Attachment D

Affidavit of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Andrew W. Thompson

Regarding the Sixth Review of PJM's Variable Resource Requirement Curve

UNITED STATES OF AMERICA BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

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|----------------------------|---|--------------------|
| PJM Interconnection L.L.C. |) | Docket No. ER26000 |
| |) | |

Affidavit of

Dr. KATHLEEN SPEES, Dr. SAMUEL A. NEWELL, and Dr. ANDREW W. THOMPSON

Regarding the SIXTH REVIEW OF PJM'S VARIABLE RESOURCE REQUIREMENT CURVE

November 7, 2025

I. Introduction

- Our names are Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Andrew W. Thompson. Dr. Spees and Dr. Newell are employed as Principals and Dr. Thompson is employed as an Energy Associate with The Brattle Group ("Brattle"). We submit this affidavit to the Federal Energy Regulatory Commission ("Commission") on behalf of PJM Interconnection, L.L.C. ("PJM") in support of its proposal to use a Variable Resource Requirement ("VRR") demand curve that employs a combustion turbine ("CT") Reference Resource for the Base Residual Auctions ("BRAs") 2028/29 to 2031/32 in PJM's capacity market, the Reliability Pricing Model ("RPM").
- Our qualifications as experts derive from our extensive experience evaluating and designing capacity markets and alternative market designs for resource adequacy. Our experience working for Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") across North America and internationally has given us a broad perspective on the practical implications of capacity market design rules under a range of different economic and policy conditions. Complete details of our qualifications, publications, reports, and prior experiences are set forth in our resumes included as Exhibit No. 1 to this affidavit.
- A subset of our market design work has focused on developing and evaluating capacity market demand curves for achieving reliability and other market design objectives. In the PJM region, we served as the experts conducting the independent review of the VRR Curve performance and parameters for the sixth VRR Curve review process conducted over the past year, and have supported all five prior reviews.¹ In other capacity markets, our experience in developing capacity market demand curves includes: (1) Midcontinent Independent System Operator's ("MISO's") reliability-based demand curves; (2) ISO New England's ("ISO-NE's") first downward-sloping demand curve design filed before the Commission; (3) a study on the economics of reliability for the Commission, including calculating a value-based capacity demand curve designed to procure an economically optimal quantity of capacity; (4) support to the Ontario Independent Electricity System Operator ("IESO") to develop its two-season capacity market demand curves; and (5) assistance in defining or refining the capacity market demand curves for four other international capacity markets.²

The full report documenting our analysis, findings, and recommendations of our independent review are included as attachments to the present filing, and are available at: Spees, Newell, Thompson, Snyder & Bartone, Sixth Review of PJM's Variable Resource Requirement Curve for Planning Years 2028/29 Through 2031/32, The Brattle Group (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf ("2025 VRR Curve Study"), attached as Exh. No. 2.

See Submittal of Midcontinent Independent System Operator, Inc., Docket No. ER23-2977-000, Tab E (Sep. 29, 2023) (Testimony of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Linquan Bai regarding an assessment of MISO's proposed Reliability Based Demand Curves (RBDCs) to be used to support resource adequacy in its

- 4. Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She 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.
- Dr. Newell is an economist and engineer with over 25 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and RTO market rules. 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.
- Or. Thompson is an energy economist with a background in electrical engineering and expertise in wholesale electricity market design, regulatory economics, and policy analysis of network industries, particularly in the energy sector. He earned a Ph.D. in Economics from the Université Paris-Saclay, an M.S. in Energy Economics from the Universidad Pontificia Comillas, an M.Sc. in Engineering and Policy Analysis from the Delft University of Technology, and a B.Sc. in Electrical and Computer Engineering from Rowan University.

Planning Resource Auctions (PRAs).); Submittal of ISO New England Inc., Docket No. ER14-1639-000, Attached Testimony of Newell and Spees (Apr. 1, 2014) (Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve.); and Johannes P. Pfeifenberger and Kathleen Spees, The Brattle Group, and Kevin Carden and Nick Wintermantel, Astrape Consulting, Resource Adequacy Requirements: Reliability and Economic Implications, Docket No. AD14-14-000, at 83-84 (Sept. 2013), http://www.brattle.com/system/publications/pdfs/000/004/984/original/Resource_Adequacy_Requirements_Pfeifenberger_Spees_FERC_Sept_2013.pdf?139230316.

II. PJM's Proposed VRR Curve Updates

- Beginning in fall 2024, PJM retained Brattle to conduct an independent review and performance assessment of its VRR Curve and parameters, as required periodically under PJM's Open Access Transmission Tariff ("Tariff"). We conducted our review with input from stakeholders within the PJM Market Implementation Committee ("MIC"), where we frequently presented and iterated on findings, analysis, and potential recommendations related to the VRR Curve parameters.³ The results of our independent review of the VRR Curve parameters are described in the attached complete report, *Sixth Review of PJM's Variable Resource Requirement Curve for Planning Years* 2028/29 through 2031/32 ("2025 VRR Curve Study") (.⁴ The results of Brattle's independent review of the Gross Cost of New Entry ("CONE", or "Gross CONE") and the energy and ancillary services offset ("EAS Offset") methodology are set forth in a separate report ("2025 CONE Report").⁵ Concurrently with this affidavit, Brattle, in collaboration with Sargent & Lundy (S&L), is also submitting an affidavit regarding Gross CONE and the EAS Offset ("Brattle/S&L CONE Affidavit").⁶
- 8. After the publication of our 2025 VRR Curve Study and 2025 CONE Report in April 2025, PJM and stakeholders engaged in continued discussions to evaluate potential updates to the VRR Curve and Net CONE parameters. PJM and stakeholders considered the recommendations we offered in our independent review, as well as a range of alternative options developed by PJM staff, stakeholders, and the independent market monitor ("IMM"). PJM and stakeholders engaged in iterative efforts to evaluate and update potential VRR Curve formulations, which were informed by further input from stakeholders, as well as qualitative analysis and probabilistic simulations we provided under base case and stress conditions at PJM's request. The outcome of these

³ See Market Implementation Committee, Meeting Materials, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/committees/mic (last visited Nov. 7, 2025) (see Meeting Materials for the Quadrennial Review from September 2024 to April 2025).

⁴ See Exh. No. 2, 2025 VRR Curve Study.

See PJM Interconnection, L.L.C., Attach. E, Exh. No. 2 (Newell, Thompson, and Zhou, et al., Brattle 2025 CONE Report for PJM Informing Parameters for PJM's RPM Auctions for Delivery Year 2028/29 through 2031/32, The Brattle Group (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Brattle-2025-CONE-Report-for-PJM.pdf ("2025 CONE Report").

See 2025 CONE Report; See also Attach. E, Affidavit of Dr. Samuel A. Newell, Dr. Andrew W. Thompson, Dr. Bin Zhou, and Joshua C. Junge, Regarding Updates to PJM's CONE and Net Energy and Ancillary Service Offset Parameters for Delivery Years 2028/29 through 2031/32 (Nov. 7, 2025) ("Brattle/S&L CONE Affidavit").

⁷ See Market Implementation Committee, Meeting Materials, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/committees/mic (last visited Nov. 7, 2025) (see proposals and evaluations in Meeting Materials for the Quadrennial Review from September 2024 to September 2025).

efforts is a set of VRR Curve parameters that gained a majority vote of stakeholder support in the MIC, and that PJM is proposing for Commission approval in the present filing.⁸

9. Table 1 and Figure 1 summarize the price and quantity points of PJM's proposed curve ("Proposed Curve"). PJM proposes that the price cap at point 1 will be set by the Gross CONE and Net EAS parameters of a gas CT as the Reference Resource. The price of the kink at point 2 will be set at 50% of the price cap. The foot at point 3 will continue to be at a price of \$0, but PJM proposes to widen the curve by right-shifting the quantity at the foot from 104.5% to 106% of the Reliability Requirement. The result is a wider curve with a lower price cap compared to the current VRR Curve ("Current Curve") in PJM's Tariff. Figure 1 shows the Current Curve and the Proposed Curve, consistent with PJM's current Net CONE estimate of \$289/MW-day UCAP for a gas CT resource for the 2028/29 Delivery Year. To calculate Net CONE, PJM used the latest Gross CONE estimate for a CT (\$776/MW-day UCAP for the RTO),9 then applied PJM's EAS Offset for each individual Load Delivery Area ("LDA"). Net CONE for the RTO is calculated as the 33rd percentile of all LDA Net CONEs, as recommended in the 2025 CONE Report and the Brattle/S&L CONE Affidavit concurrently filed with this affidavit.¹⁰

See Market Implementation Committee, Draft Minutes, PJM Interconnection L.L.C. (Sep. 10, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250925/20250925-item-13b---mic-report.pdf.

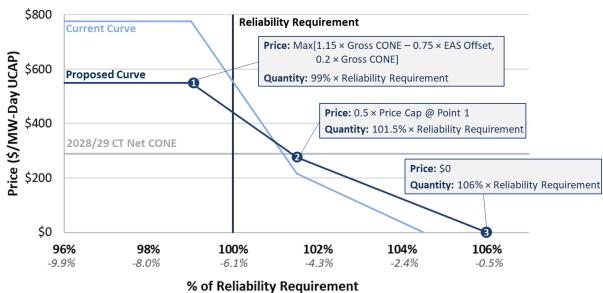
See Newell, Zhou, Thompson, et al., Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates, PJM Interconnection, L.L.C. (Aug. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/brattle-updated-cone-presentation.pdf. Presented at the August 18, 2025, PJM MIC Meeting. As per PJM's approach, the RTO-wide CONE is calculated as the simple average of the CT CONE for Areas 1 through 5, where the CT Effective Load Carrying Capacity (ELCC) is 79% for 2028/29.

See Attach. C, Affidavit of Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., ("Marzewski Affidavit"); see also Brattle/S&L CONE Affidavit § V.

TABLE 1: PROPOSED VS. CURRENT VRR CURVE PARAMETERS

| Point | Current VRR Curve | Proposed VRR Curve |
|-----------------------|--|---|
| Reference Resource | СТ | СТ |
| point 1 the cap | Price : Max [1.75 × Net CONE, Gross CONE] Quantity : 99% × Reliability Requirement | Price: Max [1.15 × Gross CONE – 0.75 × EAS Offset, 0.2 × Gross CONE] Quantity: 99% × Reliability Requirement |
| point 2 the kink | Price: 0.75 × Net CONE Quantity: 101.5% × Reliability Requirement | Price: 0.5 × Price Cap @ point 1 Quantity: 101.5% × Reliability Requirement |
| point 3 the foot | Price: \$0 Quantity: 104.5% × Reliability Requirement | Price: \$0 Quantity: 106% × Reliability Requirement |

FIGURE 1: CURRENT AND PROPOSED VARIABLE RESOURCE REQUIREMENT CURVES



UCAP Reserve Margin

Sources and Notes: The Current Curve and Proposed Curve both reflect use of the 2028/29 CT natural gas plant as the Reference Resource. 2028/29 CT CONE from Brattle/S&L CONE Affidavit. EAS Offset, and Net CONE were provided by PJM, see Marzewski Affidavit. For the Current Curve, the 1 × CONE value is the higher value and hence sets the price cap; for the Proposed Curve the first term in the point 1 formula (1.15 × Gross CONE - 0.75 × EAS Offset) is the higher term and hence sets the value for the price cap.

III. Simulated Performance of PJM's Proposed Curve

- We assess the simulated reliability and performance outcomes of the Proposed Curve using the 10. same probabilistic Monte Carlo simulation model used in our 2025 VRR Curve Study, as well as our prior periodic reviews of PJM's VRR Curve performance. We applied the usual assumptions of a market in a long-term equilibrium where prices equal long-run marginal cost at Net CONE on average, with year-to-year variability in price and quantity outcomes driven by historically-based fluctuations in supply and demand conditions, the demand curve formula, and historically-based supply curve shapes. 11 As explained in our 2025 VRR Curve Study and prior VRR Curve reports, this simulation modeling approach is useful to inform the distribution of potential outcomes and performance trade-offs that may be presented by alternative VRR Curve shapes under the assumed conditions with unconstrained, rational entry and exit until the average price across simulation draws is equal to Net CONE. This Monte Carlo simulation does not attempt to predict the near-term pricing or quantity outcomes that may prevail in any particular year, especially not in a near-term year for which most entry decisions have already been made and further entry is constrained. For these reasons, these simulated performance outcomes should not be interpreted as a forecast, but rather as a test of the Proposed Curve's consistency with underlying design objective of supporting the resource adequacy standard in expectation and under longterm equilibrium conditions when a portion of supply needs are to be met through merchant capacity investments. We assess the curve relative to the same criteria used to assess prior VRR Curves' performance.12
- Table 2 summarizes the simulated performance of the Current Curve compared to the Proposed Curve under the Base Scenario in which the administrative estimate of Net CONE (used to set VRR Curve parameters) is equal to the true Net CONE (the price required to attract new investments). Under these base assumptions, clearing prices equal this Net CONE on average. Though both curves produce the same simulated price on average across all draws (as dictated by the modeling approach), the distributions of price and quantity outcomes differ. The Current Curve produces a standard deviation of simulated prices across draws of \$151/MW-day UCAP compared to a lower \$108/MW-day UCAP with the Proposed Curve. This lower price volatility is due to the Proposed Curve being flatter than the Current Curve with a lower cap and a wider foot. The lower price cap improves price volatility, but with the trade-off of producing more frequent clearing outcomes below the reliability requirement (11.1% vs. 7.3%) and more outcomes at the price cap (4.0% vs 2.2%).
- 12. In terms of simulated reliability, the curves perform similarly to each other, and both outperform relative to the 1-in-10 reliability standard, measured as 1 event in 10 years (1-in-10) or 0.1 loss-of-load events ("LOLE"). The Current Curve produces 0.065 LOLE (1-in-15.4) while the proposed curve produces reliability at 0.063 LOLE (1-in-15.9). This similarity in reliability outcomes,

²⁰²⁵ VRR Curve Study at 44-45, 86-94. (showing complete description of the Monte Carlo simulation model).

¹² See 2025 VRR Curve Study § II. (for full discussion of design objectives).

combined with the model's enforcement of average prices converging to Net CONE in both cases, translates to little change in procurement costs. The Proposed Curve produces average costs approximately 0.04% below the Current Curve.

TABLE 2: SIMULATED PERFORMANCE OF CURRENT CURVE VS. PROPOSED CURVE (BASE SCENARIO)

| | Price | | | | Reliability | | | | | Cost |
|---------------------------------|----------------|----------------|--------------|----------------|----------------|----------------|----------------|---------------|--------------|----------------------|
| | Average | Standard | Frequency | Average | Average | Average | Normalized | Frequency | Frequency | Average |
| | Clearing | Deviation | at Cap | LOLE | Excess | Excess | Portfolio | Below | Below 99% | Procurement |
| | Price | | | | (Deficit) | (Deficit) | EUE | RR | of RR | Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (RR+X%) | (% Target) | (%) | (%) | (\$ mln/yr) |
| Current Curve Proposed Curve | \$289 \$289 | \$151 \$108 | 2.2% 4.0% | 0.065 0.063 | 1,773 2,069 | 1.26% 1.48% | 66.3% 65.9% | 7.3% 11.1% | 2.2% 4.0% | \$14,363 \$14,357 |

Sources/Notes: All prices in 2028\$/MW-day UCAP. RR = Reliability Requirement. VRR curve model from the 2025 Quadrennial Review updated with latest 2028/29 CT CONE for the RTO = \$776/MW-day from Brattle CONE study and the RTO Net CONE provided by PJM. See the 2025 VRR Curve Study, Brattle/S&L CONE Affidavit, and the 2025 CONE Report.

- Overall, our simulations indicate that the Proposed Curve should perform similarly to the current curve in terms of reliability outcomes, but with improvements in terms of lower price volatility and (as discussed further below) lower customer exposure to price cap events. As noted above, we reiterate that these results should be interpreted as an assessment of estimated curve performance under long-run equilibrium conditions where supply investments can enter freely in response to expected market prices. These results therefore indicate that the curve is consistent with the RPM market design objective of attracting competitive investments sufficient to maintain reliability objectives over the long term.
- 14. However, we recognize that the current market is not in long-run equilibrium conditions, and actual outcomes over the next several years could differ, most likely in the direction of higher prices and lower reliability. Acute tight supply conditions in the face of substantial increases in demand growth are present in PJM and many parts of North America. As discussed more extensively in the 2025 CONE Report, the cost and feasibility of building incremental capacity supply is presently constricted by supply chain limitations for turbines and other inputs, siting and permitting delays, a compressed forward period in the BRAs, and extended resource development timelines. These acute supply challenges may increase supply costs, limit the volume and types of new supply that can be developed in the initial years relevant to this Quadrennial Review (though we anticipate these restrictions could moderate by the end of the review period as industry supply chains expand to keep pace with demand growth). Under these conditions, it is possible that one or more BRAs may clear at the VRR Curve price cap, but yet may not attract sufficient volumes of new entry until supply-demand conditions resolve. In this situation, the role of the VRR curve and price cap are to ensure that prices can rise high enough to motivate entry and retention of all categories of existing and new supply that can react over the short term and produce prices high enough to motivate continued development of new entry whenever it can become available, while at the same time managing customer cost exposures from capacity market outcomes at the price cap. We therefore stress that modeled outcomes

under base conditions representing a well-behaved long-run equilibrium conditions should be incorporated as only one consideration in assessing VRR Curve suitability, alongside an assessment of potential performance in light of potential Net CONE estimation errors and other factors informing the price cap.

IV. Performance Sensitivity to Net CONE Estimation Error

- As discussed in the 2025 CONE Report, Net CONE estimates always carry inherent uncertainty, and they can vary over the assessment period in ways that formulaic updates may not perfectly capture. Thus, the VRR Curve must be capable of offering reasonable outcomes even when Net CONE is over- or under-estimated. To the extent possible, the VRR Curve should be robust to a range of realized Net CONE values that may be faced by developers. We reviewed the Proposed Curve for its robustness to such deviations.
- The Proposed Curve has a lower cap and a wider/flatter shape compared to the Current Curve, which improves performance on dimensions of price volatility and maximum cost exposure. The primary trade-off of this improvement in pricing stability is that the market must absorb greater exposure to quantity uncertainties. To test the Proposed Curve and Current Curve, we conducted a sensitivity analysis that included a scenario where the administrative Net CONE is overestimated by 40% (true Net CONE is \$173/MW-day UCAP), and another scenario where administrative Net CONE is underestimated by 40% (true Net CONE is \$405/MW-day UCAP). The results of this sensitivity analysis are shown in Table 3. This is the same sensitivity range we employed in the 2025 VRR Curve Study.

TABLE 3: PERFORMANCE OF CURRENT CURVE VS. PROPOSED CURVE UNDER BASE SCENARIO (NET CONE CORRECTLY ESTIMATED) AND UNCERTAINTY SCENARIOS (NET CONE OVER- OR UNDER-ESTIMATED)

| | | Price | | | | R | eliability | | | Cost |
|--------------------------|-----------|-----------|-----------|-------------|-----------|-----------|------------|-----------|-----------|-------------|
| | Average | Standard | Frequency | Average | Average | Average | Normalized | Frequency | Frequency | Average |
| | Clearing | Deviation | at Cap | LOLE | Excess | Excess | Portfolio | Below | Below 99% | Procurement |
| | Price | | | | (Deficit) | (Deficit) | EUE | RR | of RR | Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (RR+X%) | (% Target) | (%) | (%) | (\$ mln/yr) |
| Current Curve | | | | | | | | | | |
| Net CONE Overestimate | \$173 | \$83 | 0.1% | 0.044 | 2,996 | 2.12% | 45.2% | 0.3% | 0.1% | \$8,681 |
| Net CONE Accurate (Base) | \$289 | \$151 | 2.2% | 0.065 | 1,773 | 1.26% | 66.3% | 7.3% | 2.2% | \$14,363 |
| Net CONE Underestimate | \$405 | \$194 | 10.4% | 0.092 | 743 | 0.55% | 98.3% | 24.3% | 10.4% | \$19,931 |
| Proposed Curve | | | | | | | | | | |
| Net CONE Overestimate | \$173 | \$72 | 0.1% | 0.032 | 4,231 | 2.99% | 33.4% | 0.3% | 0.1% | \$8,745 |
| Net CONE Accurate (Base) | \$289 | \$108 | 4.0% | 0.063 | 2,069 | 1.48% | 65.9% | 11.1% | 4.0% | \$14,357 |
| Net CONE Underestimate | \$405 | \$118 | 24.3% | 0.126 | (82) | -0.02% | 145.0% | 41.9% | 24.3% | \$19,751 |

Notes: All prices in 2028\$/MW-day UCAP. RR = Reliability Requirement.

17. When administrative Net CONE is overestimated and the true Net CONE is lower ("Net CONE Overestimate"), the primary performance concern relates to susceptibility to over-procurement. As expected, PJM's proposed wider curve is more susceptible to additional over-procurement in the event of over-estimated Net CONE (4,231 MW UCAP of excess supply, compared to 2,996 MW UCAP with the Current Curve). The larger volume of supply procured in an over-procurement scenario comes at an incremental cost of approximately \$64 million/year (or 0.7% higher cost).

- 18. When administrative Net CONE is underestimated and the true Net CONE is higher ("Net CONE Underestimate"), the primary performance concern relates to susceptibility to reliability risks. A lower price cap protects customers from cost exposure in extreme high price events but also limits the upside potential for sellers to consider in making investments. If the price cap is only modestly above developers' true Net CONE, then the curve will not be able to produce prices at true Net CONE on average unless price cap (and low reliability) events are common. As expected, the proposed wider curve shows somewhat more susceptibility to price-cap and low-quantity outcomes. In the Net CONE Underestimate scenario, the Proposed Curve shows a higher frequency of clearing at the cap (24.3% vs 10.4%) and below the Reliability Requirement (41.9% vs 24.3%) relative to the Current Curve. Further, in the Net CONE Underestimate scenario, the Proposed Curve produces lower reliability (0.126 LOLE or 1-in-7.9) compared to the Current Curve (0.092 LOLE or 1-in-10.9). The Proposed Curve would experience a larger erosion in reliability in the event that Net CONE is underestimated, as the lower price cap offers less protection against reliability events. Still, in a Net CONE Underestimate scenario, the Proposed Curve would produce reliability that is only modestly poorer than the 0.1 LOLE standard, and so offers relatively robust performance to the risk of a 40% Net CONE underestimate.
- 19. Overall, we conclude that PJM's Proposed Curve is modestly more susceptible to quantity deviations compared to the Current Curve, but this erosion in performance is modest even in the presence of a relatively large 40% Net CONE estimation error.

V. Price Cap

- 20. Given PJM's current acute tight supply conditions, PJM, state regulators, and stakeholders have placed substantial focus on the price cap throughout the Sixth Quadrennial Review process. As we discuss more fully in the 2025 VRR Curve Study, a demand curve price cap reflects trade-offs. A higher cap curve tends to be better at reducing the potential for low reliability outcomes, but with the trade-off that a higher cap exposes the market to higher levels of price volatility and greater customer cost exposure to price cap events. A lower cap curve will better protect consumers against high prices in scarcity events and maintain lower price volatility, at the expense of a higher frequency of clearing at the cap, and the potential for low reliability events. Considering these trade-offs, most capacity market price caps are set in the range of 1.5-2 × Net CONE, in order to enable prices high enough on average to attract merchant new entry while still reasonably limiting customer cost exposure and price volatility.¹³
- Acknowledging these trade-offs, our 2025 VRR Curve Study identified various considerations to inform a workable range of price caps and balance of trade-offs. The Proposed Curve produces an estimated price cap of \$550/MW-day UCAP or 190% of the CT Net CONE for the 2028/2029 Delivery Year, which falls within a reasonable range of price caps. Applying the same considerations as we assessed in our independent review, we note that:
 - **Percent of Net CONE:** The Proposed Curve produces a price cap of \$550/MW-day UCAP or 190% of the CT Net CONE, which falls within the range of historical experience in PJM, in other capacity markets, and the theoretically workable range of approximately 1.5-2 × Net CONE.
 - Alignment with Neighboring Markets' Price Caps: Neighboring capacity markets have price caps in the range of \$524–\$631/MW-day UCAP (in 2028\$).¹⁶ The proposed cap of \$550/MW-day UCAP is in reasonable alignment with this range, which enables the market to compete for capacity imports (and retain potential exports). Alignment with neighboring markets' price caps is particularly relevant for prioritizing efficient capacity trade with neighbors that may also face tight supply conditions until the pace of supply entry can increase sufficiently to support demand growth.
 - **Simulation Modeling:** As presented above, the proposed price cap suggests that it is high enough to maintain LOLE above target in the base scenario (0.063 LOLE, or 1-in-15.9). A lower cap produces greater exposure to potential shortfall if Net CONE is persistently underestimated by 40%, but the erosion of reliability is only modestly poorer than the reliability target (0.126 LOLE or 1-in-7.9).

This range of price caps reflects the theory that prices need to align with 1 × Net CONE on average over the long term, and practical experience across other capacity markets. See a comparison of price caps and price cap formulas in other markets in Table 9 of the 2025 VRR Curve Study.

See 2025 VRR Curve Study § VI.

¹⁵ See Marzewski Aff.

¹⁶ See 2025 VRR Curve Study at 66 (Showing Table 9: Considerations Informing the Price Cap (\$/MW-Day UCAP).

- Temporarily reduced price cap: For the 2026/27 and 2027/28 BRAs, the cap has been set at a temporary reduced level of \$329/MW-day UCAP and \$333/MW-day UCAP respectively. A temporary floor of \$177/MW-day UCAP and \$180/MW-day UCAP were also introduced for 2026/27 and 2027/28 respectively, as a means to mitigate price uncertainty and maintain suppliers' interest in future resource development. Absent a change to the curve formula, the temporary collar would expire, and the cap would increase to \$776/MW-day UCAP for 2028/29 if using the 2028/29 CT Reference Resource. The temporarily restricted price cap and floor were put in place to mitigate customer price exposures under extraordinary conditions and accepted by the Commission as a "time-limited approach." The temporary cap is too low to be sustainable long-term to attract new entry when needed.
- Customer exposure to price-cap events: The proposed cap of \$550/MW-day UCAP under current CONE and EAS values is higher than the temporary cap, but lower than the \$776/MW-day UCAP if the Current Curve is used in 2028/29. Therefore, the Proposed Curve will substantially reduce the maximum price exposure to customers. Table 4 below illustrates the maximum 1-year cost exposure that customers could face in an RTO-wide price cap event, compared to prices that would be expected on a long-run average basis (at the assumed \$289/MW-day Net CONE). The table illustrates that the Proposed Curve substantially limits the extent of customers' potential exposure to price cap outcomes compared to the Current Curve.
- Overall, the Proposed Curve formula produces a cap is within the reasonable range of price caps as estimated consistent with the 2028/29 year estimated values. The cap is high enough to signal new entry when needed, it enables competition for capacity trade, mitigates exposure to reliability events if net CONE is under-estimate, and substantially limits customers' cost exposure to price cap events compared to the Current Curve.

PJM Interconnection, L.L.C., Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, Docket No. ER25-1357 (Feb. 20, 2025); PJM Interconnection, L.L.C., Commonwealth of Pennsylvania v. PJM Interconnection L.L.C., 191 FERC ¶ 61,066, order on reh'g & clarification, 192 FERC ¶ 61,258 (2025).

See Newell, Zhou, Thompson, et al., Sixth Review of PJM's RPM VRR Curve Parameters, Interim Update: Gross CONE with Technology Cost and Depreciation Updates, PJM Interconnection, L.L.C. (Aug. 18, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250822-special/brattle-updated-cone-presentation.pdf

¹⁹ PJM Interconnection L.L.C., Commonwealth of Pennsylvania v. PJM Interconnection L.L.C., 191 FERC \P 61,066, at 26 (2025).

The table is a conceptual extreme in that it assumes that no customers are hedged against year-to-year capacity price spikes. Customers in regions with regulated planning are not heavily exposed to these prices, while customers in other states have a partial hedge on capacity prices through a combination of state contracts and standard offer service auctions. However, a subset of customers, particularly in retail choice states, are substantially exposed to these prices.

TABLE 4: MAXIMUM 1-YEAR CUSTOMER COST EXPOSURE IN CAPACITY PRICE CAP EVENTS (ASSUMES NO CUSTOMERS ARE HEDGED AGAINST CAPACITY PRICES)

| | | Curve Paramet | ters | Customer Costs | | | |
|------------------------------|----------------------------|---------------|--|---|--------------------------------|---|--|
| | Price @ Cap Quantity @ Cap | | Quantity @ Cap (for Maximum Cost Exposure) | Expected Avg. Customer Cost @ \$289 | Maximum Cost Exposure @ Cap | Ratio of Maximum to Average Cost Exposure | |
| | (\$/MW-day) | (% of RR) | <i>(MW)</i> | (\$ mln/yr) | (\$ mln/yr) | <i>(%)</i> | |
| | [1] | [2] | [3] | [4] | [5]: [1] x [3] | [6]: [5] / [4] | |
| Current Curve Proposed Curve | \$776 | 99.0% | 132,228 | \$14,363 | \$37,459 | 261% | |
| | \$550 | 99.0% | 132,228 | \$14,357 | \$26,553 | 185% | |

Sources and Notes: [1]: Price cap for each curve, expressed in \M MW-day UCAP; [2]: Price cap quantity for each curve, expressed as a percent of the Reliability Requirement; [3]: Equal to the baseline simulated Reliability Requirement (133,564 MW) × [2], see 2025 VRR Curve Study; [4]: Expected average customer cost under baseline modeling assumptions (i.e., True Net CONE equal to baseline value of \$289/MW-day UCAP for all curves); [5]: [1] × [3], with additional unit conversions; [6]: [5] / [4].

VI. Summary

In summary, the Proposed Curve reflects a reasonable balance of objectives. The proposed price cap is within a workable range that is high enough to support short-term and long-term supply adequacy. The Proposed Curve will feature a lower price cap and a wider/flatter shape that will reduce price volatility under all scenarios. The lower price cap will also substantially reduce customers' cost exposure to price cap events compared to the Current Curve. These advantages of lower price volatility and exposure to high-price events come with a trade-off of modestly increased exposure to quantity uncertainties, with a modest increase in cost if Net CONE is overestimated and a moderate erosion of reliability if Net CONE is underestimated. The result is a curve that is consistent with the primary objective of maintaining resource adequacy in the long run in a competitive marketplace, and that strikes a reasonable balance of other design objectives regarding price and quantity sensitivity to changes in market conditions.

VII. Certification

24. We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

Kathleen Spees

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November 7, 2025

Exhibit No. 1

Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Andrew W. Thompson

Qualifications

Dr. Kathleen Spees

Washington, DC

c. 412.445.2694

kathleen.spees@brattle.com

Dr. Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis.

Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets. Her clients include electricity system operators in PJM, Midcontinent, New England, Ontario, New York, Alberta, Texas, Italy, and Australia. Electricity market design assignments involve ensuring adequacy of capacity and energy market investment incentives to achieve reliability objectives at least cost; designing carbon and clean energy policies that effectively interact with wholesale electricity markets; enhancing operational reliability and efficiency through energy market, scarcity pricing, and ancillary service market improvements; effectively integrating intermittent renewables, storage, demand response, and other emerging technologies; evaluating benefits and costs of industry reform initiatives; and enhancing efficiency at market interties.

For system operators and regulators, Dr. Spees provides expert support through stakeholder forums, independent public reports, and testimony in regulatory proceedings. For utilities and market participants, her assignments support business strategy, investment decisions, asset transactions, contract negotiation, regulatory proceedings, and litigation. Dr. Spees has developed and applied a wide range of analytical and modeling tools to inform these policy, market design, and business decisions.

AREAS OF EXPERTISE

- Wholesale Power Market Reform
- Carbon and Environmental Policy
- Capacity Market Design
- Wholesale Energy and Ancillary Service Market Design
- Generation and Transmission Asset Valuation
- Integration of Emerging Technologies and Specialized Products



Dr. Kathleen Spees

EDUCATION

- Carnegie Mellon Electricity Industry Center
 PhD in Engineering and Public Policy
- Carnegie Mellon University
 MS in Electrical and Computer Engineering
- Iowa State University
 BS in Physics and Mechanical Engineering

SELECTED CONSULTING EXPERIENCE

WHOLESALE POWER MARKET REFORM

- South Carolina Competitive Reforms Study. For the South Carolina State Legislature, conducted a comprehensive assessment of potential benefits and risks from competitive reforms to the state's electricity sector regulatory model. Examined potential reforms to join or integrate with a regional transmission organization, introduce competition into resource planning, and pursue partial or full retail choice.
- Ontario Market Renewal Benefits Case. For the Ontario Independent Electricity System Operator (IESO), developed an analysis evaluating the benefits and implementation costs associated with fundamental reforms to wholesale power markets, including implementing nodal pricing, a day-ahead energy market, enhanced intra-day unit commitment, operability reforms, an enhanced intertie design, and a capacity market. Analysis included: (a) market visioning sessions with IESO staff and stakeholders to identify future market design requirements; (b) identify primary drivers and quantify system efficiency benefits; (c) review lessons learned from other markets' reforms to identify opportunities and reform risks; (d) conduct a bottom-up analysis of implementation costs for replacing market systems; and (e) evaluate interactions with existing supply contracts.
- MISO Market Development Vision. For the Midcontinent Independent System Operator (MISO), worked with 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.



- Australia NEM Electricity Market Vision for Enabling Innovation and Clean Energy. On
 behalf of the Australian Energy Market Operator reviewed electricity market design options
 for the future of the NEM. Evaluated opportunities for relying on markets, innovation, and
 new technologies to address a range of challenges in the context of significant increases in
 customer costs, high gas prices, large clean energy penetration, coal retirements, uncertain
 carbon policies, and emerging reliability and security concerns.
- RTO Value Proposition. Supported an RTO to develop methods for estimating and
 communicating its value proposition that describes the societal benefit created by
 participating in the RTO, derived from RTO market services including energy and ancillary
 service markets, resource adequacy, and transmission planning. Reviewed the approaches
 and magnitudes of estimated value of RTO membership across available studies and peer
 organizations.
- Thailand Power Market Reform. Supported market design options and recommendations
 for potential power market reforms in Thailand, including the introduction of forward, dayahead, and real-time energy markets, as well as the potential introduction of a bilateral or
 centralized capacity market. Examined interactions with retail rates, existing contracts, and
 self-supply arrangements.
- Power Market Reform to Accommodate Decarbonization and Clean Energy Policies. For the system operator in a jurisdiction pursuing significant clean energy and decarbonization policies, assisted in evaluating market design alternatives. Estimated energy price, customer cost, and reliability implications under alternative energy, ancillary service, and capacity market design scenarios. Quantified implications of key uncertainties such as intermittent resource penetration levels and impacts of interties with external regions. Provided research and comparative analysis of design alternatives and lessons learned from other jurisdictions.
- 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.
- PJM 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.



- Options for Reconciling Regulated Planning and Wholesale Power Markets in MISO. For NRG, developed a whitepaper assessing reliability and economic implications of current capacity market and integrated planning approaches, and the challenges in accommodating retail access and integrated planning within the same market region. Recommended options for enhancing the MISO capacity market and regulated entities' approaches to planning.
- Review of California Planning and Market Mechanisms for Resource Adequacy. For
 Calpine, evaluated interactions and implications of California's policy, planning, and market
 mechanisms affecting resource adequacy. Recommended improvements to reconcile
 inconsistencies and enhance efficiencies in regulated long-term procurements, short term
 local resource adequacy construct, and CAISO backstop mechanisms.

