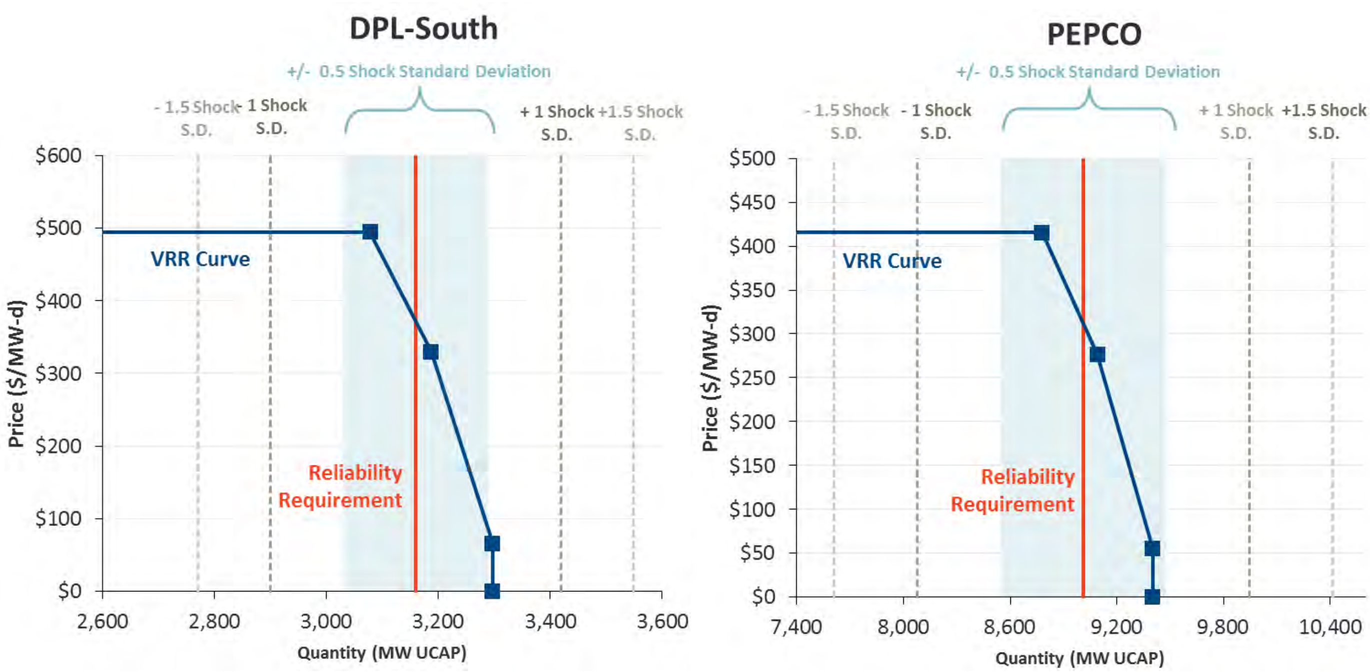
Sources and Notes:
Current VRR Curve reflects the system VRR curve in the 2016/17 PJM Planning Parameters. See PJM (2013a.)
The Conditional LOLE curves reflect the relationship between total quantity and reliability for each of the ten LDAs.

4. Width of the Curves Compared to Net Supply Shock Sizes

Similar to our analysis in Section V.A.4 above, we examine here the width of the locational VRR curves compared to expected year-to-year shocks to the net supply (including imports) minus demand at the local level. We show the width of the VRR curve compared to the standard deviation in net supply shocks for the largest and smallest LDAs (MAAC and DPL-South respectively) in Figure 27 and for all LDAs in Table 16.

Similar to our finding at the system-wide level, we observe that the year-to-year shocks to net supply minus demand at the local level are large relative to the width of the VRR curve. This is particularly true for the smallest LDAs and the LDAs with the greatest level of import-dependence. In these locations, small increases or decreases in supply the size of a single generation plant could result in price changes from the cap to the floor. In fact, in the smallest LDA of DPL-South, a single 700 MW power plant has a size more than three times the width of the entire VRR curve. For highly import-dependent LDAs, changes to the CETL also introduce a substantial source of volatility. For example, in the import-dependent LDA of PepCo, CETL would represent 76% of the Reliability Requirement whenever the LDA is import-constrained. A drop in the 2016/17 CETL by our estimated 12% standard deviation would correspond to an 822 MW drop in total supply, or more than 130% of the width of the entire VRR curve.

Figure 27
Locational VRR Curve Width Compared to Expected Net Supply Shocks



Sources and Notes:

Current VRR Curve reflects the DPL-South and PepCo VRR curves in the 2016/17 PJM Planning Parameters. See PJM (2013a.)
The range of expected net supply shocks are based on simulated outcomes of supply minus demand shocks for DPL-S and PepCo.
As reported in Table 5, the standard deviation of simulated shocks is 259 MW for DPL-S and 935 MW for PepCo.

Table 16
Locational VRR Curve Width Compared to Shock Sizes

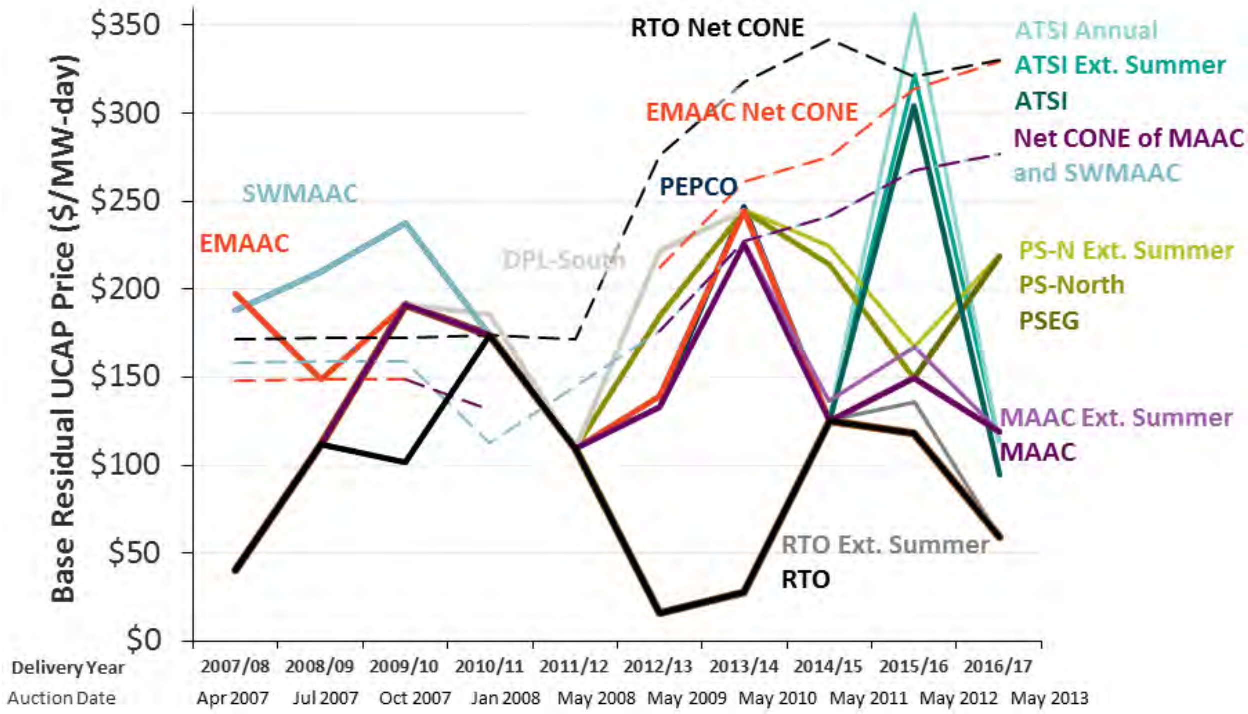
LDA	VRR Curve Width (MW) [1]	Estimated Net Shocks St. Dev. (MW) [2]	Net Shocks as Percent of Curve Width (%) [3]
RTO	11,497	4,277	37%
MAAC	5,003	2,984	60%
EMAAC	2,747	1,954	71%
SWMAAC	1,198	1,214	101%
ATSI	1,125	1,186	105%
PSEG	891	908	102%
PEPCO	624	935	150%
PS-N	446	446	100%
ATSI-C	427	699	164%
DPL-S	219	259	119%

Notes:
[1]: Distance from 2016/17 VRR Curve Point "a" to Point "c", See PJM (2013a).
[2]: Equal to simulated net supply shocks by LDA from Table 5.
[3]: [2]/[1].

While these net shock estimates indicate substantial potential for price volatility and reliability concerns in smaller and more import-constrained LDAs, we caution that this simplified comparison does not consider the price volatility-mitigating effects of the nested LDA structure. The potential for low-price outcomes are substantially mitigated by the fact that import-constrained LDAs' prices cannot fall below the parent LDA or RTO prices and so are protected from downside price outcomes to some extent. Our simulation analysis presented in Section VI.B does account for this effect.

However, the reverse is not true in that high-price and low-reliability outcomes are not mitigated under this structure and therefore can result in periodic price spikes in excess of what would be seen in the broader RTO or larger LDAs. We observe several examples of such events historically as shown in Figure 28. The biggest driver of these historical spikes has been sudden contractions in the estimated CETL for particular LDAs, which were the primary cause of the realized price spikes in MAAC, EMAAC, and SWMAAC in the auction for 2013/14. As at the system level, such price spikes at the local level introduce a greater level of uncertainty in the market, and consequently generate concern among market participants and other stakeholders.

Figure 28
Historical BRA Capacity Prices for Individual LDAs



Sources and Notes:
PJM Base Residual Auction Reports and Planning Parameters, See PJM (2007 – 2013a).

Mitigating the potential for low-reliability, high-price outcomes at the LDA level could be addressed in a number of ways, especially by changing the shape of the VRR curve. Low reliability events could be mitigated by shifting the curve to the right, thus providing price signals earlier and right-shifting the entire distribution of reserve margin outcomes. Alternatively or in addition, low reliability and high price events (and volatility) could both be mitigated by stretching the curve rightward, with the lower-priced parts of the curve shifting the furthest to the right. This too would work by providing price signals earlier and right-shifting the entire distribution of reserve margin outcomes. We would not recommend mitigating price volatility by simply flattening the curve with a left-shifted point “a” as that would introduce substantial risks of low-quantity events and reduce the incentives to locate capacity in import-constrained zones, as we explained in our 2011 review.[66] We more fully evaluate the price volatility, reliability, and customer cost tradeoffs among such potential changes to the local VRR curves based on results of a simulation analysis as in the following sections.

Changes to the locational VRR curve are not the only way to address these concerns. In particular, we recommend that PJM continue to review options for increasing the predictability and stability of its administrative CETL estimates. Reducing volatility in this parameter could substantially reduce

66 See 2011 RPM Review, Section V.D.2, pp. 109-111.

the likelihood and magnitude of price spikes in LDAs. However, we caution that approaches to reducing CETL volatility should be focused on reducing volatility within the bands of administrative uncertainty, but should not prevent CETL from changing with physical changes to the transmission system.[67] For example, one reason for administrative uncertainty in CETL is the impact of modeling assumptions, such as load flow cases, with reasonable differences in modeling assumptions resulting in power flowing over different transmission paths. The stability of CETL might, therefore, be improved if PJM were able to identify primary modeling uncertainties and calculating CETL as a midpoint among different estimated values.

Other options for addressing volatility impacts of CETL include changing the representation of locational constraints in RPM. One of those options would be to explore a more generalized the approach to modeling locational constraints in RPM beyond just import-constrained, nested LDAs with a single import limit. It is possible that some alternative approaches to modeling locational constraints could be less volatile that the current approach, for example an alternative zone structure might be able to better reflect the underlying transmission topology to be less sensitive to modeling assumptions factors such as load flow cases. The most generalized "meshed zone" approach would allow for the possibility that some locations may be export-constrained, may have multiple transmission import paths, or may have the possibility of being either import- or export-constrained, depending on RPM auction outcomes.[68] Adopting a generalized approach may also provide more accurate representation of underlying transmission constraints as reserve margins decrease and the number of modeled LDAs continues to increase. A final option for mitigating price volatility in LDAs would be to revise the RPM auction clearing mechanics according to locational reliability, as discussed in the following section.

5. Clearing Mechanics Rationalized for Locational Reliability Value

One reason that volatility in CETL has such a large impact in producing price spikes in LDAs is that transmission limits in RPM are treated as binary constraints in the auction clearing engine. This means that LDAs will tend to clear with parent zones most of the time, providing no incremental incentives to invest in an import-constrained LDA. Only under periodic short-supply shocks to supply, demand, or especially to CETL, will the LDA experience a price spike above the parent LDA, usually for just one year, before a small increase in net supply causes prices to collapse back to the parent value. The result is a structural volatility and propensity for price spikes in LDAs. To attract investment in an LDA with Net CONE above the parent LDA Net CONE, those spikes would need to be frequent enough and severe enough to achieve the higher local Net CONE on average.

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67 See our 2011 study, Pfeifenberger (2011), for a more comprehensive discussion of uncertainty in CETL and options for addressing the volatility in this parameter.

68 We provide a more comprehensive discussion of "meshed" and "nested" approach to locational modeling in our 2011 RPM Review, Pfeifenberger (2011).