CARBON AND ENVIRONMENTAL POLICY

- Greenhouse Gas Cap-and-Trade Market Design and Modeling. For the New York City Mayor's Office of Sustainability, conducted a study to develop market design options for a greenhouse gas cap-and-trade market under Local Law 97 that imposes 80% carbon reductions on large buildings in New York City by 2050. Utilized Brattle's Decarbonized Energy Economy Planning (DEEP) model to assess the outcomes of alternative market designs including cost, pricing, emissions, City revenues, distributional impacts, and implications on environmental justice communities.
- Clean Electricity Market for PJM. For the Organization of PJM States, Inc. (OPSI) supporting
 13 states and the District of Columbia to examine a range of regional clean energy market
 designs that the states and consumers in the PJM region could pursue. Supported multistate discussions and evaluation and presented to PJM's stakeholder group on design
 options.
- Electricity Sector Greenhouse Emissions Accounting in the West. For the WEST Associates, developed a whitepaper documenting 56 distinct greenhouse gas emissions accounting frameworks in use by 16 utilities across the West, considering state, federal, and voluntary reporting programs. Documented differences in practices, outcomes, and opportunities for regional coordination. Described interactions among GHG accounting, operational and investment incentives, and regional market expansion.
- New England Forward Clean Energy Market. For the Massachusetts Department of Energy Resources, and in consultation with New England States Committee on Electricity (NESCOE) and policymakers in the six New England states, developed a comprehensive design proposal for a regional market for the competitive procurement of clean energy attributes.



- Design of a Competitive Forward Clean Energy Market. For NRG, developed a market
 design to attract investment in clean energy resources to serve state policy goals and
 customer demand for clean energy. Developed detailed design proposal for integrating and
 aligning the market with wholesale electricity markets and competitive retail markets.
 Supported drafting of state legislation and testimony before state legislature.
- Illinois Renewable Energy Access Plan. For the Illinois Commerce Commission, led a team to develop the state's Renewable Energy Access Plan. Included assessment of regional and state processes to support effective transmission planning, renewable resource interconnection, siting, permitting, land use, economic incentives, and wholesale electricity market interactions. Developed a state-wide plan for renewable deployments and policy actions to achieve 100% clean energy policy goals.
- New Jersey Ratepayer Impact Study of 100% Clean Energy Policy. For the New Jersey
 Board of Public Utilities, Conducted an economic impact assessment of the ratepaper
 energy burden facing customers from the pursuit of the state's clean energy policies,
 considering natural gas bills, electricity bills, and vehicle fuel. Examined impacts for
 customers in multiple utility service areas, customer classes, and focusing on low income
 customer segments.
- Power Market Reforms for 100% Clean Electricity for the District of Columbia. For the
 District of Columbia Department of Energy and the Environment (DOEE) conducted a study
 of wholesale power market reforms needed to support the District's 100% clean electricity
 policy goals. Described reforms including greenhouse gas tracking and data, capacity
 market reforms, energy and ancillary reforms, and enhanced integration of emerging
 technologies.
- Integrating Markets and Public Policy in New England. For a coalition of stakeholders, engaged in a collaborative effort to develop market-based approaches for accommodating and achieving state decarbonization objectives. Developed and refined design proposals including carbon pricing and market-based clean energy procurements, while identifying options for reducing regulatory uncertainties, avoiding cross subsidies across states, and mitigating customer cost impacts. Evaluated options for improving interactions with existing energy, capacity, renewable energy credit, and carbon markets. Conducted modeling of price, cost, and emissions outcomes under a range of designs. Engaged in an iterative process to develop, present, and refine design proposals based on input from a broad array of stakeholders. Provided expert support in outreach to state policymakers and industry groups.



- Ontario Market Evolution to Support a 90% Clean Energy System and Increasing
 Distributed Resources. For the IESO, supported the activities of the non-emitting
 stakeholder committee to model market reforms necessary to fully enable the 90% clean
 energy fleet. Supported stakeholder workshops to identify potential futures with many
 more distributed resources, a range of technology costs, and a variety of market designs.
 Conducted modeling analysis to analyze market outcomes including cost, reliability,
 resource curtailment, and resource revenues.
- Locational Marginal Emissions. Co-authored a whitepaper with ReSurety proposing an
 approach to valuing clean energy, demand reductions, and storage relative to locational, 5minue carbon abatement value. Descripted the next generation of renewable
 procurements, contract incentives, sustainability accounting, and renewable energy credits
 in alignment with carbon abatement value.
- Advising on Federal Clean Energy Legislation (Multiple Clients). Provided expert advice and language on the development of cost-effective clean energy legislation. Supported engagement with interest groups and legislative committee staff.
- National Carbon Policy Design and Interactions with Power Markets. For an international regulator, analyzed a range of options for the design of a carbon policy for the electricity sector, considering impacts on the wholesale electricity market and interactions with other sectors. Analyzed a range of alternatives for intensity-based and cap-and-trade based approaches, alternative allocations methods, and interactions with renewables standards. Developed two detailed design alternatives within the specified policy constraints.
- Review of International Carbon Mechanisms. For an RTO, conducted a survey of
 international carbon pricing, cap-and-trade, and rate-based mechanisms, and detailed
 review of design elements of the mechanisms implemented in Europe, California, Alberta,
 and the Regional Greenhouse Gas Initiative. Evaluated a range of alternatives for
 implementing the Clean Power Plan across states while effectively integrating with
 wholesale markets.
- New York ISO Carbon Pricing. For the New York ISO, examined economic implications of a
 possible carbon pricing proposal within the wholesale electricity market. Developed a
 whitepaper evaluating interactions with state environmental policies, wholesale power
 markets, intertie pricing, capacity market, and transmission planning. Estimated energy
 price and customer cost impacts.
- Carbon Allowance Allocations Alternatives. For the National Resources Defense Council, developed a whitepaper examining the advantages and disadvantages of auction-based,



customer-based, and generator-based approaches to allocating carbon allowances. Developed recommendations for avoiding the introduction of inefficient investment, retirement, and operational incentives under each type of design, and for mitigating customer cost impacts.

- Power Market Impacts of Clean Power Plan Alternatives. Conducted a modeling
 assessment of price, cost, and emissions implications of different rate-based, subcategory
 rate-based, and mass-based implementation of the Clean Power Plan in Texas. Estimated
 energy, emission reduction credit, and carbon prices under each scenario, and net revenue
 and operating implications for several types of generating plants.
- 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.
- Enabling Canadian Imports for U.S. Clean Energy Policies. For a coalition of Canadian
 electricity producers and policymakers, reviewed a range of options for U.S. states to
 pursue clean energy policies and the Clean Power Plan while enabling contributions from
 clean energy imports.
- Clean Power Plan Regulatory and Stakeholder Support. For a cooperative entity, provided support in developing internal and external positioning associated with the Clean Power Plan. Analyzed state-wide emissions targets and compliance alternatives. Supported messaging and stakeholder engagement at the state and federal levels. Submitted testimony before the Environmental Protection Agency.
- State Compliance Strategy under the Clean Power Plan. 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.
- New Gas Combined Cycle Plants Under the Clean Power Plan. For the National Resources Defense Council, developed a whitepaper evaluating the economic implications of Clean



Power Plan implementation plans that do or do not cover gas combined cycle plants on a level basis with other fossil-emitting plants. Conducted simulation analyses comparing the economic and emissions implications of alternative approaches.

- MISO Coal Retrofit Supply Chain Analysis. For the MISO, analyzed the fleet-wide
 requirements for retrofitting plants to upgrade for the Mercury and Air Toxics Standard.
 Reviewed the upstream engineering services, procurement, and construction supply chain
 to evaluate the ability to upgrade the fleet within the available time window. Analyzed the
 potential for operational and reliability concerns from simultaneous planned outages
 needed to support fleet-wide retrofit requirements in the MISO footprint.
- Impact of Environmental Policies on Coal Plant 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.

CAPACITY MARKET DESIGN

- PJM Review of Capacity Market Design and Demand Curve Parameters: 2011, 2014, 2018, 2022 and 2025. For PJM Interconnection, conducted independent periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, net cost of new entry parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Provided expert support to stakeholder proceedings, testimony submitted before the Federal Energy Regulatory Commission, and before the Maryland Public Service Commission.
- MISO Reliability-Based Demand Curves. For MISO, supported the development and
 testimony filings before the FERC in the development of the capacity market ReliabilityBased Demand Curves to be used in the planning resource auction. Established the
 economic and reliability concepts underpinning the curves, derived from the marginal
 reliability impact (MRI) of the curves as differentiated by season and by capacity market
 region.
- Capacity Auction Clearing Engine. For an RTO, developed the capacity auction clearing engine. Engine used in production to clear all supply offers relative to administrative



- demand curves, reflecting all transmission constraints and market rules in a valuemaximizing objective function. Engine used to produce clearing results and prices.
- Integrated Clean Capacity Market (ICCM). For the New Jersey Board of Public Utilities, supported a Board investigation of alternative resource adequacy structures in alignment with the state's 100% by 2040 economy-wide clean energy mandates. Developed detailed design proposal for the ICCM and conducted economic modeling of clean energy achievement and customer costs across alternative design structures. Supported a series of stakeholder engagements to review alternative structures.
- New York Capacity and Resource Adequacy Alternatives. For the New York Department of Public Service and New York State Energy Research & Development Authority, conducted a study evaluating a range of capacity market and resource adequacy alternatives. Implemented modeling analysis of impacts across alternative capacity market designs, minimum offer price rule scenarios, and interactions with state clean energy mandates. Supported a technical workshop and authored reports filed within docket proceedings.
- Maryland Resource Adequacy Alternatives. For the Maryland Environmental Service and Maryland Energy Administration, conducted an analysis of resource adequacy and capacity market alternatives in alignment with state clean energy policy. Conducted modeling analysis, authored a public report, and presented results to state policymakers.
- **Singapore Capacity Market Design.** For the Energy Market Authority, supported market design and market rules development for all aspects of the new capacity market design. Supported an iterative series of stakeholder engagements to iteratively refine market rules.
- Economic Implications of Resource Adequacy Requirements. For the U.S. Federal Energy Regulatory Commission, 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 different energy-only and capacity market designs.
- Winter Resource Adequacy and Reliability. For an RTO, analyzed the risk of winter
 reliability and resource adequacy shortages. Examined the drivers of winter reliability
 concerns including unavailability of specific resource types, winter fuel supply shortages,
 and weather-driven outages. Developed a range of potential reforms for addressing
 identified concerns.
- Testimony on the Impacts of the Minimum Offer Price Rule. For a coalition of environmental organizations, authored testimony on the economic impacts of the Minimum



- Offer Price Rule in the New York capacity market, filed before the Federal Energy Regulatory Commission.
- Alberta Capacity Market Design. Supported the development of a capacity market design in Alberta. Provided expert support to public working groups and AESO staff to review analytical questions, develop and evaluate design alternatives, and draft design documents. Supported on all aspects of market design including establishing reliability requirements, developing demand curve parameters, evaluating seasonal capacity resources, setting capacity ratings, product definition and obligations, and penalty mechanisms.
- European Market Flexibility and Capacity Auction Design. For European client, developed a market-based design for meeting flexible and traditional capacity needs in the context of high levels of intermittent resource penetration, degraded energy and ancillary pricing signals, and ongoing electricity market reforms. Engaged in meetings with industry and European Commission staff to develop and refine design options. Developed a model simulating market clearing results in a two-product auction and projecting prices over time.
- **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.
- Capacity Auction Design for Western Australia. For Western Australia's Public Utility
 Office, drafted a whitepaper and advised on the design of its new capacity auction
 mechanism.
- IESO Capacity Auction Design. Provided expert support to IESO staff in support of a new
 capacity auction design. Provided detailed memos describing options, tradeoffs, and
 lessons learned on every aspect of capacity auction design. Supported stakeholder
 engagement, conducted analysis of design alternatives, and developed design proposals.
- PJM Seasonal Capacity Market Design. For the Natural Resources Defense Council, provided testimony and economic analysis in support of improving the capacity market design to better accommodate seasonal capacity resources.
- **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 the Federal Energy Regulatory



- Commission supporting a proposed system-wide demand curve, with ongoing support to develop locational demand curves for individual capacity zones.
- MISO-PJM Capacity Market Seams Analysis. For MISO, evaluated barriers to capacity trade
 with neighboring capacity markets, including mechanisms for assigning and transferring firm
 transmission rights and cross-border must-offer requirements. Evaluated economic impacts
 of addressing the barriers and identified design alternatives for enabling capacity trade.
- MISO Competitive Retail Choice Solution. For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the Federal Energy Regulatory Commission.
- Demand Curve and Net Cost of New Entry Review. For an RTO, provided a high-level
 conceptual review of its approach to establishing demand curve and net cost of new entry
 parameters. Identified potential reliability and economic efficiency concerns, and
 recommended enhancements.
- Western Australia Reserve Capacity Mechanism and Transition Mechanism. For EnerNOC, authored two public reports related to the energy market reforms in Western Australia.
 The first report evaluated the characteristics of the Western Australia Reserve Capacity Mechanism in comparison with international best practices and made recommendations for improvements, whether pursuing a capacity market or energy-only market design. The second report evaluated and recommended changes to the regulator's proposed mechanism for transitioning to its long-term capacity market design.
- MISO Resource Adequacy Construct. For MISO, conducted a review of MISO's resource
 adequacy construct. Subsequent 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.
- 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 settlement discussions on the same



WHOLESALE ENERGY, ANCILLARY, AND SPECIALIZED PRODUCTS MARKET DESIGN

- Alberta Renewed Energy Market to Enhance System Flexibility and Reliability. For Alberta
 Electric System Operator, supported the development of market design enhancements to
 better support flexibility needs addressing emerging reliability needs. Developed design
 proposals and evaluated alternatives for immediate and long-term reforms including
 monitoring and mitigation, an operating reserve demand curve, 30-minute ramping
 product, ancillary service co-optimization, and day-ahead markets.
- Greece Energy and Ancillary Service Market Reform. For the Hellenic Association of Independent Power Producers, provided expert advice and a report on how to reform wholesale power markets to conform with policy mandates and meet system flexibility needs. Analyzed energy and ancillary market pricing and rules to identify opportunities to enhance efficiency, improve participation of emerging resources, achieve market coupling, and better integrate intermittent resources. Proposed high-level design recommendations for implementing forward, day-ahead, intraday, and balancing markets consistent with European Target Model requirements. Developed detailed design recommendations for near-term and long term enhancements to market operations, pricing, dispatch, and settlements. Provided expert support in meetings with European Commission staff.
- Ramping Reserve Product Definition. For New York State Research and Development
 Authority (NYSERDA), authored testimony on design principles and value proposition of
 ramping reserve products at multiple operating timeframes to manage increasing net load
 variability, and leverage the capabilities of emerging technologies.
- Ramping Product Design. For a market operator, developed a design proposal for a ramping
 product that would serve system ramping needs across multiple forward intervals and
 across locations. Developed rules that would enable distributed and demand response
 resources to participate in providing system ramping needs and incentives to become
 visible and controllable by the system operator.
- MISO Reliability Attributes Solution Space. Conducted assessment of a wide range of
 potential solutions to support emerging reliability needs in MISO, including those related to
 system adequacy, flexibility, and stability. Reviewed experience with solutions to similar
 problems in other markets across the globe and offered recommendations to MISO for
 reforms, presented recommended reforms to stakeholders.
- SPP Ramp Product Proposal. For Golden Spread Electric Cooperative, developed recommendations for the design and implementation of a ramping product to most efficiently and cost-effectively manage intermittency needs. Reviewed opportunities to



- determine the most appropriate quantity of resources, forward product timeframe, price formation, and interactions with existing pricing and commitment procedures.
- ERCOT Energy Market Design and Investment Incentives Review. For the Electric Reliability Council of Texas (ERCOT), conducted a study to: (a) characterize the factors influencing generation investment decisions; (b) evaluate the energy market's ability to support investment and resource adequacy at the target level; (c) examine efficiency of pricing and incentives for energy and ancillary services, focusing on scarcity events; and (d) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Performed 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. Supported ongoing proceedings with stakeholders and before the Public Utility Commission of Texas.
- Scarcity and Surplus Event Pricing. For an RTO, examined the efficiency and reliability implications of its pricing mechanisms during scarcity and surplus events, and evaluated potential market reforms. Options reviewed included adjusting the price cap consistent with the value of lost load, adjusting supplier offer caps, imposing administrative scarcity prices at varying levels of emergency events, ancillary service market pricing interactions, and reducing the price floor below zero.
- MISO Wind Curtailment Interactions with Energy Market Pricing and Transmission
 Interconnection Processes. 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.
- 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.
- **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.
- New England Fuel Security Market Design. For NextEra, developed design proposals for
 using market-based mechanisms to meet regional fuel security needs including through a
 fuel security reserve product that would enhance pricing and operations for fuel security in
 the energy and ancillary service markets, and options for a long-term solution through
 forward auctions for fuel security.
- Reliability Auctions for the NEM. For the Australian Electricity Market Operator conducted
 an international review of the range of approaches to supporting reliability and system
 security through competitive auctions. Focused on product definition including, various
 aspects of reliability and system security, auctions focused on enabling non-traditional
 resource types, options ranging from strategic reserve models to partial needs
 procurements to capacity markets, and potential for impacts on energy-only market pricing
 and performance.
- eRCOT Operating Reserves Demand Curve and Economically Optimal Reserve Margin 2014 and 2018. For the Public Utility Commission of Texas and 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.
- Financial Transmission Right 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.
- Southern Company Independent Auction Monitor. For Southern Company, developed
 auction monitoring capability and protocol development for monitoring hourly and daily
 auctions. Supported functions included daily and annual audits of internal company
 processes and data inputs related to load forecasting, purchases and sales, and outage
 declarations. Analyzed 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.



GENERATION AND TRANSMISSION ASSET VALUATION

- Revenue Projections for Generation and Transmission Assets (Multiple Clients). For multiple clients, top-line operating cost and revenues estimation for generation and transmission assets in PJM, ISO-NE, MISO, SPP, and ERCOT; experience with a range of asset types including gas CCs, gas CTs, coal, renewables, waste-to-energy, cogeneration, and HVDC lines. Evaluation exercises include forecasting market prices and net revenues from energy, capacity, ancillary service, and (if applicable) renewable energy credit markets. Valuations account for the operational impacts and economic value of existing power purchase agreements and other hedges. Clients typically require qualitative and quantitative analysis of regulatory risks under a range of operational and market scenarios. Valuation efforts often conducted in the context of due diligence for transactions, business decisions, and contract negotiations.
- Executive Education and Investment Opportunities Surveys (Multiple Clients). For multiple clients, provided executive education and detailed survey material to support investments in new markets and strategic decision-making. Educational efforts provided over a range of levels including high-level executive sessions, all-day workshop sessions, and detailed support for analytical teams. Examples of subject matter include: (a) cross-market surveys comparing investment attractiveness in many dimensions based on market fundamentals, regulatory structure, and contracting opportunities; and (b) single-market deep-dive educational sessions on capacity, energy, ancillary service, and financial/hedging product functioning and market performance.
- In-House Fundamentals Capability Development (Multiple Clients). For multiple clients, supported the development of in-house capability for market fundamentals analysis. Typically needed in the context of new entrants to a market or system operators expanding the scope of their internal analytical capabilities. Scope of support has included: (a) initial education, backup support, and advisory support for fundamentals teams entering a new market; (b) development and transfer of new purpose-built modeling tools such as capacity market models; and (c) external peer review or independent assessment functions.
- Asset or Fleet Valuation in Support of Litigation and Arbitration Proceedings (Multiple Clients). In litigation and arbitration contexts, provided estimates of economic damages or asset/fleet value estimates that would have applied at the time of a particular business decision. Supported expert testimony, litigation workpapers, and assessment of opposing experts' analysis.
- Economic Analysis of Plant Retrofit and Fuel Contracting Decisions (Multiple Clients).

 Supported plant operational and investment decisions for enhancing the value of particular



assets, including contexts such as: (a) retrofitting plants from oil to gas generation; (b) retrofitting single-cycle to combined cycle with different capacities for duct firing; (c) enhancing ancillary service capability; and (d) and contracting for firm gas capability. Evaluated operational, cost, and revenue impacts of alternatives and compared to present investment costs.

Financial Implications of Regulatory, Policy, and Market Design Changes (Multiple Clients).
 Conducted analyses of risks and opportunities associated with regulatory, policy, and market design changes. Examples include an analysis of potential Trump administration policies, implications of potential clean energy and carbon policies, and assessing private risks from changes to ancillary service market rules.

INTEGRATION OF EMERGING TECHNOLOGIES

- Illinois Renewable Energy Access Plan. For the Illinois Commerce Commission, led a team to develop the state's Renewable Energy Access Plan. Included assessment of regional and state processes to support effective transmission planning, renewable resource interconnection, siting, permitting, land use, economic incentives, and wholesale electricity market interactions. Developed a state-wide plan for renewable deployments and policy actions to achieve 100% clean energy policy goals.
- Revenue Projections for Storage, Hybrid, Renewable, Demand Response, and Distributed Resource Technologies (Multiple Clients). For multiple clients across many wholesale electricity markets, conducted projections of net revenues available to assets of many different technology types considering: access to participate in various wholesale electricity products, opportunities to sell environmental attributes or earn policy incentives, and contracted asset revenues. Provided revue projections across alternative market and policy scenarios and alternative asset configurations, in the context of informing investment strategy and investor due diligence. Review policy context and regulatory uncertainties that may enhance or erode market opportunities for particular assets or investment portfolios of emerging resources.
- RTO Business Models Analysis for Enabling Customer-Side Disruption and the Clean Energy Future. For a system operator, engaged in an executive strategy analysis to evaluate a range of electricity sector business models under a future with high penetrations of distributed resources and decarbonization. Developed detailed scenario descriptions of the business models envisioned considering different roles and scope of services provided by the RTO, distribution companies, load serving entities, and third-party aggregators. Created an interactive tool for mapping financial flows and energy flows at all points in the



- electricity value chain under each business model considered, and drew implications for value proposition of each segment of the market.
- Enabling Market Participation from Non-Emitting and Emerging Technologies. For an
 Ontario stakeholder group, provided expert support to identify market design
 enhancements to enable and integrate non-emitting and emerging technologies. Examined
 participation barriers and design enhancements to unlock full value of resources for
 supporting energy, flexibility, capacity, and other value streams to the province.
- New Jersey Offshore Wind Transmission Solicitation. For the New Jersey Board of Public
 Utilities, supporting the competitive solicitation of transmission investments to support the
 integration of up to 7,500 MW of offshore wind, including solutions for on-shore upgrades,
 offshore connections, and offshore network options. Economic, environmental, and legal
 analysis will support Board selection of winning projects under the first-ever PJM State
 Agreement Approach process for transmission development in support of state policies.
- International Review of Demand Response Integration into Wholesale Electricity Markets.
 For the Australian Energy Market Commission, authored a report describing the range of approaches and market experience integrated demand response into wholesale energy, ancillary service, and capacity markets. Provided detailed discussion of approaches in Singapore, Alberta, ERCOT, PJM, ISO New England, and Ontario. Summarized lessons learned regarding demand response business models, efficient wholesale pricing signals, and interactions with retail markets.
- Integration of Energy Efficiency in Capacity Markets. For Advanced Energy Economy, developed a series of papers focused on best practices for integrating energy efficiency into wholesale capacity markets in a competitive, resource-neutral fashion that enables all business models.
- Integration of Demand Response into Ontario Energy Markets. For the Ontario market operator, conducted a review of opportunities to better integrate demand response into energy market dispatch, price formation, and settlements. Reviewed interactions amongst capacity, energy, and retail pricing incentives. Authored a recommendations report, evaluated the magnitude of potential consumer benefits, and supported stakeholder engagement.
- Oncor Distributed Storage Business Models to Supply Customer, Distribution System, and Wholesale Value Streams. For Oncor Electric Delivery Company, conducted a <u>benefit-cost</u> <u>analysis</u> of adding varying levels of distributed storage into the Texas market.
 Recommended policy changes to enable storage under a range of business models



(merchant, utility-owned, customer-owned, and third-party owned), and to allow for the development of resources that could provide multiple value streams. Value streams considered including market values such as energy and ancillary services, distributionsystem values including deferred transmission and distribution costs, and customer value streams including avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.

- Risk and Financial Analysis of PJM Capacity Performance Product. For a market participant, conducted a probabilistic assessment of the expected value, upside, and downside risks (both market-wide and private) associated with PJM's capacity performance product. Evaluated the likely frequency of scarcity events on average and as concentrated in particular years to estimate the expected value of bonus payments if operating as an energy-only asset, and the net potential bonus/penalty if operating as a capacity performance resource. Estimated risk-neutral and risk-averse capacity price offer levels; characterized the magnitude of risk exposure of poor asset performance coincided with system scarcity events.
- Capacity Auction Design and Auction Clearing Software Testing. For a system operator, assisted in the high-level and detailed designs of a capacity auction. Supported market rule development and auction clearing optimization specification. As part of software implementation testing, developed optimization engine in GAMS/CPLEX to replicate auction clearing results, conducted quality control testing of auction clearing engine across 100+ test cases to ensure fidelity and consistency with market rules; conducted software quality control testing across multiple design iterations across several years.
- Hedging Products for Wind. For a hedge fund, provided analytical support for the
 development of a hedging product for wind developers. Evaluated the risk exposure based
 on day-ahead and real-time participation, locational price differentials, profile and
 curtailment risks, and discrepancies with exchange-traded hedging products.
- 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.
- 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.

 Market Reforms to Meet Emerging Flexibility Needs. For the Natural Resources Defense Council, authored a report on the electricity market reforms needed in the context of declining needs for baseload resources, increasing levels of intermittent supply, and increasing needs for flexible resources.

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Kathleen Spees and Samual A. Newell, "Written Testimony of Dr. Kathleen Spees And Dr. Samuel A. Newell re Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market," before the Federal Energy Regulatory Commission, Docket No. ER21-2582-000, August 20, 2021.

Kathleen Spees and Samual A. Newell, "Written Testimony of Dr. Kathleen Spees And Dr. Samuel A. Newell on the Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market," before the Federal Energy Regulatory Commission, Docket No. EL21-7-000, November 18, 2020.

Kathleen Spees and Samual A. Newell, "Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy-Supported Resource Rules," before the Federal Energy Regulatory Commission on behalf of Dominion Energy Services, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, and ER18-178-000, October 2, 2018.

Samuel A. Newell, Kathleen Spees, and David Luke Oates. "Response on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution," before the Federal Energy Regulatory Commission, Docket No. ER17-284-000, January 13, 2017.

Samuel A. Newell, Kathleen Spees, and David Luke Oates, "Testimony on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution." Docket No. ER17-284-000. November 1, 2016.

Judy Chang, Kathleen Spees, and David Luke Oates, "Comments on the Clean Power Plan Federal Implementation Plan Proposal Sponsored by Wolverine Power Supply Cooperative, Inc.," before the Environmental Protection Agency, Docket No. EPA-HQ-OAR-2015-0199, January 21, 2016.

Samuel A. Newell and Kathleen Spees, "Affidavit on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve, for Use in PJM's Capacity Market," before the Federal Energy Regulatory Commission, Docket ER14-2940-000, November 5, 2014.

Samuel A. Newell and Kathleen Spees, "Affidavit on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," before the Federal Energy Regulatory Commission, Docket ER14-2940-000, September 25, 2014.



Samuel A. Newell and Kathleen Spees, "Testimony on Behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," before the Federal Energy Regulatory Commission, Docket No. ER14-1639-000, April 1, 2014.

Samuel A. Newell and Kathleen Spees, "Response on Behalf of PJM Interconnection, LLC, Regarding the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model," before the Federal Energy Regulatory Commission, Docket No. ER12-13-000, January 13, 2012.

Samuel Newell, Kathleen Spees, and Philip Q Hanser, "Supplemental Comments Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets," before the Federal Energy Regulatory Commission, Docket Nos. RM10-17-000 and EL09-68-00, October 4, 2010.

Johannes P. Pfeifenberger and Kathleen Spees, "Comments In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results," before the State of Maryland Public Service Commission, Administrative Docket PC22, filed October 1, 2010.

Samuel Newell, Kathleen Spees, and Philip Q Hanser, "Comments Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets," before the Federal Energy Regulatory Commission, Docket Nos. RM10-17-000 and EL09-68-00, May 13, 2010..

PRESENTATIONS

Kathleen Spees and Sarah Sofia, "Lessons from Other Markets' Reform Efforts for Enabling Energy Storage," presented at the Energy Storage Alberta CanREA Summit, June 3, 2025.

Kathleen Spees (moderator), Adam Keech, Zakaria Joundi, Pamela Sporborg (panelists), "Are Resource Adequacy Markets Adequate?," presented at the Energy Bar Association 2025 Annual Meeting and Conference, May 1, 2025.

Sam Newell, Kathleen Spees, Andrew W. Thompson, Ethan Snyder, Xander Bartone, Nathan Felmus, Sang H. Gang, Joshua C. Junge, Hyojin Lee, and Liam Tawelian, "Sixth Review of PJM's RPM VRR Curve Parameters: Final Recommendations," presented to the PJM Market Implementation Committee, April 11, 2025.

J. Michael Hagerty, Kathleen Spees, and Jadon Grove, "Thermal Batteries and Industrial Decarbonization Load Growth: Opportunities to Accelerate Decarbonization of Industrial Heating," presented at the ESIG 2024 Forecasting & Markets Workshop, June 12, 2024.

Kathleen Spees, "What GHG Accounting Data do States Need?: Measuring GHG Emissions Reductions in the Electricity Sector," presented to the Clean Energy States Alliance, April 18, 2024.



Sam Newell, Kathleen Spees, Andrew Levitt, Daniel Shen, and John Higham, "MISO Reliability Attributes "Solution Space": Initial Assessment of Promising Solutions to Meet Identified Priority Attribute Needs," October 4, 2023.

John Tsoukalis, Kathleen Spees, Johannes Pfeifenberger, Andrew Levitt, Andrew W. Thompson, "South Carolina Electricity Market Reform Measures Study," presented to the South Carolina Electricity Market Reform Measures Study Committee, May 1, 2023.

Kathleen Spees, "Locational Marginal Emissions: Opportunities to Improve Cost-Effective Clean Energy Transition with Granular Greenhouse Gas Emissions Data," presented at the New England Electricity Restructuring Roundtable, December 9, 2022.

Kathleen Spees and Matthew O'Loughlin, "Stranded Fossil Fuel Infrastructure: How Big is the Stranded Asset Problem and What Should We Do About it?," presented to American Gas Association FERC Regulatory Committee, June 2021.

Kathleen Spees, "The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition," presented to New England Power Pool, October 2020.

Judy Chang, Kathleen Spees, and Pearl Donohoo-Vallett, "Enabling Canadian Imports for Advancing Clean Energy Strategies for the US—Considerations for Policymakers," prepared for the Canadian Electricity Association and Canadian Embassy Event, July 2020.

Kathleen Spees, "The Next Generation of Energy Resource Plannin," presented at the National Conference of State Legislatures 2019 Legislative Summit, August 2019.

Kathleen Spees and Matthew Witkin, "Market Design for a Clean Grid: Unlocking the Potential for Non-Emitting and Emerging Technologies," presented to IESO Non-Emitting Resource Subcommittee, January 22, 2018.

Kathleen Spees, "Clean Energy Markets: The 'Missing Link' to Market Design 3.0," presented to the Harvard Electricity Policy Group, October 4, 2018.

Kathleen Spees, "The Cutting Edge in Resource Planning," presented to the Solar Energy Industries Association, November 12, 2018.

Kathleen Spees, "An Economic Perspective on Reliability: Rethinking System Needs and in a Future Dominated by Renewables, New Tech, and Engaged Consumers." Presented at the Electricity Consumers Resource Council. November 28, 2018.

Kathleen Spees, Judy Chang, and David Luke Oates, "A Dynamic Clean Energy Market in New England," prepared for Conservation Law Foundation, Brookfield Renewable, NextEra Energy Resources, and National Grid, November 2017.

Judy Chang, Kathleen Spees, and Johannes Pfeifenberger, "Hello World: Alberta's Capacity Market," presented at the 2018 IPPSA Conference, November 2017.

Kathleen Spees, "Decarbonisation and Tomorrow's Electricity Market," presented at the 2017 IESO Stakeholder Summit, June 12, 2017.



Kathleen Spees, Johannes P. Pfeifenberger, Judy Chang, Yingxia Yang, Rebecca Carroll, Roger Lueken, and Colin McIntyre, "Flexibility Enhancements: Alberta Needs and Experience from Other Jurisdictions," prepared for the Alberta Electricity System Operator," August 10, 2017.

Kathleen Spees, "Rethinking Capacity Mechanisms in the Context of Emerging Flexibility Challenges," presented at the European Capacity Mechanisms Forum, February 3, 2017.

Kathleen Spees, "CO₂e Cap-and-Trade: Interactions with Electricity Markets," presented to the Associated of Power Producers of Ontario, November 15, 2016.

Kathleen Spees, Samuel A. Newell, and Judy Chang, "Using Competitive Markets to Achieve Policy Objectives: How the Systems Built for Fossil Plants Can Evolve to Support the Clean, Distributed Grid of the Future," presented at the Energy Bar Association 2017 Annual Meeting & Conference, March 29, 2017.

Judy Chang, Kathleen Spees, and Pearl Donohoo-Vallett, "Enabling Canadian Imports for Advancing Clean Energy Strategies for the U.S.: Considerations for Policymakers," presented at the Embassy of Canada and Canadian Electricity Association's Half-day Conference, October 24, 2016.

Kathleen Spees, Samuel A. Newell, David Luke Oates and James Mashal, "Clean Power Plan in Texas: Implications for Renewables and the Electricity Market," presented at the 2016 Renewable Energy Law Conference, February 9, 2016.

Johannes P. Pfeifenberger, Judy Chang, Kathleen Spees, and Matthew K. Davis, "Impacts of Distributed Storage on Electricity Markets, Utility Operations, and Customers," presented at the 2015 MIT Energy Initiative Associate Member Symposium, May 1, 2015.

Judy Chang, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis, "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," presented at the Energy Storage Policy Forum 2015, Washington, DC, January 29, 2015.

Kathleen Spees, "EPA's Clean Power Plan: Potential Impacts on Asset Values," presented at the Infocast 7th Annual Projects & Money Summit 2015, January 13, 2015.

Judy Chang, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis, "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," presented at the UBS Investment Research Webinar, December 5, 2014.

Kathleen Spees and Judy Chang, "Evaluating Cooperation Opportunities under CAA 111(d)," presented at the Eastern Interconnection States' Planning Council, October 2, 2015.

Kathleen Spees, "Implications of EPA's Clean Power Plan under Clean Air Act Section 111(d)," presented to the Department of Engineering and Public Policy at Carnegie Mellon University, September 18, 2015.



Kathleen Spees, Samuel A. Newell, and Johannes P. Pfeifenberger, "ERCOT's Optimal Reserve Margin: As Estimated for the Public Utility Commission of Texas and the Electric Reliability Council of Texas," presented at the 2014 Texas Industrial Energy Consumers Annual Meeting, July 15, 2014.

Johannes P. Pfeifenberger, Samuel A. Newell, and Kathleen Spees, "Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks," presented to the Harvard Electricity Policy Group Seventy-Fourth Plenary Session, February 27, 2014.

Kathleen Spees, Johannes P. Pfeifenberger, and Samuel A. Newell, "ERCOT's Optimal Reserve Margin," presented at the UBS Investment Research investor conference call, February 19, 2014.

Kathleen Spees, "Capacity Markets: Lessons Learned from the First Decade," presented at EUCI 10th Annual Capacity Markets Conference, November 7, 2013.

Johannes P. Pfeifenberger and Kathleen Spees, "Characteristics of Successful Capacity Markets," presented at the APEx Conference 2013, New York. NY, October 31, 2013.

Kathleen Spees and Johannes Pfeifenberger, "Outlook on Fundamentals in PJM's Energy and Capacity Markets," presented at the 12th Annual Power and Utility Conference, Hosted by Goldman Sachs, August 8, 2013.

Samuel A. Newell and Kathleen Spees, "Get Ready for Much Spikier Energy Prices: The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented at the Cadwalader Energy Investor Conference, February 7, 2013.

Kathleen Spees and Johannes P. Pfeifenberger, "PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update," presented at the Barclays North American Utilities Investor Call, February 4, 2013.

Kathleen Spees and Johannes P. Pfeifenberger, "Seams Inefficiencies: Problems and Solutions at Energy Market Borders," presented at the EUCI Canadian Transmission Summit, July 17, 2012.

Kathleen Spees, "New U.S. Emission Regulations: Electric Industry Impacts," presented at the U.S. Energy 24th Annual Energy Conference, May 11, 2012.

Kathleen Spees, "Market Design from a Practitioner's Viewpoint: Wholesale Electric Market Design for Resource Adequacy," presented at the Lawrence University Economics Colloquium, April 23, 2012.

Kathleen Spees, "Options for Extending Forward certainty in Capacity Markets," presented at the EUCI Conference on Capacity Markets: Achieving Market Price Equilibrium, November 9, 2011.

Kathleen Spees and Johannes P. Pfeifenberger, "Resource Adequacy: Current Issues in North American Power Markets," presented at the Alberta Power Summit, November 19, 2011.

Kathleen Spees and Samuel Newell, "Capacity Market Designs: Focus on CAISO, NYISO, PJM, and ISO-NE," presented at the Midwest ISO Supply Adequacy Working Group, July 19, 2010.



Johannes P. Pfeifenberger and Kathleen Spees, "Best Practices in Resource Adequacy," presented at the PJM Long Term Capacity Issues Symposium, January 27, 2010.

Judy Chang, Kathleen Spees, and Jurgen Weiss, "Using Storage to Capture Renewables: Does Size Matter?," working paper presented at the 15th Annual POWER Research Conference, University of California Energy Institute's Center for the Study of Energy Markets, March 18, 2010.



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Dr. Newell leads Brattle's Electricity Group of 60 consultants addressing economic questions in the industry's energy transition.

His 25 years of consulting experience centers on electricity wholesale markets, market design, transmission planning, resource planning and contracting, resource valuation, and policy analysis. He advises, conducts studies, and testifies in state and federal proceedings for a variety of clients, including ISOs, state energy agencies, infrastructure investors, and wholesale market participants.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Electricity Litigation & Regulatory Disputes

EDUCATION

- Massachusetts Institute of Technology
 PhD in Technology Management and Policy
- Stanford University
 MS in Materials Science and Engineering
- Harvard University
 AB in Chemistry and Physics

PROFESSIONAL EXPERIENCE

- The Brattle Group (2004–Present)
 Principal and Electricity Group Leader
- Cambridge Energy Research Associates (2003–2004)
 Director of Transmission
- Kearney, f.k.a "A.T.Kearney" (1998–2002)
 Manager



Samuel Newell

CONSULTING EXPERIENCE

CAPACITY MARKET DESIGN (ORGANIZED BY JURISDICTION)

- PJM's Capacity Market Reviews and Parameters. For PJM, co-led all six official reviews of its Reliability Pricing Model (2008, '11, '14, '18, '22, and '25). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE), the methodology for estimating net energy and ancillary services revenues, and indicative Net CONE. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. Separately, provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources for use in the Minimum Offer Price Rule and in Market Seller Offer Caps. Submitted testimonies before the FERC.
- Forward Energy and Ancillary Services (EA&S) Revenues in PJM. For PJM, developed a
 method for using forward prices to estimate energy and ancillary services revenues for
 the purposes of determining capacity market parameters. Collaborated with Sargent &
 Lundy to establish resource characteristics, and with PJM staff to conduct hourly virtual
 dispatch. Filed testimony with the FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at the FERC.
- Buyer Market Power Mitigation in PJM. On behalf of the "Competitive Markets
 Coalition" group of generating companies, helped develop and evaluate proposals for
 improving PJM's Minimum Offer Price Rule so that it more effectively protected the
 capacity market from manipulation by buyers while reducing interference with nonmanipulative activity. Participated in discussions with other stakeholders. Submitted
 testimony to the FERC supporting tariff revisions that PJM filed.
- Resource Accreditation. Co-authored two whitepapers in 2022 for the Massachusetts
 Attorney General's Office on resource accreditation methodologies, including "ELCC" and
 empirical methods; evaluated reform options for New England.
- ISO-NE Capacity Demand Curve. For ISO-NE, designed the first demand curve for its
 Forward Capacity Market. Solicited input from staff and stakeholders on objectives.
 Provided and evaluated curves, showing tradeoffs between reliability uncertainty and
 price volatility using Brattle's probabilistic capacity market simulation model. Worked
 with Sargent & Lundy to estimate the Net Cost of New Entry to which demand curve
 prices were indexed. Submitted testimonies to the FERC, which accepted the proposed
 curve.
- Offer Review Trigger Prices. For ISO-NE's Internal Market Monitor, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity



Market. Worked with Sargent & Lundy to analyze the costs of constructing and operating gas-fired generation technologies and onshore wind and estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable given their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, whether to have an auction price ceiling and floor, and other auction parameters.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits from neighbors for capacity costs and prices, emergency procurement costs, and energy prices. Submitted whitepaper to the FERC.
- New York State Resource Adequacy Constructs. For NYSERDA, evaluated the customer
 cost impacts of several alternative constructs that differed in whether the FERC or the
 state set the rules and how buyer-side mitigation was implemented.
- Evaluation of Moving to a Forward Capacity Market in NYISO. For NYISO, conducted a
 benefit-cost analysis of replacing its prompt capacity market with a four-year forward
 capacity market. Evaluated options based on stakeholder interviews and experience
 from PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation,
 implementation costs, and long-run costs.
- MISO Resource Adequacy Framework for a Transforming Fleet. Advised MISO on its
 Resource Availability and Need initiative (2020-2022) to address year-round shortage
 risks as the fleet transformed. Presented to stakeholders on resource accreditation,
 determination of load requirements, modifications to the Planning Reserve Auction, and
 interactions with outage scheduling and with energy and ancillary services markets.
- MISO Competitive Retail Choice Solution. For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the FERC.
- MISO's Resource Adequacy Construct and Market Design Elements. For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.
- **Singapore Capacity Market Development**. For Singapore's Energy Market Authority (EMA), developed a complete forward capacity market (FCM) design in 2018-2021.



- Worked with EMA, other government entities, and stakeholders. Analyzed Singapore's market and regulatory context. Published high-level design documents and presented to stakeholders. The FCM was shelved due to a change in government priorities.
- Western Australia Capacity Market Design. For the Public Utilities Office (PUO) of
 Western Australia, led a Brattle team to advise on the design of a new forward capacity
 market. Reviewed design proposed by the PUO; evaluated options for auction
 parameters such as the demand curve; recommended supplier-side and buyer-side
 market power mitigation measures; and helped define administrative processes needed
 to conduct the auction and the governance of such processes.
- Western Australia Reserve Capacity Mechanism. For EnerNOC, evaluated Western Australia's Reserve Capacity Mechanism in comparison to international capacity markets, and recommended improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other officials.
- Preparing a Gentailer for a Transformed Wholesale Market Design. Supported a
 gentailer in Alberta to prepare its generation and retail businesses for the proposed
 implementation of a capacity market.

ENERGY & ANCILLARY SERVICES (AND OTHER) MARKET DESIGN AND ANALYSIS

- Independent Monitoring Report. For Vistra Corp., prepared an independent monitoring
 report on certain natural gas-fired generation assets' offers into PJM's energy market to
 ensure that they complied with requirements imposed by the FERC to offer their energy
 at cost for an interim period until the assets could be divested following a merger.
- Market & Regulatory Mechanisms to Maintain Reliability in Transforming Grid. For MISO, led a study to identify, evaluate, and recommend solutions to MISO's projected challenges with resource adequacy, flexibility, and system stability, as input into MISO's market development roadmap. Resource adequacy solutions included enhanced accreditation bolstered by stronger real-time incentives; flexibility solutions pointed to a suite of ancillary service products and to enhancements to unit commitment and multiinterval dispatch; system stability solutions pointed mostly to transmission planning but also identified a need for standardizing inverter capabilities and settings.
- Market Development Vision for MISO. For MISO, worked with staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next two to five 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; and proposing criteria for prioritizing initiatives within and across focus areas.



- RTO Accommodation of Retail Access. For MISO, identified business practice
 improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and
 OH. Studied retail accommodation practices in other RTOs, focusing on how they
 modified their procedures surrounding transmission access, qualification of capacity
 resources, capacity markets, FTR allocations, and settlement.
- Gas-Electric Reliability Challenges. For MISO, provided a report assessing future gaselectric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.
- ERCOT Cost of New Entry. For ERCOT, estimated the cost of new entry for merchant
 entry in the ERCOT market for 2026, for use in various analyses and energy market
 parameters. Focused on aeroderivative turbines and solar-storage hybrid plants, as the
 predominant resource types being built in ERCOT. Collaborated with Sargent & Lundy on
 bottom-up cost analyses, and developed financial model to produce levelized costs.
 Presented to stakeholders and met with PUCT Commissioners.
- ERCOT Post-Uri Market Reform. Advised ERCOT and the Public Utility Commission of Texas (PUCT) regarding market design for reliability. Interviewed commissioners, ERCOT, and stakeholders. Helped frame the problem as primarily resource adequacy and secondarily as operational flexibility; evaluated market design proposals to support resource adequacy; evaluated refinements to the Operating Reserve Demand Curve and to Ancillary Services; presented recommendations and commented on stakeholder proposals at numerous PUCT workshops. Later invited by the State Energy Plan Advisory Committee to testify.
- ERCOT's Proposed Future Ancillary Services Design. For ERCOT, evaluated the benefits
 of its proposal to create more ancillary services, enable broader participation by load
 resources and new technologies, and tune procurement amounts to system conditions.
 Worked with ERCOT staff to assess each ancillary service and how generation, load
 resources, and new technologies could participate. Directed their simulation of the
 market using PLEXOS and evaluated non-modeled benefits.
- Investment Incentives in ERCOT. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy; and (3) evaluate options to enhance resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Conclusions were filed and presented at a subsequent PUCT proceeding.
- Operating Reserve Demand Curve (ORDC) in ERCOT. For ERCOT, evaluated several
 alternative ORDCs' effects on real-time price formation and investment incentives.
 Conducted back-cast analyses using interval-level data provided by ERCOT and assuming
 generators modified their commitment and dispatch in response to higher prices under
 the ORDC. Informed ERCOT's and the PUCT's selection of final ORDC parameters.



- Economically Optimal Reserve Margins in ERCOT. For ERCOT, co-led studies (2014 and 2018) estimating the economically optimal reserve margin and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- Vertical Market Power. Before the New York Public Service Commission (NYPSC),
 examined whether the merger between National Grid and KeySpan could create
 incentives to exercise vertical market power. Employed nodal production cost
 simulations using the DAYZER model and examined whether outages of National Grid's
 transmission assets significantly affected KeySpan's generation profits.
- Energy Price Formation in PJM. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices.
 Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with the FERC, and which the FERC largely accepted and cited in its April 2019 Order.
- Energy Market Monitoring & Market Power Mitigation. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- Market Design for Energy Security in ISO-NE. For NextEra Energy, evaluated and
 developed proposals for meeting winter energy security needs in New England when
 pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with
 new day-ahead operating reserves. Developed competing proposal for new operating
 reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also
 developed criteria and high-level approach for potentially incorporating energy security
 into the forward capacity market. Presented evaluations and proposals to stakeholders.
- 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. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- LMP Impacts on Contracts. For a California agency, reviewed the California ISO's
 proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed
 implications for "seller's choice" supply contracts where the supplier could select the
 delivery point. Estimated congestion costs ratepayers would face if suppliers financially
 delivered power to the lowest priced nodes; estimated incremental contract costs using



Samuel Newell

- 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.
- Wholesale Rates. On behalf of Tri-State Electric Co-op before the Public Service
 Commission of Colorado, provided testimony regarding its wholesale rates, which were
 contested by member co-ops. Analyzed the co-op's cost of service and its marginal cost
 of meeting customers' energy and peak demand requirements.
- IESO's Market Renewal Program / Energy Market Settlements. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for new day-ahead and real-time nodal markets, including make-whole payments for combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- Alberta Market Design. For a utility in Alberta, presented market/regulatory design reform options for the province to attract and retain enough resources and efficiently allocate risk in the transition to clean energy.
- Australian Electricity Market Operator (AEMO) Redesign. Advised AEMO on reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- Energy Market Power Mitigation in Western Australia. Led a Brattle team to help
 Western Australia's Public Utilities Office design market power mitigation measures for
 its newly reformed energy market. Established objectives, interviewed stakeholders,
 assessed local market characteristics, and synthesized lessons learned from the existing
 energy market and from several international markets. Recommended criteria, screens,
 and mitigation measures for day-ahead and real-time energy and ancillary services
 markets. The client used our whitepaper to support its conclusions.

CLEAN ENERGY MARKET DESIGN

- Malaysia Clean Energy Exchange. Worked with Single Buyer to develop the market design for an international clean energy exchange for selling solar power into Singapore and to/between other adjacent countries. Work scope encompassed product definition, demand and supply participation, auction format, scheduling and delivery, financial settlements, market power mitigation, governance, and implementation plan.
- Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals. Led a
 Brattle team to help NYISO: (1) develop and evaluate market design options, including
 mechanisms for charging emitters and allocating revenues to customers, border
 adjustments to prevent leakage, and interactions with other market design and policy
 elements; and (2) develop a model to evaluate how carbon pricing would affect market
 outcomes, emissions, system costs, and customer costs under a range of assumptions.
 Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in
 detailed market design and stakeholder engagement.



ELECTRICITY LITIGATION

- Expert Testimony in Ongoing Contract Disputes over Ancillary Services. In several similar cases in Texas state court, on behalf of two energy services companies that served as qualified scheduling entities for and/or as bilateral buyers of Responsive Reserve Service (RRS) supply responsibility credits from industrial companies with Load Resources, testified on which party was responsibility for paying ancillary services imbalance charges incurred when the resources were deployed in February 2021 during Winter Storm Uri. Assessed, in relation to the agreements between the parties, ERCOT's protocols for financially settling imbalance charges and other related credits surrounding RRS, and the economic implications of allocating imbalance charges to one party versus the other. Submitted expert reports and rebuttal reports and was deposed in each case.
- Expert Testimony in Contract Disputes over Ancillary Services Imbalance Charges. In another ongoing case similar to the above, on behalf of the same company against a different plaintiff in Texas state court, submitted expert report and rebuttal report.
- Consulting Support in Brazos Bankruptcy. For a major generation company intervening
 in the Brazos Bankruptcy in Texas state court, provided consulting support regarding
 ERCOT wholesale power prices during Winter Storm Uri, when extreme weather
 conditions caused nearly half of Texas to lose power for several days.
- Expert Testimony in FERC Enforcement Matter. In the U.S. District Court of Maine, provided expert testimony on behalf of the FERC Office of Enforcement in Fed. Energy Regulatory Comm'n v. Silkman regarding allegations that defendant "engag[ed] in a fraudulent scheme to manipulate the ISO New England, Inc. (ISO-NE) Day-Ahead Load Response Program" by gaming the baseline and claiming false reductions in load. Submitted initial and rebuttal reports analyzing if defendant's conduct was consistent with industry practice and the purpose of demand response. The matter settled.
- Expert Testimony in Contract Dispute in New England. On behalf of an international engineering, procurement, and construction (EPC) contractor in a dispute with a plant owner regarding payments for constructing the plant and in support of client's motion about the use of its letter of credit; co-authored written testimony on the fair market value of the plant and on whether the value would suffice to cover the plant's debt and certain other obligations. Simulated energy and capacity markets to forecast net revenues and estimated exposure to capacity performance penalties. Compared the valuation to transaction prices of similar plants. Submitted report to the American Arbitration Association and the International Centre for Dispute Resolution.
- Expert Testimony on Damages from Alleged Misrepresentations of a DR Company.
 Provided testimony on behalf of a client alleging that a demand response (DR) company it had acquired had overstated its DR capacity and technical capabilities. Analyzed discovery materials including detailed DR 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 expert report, deposition, and testimony at hearing before the American Arbitration Association (non-public).



- Litigation Support on Damages in Contract Dispute. For California's Department of
 Water Resources and Attorney General's office, supported testifying expert on damages
 resulting from an electricity supplier's alleged 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.
- Litigation Support on Damages in Contract Dispute. For the California Department of
 Water Resources and the California Attorney General's office, 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.
- Litigation Support on Contract Termination Payment. For an independent power
 producer, supported testifying expert on damages from a buyer's termination of a longterm tolling contract for a gas-fired plant in PJM. Involved wholesale market price
 forecasting, assessing the plant's costs and operations, and financial valuation. Prepared
 witness for arbitration; helped counsel to depose and cross-examine opposing experts.

TRANSMISSION PLANNING AND MODELING

- Initial Report on the New York Power Grid Study. With NYSERDA, NYDPS, and Pterra, submitted a report to the NYPSC projecting New York's transmission needs to support its long-term clean energy goals under the Climate Leadership and Community Protection Act. Our work synthesized findings from three sub-reports addressing local T&D needs, offshore wind, and overall bulk system needs.
- Value of a NY Public Policy Transmission Project. On behalf of NY Transco LLC, submitted testimony in 2020 regarding the economic benefits of Transco's proposed "Segment B" transmission project. Critiqued an opposing expert's production cost analysis and broader benefit-cost analysis.
- Benefit-Cost Analysis of New York AC Transmission Upgrades. For the NYDPS and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability from Upstate to Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. Informed DPS's recommendation to the NYPSC to declare a Public Policy Need to build a project such as the best ones identified.



- Evaluation of New York Transmission Projects. For the NYDPS, provided a cost-benefit
 analysis for the "TOTS" transmission projects. Found net production cost and capacity
 resource cost savings exceeding project costs, and the lines were approved. Involved
 running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- Economic and Environmental Evaluation of New Transmission to Quebec. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- Benefit-Cost Analysis of a Transmission Project for Offshore Wind. Submitted testimony
 on the economic benefits of the Atlantic Wind Connection, a proposed 2,000 MW DC
 offshore backbone from New Jersey to Virginia with seven landing points. Described and
 quantified the effects on congestion, capacity markets, CO₂ emissions, system reliability
 and operations, jobs and the economic, and the installed cost of offshore wind farms.
 Directed Ventyx staff to simulate energy market impacts using the PROMOD model.
- 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 the FERC.
- Benefit-Cost Analysis of New Transmission in the Midwest. For American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed Paddock-Rockdale 345 kV line. Advised client on running PROMOD IV to quantify energy benefits, and developed metrics to account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methods 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.
- Analysis of Transmission Congestion and Benefits. Analyzed impacts on transmission congestion and customer benefits in California and Arizona of a proposed interstate transmission line. Used the DAYZER model to simulate congestion and power market conditions considering increasing renewable generation requirements.
- 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. Evaluated benefits beyond those captured in a
 production cost model, including the value of integrating a pumped storage facility for
 accommodating a larger amount of intermittent renewable resources at a reduced cost.
- Transmission Investments and Congestion. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.



- Analysis of Transmission Constraints and Solutions. Performed a multi-client study identifying major transmission bottlenecks in the western and eastern Interconnections and evaluating potential solutions. Worked with transmission engineers from client 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 major economic transmission projects.
- Market Impacts of RTO Seams. For a consortium of Midwestern 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 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 proceeding before the FERC, assisted expert witness on: (1) MISO and PJM's real-time inter-RTO coordination process; and (2) the benefits of implementing a full joint-and-common market. Analyzed lack of convergence between MISO and PJM energy prices and shadow prices on reciprocal coordinated flow gates.
- RTO Participation. For an integrated Midwest utility, advised on alternative RTO choices.
 Used GE-MAPS to model the transmission system and wholesale markets under various
 scenarios. 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.
- Transmission Tariffs. For a merchant generating company participating in FERC hearings
 on developing a Long-Term Transmission Pricing Structure, helped a stakeholder
 coalition 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 MISO-PJM.
- Merchant Transmission Impacts. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices.
- Security-Constrained Unit Commitment and Dispatch Model Calibration. For a
 Midwestern utility, calibrated its PROMOD IV model, focusing on LMPs, unit
 commitment, flows, and transmission constraints. Helped client understand the model's
 shortcomings and identify improvements. Assisted with initial assessments of FTRs in
 preparation for its submission of nominations in MISO's first allocation of FTRs.



VALUATION OF GENERATION, FUEL, STORAGE ASSET VALUATION, AND PROCUREMENTS

- Solar and Storage Procurements. On behalf of the Carolinas Clean Energy Business Association, submitted testimony and presented at workshop regarding Duke Energy's Carbon Plan. Assessed opportunities for Duke Energy to procure solar PV energy from independent power producers to avail itself of the lowest cost option for ratepayers to meet clean energy goals and system needs: evaluated drivers of recent attrition of contracted projects and prospects going forward; evaluate the cost savings Duke and its ratepayers could enjoy if Duke exercised its ability to competitively solicit standalone storage projects in "Build Own Transfer" (BOT) arrangements.
- Value of Flexibility in ERCOT. For a company evaluating a range of investment strategies, assessed the value of flexibility in ERCOT both in present day and in the future as wind and solar penetration increased. Used Brattle's GridSIM model to project investments and retirements over the next ten years. Analyzed the likely increase in demand for ancillary services. Simulated system operations accounting for short-term uncertainty in net load forecasts, using ENELYTIX PSO to model day-ahead and real-time operations.
- Storage Development Company Due Diligence. For an investor considering an equity investment in a storage development company in ERCOT, reviewed the developer's business model, interviewed the developer, and evaluated its revenue projections.
- Storage Asset Development in New York. For a renewable generation company
 considering developing new storage assets in New York City and Long Island, provided a
 wholesale market analysis, including a 20-year estimate of net revenues. Used Brattle's
 GridSIM model to simulate investment, operations, prices, and revenues over that
 timeframe, after calibrating the model to current actual prices.
- Evaluation of Clean Energy & Transmission Procurement Options. For a potential buyer
 of new transmission and remote clean resources (incl. hydropower from Canada),
 supported the development of a regulatory order and subsequent RFP drafting.
 Evaluated costs and benefits under various contracting approaches; assessed the
 possibility of resource shuffling and emissions backfilling; considered the value of storage
 services. After the RFP was issued, helped evaluate responses, informing awards.
- Offshore Wind Developer Bid Analysis. Supported an offshore wind developer with its
 Index OREC bid of an 800+ MW project into NYSERDA's NY1 solicitation. Informed energy
 basis risk by conducting nodal market simulations at various candidate interconnection
 points; informed capacity basis risk by modeling the ICAP market and estimated marginal
 capacity accreditations that could be applicable in the future.
- Valuation of a Gas-Fired Combined-Cycle Plant in ERCOT. For a generation company, estimated net revenues for an existing plant using Brattle's GridSIM model to project investment/retirement, operations, prices, and revenues over that time period, after calibrating the model to recent prices. Assessed market risks.
- Valuation of a Portfolio of Combined-Cycle Plants across the US. For a lender to a portfolio of plants, estimated the fair market value of each plant in 2018 and the



- plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our models and reference points from futures markets and publicly available studies. Performed probability-weighted discounted cash flow valuations across a range of scenarios. Provided insights into market and regulatory drivers and how they might evolve.
- Wholesale Market Value of Storage in PJM. For an investor in battery storage, estimated the energy, ancillary services, and capacity market revenues it could earn in PJM. Reviewed market participation rules. Forecasted capacity market revenues and performance penalties. Developed a real-time energy and ancillary service bidding algorithm the asset owner could employ to optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- Valuation of a Generation Portfolio in ERCOT. For the owners of a portfolio of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over several plausible scenarios. Analyzed the effects that load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how changes in drivers could change the value over time.
- Gas Pipeline Investment for Electricity. For the Maine Office of Public Advocate, cosponsored testimony regarding the reliability and economic impacts if the Maine PUC
 signed long-term contracts for electricity customers to pay for new gas pipeline capacity
 into New England. Analyzed other expert reports and provided a framework for
 evaluating whether such procurements would be in the public interest, considering their
 costs and benefits vs. alternatives.
- Gas Pipeline Investment for Electricity. For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- Valuation Methodology for a Coal Plant Transaction in PJM. For an owner of a large coal
 plant being transferred at a value yet to be assessed by a third party, wrote a guide on
 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. Our guide was used to inform their preassessment 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 on effects
 of coal and gas prices on cash flows and 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. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.



Samuel Newell

- Valuation of Generation Assets in New England. To inform several potential buyers'
 valuations of existing assets, 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 scenarios to test whether the plant could be worth less than the debt. Reviewed documents in the "data room" to identify market, operational, and fuel supply risks.
- Valuation of Generation Asset Bundle in PJM. For a potential buyer, provided energy
 and capacity price forecasts and reviewed their valuation analysis. Analyzed 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 of a wind farm in Michigan, forecasted energy and capacity revenues under a range of scenarios.
- Wind Power Financial Modeling. For an offshore wind developer proposing a 350 MW project off the coast of New Jersey, analyzed market prices for energy, RECs, and capacity. Provided a 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 cogen plant in PJM, analyzed 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**. For an independent power producer, served for two years as an advisor on its growth. Led a team to assess the profitability of proposed power plants and acquisitions of plants throughout the US. Used GE-MAPS to simulate power prices, congestion, and generator dispatch, and forecasted capacity prices.
- 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 scenarios. Identified key uncertainties and risks.

ENERGY POLICY ANALYSIS

• Effect of Clean Energy Tax Credits on Electricity Costs and the Economy. For ConservAmerica, led a study of the effects of clean energy tax credits on US investment in generation, electricity rates, economic growth, and jobs through 2035. Leveraged Brattle's gridSIM capacity expansion model and its BEYOND model of the US economy.



- Blueprint for Consideration of Advanced Nuclear Energy Technologies. Co-led a Brattle
 team to support NYSERDA's development of a blueprint for pursuing possible nuclear
 development in New York state. Addressed the potential value, technology options, and
 a broad range of issues that would need to be considered; helped incorporate responses
 to stakeholder comments.
- Life Extension for Diablo Canyon. For an environmental organization in California in 2022, evaluated the net benefits of extending the operating life of the Diablo Canyon Nuclear Power Plant. Calibrated the base case in Brattle's gridSIM capacity expansion model to existing studies sponsored by CA state agencies and estimated the impacts of retaining Diablo Canyon in terms of emissions, fixed and variable costs, and ability to meet both reliability objectives and clean energy goals.
- Tariffs on PVs. For a renewable energy advocacy group in 2022, evaluated the impacts of
 potential anti-circumvention tariffs that the Department of Commerce was considering
 imposing on PVs from four countries. Our team developed a trade model to estimate the
 impact on market prices for panels in the US; leveraged our gridSIM capacity expansion
 model to estimate the impact on utility-scale investments, emissions, and energy
 prices/costs, and then created a macroeconomic model to estimate effects on jobs and
 GDP.
- Renewable Energy Tax Policy Impacts. For ACORE, a renewable energy advocacy group, evaluated alternative proposals to extend and expand tax credits in 2021. Simulated investment, costs, prices and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model.
- Clean Energy Transformation. For NYISO, led a team to project how the fleet might
 evolve to meet the state's mandates for 70% renewable electricity by 2030 and 100%
 carbon-free electricity by 2040. Used gridSIM to model investment and operations
 subject to constraints on reliability and clean energy. Evaluated technology needs for
 meeting load during extended periods of low wind/solar. The study helped inform
 questions about future market design and reliability.
- Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal. For a broad group of stakeholders opposing the rule in a filing before the FERC, evaluated the Department of Energy's (DOE) proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply, the likely cost of the rule, and the incompatibility of DOE's proposal with the principles and function of competitive wholesale electricity markets.
- Retail Rate Riders. For a traditionally regulated Midwest utility, helped general counsel
 to evaluate and support legislation and proposed 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 and drafted proposed rules
 and tariff riders for client.



INTEGRATED RESOURCE PLANNING (IRP)

- Resource Planning in Hawaii. Assisted the Hawaiian Electric Companies in developing its
 Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain
 system security as renewable penetration increases toward 100% and displaces
 traditional synchronous generation. Solutions involved defining technology-neutral
 requirements that may be met by demand response, distributed resources, and new
 technologies as well as traditional resources.
- IRP in Connecticut (for 2008, 2009, 2010, 2012, and 2014 Plans). For two utilities and the state Department of Energy and Environmental Protection (DEEP), led the analysis for five IRPs, coordinating multiple teams across several organizations. Projected a tenyear scenarios for resource adequacy, customer costs, emissions, and RPS compliance; evaluated resource procurement strategies for energy efficiency, renewables, and traditional sources. Used an integrated modeling system to simulate the New England locational energy market, the Forward Capacity Market, REC markets, and investments and retirements. Addressed electricity supply risks, natural gas supply, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided testimony before the DEEP.
- Contingency Plan for Indian Point Nuclear Retirement. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant retired. Evaluated generation and transmission proposals on three dimensions: reliability contributions, viability for completion by 2016, and the net present value of costs. Partnered with engineering sub-contractors, ran GE-MAPS and a capacity market model, and provided 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 CO₂ 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 client gain support internally and begin to prepare for regulatory communications.

DEMAND RESPONSE MARKET PARTICIPATION, MARKET POTENTIAL, AND MARKET IMPACT

Demand Response (DR) Integration in MISO. Through several assignments, helped MISO incorporate DR into its energy market and resource adequacy constructs, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy and ancillary services markets; (2) analyzed market



participation barriers; (3) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets and identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; and (4) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying other RTOs' practices and by characterizing the DR resources within the MISO footprint.

- Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity. For
 the Australian Energy Market Commission (AEMC), co-authored a report on market
 designs and participation patterns in several international markets. AEMC used the
 findings to inform its integration of DR into its National Energy Market.
- 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.
- Compensation Options for DR in ISO-NE's Energy Market. 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 the FERC.
- ERCOT DR Potential Study. For ERCOT, estimated the market size 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 findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- DR Potential Study. For an eastern ISO, analyzed the potential 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
 curtailment service providers and ISO personnel.
- 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.
- Value of DR Investments. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated 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 short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to the DE, NJ, MD, and DC commissions. Presented findings to the Delaware Public Service Commission.



TESTIMONY AND REGULATORY FILINGS

- Before the FERC, Docket No. ER25-682-000, Affidavit of Dr. Samuel A. Newell, Attachment C to on behalf of PJM Interconnection, L.L.C.'s filing, Revisions to Reliability Pricing Model, December 9, 2024.
- Before the North Carolina Utilities Commission, Docket No. E-100, Sub 190, "Direct Testimony of Samuel A. Newell on behalf of Carolinas Clean Energy Business Association," in the matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and§ 62-110.1(c), May 28, 2024.
- Before the FERC, Docket No. EC23-74-000, Independent Monitoring Report, report prepared for Vistra Corp., April 30, 2024 (with J. Higham).
- Before the FERC, Docket No. ER23-2977-000, "Written Testimony of Dr. Kathleen Spees, Samuel
 A. Newell, and Dr. Linquan Bai" on behalf of Midcontinent Independent System Operator, Inc.,
 regarding the reliability-based demand curve, September 28, 2023.
- Before the FERC, Docket No. ER22-2984-000, "Answering Affidavit of Dr. Samuel A. Newell,
 Kathleen Spees, and John M. Hagerty on Behalf of PJM Interconnection, L.L.C.," regarding
 periodic review of variable resource requirement curve shape and key parameters, November 8,
 2022.
- Before the FERC, Docket No. ER22-2984-000, "Affidavit of Kathleen Spees and Dr. Samuel A.
 Newell on Behalf of PJM Interconnection, L.L.C.," regarding periodic review of variable resource requirement curve shape and key parameters, September 30, 2022.
- Before the FERC, Docket No. ER22-2984-000, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the administrative Cost of New Entry parameter, representing the cost of building a generation plant for use in PJM's capacity market, September 30, 2022.
- Before the FERC, Docket No. ER22-2984-000, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the use of forwardlooking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, September 30, 2022.
- Before the California Senate Committee on Energy, Utilities and Communications,
 Subcommittee on Clean Energy Future, hearing on "Clean reliability: What does California need to ensure grid reliability while reducing fossil fuels?," live, videographic testimony on "Near-



- Term Resource Adequacy Benefits of Retaining Diablo Canyon" for Policy Impact on behalf of Carbon Free California, August 9, 2022.
- Before the Texas State Energy Plan Advisory Committee to the Governor and Legislature (on invitation by the Committee), oral testimony on market design and policy options for supporting resource adequacy in ERCOT, June 28, 2022.
- Before the FERC, Docket No. AD21-10-000, Post-technical Conference Comments and Testimony
 of Dr. Kathleen Spees and Samuel A. Newell on behalf of the New York State Energy Research
 and Development Authority, "Modernizing Electricity Market Design Efficiently Managing Net
 Load Variability in High-Renewable Systems: Designing Ramping Products to Attract and
 Leverage Flexible Resources," February 4, 2022.
- Before the FERC, Docket No. ER21-2582-000, Written Testimony of Dr. Kathleen Spees and Samuel A. Newell on behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, and Union of Concerned Scientists, "Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market," August 20, 2021.
- Before the FERC, Docket No. EL21-7-000, Written Testimony of Dr. Kathleen Spees and Samuel
 A. Newell on behalf of the Natural Resource Defense Council, the Sustainable FERC Project,
 Earthjustice, Sierra Club, American Wind Energy Association, Alliance for Clean Energy New York,
 and Advanced Energy Economy, regarding the economic impacts of buyer-side mitigation in the
 NYISO capacity market, November 18, 2020.
- Before the NY Public Service Commission, Case 19-T-0684, "Rebuttal Testimony of Samuel A.
 Newell on Behalf of New York Transco LLC," in response to the direct testimony of Cricket Valley
 Energy Center, LLC and Guidehouse Inc. regarding the economic benefits of Transco's proposed
 "Segment B" transmission project, September 30, 2020.
- Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Supplemental Affidavit of Samuel A.
 Newell and James A. Read Jr. on Behalf of PJM Interconnection, L.L.C.," regarding the use of
 forward-looking data to estimate energy and ancillary services revenues for the purposes of
 determining capacity market parameters, September 17, 2020.
- Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, August 5, 2020.
- Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000
 (consolidated), "Supplemental Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang



- on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 23, 2020.
- Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000
 (consolidated), "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of
 PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its
 forward capacity market, March 17, 2020.
- Before the Indiana General Assembly 21st Century Energy Policy Development Task Force,
 "Electricity Transmission Basics," oral testimony on behalf of the Indiana Energy Association,
 October 17, 2019.
- Before the American Arbitration Association, International Centre for Dispute Resolution, coauthored confidential expert report for an international engineering, procurement, and construction (EPC) contractor to estimate the fair market value of a power plant at a future date based on projected cash flows and comparables, November 27, 2018.
- Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement
 Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H.
 Gang on Behalf of PJM Interconnection, L.L.C.," regarding the Cost of New Entry, accompanied
 by report, PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants, June 1, 2022,
 online date, October 12, 2018.
- Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Dr. Samuel A. Newell and David Luke Oates on behalf of PJM Interconnection, L.L.C," regarding the Variable Resource Requirement Curve Shape, accompanied by report, Fourth Review of PJM's Variable Resource Requirement Curve, October 12, 2018.
- Before the FERC, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000
 (consolidated), "Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.
- Before the FERC, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A.
 Newell, Dr. Kathleen Spees, and Yingxia Yang on behalf of the Natural Resources Defense
 Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15,
 2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical
 Conference on April 24, 2018.