It would be more desirable from the perspective of both suppliers and customers if the same overall average price differential were produced in a more stable fashion, with RPM providing a modest price differential in most years (rather than a large price differential in only a few years). A smaller and more stable price differential also makes sense from an economic and reliability perspective because such prices would be more reflective of the higher reliability value of resources in import-constrained LDAs. This greater reliability value exists at all times, because resources in import-constrained zones contribute not only to RTO-level and parent-level reliability, like resources in those external LDAs, but also to local reliability in that LDA. Local resources help avoid local reliability events that external resources cannot always address, because dispatch conditions or transmission facility deratings may prevent them from doing so or alternately because as an LDA becomes more import-dependent load diversity benefits decline.[69] The value premium of local resources is of course smaller when local resources are plentiful, but it should change gradually rather than in a binary fashion as in PJM's current auction clearing mechanics. Recognizing this differential reliability value in the auction would allow prices to separate more gradually in proportion to reliability value as zones become more import constrained. Doing so might introduce more complexity into RPM parameters, but it could improve both the economics of price signals as well as the volatility of realized prices.

Defining appropriately gradual differentials in reliability value between resources locating in import-constrained LDAs and resources imported from the parent LDA would require enhancing PJM's reliability modeling. PJM could use the same multi-area reliability model it already uses to estimate system Reliability Requirements, but it would have to design its studies differently.[70] The studies would be designed to calculate the MW equivalence between LDA-internal resources and resources imported from the parent zone, for example, showing that relying on 100 MW more imports would provide only as much local LDA reliability value as adding 75 MW more local supply, at a given local reserve margin.[71]

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69 Similar to load diversity benefits or "tie benefits" among RTOs as studied in PJM's reliability studies, load diversity benefits also occur within sub-regions of the RTO. For example, if EMAAC peaks at a different time from MAAC as a whole, then EMAAC will typically be able to benefit from capacity resources that were committed primarily to meet the resource adequacy needs of other loads in MAAC. However, if EMAAC relies very heavily on imports even under normal and near-peak conditions, then there will be less unused import capability available during EMAAC's local peak. In that case, it will not be possible to import additional supplies even if other areas are not peaking (*i.e.*, some load diversity benefits have been lost).

70 Implementing this calculation would require PJM to revise its locational modeling approach, which currently considers only one LDA at a time and does not simultaneously model reliability outcomes in multiple areas at once, which is necessary to account for lost load diversity benefits. This multi-area modeling capability could be developed through extensions to PJM's PRISM model that is currently used for local modeling, or could be implemented through vendor software packages such as GE MARS or Astrape's SERVM. See Astrape Consulting (2014).

71 One approach to calculating this differential reliability value, as shown in the illustrative Figure 33, would be to: (1) model an import-constrained zone at its Reliability Requirement, with transmission fully

Continued on next page

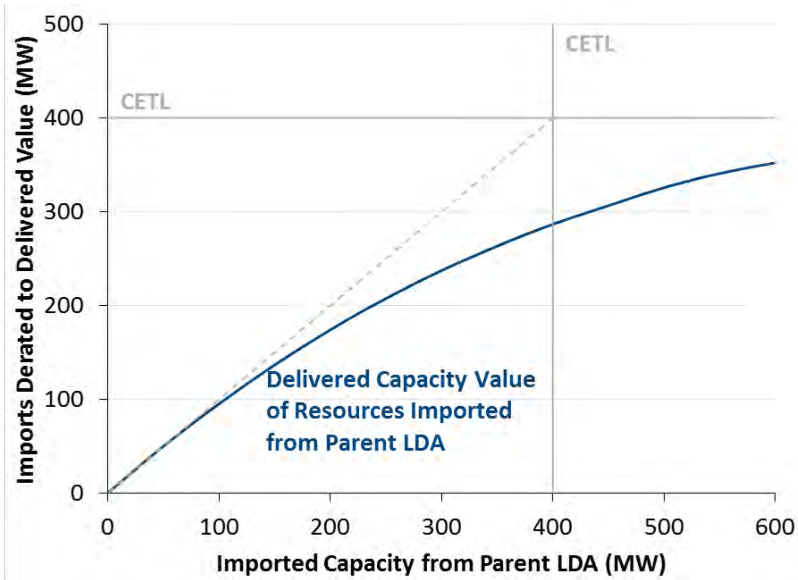
Figure 29 provides an illustrative example of such a calculation, showing the quantity of imports into an LDA on the x-axis, and the "delivered reliability value" of those imports on the y-axis. The chart illustrates that if an LDA has abundant local supply and is not relying heavily on imports, then increasing imports will have almost the same reliability value as adding local supply. Under a revised clearing mechanism, there would be no or only a small price differential from the parent LDA since 1 MW of imports would provide the same reliability value as 1 MW of local supply.

However, as the LDA becomes more import-dependent, the realized reliability value of external resources diminishes, and local supply becomes relatively more valuable. In this example, when the LDA is importing 300 MW total from the parent LDA, an additional 1 MW of imported capacity provides only as much reliability value as 0.75 MW of local supply. If the parent LDA price were $100/MW-d in this case, the auction clearing algorithm would treat imported resources as if they had a cost of $100 / 0.75 delivered MW = $133/MW-d. The auction would select the lowest cost resources between imports at $133/MW-d (delivered MW value) and locally-sourced supply.

Continued from previous page

import-constrained at CETL and local reliability at the reliability standard; (2) conduct a series of simulation runs where supply is moved from the parent LDA into the import-constrained LDA, with local supply increasing over quantities starting at Reliability Requirement minus CETL, up to the total Reliability Requirement (thereby reducing the level of import dependence from the maximum value down to zero), with the resulting level of import-dependence shown as the figure x-axis; (3) at each level of import-dependence, calculate the marginal avoided EUE in the LDA if adding 1 MW of supply locally, compared to marginal avoided EUE in the LDA if adding 1 MW of supply in the parent LDA; and (4) calculating the "delivered capacity value" into the import-constrained LDA based on this ratio, shown as the figure y-axis. Note that this methodology requires that the local reliability be calculated as the total LOLE including LOLE from local events, parent events, and system-level events. The method would also reflect a more rational calculation if implemented according to a normalized EUE metric, rather than an LOLE metric, which is why we describe it this way. However, alternative methods could be developed that rely on LOLE instead of EUE.

Figure 29
Delivered Capacity Value vs. Level of LDA Import Dependence



Note:
Illustrative figure does not reflect actual simulation data.

B. Simulated Performance of System Curves Applied Locally

In this Section, we present simulation analyses of the performance of the current VRR curve, as well as the 1.5× Convex Tuned, 1.7× Convex Tuned, and 1.5× Convex Right-Shifted curves that we developed at the system level in Section V.C above. To test the performance of these curves, we evaluate them primarily against a non-stress scenario in which each LDA has Net CONE at a moderate 5% above the parent LDA Net CONE, which provides an indicator of performance under relatively typical conditions. We find that neither the current VRR curve nor the 1.5× Convex Tuned curve is likely to meet the 0.04 LOLE target on average across all LDAs in this non-stress scenario, although the 1.7× Convex Tuned and right-shifted curves would do so. The relatively poorer reliability performance of the curves at the local level is due primarily to the disproportionate impact of shocks to supply, demand, and CETL in smaller areas.

We also test the sensitivity of this performance to administrative errors in Net CONE and to modeling uncertainties, finding that the current curve is the least robust of these options. We also find that the 1.5× Convex Tuned curve that we recommend at the system level performs better than the current curve as applied at the local level, but still falls short of performance and robustness objectives. This is particularly true in the most import-dependent and smallest LDAs, which are more susceptible to errors in Net CONE and have proportionately greater exposure to shocks.

1. Performance under Base Case Assumptions

Table 17 summarizes the simulated performance of the current VRR curve under our Base Case assumptions, with revised price and quantity metrics relevant for comparing performance at the

LDA level. We report these Base Case values for reference, although these results provide limited insight regarding the performance of the VRR curve as applied at the local level. This is because, consistent with the 2016/17 BRA parameters, we adopt a Base Case assumption in which most LDAs have Net CONE below the RTO Net CONE.

As we noted in Section III.C.3, if an import-constrained LDA has a lower Net CONE, then we would expect new supplies to locate in that location. The local VRR curve might eventually become a non-binding constraint (or will not be modeled at all), leaving local price and reliability results will converge to parent or RTO levels. Our simulation model discovered this intuitive result, as shown in Table 17. In that trivial case, there are no local reliability concerns, and any adjustments to the VRR curve would be irrelevant in the long term. (Recall that all simulation results reflect long-term equilibrium conditions in which annual outcomes fluctuate but long-term average prices equal Net CONE, not current or near-term market conditions).

The case where LDAs have a higher Net CONE than the parent area is more important, since that is the only case where the local VRR curve will impact price and quantity outcomes in the long-term. Thus, VRR curves should be designed to perform well in this case, being otherwise irrelevant in the long-term. We also believe this case will usually be the most likely if import-constrained areas tend to be import-constrained because costs are greater there. Even in cases where Net CONE appears lower in an LDA, it may be because of an error in estimating CONE or E&AS offsets, as we demonstrated for SWMAAC in Section III.B.1. In other cases, Net CONE may appear lower only temporarily until new entrants reduce the local energy price premium. Therefore, in the remainder of our analysis we analyze only cases where each LDA is import-constrained, with a higher Net CONE than the parent LDA.

Table 17
Performance of VRR Curve in LDAs under Base Case Assumptions

	Price				Reliability								Procurement Costs		
	Average ($/MW-d)	St. Dev ($/MW-d)	Freq. at Cap (%)	Freq. of Price Separation (%)	Conditional Average LOLE (Ev/Yr)	Conditional Average LOLE (Additive) (Ev/Yr)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req. (%)	St. Dev. as % of Rel. Req. (%)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-15 (%)	Average ($mil)	Average of Bottom 20% ($mil)	Average of Top 20% ($mil)
Current VRR Curve															
MAAC	$331	$95	6%	0%	0.000	0.121	***	***	***	***	***	***	$8,040	$5,056	$11,220
EMAAC	$330	$95	6%	0%	0.000	0.122	***	***	***	***	***	***	$4,376	$2,761	$6,103
SWMAAC	$331	$95	6%	0%	0.000	0.121	***	***	***	***	***	***	$1,855	$1,167	$2,594
ATSI	$363	$116	13%	29%	0.073	0.195	795	1,114	105%	7%	23%	19%	$1,904	$1,134	$2,705
PSEG	$330	$95	6%	0%	0.000	0.122	***	***	***	***	***	***	$1,393	$880	$1,943
PEPCO	$331	$95	6%	0%	0.000	0.121	***	***	***	***	***	***	$895	$566	$1,247
PS-N	$330	$95	6%	0%	0.000	0.122	***	***	***	***	***	***	$676	$425	$945
ATSI-C	$363	$116	13%	0%	0.000	0.195	***	***	***	***	***	***	$680	$391	$1,016
DPL-S	$330	$95	6%	0%	0.000	0.122	***	***	***	***	***	***	$320	$200	$448

Notes:
*** An arbitrary quantity of excess supply is attracted into an LDA with Net CONE below system Net CONE.
Price and cost results may be affected by a +/- 0.2% convergence error in Net CONE in this and subsequent tables.
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

2. Performance with Net CONE Higher than Parent

We report here the simulated performance of the current VRR curve under two different assumptions regarding local Net CONE values. In this section, we also compare the performance to that of three enhanced VRR curve shapes that we analyzed for the system above, and we will identify improvements but shortfalls with the alternatives tested. The following Section VI.C will present more alternative shapes, including special modifications tuned to local areas. Finally, Section VI.D presents our overall recommendations for modifying local VRR curves to meet reliability objectives, including in the most vulnerable import-dependent LDAs.

In Table 18, we present results if assuming that local Net CONE is 5% higher than the parent Net CONE in each successive import-constrained LDA (with the MAAC value fixed at its Base Case value). This case provides a reasonable basis for evaluating the performance of the VRR Curve under typical conditions, where more import-constrained locations do show higher net investment costs but are only modestly higher than elsewhere.

In Table 19, we show a more stressed case in which Net CONE is 5% higher in each LDA (as in the first case) but the lowest-level LDAs (PS-North, DPL-South, PepCo, and ATSI-C) have a substantially higher Net CONE that is 20% above the parent LDA value. For example, PS-North would have a 35% higher Net CONE than the Rest of RTO. This provides an illustration of the VRR curve performance in locations with much higher investment costs associated with siting difficulties, environmental restrictions, or lack of available gas and electric infrastructure. In both cases, we assume that the administrative Net CONE is accurate and equal to the true developer Net CONE.

Under the 5% higher case, we observe that the current VRR curve falls short of the local Reliability Requirement of 1-in-25 (or 0.04 LOLE) in four of nine LDAs, and produces a frequency of low reliability events below 1-in-15 in three LDAs. For ease of reference, we highlight the locations that fall short of these thresholds in all tables reported in this and the following sections. By comparison, all three of the alternative VRR curves developed in Section V above show better reliability performance, with: (a) the 1.5× Convex curve showing modest improvement but also falling short of Reliability Requirements in three LDAs, and (b) the 1.7× Convex curve and the Right-Shifted Convex curve meeting or slightly exceeding the reliability Requirements in all cases.

In terms of price volatility, we observe that, similar to our system-wide results, the VRR Curve performs somewhat better than the convex curves, primarily because the concave shape mitigates the impact of price volatility in the high-price region (which also has the problematic effect of increasing the frequency of very low reliability events).

In the more stressed case reflected in Table 19, we see that the locations with Net CONE 20% above the parent all fail to meet the reliability objective under the current VRR curve as well as under all of the alternative curves. The two poorest-performing LDAs in this case are the most import-dependent locations of PepCo and ATSI-C, showing very low reliability levels of approximately 1-in-2 and 1-in-1 respectively under the current VRR Curve. Each of the convex curves shows improvement in reliability relative to the current VRR curve, but the most import-constrained LDAs continue to fail to meet the Reliability Requirement in all cases. The best-performing curve is the 1.7× Convex curve, under which reliability events drop by half but still remain an order of magnitude above the target level.