- Before the FERC, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C.
 Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," prepared for NextEra Energy Resources and attached to Reply Brief of Joint Commenters, March 14, 2018.
- Before the US District Court of Maine, in "Fed. Energy Regulatory Comm'n v. Silkman" (1:16-cv-00205-JAW), submitted "Expert Report of Samuel A. Newell" on behalf of the FERC Office of Enforcement, January 29, 2018, and "Rebuttal Report of Samuel A. Newell," March 15, 2018.
- Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, written and oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.
- Before the FERC, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell regarding "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.
- Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.
- Before the FERC, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.
- Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct
 Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the
 Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass
 Transmission Project," December 30, 2016.
- Before the FERC, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.
- "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.



- Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.
- Before the FERC, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.
- Before the FERC, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.
- Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to testify orally on "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.
- Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.
- Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.
- 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.'s Third Set of Data Requests, Interrogatory,
 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,
 Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets,"
 July 11, 2014.
- Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.



- Before the FERC, Docket No. ER14-1639-000, filed "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.
- Before the FERC, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 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 Public Utility Commission of Texas, at a workshop on Project No. 40000, presented
 "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The
 Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25, 2013.
 Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning
 Reserve Margin Estimates," July 29, 2013.
- Before the FERC, Docket No. ER13-535-000, 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, December 28, 2012.
- Before the FERC, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.
- Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, testified orally on "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.
- Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.
- Before The Public Utility Commission of Texas workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.
- Before The Public Utility Commission of Texas workshop on Project No. 40480, presented
 "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.



- Before the FERC, Docket No. ER12-___-000, Affidavit of 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 FERC, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.
- Before the FERC, Docket No. ER12-13-000, Affidavit of Samuel A. Newell on Behalf of PJM
 Interconnection, LLC, regarding the Cost of New Entry Estimates for Delivery Year 2015/16 in
 PJM's Reliability Pricing Model, December 1, 2011.
- Before the FERC, Docket Nos. ER11-4069 and ER11-4070, Direct Testimony of Johannes
 Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, regarding the public
 policy, congestion relief, and economic benefits of the RITELine Transmission Project, July 18,
 2011.
- Before the FERC, Docket No. No. EL11-13-000, Direct Testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies regarding 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 FERC, Docket No. RM10-17-000, Filed Comments regarding: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).
- Before the FERC, Docket No. RM10-17-000, Filed Comments regarding 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 Board January 8, 2010.



- "Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Dr. 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," 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 Samuel A. Newell, Dr. Metin Celebi, and Attila Hajos, 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," September 22, 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, and D. Murphy, 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 Dr. 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 regarding transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).



- Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the FERC, Docket No. ER04-718-000 et al., regarding 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 FERC, Docket No. ER04-375-002 et al., regarding 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 FERC, Docket No. ER04-375-002 et al., regarding Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

REPORTS & ARTICLES

- A Wide Array of Resources Is Needed to Meet Growing US Energy Demand, report prepared for ConservAmerica, February 2025 (with W. Chang, P. Vincent, and S. Willet).
- *ERCOT CONE for 2026*, <u>report</u> prepared for ERCOT, June 10, 2024 (with A. Thompson, R. Janakiraman, S. Gang, J. Jungé, H. Lee, and P. Nair).
- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 1:
 Foundations of Resource Accreditation, report prepared for Massachusetts Attorney General's
 Office June 2022 (with K. Spees and J. Hingham).
- Capacity Resource Accreditation for New England's Clean Energy Transition: Report 2: Options for New England, report prepared for Massachusetts Attorney General's Office June 2022 (with K. Spees and J. Hingham).
- Offshore Wind Transmission: An Analysis of Options for New York, report prepared for Anbaric, August 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- Singapore Foreward Capacity Market—FCM Design Proposal (Third Consultation Paper),
 prepared for the Singapore Energy Market Authority, May 2020 (with J. Chang and W. Graf).
 Followed draft proposals in first and second Consultation papers in May 2019 and Dec 2019.
- Quantitative Analysis of Resource Adequacy Structures, report prepared for NYSERDA and NYSDPS, July 1, 2020 (with K. Spees, J. Imon Pedtke, and M. Tracy). Update to presentation from July 1, 2020.
- New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment
 Through 2040 Including Alternative Scenarios, report prepared for NYISO Stakeholders, June 22,



Samuel Newell

- 2020 (with R. Lueken, J. Weiss, S. Crocker Ross, and J. Moraski). Update to presentation from May 18, 2020.
- Qualitative Analysis of Resource Adequacy Structures for New York, report prepared for NYSERDA and NYSDPS, May 19, 2020 (with K. Spees and J. Imon Pedtke).
- Offshore Transmission in New England: The Benefits of a Better-Planned Grid, report prepared for Anbaric, May 2020 (with J. Pfeifenberger and W. Graf).
- Implementing Recommended Improvements to Market Power Mitigation in the WEM, report prepared for Energy Policy WA in Western Australia, April 2020 (with T. Brown).
- Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy
 Efficiency, report prepared for PJM, March 17, 2020 (with M. Hagerty, S. Sergici, E. Cohen, S.
 Gang, J. Wroble, and P. Daou).
- "Forward Clean Energy Markets: A New Solution to State-RTO Conflicts," <u>Utility Dive</u>, January 27, 2020 (with K. Spees and J. Pfeifenberger.)
- How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes: Expanded Report Including a Detailed Market Design Proposal, report prepared for NRG, September 2019 (with K. Spees, W. Graf, and E. Shorin). International Review of Demand Response Mechanisms in Wholesale Markets, report for the Australian Energy Market Commission, June 2019 (with T. Brown, K. Spees, and C. Wang).
- Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, 2018 Update, <u>Final Draft</u>, prepared for the Electric Reliability Council of Texas, December 20, 2018 (with R. Carroll, A. Kaluzhny, K. Spees, K. Carden, N. Wintermantel, and A. Krasny).
- Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power Markets
 to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively,
 discussion paper, July 2018 (with K. Spees, J. Pfeifenberger, and J. Chang).
- Fourth Review of PJM's Variable Resource Requirement Curve, report prepared for PJM
 Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Pfeifenberger, K. Spees, and others).
- PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, report prepared for PJM Interconnection LLC for submission to FERC and PJM stakeholders, April 19, 2018 (with J. Michael Hagerty, J. Pfeifenberger, S. Gang of Sargent & Lundy, and others).



Samuel Newell

- Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule, whitepaper prepared for NextEra Energy Resources, October 23, 2017 (with M. Celebi, J. Chang, M. Chupka, and I. Shavel).
- Near Term Reliability Auctions in the NEM: Lessons from International Jurisdictions, report
 prepared for the Australian Energy Market Operator, August 23, 2017 (with K. Spees, D.L. Oates,
 T. Brown, N. Lessem, D. Jang, and J. Imon Pedtke).
- Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals, whitepaper prepared for the New York Independent System Operator, August 10, 2017 (with R. Lueken, J. Weiss, K. Spees, P. Donohoo-Vallett, and T. Lee).
- "How wholesale power markets and state environmental Policies can work together," <u>Utility</u>
 <u>Dive</u>, July 10, 2017 (with J. Pfeifenberger, J. Chang, and K. Spees).
- Market Power Mitigation Mechanisms for the Wholesale Electricity Market in Western Australia, whitepaper prepared for the Public Utilities Office in the Government of W. Australia's Department of Finance, September 1, 2016 (with T. Brown, W. Graf, J. Reitzes, H. Trewn, and K. Van Horn).
- Western Australia's Transition to a Competitive Capacity Auction, report prepared for Enernoc, January 29, 2016 (with K. Spees and C. McIntyre).
- Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal, report prepared for ERCOT, November 2015 (with R. Carroll, P. Ruiz, and W. Gorman).
- Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint—Options for MISO, Utilities, and States, report prepared for NRG, November 2015 (with K. Spees and R. Lueken).
- International Review of Demand Response Mechanisms, report prepared for Australian Energy Market Commission, October2015 (with T. Brown, K. Spees, and D.L. Oates).
- 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 for 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.
 Pfeifenberger, Q. Liao, and with C. Ungate and J. Wroble at Sargent & Lundy).



Samuel Newell

- 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).
- "Capacity Markets: Lessons Learned from the First Decade," <u>article</u>, Economics of Energy & Environmental Policy. Vol. 2, No. 2, Fall 2013 (with J. Pfeifenberger and 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* article, 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).
- 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 for the NYISO and 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).



Samuel Newell brattle.com | 30 of 36

- 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, newsletter, <u>The Brattle Group</u> (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," <u>article</u>, *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, 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, 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 <u>Newsletter</u>, American Bar Association, Section on Environment, Energy, and Resources: Vol. 3 No. 1 (with J. Pfeifenberger).



PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Planning Future Load Growth," panelist at NJBPU Technical Conference, August 5, 2025.
- "Meeting Soaring Demand More Quickly...While Mitigating Increases in Rates and Emissions," presented at the Energy Bar Association Northeast Chapter Annual Meeting, June 18, 2025.
- "Avoiding Attrition of Solar PV," presented to NCUC Carolinas Resource Plan Technical Conference on behalf of the Carolinas Clean Energy Business Association, June 17, 2024.
- "Renewable Energy Economics: Updated on Development Fundamentals," presented at the Institute for Energy Law 2024 Renewables Conference, Houston, TX, April 25, 2024.
- "ERCOT Resource Adequacy: Reliability Standard and Market Design Implications," panelist at GCPA 38th Annual Fall Conference, Austin, TX, October 3, 2023.
- "Priorities for Reforming Resource Accreditation and the Resource Adequacy Framework in New England," presented to NEPOOL Markets Committee, September 14, 2022.
- "Observations and Implications of the 2021 Texas Freeze," presented to Power Markets Today webinar on the February 2021 ERCOT electricity failure, April 14, 2021.
- "Offshore Wind Transmission: An Analysis of Options for New York," presented at LCV Virtual Policy Forum, August 6, 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).
- "Possible Paths Forward from MOPR," presented to Power Markets Today webinar on "Capacity Market Alternatives for States," July 15, 2020.
- "Considerations for Meeting Sub-Annual Needs, and Resource Accreditation across RTOs," presented to MISO Resource Adequacy Subcommittee, July 8, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "New York's Evolution to a Zero Emission Power System—Modeling Operations and Investment through 2040 Including Alternative Scenarios," presented to NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Ross, and J. Moraski).
- "Singapore Foreward Capacity Market Design—Industry Briefing Sessions," presented via video to Singapore electricity market stakeholders, June 5 & 9, 2020 (with W. Graf).
- "Industry Changes in Resource Adequacy Requirements," presented to MISO Resource Adequacy Subcommittee, May 6, 2020 (with J. Pfeifenberger, M. Hagerty, and W. Graf).
- "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," presented to NYISO Stakeholders, March 30, 2020 (with R. Lueken, J. Weiss, J. Moraski, and S. Ross).



- "Electricity Market Designs to Achieve and Accommodate Deep Decarbonization," presented to Advanced Energy Economy (AEE) video conference, "ISO-NE in 2050: Getting To An Advanced Energy Future In New England," March 18, 2020.
- "U.S. Offshore Wind Generation, Grid Constraints, and Transmission Needs," presented at Offshore Wind Transmission, USA Conference, September 18, 2019 (with J. Pfeifenberger and K. Spokas).
- "Pollution Pricing in the Power Sector: Market-Friendly Tools for Incorporating Public Policy," presented to GCPA Spring Conference, Houston, TX, April 16, 2019.
- "The Transformation of the Power Sector to Clean Energy: Economic and Reliability Challenges," keynote address to the Power Engineers 4th Annual Power Symposium, Weehawken, NJ, April 4, 2019.
- "Market Design for Winter Energy Security in New England: Further Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, February 6, 2019 (with D.L. Oates and P. Ruiz).
- "Market Design for Winter Energy Security in New England: Discussion of Options," presented to The New England Power Pool Markets Committee on behalf of NextEra Energy Resources, Westborough, MA, January 9, 2019 (with D.L. Oates).
- "Market Equilibrium Reserve Margin in ERCOT," presented to Power Markets Today webinar, "A
 Post Summer Check-in of ERCOT's Market," October 31, 2018.
- "Carbon Pricing in NYISO's Wholesale Energy Market, and Applicability to Multi-State RTO
 markets," presented to Raab Policy Roundtable, May 23, 2018; presented to the Energy Bar
 Association, 2018 EBA Energizer: Pricing Carbon in Energy Markets, June 5, 2018; presented to
 Bank of America Merrill Lynch, June 25, 2018.
- "Reconciling Resilience Services with Current Market Design," presented to RFF/R-Street Conference on "Economic Approaches to Understanding and Addressing Resilience in the Bulk Power System," Washington, DC, May 30, 2018.
- "System Flexibility and Renewable Energy Integration: Overview of Market Design Approaches," presented to Texas-Germany Bilateral Dialogue on Challenges and Opportunities in the Electricity Market, Austin, TX, February 26, 2018.
- "Natural Gas Reliability: Understanding Fact from Fiction," panelist at the NARUC Winter Policy Summit presented to The Committee on Gas, Washington, D.C., February 13, 2018 (with A. Thapa, M. Witkin, and R. Wong).



- "Carbon Pricing in Wholesale Markets: Takeaways from NYISO Carbon Charge Study," presented to Harvard Electric Policy Group, October 12, 2017.
- "Pricing Carbon into NYISO's Wholesale Energy Market: Study Overview and Summary of Findings," presented to NYISO Business Issues Committee, September 12, 2017.
- "Carbon Adders in Wholesale Power Markets—Preventing Leakage," panelist at Resources for the Future's workshop on carbon pricing in wholesale markets, Washington, D.C., August 2, 2017.
- "Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.
- "ERCOT's Future: A Look at the Market Using Recent History as a Guide," panelist at the Gulf Coast Power Association's Fall Conference, Austin, TX, October 4, 2016.
- "The Future of Wholesale Electricity Market Design," presented to Energy Bar Association 2016 Annual Meeting & Conference, Washington, DC, June 8, 2016.
- "Performance Initiatives and Fuel Assurance—What Price Mitigation?" presented to Northeast Energy Summit 2015 Panel Discussion, Boston, MA, October 27, 2015.
- "PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).
- "Energy and Capacity Market Designs: Incentives to Invest and Perform," presented to EUCI Conference, Cambridge, MA, September 1, 2015.
- "Electric Infrastructure Needs to Support Bulk Power Reliability," presented to GEMI Symposium: Reliability and Security across the Energy Value Chain, The University of Houston, Houston, TX, March 11, 2015.
- Before the Arizona Corporation Commission, Commission Workshop on Integrated Resource Planning, Docket No. E-00000V-13-0070, presented "Perspectives on the IRP Process: How to get the most out of IRP through a collaborative process, broad consideration of resource strategies and uncertainties, and validation or improvement through market solicitations," Phoenix, AZ, February 26, 2015.
- "Resource Adequacy in Western Australia—Alternatives to the Reserve Capacity Mechanism (RCM)," presented to The Australian Institute of Energy, Perth, WA, October 9, 2014.
- "Customer Participation in the Market," panelist on demand response at Gulf Coast Power Association Fall Conference, Austin, TX, September 30, 2014.



Samuel Newell brattle.com | 34 of 36

- "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 CO₂ 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, NY, 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, Austin, TX, 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 J. 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, TN, 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.



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Dr. Thompson is an energy economist with a background in electrical engineering and expertise in wholesale electricity market design, regulatory economics, and policy analysis of network industries, particularly in the energy sector.

His work focuses on:

- Wholesale electricity market design and reform
- Capacity market/auction design and resource adequacy
- Integration of emerging energy technologies
- Energy market regulation
- The hydrogen economy
- Energy finance, cost of capital estimation, and utility rate cases
- Energy asset evaluation and economic damages assessments for renewable generation, transmission, and storage assets

Dr. Thompson has supported clients and diverse stakeholder groups – including electricity system operators, energy regulators, governments, clean energy advocacy groups, market participants, institutional investors, and utilities – in several international jurisdictions. This includes PJM, CAISO, ERCOT, NYISO, ISO-NE, the Non-ISO/RTO United States, Ontario, Alberta, the United Kingdom, Spain, Colombia, Saudi Arabia, Australia, and New Zealand.

He has published thought leadership on energy policy and market reforms to integrate emerging resources (renewables, battery storage, long-duration energy storage, distributed energy resources, and flexible load); the regulation of the energy sector; the hydrogen economy; and the economic implications of lithium-ion battery degradation for energy storage and electric vehicle technologies.

AREAS OF EXPERTISE

- Electricity Wholesale Markets & Planning
- Regulatory Economics, Finance & Rates



EDUCATION

Université Paris-Saclay (Paris, France)

PhD in Economics

Universidad Pontificia Comillas (Madrid, Spain)

MS in Energy Economics

Delft University of Technology (Delft, The Netherlands)

MSc in Engineering and Policy Analysis

Rowan University (New Jersey, USA)

BSc in Electrical and Computer Engineering

PROFESSIONAL EXPERIENCE

The Brattle Group (2020–Present)

Energy Associate

University of California Berkeley/Lawrence Berkeley National Laboratory (2017–2019)

Visiting Researcher

US Department of Energy: ARPE-E (2018)

Technology-to-Market Scholar

Institut Vedecom (2016–2018)

Electric Vehicle and Battery Storage Researcher

Spanish and Portuguese Energy Market Operator (OMIE) (2014–2015)

Energy Analyst

SELECTED CONSULTING EXPERIENCE

WHOLESALE ELECTRICITY MARKET DESIGN AND REFORM

- Energy Storage Wholesale Market Reforms Roadmap: For the American Clean Power
 Association (ACP) analyzed and developed a comprehensive roadmap for near-term
 wholesale market reforms needed to better integrate and enable energy storage resources,
 with a particular focus on implementing reform efforts in PJM, MISO, and NYISO.
- **IESO Future Market Reforms Initiatives**: For the Ontario Independent Electricity System Operator (IESO) conducted a benefits assessment of near-term, mid-term, and long-term market reform initiatives.
- AESO Market Pathways Initiative: For the Alberta Electric System Operator (AESO) and the
 Executive Working Group (EWG), provided support for various inquiries into energy market
 enhancements as part of the Market Pathways initiative that aims to inform the future
 evolution of Alberta's electricity market design.



- ERCOT CONE for 2026 Study: For the Electric Reliability Council of Texas (ERCOT) developed an updated estimate of the Cost of New Entry (CONE) for use in setting the Peaker Net Margin (PNM) threshold, evaluating the cost of proposed reliability standards, analyzing the Market Equilibrium Reserve Margin (MERM) and Economically Optimal Reserve Margin (EORM), and potentially setting demand curves for a Performance Credit Mechanism (PCM). Developed updated model to calculate CONE accounting for fixed and variable costs, lifetime estimates, financial parameters, and levelization of future net revenue requirements.
- South Carolina Wholesale Energy Market Reforms Study: For the South Carolina State
 Legislature, conducted a comprehensive assessment of potential benefits and risks from
 competitive reforms to the state's electricity sector and regulatory model. Examined
 potential reforms to join or integrate with a regional transmission organization, introduce
 competition into resource planning, and pursue partial or full retail choice.
- US Bulk System Reliability for Tomorrow's Grid: For the Center for Applied Environmental
 Law and Policy (CAELP), co-authored a report submitted to the US EPA as public comments
 of the New Source Performance Standards for greenhouse gas emissions. The report outlines
 current and emerging reliability impacts on the bulk power system due to recent and
 projected changes in the energy sector and explains the suite of solutions grid operators have
 at their disposal to ensure reliability is maintained throughout the ongoing energy transition.
- Generation Interconnection Reform: For Hydro Quebec, provided a summary of ongoing generation interconnection reform processes and identified best practices in North America.
- **IESO Wholesale Market Participation Model Design for DERs:** Provided expert support to IESO staff for proposed changes to wholesale market participation models and rules to better enable DER and hybrid resource integration.
- Costs of Decarbonizing the US Electricity Sector: For the American Council on Renewable Energy (ACORE), a renewable energy advocacy group, evaluated costs to decarbonize the US electricity sector under alternative proposals to extend and expand renewable energy tax credits in 2021. Simulated investment, costs, prices, and emissions nationally to 2050 using gridSIM, Brattle's capacity expansion model. Informed client's policy position.

CAPACITY MARKET/AUCTION DESIGN AND RESOURCE ADEQUACY

PJM Quadrennial Review of Capacity Market Design and Demand Curve Parameters: For PJM, conducted periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy, including uncertainty and volatility of prices, net cost of new entry (CONE) parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Assisted expert support to stakeholder proceedings and testimony submitted before the Federal Energy Regulatory Commission.



- PJM Development of Gross Avoidable Cost Rates: For PJM, developed Avoidable Cost Rates
 (ACRs) for existing resource types for use in the Minimum Offer Price Rule (MOPR) and in
 Market Seller Offer Cap (MSOC). Contributed to submitted testimonies before FERC.
- Ontario Capacity Auction Design: Provided expert support to IESO staff in support of a new
 capacity auction design and enhancements. Delivered detailed reports describing options,
 tradeoffs, and lessons learned on every aspect of capacity auction design. Developed analysis
 and design proposals for the capacity market demand curve, capacity accreditation
 methodologies, and penalty mechanism design. Supported IESO stakeholder engagement
 efforts and presented analyses of design alternatives in public forums.
- Assessment of Resource Adequacy Alternatives: For a market operator, assessed potential
 alternative resource adequacy options including a centralized capacity market with single and
 bi-furcated pricing, a residual market, a bilateral market, and alternative capacity hedging
 strategies that could be pursued for end-customers.
- **Capacity Market Overview Study**: For a major renewable investment company, presented an overview of US and international capacity markets and resource adequacy mechanisms.
- Capacity Accreditation Approaches for Hybrid Resources: For a major renewable investment company, presented an assessment of current approaches to capacity accreditation using Effective Load Carrying Capability (ELCC) methods for evaluating hybrid resources.

INTEGRATION OF EMERGING ENERGY TECHNOLOGIES

- Long-Duration Energy Storage (LDES) Technology Landscape: For the Center for Climate and Energy Solutions (C2ES) provided expert support and research to an industry working group on the Long-duration Energy Storage (LDES) technology landscape. Assessed costs, technology readiness, and value proposition of Inter-day LDES (10-36 hrs) and Multi-day LDES (36+ hrs) technologies to address emerging system needs under deep decarbonization. Provided support on developing policy reforms to encourage greater LDES deployment at state and federal levels.
- EPRI Long-Duration Energy Storage Working Group: For the Electric Power Research Institute (EPRI) presented to an industry working group on the challenges associated with modeling LDES in capacity expansion models.
- IESO (Ontario) Long-term Contract Design for Renewable, Storage, and Hybrid Resources: Provided expert support to IESO staff for long/mid-term RFP contract design to procure energy, capacity, and environmental attributes from emerging resources including renewables, energy storage, and hybrid storage assets in Ontario.
- NEOM Saudi Arabia Load Flexibility Integration Study: Developed supporting analysis and a
 load flexibility roadmap to assist the public utility (ENOWA) in developing their load flexibility
 integration plan for various sources of large-scale electricity demand within NEOM.



ENERGY MARKET REGULATION

- Recent Developments in International Rate of Return Methods: For Energy Networks Australia (ENA), developed an updated overview of international rate of return methods for regulators in the US, Great Britain, New Zealand, Italy, and The Netherlands. This paper also provided a review of the Australian Energy Regulator's draft 2022 Rate of Return Instrument and recommend improvements as well as a comparison on a like-for-like basis of recent rate of return decision from each regulator.
- International Approaches to Regulated Rates of Return: For the Australian Energy Regulator
 (AER), researched international approaches to rate of return and WACC estimations across
 six countries: Australia, Italy, the Netherlands, New Zealand, the US, and the UK. This report
 reviewed and summarized international regulators' approaches to utility regulation and
 compared the rate of return approach of each regulator to that of the AER as part of the 2022
 Rate of Return Instrument.

THE HYDROGEN ECONOMY

 Future of Hydrogen in the Power Sector: For the Environmental Defense Fund (EDF), developed an assessment of the potential role of hydrogen in a decarbonized power sector. Explained the nature of reliability needs in renewable power systems and assessed hydrogen technologies' ability to address system reliability, resiliency, and resource adequacy challenges.

ENERGY FINANCE, COST OF CAPITAL ESTIMATION, UTILITY RATE CASES

- PacifiCorp Rate Case: Supported Mr. John Tsoukalis' expert testimony before the Wyoming Public Service Commission regarding the reliability value of inter-state transmission, the risks and costs of operating the Bulk Electricity System (BES) in non-compliance with NERC standards, the economic impact of reliability events particularly to large industrial customers, and transmission cost allocation approaches in multi-state jurisdictions.
- Alberta Utilities Commission Generic Cost of Capital (GCOC) Estimation: Supported Dr.
 Bente Villadsen's expert testimony on the cost of equity and appropriate capital structure
 presented before the Alberta Utilities Commission (AUC).
- Cost of Capital Estimation for North American Regulated Electric Utilities: For several major
 North American regulated electric utilities, conducted financial and economic analyses to
 support expert testimony estimating allowed Return on Equity to inform upcoming rate case
 hearings before state utility commissions and the FERC.
- Cost of Capital Estimation for North American Regulated Gas Utilities: For several major North American regulated gas utilities, conducted financial and economic analyses to support expert testimony estimating allowed Return on Equity to inform upcoming rate case hearings before state utility commissions and the FERC.



ENERGY ASSET EVALUATION AND ECONOMIC DAMAGES ASSESSMENTS

- HVDC Transmission Energy, Capacity, and Resource Adequacy Value: For several major transmission companies, assessed the energy, capacity, and additional resource adequacy value of proposed inter-regional high-voltage DC (HVDC) transmission projects under various carbon price and future resource mix scenarios for due diligence processes.
- PJM Battery Storage Asset Valuation and Damages: For a major renewable energy developer, developed an economic damages estimation due to an alleged breach in contractual performance warranties of a battery storage asset in PJM Interconnection LLC.
- Spanish Wind Asset Regulatory Impacts: For a major renewable energy developer, contributed to expert report on the financial impact on wind assets of a mid-stream switch in the regulatory regime for Spanish renewables.
- Spanish Solar PV Asset Valuation and Damages: For a major renewable energy developer, contributed to litigation support and damages estimation of an international arbitration concerning the financial impact of a mid-stream switch in the regulatory regime for Spanish renewables. The damages estimate considers the valuation of both the reduction in remuneration and financial instruments related to the project financing.
- Spanish Wind Asset Valuation and Damages: For a major renewable energy developer, contributed to litigation support and damages estimation of an international arbitration concerning the financial impact of a mid-stream switch in the regulatory regime for Spanish renewables. The damages estimate considers the valuation of both the reduction in remuneration and financial instruments related to the project financing.
- Spanish Concentrated Solar Power (CSP) Asset Valuation and Damages: For a major renewable energy developer, contributed to litigation support and damages estimation of an international arbitration concerning the financial impact of a mid-stream switch in the regulatory regime for Spanish renewables. The damages estimate considers the valuation of both the reduction in remuneration and financial instruments related to the project financing.
- Colombia Energy Investors Dispute: For a group of investors in electricity companies, contributed to analysis for expert testimony regarding a dispute over dividend payments before the Bogotá Chamber of Commerce Arbitration Centre.

REPORTS, ARTICLES, & PUBLICATIONS

- "Sixth Review of PJM's Variable Resource Requirement Curve", with Kathleen Spees and Samuel A. Newell, prepared for PJM Interconnection, LLC (April 2025)
- "Brattle 2025 CONE Report for PJM", with Samuel A. Newell and Bin Zhou, prepared for PJM Interconnection, LLC (April 2025)
- "Energy Storage Market Design Roadmap", with Samuel A. Newell, Andrew Levitt, and Serena Patel, prepared for American Clean Power (April 2025)



- "LDES Scoping Report", with J. Michael Hagerty and Andrew Levitt, prepared for the Center for the Center for Climate and Energy Solutions (C2ES) (March 2024)
- "ERCOT CONE for 2026," with Samuel A. Newell, prepared for the Electric Reliability Council
 of Texas, Inc. (ERCOT) (June 2024)
- "Bulk System Reliability for Tomorrow's Grid," with Metin Celebi, Andrew Levitt, and Ragini Sreenath, prepared for prepared for the Center for Applied Environmental Law and Policy (CAELP) (December 2023)
- "Ontario's Experience with the Single Buyer Contracting Model", with Kathleen Spees, Andrew Levitt, and Xander Bartone, prepared for the Alberta Electric System Operator (AESO) and the Executive Working Group (EWG)(November 2023)
- "Assessment of Potential Market Reforms for South Carolina's Electricity Sector," with John H. Tsoukalis, Kathleen Spees, Johannes P. Pfeifenberger, Andrew Levitt, and Oleksandr Kuzura, prepared for the South Carolina General Assembly Electricity Market Reform Measures Committee (April 2023)
- "Gross Avoidable Costs for Existing Generation," with Samuel Newell, prepared for PJM Interconnection, L.L.C. (January 2023)
- "International Rate of Return Methods Recent Developments," with Bente Villadsen and Toby Brown, prepared for Energy Networks Australia (September 2022)
- "Fifth Review of PJM's Variable Resource Requirement Curve," with Kathleen Spees and Samuel Newell, prepared for PJM Interconnection (April 2022)
- "Vehicle-to-Everything (V2X) Energy Services, Values Streams, and Regulatory Policy Implications," with Yannick Perez, Energy Policy, 137, Article 111136 (2020)
- "Economic implications of lithium-ion battery degradation for Vehicle-to-Grid (V2X) services,"
 The Journal of Power Sources, 396, pp. 691–709 (2018)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Evolving Resource Adequacy Approaches in North America", Presentation and panel discussions at the International Energy Agency (IEA) Expert Workshop on Power Market Design, (May 2025)
- Bank of America, US Power & Utilities Research Expert Presentation on PJM CONE Estimation, with Samuel Newell, Sang Gang, and Joshua Junge, (May, 2025)
- Jefferies, US Power, Utilities, & Clean Energy Research Expert Presentation on PJM Parameters, with Samuel Newell and Kathleen Spees, (May, 2025)
- UBS, Utilities and Power Equity Research Expert Presentation on PJM Parameters, with Samuel Newell and Kathleen Spees, (April, 2025)



- "Sixth Review of PJM's RPM VRR Curve Parameters: Final Recommendations," with Samuel Newell and Kathleen Spees, PJM Market Implementation Committee (April, 2025)
- "The Need for Mechanisms to Support Flexibility or Capacity" and "Aligning the Security of <u>Supply and Decarbonization Targets</u>", Panel Discussions at the 7th Capacity Mechanisms Forum: Ensuring the European Electricity Supply (October 2024)
- "Resource Adequacy Trends of the Energy Transition: Experience from North America," 7th Capacity Mechanisms Forum: Ensuring the European Electricity Supply (October 2024)
- "Modeling Storage Adequacy in Capacity Expansion Models," with Kate Peters, EPRI Long-Duration Energy Storage Working Group (July 2024)
- "Long-duration Energy Storage Scoping Report," with Andrew Levitt and Michael Hagerty, C2ES LDES Working Group, (March 2024)
- "Resource Adequacy Trends of the Energy Transition: Experience from North America," NTNU Energy Transition Week: Power Markets (March 2024)
- "Role of Hydrogen in a Decarbonized Future," with Josh Figueroa and Metin Celebi, Bank of America Global Research US Alternative Energy Hydrogen Conference (December 2023)
- "<u>Discussion on Demand Curve Review</u>," IESO Technical Session (October 2022)
- "PJM Market Implementation Committee Special Session: Quadrennial Review," with Kathleen Spees and Samuel Newell, PJM Interconnection (December 2021)
- "Vehicle-to-Everything (V2X) Energy Services," presented to Smart Charging Webinar hosted by Newcastle University in conjunction with The Alan Turing Institute, CESI and Supergen Energy Networks, (October 2020)
- "Vehicle-to-Everything (V2X) Energy Services," presented to the International Smart Grid Action Network (ISGAN), (April 2019)
- "Economic Feasibility of Wind Energy Participation in Secondary Reserves Markets," Proceedings of the 1st Italian Association of Energy Economists (IAEE) Energy Symposium, Milan, Italy (2016)
- "PV by-pass diode performance in landscape and portrait modalities," with Carlos Barreiro, Peter M. Jansson, and John L. Schmalzel, 37th IEEE Photovoltaic Specialists Conference (2011)

TRADE PRESS & MEDIA COVERAGE

- E&E News, "Spain's big blackout: A cautionary tale for US grid managers", June 2025
- Utility Dive, "PJM, MISO, NYISO ripe for energy storage market reforms: Brattle/ACP", April 2025
- RTO Insider, "<u>ACP Road Map Suggests Market Changes to Increase Storage Participation</u>", April 2025



- Energy Storage News, "American Clean Power report recommends energy storage-friendly market reforms to US grid operators", April 2025
- PV Magazine: Energy Storage, "<u>US call for better energy storage rules in wholesale markets</u>", April 2025

PROFESSIONAL ASSOCIATIONS & MEMBERSHIPS

International Association for Energy Economics (IAEE)
Institute of Electrical and Electronics Engineers (IEEE) Power and Energy Society

LANGUAGES

Spanish (fluent), French (conversational)



Exhibit No. 2

2025 VRR Curve Study

Sixth Review of PJM's Variable Resource Requirement Curve

FOR PLANNING YEARS 2028/29 THROUGH 2031/32

PREPARED BY

Kathleen Spees
Samuel A. Newell
Andrew W. Thompson
Ethan Snyder
Xander Bartone

PREPARED FOR

PJM Interconnection, LLC

APRIL 9, 2025





NOTICE

This report was prepared for PJM Interconnection, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

TABLE OF CONTENTS

| Exe | ecutive Summary | 1 |
|------|--|---------|
| l. | Detailed Recommendations | 6 |
| II. | Background and Context | 13 |
| | A. Quadrennial Review and Demand Curve Design Objectives | 13 |
| | B. Recent Changes to the VRR Curve Formula | 15 |
| | C. Focus Areas of the Sixth Quadrennial Review | 18 |
| III. | Analysis of Recent Capacity Market Outcomes | 19 |
| | A. Historical RPM Procurement Levels and Clearing Prices | 19 |
| | B. Diagnosis of Outcomes from the 2025-26 BRA | 21 |
| | C. Impact of the Compressed Forward Capacity Auction Schedules | 24 |
| | D. Interactions with Capacity Accreditation Reforms | 28 |
| | E. Implications of Seasonally Distinct Reliability Drivers and Resource Capabilities | 30 |
| IV. | Development of System-Wide MRI-Based VRR Curves | 36 |
| | A. Comparison to Current VRR Curve and Other Capacity Markets' Curves | 36 |
| | B. Constructing an MRI-Based VRR Curve | 38 |
| | C. MRI Curves Tuned to 1-in-10 Standard | 42 |
| | D. Tuned MRI Curves with Varying Reference Prices | 45 |
| V. | Performance of Candidate MRI-Based Curves | 49 |
| | A. Current Curve vs MRI-Based Curves (Base Assumptions) | 49 |
| | B. Performance Sensitivity to Net CONE Estimation Error | 53 |
| | C. Performance Sensitivity to Forward Period | 55 |
| | D. Performance Sensitivity to Higher/Lower Net Supply Variability | 57 |
| | E. Summary of MRI-Based Curves' Performance | 59 |
| VI. | Managing Acute Tight Supply Conditions | 61 |
| | A. Considerations in Setting the Price Cap | 61 |
| | B. Implications of Transient Acute Tight Supply Conditions | 67 |
| | C. Contingency Plan for Shortfalls | 70 |
| VII. | . Implementation Considerations for MRI-Based VRR Curves | 75 |
| | A. Locational VRR Curves Based on Marginal Reliability Impact | 75 |
| | B. Adapting MRI-Based VRR Curve to a Potential Sub-annual Capacity Market Const | ruct 82 |

| Appendix | 86 |
|---|----|
| A.1 Overview of Model Structure and Assumptions | 86 |
| A.2 Reliability | 88 |
| A.3 Demand | 90 |
| A.4 Supply | 91 |
| A.5 Net Supply Variability | 93 |
| List of Asymptotic | ٥٢ |
| List of Acronyms | 95 |

Executive Summary

We have been commissioned by PJM Interconnection (PJM) to evaluate the parameters and shape of the Variable Resource Requirement (VRR) curve used to procure capacity under the Reliability Pricing Model (RPM), as required periodically under the PJM Tariff. In this Sixth Quadrennial Review, we have conducted several rounds of stakeholder presentations and individual meetings, and reviewed written feedback to incorporate input from stakeholders and the Independent Market Monitor (IMM).²

We have conducted this Sixth Quadrennial Review with a focus on priorities identified by stakeholders, PJM staff, and our own assessment of challenges likely to affect the performance of the VRR curve and RPM in the relevant delivery years 2028/29 through 2031/32. The focus areas for this review include:

- Tight market conditions that have recently resulted in a substantial contraction in the
 capacity supply-demand balance, exacerbated by suddenly high load growth, a compressed
 forward period for upcoming auctions, and a limited development pipeline of gas-fired
 resources with long lead times and scarcity pricing for new projects;
- Uncertainty in Net Cost of New Entry (CONE) and reference resources, considering the
 ongoing transition in the resource mix, uncertainties in the cost and economic outlook for
 each technology, differences in consumer and policy requirements across the PJM footprint,
 and evolving energy market conditions, all making it difficult to set auction parameters that
 provide stable long-term investment signals despite these uncertainties; and
- Recent and anticipated RPM market design changes, including recent updates to reliability
 modeling and resource accreditation, as well as the potential to transition to a sub-annual
 capacity market.