These results demonstrate that the current VRR curve will achieve local reliability objectives only under certain conditions, and would be unlikely to achieve reliability objectives in the most import-dependent locations or in those with Net CONE substantially above the parent value. The alternative VRR curves that we analyzed for the system would improve reliability outcomes, with the 1.7× Convex curve showing the most improvement and meeting reliability objectives in most LDAs if local Net CONE values only modestly exceed parent levels. However, none of the curves we analyzed for the system is robust to a circumstance with substantially higher Net CONE in an LDA, with all curves showing very poor reliability in the most import-dependent LDAs. The following two sections will show how performance could deteriorate even further if Net CONE is under-estimated or if shocks are larger than in our Base modeling assumptions.

Table 18
VRR and Alternative Curves' Performance with Net CONE always 5% Higher than Parent Net CONE

	Price				Reliability								Procurement Costs		
	Average ($/MW-d)	St. Dev ($/MW-d)	Freq. at Cap (%)	Freq. of Price Separation (%)	Conditional Average LOLE (Ev/Yr)	Conditional Average LOLE (Additive) (Ev/Yr)	Average Excess (Deficit) Above Rel. Req. (MW)	St. Dev. (MW)	Average Quantity as % of Rel. Req. (%)	St. Dev. as % of Rel. Req. (%)	Freq. Below Rel. Req. (%)	Freq. Below 1-in-15 (%)	Average ($mil)	Average of Bottom 20% ($mil)	Average of Top 20% ($mil)
Current VRR Curve															
MAAC	$277	$89	12%	33%	0.053	0.160	1,389	2,356	102%	3%	27%	17%	$7,218	$4,199	$10,669
EMAAC	$291	$98	8%	25%	0.033	0.193	1,349	1,706	103%	4%	22%	15%	$4,058	$2,275	$6,049
SWMAAC	$291	$96	6%	17%	0.042	0.202	1,215	1,163	107%	7%	14%	8%	$1,689	$969	$2,504
ATSI	$277	$87	11%	18%	0.035	0.143	1,152	1,121	107%	7%	14%	11%	$1,476	$904	$2,120
PSEG	$305	$105	5%	15%	0.022	0.215	1,036	886	108%	7%	13%	9%	$1,350	$730	$2,002
PEPCO	$305	$104	25%	14%	0.064	0.266	1,099	923	112%	10%	11%	10%	$857	$471	$1,292
PS-N	$321	$116	31%	15%	0.023	0.238	503	442	108%	7%	12%	8%	$687	$361	$1,047
ATSI-C	$291	$95	10%	12%	0.059	0.202	906	694	115%	11%	9%	8%	$533	$316	$796
DPL-S	$305	$105	13%	15%	0.027	0.220	309	259	110%	8%	12%	7%	$308	$167	$464
Convex Tuned, 1.5x Cap															
MAAC	$277	$97	14%	31%	0.043	0.131	1,615	2,315	102%	3%	23%	14%	$7,231	$4,045	$11,064
EMAAC	$291	$107	12%	23%	0.027	0.158	1,536	1,694	104%	4%	18%	11%	$4,065	$2,194	$6,293
SWMAAC	$291	$104	8%	16%	0.034	0.165	1,311	1,159	108%	7%	12%	7%	$1,692	$934	$2,604
ATSI	$277	$95	9%	17%	0.030	0.117	1,232	1,118	108%	7%	12%	9%	$1,479	$878	$2,209
PSEG	$305	$114	8%	14%	0.019	0.177	1,106	885	109%	7%	11%	7%	$1,353	$698	$2,073
PEPCO	$305	$111	9%	14%	0.055	0.219	1,138	922	113%	10%	10%	8%	$858	$454	$1,337
PS-N	$321	$123	8%	14%	0.019	0.196	537	443	108%	7%	10%	6%	$688	$342	$1,077
ATSI-C	$291	$102	7%	11%	0.048	0.166	943	695	115%	11%	9%	7%	$534	$303	$822
DPL-S	$305	$113	7%	15%	0.023	0.182	323	259	110%	8%	10%	6%	$309	$160	$480
Convex Tuned, 1.7x Cap															
MAAC	$277	$115	12%	27%	0.039	0.133	1,595	2,202	102%	3%	21%	12%	$7,199	$3,657	$11,865
EMAAC	$291	$126	11%	20%	0.023	0.156	1,643	1,658	104%	4%	16%	9%	$4,047	$1,965	$6,747
SWMAAC	$291	$122	7%	13%	0.028	0.161	1,367	1,145	108%	7%	11%	6%	$1,683	$849	$2,788
ATSI	$277	$113	7%	14%	0.024	0.118	1,313	1,112	108%	7%	11%	8%	$1,472	$792	$2,391
PSEG	$305	$134	7%	12%	0.016	0.172	1,160	882	109%	7%	10%	6%	$1,348	$634	$2,243
PEPCO	$305	$131	7%	11%	0.034	0.194	1,234	915	114%	10%	9%	6%	$851	$410	$1,430
PS-N	$321	$145	6%	12%	0.015	0.187	580	439	109%	7%	9%	5%	$685	$308	$1,177
ATSI-C	$291	$120	6%	9%	0.035	0.153	1,001	695	116%	11%	7%	6%	$531	$274	$875
DPL-S	$305	$134	6%	12%	0.020	0.177	336	259	111%	8%	9%	6%	$306	$145	$514
Convex 1.5x, Right-Shifted															
MAAC	$277	$97	14%	31%	0.028	0.080	2,237	2,314	103%	3%	15%	9%	$7,295	$4,087	$11,175
EMAAC	$291	$107	13%	23%	0.020	0.100	1,879	1,694	105%	4%	14%	8%	$4,102	$2,211	$6,350
SWMAAC	$291	$104	8%	16%	0.024	0.105	1,460	1,159	108%	7%	8%	6%	$1,707	$941	$2,627
ATSI	$277	$95	9%	17%	0.022	0.074	1,373	1,118	108%	7%	10%	7%	$1,492	$886	$2,229
PSEG	$305	$114	8%	14%	0.014	0.114	1,218	885	109%	7%	9%	5%	$1,365	$706	$2,094
PEPCO	$305	$111	9%	14%	0.040	0.144	1,224	922	114%	10%	9%	7%	$866	$458	$1,349
PS-N	$321	$123	8%	14%	0.015	0.129	593	443	109%	7%	8%	5%	$694	$345	$1,087
ATSI-C	$291	$102	7%	11%	0.036	0.110	999	695	116%	11%	8%	6%	$539	$306	$831
DPL-S	$305	$113	7%	14%	0.018	0.118	351	259	111%	8%	7%	5%	$311	$162	$484

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

Table 19
Performance with LDA Net CONE 5% Higher than Parent (for Most LDAs)
or 20% Higher (Most Import-Constrained LDAs of PS-North, DPL-South, PepCo, and ATSI-C)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Current VRR Curve															
MAAC	$277	$89	8%	33%	0.054	0.162	1,380	2,364	102%	3%	27%	17%	$7,342	$4,311	$10,760
EMAAC	$291	$99	10%	25%	0.034	0.196	1,335	1,709	103%	4%	23%	15%	$4,138	$2,340	$6,100
SWMAAC	$291	$96	8%	17%	0.043	0.205	1,221	1,167	107%	7%	14%	9%	$1,730	$1,005	$2,523
ATSI	$277	$87	8%	18%	0.036	0.145	1,143	1,123	107%	7%	15%	11%	$1,495	$923	$2,131
PSEG	$305	$106	9%	14%	0.022	0.218	1,046	888	108%	7%	13%	9%	$1,411	$761	$2,066
PEPCO	$349	$131	12%	35%	0.487	0.693	504	900	106%	10%	28%	24%	$913	$504	$1,332
PS-N	$366	$142	12%	40%	0.075	0.293	209	430	103%	7%	31%	21%	$755	$375	$1,129
ATSI-C	$332	$120	12%	32%	0.765	0.910	425	687	107%	11%	25%	22%	$566	$326	$824
DPL-S	$349	$132	12%	36%	0.126	0.322	146	253	105%	8%	28%	22%	$335	$175	$500
Convex Tuned, 1.5x Cap															
MAAC	$277	$98	14%	31%	0.044	0.132	1,604	2,319	102%	3%	23%	14%	$7,358	$4,148	$11,152
EMAAC	$291	$107	13%	24%	0.028	0.160	1,523	1,697	104%	4%	19%	12%	$4,147	$2,227	$6,340
SWMAAC	$291	$104	8%	16%	0.034	0.166	1,317	1,162	108%	7%	12%	7%	$1,733	$969	$2,630
ATSI	$277	$95	9%	17%	0.030	0.118	1,232	1,119	108%	7%	12%	9%	$1,498	$893	$2,213
PSEG	$305	$114	9%	14%	0.019	0.178	1,108	885	109%	7%	11%	8%	$1,415	$719	$2,139
PEPCO	$349	$137	23%	35%	0.423	0.589	540	899	106%	10%	26%	22%	$914	$488	$1,382
PS-N	$366	$149	22%	39%	0.067	0.245	237	429	104%	7%	28%	19%	$757	$356	$1,154
ATSI-C	$332	$127	21%	31%	0.630	0.748	461	686	108%	11%	23%	21%	$567	$317	$850
DPL-S	$349	$139	21%	35%	0.107	0.267	164	253	105%	8%	26%	20%	$336	$166	$511
Convex Tuned, 1.7x Cap															
MAAC	$277	$116	12%	26%	0.040	0.134	1,590	2,210	102%	3%	22%	12%	$7,323	$3,729	$12,006
EMAAC	$291	$126	11%	19%	0.024	0.158	1,647	1,662	104%	4%	16%	10%	$4,128	$2,022	$6,830
SWMAAC	$291	$123	7%	14%	0.029	0.163	1,361	1,147	108%	7%	11%	6%	$1,726	$864	$2,830
ATSI	$277	$113	8%	14%	0.024	0.119	1,312	1,111	108%	7%	11%	8%	$1,494	$814	$2,391
PSEG	$305	$134	7%	12%	0.016	0.174	1,151	882	109%	7%	10%	6%	$1,408	$648	$2,320
PEPCO	$349	$163	18%	28%	0.244	0.407	678	894	108%	10%	21%	17%	$909	$429	$1,488
PS-N	$366	$178	18%	31%	0.050	0.224	297	426	105%	7%	23%	15%	$754	$321	$1,270
ATSI-C	$332	$151	17%	25%	0.379	0.498	543	684	109%	11%	19%	17%	$562	$285	$896
DPL-S	$349	$165	18%	29%	0.077	0.235	194	253	106%	8%	22%	16%	$334	$149	$556
Convex 1.5x, Right-Shifted															
MAAC	$277	$98	14%	31%	0.029	0.081	2,231	2,319	103%	3%	15%	9%	$7,424	$4,185	$11,258
EMAAC	$291	$107	13%	24%	0.020	0.102	1,866	1,697	105%	4%	14%	8%	$4,183	$2,247	$6,400
SWMAAC	$291	$104	8%	16%	0.024	0.105	1,472	1,162	109%	7%	8%	6%	$1,749	$978	$2,659
ATSI	$277	$95	9%	17%	0.023	0.075	1,367	1,119	108%	7%	10%	7%	$1,512	$901	$2,233
PSEG	$305	$114	9%	14%	0.014	0.115	1,219	885	109%	7%	9%	5%	$1,428	$726	$2,158
PEPCO	$349	$137	23%	35%	0.318	0.423	620	899	107%	10%	23%	20%	$923	$493	$1,396
PS-N	$366	$149	22%	39%	0.053	0.168	293	429	105%	7%	23%	16%	$764	$359	$1,166
ATSI-C	$332	$127	21%	31%	0.480	0.555	511	686	108%	11%	21%	18%	$573	$319	$859
DPL-S	$349	$139	21%	35%	0.083	0.185	191	253	106%	8%	22%	17%	$339	$168	$516

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Sensitivity to Errors in Administrative Net CONE

The reliability risks introduced by the potential for errors in Net CONE are even more important at the LDA level than on a system-wide basis, although we view these as important risks in both cases. We view these risks as more important at the LDA level partly because we believe the potential for errors in Net CONE is greater at the LDA level, particularly for the smallest LDAs for which there is no location-specific Gross CONE or E&AS estimate. Adopting more location-specific Net CONE estimates as we recommended in Section III will reduce these risks, but small LDAs will still be at greater risk for Net CONE estimation error. This is because the smallest LDAs are the most prone to idiosyncratic siting, environmental, or infrastructure limitations that do not apply in the larger CONE Area. Further, these locations are unlikely to have a substantial number of units similar to the reference unit, and so calibrating E&AS to plant actual data will not be possible.

As at the system level, underestimating Net CONE results in substantially degraded reliability under the current VRR curve as well as all of the alternative curves. However, the alternative curves are more robust to these errors, with the 1.7× Convex curve showing some LDAs that continue to meet the reliability standard, and reducing the frequency of load-shed events by 50-65% depending on the LDA. These results indicate that increasing the price cap at the LDA level would be a beneficial protection against low reliability events. We further examine this option, along with alternative approaches for addressing these concerns, in Section VI.C.1 below.