We have conducted this Sixth VRR Curve Review in light of these focus areas and the overarching design objectives of the RPM and VRR Curve. The uncertainties affecting the RPM market will be

¹ PJM Interconnection, LLC. (2024). <u>PJM Open Access Transmission Tariff</u>. Effective January 1, 2024. ("PJM Tariff"), Attachment DD, Section 5.10.a.iii.

See stakeholder materials posted within the PJM Market Implementation Committee, special sessions focused on the Quadrennial Review. Meeting dates: September 27, 2024; October 24, 2024; November 26, 2024; December 17, 2024; February 21, 2025; March 11, 2025; and April 11, 2025. Monitoring Analytics has been the IMM for PJM since 2008. See Monitoring Analytics, Homepage, accessed February 26, 2025.

further affected by the impacts of major US tariffs announced on April 2, 2025 just before the issuance of this report, in ways that are not yet considered in this review. The primary design objective of the RPM is to attract and retain capacity sufficient to meet the region's reliability objectives on a long-run average basis. This means that the RPM should provide accurate accounting of supply and demand and structure the market to produce prices aligned with the underlying fundamentals. Prices should be high enough to attract private investors to bring forward merchant capacity resources and to support demand-side solutions when those resources are needed for reliability; prices should be lower in long market conditions when retirements can be absorbed in an orderly fashion. For state agencies and utilities engaged in regulated planning, RPM price and quantity outcomes can similarly inform cost-effective policy and resource decisions. The downward-sloping VRR curve helps to support price formation, mitigate pricing volatility, and express the incremental value of reliability across reserve margins.

Over nearly two decades since its launch, the RPM has fulfilled these objectives, including managing over 64 GW of capacity de-ratings and retirements, attracting over 74 GW of new generation capacity, and attracting other cost-effective competitive resources such as demand response, uprates, and imports.³ The role of the RPM to provide accurate and efficient signals for reliability needs will become even more critical in the coming years and decades, as the sector must mobilize to serve rapid demand growth; as states and customers pursue policy and clean energy goals; and as the system becomes increasingly dependent on intermittent resources to support reliability needs. The RPM market design will need to continue to evolve if it is to keep pace with the rate of change in market fundamentals and resource transition. Throughout this evolution, the market design should remain focused on economic principles including the accurate measurement of supply and demand; supporting competitive price outcomes driven by market fundamentals; and enabling new entrants and technology innovation.

Forefront in present conditions is an acutely tight supply conditions in the face of rapid growth in demand. As discussed more extensively in our concurrent report *Brattle 2025 PJM CONE Report* ("Brattle 2025 PJM CONE Report"), the cost and feasibility of building incremental capacity supply is presently constricted by supply chain limits for turbines and other inputs, siting and permitting delays, a compressed forward period in the Base Residual Auctions (BRAs), extended resource development timelines, and a lengthy (although shortening) interconnection queue process.⁴ These acute supply challenges may increase the cost or limit the volume or types

³ Capacity ratings are expressed in ICAP GW. Data on capacity de-ratings, retirements, and new generation capacity is recent as of the 2023/24 Base Residual Auction and does not include changes in installed capacity that have occurred since, see PJM, 2023/2024 RPM Base Residual Auction Results, June 21, 2022, p. 19.

⁴ See Newell, et. al., Brattle 2025 CONE Report for PJM ("Brattle 2025 PJM CONE Report"), April 9, 2025.

of new supply that can be developed into the initial years relevant to this Quadrennial Review, but may moderate by the end of the review period as industry-wide supply increases capability to keep pace with demand growth.⁵ Under these conditions, it is possible that one or more BRAs may clear at the VRR Curve price cap, but still remain insufficient to attract new entry until supply-demand conditions resolve.

Further, moderate increases to the price cap would not be an effective means to address this transient and acute supply tightness, considering that the high prices can only be made available under one-year commitments in the RPM and that higher prices do not address the underlying barriers to timely supply entry. A well-functioning capacity market should be structured to limit the frequency of price cap and reliability shortfall events to the extent possible, while incorporating a price cap and/or other mechanisms that manage impacts for both the consumer and the broader market.

Despite these challenges, we continue to take as a premise that the role of the RPM and VRR Curve should be to support short-term decisions on an ongoing basis, and to attract new merchant supply as soon as it becomes available. In other words, the VRR Curve and price cap should be sufficient to support reliability under long-run equilibrium conditions when new entry can be attracted at the long-run marginal cost of supply. This is the same economic concept that we have adopted in all prior VRR Curve reviews, although factors affecting the most relevant Reference Price or Net CONE are more complex than in prior reviews considering that the price and term required to attract supply may be substantially higher in the first year compared to the last year of the upcoming Review Period (see the *Brattle 2025 PJM CONE Report* for a comprehensive discussion of our recommended Reference Price).

To support reliability over the long term and to more meaningfully represent the value of reliability in this shifting landscape, we recommend that the VRR Curve be reshaped to align with the concept of marginal reliability impact (MRI). An MRI-based curve is more meaningfully grounded in the underlying reliability value of capacity, considering that it reflects a constant willingness-to-pay to avoid expected unserved energy (EUE) as a function of procurement volume. The MRI curve will more accurately reflect how marginal reliability value of capacity declines with an increasing reserve margin and can naturally be adapted to a potential future sub-annual capacity market construct. We further recommend returning to the 3-year forward period for the BRAs and transitioning to a sub-annual capacity construct with at least two capacity

GE Vernova, <u>GE Vernova to invest almost \$600 million in U.S. factories and facilities over next two years</u>, January 29, 2025.

seasons as soon as practicable, so the MRI-based VRR Curves can be used to more accurately and economically guide resource investments.

Relevant to initial implementation with the present annual construct, we have examined three variations of MRI-based VRR Curves as illustrated in the following Figure 1. Each of these MRIbased curves is "tuned" to meet the PJM reliability standard of 0.1 loss of load events (LOLE) per year, or one-day-in-ten years (1-in-10) on a long-run average basis. Curves 1, 2 and 3 have respective price caps at 2.5×, 1.7×, and 1.5× the Net CONE or "Reference Price" which is expressed in \$/MW-day in Unforced Capacity (UCAP) terms. The three curves present different trade-offs, with Curve 1 having the highest price volatility and customer cost exposure in price cap events and Curve 3 having the greatest quantity uncertainty and reliability risk exposure (i.e. if the price cap is too low). Under relatively stable or long-run equilibrium conditions with typical levels of year-to-year variability in the supply-demand balance and moderate uncertainties in the long-run marginal cost of supply, we would anticipate Curve 2 as one that offers strong performance across competing design objectives. Curve 3 would offer more protection to customers by applying a lower price cap but has the downside of introducing a greater risk of low-reliability and price cap events. These analyses indicate that a price cap in the range of 1.5-1.75 × Reference Price will be sufficient to attract new entry and support reliability under longrun equilibrium conditions.

In Figure 1 and all analyses in this report, the reference prices used to develop the MRI-based VRR curves are derived from our analysis of Net CONE in the *Brattle 2025 PJM CONE Report* as part of this Quadrennial Review.

\$1,000 **Current Curve** Reliability Requirement \$800 MRI Curve @ 99% of the Reliability Requirement Price (\$/UCAP MW-day) MRI Curve @1.5 × Reference Price \$600 MRI Curve @ Target Point \$400 Reference Price \$200 \$0 96% 98% 100% 102% 104% 106% 108% - 7.7% - 4.5% - 0.5% - 10.1% - 6.1% - 2.1% 1.1% % of Reliability Requirement **UCAP** Reserve Margin

FIGURE 1: MRI-BASED VRR CANDIDATE CURVES TURNED TO 1-IN-10 LOLE STANDARD

Sources and Notes: Throughout this report we utilize a Reference Price of \$350/MW-day. The MRI-based VRR curves are defined by the highlighted anchor point (signified by the numbered dot for each curve) and as described in more detail in Section IV.B below. The Current Curve is developed using the current VRR curve formula and estimates of a dual-fuel combustion turbine (CT) reference resource Net CONE (\$528/MW-day UCAP) and Gross CONE (\$832/MW-day UCAP) from the Brattle 2025 PJM CONE Report. We note that the Net CONE and Gross CONE values used to generate the Current Curve in our simulation analysis are slightly different from the final numbers in the Brattle 2025 PJM CONE Report; however, this does not materially impact the conclusions of the analyses.

To manage the reliability risks under these acute supply conditions, we do not recommend increasing the price cap above our recommended range of 1.5–1.75 × Reference Price. We instead recommend addressing underlying barriers directly to the extent possible, including by prioritizing ongoing efforts to enable and maximize capacity supply participation, expedite interconnection queue processes, address other barriers to entry, and consider refining risk modeling more fully account for the benefits of interties and non-firm resources that can contribute to meeting demand. In addition, we recommend developing contingency plans for the event that inadequate supply is procured. Such plans could allow some combination of accepting lower reliability temporarily while still aiming to meet reliability criteria on a long-term average basis; and/or enhancing the RPM Reliability Backstop mechanism so that it can be triggered in any locational deliverability area (LDA) and so that it can more quickly and efficiently secure backstop commitments without undermining the primary competitive signals issued through the BRAs.

Detailed Recommendations

1. RECOMMENDED SYSTEM VRR CURVE BASED ON MARGINAL RELIABILITY IMPACT

We recommend adopting an MRI-based curve similar to those already adopted by the Independent System Operator of New England (ISO-NE) and the Midcontinent Independent System Operator (MISO) in their respective capacity markets, but that has been adapted to align with PJM's reliability modeling and other RPM design elements. We offer two specific MRI-based VRR curves, Curve 2 and Curve 3 to illustrate the approximate "workable range" of curves (shown approximately as the gray shaded area in Figure 2) which would offer sufficient system reliability but with a different balance of performance trade-offs.

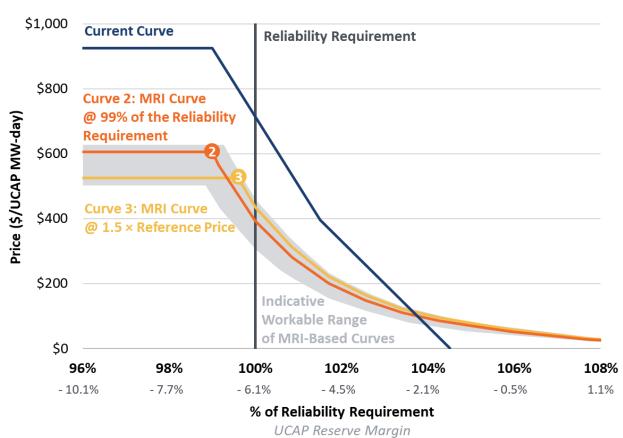


FIGURE 2: RECOMMENDED "WORKABLE RANGE" OF MRI-BASED VRR CURVES

Sources and Notes: MRI-based Curves shown in figure are drawn relative to a Reference Price of \$350/MW-day. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on the dual-fuel current combustion turbine (CT) reference resource at an indicative Net CONE of \$528/MW-day UCAP and an indicative Gross CONE of \$832/MW-day UCAP.

Compared to the Current Curve, we recommend the following changes for transitioning to an MRI-Based Curve:

- 1.1. Develop VRR pricing parameters relative to the updated concept of a "Reference Price" parameter, that is informed by the uncertainty range in Net CONE for multiple potential reference resources (rather than the Net CONE of a specific Reference Resource). We anticipate that transitioning to a Reference Price approach will provide more pricing stability to the VRR curve, while ensuring that the curve is robust to the uncertainties in Net CONE and reference resources. Specific values for recommended RTO-wide and LDA Reference Prices are documented in the Brattle 2025 PJM CONE Report, considering the uncertainty range of the cost of developing new supply such as a gas-fired combustion turbine (CT) plants, gas-fired combined cycle (CC) plants, and battery energy storage systems (BESS). For the purposes of this report, we use an RTO Reference Price of \$350/MW-day for the 2028/29 delivery year and have developed our MRI curve recommendations considering that the MRI curve performance outcomes are similar across an uncertainty range of approximately +/- \$100/MW-day in Reference Price.
- 1.2. Adopt an RTO-wide price cap in the range of 1.5-1.75 × Reference Price, and within the range of \$500-\$625/MW-day for the 2028/29 Planning Year. An RTO price cap in this range would manage competing design objectives including being high enough to attract merchant capacity supply entry; aligning with the price caps of neighboring capacity markets that may engage in capacity trade with PJM; and mitigating customers' cost exposure in sustained high pricing. We caveat this recommendation based on our finding that a price cap in this range is not sufficient to manage all reliability risks that may materialize during near-term acute tight supply conditions, and so should be adopted alongside reviewing the reliability backstop mechanism (Recommendation 3.2 below). The specific parameters for the price cap if adopting either MRI-based Curve 2 or Curve 3 would be:
 - Curve 2: Price cap at 1.7 × Reference Price and 99.0% of the Reliability Requirement, or
 - Curve 3: Price cap at 1.5 × Reference Price and 99.6% of the Reliability Requirement
- 1.3. Derive other points on the VRR curve based on a modeled MRI curve. Transitioning to an MRI-based demand curve will produce a consistent expression of the willingness to pay to avoid involuntary load shedding at each quantity/price point along the curve. The MRI-based curve will provide a more economically meaningful expression of the reliability value to consumers accomplished by procuring more capacity and allow for a more rationalized expression of reliability value at different reserve margins, over time, and on a sub-annual

basis (relevant if the RPM transitions to a sub-annual construct). The specific steps conducted each year to derive the MRI-based curve would include:

- Using PJM's annual reliability modeling study to estimate both the Reliability Requirement (as conducted today) and to produce reliability metrics across a range of UCAP MW quantities above and below the Reliability Requirement;
- Calculating the MRI across UCAP MW quantities, in the units of MWh of avoided expected unserved energy (EUE) per 1 MW of UCAP capacity added; and
- Calculating the "Scaling Factor" in \$/MWh that aligns with the defined price and quantity at the price cap.
- 1.4. Stabilize annual updates to the VRR curve pricing parameters based on the Consumer Price Index (CPI) and fleet-wide UCAP Ratings, as discussed further in the Brattle 2025 PJM CONE Report. To increase stability in the pricing parameters of the VRR curve, we recommend updating the pricing parameters of the VRR curve to reflect broad economic trends as reflected in the CPI and to move away from the present formula based on annual updates to CONE and Net CONE as currently calculated in each delivery year. Specifically:
 - Between Review Periods: the Reference Price for 2028/29 would be updated using a simplified updating approach for the subsequent delivery years 2029/30, 2030/31 and 2031/32. The two updates to be applied would be: (1) an inflation-based update based on the CPI increase between auction dates;⁶ and (2) a UCAP update based on the change in pool-wide accredited UCAP factor considering all resources. By extension, the Price Cap and Scaling Factor relevant for each delivery year would also be updated with CPI and Unforced Capacity (UCAP) ratings;
 - In Future Quadrennial Reviews: At the time of each future Quadrennial, we recommend
 more comprehensively reviewing potential updates to the Reference Price, price cap
 formula, and scaling factor parameters, considering updated estimates of Net CONE for
 different Reference Technologies and other market evidence that may be available.

2. RECOMMENDED LDA VRR CURVES BASED ON MARGINAL RELIABILITY IMPACT

Consistent with transitioning to an MRI-based curve on a system-wide basis, we recommend to use location-specific MRI-based VRR curves for each modeled LDA in RPM. Figure 3 provides an

⁶ As discussed in the *Brattle 2025 PJM CONE Report*, we propose the "Consumer Price Index for All Urban Consumers (CPI-U) for the U.S. City Average for All Items, 1982-84=100" as reported by the U.S. Bureau of Labor Statistics (BLS), since this is the broadest, most comprehensive CPI. See U.S. BLS, <u>Consumer Price Index for All Urban Consumers (CPI-U)</u>.

illustration of LDA MRI curves for a large and small LDA: Mid-Atlantic Area Council (MAAC) and Delmarva Power and Light Company (DPL) South.

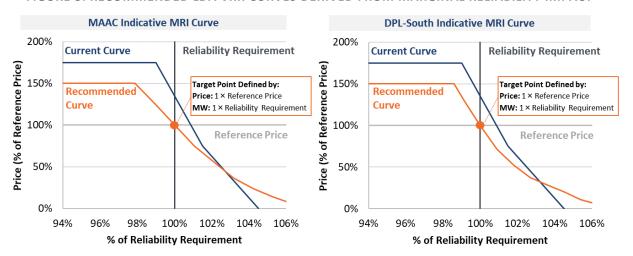


FIGURE 3: RECOMMENDED LDA VRR CURVES DERIVED FROM MARGINAL RELIABILITY IMPACT

Sources and Notes: The LDA MRI-based curves would be defined by the target point at $1 \times \text{LDA}$ Reference Price and the LDA Reliability Requirement.

Compared to the Current Curve, we recommend the following changes for transitioning to an MRI-Based Curve for each LDA:

- 2.1. Initial Implementation: Derive LDA VRR curves based on locational MRI, with a different scaling factor derived for each LDA. By applying the MRI concept on a locational basis, each LDA VRR curve will be calculated in a fashion similar to the system-wide MRI-based curve. The resulting MRI-based curves will be flatter with more gradual slopes than the current LDA VRR Curves, meaning they will reduce the potential for price spikes and offer more pricing stability to producers and consumers. Similar to the approach used to calculate the system-wide MRI-based VRR curve, the locational MRI-based VRR curves would be calculated as follows:
 - Using PJM's annual reliability modeling analysis to estimate both the LDA Reliability Requirement (as conducted today) and to produce reliability metrics across a range of UCAP MW quantities above and below the LDA Reliability Requirement;
 - The LDA MRI curves would be defined by and drawn through the "LDA Target Point",
 defined by the LDA Reliability Requirement and the LDA Reference Price. LDAs may have
 the same or higher Reference Price than the RTO, for example if they are affected by
 specific policy requirements or siting limitations (see *Brattle 2025 PJM CONE Report*);

- Developing a scaling factor specific to each LDA such that the LDA MRI curve is drawn through the "LDA Target Point" defined by the LDA Reliability Requirement and LDA Reference Price; and
- Setting an LDA price cap at the greater of either the 1.5 × LDA Reference Price, the parent LDA price cap, or the RTO price cap. The volume at this price cap would be dictated by the shape of the MRI curve and may be at higher or lower levels depending on the extent to which lower volumes more quickly drive reliability challenges in each LDA (initial PJM modeling results indicate the price cap would be consistent with a volume of 96%–99% of the LDA Reliability Requirement, depending on the LDA).
- 2.2. Longer Term: Update LDA VRR curves to incorporate a uniform scaling factor across the RTO and all LDAs. The above implementation of the LDA MRI curves allows for immediate implementation without requiring updates to PJM's capacity auction clearing engine. However, it does not allow for a unified approach to reflecting differences in reliability value across different LDAs over the footprint. To allow for more efficient pricing signals that fully reflect these differences in reliability value, we recommend that PJM and stakeholders eventually transition to an LDA MRI curves that incorporate a uniform scaling factor across the RTO footprint and all LDAs. The updated approach would be similar to the ISO-NE approach to locational MRI curves and would require updates to capacity auction clearing in RPM. These updates would naturally align with the implementation of a sub-annual capacity auction, and so we recommend that these changes could be considered at the same time (see Recommendation 3.2 below and more comprehensive discussion of the implications for locational and sub-annual MRI curves in Sections VII.A and VII.B in the body of this report).

3. RECOMMENDATIONS RELATED TO VRR CURVE IMPLEMENTATION

In addition to the specific recommendations to update the VRR curve parameters, we have identified several ways in which the performance of the VRR curve may interact with other aspects of the RPM design. We offer the following recommendations to improve performance of the VRR curve performance in the context of the broader RPM design:

3.1. Avoid delays to future Base Residual Auction (BRA) schedules and restore the RPM to the intended three-year forward period. We recommend following through on the current planned schedule of BRA auctions that will restore the RPM to a full 3-year forward period by 2030/31; this may require delaying or phasing in the implementation of future RPM design changes to later delivery years in order to prioritize maintaining the auction schedule. Restoring the regularized auction schedule will offer customers and producers

more time to incorporate new information and proactively consider design changes before they come into effect and will allow more resources to make entry and exit decisions as an outcome of the BRA (rather than in advance of the BRA). We anticipate that the result will be to improve pricing stability, mitigate the potential for large year-over-year price increases such as observed in the 2025/26 BRA, and improve confidence in the market.

- 3.2. Enhance the RPM Reliability Backstop Mechanism to Mitigate Potential for Acute Reliability Risks. We find that the RPM faces the potential for acute reliability challenges over an upcoming period of tight supply conditions due to rapid growth in demand and limited capacity to rapidly deploy new supply resources (see additional discussion in the Brattle 2025 PJM CONE Report). Currently, RPM incorporates two levels of reliability backstop mechanisms to: (1) trigger an investigation of the causes and solutions for a shortfall event (if shortfall is experienced in 1 year); or (2) trigger a Reliability Backstop Auction (may procure supply under up to 15-year commitments if shortfall is experienced in 3 consecutive years). To mitigate the potential for acute reliability challenges in the upcoming years, we recommend:
 - For the investigative review, update the mechanism so that it can be triggered either on an RTO-wide basis or also on an LDA-specific basis, triggered by a "minimum acceptable" reliability level, defined as: (a) 99% of the Reliability Requirement for the RTO; and (b) volume at the price cap for each LDA (approximately 96%–99% of LDA reliability requirements, consistent with recommended MRI-based curves for each LDA); and
 - For Backstop Procurements, consider whether the current mechanism offers sufficient reliability protections or whether enhancements to the mechanism are warranted. We recommend that any adjusted or expanded role for backstop procurements would be developed in close coordination with state regulatory agencies.
- 3.3. Transition to a sub-annual capacity construct with at least two seasons (summer and winter). The transition to a sub-annual capacity market is naturally aligned with the transition to an MRI-based VRR curve as we have recommended, using a seasonal VRR curve approach similar to that already adopted by MISO. Each sub-annual period would be defined by its own VRR curve, and each supply resource would receive UCAP accreditation that reflects its reliability value in that specific season. If the RTO and each LDA were to incorporate the same scaling factor for all VRR curves (system-wide and LDA, and for each sub-annual period) this would offer more granular signals by location and season to guide the market toward the supply investments that offer the greatest reliability value proposition to customers. We find that a sub-annual capacity market will offer a substantially improved basis for which to accurately measure capacity supply and demand

in the most accurate and economically meaningful manner; reduce barriers to entry for resources with seasonally distinct reliability value; provide a more stable basis for measuring capacity needs and value over time; and increase economic efficiency.

II. Background and Context

A. Quadrennial Review and Demand Curve Design Objectives

PJM's capacity market, the Reliability Pricing Model (RPM), aims to support long-term grid reliability by procuring the required volume of capacity resources needed to meet predicted electricity demand in the future.⁷ The RPM is an auction mechanism that employs a downward sloping demand curve and consists of the Base Residual Auction (BRA) which procures capacity on a forward basis and three Incremental Auctions (IAs), which serve to procure or release capacity closer to the Delivery Year.

To ensure reliability and that the VRR Curve is reasonably updated over time to align with changes in market conditions, PJM is required to undergo this periodic review process. Initially the periodic review took place every three years but has been extended to every four years since 2018.

"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. 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." -PJM Open Access Transmission Tariff ("OATT"), Attachment DD.5.10, Section (a)(iii).

This report addresses the VRR Curve shape and the second companion report *Brattle 2025 PJM CONE Report* addresses the Reference Price, Cost of New Entry (CONE), and the Energy and

⁷ PJM, <u>Capacity Market (RPM)</u>, 2025.

Ancillary Services (E&AS) offset methodology used to calculate Net CONE that will apply for planning years 2028/29 through 2031/32.

The VRR Curve is designed to fulfill the objectives summarized in Table 1. As in all prior reviews, our assessment of the VRR Curve performance and design is grounded by these long-term capacity market design objectives which constitute inherent trade-offs between reliability outcomes, price volatility, and procurement cost.⁸ Any workable VRR Curve shape must ensure adequate performance while reasonably balancing these competing objectives. Some objectives are central to RPMs functioning and are codified in the PJM OATT and PJM Manuals such as meeting the 1-in-10 Loss of Load Expectation (LOLE) system-wide reliability standard. The locational reliability standard has recently changed to be defined as maintaining the normalized Expected Unserved Energy (EUE) of no more than 40% of the RTO-wide normalized EUE at criterion.⁹ Given increasingly differentiated seasonal risks, the system-wide performance and reliability is being considered in a new light and potentially expanded to include additional metrics such as LOLE, EUE, and Loss of Load Hours (LOLH). Others are our interpretation of RPM's overarching role to support reliability and economic efficiency in a financially sustainable merchant investment context.

Spees, Newell, Thompson, and Bartone, Fifth Review of PJM's Variable Resource Requirement Curve For Planning Years Beginning 2026/27, April 19, 2022; Newell, Oates, Pfeifenberger, Spees, Hagerty, Pedtke, Witkin, and Shorin, Fourth Review of PJM's Variable Resource Requirement Curve, April 19, 2018; Pfeifenberger, Newell, Spees, Murray, and Karkatsouli, Third Triennial Review of PJM's Variable Resource Requirement Curve, May 15, 2014; Pfeifenberger, Newell, Spees, Hajos, and Madjarov, Second Performance Assessment of PJM's Reliability Pricing Model, August 26, 2011; and Pfeifenberger, Newell, Earle, Hajos, and Geronimo, Review of PJM's Reliability Pricing Model, June 30, 2008.

⁹ PJM, <u>PJM Manual 20A</u>. Effective June 27, 2024. Section 1.3.

TABLE 1: VRR CURVE DESIGN OBJECTIVES

| | VRR Curve Design Objectives |
|-----------------------|--|
| Reliability | Maintain 1-in-10 LOLE system-wide planning target on a long-term average basis |
| | • For each LDA, normalized EUE no more than 40% above RTO-wide normalized EUE at criterion |
| | Assess curve performance with additional criteria including LOLE, LOLH, and EUE on average and in extremes (ensure robustness across potential market conditions) |
| | Maintain reliability across a range of potential market conditions |
| | Rarely drop below a "minimum acceptable" level when PJM may intervene (<99% of reliability requirement on a system-wide basis, though no specific value is defined for LDAs) |
| Pricing Efficiency | Outcomes reflective of economic fundamentals in a well-functioning, competitive market: prices high enough to attract entry when needed for reliability; prices low enough to enable efficient exit and retirements during surplus |
| | Reduce price volatility due to small changes in supply and demand, but allow prices to move sufficiently to reflect changes in market conditions and enable competition |
| | Mitigate susceptibility to exercise of market power |
| | Few outcomes at the administrative cap |
| | • Mitigate customers' exposure to price spikes and the costs of over-procurement |
| Other | Aim for simplicity, stability, and transparency |
| | Provide a sustainable value proposition to states, members and market participants with diverse customer segments, business interests, policy requirements and regulatory models |
| | Strike a balance among competing objectives |

Sources and Notes: For detail on reliability criteria, see PJM, <u>PJM Manual 20A</u>. Effective June 27, 2024. Section 1.3; and Reliability Assurance Agreement, <u>Definitions</u>, Capacity Emergency Transfer Objective (CETO).

B. Recent Changes to the VRR Curve Formula

The VRR curve has undergone a series of changes recently including updates to PJM's reliability modeling, as well as recent fundamentals-driven and rules updates affecting the Reference Technology and Net CONE parameter (where Net CONE = Gross CONE minus E&AS Offset). Figure 4below shows some of the most recent VRR curve shapes in Installed Capacity (ICAP) terms on the left and UCAP price units on the right. Note that the changes on the left chart (in ICAP terms) offer a more valid comparison of the overall financial consequences of recent updates, since the different curves are reflected on common ICAP-based units of measure. On an ICAP basis, prices are lower and more reflective of what generators earn and what customers pay.

The UCAP-based units are more relevant for a different reason, as the units of measure for clearing and settling the RPM market. However, UCAP-based prices are not self-consistent across recent years, considering that market-wide cleared volumes are substantially lower as of the 2025/26 delivery year when the market-wide Forecast Pool Requirement (FPR) dropped from 109% to 93.87% of the annual peak load. Sellers ELCC-adjusted UCAP ratings have dropped by a

similar amount from 94.98% to 79.69% of ICAP ratings for the same reason.¹⁰ In other words, UCAP-based prices would need to be 19% higher in 2025/26 than in 2024/25 in order to result in the same revenues to producers on an ICAP basis.¹¹ Throughout this report, we use the updated UCAP-based accounting where possible, and (other than in this figure) adjust prior years' prices upwards as relevant to compare results on a common basis.

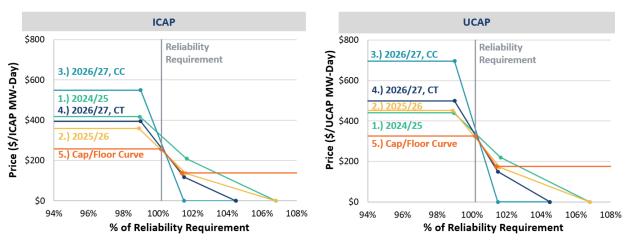


FIGURE 4: COMPARISON OF RECENT CHANGES TO VRR CURVE FORMULA

Sources and Notes: 2024/25 curve from PJM, <u>Planning Period Parameters</u>, 2024, converted from UCAP to ICAP using Fleet Equivalent Forced Outage Rate on demand (EFORd) for 2024/25 auction and Fleet Effective Load Carrying Capacity (ELCC) for the 2025/26 auction; 2026/27, CC values calculated from data provided by PJM; 2026/27 CT curve based on PJM, <u>Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection</u>, L.L.C., Docket No. ER25-682-000; Cap/Floor Curve provided by PJM.

Considering each change individually, the recent changes to the VRR curve shape include:

- 2024/25 BRA—VRR Curve in the 2024/25 BRA used the prior curve formula and prior capacity accreditation with a gas-fired CT plant as the Reference Resource. The price cap was set at the maximum of either 1.5 × Net CONE or 1 × CONE as it had been for several previous auctions. The quantity points on the curve ranged across 99% to 106.8% of the Reliability Requirement.
- 2. 2025/26 BRA—VRR Curve in the 2025/26 BRA similarly used the prior curve formula with a CT as the Reference Resource. However, PJM adopted a new capacity accreditation method and reliability modeling approach to adjust ICAP to UCAP values and model reliability risk. The combination of the new methods reduced the total procured volumes, Reliability Requirement, and pool-wide UCAP accreditation factor, such that starting in 2025/26 all

See PJM Capacity Market: 2024/25 and 2025/26 Base Residual Auction Planning Parameters.

Example calculation: Consider a \$100/MW-day ICAP price. In 2024/25 that price would translate into \$100 \div 94.08% = \$105.28/MW-day UCAP. In 2025/26, the same ICAP-based price would translate into \$100 \div 79.69% = \$125.49/MW-day UCAP (or a 19% increase in prices with no increase in revenues from a generator perspective).

- future curves appear 19% more expensive in UCAP terms relative to prior curves based on the prior reliability modeling and accreditation.¹²
- 3. 2026/27, CC (Overwritten)—The initially-calculated (but since over-written) VRR curve for the 2026/27 BRA used an updated curve formula where the price cap was determined by the maximum of either 1.75 × Net CONE or 1 × CONE, but with the new capacity accreditation, with a CC as the Reference Resource, a forward-looking approach for estimating the Net E&AS, and additional changes from the prior Quadrennial Review. The updated Curve formula is a steeper shape that crosses fewer quantity points ranging from 99% to 104.5% of the Reliability Requirement. While the auction was scheduled to run with this curve, the auction was delayed due to the impact of these changes and broader economic conditions which resulted in a Net CONE and price cap that were outside of the anticipated ranges the curve was designed for. The Net CONE of the CC reference resource went to zero which caused the price cap to be set by the CONE parameter and resulted in much steeper curve that only consisted of two points.
- 4. 2026/27, CT (Approved, but Subject to More Recent Filing)—In December 2024 PJM submitted a 205 filing that was accepted by FERC in February 2025 intended to address the above issues and maintain a CT as the Reference Resource with an updated estimate of CT Net CONE.¹⁴ The updated curve is still steeper than prior curves (considering the smaller quantity range of 99% to 104.5% of Reliability Requirement), but the price cap is lower and more consistent with prior curves.
- 5. Cap/Floor Curve (Most Recent Filing, Pending FERC Review)—Meanwhile the Commonwealth of Pennsylvania filed a 206 filing at FERC protesting the 2025/26 BRA clearing results, and expressing concerns about the VRR Curve and customers' exposure to price cap events if tight supply conditions continue. In response, PJM has most recently filed a 205 filing before FERC as of February 2025. The updated proposed VRR curve would limit the range of

Dependent upon FPR and resource risk modeling, if there is a sizable shift to summer risk, this would not hold true.