Table 20
VRR Curve Performance with 20% Under-Estimate in Net CONE
(True Net CONE 5% Higher than Parent)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Current VRR Curve															
MAAC	$277	$63	24%	52%	0.219	0.518	-365	2,570	100%	4%	54%	41%	$7,175	$4,862	$9,333
EMAAC	$291	$70	25%	40%	0.103	0.621	151	1,790	100%	5%	46%	34%	$4,032	$2,644	$5,301
SWMAAC	$291	$67	22%	29%	0.180	0.699	593	1,182	103%	7%	32%	24%	$1,684	$1,116	$2,192
ATSI	$277	$61	22%	31%	0.128	0.427	528	1,137	103%	7%	33%	27%	$1,464	$1,022	$1,882
PSEG	$305	$73	22%	26%	0.085	0.706	512	897	104%	7%	28%	22%	$1,340	$866	$1,745
PEPCO	$305	$71	22%	24%	0.404	1.103	639	934	107%	10%	25%	21%	$857	$554	$1,132
PS-N	$321	$78	21%	27%	0.076	0.782	233	446	104%	7%	30%	21%	$683	$426	$901
ATSI-C	$291	$65	20%	20%	0.445	0.873	543	694	109%	11%	20%	18%	$533	$357	$704
DPL-S	$305	$73	21%	24%	0.106	0.727	175	259	106%	8%	26%	20%	$307	$194	$409
Convex Tuned, 1.5x Cap															
MAAC	$277	$70	33%	49%	0.161	0.382	36	2,516	100%	3%	45%	33%	$7,209	$4,494	$9,562
EMAAC	$291	$76	30%	41%	0.084	0.466	384	1,771	101%	4%	39%	29%	$4,053	$2,464	$5,406
SWMAAC	$291	$73	22%	28%	0.139	0.521	714	1,178	104%	7%	27%	20%	$1,692	$1,041	$2,242
ATSI	$277	$68	23%	31%	0.104	0.326	630	1,129	104%	7%	29%	23%	$1,475	$949	$1,943
PSEG	$305	$79	21%	25%	0.070	0.536	593	895	105%	7%	25%	20%	$1,347	$802	$1,790
PEPCO	$305	$77	19%	24%	0.318	0.840	703	932	108%	10%	22%	18%	$861	$518	$1,156
PS-N	$321	$84	21%	27%	0.064	0.600	274	445	104%	7%	26%	19%	$687	$401	$917
ATSI-C	$291	$71	15%	19%	0.334	0.659	596	694	110%	11%	18%	15%	$536	$333	$724
DPL-S	$305	$79	18%	24%	0.083	0.549	201	259	106%	8%	23%	17%	$309	$180	$417
Convex Tuned, 1.7x Cap															
MAAC	$277	$90	27%	41%	0.106	0.290	417	2,364	101%	3%	40%	27%	$7,197	$3,948	$10,566
EMAAC	$291	$98	23%	30%	0.057	0.347	774	1,713	102%	4%	31%	22%	$4,043	$2,144	$5,977
SWMAAC	$291	$94	16%	22%	0.082	0.372	940	1,166	105%	7%	21%	14%	$1,687	$913	$2,466
ATSI	$277	$87	16%	23%	0.064	0.248	852	1,114	105%	7%	23%	17%	$1,468	$851	$2,088
PSEG	$305	$103	15%	19%	0.038	0.385	836	890	107%	7%	18%	13%	$1,345	$691	$1,970
PEPCO	$305	$99	14%	18%	0.146	0.518	892	924	110%	10%	17%	13%	$857	$452	$1,269
PS-N	$321	$110	14%	20%	0.040	0.425	377	443	106%	7%	19%	12%	$685	$339	$1,011
ATSI-C	$291	$92	12%	15%	0.153	0.401	737	694	112%	11%	14%	12%	$533	$297	$779
DPL-S	$305	$102	12%	18%	0.045	0.392	259	258	108%	8%	17%	12%	$307	$159	$460
Convex 1.5x, Right-Shifted															
MAAC	$277	$70	33%	49%	0.106	0.247	663	2,516	101%	3%	36%	27%	$7,275	$4,522	$9,642
EMAAC	$291	$76	31%	41%	0.064	0.310	716	1,771	102%	4%	32%	24%	$4,089	$2,484	$5,451
SWMAAC	$291	$73	22%	29%	0.103	0.350	859	1,178	105%	7%	23%	17%	$1,708	$1,050	$2,262
ATSI	$277	$68	23%	31%	0.079	0.220	776	1,129	105%	7%	24%	19%	$1,489	$955	$1,960
PSEG	$305	$79	21%	25%	0.054	0.364	701	895	105%	7%	21%	17%	$1,359	$808	$1,805
PEPCO	$305	$77	19%	24%	0.243	0.593	778	932	109%	10%	20%	16%	$869	$524	$1,167
PS-N	$321	$84	21%	27%	0.049	0.413	335	445	105%	7%	22%	14%	$694	$404	$926
ATSI-C	$291	$71	15%	19%	0.246	0.466	653	694	111%	11%	16%	14%	$541	$337	$731
DPL-S	$305	$79	18%	24%	0.064	0.375	228	259	107%	8%	19%	15%	$312	$182	$421

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

4. Sensitivity to Modeling Uncertainties

As we did at the system level, we also tested robustness of our conclusions at the LDA level under alternative modeling assumptions, after introducing 33% larger shocks, 33% smaller shocks, or eliminating all CETL shocks. With larger or smaller shocks, results are consistent with our expectations. We see that price volatility increases and reliability decreases with 33% larger shocks, and that the reverse is true with smaller shocks. If shocks are 33% lower than under our base assumptions, then the current VRR Curve would achieve reliability objectives in all LDAs. With 33% higher shocks reliability would be substantially worse in all LDAs, with only two of nine LDAs meeting the reliability target.

Eliminating shocks to CETL has a large effect in improving reliability in the most import-dependent zones, as expected. However, removing these shocks in the larger and less import-dependent LDAs has minimal reliability impacts, with the primary effects being a reduction in the quantity of excess supply in that location, which, therefore, causes an increase in the frequency of price separation above the parent LDA, although the smaller shocks reduce the scale of the price spikes associated with price separation and also reduce the frequency of price-cap events.[72]

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72 This is because: (a) reductions in CETL volatility reduce the frequency of low quantity, high-price events, reducing prices closer to parent zone prices more often; (b) the result of the lower prices is a lower quantity of supply locating in those zones (this is the largest effect of removing CETL volatility); until (c) the lower quantity, combined with other shocks to supply and demand, result frequent enough price spikes to increase prices back up to Net CONE.

Table 21
VRR Curve Performance Sensitivity to Modeling Uncertainties
(Net CONE 5% Higher than Parent)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Base Shocks															
MAAC	$277	$89	12%	33%	0.053	0.160	1,389	2,356	102%	3%	27%	17%	$7,218	$4,199	$10,669
EMAAC	$291	$98	8%	25%	0.033	0.193	1,349	1,706	103%	4%	22%	15%	$4,058	$2,275	$6,049
SWMAAC	$291	$96	6%	17%	0.042	0.202	1,215	1,163	107%	7%	14%	8%	$1,689	$969	$2,504
ATSI	$277	$87	11%	18%	0.035	0.143	1,152	1,121	107%	7%	14%	11%	$1,476	$904	$2,120
PSEG	$305	$105	5%	15%	0.022	0.215	1,036	886	108%	7%	13%	9%	$1,350	$730	$2,002
PEPCO	$305	$104	25%	14%	0.064	0.266	1,099	923	112%	10%	11%	10%	$857	$471	$1,292
PS-N	$321	$116	31%	15%	0.023	0.238	503	442	108%	7%	12%	8%	$687	$361	$1,047
ATSI-C	$291	$95	10%	12%	0.059	0.202	906	694	115%	11%	9%	8%	$533	$316	$796
DPL-S	$305	$105	13%	15%	0.027	0.220	309	259	110%	8%	12%	7%	$308	$167	$464
Zero CETL Shocks															
MAAC	$277	$90	9%	35%	0.051	0.160	1,163	2,202	102%	3%	29%	19%	$7,207	$4,066	$10,918
EMAAC	$291	$101	11%	40%	0.044	0.204	650	1,374	102%	3%	32%	20%	$4,062	$2,245	$6,206
SWMAAC	$291	$99	10%	36%	0.048	0.207	334	623	102%	4%	28%	17%	$1,705	$945	$2,600
ATSI	$277	$92	10%	29%	0.036	0.145	430	620	103%	4%	24%	17%	$1,492	$848	$2,229
PSEG	$305	$107	7%	31%	0.034	0.238	226	388	102%	3%	27%	14%	$1,362	$735	$2,078
PEPCO	$305	$105	8%	28%	0.035	0.243	270	378	103%	4%	24%	15%	$881	$469	$1,371
PS-N	$321	$115	9%	31%	0.036	0.274	144	255	102%	4%	29%	13%	$698	$357	$1,081
ATSI-C	$291	$99	6%	25%	0.030	0.175	171	217	103%	4%	22%	15%	$551	$297	$874
DPL-S	$305	$107	7%	27%	0.032	0.236	87	119	103%	4%	21%	12%	$313	$165	$485
33% Higher Shocks															
MAAC	$277	$106	13%	32%	0.115	0.267	1,612	3,139	102%	4%	29%	21%	$7,202	$3,617	$11,171
EMAAC	$291	$115	11%	24%	0.047	0.314	1,743	2,269	104%	6%	22%	17%	$4,046	$1,970	$6,360
SWMAAC	$291	$113	7%	16%	0.082	0.349	1,648	1,539	110%	9%	13%	10%	$1,685	$842	$2,621
ATSI	$277	$103	9%	17%	0.068	0.220	1,524	1,491	109%	9%	15%	12%	$1,471	$791	$2,232
PSEG	$305	$122	7%	14%	0.032	0.346	1,402	1,178	111%	9%	13%	10%	$1,346	$627	$2,096
PEPCO	$305	$120	8%	13%	0.162	0.511	1,509	1,223	117%	14%	11%	9%	$852	$405	$1,345
PS-N	$321	$133	7%	13%	0.029	0.376	686	584	111%	9%	11%	8%	$683	$304	$1,086
ATSI-C	$291	$110	6%	11%	0.172	0.392	1,233	925	120%	15%	9%	8%	$531	$275	$826
DPL-S	$305	$122	6%	14%	0.049	0.364	413	343	113%	11%	11%	8%	$307	$142	$483
33% Lower Shocks															
MAAC	$277	$67	3%	39%	0.033	0.116	1,100	1,600	102%	2%	25%	11%	$7,257	$4,915	$10,003
EMAAC	$291	$77	4%	27%	0.027	0.143	952	1,158	102%	3%	21%	11%	$4,086	$2,678	$5,675
SWMAAC	$291	$75	4%	20%	0.025	0.140	793	784	105%	5%	15%	7%	$1,702	$1,136	$2,357
ATSI	$277	$67	4%	20%	0.023	0.107	782	756	105%	5%	15%	9%	$1,481	$1,038	$1,985
PSEG	$305	$83	3%	16%	0.018	0.161	686	596	105%	5%	14%	7%	$1,360	$867	$1,888
PEPCO	$305	$84	6%	16%	0.028	0.169	722	624	108%	7%	12%	9%	$865	$555	$1,224
PS-N	$321	$92	4%	18%	0.020	0.181	329	302	105%	5%	13%	6%	$693	$425	$983
ATSI-C	$291	$76	5%	14%	0.026	0.133	585	466	110%	8%	11%	8%	$538	$360	$754
DPL-S	$305	$84	4%	17%	0.019	0.161	205	175	107%	6%	12%	7%	$310	$196	$437

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

C. Options for Improving Performance in LDAs

As discussed in Section V.B, we find that LDAs are susceptible to low reliability under the current VRR curve, particularly in LDAs that are highly import-dependent or that have Net CONE substantially above the parent Net CONE. We also find that the 1.5× Convex Tuned curve that we recommend at the system level performs better than the current curve as applied at the local level, but still falls short of performance and robustness objectives (although the 1.7× Convex Tuned and Right-Shifted Curves showed better performance).

To develop a VRR curve recommendation at the local level that is also consistent with our system-wide recommendations, we begin with the recommended 1.5× Convex Tuned curve from the system level, and then test a series of approaches to improving performance and protection against low-reliability events. In this Section, we rely primarily on a realistic stressed scenario, in which most LDAs have Net CONE at 5% above the parent level, but where the lowest-level LDAs have Net CONE at 20% above the parent level (and where administrative Net CONE is accurate in each location). We focus on performance results in these lowest-level LDAs because these areas are the most susceptible to reliability performance concerns.

First, we first test the level of reliability improvement under a number of different options for increasing the cap, right-shifting the curve, or right-stretching the curve, finding that increasing the price cap to 1.7× Net CONE is the most beneficial followed by right-stretching. Second, we test the impacts of combining these two approaches, testing alternative approaches to right-stretching the curve that are or are not proportional to LDA size and CETL. In this test, we find that right-stretching the curves to a minimum width of 25% of CETL provides substantial protection against reliability shortfalls in the most vulnerable, import-dependent LDAs without substantially increasing procurement costs in the less-vulnerable locations. Finally, in the last sub-section here, we report the performance of the 1.5× Convex Turned curve after adopting both of these recommendations under both non-stress and stress scenarios, showing substantially improved performance and robustness.

1. Reducing Susceptibility to Low-Reliability Events

In this Section, we begin with the 1.5× Convex Curve that we recommend adopting at the system level, but test a series of options for improving its performance in the most import-dependent locations and protecting against low-reliability events. We, therefore, present performance results in a stress scenario for the 1.5× Convex Tuned curve as-is, and, after applying four different adjustments, comparing:

- **1.5× Convex Curve,** *i.e.*, the curve shape we are recommending for the system, but applied at the LDA level;
- **LDA Cap at 1.7×,** assuming the 1.5× Convex curve with no revisions at the system level, and increasing the cap to 1.7× Net CONE at the LDA level (but keeping all other price and quantity parameters unchanged);

- **Right-Shifting the Entire Curve,** with point "a" shifted from the quantity corresponding to 1-in-5 for system to the Reliability Requirement, and right-shifting all other quantity points by the same amount;
- **Doubling the Width** by keeping the cap quantity fixed at the quantity corresponding to 1-in-5 for system, but right-stretching the curve until the kink and foot quantities are both twice the original distance from the cap; and
- **Imposing a 1,500 Minimum Width** on the curve while keeping the quantity at the cap is fixed at the quantity corresponding to 1-in-5 for system, so that even in the smallest LDAs the quantity at the foot will be at least 1,500 MW higher than the quantity at the cap, with the quantity at the kink adjusting proportionately.

Table 22 shows simulated performance for each of these curve shapes. In all cases, we show results for the 5% / 20% higher Net CONE assumption, reporting results only for the most import-constrained LDAs in which we have assumed a 20% higher Net CONE. As the table shows, increasing the cap to 1.7× Net CONE and increasing the width of the VRR Curves each improve reliability. Based on these results and the protection it provides against under-estimates to Net CONE as discussed in Section VI.B.3, we recommend that PJM consider increasing the price cap in the LDAs to at least 1.7× Net CONE (even if not doing so on a system-wide basis). We also observe that right-stretching the local curves provides additional reliability and volatility-mitigating benefit, and so we examine refinements to these options in the following section.

Table 22
Performance of 1.5× Convex Curve with Adjustments to Improve Local Reliability
(Net CONE 5% Higher for Most LDAs; 20% Higher for PS-North, DPL-South, PepCo, and ATSI-C)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Convex Tuned, 1.5x Cap															
PEPCO	$349	$137	23%	35%	0.423	0.589	540	899	106%	10%	26%	22%	$914	$488	$1,382
PS-N	$366	$149	22%	39%	0.067	0.245	237	429	104%	7%	28%	19%	$757	$356	$1,154
ATSI-C	$332	$127	21%	31%	0.630	0.748	461	686	108%	11%	23%	21%	$567	$317	$850
DPL-S	$349	$139	21%	35%	0.107	0.267	164	253	105%	8%	26%	20%	$336	$166	$511
LDA Cap at 1.7x (System Cap at 1.5x)															
PEPCO	$349	$156	17%	29%	0.218	0.360	716	899	108%	10%	20%	16%	$911	$473	$1,468
PS-N	$366	$171	17%	32%	0.045	0.196	326	429	105%	7%	22%	14%	$757	$348	$1,263
ATSI-C	$332	$142	16%	26%	0.342	0.449	566	685	109%	11%	18%	16%	$565	$313	$870
DPL-S	$349	$158	16%	30%	0.070	0.206	205	253	107%	8%	20%	16%	$335	$162	$553
Double Width															
PEPCO	$349	$128	19%	38%	0.257	0.389	682	900	108%	10%	22%	18%	$935	$531	$1,358
PS-N	$366	$136	16%	45%	0.043	0.182	343	430	105%	7%	21%	13%	$776	$410	$1,147
ATSI-C	$332	$121	17%	34%	0.398	0.507	548	685	109%	11%	19%	17%	$577	$324	$844
DPL-S	$349	$128	16%	40%	0.071	0.199	209	253	107%	8%	20%	16%	$344	$189	$509
1,500MW Min Width															
PEPCO	$349	$131	18%	39%	0.239	0.405	700	898	108%	10%	21%	17%	$929	$494	$1,389
PS-N	$366	$130	10%	49%	0.026	0.201	456	431	107%	7%	14%	9%	$781	$413	$1,153
ATSI-C	$332	$116	13%	38%	0.222	0.338	658	685	111%	11%	15%	14%	$586	$337	$854
DPL-S	$349	$102	3%	58%	0.007	0.168	438	255	114%	8%	4%	3%	$368	$234	$514
Point "a" Right-Shifted to Reliability Requirement															
PEPCO	$349	$137	23%	35%	0.301	0.439	635	899	107%	10%	23%	19%	$923	$488	$1,398
PS-N	$366	$149	22%	39%	0.050	0.197	305	429	105%	7%	22%	15%	$764	$357	$1,168
ATSI-C	$332	$127	21%	31%	0.455	0.565	521	686	109%	11%	21%	18%	$571	$317	$859
DPL-S	$349	$139	21%	35%	0.079	0.213	196	253	106%	8%	21%	16%	$339	$167	$517

Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

2. Mitigating the Impacts of CETL Volatility and Import Dependence

In the prior sections, we discussed two related concerns: (1) that all LDAs are subject to price spikes, of which volatility in CETL is a substantial driver; and (2) the most import-dependent LDAs are susceptible to a greater frequency of low reliability events. We evaluate here options for mitigating against both concerns, by combining a higher LDA price cap at 1.7× Net CONE with various options for right-stretching the local curves. Under each case, we adopt the same modeling assumptions described in the prior section, and again report results only for the most import-constrained LDAs where we assume Net CONE at 20% above the parent value.

We evaluate two of the same right-stretching options evaluated in the prior section (doubling the width, and imposing a 1,500 MW minimum width) combined with a higher price cap. We also test the impacts of imposing a minimum width at 25% or 50% of CETL, in order to tie the level of right-stretching more closely with both LDA size (which approximately scales with CETL) as well as the level of import dependence. The resulting curve widths under each case are summarized in Table 23, along with a comparison to the current VRR curve width as well as the 2016/17 CETL and Reliability Requirement parameters in each location.

Table 23
VRR Curve Width under 1.5× Convex Curve, and if Stretched by Varying Amounts

LDA	2016/17 Parameters				Absolute Width					Width Normalized by Reliability Requirement				
	RR *(MW)*	CETL *(MW)*	VRR Curve Width *(MW)*	VRR Curve Width *(%)*	1.5 Convex *(MW)*	Double Width *(MW)*	1,500 MW Min Width *(MW)*	Min Width 25% of CETL *(MW)*	Min Width 50% of CETL *(MW)*	1.5 Convex *(%)*	Double Width *(%)*	1,500 MW Min Width *(%)*	Min Width 25% of CETL *(%)*	Min Width 50% of CETL *(%)*
MAAC	72,299	6,155	5,003	6.9%	5,639	11,279	5,639	5,639	5,639	7.8%	15.6%	7.8%	7.8%	7.8%
EMAAC	39,694	8,286	2,747	6.9%	3,096	6,192	3,096	3,096	4,143	7.8%	15.6%	7.8%	7.8%	10.4%
SWMAAC	17,316	7,140	1,198	6.9%	1,351	2,701	1,500	1,785	3,570	7.8%	15.6%	8.7%	10.3%	20.6%
ATSI	16,255	7,256	1,125	6.9%	1,268	2,536	1,500	1,814	3,628	7.8%	15.6%	9.2%	11.2%	22.3%
PSEG	12,870	6,241	891	6.9%	1,004	2,008	1,500	1,560	3,121	7.8%	15.6%	11.7%	12.1%	24.2%
PEPCO	9,012	5,733	624	6.9%	703	1,406	1,500	1,433	2,867	7.8%	15.6%	16.6%	15.9%	31.8%
PSEG-N	6,440	2,733	446	6.9%	502	1,005	1,500	683	1,367	7.8%	15.6%	23.3%	10.6%	21.2%
ATSI-C	6,164	5,093	427	6.9%	481	962	1,500	1,273	2,546	7.8%	15.6%	24.3%	20.7%	41.3%
DPL-S	3,160	1,836	219	6.9%	246	493	1,500	459	918	7.8%	15.6%	47.5%	14.5%	29.1%

Note:
Curve widths represent the difference between point "a" and point "c" on the VRR Curve, relative to 2016/17 parameters.

Table 24 summarizes curve performance under each of these options, combined with a higher LDA price cap at 1.7× Net CONE. As expected, the widest-stretched curves provide the greatest reliability and price volatility benefits. However, these benefits come at the expense of increasing the average quantity of supply, which increases average customer costs in that LDA by a proportional amount.[73] Increasing the width of the curves in proportion to CETL appears to be the most attractive of these options, as the consequence is to provide the most reliability benefit in the locations where the additional local supply is needed most. While increasing the width to a bit more than 50% of CETL would be necessary to fully meet the 0.04 LOLE standard in all of these LDAs with Net CONE 20% higher than parent, we recommend the more modest 25% minimum width because this adjustment achieves most of the reliability benefits at only about 30% of the cost compared to the 50% higher case.

[73] Note that aggregate system costs increase only marginally because increasing the quantity procured in an LDA does not increase the total system procurement but only shifts the location of that procurement from a higher-level to lower-level LDA, resulting in a small total system cost increase equal to the quantity of supply shifted times the Net CONE differential between the two locations. However, *customer costs* within that LDA *do* increase relatively proportionally to any right-shift in demand curves for that sub-region, because the share of procurement costs borne by local customer's increases.

Table 24
Performance of 1.5× Convex Curve with LDA Cap increased to 1.7× and LDA Curve Width Right-Stretched by Varying Amounts
(Net CONE 5% Higher for Most LDAs; 20% Higher for PS-North, DPL-South, PepCo, and ATSI-C)

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
LDA Cap at 1.7x Net CONE															
PEPCO	$349	$156	17%	29%	0.218	0.360	716	899	108%	10%	20%	16%	$911	$473	$1,468
PS-N	$366	$171	17%	32%	0.045	0.196	326	429	105%	7%	22%	14%	$757	$348	$1,263
ATSI-C	$332	$142	16%	26%	0.342	0.449	566	685	109%	11%	18%	16%	$565	$313	$870
DPL-S	$349	$158	16%	30%	0.070	0.206	205	253	107%	8%	20%	16%	$335	$162	$553
LDA Cap at 1.7x Net CONE, Double Width of Curves															
PEPCO	$349	$147	14%	32%	0.135	0.252	853	899	110%	10%	16%	14%	$932	$510	$1,450
PS-N	$366	$156	11%	38%	0.029	0.154	426	430	107%	7%	15%	9%	$774	$391	$1,236
ATSI-C	$332	$135	13%	30%	0.206	0.307	662	685	111%	11%	15%	13%	$576	$320	$871
DPL-S	$349	$146	12%	35%	0.044	0.160	254	253	108%	8%	15%	11%	$343	$179	$542
LDA Cap at 1.7x Net CONE, 1,500MW Min Width of Curves															
PEPCO	$349	$150	14%	33%	0.125	0.266	871	897	110%	10%	16%	13%	$926	$483	$1,479
PS-N	$366	$150	8%	44%	0.018	0.166	539	430	108%	7%	9%	6%	$782	$396	$1,241
ATSI-C	$332	$131	11%	33%	0.109	0.215	781	684	113%	11%	13%	11%	$584	$329	$886
DPL-S	$349	$118	2%	55%	0.004	0.142	486	254	115%	8%	3%	2%	$367	$225	$547
LDA Cap at 1.7x Net CONE, Min Width of Curves at 25% of CETL															
PEPCO	$349	$150	14%	32%	0.132	0.270	857	897	110%	10%	16%	14%	$925	$485	$1,476
PS-N	$366	$167	15%	34%	0.039	0.186	363	429	106%	7%	19%	11%	$761	$356	$1,261
ATSI-C	$332	$133	12%	32%	0.143	0.248	730	684	112%	11%	13%	12%	$580	$327	$880
DPL-S	$349	$152	13%	33%	0.047	0.185	247	253	108%	8%	16%	12%	$339	$168	$553
LDA Cap at 1.7x Net CONE, Min Width of Curves at 50% of CETL															
PEPCO	$349	$137	8%	41%	0.046	0.174	1,150	897	113%	10%	10%	8%	$962	$522	$1,486
PS-N	$366	$150	9%	43%	0.021	0.161	503	430	108%	7%	11%	7%	$783	$402	$1,230
ATSI-C	$332	$118	6%	41%	0.033	0.129	1,008	684	116%	11%	8%	6%	$611	$359	$897
DPL-S	$349	$136	6%	45%	0.018	0.153	347	253	111%	8%	8%	5%	$352	$191	$552

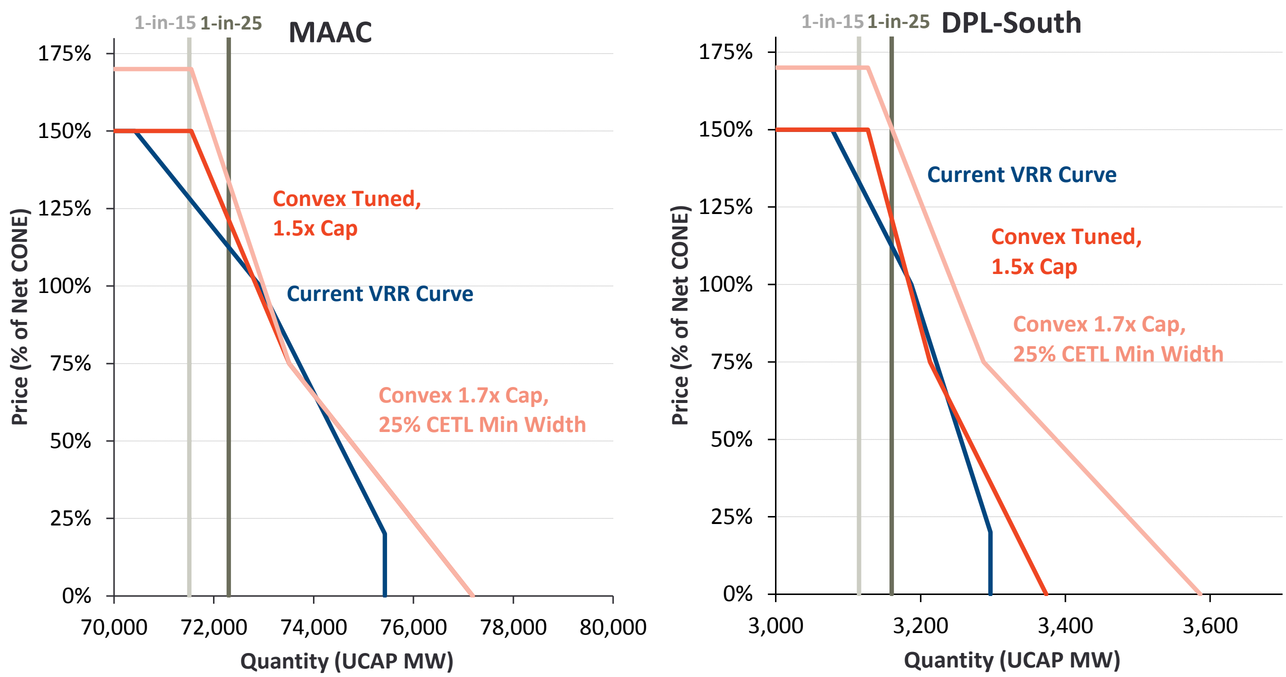
Notes:
Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

3. Performance after Recommended Adjustments

We provide here additional results illustrating the performance of the LDA VRR curves if adopting each of the recommended adjustments. The resulting curves are illustrated in Figure 30 for the largest LDA MAAC and the smallest LDA DPL-South, compared to the current VRR Curve. Parameters for the rest of the LDAs are summarized in Table 25. These adjusted LDA curves reflect the following progressive refinements: (a) start with the 1.5× Convex Tuned curve, adapted to the LDA level; (b) increase the price cap to 1.7× Net CONE for the LDAs, without adjusting the other curve parameters; and (c) right-stretch the curves to a minimum width of 25% of the LDA CETL value.