Spees et. al., Fifth Review of PJM's Variable Resource Requirement Curve, For Planning Years Beginning 2026/27 ("2022 VRR Curve Report"), April 19, 2022; PJM Interconnection, L.L.C., Tariff filing per 35.13(a)(2)(iii: Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters to be effective 12/1/2022 under ER22-2984, filed before the Federal Energy Regulatory Commission, September 30, 2022, Docket No. ER22-2984-000; 182 FERC ¶ 61,073, Order Accepting Proposed Tariff Revisions re PJM Interconnection, L.L.C. under ER22-2984, February 14, reference 2023, Docket Nos. ER22-2984-000 and ER22-2984-001.

PJM Interconnection, L.L.C., <u>Revisions to Reliability Pricing Model</u>, <u>Request for a 28-day comment period</u>, i.e., <u>January 6</u>, <u>2025 comment date</u>, filed before the Federal Energy Regulatory Commission, Docket No. ER25-682-000, December 9, 2024; 190 FERC ¶ 61,088, <u>Order Accepting Tariff Revisions Subject to Condition re PJM Interconnection</u>, <u>L.L.C. under ER25-682</u>, February 14, 2025, Docket No. ER25-682-000.

potential pricing outcomes by applying temporary cap and floor at \$325 and \$175/MW-day respectively, and is intended to be in place for 2 years for the 2026/27 and 2027/28 auctions.¹⁵

For the purposes of our analysis in this report, we describe the "Current Curve" as the current VRR curve formula using a CT Reference Resource with the price cap at 1.75 × Net CONE or CONE and updated with 2028/29 values for the CT (the first year in the review period) from our concurrently issued *Brattle 2025 PJM* CONE *Report*.

C. Focus Areas of the Sixth Quadrennial Review

We have conducted this Sixth Quadrennial Review with a focus on priorities identified by stakeholders, PJM staff, and our own assessment of challenges likely to affect the performance of the VRR curve and RPM in the relevant delivery years 2028/29 through 2031/32. The focus areas for this review include:

- Tight market conditions that have recently resulted in a substantial contraction in the
 capacity supply-demand balance, exacerbated by suddenly high load growth, a compressed
 forward period for upcoming auctions, and a limited development pipeline of gas-fired
 resources with long lead times and scarcity pricing for new projects;
- Uncertainty in Net CONE and reference resource, considering the ongoing transition in the
 resource mix, uncertainties in the cost and economic outlook for each technology, differences
 in consumer and policy requirements across the PJM footprint, and evolving energy market
 conditions, all making it difficult to set auction parameters that provide stable long-term
 investment signals despite these uncertainties; and
- Recent and anticipated RPM market design changes, including recent updates to reliability
 modeling and resource accreditation, as well as the potential to transition to a sub-annual
 capacity market.

Governor Josh Shapiro and The Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C., Complaint of Governor Josh Shapiro and The Commonwealth of Pennsylvania, filed before the Federal Energy Regulatory Commission, Docket No. EL25-46-000, December 30, 2024; Governor Josh Shapiro and The Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C., Stipulation of Satisfaction and Joint Motion to Dismiss Complaint of PJM Interconnection, L.L.C, Governor Josh Shapiro, and the Commonwealth of Pennsylvania, filed before the Federal Energy Regulatory Commission, Docket No. EL25-46-000, February 14, 2025; and PJM Interconnection L.L.C, re PJM Interconnection, L.L.C., Docket No. ER25-1357-000 Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, filed before the Federal Energy Regulatory Commission, Docket No. ER25-1357-000, February 20, 2025.

III. Analysis of Recent Capacity Market Outcomes

A. Historical RPM Procurement Levels and Clearing Prices

Clearing prices and volumes vary depending on market conditions. By design, RPM aims to support long-term reliability by targeting a cleared volume of capacity resources consistent with the reliability requirement, the 1-in-10 reliability standard. Consistent with expected outcomes in a competitive marketplace where supply is attracted by prices sufficient to cover investment costs, a functioning capacity market should be anticipated to produce clearing prices that investors expect will converge on average to the Net CONE in long-term equilibrium conditions.

In reality, no market is ever in a true long-term equilibrium but rather shifts through a series of disequilibrium conditions that depend on unforeseen circumstances or shifts in fundamentals. Times of shortfall will produce periods of high prices, while times of surplus will produce low prices. A large, competitive marketplace such as the RPM should be well-positioned to manage and compensate for these shifts, using price outcomes as the signal of when new supply should come forward and older resources should retire.

The most recent shifts in RPM prices however, require additional focus in this Quadrennial Review, particularly the substantial price increase observed in the 2025/26 BRA that arrived after several years of low prices. As shown in Figure 5, RTO clearing prices ranged between \$16/MW-day and \$165/MW-day between the 2012/13 Delivery Year and the 2024/25 Delivery Year, prices that were substantially below administrative estimates of Net CONE due to consistent procurement in excess of reliability requirements and long market conditions. Despite prices substantially below Net CONE, over time the RPM has attracted large volumes of new investment (for example 34 GW ICAP of new gas-fired combined cycle resources since the 2014/15 auction). 17

In several instances, constrained LDAs cleared above the system price driven by transmission constraints and local resource retirements. See PJM BRA results reports available at PJM, <u>Capacity Market (RPM)</u>, accessed February 10, 2025 and 2022 VRR Curve Report, Sections II.A and II.B.

New supply provided in ICAP MW. Does not include data from the 2014/15 BRA. Data is recent as of the 2023/24 Base Residual Auction and does not include changes in installed capacity that have occurred since. See PJM, 2023/2024 RPM Base Residual Auction Results, 2022, Table 8.

Following several years of supply entry at moderate prices, the RPM has most recently had a period over 2022/23-24/25 in which prices were relatively low and commensurate with prices that signaled long market conditions and encouraged sellers to exit the market or defer their entry decisions. Low prices were a reflection of long market conditions relative to the supply-demand accounting of the RPM capacity market. However, these prices did not yet account for the challenges that PJM has increasingly observed in accurately measuring system reliability risks as the fleet changes and as winter reliability risks grow. For that reason, the extent and nature of reliability needs were not fully reflected in prices signaled via the RPM over that period.

In the most recent BRA, the 2025/26 BRA system price (RTO) rose to \$270/MW-day, which is above the RTO Net CONE estimate of \$229/MW-day. Additionally, the Baltimore Gas and Electric (BGE) and Dominion Load Deliverability Areas (LDAs) cleared at their price caps at \$466/MW-day and \$444/MW-day respectively. ¹⁸ The sudden price increases came as a surprise to many stakeholders, regulators, and market participants, and warrant specific analysis in the current quadrennial review to understand the causes of these price changes and understand the implications for the appropriate VRR Curve parameters for the coming years.

As an initial observation on the levels of resulting prices: we note that the absolute level of the clearing prices should be considered in the context of a long-run resource adequacy construct. Prices at or near Net CONE are the level that should be expected over the long term in a market that relies on merchant capacity entry for a portion of supply needs. Further, multi-year periods of prices above or below that level should also be expected as the market predicts and reacts to supply-demand conditions and broader market fundamentals. However, a sudden price increase (and LDA price cap event) of the size observed in the last auction is problematic in particular for customers that have unhedged exposure to capacity market prices. On the supply side, unexpected and unpredictable price increases can also be problematic since some resources that could have been available may have failed to bring their projects forward (but are likely relatively quickly resolved in the next auction or as soon as those resources can mobilize). A final category of drivers for price increases can relate to market design changes and one-time transition effects, most notably the recent changes to more accurately account for reliability risks in setting capacity demand parameters and resource accreditation. In the following sections, we unpack the multiple factors influencing 2025/26 BRA and assess the implications for upcoming auctions. ¹⁹

¹⁸ PJM, 2025/25 Base Residual Auction Report, July 30, 2024.

See PJM, 2025/26 Base Residual Auction Results, August 21, 2024; PJM, 2025/26 Base Residual Auction Report, July 30, 2024.

\$400 **RTO Net CONE** \$350 Clearing Price (\$/ MW-day UCAP) \$300 \$250 **EMAAC** 2025/26 Price \$200 with 2024/25 Accreditation \$150 MAAC \$100 RTO \$50 \$0 2014/15 2015/16 2017/18 2018/19 2013/14 2019/20 2016/17 2020/21 2021/22

FIGURE 5: HISTORICAL RPM CLEARING PRICES AND NET CONE

Sources and Notes: Prices in nominal dollars. Data from historical PJM BRA Planning Parameters and Results reports available on the PJM website. See PJM, <u>Capacity Market (RPM)</u>, accessed February 4, 2025.

B. Diagnosis of Outcomes from the 2025-26 BRA

The elevated clearing prices in the 2025/26 BRA indicate that PJM is entering into a period of tight supply conditions which signals a need for further investment in capacity resources. ²⁰ In total, there was a 15,500 MW contraction in the market-wide supply demand balance with the 2024/25 auction running with a 16,000 MW surplus in offered supply relative to the Reliability Requirement (a large portion of this surplus did not clear the auction). The level of supply surplus contracted to only a 500 MW in 2025/26 (i.e., nearly all available supply was cleared). As shown in Figure 5, the system-wide clearing price increase from \$29/MW-day in 2024/25 to \$270/MW-day in 2025/26 was driven by a substantial tightening of the supply-demand balance paired with insufficient forward time for supply to react. ²¹ These tightening supply conditions were driven by a combination of market fundamentals and one-off events including the market reforms effecting reliability modeling and capacity accreditation approach.

²⁰ PJM, <u>2025/25 Base Residual Auction Report</u>, July 30, 2024.

²¹ PJM, <u>2025/2026 Base Residual Auction Report</u>, July 30, 2024, p. 4.



FIGURE 6: DRIVERS OF TIGHTENING SUPPLY CONDITIONS IN BETWEEN THE 2024/25 AND 2025/26 BRAS

Sources and Notes: Data compiled based on supply offer data provided by PJM staff and public reports. Supply offer values only include annual offers (exclude summer-only or winter-only offers). See PJM, 2025/26 Base Residual Auction Results, August 21, 2024; PJM, 2025/26 Base Residual Auction Report, July 30, 2024.

There were many factors that contributed to a tightening supply-demand balance for the 2025/26 BRA. Any one of these factors would likely have proven only to have a modest impact on market outcomes as a stand-alone driver (or if these individual drivers moved in offsetting directions). But the combination of the following factors led to a significant tightening event for the 2025/26 BRA:

- The re-entry of entities from the FRR alternative contributed similar size increases in both supply and demand, considering that FRR entities self-supply outside the RPM and tend to affect the market with a modest impact based on their net supply or net demand position (net demand in this case);
- An increase in the load forecast used for the 2025/26 BRA relative to the 2024/25 BRA. The 2024/25 BRA used the 2022 load forecast which estimated a summer peak of 150,300 MW and a winter peak of 135,500 MW for the 2024/25 delivery year.²² The 2025/26 BRA used the more recent 2024 load forecast which projected a summer peak of 153,500 MW and a winter peak of 139,200 MW for the 2025/26 delivery.²³ The increases in load are driven primarily by

²² PJM, PJM Load Forecast Report: January 2022, January 2022, Tables B-1 and B-2.

²³ Ibid.

increasing data center and electrification load. In January, PJM released the 2025 load forecast which projects additional load growth relative to the 2024 load forecast, primarily from data centers. Demand is expected to continue to grow in PJM with the 2025 load forecast projecting approximately 31,600 MW of peak demand growth by 2030.²⁴

- **Updated reliability modeling increased the IRM** putting upward pressure on the reliability requirement.²⁵ The increase in the IRM was driven primarily by modeling enhancements that more accurately capture winter reliability risks.
- **New additions and uprates** increased supply availability by 4,200 MW (a factor that offsets most of the other drivers that decreased the supply-demand balance).
- A decrease to net imports, retirements of existing resources, and unoffered resources with a must-offer exemption lowered supply offered by 10,500 MW. PJM filed updated market rules with FERC which were accepted in February 2025 that are meant to remove the must-offer exemption from intermittent resources. The IMM has estimated that approximately 3,745 MW of accredited intermittent and storage resources did not offer in the last BRA under the must-offer exemption.²⁶
- The implementation of new marginal ELCC resource accreditation methodology decreased supply offers through a decrease in accreditation of existing resources of 29,700 MW. ²⁷ However, the updated resource accreditation methodology also decreased the reliability requirement by a similar volume of 27,500 MW. The two adjustments are large individually, but are associated with the same transitional change to the accreditation reforms and together produced much smaller decrease in net supply of 2,200 MW directly attributable to

²⁴ PJM forecasts approximately 31,600 MW of RTO summer peak demand growth between 2024 and 2030; and approximately 34,500 MW of RTO winter peak demand growth between the 2023/24 and 2029/30 winter periods. The PJM RTO is predicted to be summer-peaking in 2030. See PJM, 2025 Load Forecast Tables, January 24, 2025, Tables B-1 and B-2.

²⁵ PJM, 2023 <u>Reserve Requirement Study</u>, October 3, 2023.

Approximately 13,000 UCAP-MW of resources were exempt from the most-offer requirement in the 2025/26 BRA that will now be subject to the must-offer requirement. However, the majority of these resources still offered into the 2025/26 BRA. See Monitoring Analytics, Comments of the Independent Market Monitor for PJM, Docket No. ER25-785-000, January 10, 2025, p. 5.

Based on analysis of supply offers of existing resources that offered into both the 2024/25 and 2025/26 BRAs. Value does not include the accreditation effect of new resources that offered into the 2025/26 BRA but not the 2024/25 BRA.

the resource accreditation changes.²⁸ Further discussion on PJM's resource accreditation is contained in Section III.D below.

In total, the net supply decreased from 16,000 MW for the 2024/25 BRA to 500 MW for the 2025/26 BRA, of which the majority was due to adjustments to the updated resource accreditation methodology, FRR re-entry, and increased IRM.²⁹ The market was unable to fully respond because the magnitudes may have come as a surprise to many market participants and the auction occurred with a shorter forward period than usual, resulting in a substantial increase in prices.³⁰

Looking forward, tight supply conditions may persist or worsen for several years given outlook for strong load growth, development time needed for sellers, and reforms needed to address barriers to supply entry.

C. Impact of the Compressed Forward Capacity Auction Schedules

The RPM is designed as a three-year forward auction but has operated with a compressed forward period since 2021/22 due to implementation of several market reforms which have delayed auction timelines, both for the most recent four auctions and for the upcoming four auctions. Figure 7 summarizes the forward period of the most recent auctions in addition to the planned schedule for future auctions.^{31,32} The current plan is to extend the forward auction

Continued on next page

The numbers in the text differ slightly from the numbers presented separately by PJM due to treatment of resources that did not participate in both the 2024/25 and 2025/26 BRAs and the treatment of FRR entities on the demand-side. PJM, 2025/2026 Base Residual Auction Results, Presented at Markets & Reliability Committee meeting, August 21, 2024, slide 22.

²⁹ PJM, <u>2025/2026 Base Residual Auction Results</u>, presented at Markets and Reliability Committee, August 21, 2024.

³⁰ Further discussion on the impacts of the shortened forward period of the 2025/26 BRA can be found in Section III.C.

The 2022/23 auction was delayed due to changes to the minimum offer price rule (MOPR), the 2023/24 auction was delayed due to updated minimum office seller cap (MSOC) rules, and the 2025/26 auction was delayed to enable time to implement the new reliability modeling and resource accreditation methodologies. See, Monitoring Analytics, Analysis of the 2022/23 RPM Base Residual Auction: Revised, February 22, 2022, revised January 13, 2023; Monitoring Analytics, Analysis of the 2023/24 RPM Base Residual Auction, October 28, 2022; and PJM, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, FERC Sets New Date for PJM 2025/2026 Capacity Auction, <a href="FERC S

The 2026/27 auction has already been delayed until July 2025 to allow time to change the participation rules for Reliability Must Run resources, to maintain a gas-fired combustion turbine (CT) as the reference resource, and to implement a new temporary price cap and floor to the 2026/27 and 2027/28 VRR curves among other rule

period on a staged basis, reverting to the full three-year forward period by the 2030/31 BRA (and only if there are no further BRA delays to accommodate future design changes). Therefore, we anticipate that any VRR Curve updates resulting from this Review may apply to auctions with a compressed forward period, and so consider the interactions the non-forward period may have with the VRR Curve in the 2028/29 and 2029/20 BRAs.³³

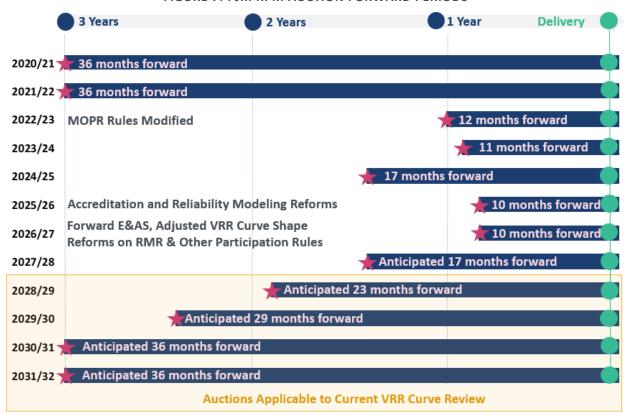


FIGURE 7: PJM RPM AUCTION FORWARD PERIODS

Sources and Notes: Timelines of historical auctions are based on PJM and IMM reports. Timeline for future auctions based on PJM published auction schedule as of 2024. See Monitoring Analytics, <u>Analysis of the 2022/23 RPM Base Residual Auction: Revised</u>, February 22,2022, Revised January 13, 2023; Monitoring Analytics, <u>Analysis of the 2023/24 RPM Base Residual Auction</u>, October 28, 2022; PJM, <u>Auction Schedule</u>, accessed April 7, 2025.

There are two distinct aspects of forward period that affect capacity market performance:

• The three-year forward period of the BRA auctions, which is intended to allow sufficient time for some resources to respond to price signals and make efficient entry and exit

changes. See FERC, Order on Contested Settlement, Docket No. ER22-1539-000, January 26, 2025 and PJM, Proposal for Revised Price Cap and Price Floor for the 2026/27 and 2027/28 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. No. ER25-01357-000, February 20, 2025.

See discussion on analysis of VRR curve options in the context of forward periods as opposed to non-forward periods in Section V.C.

decisions. The volume of incremental supply options is greater with a farther-forward period, with a 6-12 month forward period allowing for only limited responsiveness to price (e.g. from demand response and net imports); while a 2-3 year forward period can allow a wider array of supply responses (e.g. including uprates, life-extensions, and BESS investments). Some gas plants may also be able to finalize or accelerate construction timelines to meet a three-year forward period if their projects are sufficiently developed and permitted. Though other longer-lead resources or those that are not at a sufficient stage of development will still not be able to come online within a 3-year forward period, they will at least receive an earlier and clearer signal on when to initiate construction. By comparison, a compressed forward period leaves fewer options for sellers to adjust supply plans before the delivery period.

• The forward timeframe over which market participants are notified of material rule changes and other information, so that they can proactively plan for and manage needs as they arise. If new rule changes, capacity ratings updates, load forecast increases, or auction parameters come as a surprise or with limited forward time before the relevant auction, then market participants may not have sufficient time to adjust their plans. If market participants learn of an impending supply shortfall or rule change immediately prior to an auction, they will not be able to adjust or accelerate their plans in time to bring forward more resources to be offered into the auction. However, if rule changes are anticipated and implemented over a multi-year schedule that is communicated in advance, then market participants can be ready to meet new requirements by the time rule changes are in effect (this is true even in a non-forward capacity market). Beyond rule changes, anticipated changes to the load forecast, capacity ratings, transmission parameters, queue completion rates, and other factors that may materially affect supply and demand are critical information for market participants to assess the timing of their own projects.

Both of these factors have influenced recent RPM performance and contributed to pricing outcomes in the most recent 2025/26 BRA. The influence of the compressed forward period can be observed empirically in Figure 8 below, which illustrates that the 2025/26 BRA and other auctions with a compressed forward period had much steeper supply curves compared to the 2021/22 BRA and other auctions with the full 3-year forward period. The steeper supply curves are a manifestation of the reality that in a non-forward auction, nearly all supply decisions must be made before the auction based on their expectations of market price: new resources must decide to build or defer, aging resources must decide whether to retire or life-extend. They cannot wait until they know the auction clearing price in order to finalize these decisions. If many sellers inaccurately predict low prices (as they did prior to the 2025/26 auction) some sellers may fail to make an offer, even if their projects would have been in the money. The pre-auction

decision-making and steeper supply curves make non-forward capacity auctions somewhat more susceptible to price volatility and exposed to shortage events compared to forward capacity auctions.

In a full three-year forward auction, a much larger scope of potentially marginal resources can make a capacity offer and finalize their go/no-go decisions after the auction. The result is a higher and flatter supply curve, where more resources can be available to meet demand if prices are attractive and others can retire if prices are too low. Over most years since RPM's implementation, the market has attracted a volume of supply offers that was substantially beyond what was needed to meet the Reliability Requirement and, as a consequence, the BRA supply curve intersected with the VRR Curve at low or medium prices. At the same time, RPM has enabled over 58 GW of retirements of existing resources.³⁴ We view those outcomes as strong indicators that the market was healthy and performing well on the dimensions of attracting supply interest, producing a dynamic and competitive marketplace with robust competition between new and existing resources and amongst multiple technologies.

Considering these observations and the advantages of a farther-forward period, we recommend that PJM should prioritize maintaining its auction schedule and returning to the full three-year forward period. This may mean that some design changes may not be possible to implement until later delivery years, e.g., under a staged transition period. Staged rule changes with planned and Tariff-defined implementation dates can also often offer the additional benefit of providing stakeholders time to more proactively and effectively manage the transition.

As of 2023/24 BRA, See Monitoring Analytics, <u>2024 State of the Market Report for PJM</u>, Section 5: Capacity Markets, Table 5-6.

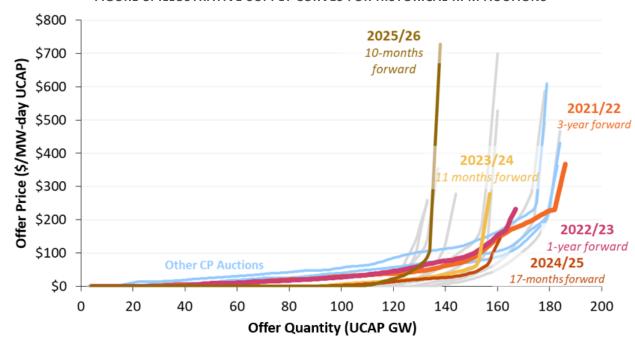


FIGURE 8: ILLUSTRATIVE SUPPLY CURVES FOR HISTORICAL RPM AUCTIONS

Sources and Notes: Curves shown are illustrative and based on confidential supply offer data provided by PJM staff. More recent Capacity Performance (CP) auctions are shown in light blue while later auctions before CP rules were implemented are shown in gray.

D. Interactions with Capacity Accreditation Reforms

PJM implemented updated marginal ELCC resource accreditation rules effective for the 2025/26 BRA. The updates to the accreditation methodology aim to improve reliability value assessments of all resource types, apply a consistent approach to all resources, and to account for correlated outages for thermal resources driven by extreme weather.³⁵ Figure 9 below shows the impact of the resource accreditation reforms on the existing resource fleet in PJM. Overall, the fleet-wide average accreditation fell from 95% for the 2024/25 BRA to 80% for the 2025/26 BRA. Much of the reduction in the fleet-wide average was due to reductions in accreditation of dispatchable fossil resources where gas-fired CC accreditation decreased from 97% to 79% and dual-fuel CT accreditation decreased from 95% to 79%. While other resources such as wind and solar also

After Winter Storm Elliot in December 2022, it became clear that accreditation levels for existing resources were overvaluing the winter reliability contributions for much of the resource fleet. During Winter Storm Elliot, 47,000 MW of capacity-qualified resources were unable to operate up to expected levels leading to \$1.8 billion in performance related penalties. PJM subsequently enacted reforms to better account for system reliability risks and resource performance during extreme weather. See FERC, Order Accepting Tariff Revisions Subject to Conditions, Docket No. ER24-99-000, January 30, 2024; PJM, Winter Storm Elliott: Event Analysis an Recommendation Report, July 17, 2023, pp. 1–2; Howland, "PJM, market participants reach agreement to resolve \$1.88 in Winter Storm Elliott fines," September 5, 2023.

experienced decrease in accreditation levels, there is less installed capacity of these resources currently in operation which reduces the impact of their lower accreditation levels.

The substantial changes in resource accreditations will have material implications for the resource mix in PJM, considering that some resources' ELCC values (especially solar, battery, and gas plants) will now earn lower capacity revenues and appear less competitive compared to other resources that retained higher capacity value (such as nuclear, coal, and offshore wind). Resources will also identify opportunities to improve their capacity ratings, such as by improving their access to firm fuel or battery storage duration. These values will also shift further as PJM and stakeholders continue to update and improve both reliability modeling and accreditation approaches.

However, the implications of the accreditation changes to the VRR Curve itself may be relatively more limited (since the VRR Curve is a measure of total demand needs rather than individual suppliers' capabilities). One substantive implication for the VRR curve is that, as noted above, the VRR curve pricing parameters under current UCAP accreditations appear 19% higher than they would under prior UCAP accreditations (see Section II.B above). Another implication is that if fleet-wide resource accreditations differ substantially from year to year, the VRR Curve pricing points may be similarly inflated or deflated in terms of their implications for customers and producers (the magnitude of these shifts will likely be reduced by the transition to a sub-annual construct, as discussed further below). It will take several years of experience with the new construct before it is possible to determine the scale and implications of these year-to-year updates in accreditation ratings. To maintain a more stable alignment between the VRR Curve pricing parameters and total volumes procured and accredited, the Reference Price can be updated alongside the pool-wide UCAP accreditation factor (e.g., such that on a fleet-wide average basis, a 5% increase in ELCC-accredited ratings would correspond to a 5% reduction in VRR Curve pricing parameters—this is similar to how the Net CONE parameter is currently updated based the UCAP of the Reference Technology).

100% Capacity Accreditation (% of Nameplate) Nuclear Diesel 80% Combined Cycle; Gas CT - Dual Fuel Demand Response **Combustion Turbine** 60% Offshore Wind Storage (4-hour) Landfill (Intermittent) 40% Hydro (Intermittent) **Onshore Wind**

FIGURE 9: IMPACT OF ACCREDITATION REFORMS BY RESOURCE CLASS FROM 2024/25 TO 2025/26

Sources and Notes: "Average" class in the 2024/25 BRA refers to 1—Pool-Wide Average Equivalent Forced Outage Rate on demand (EFORd); "average" class in the 2025/26 BRA refers to the Pool-Wide Accredited UCAP Factor; resource classes units without explicitly-defined capacity accreditation ratings in the 2024/25 BRA are assigned to "average" for this figure; 2024/25 EFORd from PJM, Planning Period Parameters for the 2024/25 Base Residual Auction, 2024; 2025/26 Pool-Wide Accredited UCAP Factor from PJM, Planning Period Parameters for the 2025/26 Base Residual Auction, 2024; 2024/25 ratings for non-dispatchable resources from PJM, ELCC Class Ratings for 2024/2025, 2023; 2024/25 ratings for dispatchable resources from PJM, 2021 PJM Reserve Requirement Study, 2021; 2025/26 ratings provided by PJM.

2025/26 BRA

Solar (Tracking)

E. Implications of Seasonally Distinct Reliability **Drivers and Resource Capabilities**

Historically, PJM has been a summer-peaking system and is expected to remain so into the future. 36 However, through enhanced reliability modeling PJM has determined that more

20%

0%

2024/25 BRA

³⁶ The 2025 Long-term Load Forecast Report projected the PJM summer peak to be 209,923 MW in 2035 and 228,544 MW in 2045 relative to a forecasted winter peak of 198,175 MW in 2033/35 and 218,760 MW in 2044/45. See PJM, 2025 Long-Term Load Forecast Report, prepared by the PJM Resource Adequacy Planning Department, January 24, 2025.

reliability risk now occurs in the winter season despite its lower peak demand.³⁷ Higher winter reliability risk is driven by a higher risk of correlated outages in extreme cold weather paired with supply availability from dispatchable and non-dispatchable resources relative to summer output. Additionally winter adequacy risk events tend to be longer, which impacts the ability of duration-limited resources to meet demand, relative to summer adequacy risk events which tend to be shorter and more concentrated into a few hours in July.³⁸ As electrification of heating increases, peak winter demand will continue to grow and at a pace that may be higher than summer demand increases. ³⁹ Combined, these risk factors result in relatively more reliability risk identified in winter than in summer, though both seasons will continue to present their unique profile of reliability challenges with different underlying risk drivers. In the current annual capacity market construct, the distinct reliability risks and volume of capacity needs presented by each season is reflected on a weighted-average basis as the combined annual Reliability Requirement.

An additional complexity in the annual capacity market construct is that different resource types have substantially different reliability and resource adequacy value between the summer and winter seasons. Figure 10 below shows illustrative projected capacity accreditations by resource type and season compared to an annual accreditation. As shown, the summer accreditation levels are distinct and generally higher across most resource types relative to the winter accreditations. This highlights that more resources are available and able to reliably serve demand at higher levels during summer periods of adequacy risk than during winter periods of risk. The figure also demonstrates that adequacy risk is not static and should be expected to evolve with the changing resource mix and demand profile over time. Under the current annual construct, these resources' distinct reliability value in summer and winter seasons is accredited on a combined annual basis, with the annual capacity value influenced by the share of system-wide risk exposure anticipated across the seasons.

PJM, <u>Capacity Market Reform: PJM Proposal</u>, Critical Issue Fast Path-Resource Adequacy ("CIFP-RA"), July 27, 2023, slide 57; and PJM, <u>Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid</u>, May 17, 2022.

Annual heat maps of Expected Unserved Energy show that winter adequacy risk tends to be spread across more hours and peaks twice daily in the early morning and late evening in January and February, as opposed to summer adequacy risk which is mostly concentrated to three afternoon hours in July. See PJM, Capacity Market Reform: PJM Proposal, Critical Issue Fast Path-Resource Adequacy ("CIFP-RA"), July 27, 2023, slides 63 and 64.

³⁹ See PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022 and Celebi et al., Bulk System Reliability for Tomorrow's Grid, The Brattle Group, prepared for the Center for Applied Environmental Law and Policy, December 20, 2023.

Annual Accreditation Summer Accreditation Winter Accreditation 100% 100% 100% Nuclear ELCC Rating (% Nameplate Capacity) 90% 90% 90% Coal Gas CC 80% 80% 80% Gas CT - Dual Fuel 70% 70% 70% Gas CT 60% 60% 60% 50% 50% 50% 40% 40% 40% 4-Hr Storage 30% 30% 30% **Onshore Wind** 20% 20% 20% 10% 10% 10% **Tracking Solar** 0% 0% 0% 2027 2029 2031 2029 2031 2027 2027 2029 2031

FIGURE 10: SEASONAL RESOURCE ACCREDITATION PROJECTIONS FOR PJM

Sources and Notes: Data provided by PJM staff.

Overall, the current approach to reflecting supply and demand on an annual basis is becoming an increasingly imprecise way to measure capacity needs and commitments. While reliability risk is currently greater in the winter months, it is possible that more reliability risk could shift back into the summer season in the future. For example, a shift to more summer reliability risk could occur if, under the annual construct, accreditations that reflect current greater winter risk incentivize more winter-focused resources to the point that summer-focused resources (e.g. solar and demand response) exit the market. Furthermore, there is a possibility that some LDAs in PJM could experience greater summer reliability risks compared to winter, even if RTO-wide risks are greatest in winter.

The annual construct as it is currently structured will eventually measure and track these shifting seasonal risks as they occur, but will tend to do so on a lagging basis that trails (rather than guides) the resource mix. To the extent that PJM's reliability modeling materially mis-estimates the balance of summer vs. winter risks, the result could be that the winter-focused accreditations produce low prices and apparently long market conditions; while at the same time the summer season remains insufficiently protected because summer-focused reliability needs and supply capabilities have not been meaningfully reflected in capacity market prices. Another challenge could occur if estimated seasonal risks shift back and forth frequently or even between each auction; in that scenario, the volumes of demand procured and resources' accreditation could be subject to material instability without being reflective of underlying supply-demand fundamentals. Overall, the performance of an annual construct to accurately measure reliability needs and supply capabilities will become increasingly eroded to the extent that: (1) more than

one season is anticipated to present material reliability risks, and (2) a substantial and/or increasing share of the resource mix has substantially different reliability value across these seasons.

Transitioning to a sub-annual or seasonal capacity construct would address these reliability risks and improve overall economic efficiency of capacity market outcomes. A sub-annual capacity construct can better align assessments of seasonally-distinct resource adequacy needs with more effective economic signals to attract investment in a supply mix that is better aligned to meet those needs over the year. Further, the PJM capacity market would be better-positioned to attract season-specific capacity commitments (e.g. from summer demand response) and engage in mutually beneficial seasonal capacity trade with neighboring jurisdictions that have complementary needs (e.g. importing in summer and exporting in winter, or vice versa).

Most other capacity markets have already acknowledged the reliability needs and economic rationale for moving to more accurate and seasonally-distinct capacity needs. For example, Ontario's Independent Electricity System Operator (IESO) conducts a two-season capacity auction with co-optimized auction clearing that sets separate prices in the summer and winter seasons; MISO has moved to a four-season capacity market starting with the 2023/24 delivery year; and ISO-NE is developing its proposal to adopt a seasonal auction for the 2028/29 delivery year. Though the reasons for a seasonal capacity market differ in each of these regions, the common thread is that each region faces a shift in reliability drivers that may produce materially different and distinct costs and capability to manage reliability needs on a seasonal basis.

PJM and the PJM Board have previously recognized the value in a sub-annual construct, and PJM staff have presented a high-level concept for how a sub-annual capacity construct would be structured over stakeholder processes conducted in 2022 and 2023.⁴¹ The outcomes of the most recent auction highlight further the reliability and economic benefits of transitioning to a sub-annual construct, considering the substantially tighter supply-demand conditions and winter-focused reliability challenges revealed by the 2025/26 auction results.

To ensure that a sub-annual construct supports reliability needs and produces efficiency benefits, it should have the following primary components, each of which can be built upon the experience

⁴⁰ ISO-NE is considering a sub-annual capacity auction but it is not yet approved. See Schatzki, Cavicchi, Ross, Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets, January 2024.