As shown in Table 26, the adjusted curves show substantially improved reliability performance compared to the current VRR curve, with all LDAs achieving the reliability objective if Net CONE is at a typical level of approximately 5% above the parent LDA level. Under a more stressed case where the most import-constrained LDAs have Net CONE 20% above parent, only one of these LDAs continues to meet the reliability objective but the reliability impacts of falling short are substantially mitigated, with the lowest-reliability LDA having LOLE 70% lower than under the current VRR curve in the same sensitivity case. Finally, the reliability impacts are substantially mitigated in the presence of under-estimates to Net CONE, with LOLE in the most-affected LDA dropping by 80% compared to the same sensitivity case under the current VRR curve.

Figure 30
PJM's Current VRR Curve Compared to Recommended Local Curve
(LDA Price Cap increased to 1.7× Net CONE, with Minimum Width at 25% of CETL)



Sources and Notes:

Current VRR Curve reflects the locational VRR curve parameters for MAAC and DPL-South in the 2016/2017 PJM Planning Parameters. See PJM (2013a.)

Convex Tuned, 1.5× Cap shows our recommended curve for system applied to the MAAC and DPL-South.

Convex 1.7× Cap, 25% CETL Min Width modifies the Convex Tuned 1.5× CAP by raising the cap to 1.7× Net CONE, and stretching points "b" and "c" such that the width of the curve ("the distance between "a' and "c") is at least 25% of CETL.

Table 25
Resulting Curve Width by LDA, if Applying a Minimum Width of 25% CETL

LDA	Absolute Curve Width			Curve Width (% of RR)		
	Current VRR *(MW)*	Convex Tuned *(MW)*	Min Width 25% of CETL *(MW)*	Current VRR *(%)*	Convex Tuned *(%)*	Min Width 25% of CETL *(%)*
MAAC	5,003	5,639	5,639	6.9%	7.8%	7.8%
EMAAC	2,747	3,096	3,096	6.9%	7.8%	7.8%
SWMAAC	1,198	1,351	1,785	6.9%	7.8%	10.3%
ATSI	1,125	1,268	1,814	6.9%	7.8%	11.2%
PSEG	891	1,004	1,560	6.9%	7.8%	12.1%
PEPCO	624	703	1,433	6.9%	7.8%	15.9%
PSEG-N	446	502	683	6.9%	7.8%	10.6%
ATSI-Cleveland	427	481	1,273	6.9%	7.8%	20.7%
DPL-S	219	246	459	6.9%	7.8%	14.5%

Sources and Notes:
"Width" is defined as the horizontal distance from point "a" at the cap to "c" at the bottom of the curve, expressed in in UCAP terms and as a percentage of the Reliability Requirement.

Table 26
Performance of 1.5× Convex Curve with LDA Cap at 1.7× and Minimum Width of 25% CETL

	Price				Reliability								Procurement Costs		
	Average	St. Dev	Freq. at Cap	Freq. of Price Separation	Conditional Average LOLE	Conditional Average LOLE (Additive)	Average Excess (Deficit) Above Rel. Req.	St. Dev.	Average Quantity as % of Rel. Req.	St. Dev. as % of Rel. Req.	Freq. Below Rel. Req.	Freq. Below 1-in-15	Average	Average of Bottom 20%	Average of Top 20%
	($/MW-d)	*($/MW-d)*	*(%)*	*(%)*	*(Ev/Yr)*	*(Ev/Yr)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*($mil)*	*($mil)*	*($mil)*
Net CONE 5% Higher than Parent															
MAAC	$277	$103	9%	24%	0.030	0.116	2,113	2,301	103%	3%	17%	9%	$7,211	$3,997	$11,589
EMAAC	$291	$115	9%	19%	0.020	0.137	1,829	1,691	105%	4%	14%	8%	$4,054	$2,168	$6,583
SWMAAC	$291	$112	6%	15%	0.020	0.136	1,531	1,154	109%	7%	7%	5%	$1,691	$922	$2,720
ATSI	$277	$98	6%	15%	0.018	0.104	1,486	1,120	109%	7%	8%	6%	$1,481	$879	$2,225
PSEG	$305	$122	4%	13%	0.010	0.147	1,317	883	110%	7%	6%	4%	$1,354	$697	$2,184
PEPCO	$305	$119	5%	12%	0.017	0.154	1,422	919	116%	10%	6%	4%	$859	$452	$1,394
PS-N	$321	$133	5%	13%	0.012	0.159	637	442	110%	7%	7%	4%	$689	$340	$1,147
ATSI-C	$291	$105	4%	12%	0.014	0.118	1,169	694	119%	11%	4%	4%	$539	$304	$833
DPL-S	$305	$122	4%	14%	0.012	0.148	391	258	112%	8%	5%	3%	$309	$159	$505
Net CONE 5% Higher than Parent, 20% in Smallest LDAs															
MAAC	$277	$104	9%	24%	0.030	0.117	2,115	2,308	103%	3%	17%	9%	$7,342	$4,113	$11,678
EMAAC	$291	$116	9%	19%	0.020	0.137	1,841	1,695	105%	4%	14%	8%	$4,139	$2,215	$6,658
SWMAAC	$291	$112	6%	15%	0.021	0.138	1,529	1,158	109%	7%	8%	5%	$1,736	$955	$2,750
ATSI	$277	$98	6%	15%	0.018	0.104	1,488	1,120	109%	7%	8%	6%	$1,505	$900	$2,241
PSEG	$305	$123	4%	13%	0.011	0.148	1,318	884	110%	7%	6%	4%	$1,418	$714	$2,255
PEPCO	$349	$150	14%	32%	0.132	0.270	857	897	110%	10%	16%	14%	$925	$485	$1,476
PS-N	$366	$167	15%	34%	0.039	0.186	363	429	106%	7%	19%	11%	$761	$356	$1,261
ATSI-C	$332	$133	12%	32%	0.143	0.248	730	684	112%	11%	13%	12%	$580	$327	$880
DPL-S	$349	$152	13%	33%	0.047	0.185	247	253	108%	8%	16%	12%	$339	$168	$553
Net CONE 5% Higher than Parent with 20% Under-Estimate															
MAAC	$277	$78	20%	31%	0.069	0.279	1,177	2,460	102%	3%	30%	20%	$7,162	$4,375	$10,201
EMAAC	$291	$88	20%	30%	0.049	0.328	983	1,745	102%	4%	29%	19%	$4,031	$2,376	$5,855
SWMAAC	$291	$85	14%	22%	0.066	0.345	1,055	1,175	106%	7%	19%	12%	$1,683	$1,006	$2,407
ATSI	$277	$73	13%	22%	0.047	0.257	1,023	1,126	106%	7%	17%	13%	$1,469	$947	$1,972
PSEG	$305	$93	12%	19%	0.028	0.356	962	893	108%	7%	15%	11%	$1,345	$770	$1,936
PEPCO	$305	$89	10%	19%	0.089	0.434	1,033	927	112%	10%	13%	10%	$858	$504	$1,252
PS-N	$321	$101	12%	20%	0.032	0.388	430	445	107%	7%	16%	10%	$686	$378	$1,002
ATSI-C	$291	$78	9%	17%	0.076	0.333	871	693	114%	11%	10%	9%	$536	$334	$761
DPL-S	$305	$93	9%	18%	0.030	0.358	299	258	110%	8%	12%	8%	$308	$173	$454

Notes:

Capacity procurement costs are inclusive of higher-cost procurement in import-constrained sub-LDAs.

D. Recommendations for Locational Curves

Similar to the system, the local VRR curves have maintained reliability to date. However, the forward-looking concerns we identified for the system also exist for modeled LDAs, but to a greater extent due to the LDAs' susceptibility to changes in CETL, their smaller size relative to likely shocks, and the challenge of attracting investments in small LDAs where the local Net CONE is higher than in the parent zone. Our simulations demonstrate these risks and show that the existing VRR curves would not likely achieve the 1-in-25 conditional target, with the greatest susceptibility in the most import-dependent LDAs and LDAs with Net CONE substantially above the parent LDA Net CONE. To ensure more robust performance from a reliability perspective, provide more price stability, and produce prices that are more reflective of local reliability value, we recommend that PJM and stakeholders consider the following changes to local VRR curves:

1. **Adopt the changes we recommended for the system VRR curve**. We find that right-shifting point "a" and stretching the curve into a convex shape offer improvements over the current VRR curve and are a good starting point for the incremental refinements defined below.
2. **Increase the LDA price cap to 1.7× Net CONE**. We find that a higher cap substantially improves simulated outcomes in LDAs because it introduces stronger price signals when supplies become scarce. The prospect of higher prices during low reliability outcomes provides greater incentives for suppliers to locate there rather than in the parent LDA. This change would also provide substantial protection against the risks of under-procurement in stress scenarios.
3. **Impose a minimum curve width equal to 25% of CETL**. We find that raising the LDA price cap to 1.7× Net CONE would not by itself achieve the local reliability objective in a realistic stress scenario with Net CONE in an LDA is substantially above the parent level, with even larger gaps under a sensitivity scenario with under-estimated Net CONE. Performance is worst in the smallest, most import-dependent zones. To address this gap, we find that applying a minimum curve width based on CETL to be a targeted and effective way to improve performance.

In addition, we have four other recommendations affecting local VRR curves, although they are not strictly about the VRR curve shape and thus are not directly within the scope of the review prescribed in PJM's tariff:

1. **Consider defining local reliability objectives in terms of normalized unserved energy.** As discussed in Section VI.A.2, we recommend that PJM evaluate options for revising the definition of local reliability objective, currently set at a 1-in-25 conditional LOLE standard. Instead, PJM could explore options for an alternative standard based on normalized expected unserved energy, which is the expected outage rate as a percentage of total load. We also recommend exploring this alternative standard based on a multi-area reliability model that simultaneously estimates the location-specific EUE among different PJM system and sub-regions. The result would be a reliability standard that better accounts for the level of correlation between system-wide and local generation outages, and results in a more uniform level of reliability for LDAs of different sizes and import dependence.
2. **Consider alternatives to the "nested" LDA structure.** As discussed in Section VI.A.4, we recommend that PJM consider generalizing its approach to modeling locational constraints in RPM beyond import-constrained, nested LDAs with a single import limit. As the number of modeled LDAs increases and the system reserve margin decreases, we see the potential for different types of constraints emerging that do not correspond to a strictly nested model. A more generalized "meshed" LDA model (with simultaneous clearing during the auction) would explicitly allow for the possibility that some locations may be export-constrained, that some LDAs may have multiple transmission import paths, and some may have the possibility of being either import- or export-constrained, depending on RPM auction outcomes.
3. **Evaluate options for increasing stability of Capacity Emergency Transfer Limits (CETL).** As discussed in Section VI.A.4, we recommend that PJM continue to review its options for

increasing the predictability and stability of its CETL estimates. Based on our simulation results, we find that reducing CETL uncertainty could significantly reduce capacity price volatility in LDAs. Physical changes to the transmission system would need to continue to be reflected as changes in CETL, but reducing uncertainty would provide substantial benefits in reducing price volatility. We have provided more detailed suggestions on options to evaluate for mitigating volatility in CETL in our 2011 RPM Review.

4. **Consider revising the RPM auction clearing mechanics within LDAs based on delivered reliability value.** As another option for enhancing locational capacity price stability and overall efficiency, we recommend that PJM consider revising its auction clearing mechanics to produce prices that are more proportional to the marginal reliability value of incremental resources in each LDA. Such a mechanism would determine the lowest-cost resources for achieving local reliability objectives by selecting either: (a) a greater quantity of lower-cost imports from outside the LDA, but recognizing the lower reliability of imported resources (due to added transmission import capability risk and lost diversity benefits as an LDA becomes more import-dependent); or (b) a smaller quantity of locally-sourced resources with greater reliability value (*i.e.*, without the additional transmission availability risk). This approach would also stabilize LDA pricing by allowing for more gradual price separation as an LDA becomes more import-dependent (rather than price-separating only once the administratively-set import constraints bind).

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List of Acronyms

AECO	Atlantic City Electric Company
AEP	American Electric Power
APS	Allegheny Power System
A/S	Ancillary Service
ATSI	American Transmission Systems, Inc. (a FirstEnergy subsidiary)
ATSI-C	American Transmission Systems, Inc.-Cleveland
ATWACC	After-Tax Weighted-Average Cost Of Capital
BGE	Baltimore Gas and Electric Company
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
CC	Combined Cycle
CETL	Capacity Emergency Transfer Limit
ComEd	Commonwealth Edison, Exelon Corporation
CONE	Cost of New Entry
CT	Combustion Turbine
Dayton	Dayton Power and Light Company, aka DAY
DEOK	Duke Energy Ohio/Kentucky
DLCO	Duquesne Lighting Company, aka DUQ or DQE or DLCO
DPL-South	Delmarva Power and Light-South
DR	Demand Response
E&AS	Energy and Ancillary Services
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
FRR	Fixed Resource Requirement
H-W	Handy-Whitman Index
IA	Incremental Auction

IMM	Independent Market Monitor
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	ISO New England
JCPL	Jersey Central Power and Light Company
kW	Kilowatt
kWh	Kilowatt Hours
LDA	Locational Deliverability Area
LMP	Locational Marginal Price
LOLE	Loss of Load Event
LSE	Load-Serving Entities
MAAC	Mid-Atlantic Area Council
MetEd	Metropolitan Edison Company
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt Hours
NYISO	New York ISO
OATT	Open Access Transmission Tariff
PECO	PECO Energy Company, Exelon Corporation, aka PE
PenElec	Pennsylvania Electric Company
PepCo	Potomac Electric Power Company
PJM	PJM Interconnection, LLC
PPI	Producer Price Index
PPL	Pennsylvania Power and Light Company
PS-North	Public Service Enterprise Group-North
PSEG	Public Service Enterprise Group
PSEG North	Public Service Enterprise Group-North
QCEW	Quarterly Census of Employment and Wages
RECO	Rockland Electric Company
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization

STRPT	Short-Term Resource Procurement Target
SWMAAC	Southwestern Mid-Atlantic Area Council
UCAP	Unforced Capacity
VOM	Variable Operations and Maintenance
VRR	Variable Resource Requirement
WMAAC	Western Mid-Atlantic Area Council

Appendix A: Magnitude and Implementation of Monte Carlo Shocks

In this appendix we provide additional detail on our approach to estimating and implementing a realistic magnitude of shocks into our Monte Carlo simulation modeling, including shocks to: (1) supply offer quantity; (2) load forecast and Reliability Requirement; (3) administrative net CONE; and (4) CETL. A summary of these shocks and the combined supply minus demand shocks in each location is included in Section IV.C above.

A1. Shocks to Supply Offer Quantity

We estimate gross supply shocks based on the range of actual total supply offer quantities in historical BRAs over delivery years 2009/10 to 2016/17, based on offer data provided by PJM. Table 27 summarizes the total supply offered by LDA, as well as several series of historical shocks calculated in differed ways, based the distributions of total supply offers, year-to-year changes in supply offers, and differences in supply offers relative to a linear time trend. We determine reasonable supply shock magnitudes based on the historical shocks as an exponential function of LDA size, resulting in the final supply shock values shown in column 7 of Table 27.

Table 27
Shocks to Supply Offers

		Total Supply Offered by Delivery Year								Standard Deviation of Historical "Shocks"						Simulated Shock Std. Dev
		2009	2010	2011	2012	2013	2014	2015	2016	Total Offers	Annual Change in Offer	Diff. from Trend	Total Offers	Annual Change in Offer	Diff. from Trend	
		(MW)	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(MW)*
										[1]	[2]	[3]	[4]	[5]	[6]	[7]
RTO Including Subzones																
Total Offered (No Adjustments)		133,551	133,093	137,720	145,373	160,898	160,486	178,588	184,380	20,040	7,229	4,816	13%	5%	3%	4,054
Adjust for Expansions Only	[A]	133,551	133,093	137,057	144,333	146,479	146,646	163,802	165,729	12,594	6,105	3,983	9%	4%	3%	
Adjust for FRR Only	[B]	133,551	133,093	137,720	145,373	160,898	160,486	163,231	169,023	14,604	5,518	3,878	10%	4%	3%	
Adjust for Expansions and FRR	[C]	133,551	133,093	137,057	144,333	146,479	146,646	158,769	160,696	10,537	4,452	2,697	7%	3%	2%	
Parent LDAs Including Sub-LDAs																
MAAC		63,443	63,919	65,582	68,283	68,338	70,885	74,261	71,608	3,842	2,069	1,229	6%	3%	2%	2,767
EMAAC		31,684	31,218	32,034	32,983	33,007	34,520	37,226	34,140	1,939	1,829	1,102	6%	5%	3%	1,591
SWMAAC		10,312	10,928	11,651	12,396	11,768	12,458	12,722	12,386	843	562	409	7%	5%	3%	644
ATSI		n/a	n/a	n/a	n/a	13,335	12,679	11,777	12,791	646	1,043	557	5%	8%	4%	663
PSEG		6,957	7,220	7,403	7,431	8,033	8,184	8,964	6,784	725	987	657	10%	13%	9%	363
Average LDA Shock										**1,599**	**1,298**	**791**	**7%**	**7%**	**4%**	
Smallest LDAs																
PEPCO		5,064	5,498	5,670	5,382	5,289	5,875	6,235	6,126	412	325	234	7%	6%	4%	328
PS-North		3,767	3,871	4,010	3,420	4,173	4,170	4,931	4,182	436	586	338	11%	14%	8%	226
ATSI-Cleveland		n/a	n/a	n/a	n/a	2,232	2,341	1,657	2,874	499	956	473	22%	42%	21%	157
DPL-South		1,587	1,546	1,486	1,499	1,612	1,600	1,768	1,764	108	84	70	7%	5%	4%	97
Average LDA Shock										**364**	**488**	**279**	**12%**	**17%**	**9%**	

Sources and Notes:

[A] Supply located in ATSI, DEOK, and East Kentucky Power Cooperative, Inc. (EKPC) zones are subtracted from Rest of RTO Supply.

[B] Supply from FRR is subtracted from Rest of RTO Supply in 2015/16. Supply from FRR is assumed to be equal to the decrease in the FRR obligation between 2014/14 and 2015/16.

[C] The adjustments from [A] and [B] are combined. For the FRR, adjustment, the portion of the decrease in FRR obligation due to DEOK is not included.

[1] Standard deviation of total supply offers by delivery year.

[2] Standard deviation of year to year delta in total supply offer.

[3] Standard deviation of MW difference from a linear time trend of total supply offer.

[4] Column [1] divided by average total historical supply offer.

[5] Column [2] divided by average total historical supply offer.

[6] Column [3] divided by average total historical supply offer.

[7] Exponential formula of column [6] and average total historical supply offer

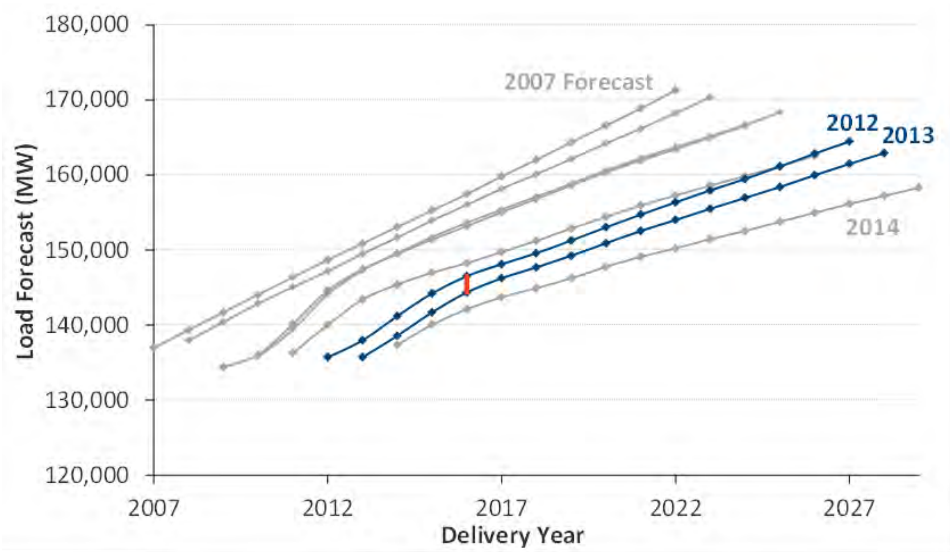
A2. SHOCKS TO LOAD FORECAST AND RELIABILITY REQUIREMENT

We estimate demand shocks in two components: (1) shocks to load forecast, and (2) shocks to the Reliability Requirement expressed as a percentage of system or local peak load. We estimate the shocks to system load forecast as a normally-distributed distribution around the expected value, based on historical year-to year changes in annual load forecasts. We calculate historical shocks to the system load forecast as the delta between four- and three-year ahead forecasts for the same delivery year, as illustrated in Figure 31.[74] The resulting standard deviation of the system shocks is 0.8% of the expected RTO system-wide peak load. Note that this calculated shock measures

74 See PJM Load Forecasts PJM (2007 – 2014).

only the *uncertainty* in year-to-year changes in the load forecast, but excludes any *bias* in the load forecast.

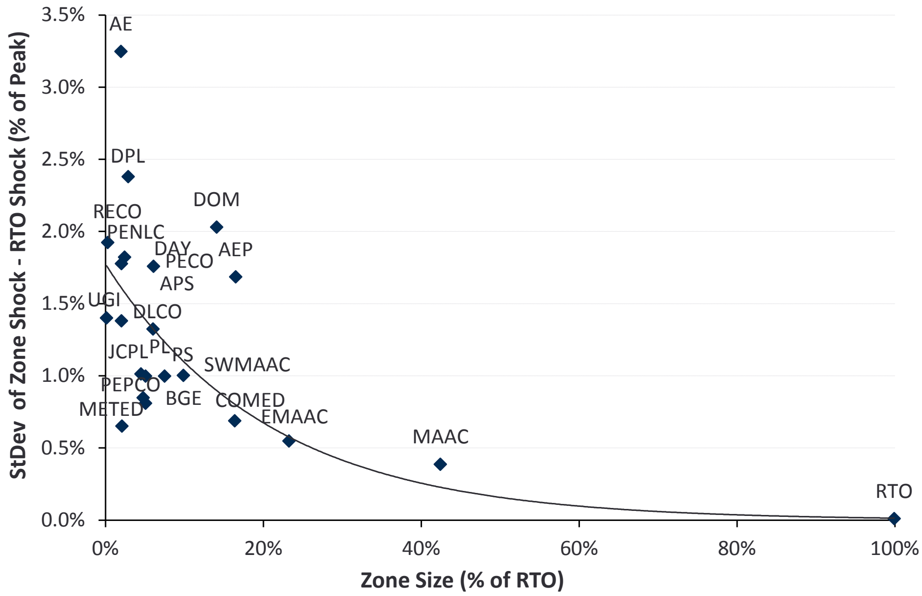
Figure 31
RTO Load Forecast



Sources and Notes:
Load forecasts as reported in PJM Load Forecast Reports. See PJM (2007 – 2014).

To develop peak load shocks for the LDAs, we use a similar method but account for correlations between the shocks to the LDA peak load, the system peak load, and the parent LDA's peak load. In particular, we generate shocks for the smallest LDAs as the system shock plus an independently-generated shock that depends on LDA size, as shown in Figure 32. Bigger LDAs aggregate small LDA shocks and an appropriately-sized "rest of" LDA shock. The "Rest of" LDA includes all the zones within this LDA that are not part of a sub-LDA. Table 28 shows the aggregate load forecast shocks for the RTO and all LDAs.

Figure 32
LDA Load Forecast Error Shock
(Zone or LDA Shock minus RTO Shock)



Sources and Notes:
Standard Deviation of Zone Shock minus RTO shock calculated based on historic PJM Load Forecast Reports. See PJM (2007 – 2014.)
Zone Size calculated based on 2016/17 Reliability Requirement. See PJM (2013a.)

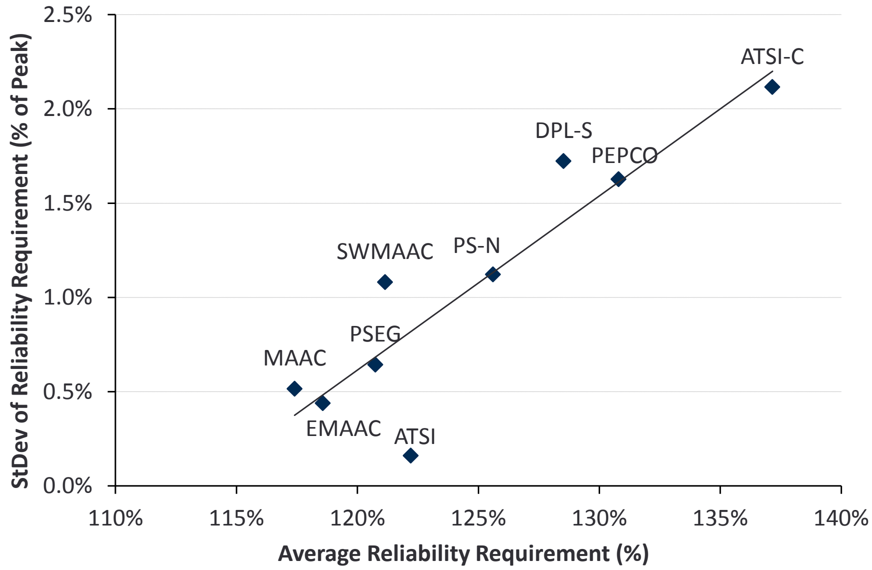
Table 28
Aggregate RTO and LDA Load Forecast Shocks

Location	**Base Assumptions 2016/17**		**Simulated Shock Standard Deviation**			Historical
	Peak Load	Total Shocks	RTO-Correlated Shock	Shock on Top of RTO	Total Shock	Load Forecast Shocks
	(MW)	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*
RTO	152,383	1,237	0.8%	0.0%	0.8%	0.8%
MAAC	61,080	604	0.8%	0.6%	1.0%	1.0%
EMAAC	33,299	373	0.8%	0.8%	1.1%	1.3%
SWMAAC	14,088	187	0.8%	1.1%	1.3%	1.2%
ATSI	13,295	183	0.8%	1.1%	1.4%	1.3%
PSEG	10,600	158	0.8%	1.3%	1.5%	1.3%
PEPCO	6,800	114	0.8%	1.5%	1.7%	1.0%
PS-N	5,141	87	0.8%	1.5%	1.7%	n/a
ATSI-C	4,562	77	0.8%	1.5%	1.7%	n/a
DPL-S	2,439	46	0.8%	1.7%	1.9%	n/a

Sources and Notes:
Peak Load from PJM 2016/17 Planning Parameters, see PJM (2013a.)
RTO-Correlated Shock and Shock on top of RTO are treated as independent random variables.