PJM, Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, October 13, 2023, Docket No. ER24-99-000; PJM, Executive Summary: PJM Seasonal and Annual Proposals, CIFP-RA, August 23, 2023; PJM, Seasonal Demand Curves, CIFP-RA, August 14, 2023; and PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

of other markets where they have already been tested and implemented. Elements of a subannual capacity market would include:

- Sub-annual reliability requirements reflecting the capacity quantity needed to maintain reliability: PJM's reliability modeling already incorporates the capability to separately measure reliability risks and needs by season, which can be used to establish seasonally-distinct Reliability Requirements. To first order, these season-specific reliability needs are closely associated with peak demand in each season, after accounting for other factors such as season-specific demand uncertainties, event durations, and seasonal capacity ratings. The seasonal capacity needs would be reflected in the RPM auctions as season-specific capacity demand curves as is done in both MISO and IESO (see additional discussion in Section VII.B below regarding the potential for seasonal MRI-based VRR curves in PJM).
- Sub-annual resource accreditation, offer quantities, and commitment obligations: Capacity resources would also have distinct seasonal UCAP ratings, reflecting their seasonal capacity ratings and resource capabilities. These seasonal drivers of resource value are already accounted for in establishing the marginal ELCC accreditation methodology, but the season-specific results would need to be used directly rather than combined into an annual composite value. Sub-annual accreditation has the potential to unlock more supply to participate in the RPM, such as: (a) thermal resources that would likely have higher winter capacity ratings than under the current annual construct, as long as incremental thermal ICAP (including above their annual capacity injection rights (CIR) ratings) can be considered in the accreditation;⁴² (b) demand response, batteries, and solar resources that have substantially higher summer capacity accreditations compared to winter; and (c) seasonal net imports.
- Prices that reflect the marginal costs of meeting demand, as driven by the supply-demand balance in each sub-annual commitment period: A sub-annual auction construct can more accurately reflect the marginal value of incremental capacity in each season, sending economically rational price signals for investment and aligning market-based payments with sub-annual contributions to reliability by season. To most accurately reflect the costs of supply, resources would be able to reflect the distinct cost profiles if cleared to meet the needs in only one season versus if they are committed across the entire year (where the total revenues received over the year would need to be sufficient to recover total costs). Market prices would also be most accurately set if they are the product of a co-optimized auction clearing that minimizes the total annual cost of supply and ensures that cleared participants recover the avoided costs that occur for clearing in one or both seasons.

⁴² Monitoring Analytics, <u>Analysis of the 2025/2026 RPM Base Residual Auction Part A</u>, September 20, 2024, p. 6.

Together, these components of a sub-annual capacity construct could produce substantial cost savings, particularly under present conditions when supply needs are tight. These cost savings arise due to the ability to unlock additional supply capability in individual seasons in the near term, and over the longer-term by guiding a more economic and right-sized capacity mix to meet reliability needs across seasons. A sub-annual construct would also be more robust to changing reliability risks and able to achieve efficient market outcomes even without perfect foresight into the precise resource mix will be in future years. MRI-based VRR Curves such as we recommend in this Review are also aligned with a transition to a sub-annual construct, as discussed in more detail in Section VII.B below.

IV. Development of System-Wide MRI-Based VRR Curves

A. Comparison to Current VRR Curve and Other Capacity Markets' Curves

Figure 11 illustrates the current PJM VRR curve and an MRI-based VRR curve, in comparison to the downward-sloping capacity demand curves used in other capacity markets including in New York Independent System Operator (NYISO), Midcontinent Independent System Operator (MISO), ISO New England Inc. (ISO New England), and Ontario's Independent Electricity System Operator (IESO).

As in PJM, these other capacity markets' demand curves are designed so that, on average and over the long term, clearing prices can reflect long-run marginal costs and clearing quantities align with reliability needs.⁴³ While this economic logic is shared across all capacity markets, there are variations in demand curve shape associated with different preferences in the trade-off between lower price volatility (accomplished through a lower price cap and/or flatter demand curve) and certainty over the cleared quantity (accomplished through a higher price cap and steeper demand curve).

Additional variation between curves is tied to other market features, such as the forward period and seasonality of the auction. For example, NYISO's curve is notably flatter than neighboring markets' curves and features a higher price cap, in part due to NYISO's non-forward capacity auction structure, which includes seasonal, monthly and spot auctions. The demand curve is incorporated only into the final spot auction, with the farther forward auctions and bilateral markets serving to support hedging against the spot auction price.⁴⁴

These capacity markets also account for seasonality in distinct ways. The IESO capacity auction is structured relative to two distinct capacity seasons with different volumes of supply and demand

While the terminology varies by market, all capacity markets aim to procure a level of quantity equal to the Reliability Requirement, i.e., the peak load plus a reserve margin, as adjusted to a UCAP or ELCC basis.

NYISO's capacity market includes three types of capacity auctions: Strip Auctions for each Capability Period (i.e., twice a year); Monthly Auctions (held every monthly for the remaining months in the Capability Period); and Spot Auctions (held every month for procurement of capacity for use in the upcoming month). For more information, see Mathangi Srinivasan Kumar, "NYISO Administered ICAP Market Auctions," September 26-27, 2024.

and different clearing prices; MISO has supported a four-season capacity market starting in 2023/24. In both of these seasonal capacity markets, the parameters and shape of the demand curves are influenced by the seasonal nature of the constructs (chiefly, because the volumes are a product of peak load in the relevant season). The NYISO market incorporates a mixture of annual, seasonal, and monthly components.⁴⁵ The ISO-NE capacity market is currently an annual construct, but the region is in the process of developing a proposal to transition to a two-season construct.⁴⁶

The shape and slope of the other markets' capacity demand curves are also influenced by considerations similar to those that we have previously considered in the VRR Curve reviews, including the relationship of prices to the implied willingness-to-pay for reliability. The relationship of the capacity demand curve to reliability value is strongest in both ISO-NE and MISO, where both markets derive their demand curve shapes directly from their modeling estimates of the marginal reliability impact. ISO-NE was the first region to adopt MRI-based demand curves in 2016, with different MRI curves utilized system-wide as well as for import-constrained and export-constrained regions.⁴⁷ MISO will first utilize its MRI-based demand curves in its seasonal auction in the upcoming auction for the 2025/26 delivery year.⁴⁸

Demand parameters are primarily associated with annual peak load, while supply accreditation is mostly related to 6-month seasonal capability. Individual supply commitment periods have a duration of one-month at a time, consistent with the timeframe relevant for the monthly and spot auctions.

⁴⁶ See ISO-NE, "Capacity Auction Reforms Key Project."

⁴⁷ 155 FERC ¶ 61,319, Order Accepting Filing re ISO New England Inc. and New England Power Pool Participants Committee under ER16-1434, June 28, 2016, Docket No. ER16-1434-000.

The MISO reliability-based demand curves are defined on a system-wide basis and across the two large market regions, with separate curves in each of the four capacity seasons (3 distinct geographies × 4 seasons = 12 curves in each auction). 187 FERC ¶ 61,202, Order Accepting Tariff Revisions, re Midcontinent Independent System Operator, Inc. proposed Reliability Based Demand Curves, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002; see also Written Testimony of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Linquan Bai, filed before the Federal Energy Regulatory Commission, September 28, 2023, Docket No. ER23-2977-000.

300% **NYISO** 250% % of Net CONE 200% PJM, Current Curve 150% PJM, MRI-based Curve **MISO** 100% 50% **IESC** 0% 80% 85% 90% 95% 100% 105% 110% 115% % of Reliability Requirement

FIGURE 11: DEMAND CURVE COMPARISON OF NEIGHBORING CAPACITY MARKETS

Sources/Notes: "PJM, MRI-based Curve" shown as Curve 2, Price Cap at 99% of the Reliability Requirements, described in detail in Section IV.B, "PJM, Current Curve" constructed using updated Gross CONE and Net CONE estimates for a dual-fuel CT with a June 2028 online date from the Brattle 2025 PJM CONE Report (although the y-axis is shown as a percentage of Net CONE, this information is relevant to determine the price cap) and the current VRR curve formula; PJM, Open Access Transmission Tariff, Attachment DD, Section 5.10, accessed March 3, 2025; NYISO curve based on NYCA Zone summer 2024 curve; NYISO, ICAP/UCAP Translation of Demand Curve, Summer 2024 Capability Period, 2024; NYISO, Annual Update for 2024-2025 ICAP Demand Curves, November 17, 2023; IESO curve from the 2025 capacity auction, this curve includes implied long-term contracted capacity, auction parameters from the 2025 capacity auction; IESO, Annual Planning Outlook, March 2024; IESO, Capacity Auction: Pre-Auction Report, August 16, 2024; MISO curve from Brattle testimony supporting MISO's implementation of Reliability-Based Capacity Demand Curve, The Brattle Group, Written Testimony of Dr. Kathleen Spees, Dr. Samuel A. Newell, and Dr. Linquan Bai, filed before the Federal Energy Regulatory Commission, September 28, 2023, Docket No. ER23-2977-000; ISO-NE curve from Forward Capacity Auction 18 for Capacity Commitment Period 2027/28; ISO-NE, FCA 18 Demand Curves, August 14, 2023.

B. Constructing an MRI-Based VRR Curve

Following the concept demonstrated in both ISO-NE and MISO, we recommend that PJM's VRR Curve should be updated to a shape aligned with the marginal reliability value or MRI. In prior quadrennial reviews we have used the MRI-based curve as a key indicator of the alignment of the VRR Curve with reliability benefits delivered to customers but have not previously recommended to formally adopt the MRI-based approach primarily because PJM was in the midst of enhancing its approaches to more accurately model reliability value of incremental

capacity and accredit capacity. ⁴⁹ Now that these reforms have been implemented, we recommend taking the next step toward more accurate supply-demand accounting with an MRI-based VRR Curve. Adopting an MRI-based curve in PJM can also leverage the experience from ISO-NE and MISO, which have both demonstrated the feasibility and implementation details associated with MRI-based demand curves that can be adapted into the PJM context.

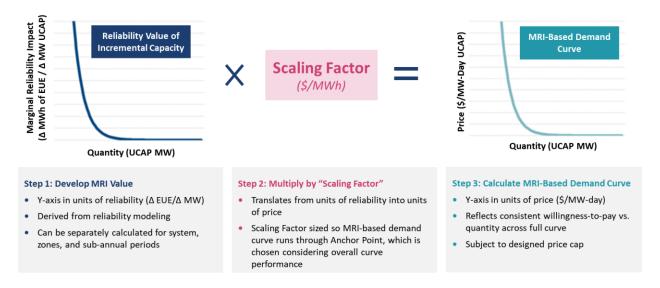
MRI-based curves have the conceptual advantage of reflecting a more uniform and unified representation of the willingness-to-pay for reliability, meaning that market prices are more meaningfully aligned with reliability value delivered to customers. The wider and more gradually declining foot of these curves reflects the diminishing need for and value of capacity when the market is long, while the steeper slope near the cap reflects more acute reliability needs when the market is tight. To the extent that the same \$/MWh scaling factor is used to for multiple capacity demand curves, this also offers a more unified signal on the value of capacity by location (like in New England) and by season (like in MISO). The capability of an MRI curve to more accurately and meaningfully reflect differentiated reliability value across seasons will be particularly valuable in the PJM region, considering the other economic and reliability benefits that will be realized if PJM proceeds with implementing a sub-annual construct. For the majority of this report, we describe the MRI curve as it would be implemented in the current annual capacity market construct (consistent with the scope of this Quadrennial Review), and provide an indicative description of the method that would be applied to adapt the curve into a subannual or seasonal market (in Section VII.B below). To develop these MRI-based curves, we used reliability modeling results provided by PJM staff from the same modeling platform that is currently used to set the RTO and LDA Reliability Requirements.⁵⁰

The process we used to develop MRI-based VRR Curves in PJM is illustrated at a high-level in Figure 12. The process includes three steps to: (1) develop the MRI curve in units of reliability (Δ EUE MWh / Δ MW UCAP); (2) multiply the MRI value by a "Scaling Factor" in units of \$/MWh to translate from units of reliability to units of capacity price; and (3) determine the resulting capacity market demand curve in units of capacity price (\$/MW-day UCAP). We describe these steps in more detail below.

⁴⁹ See 2022 VRR Curve Report, Section III.B.

⁵⁰ PJM, <u>2023 Reserve Requirement Study</u>, October 3, 2023.

FIGURE 12: CONCEPTUAL STEPS TO DESIGNING AN MRI-BASED DEMAND CURVE



In **Step 1,** PJM's reliability modeling is used to determine quantity of capacity at which the system achieves the Reliability Requirement, at 1-in-10 or 0.1 LOLE (this process is already utilized in PJM's current reliability modeling). Next, an additional modeling step is conducted in which perfectly available UCAP MWs of capacity are added or subtracted to determine the incremental reliability value of adding/subtracting capacity. The MRI curve is defined as the MWhs of reduction to Expected Unserved Energy accomplished by adding 1 UCAP MW of incremental supply. The MRI can be calculated relative to the entire system, a specific LDA, or in a sub-annual period, which has the potential to support more accurate pricing signals at specific locations and across seasons. The MRI curves utilized in this report are derived from the Loss of Load Hours (LOLH) metric and is mathematically defined in Equation 1.

Figure 13 shows the resulting PJM RTO-wide MRI curve for the PJM region, which is convex and downward-sloping. When supply is scarce, incremental capacity additions lead to large improvements in system reliability, as reflected by the steep slope of the MRI curve at low quantities. However, when supply is abundant, the gradual slope of the MRI curve reflects the diminishing, but non-zero, reliability impact of incremental capacity additions.

EQUATION 1: CALCULATION OF MARGINAL RELIABILITY IMPACT

MRI = Avoided EUE from Incremental Capacity = LOLH × 1 MW UCAP

WHERE:

MRI (MWh per 1 UCAP MW): is the incremental reliability value of adding 1 UCAP MW of capacity to the system

Avoided EUE (MWh of avoided EUE per MW UCAP): is the reduction in expected involuntary load shedding caused by adding 1 UCAP MW of incremental capacity

Incremental Capacity (UCAP MW): is the volume of perfectly available capacity added (assumed to be 1 UCAP MW to calculate the marginal impact)

LOLH (hours per year): is the duration of outage hours (which may occur across one or many events) predicted in reliability simulations across the season in question, consistent with a specific quantity of UCAP MW available

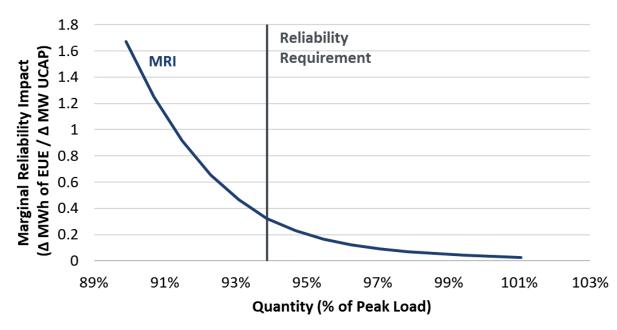


FIGURE 13: PJM SYSTEM-WIDE (RTO) ANNUAL MRI CURVE

Sources/Notes: Reliability data provided by PJM reliability modeling staff; UCAP Reserve Margin from the 2025/26 Base Residual Auction, see PJM, 2025/26 Planning Period Parameters, 2023.

In Step 2 the "Scaling Factor" is defined which translates the MRI curve from units of reliability (ΔΕUΕ /ΔΜW UCAP) into units of price (\$/MW-day UCAP). The Scaling Factor is sized so that the resulting MRI-based demand curve runs through an "Anchor Point" which is chosen considering the overall curve's performance. The anchor point itself can be defined in any number of ways, but sets a single price-quantity pair through which the MRI-based VRR curve is drawn. In both ISO-NE and MISO, the anchor point is defined by the Reliability Requirement and Net CONE. For

the purposes of this report, we focus on three different curves with differently-defined anchor points as discussed further in the following Section III.C. Equation 2 is the formula for deriving the Scaling Factor from the Anchor Point.

EQUATION 2: CALCULATION OF SCALING FACTOR FOR MRI-BASED VRR CURVE

Scaling Factor = Price @ Anchor Point ÷ MRI @ Anchor Point

WHERE:

System Scaling Factor (\$/MWh): is the payment rate at which the system VRR Curve would seek to procure additional supply

Price @ Anchor Point (\$/MW-year UCAP): is equal to the price at a defined Anchor Point, through which the MRI-based VRR Curve is drawn

MRI @ Anchor Point (MWh/MW-year UCAP): is the marginal reliability impact of additional capacity, measured at the Anchor Point quantity through which the MRI-based VRR Curve is drawn

Finally, in Step 3, the system or locational MRI-based VRR Curve is calculated by multiplying the Scaling Factor by the MRI curve at each quantity point to translate from units of reliability into units of capacity price and willingness to pay. The resulting MRI-based VRR Curve can extend to volumes above and below the Anchor Point, and is subject to a price cap.

C. MRI Curves Tuned to 1-in-10 Standard

As described in Section IV.B above, MRI curves can be developed based on different scaling factors to pass through unique anchor points. To construct Candidate MRI-based VRR Curves and evaluate their potential performance in the PJM capacity market, we identified three different approaches to defining the MRI-based curves such that the parameters would be "tuned" to the 1-in-10 LOLE reliability standard. In each case, we adjust the price and quantity of the defined Anchor Point, such that in long-term probabilistic modeling the prices and quantities supported by the MRI-based VRR Curve align with 0.1 LOLE at prices that on average are equal to the Reference Price or long-run marginal cost of supply. This simulation modeling is the same approach that we have utilized in prior VRR Curve Reviews, with modeling parameters updated to reflect recent market outcomes and present conditions as described in more detail in the Appendix.

The three Candidate Curves that we examine throughout this report are defined as follows, and are illustrated in Figure 14 below after tuning the Anchor Points to the 1-in-10 standard. The three MRI-based curves we consider are:

- Curve 1, Anchor Point at the Target: This Anchor Point is set so that clearing prices are equivalent to the Reference Price at the target point (i.e. the Reliability Requirement). The price cap quantity and price are then adjusted so the curve achieved 1-in-10 LOLE. Under base modeling conditions with the Reference Price at \$350/MW-day, Curve 1 has a price cap of \$890/MW-day and a price cap quantity at 97.8% of the Reliability Requirement.
- Curve 2, Anchor Point at 99% of the Reliability Requirement: This Anchor Point is set so that the price cap quantity is at 99% of the Reliability Requirement, which is the quantity threshold below which auction clearing results could trigger a review of the VRR curve. The price cap price was then adjusted so the curve achieved 1-in-10 LOLE under base modeling conditions. With a Reference Price of \$350/MW-day, Curve 2 has a price cap of \$605/MW-day and a price cap quantity at 99% of the Reliability Requirement.
- Curve 3, Anchor Point at 1.5 × Reference Price: This Anchor Point is set so the price cap price is 1.5 × Reference Price. The quantity at the price cap quantity is then adjusted so that the curve produces reliability at 1-in-10 LOLE under base conditions. With a Reference Price of \$350/MW-day, Curve 3 has a price cap of \$525/MW-day at a price cap quantity at 99.6% of the Reliability Requirement.

\$1,000 **Current Curve Reliability Requirement** \$800 MRI Curve @ 99% of the Reliability Requirement Price (\$/UCAP MW-day) MRI Curve @1.5 × Reference Price \$600 **MRI Curve @ Target Point** \$400 Reference Price \$200 \$0 96% 98% 100% 102% 106% 104% 108% - 7.7% - 4.5% - 2.1% - 0.5% - 10.1% - 6.1% 1.1% % of Reliability Requirement UCAP Reserve Margin

FIGURE 14: MRI-BASED VRR CANDIDATE CURVES TURNED TO 1-IN-10 LOLE STANDARD

Sources and Notes: Curves constructed using a unique scaling factor based on the Anchor Point. See Section C for additional description of Curve 1, Curve 2, and Curve 3 and their Anchor Points (indicated in the figure above by the numbered circles).

To examine the performance of the candidate VRR curves, we conducted probabilistic simulation analyses of potential market outcomes under long-run equilibrium conditions. As described more fully in the Appendix and similar to the approach used in prior Quadrennial Reviews, we conducted a Monte Carlo analysis to simulate the estimated range of price, quantity, and reliability outcomes under each VRR curve. These simulation results indicate curve performance under long-term equilibrium conditions, and accounting for year-to-year variability in supply and demand at the same scale that we have historically observed in RPM. We do not attempt in this exercise to project the near-term price or reliability outcomes that may occur over the next few years.

Table 2 below compares the resulting performance metrics of the three tuned Candidate Curves from our probabilistic Monte Carlo simulation model, in comparison with the Current VRR Curve (defined relative to a dual-fuel CT Reference Resource as updated to 2028/29 parameters). Since all three tuned Candidate Curves are designed to achieve system-wide reliability at the 1-in-10 LOLE standard under baseline long-run equilibrium conditions, average procurement costs are

similar for the three MRI-based curves. However, each curve offers trade-offs in price volatility, frequency of clearing results at the price cap, and frequency of clearing results below 99% of the Reliability Requirement.

As shown in the table, Curve 1 results in the highest price volatility with a standard deviation of \$178/MW-day across simulation runs. The higher price volatility is due to a higher price cap which leads to a broader range of potential clearing prices. Curve 2 and Curve 3 have somewhat lower levels of price volatility due to their lower price caps. However, these curves result in a higher frequency of clearing outcomes at their price caps, with Curve 2 clearing at the price cap for 12.7% of simulation runs and Curve 3 clearing at the price cap for 19.9% of simulation runs. Curve 2 has the best performance in mitigating low clearing outcomes below 99% of the Reliability Requirement (12.7% of runs) compared to 13.3% for Curve 1 and 15.0% for Curve 3. In conclusion, all three tuned curves perform adequately under the base assumptions. Shape and performance of the tuned MRI curves under alternative reference prices are discussed in Section IV.D below and the factors we investigated for determining an acceptable price cap range are discussed in Section VI.A.

TABLE 2: PERFORMANCE OF "TUNED" MRI CURVES

| | Price | | | Reliability | | | | | | | Cost |
|---------------|------------------------------|-----------------------|---------------------|-----------------|---|---|----------------|---|--|-------|--------------------------------|
| | Average Clearing Price | Standard Deviation | Frequency at Cap | Average LOLE | Average Excess (Deficit) Above Reliability Requirement | Average Excess (Deficit) Above Target Reserve Margin | Average EUE | Normalized Portfolio EUE (% of Target) | o Below Below 99% of Pro of Reliability Reliability | | Average Procurement Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (UCAP RR + X %) | (MWh) | (%) | (%) | (%) | (\$ mln/yr) |
| Current Curve | \$350 | \$183 | 2.3% | 0.053 | 2,607 | 1.86% | 834 | 54.9% | 6.3% | 2.3% | \$17,491 |
| Curve 1 | \$350 | \$178 | 3.0% | 0.100 | 366 | 0.28% | 1,615 | 106.3% | 34.7% | 13.3% | \$17,188 |
| Curve 2 | \$350 | \$141 | 12.7% | 0.100 | 463 | 0.35% | 1,643 | 108.1% | 31.2% | 12.7% | \$17,189 |
| Curve 3 | \$350 | \$122 | 19.9% | 0.100 | 566 | 0.43% | 1,668 | 109.7% | 29.1% | 15.0% | \$17,192 |

Sources and Notes: Simulated curves match curves shown in the figure above.

D. Tuned MRI Curves with Varying Reference Prices

We evaluated these three MRI-based candidate curve constructs with varying Reference Prices to understand the consequent effects on curve shape, price cap placement, and performance. For this evaluation, we utilized Reference Price values of \$150, \$250, \$350, \$450, and \$750/MW-day UCAP. This analysis aims to test the robustness of the alternative MRI-based curve approaches to a wide range of potential Net CONE values that may be associated with different economic conditions and underlying technology types, as detailed further in the *Brattle 2025 PJM CONE Report*. To properly compare curve performance across different Reference Price values,

we adjusted the Anchor Point and price cap in tandem so that each curve achieved reliability at the 1-in-10 LOLE target under base modeling conditions. Detailed results for each curve, as well as their impact on our final decision of the Candidate Curve, are provided below.

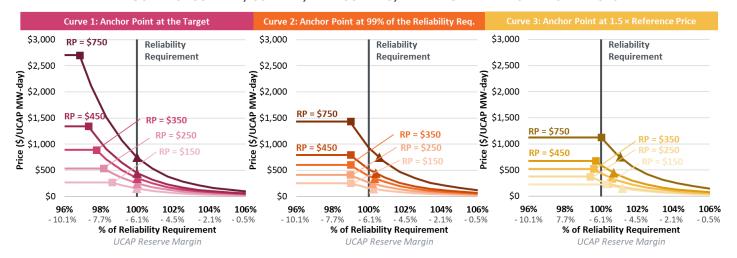


FIGURE 15: CURVE 1, CURVE 2, AND CURVE 3, VARYING REFERENCE PRICE VALUES

Sources and Notes: "RP" stands for Reference Price. Squares indicate the maximum quantity at the price cap and triangles indicate the intersection of each VRR curve with its respective reference price.

TABLE 3: PERFORMANCE OF CANDIDATE CURVES, TUNED TO VARYING REFERENCE PRICE VALUES

| | | Clearing Pri | ce | Price Cap | @ 1-in-10 | | | Relial | oility | | | Cost |
|--------------------|---------------------------|-----------------------|---------------------|--------------|------------------------------|--------------|--|--|---|--|---|-----------------------------|
| | Avg. Clearing Price | Standard Deviation | Frequency at Cap | Price | Multiple of Ref. Price | Avg. LOLE | Avg. Excess (Deficit) Above Reliability Requirement | Avg. Excess (Deficit) Above Target Reserve Margin | Normalized Portfolio EUE (% of Target) | Frequency Below Reliability Requirement | Frequency Below 99% of Reliability Requirement | Avg. Procurement Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (\$/MW-d) | (%) | (\$/MW-d) | (MW) | (UCAP RR + X %) | (%) | (%) | (%) | (\$ mln/yr) |
| Curve 1: Anchor P | oint at the | Target, Tur | ned to 1-in-1 | 0 LOLE | | | | | | | | |
| Ref. Price = \$150 | \$150 | \$65 | 3.7% | \$271 | 181% | 0.100 | 351 | 0.26% | 104.4% | 47.6% | 16.4% | \$7,340 |
| Ref. Price = \$250 | \$250 | \$104 | 3.8% | \$537 | 215% | 0.100 | 288 | 0.22% | 104.5% | 43.6% | 10.7% | \$12,264 |
| Ref. Price = \$350 | \$350 | \$178 | 3.0% | \$890 | 254% | 0.100 | 366 | 0.28% | 106.3% | 34.7% | 13.3% | \$17,188 |
| Ref. Price = \$450 | \$450 | \$273 | 3.3% | \$1,345 | 299% | 0.100 | 470 | 0.36% | 108.4% | 33.7% | 14.1% | \$22,104 |
| Ref. Price = \$750 | \$750 | \$600 | 3.8% | \$2,703 | 360% | 0.100 | 741 | 0.56% | 112.6% | 30.6% | 16.9% | \$36,812 |
| Curve 2: Anchor P | oint at 99% | of the Reli | ability Requi | rement, Tur | ned to 1-in- | 10 LOLE | | | | | | |
| Ref. Price = \$150 | \$150 | \$63 | 8.5% | \$253 | 168% | 0.100 | 503 | 0.37% | 107.5% | 40.5% | 8.5% | \$7,343 |
| Ref. Price = \$250 | \$250 | \$90 | 8.9% | \$413 | 165% | 0.100 | 351 | 0.27% | 105.5% | 39.3% | 8.9% | \$12,263 |
| Ref. Price = \$350 | \$350 | \$141 | 12.7% | \$605 | 173% | 0.100 | 463 | 0.35% | 108.1% | 31.2% | 12.7% | \$17,189 |
| Ref. Price = \$450 | \$450 | \$197 | 13.4% | \$797 | 177% | 0.100 | 558 | 0.42% | 110.0% | 31.8% | 13.4% | \$22,106 |
| Ref. Price = \$750 | \$750 | \$402 | 17.7% | \$1,434 | 191% | 0.100 | 882 | 0.66% | 114.1% | 27.3% | 17.7% | \$36,860 |
| Curve 3: Anchor P | oint at 1.5 | × Reference | Price, Tune | d to 1-in-10 | LOLE | | | | | | | |
| Ref. Price = \$150 | \$150 | \$57 | 19.2% | \$225 | 150% | 0.100 | 1,303 | 0.94% | 121.8% | 18.4% | 14.2% | \$7,374 |
| Ref. Price = \$250 | \$250 | \$83 | 13.9% | \$375 | 150% | 0.100 | 411 | 0.32% | 107.3% | 33.5% | 11.6% | \$12,264 |
| Ref. Price = \$350 | \$350 | \$122 | 19.9% | \$525 | 150% | 0.100 | 566 | 0.43% | 109.7% | 29.1% | 15.0% | \$17,192 |
| Ref. Price = \$450 | \$450 | \$166 | 22.6% | \$675 | 150% | 0.100 | 674 | 0.51% | 111.7% | 30.1% | 16.0% | \$22,111 |
| Ref. Price = \$750 | \$750 | \$305 | 28.2% | \$1,125 | 150% | 0.100 | 1,018 | 0.76% | 115.5% | 27.7% | 18.5% | \$36,890 |

Sources and Notes: The MRI-based VRR curves that produce these results are constructed using administrative Reference Prices of \$150/MW-day, \$250/MW-day, \$350/MW-day, \$450/MW-day, and \$750/MW-day. These VRR curves are calibrated to achieve 1-in-10 LOLE when the true Reference Price is equal to the administrative Reference Price, as shown in this table.

Curve 1 requires a high price cap to support 1-in-10 reliability under long-run equilibrium conditions, both in absolute terms and as a multiple of Net CONE. The resulting price caps for Curve 1 are between 1.8–3.6 × Reference Price; the price cap exceeds \$1,000/MW-day even when the Reference Price is as low as \$450/MW-day. These price caps are a substantially higher multiple of Net CONE compared to today and would introduce an escalated risk of high-priced auction clearing outcomes. As discussed further in Section VI.A, price caps at this level would be untenable due to the potential high consumer costs under shortage conditions. Since this curve passes through the Reliability Requirement at the Reference Price, it is left-shifted relative to Curve 2 and Curve 3 (as shown in Figure 14), which requires a higher price cap to support reliability and renders Curve 1 susceptible to low-reliability outcomes. The curve also as a relatively poorer capability to protect against low reliability events, since the curve does not reach the price cap until very low cleared quantities, in the range of 96.8%-98.6% of the Reliability Requirement. This lower quantity at the cap also means that the RPM Backstop provisions (which trigger at 99% of the Requirement) would be triggered more often and before the market has reached the price cap. The outcome of triggering backstop provisions before all in-market opportunities for capacity supply have been exhausted would be misaligned with design objectives of supporting reliability through market signals on a long-run basis. For these two reasons (excess customer exposure to price cap events, and inconsistency of the volume of the cap with backstop provisions), we view Curve 1 as substantially less desirable compared to Curves 2 and 3.

Curve 2 has price cap quantity fixed at 99% of the Reliability Requirement; this curve is right-shifted relative to Curve 1 and left-shifted relative to Curve 3. The price cap required to support 1-in-10 reliability under long-run equilibrium conditions is relatively stable at 1.7–1.9 × Reference Price across all tested Reference Prices; meaning that the price cap multiplier could offer more stability over the long term even as Reference Prices substantially change. Customers' exposure to price volatility and price cap events is much less than in Curve 1, but still near or above the maximum price exposure that would have prevailed for most of RPM history. Curve 2 produces significantly fewer clearings at the price cap (between 9% and 18% of clearings at the cap across all different simulated Reference Prices) compared to Curve 3, which has a lower price cap at 1.5 x Reference Price (between 19% and 28% of clearings at the cap). Further, the shape of Curve 2 is robust to changes in Reference Price, as all curves pass through the relevant Reference Price at an acceptable and stable quantity of 100.2%–100.6% of the Reliability Requirement across all tested Reference Prices.

Curve 3 is the furthest right-shifted of the three candidate MRI-based curves. The right-shifting of the curve is necessary to support 1-in-10 LOLE under long-run equilibrium conditions since the

price cap is fixed at 1.5 × Reference Price. The tradeoff is that a lower price cap limits the high end of attainable prices under shortage conditions, such that the population of pricing outcomes must contain more frequent price cap events for prices to equal the Reference Price on average. As expected, Curve 3 frequently clears at the price cap across tested Reference Prices, ranging from 19%–28% of all clearing outcomes. Similarly, Curve 3 produces a higher percentage of years with cleared volumes below 99% of the Reliability Requirement than Curves 1 and 2. This suggests a greater likelihood of PJM needing to take corrective actions to ensure sufficient capacity in the RPM, as this threshold triggers Reliability Backstop provisions. The relatively high potential for outcomes at the price cap would be a substantial drawback of Curve 3, a performance tradeoff against the benefit of achieving lower price volatility and customer exposure to high price events.

V. Performance of Candidate MRI-Based Curves

A. Current Curve vs MRI-Based Curves (Base Assumptions)

In Figure 16 we show the tuned MRI-based curves, Curve 1 (pink), Curve 2 (orange), and Curve 3 (yellow) in comparison to the Current Curve (blue). Under the current formula, the price cap of the Current Curve is set based on 1.75 × the Net CONE of a CT, which is estimated to be \$528/MW-day UCAP, resulting in a price cap of \$924/MW-day UCAP. ⁵¹ Curve 1 is left-shifted relative to the Current Curve but has a similar price cap of \$890/MW-day UCAP. Curve 2 and Curve 3 have lower caps of \$605/MW-day UCAP (or approximately 1.73 × Reference Price of \$350/MW-day UCAP) and \$525/MW-day UCAP (1.5 × Reference Price) respectively.

The current formula for the VRR Curve sets the price cap equal to the maximum of 1.75 × Net CONE and 1 × Gross CONE. Gross CONE for a CT is estimated to be \$832/MW-day UCAP, meaning that 1.75 × the CT Net CONE is the binding parameter that sets the price cap. See Brattle 2025 PJM CONE Report.

\$1,000 Reliability Requirement **Current Curve** \$800 MRI Curve @ 99% of the Reliability Requirement Price (\$/UCAP MW-day) MRI Curve @1.5 × Reference Price \$600 MRI Curve @ Target Point \$400 Reference Price \$200 \$0 96% 98% 100% 102% 104% 106% 108% - 6.1% - 4.5% - 0.5% - 10.1% - 7.7% - 2.1% 1.1% % of Reliability Requirement UCAP Reserve Margin

FIGURE 16: CANDIDATE CURVES VS CURRENT CURVE

Sources and Notes: The MRI-based VRR curves are defined by the highlighted anchor point (signified by the circle containing the number for each curve). The Reference Price is \$350/MW-day is based on an estimate of the long-run marginal cost of supply in 2028\$. The scaling factor for Curve 1, (MRI Curve @ Target Point) is \$394,290/MWh based on a price cap of \$890/MW-day. The scaling factor for Curve 2, (MRI Curve @ 99% of the Reliability Requirement) is \$442,352/MWh based on a price cap of \$605/MW-day. The scaling factor for Curve 3, (MRI Curve @ 1.5 x Reference Price) is \$490,523/MWh based on a price cap of \$525/MW-day. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on the current CT reference resource with an indicative Net CONE of \$528/MW-day UCAP and Gross CONE of \$832/MW-day UCAP.