We calculate the total Reliability Requirement shock as equal to the load forecast shock plus an independent shock to the Reliability Requirement itself (when expressed as a percentage of peak load). For the RTO, we estimate a standard deviation of 0.4% in the Reliability Requirement based on historical planning parameters.[75] For the LDAs, the standard deviation of the Reliability Requirement increases with its percentage of peak load, as shown Figure 33. Table 29 below shows the total Reliability Requirement shocks for RTO and the LDAs, including shocks to both load forecast and the Reliability Requirement as a percent of peak load.

Figure 33
Shocks to LDA Reliability Requirement
(Expressed as % of Peak Load)



Sources and Notes:
LDA Reliability Requirement and Peak Load from Planning Parameters, PJM (2007 – 2013a).

Table 29
RTO and LDA Reliability Requirement Shocks

Location	2016/17 Reliability Requirement (MW)	2016/17 Reliability Requirement (% of Peak)	Simulation Shock Standard Deviations: Reliability Requirement (% of Peak)	Simulation Shock Standard Deviations: Load Forecast (MW)	Simulation Shock Standard Deviations: Total Load Forecast + RR (MW)	Historical Reliability Requirement StDev (% of Peak)
RTO	166,128	109%	0.4%	1,237	1,499	0.4%
MAAC	72,299	118%	0.4%	604	794	0.5%
EMAAC	39,694	119%	0.5%	373	492	0.4%
SWMAAC	17,316	123%	0.7%	187	279	1.1%
ATSI	16,255	122%	0.8%	183	259	0.2%
PS	12,870	121%	0.7%	158	215	0.6%
PEPCO	9,012	133%	1.6%	114	220	1.6%
PS NORTH	6,440	125%	1.1%	87	131	1.1%
ATSI-Cleveland	6,164	135%	2.2%	77	164	2.1%
DPL SOUTH	3,160	130%	1.4%	46	76	1.7%

Sources and Notes:
2016/17 Reliability Requirement and Peak Load taken from PJM Planning Parameters. See PJM (2013a.)
Simulation Shocks represent the parameters used in modeling.

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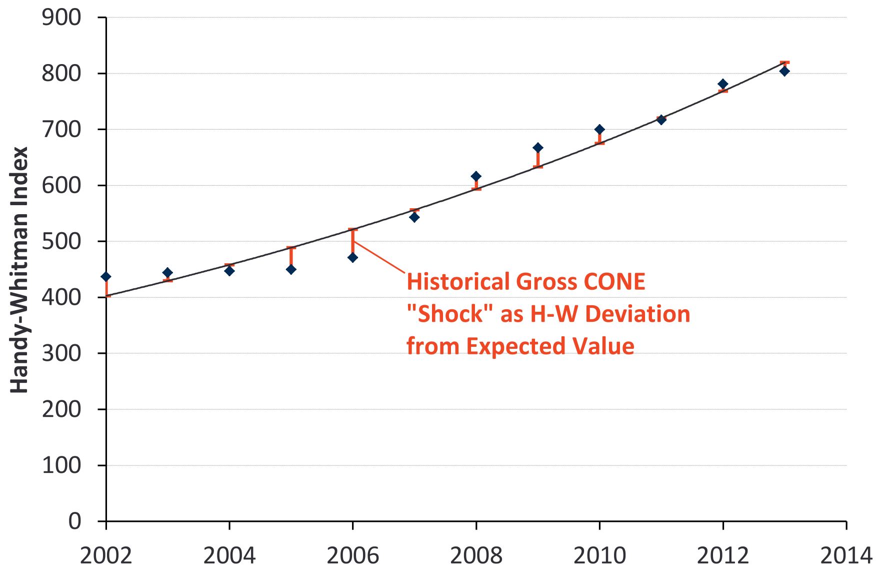
75 See PJM (2007 – 2013a.)

A3. Shocks to Administrative Net CONE

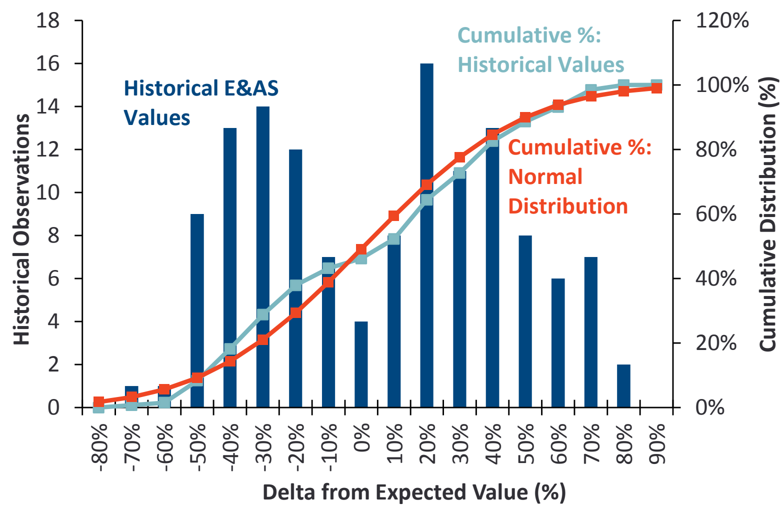
We develop Net CONE shocks as the sum of shocks to Gross CONE and a 3-year average E&AS shock. We model Gross CONE shocks of 5.4% based on deviations in the Handy-Whitman Index away from a long-term trend, as illustrated in Figure 34. For the E&AS shocks, we find the deviation of administrative E&AS estimates in each year from a fitted trend over 2002-2013. The standard deviation of these one-year historical E&AS estimates around the expected value is 38%, as summarized in Figure 35, which compares the one-year E&AS shocks relative to a normal distribution.

Figure 34
Handy-Whitman Index



Sources and Notes:
Based on the Handy-Whitman index issued in July of each year, see Whitman (2014).

Figure 35
One-Year E&AS Shocks



Consistent with the current PJM administrative Net CONE methodology, we estimate E&AS offset based on a rolling three-year average E&AS (or the average of three independent draws from the one-year E&AS distribution shown above). This results in a 22% standard deviation in the three-year average E&AS offset, compared to a 38% standard deviation in the one-year E&AS offset. The resulting standard deviation in administrative Net CONE combines the shocks in both Gross CONE and E&AS as summarized in Table 30, resulting in a an 8% standard deviation in administrative Net CONE for RTO under our base case assumptions.

Table 30
Shocks to Administrative Net CONE

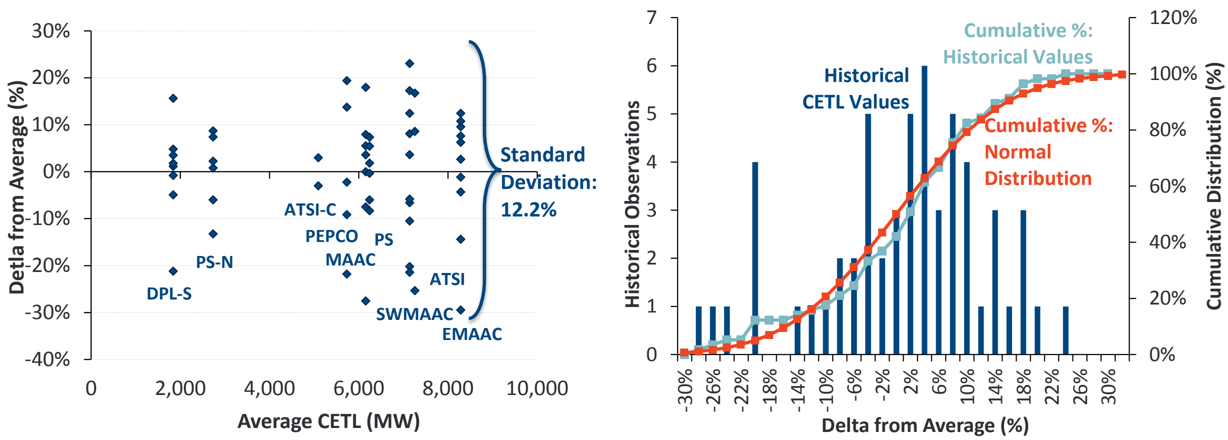
LDA	**Base Assumptions from 2016/2017**				**Standard Deviation of Shock Components**				Historical
	Expected Gross CONE *($/MW-d)*	Expected E&AS *($/MW-d)*	Expected Net CONE *($/MW-d)*	Shocks to Net CONE *($/MW-d)*	Gross CONE *(%)*	One-Year E&AS *(%)*	Three-Year E&AS *(%)*	Net CONE *(%)*	Shocks to Net CONE *(%)*
RTO	$405	$74	$331	$26	5.4%	38.4%	22.1%	8.0%	5.5%
ATSI	$405	$43	$363	$23	5.4%	38.4%	22.1%	6.4%	1.1%
ATSI-C	$405	$43	$363	$23	5.4%	38.4%	22.1%	6.4%	1.1%
MAAC	$413	$136	$277	$36	5.4%	38.4%	22.1%	13.1%	18.8%
EMAAC	$443	$113	$330	$33	5.4%	38.4%	22.1%	10.1%	9.8%
SWMAAC	$413	$136	$277	$36	5.4%	38.4%	22.1%	13.1%	12.8%
PSEG	$443	$113	$330	$33	5.4%	38.4%	22.1%	10.1%	3.0%
DPL-S	$443	$113	$330	$33	5.4%	38.4%	22.1%	10.1%	5.2%
PS-N	$443	$113	$330	$33	5.4%	38.4%	22.1%	10.1%	3.0%
PEPCO	$413	$136	$277	$36	5.4%	38.4%	22.1%	13.1%	4.6%

Sources and Notes:
Expected Gross CONE, E&AS, and Net CONE consistent with 2016/17 Planning Parameters, see PJM (2013a.)
Historical shocks expressed as average of deviations from "trend" in Net CONE, although most LDAs have few data points.

A4. Shocks to Capacity Emergency Transfer Limit

We find that shocks are proportional to absolute CETL size but are relatively constant as a percent of CETL, as summarized in Figure 36. We estimate a 12.2% standard deviation on average across all locations in all years. We implement this 12.2% standard deviation using a normal distribution around the 2016/17 CETL value for each location as summarized in Table 31.

Figure 36
Historical CETL as Delta from Average



Sources and Notes:
Historical CETL value from PJM Planning Parameters. See PJM (2009a, 2009b, 2009. 2010, 2011, 2012, 2013a.)

Table 31
Historical and Simulation CETL Shocks

LDA	Historical CETL Values				Simulation CETL Values		
	Average *(MW)*	Standard Deviation *(MW)*	Standard Deviation *(%)*	Count	2016/17 Value *(MW)*	Standard Deviation *(MW)*	Standard Deviation *(%)*
EMAAC	8,286	1,091	13%	10	8,916	1,090	12%
SWMAAC	7,140	1,095	15%	10	8,786	1,074	12%
ATSI	7,256	1,619	22%	3	7,881	963	12%
PEPCO	5,733	964	17%	5	6,846	837	12%
PSEG	6,241	387	6%	6	6,581	804	12%
MAAC	6,155	886	14%	7	6,495	794	12%
ATSI-C	5,093	216	4%	2	5,245	641	12%
PS-North	2,733	191	10%	8	2,936	359	12%
DPL-South	1,836	228	8%	6	1,901	232	12%

Sources and Notes:
Historical CETL values from Planning Parameters, PJM (2009a, 2009b, 2010, 2011, 2012, 2013a).
Simulation CETL values are equal to 12.2% of the 2106/17 CETL value.

CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
LONDON
MADRID
ROME

THE Brattle GROUP

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. ER14-___

AFFIDAVIT

STATE OF Massachusetts)
)
CITY OF Cambridge)

DR. SAMUEL A. NEWELL, being duly sworn, deposes and states: that the Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of PJM Interconnection, L.L.C. was prepared by his or under his direct supervision, that the statements contained therein and the Attachments attached thereto are true and correct to the best of his knowledge and belief, and that he adopts such prepared testimony as his direct testimony in this proceeding.

DR. SAMUEL A. NEWELL

Subscribed and sworn to before me this 23rd day of September, 2014.

Notary Public
My Commission Expires:

JENNIFER M. OSSEN
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 11, 2016

{W0034796.1}

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. ER14-___

AFFIDAVIT

STATE OF Massachusetts)
)
CITY OF Cambridge)

DR. KATHLEEN SPEES, being duly sworn, deposes and states: that the Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of PJM Interconnection, L.L.C. was prepared by her or under her direct supervision, that the statements contained therein and the Attachments attached thereto are true and correct to the best of her knowledge and belief, and that she adopts such prepared testimony as her direct testimony in this proceeding.

DR. KATHLEEN SPEES

Subscribed and sworn to before me this 23rd day of September, 2014.

Notary Public
My Commission Expires:

JENNIFER M. OSSEN
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 11, 2016

{W0034798.1 }