Table 4 and Figure 17 below summarize the baseline simulation results for the Current Curve and all three variations of MRI-based VRR curves. As shown in the table, all MRI-based curves are tuned to achieve 1-in-10 LOLE under baseline conditions where both the true and administrative Reference Price are equal to \$350/MW-day UCAP. The Current Curve, however, over-procures capacity relative to the reliability target and produces an average LOLE of 0.053 events per year (1 loss of load event every 19 years). This over-procurement would increase procurement cost under the Current Curve to approximately \$300 million per year greater than the procurement cost under each of the three MRI-based curves. Most of the increase in procured volume and cost associated with the Current Curve is caused by the continued use of the CT-based reference price, the Net CONE for which is substantially higher than the \$350/MW-day UCAP Reference Price that we adopt as the most accurate estimate of the long-run marginal cost of supply. (We assess the robustness of the MRI-based curves to administrative error in Net CONE estimation in Section V.B below).

TABLE 4: PERFORMANCE OF CURRENT CURVE AND THE MRI-BASED VRR CURVES

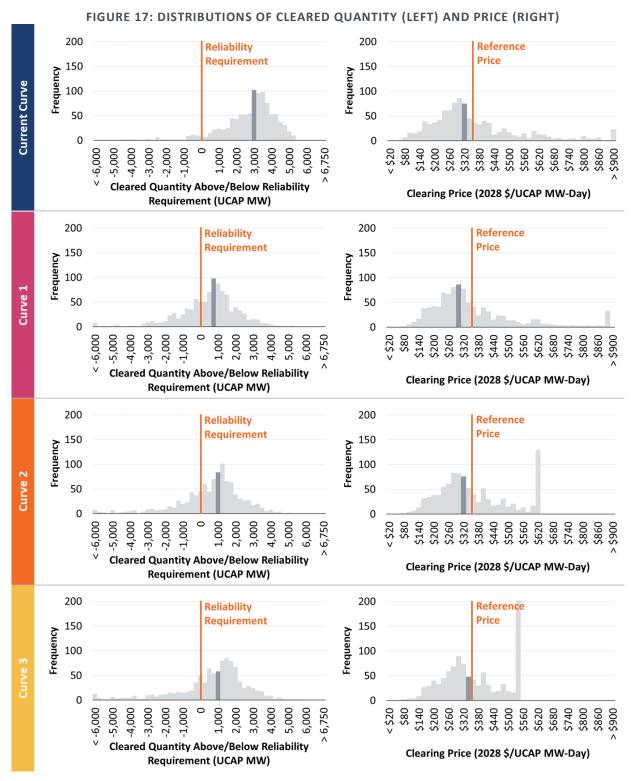
| | Price | | | | Reliability | | | | | | |
|-------------------------------------|------------------------------|-------------------------|-----------------------|-------------------------|---|---|---|--|---|----------------------------------|--|
| | Average Clearing Price | | Frequency at Cap | Average LOLE | Average Excess (Deficit) Above Reliability Requirement | Average Excess (Deficit) Above Target Reserve Margin | Normalized Portfolio EUE (% of Target) | Frequency Below Reliability Requirement | Frequency Below 99% of Reliability Requirement | Average Procurement Cost | |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (UCAP RR + X %) | (%) | (%) | (%) | (\$ mln/yr) | |
| Current Curve Curve 1 Curve 2 | \$350 \$350 | \$183 \$178 \$141 | 2.3% 3.0% 12.7% | 0.053 0.100 0.100 | 2,607 366 463 | 1.86% 0.28% 0.35% | 54.9% 106.3% 108.1% | 6.3% 34.7% 31.2% | 2.3% 13.3% 12.7% | \$17,491 \$17,188 \$17,189 | |
| Curve 3 | \$350 | \$122 | 19.9% | 0.100 | 566 | 0.43% | 109.7% | 29.1% | 15.0% | \$17,192 | |

Sources and Notes: Results generated from Base Case model run where the true Reference Price is equal to the administrative Reference Price used to construct the VRR curves (\$350/MW-day UCAP). See Section IV.C for additional description of Curve 1, Curve 2, and Curve 3. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on a dual-fuel CT reference resource with an indicative Net CONE of \$528/MW-day UCAP and a Gross CONE of \$832/MW-day UCAP.

Figure 17 summarizes the distributions of simulated clearing quantities and prices across all model draws of the MRI-based VRR curves and the Current Curve under baseline conditions. The left-hand side of the figure shows the distributions of clearing quantity while the right-hand side of the figure shows the distribution of price outcomes generated by the Current Curve and the three MRI-based VRR curves.

As seen on the left-hand side (Cleared Quantity Above/Below Reliability Requirement) the Current Curve would over-procure by a greater volume and with a greater frequency than the MRI-based VRR curves, leading to higher costs. Median over-procurement under the Current Curve (shown in dark gray in Figure 17) is 2,950 MW, compared to 575 MW under Curve 1, 775 MW under Curve 2, and 1,000 MW under Curve 3.

As can be seen on the right-hand side (Clearing Price), while all curves result in an average clearing price equal to the \$350/MW-day Reference Price under the baseline model runs, the distribution of prices differs. The Current Curve has a wider distribution of clearing prices and therefore greater price volatility due to its elevated price cap and steep slope at low volumes of cleared capacity relative to the MRI-based VRR curves. Meanwhile, Curve 3's median clearing price is closest to the Reference Price. Additionally, the rightmost vertical bar in the clearing price histograms indicates the number of clearing events at the price cap, which occurs more frequently for Curve 3 then Curve 2 then Curve 1, which all have lower price caps than the Current Curve. Figure 17 and Table 4 present a subset of inherent performance tradeoffs that must be considered when choosing a VRR curve which we explore in more detail in the following sections.



Sources and Notes: Median shown in dark gray. Results generated from Base Case model run where the true Reference Price is equal to the Administrative Reference Price (\$350/MW-day UCAP). See Section IV.C for additional description of Curve 1, Curve 2, and Curve 3. The Current Curve is developed using the current VRR curve formula, with a Net CONE based on the current dual-fuel CT reference resource with an indicative Net CONE of \$528/MW-day UCAP and a Gross CONE of \$832/MW-day UCAP.

B. Performance Sensitivity to Net CONE Estimation Error

While the three candidate MRI-based VRR curves all support long-term reliability objectives under (with different performance tradeoffs) base assumptions, we also performed a sensitivity analysis to test reliability and cost outcomes when the estimated Reference Price differs from the true Net CONE faced by resource developers. As discussed in the *Brattle 2025 PJM CONE Report*, Net CONE estimates are subject to a substantial uncertainty range. Net CONE estimates always carry inherent uncertainty, such that the VRR Curve must be capable of offering reasonable outcomes even in the event that Net CONE is over- or under-estimated. Current Net CONE estimates are subject to greater uncertainty than in prior VRR Curve Reviews due to turbine scarcity, constrained supply chains, broader economic conditions, and policy changes that may greatly impact the costs of generation equipment, all while there is expected high demand growth across PJM and neighboring regions. To the extent possible, the VRR curve should be robust to a range of realized Net CONE values that may be faced by developers.

Table 5 below summarizes the estimated performance of the tuned MRI-based VRR curves and the Current Curve when Net CONE is over- and under-estimated. We tested all MRI-based curves in a scenario where the Reference Price is overestimated and the true Net CONE is \$200/MW-day, as well as four scenarios where the Reference Price is underestimated and the true Net CONE values are \$400/MW-day, \$450/MW-day, \$500/MW-day, and \$550/MW-day. These results are compared to the baseline results when the administrative Reference Price of \$350/MW-day is accurate (base conditions or "Accurate Reference Price").

The table illustrates a somewhat different comparison for the Current CT-based VRR Curve, considering that the CT-based pricing parameters would be based on a Net Cone of \$528/MW-day (which is substantially higher than the \$350/MW-day Reference Price that we assume in the MRI-based curves). As a result, the Current CT-based curve produces higher reliability and higher cost than the MRI-based curves across all scenarios of Net CONE. This indicates that if the Current Curve were to be updated for continued use in the RPM, it should be adjusted to align with the updated estimate of long-run marginal cost of supply consistent with the \$350/MW-day Reference Price.

Considering the MRI-based curves only, they show different performance and robustness to administrative uncertainty in Reference Price. As expected, when the true Net CONE is lower

⁵² See Brattle 2025 PJM CONE Report.

than the administrative Reference Price, reliability levels exceed the 1-in-10 LOLE standard and each curve results in average procurement beyond the Reliability Requirement with fewer than 1% of clearing results at the price cap for all curves. All three MRI-based curve perform very similarly in the event that the Reference Price is over-estimated, largely do to the feature of the MRI-based curves that produces downward-sloping shapes with converging slope at higher volumes. The most right-shifted variation, Curve 3, is somewhat more susceptible to over-procurement compared to Curves 1 and 2. However, all three MRI-based curves perform very similarly on dimensions of price volatility and reliability.

The reverse situation in which Reference Price is underestimated is more challenging. As true Net CONE is progressively higher than the Reference Price, average procurement costs increase, excess cleared capacity goes down, average reliability results get worse, and frequency of clearing below the reliability requirement and frequency of clearing at the cap increase. We represent this progression in the colored cells of the table where green indicates a better performance for the metric in question, yellow indicates a moderate performance, and red indicates a worse performance.

To evaluate performance of each curve to Reference Price underestimates, we use an approximate threshold of 0.2 LOLE (1-in-5) as the level of reliability risk that is reasonable to accept. Though that level of reliability would not align with reliability objectives over the long run, it is acceptable in the context of RPM considering that periodic Reference Price updates will aim to address any potential under-estimates over the course of each review period. Considering this approximate 0.2 LOLE threshold for eroded reliability performance, Curve 1 offers the strongest robustness to Net CONE under-estimates. Even a large under-estimate of up to \$200/MW-day can be absorbed by Curve 1 with moderate reductions to reliability (primarily because of the higher price cap). Curves 2 and 3 offer acceptable reliability performance with a smaller under-estimate of up to \$100/MW-day. Performance erodes most quickly with Curve 3 in the event of Reference Price under-estimates, because it has the lowest price cap.

On the high bound of our sensitivity range, when true Net CONE is higher than the Reference Price by \$200/MW-day (i.e., true Net CONE is equal to \$550/MW-day), costs are higher for all curves and none of the three MRI-based VRR curves achieve the 0.1 LOLE reliability standard. Under this scenario, Curve 1 achieves an average LOLE of 0.180 (1 loss of load event every 5.6 years) compared to 0.312 (1 event every 3.2 years) for Curve 2. Curve 1 and 2 would procure a quantity of capacity less than the Reliability Requirement in greater than 75% of modeled runs. Results are not shown for Curve 3, because its price cap (\$525/MW-day UCAP) is lower than the true Net CONE of \$550/MW-day in this scenario, therefore prices would clear at the price cap

100% of the time and the model cannot converge to true Net CONE (in other words, the RPM would not be in a position to attract incremental supply since the price cap is below the cost of building new resources). These outcomes highlight the importance of conducting an investigative review of the causes of any price-cap events should they occur, as we discuss further in Section VI below.

TABLE 5: PERFORMANCE OF THE CANDIDATE CURVES IN CONTEXT OF NET CONE UNCERTAINTY

| | | Price | | | | Reliab | ility | | | Cost |
|--|------------------------------|-----------------------|---------------------|-----------------|---|---|---|--|---|--------------------------------|
| | Average Clearing Price | Standard Deviation | Frequency at Cap | Average LOLE | Average Excess (Deficit) Above Reliability Requirement | Average Excess (Deficit) Above Target Reserve Margin | Normalized Portfolio EUE (% of Target) | Frequency Below Reliability Requirement | Frequency Below 99% of Reliability Requirement | Average Procurement Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (UCAP RR + X %) | (%) | (%) | (%) | (\$ mln/yr) |
| Current Curve: CT-based Net CONE @ \$52 | 28, Price Cap | @ \$924 | | | | | | | | |
| \$328 Overest. (True Ref Price = \$200) | \$200 | \$98 | 0.1% | 0.033 | 3,983 | 2.81% | 34.1% | 0.1% | 0.1% | \$10,101 |
| \$178 Overest. (True Ref Price = \$350) | \$350 | \$183 | 2.3% | 0.053 | 2,607 | 1.86% | 54.9% | 6.3% | 2.3% | \$17,491 |
| \$128 Overest. (True Ref Price = \$400) | \$400 | \$204 | 4.4% | 0.062 | 2,159 | 1.54% | 64.9% | 10.4% | 4.5% | \$19,912 |
| \$78 Overest. (True Ref Price = \$450) | \$450 | \$220 | 7.3% | 0.072 | 1,713 | 1.23% | 76.9% | 15.2% | 7.3% | \$22,310 |
| \$28 Overest. (True Ref Price = \$500) | \$500 | \$231 | 10.4% | 0.084 | 1,264 | 0.92% | 91.4% | 21.3% | 10.6% | \$24,690 |
| \$23 Underest. (True Ref Price = \$550) | \$550 | \$236 | 15.3% | 0.098 | 793 | 0.59% | 109.4% | 28.9% | 15.3% | \$27,046 |
| Curve 1: Price Cap = \$890, Quantity @ Cap | p = 97.8% × R | eliability Re | quirement | | | | | | | |
| \$150 Overest. (True Ref. Price = \$200) | \$200 | \$86 | 0.1% | 0.057 | 2,278 | 1.62% | 57.6% | 4.2% | 0.6% | \$9,951 |
| Accurate (Ref. Price = \$350) | \$350 | \$178 | 3.0% | 0.100 | 366 | 0.28% | 106.3% | 34.7% | 13.3% | \$17,188 |
| \$50 Underest. (True Ref. Price = \$400) | \$400 | \$200 | 5.8% | 0.117 | (141) | -0.07% | 127.8% | 46.7% | 21.1% | \$19,562 |
| \$100 Underest. (True Ref. Price = \$450) | \$450 | \$216 | 9.8% | 0.136 | (617) | -0.40% | 152.1% | 57.5% | 29.7% | \$21,915 |
| \$150 Underest. (True Ref. Price = \$500) | \$500 | \$227 | 14.2% | 0.156 | (1,080) | -0.73% | 180.7% | 66.5% | 37.5% | \$24,253 |
| \$200 Underest. (True Ref. Price = \$550) | \$550 | \$232 | 19.3% | 0.180 | (1,573) | -1.07% | 217.1% | 74.6% | 45.3% | \$26,564 |
| Curve 2: Price Cap = \$605, Quantity @ Cap | | • | | | | | | | | |
| \$150 Overest. (True Ref. Price = \$200) | \$200 | \$84 | 0.3% | 0.051 | 2,684 | 1.91% | 51.5% | 2.5% | 0.3% | \$9,979 |
| Accurate (Ref. Price = \$350) | \$350 | \$141 | 12.7% | 0.100 | 463 | 0.35% | 108.1% | 31.2% | 12.7% | \$17,189 |
| \$50 Underest. (True Ref. Price = \$400) | \$400 | \$147 | 21.0% | 0.126 | (244) | -0.14% | 142.0% | 44.3% | 21.0% | \$19,524 |
| \$100 Underest. (True Ref. Price = \$450) | \$450 | \$142 | 33.0% | 0.161 | (1,041) | -0.70% | 192.1% | 59.3% | 33.0% | \$21,814 |
| \$150 Underest. (True Ref. Price = \$500) | \$500 | \$128 | 46.6% | 0.215 | (2,027) | -1.38% | 275.7% | 74.6% | 46.6% | \$24,036 |
| \$200 Underest. (True Ref. Price = \$550) | \$550 | \$101 | 65.7% | 0.312 | (3,397) | -2.34% | 434.1% | 87.7% | 65.7% | \$26,147 |
| Curve 3: Price Cap = \$525, Quantity @ Cap | | • | | | | | | | | |
| \$150 Overest. (True Ref. Price = \$200) | \$200 | \$82 | 0.6% | 0.046 | 3,055 | 2.17% | 46.6% | 1.6% | 0.3% | \$10,005 |
| Accurate (Ref. Price = \$350) | \$350 | \$122 | 19.9% | 0.100 | 566 | 0.43% | 109.7% | 29.1% | 15.0% | \$17,192 |
| \$50 Underest. (True Ref. Price = \$400) | \$400 | \$117 | 33.5% | 0.135 | (370) | -0.22% | 157.3% | 43.7% | 26.9% | \$19,489 |
| \$100 Underest. (True Ref. Price = \$450) | \$450 | \$101 | 52.4% | 0.195 | (1,599) | -1.08% | 247.8% | 64.2% | 43.3% | \$21,701 |
| \$150 Underest. (True Ref. Price = \$500) | \$500 | \$61 | 79.6% | 0.357 | (3,874) | -2.67% | 508.4% | 86.7% | 72.8% | \$23,681 |
| \$200 Underest. (True Ref. Price = \$550) | | | | Model do | es not converge (| Curve 3 Price Cap < | < True Referer | nce Price) | | |

Sources and Notes: All MRI curve simulations performed using an Administrative Reference Price of \$350/MW-day. The current curve is constructed using an administrative Net CONE estimate based on a dual-fuel CT of \$528/MW-day.

C. Performance Sensitivity to Forward Period

We performed an additional sensitivity to evaluate the performance of the three MRI-based VRR curves and the Current Curve considering the potential for changes in the auction forward period, which in turn affects the shape of the supply curves that determine clearing outcomes in the BRA. As explained in Section III.C, shorter forward periods can lead to contractions in the total volume

of supply offered in the auction (and at what prices) since new resources may not have sufficient lead-time to respond to price signals. As shown previously in Figure 8, the shape of offered supply curves in auctions with contracted forward periods is steeper than the shape of comparable curves from 3-year forward auctions. This sensitivity is relevant to this Quadrennial Review because both the 2028/29 and 2029/30 Base Residual Auctions are projected to operate under shortened timeframes (23 and 29 months, respectively) as shown in Figure 7. By the end of the review period, the full 3-year forward period should apply.

In this sensitivity, we evaluated the performance of the three MRI-based VRR curves and the Current Curve under base assumptions (a mix of 3-year forward and non-3-year forward period supply curves based on the historical forward periods), in comparison to two sensitivity scenarios: one considering only the flatter 3-year forward supply curves; and the other considering only the steeper non-3-year forward supply curves. Results are shown in Table 6.

We find that the performance of the three candidate MRI-based curves is robust to changes in the supply curve shape. As expected, all three curves perform better in the context of a full 3-year forward auction, in which the flatter supply curves can compensate for supply-demand fluctuations and produce greater stability in both resulting prices and quantity outcomes. With the full three-year forward period, price volatility is lower and reliability is modestly improved. In the non-forward (< 3 years) supply curve sensitivity, all three MRI-based VRR curves perform worse, with higher price volatility and slightly worse reliability than the 0.1 LOLE target (0.11–0.12 loss of load events per year). Overall, the implications for price volatility are substantially greater than the implications for reliability.

Overall, the magnitude of these performance differences are relatively small compared to the other performance sensitivities that we examine. They do suggest that any VRR Curve and RPM will offer better performance under a three-year forward period, particularly in terms of the resulting exposure to price volatility.

TABLE 6: PERFORMANCE OF CANDIDATE CURVES IN FORWARD VERSUS NON-FORWARD AUCTIONS

| | | Price | | | | Reliab | ility | | | Cost |
|--|----------------------------------|----------------------------------|--------------------------------|----------------------------------|---|---|---|----------------------------------|---|--|
| | Average Clearing Price | Standard Deviation | Frequency at Cap | Average LOLE | Average Excess (Deficit) Above Reliability Requirement | Average Excess (Deficit) Above Target Reserve Margin | Normalized Portfolio EUE (% of Target) | Below Reliability | Frequency Below 99% of Reliability Requirement | Average Procurement Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (UCAP RR + X %) | (%) | (%) | (%) | (\$ mln/yr) |
| Only 3-Year Fo | rward Supp | ply Curves | | | | | | | | |
| Current Curve Curve 1 Curve 2 Curve 3 | \$350 \$350 \$350 \$350 | \$166 \$163 \$130 \$113 | 1.9% 2.5% 9.7% 16.8% | 0.051 0.100 0.098 0.097 | 2,588 299 448 591 | 1.84% 0.23% 0.34% 0.44% | 53.0% 103.5% 104.3% 104.5% | 5.1% 36.2% 29.8% 26.1% | 1.9% 11.4% 9.7% 11.8% | \$17,491 \$17,186 \$17,190 \$17,199 |
| All Supply Cur | ves | | | | | | | | | |
| Current Curve Curve 1 Curve 2 Curve 3 | \$350 \$350 \$350 \$350 | \$183 \$178 \$141 \$122 | 2.3% 3.0% 12.7% 19.9% | 0.053 0.100 0.100 0.100 | 2,607 366 463 566 | 1.86% 0.28% 0.35% 0.43% | 54.9% 106.3% 108.1% 109.7% | 6.3% 34.7% 31.2% 29.1% | 2.3% 13.3% 12.7% 15.0% | \$17,491 \$17,188 \$17,189 \$17,192 |
| Only Non-Ford | vard (<3 ye | ars) Supply | Curves | | | | | | | |
| Curve 1 Curve 2 Curve 3 | \$350 \$350 \$350 \$350 | \$239 \$227 \$171 \$145 | 6.3% 7.5% 20.2% 30.0% | 0.058 0.106 0.112 0.116 | 2,615 542 441 397 | 1.87% 0.42% 0.35% 0.32% | 62.7% 118.7% 127.5% 134.7% | 11.1% 32.5% 36.4% 37.0% | 6.3% 19.4% 20.2% 22.9% | \$17,471 \$17,176 \$17,157 \$17,143 |

Sources and Notes: All model runs use true Reference Price and Administrative Reference Price equal to \$350/ MW-day UCAP. Auctions prior to the 2022/23 Base Residual Auction were run on a 3-year forward timeframe while all auctions since (including the 2022/23 BRA) have been run on compressed forward schedules. See Section III.C for additional description of the effect of the auction forward period on supply curve shape and Appendix A.4 for additional detail on the processing of supply curves for use in the model.

D. Performance Sensitivity to Higher/Lower Net Supply Variability

The RPM VRR Curve must manage year-to-year variability in net supply in RPM, including the potential for changes to the load forecast, supply entry and exit, FRR participation, and resource accreditations. As discussed further in Appendix A.5, we represent these variations in net supply in the model by calibrating the correlation between supply and demand variability such that the resulting net supply variability matches the historically observed variability in the BRA. Under base assumptions, this net supply variability is equal to 2.8% of the average BRA Reliability Requirement from 2012/13 to 2024/25. However, we also recognize that historically-observed levels of net supply variability may differ in the future. Recognizing the potential for changes in the RPM net supply balance, we performed an additional sensitivity to evaluate the performance of the three MRI-based VRR curves under net supply variability that is 33% larger and 33% smaller than base assumptions. Results are summarized in Table 7.

As expected, reduced net supply variability results in reduced price volatility and improved reliability relative to base assumptions, with the opposite true when net supply variability is increased. In the low net supply variability scenario, all three MRI-based VRR curves achieve reliability better than the 1-in-10 LOLE target, ranging from 0.098 average LOLE for Curve 1, 0.091 for Curve 2, and 0.086 LOLE for Curve 3. In the high net supply variability scenario, reliability is slightly worse than the 1-in-10 target for all three curves, and Curve 1 has average results closest to the 1-in-10 target at 0.108 LOLE, compared to 0.120 for Curve 2, and 0.128 for Curve 3. However, Curve 1 produces the greater price volatility across all scenarios compared to Curve 2 and 3. Similar to the forward/non-forward supply curve sensitivity, these three MRI-based VRR curves limit both over- and under-procurement when net supply variability is out of line with historically observed variability, which indicates robustness to potential future changes in net supply variability.

TABLE 7: PERFORMANCE OF CANDIDATE CURVES WITH DIFFERING NET SUPPLY VARIABILITY

| | Price | | | | | Reliab | ility | | | Cost |
|--|----------------------------------|----------------------------------|--------------------------------|----------------------------------|---|---|---|--|---|--|
| | Average Clearing Price | Standard Deviation | Frequency at Cap | Average LOLE | Average Excess (Deficit) Above Reliability Requirement | Average Excess (Deficit) Above Target Reserve Margin | Normalized Portfolio EUE (% of Target) | Frequency Below Reliability Requirement | Frequency Below 99% of Reliability Requirement | Average Procurement Cost |
| | (\$/MW-d) | (\$/MW-d) | (%) | (events/yr) | (MW) | (UCAP RR + X %) | (%) | (%) | (%) | (\$ mln/yr) |
| Low Variability | , | | | | | | | | | |
| Current Curve Curve 1 Curve 2 Curve 3 | \$350 \$350 \$350 \$350 | \$134 \$131 \$113 \$100 | 0.5% 1.4% 5.7% 11.6% | 0.050 0.098 0.091 0.086 | 2,577 243 523 762 | 1.83% 0.19% 0.39% 0.56% | 50.9% 100.1% 93.0% 87.8% | 2.2% 38.5% 27.5% 21.9% | 0.5% 8.5% 5.7% 6.7% | \$17,489 \$17,180 \$17,209 \$17,232 |
| Base Variabilit | у | | | | | | | | | |
| Current Curve Curve 1 Curve 2 Curve 3 | \$350 \$350 \$350 \$350 | \$183 \$178 \$141 \$122 | 2.3% 3.0% 12.7% 19.9% | 0.053 0.100 0.100 0.100 | 2,607 366 463 566 | 1.86% 0.28% 0.35% 0.43% | 54.9% 106.3% 108.1% 109.7% | 6.3% 34.7% 31.2% 29.1% | 2.3% 13.3% 12.7% 15.0% | \$17,491 \$17,188 \$17,189 \$17,192 |
| High Variabilit | у | | | | | | | | | |
| Current Curve Curve 1 Curve 2 Curve 3 | \$350 \$350 \$350 \$350 | \$220 \$212 \$160 \$136 | 5.2% 6.3% 17.5% 26.6% | 0.059 0.108 0.120 0.128 | 2,578 443 313 264 | 1.84% 0.35% 0.26% 0.23% | 64.4% 121.2% 140.9% 155.7% | 9.4% 33.7% 33.5% 33.3% | 5.2% 17.2% 17.5% 20.9% | \$17,468 \$17,172 \$17,141 \$17,124 |

Sources and Notes: All model runs use true Reference Price and Administrative Reference Price equal to \$350/ MW-day UCAP. Net supply variability is set equal to 2.8% in the "Base Variability" scenario, 1.8% in the "Low Variability" scenario and 3.7% in the "High Variability" scenario. For additional description of net supply variability, see Appendix A.5.

E. Summary of MRI-Based Curves' Performance

In Figure 18 we summarize the performance of the three MRI-based VRR curves and the Current Curve across base assumptions and sensitivity scenarios. The top panel shows the average excess or deficit cleared quantity for each curve and the bounds of each sensitivity; the bottom panel shows the average price volatility for each curve and the bounds of each sensitivity. We report the LOLE results for each curve in the numbers in the figure with the same colors used for each curve as throughout this report.

The top panel summarizes the scale of quantity procurement, with the Current Curve (blue) over procures relative to the 1-in-10 LOLE target across nearly all scenarios (primarily due to the continued use of a CT-based Net CONE that would be higher than our estimated \$350/MW-day reference price). The current curve shows better reliability and higher procurement levels than the other curves for the same reason.

The three MRI-based VRR curves in all produce similar reliability outcomes in most scenario and more frequently procure capacity consistent with the 1-in-10 LOLE target across sensitivities. The most impactful sensitivity is when the Reference Price is under-estimated and the MRI-curves with higher caps procure closer to the 0.1 LOLE (Curve 1, then Curve 2 respectively) and show more robustness to maintain reliability even in the face of under-estimated Reference Price. Curve 3 is the most susceptible to lower reliability outcomes than the other curves, due to the lower price cap.

The bottom panel, we see the implications of each curve's shape and price cap on clearing price volatility. The Current Curve results in the highest price volatility across all sensitivities, while MRI-based curves all offer lower price volatility (with lower price volatility accomplished primarily due to a lower price cap). For that reason Curve 3 performs best, followed by Curve 2 and then Curve 1. This performance sort-order illustrates the direct tradeoff between price stability (accomplished by a lower price cap) and reliability performance, especially in challenging scenarios (accomplished by a higher price cap).

FIGURE 18: COMPARISON OF PERFORMANCE OF CANDIDATE VRR CURVES, AVERAGE EXCESS/DEFICIT (TOP) AND PRICE VOLATILITY (BOTTOM)



Sources and Notes: *Curve 3 results not shown for the scenario where the Reference Price is under estimated by \$200/ MW-day UCAP, because the Curve 3 price cap (\$525/MW-day UCAP) is lower than the true Net CONE of \$550/MW-day in this scenario and the model therefore cannot converge to true Net CONE. Administrative Reference Price = \$350/MW-day UCAP for all runs shown above. True Reference Price = \$350/MW-day UCAP except for "Reference Price Over-Estimated" and "Reference Price Under-Estimated" sensitivities. Colored numbers show the average LOLE in each run. In base modeling results, both Administrative and True Reference Price = \$350/MW-day UCAP; the model uses a mix of 3-year forward and non-3-year forward supply curves, and net supply variability is set to the baseline level of 2.8%.

VI. Managing Acute Tight Supply Conditions

As discussed in the *Brattle 2025 PJM CONE Report*, the PJM region and other power markets are presently facing acute tight supply-demand conditions that may persist into the Planning Years relevant to this Quadrennial Review. In this context, the height of the VRR Curve price cap is a matter of heightened scrutiny and focus, beyond its usual focus as influencing VRR Curve pricing volatility and overall performance. Further, in the event that acute tight supply conditions exceed the scope of conditions that can be productively managed by the price cap, we assess the role of contingency plans to mitigate reliability risks including a possible enhanced PJM Reliability Backstop mechanism.

A. Considerations in Setting the Price Cap

Several factors influence the performance of the VRR Curve and inform the most relevant price cap. The main tradeoff is that a higher price cap provides greater certainty of attracting supply when conditions are tight and reliability needs are most acute; while a lower price cap mitigates customers' exposure to price spikes and exercise of market power.

The price cap in a market that relies on competitive forces to attract new entry needs to be high enough to: manage year-to-year variations in supply and demand conditions; to enable short-term response from resources with higher costs that may enter or exit the market on an annual basis (such as demand response and net imports); and to exceed the long-run marginal cost (i.e., at Net CONE) to support prices at Net CONE in long-run average expectations. As discussed in Section IV, we anticipate that a price cap in the range of 1.5–1.75 × Reference Price is likely sufficient to support RPM reliability objectives on a long-run basis.

Figure 19 summarizes the historical RTO-wide price cap and clearing price, which was set at 1.5 × Net CONE at RPM's inception and has been updated over time. Beginning with the 2017/18 delivery year, the price cap has also been subject to a minimum value at 1 × Gross CONE to prevent the possibility of the VRR curve collapse in the event that the Net CONE parameter would fall to low levels or close to zero. The CONE-based minimum value has only set the RTO price cap once, in the 2025/26 BRA. We note that the need for a CONE-based minimum would be obviated if the Reference Price and price cap are updated in a more simplified fashion based on a single price index, rather than considering the separate components of Gross CONE and E&AS offset of a single Reference Resource that are subject to more year-to-year variability in administrative estimates.

Since the 2012/13 Planning Year, the RTO VRR Curve price cap has been in the range of \$450–\$625/MW-day in nominal dollars, after adjusting upward by 19% for the years before 2025/26 to account for changes in accreditation affecting the "per-MW" UCAP ratings in the denominator. Over the same period, auction clearing prices have remained far below the caps. In most years, clearing prices have been less than half the administrative estimate of Net CONE, even though the market has attracted approximately 34,000 MW ICAP of new gas combined-cycle units since the 2014/15 auction. These market outcomes have demonstrated the primary role of market forces and competition to keep prices and customer costs low, and the limited role of a price cap in a well-functioning market (i.e., when the price cap is rarely or never binding).

The higher prices observed in the 2025/26 auction and current Net CONE estimates (see the *Brattle 2025 PJM CONE Report*), indicate that market conditions are tighter, the cost of building new supply has increased, and that other barriers to supply could limit entry and result in higher clearing prices in upcoming auctions. These conditions have brought greater focus to the price cap, including through two recent filings by PJM: (1) the FERC-approved filing to retain a CT as the reference resource instead of a CC, thereby lowering the price cap to approximately \$500/MW-day but not to change the price cap formula tied to the maximum of $1.75 \times Net CONE$ or $1 \times CONE$; and (2) a more recent filing (still awaiting FERC response) that would, for a temporary two-year period, further lower the price cap to \$325/MW-day alongside raising the price floor from \$0 to \$175/MW-day. Fegardless of whether the second of these filings is eventually approved by the FERC, they both highlight the concern that upcoming auctions are subject to greater risk and have a higher potential to produce prices at the cap than in prior periods since the RPM was implemented.

New entry numbers are based on data from 2015/16 to 2023/24 Base Residual Auctions. See PJM, <u>2023/2024</u> RPM Base Residual Auction Results, 2022, Table 8.

The most recent filing was made in response to a Section 206 complaint filed with the FERC by the Pennsylvania Governor's Office, which expressed concern that prevailing market conditions introduced excess customer risk and cost exposure in the event of a price cap outcome. For change to a CT as the reference resource, see FERC, Order Accepting Tariff Revisions Subject to Condition, Docket No. ER25-682-000, February 14, 2025. For PJM's illustrative estimate of the price cap for the 2026/27 Base Residual Auction using a CT reference resource, see PJM, Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., Docket No. ER25-682-000. For PJM's proposed cap and floor filing, see PJM, Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. No. ER25-1357-000, February 20, 2025.

Cap = Max[1.75 Cap = $Max[1.5 \times Net CONE, or$ Cap = 1.5 × Net CONE x Net CONE, or 1 × Gross CONE] 1 x Gross CONE \$700 Adjusted for ELCC ····· Unadjusted \$600 PJM Filed Price (\$/UCAP MW-Day) **RTO Price Cap** Dec 2024 \$500 RTO Administrative Net CONE \$400 PJM \$300 **Proposed** Feb 2025 \$200 **Clearing Price** \$100 \$0 2015/16 2019/20 2007/08 2018/19 2008/09 2009/10

FIGURE 19: HISTORICAL RPM PRICE CAPS COMPARISON

Sources and Notes: Nominal dollars; Historical price caps from PJM Planning Period Parameters and PJM BRA Results Reports, prices adjusted upward based on difference in Pool-Wide Accredited UCAP Factor between historical year and the 2025/26 BRA; 2026/27 values based on an illustrative 2026/27 RTO VRR Curve with a CT reference resource, from PJM, Affidavit of Walter Graf and Skyler Marzewski on Behalf of PJM Interconnection, L.L.C., Docket No. ER25-682-000. The proposed \$325 price cap value comes from PJM's cap and floor filing, see PJM, Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. ER25-01357-000, February 20, 2025.

From a consumer perspective, high or increasing prices always pose the potential for imposing an economic burden (even while stimulating demand-side measures), regardless of the underlying reason for those increases. But from an economic and market design perspective, it is important to distinguish price increases associated with market fundamentals from those that may be an artifact of market inefficiencies. In a scenario where prices rise over the coming years due to the underlying economic forces of supply costs and rapid demand growth, then the resulting prices should be interpreted as an economically efficient expression of market conditions. Prices may moderate over time as competitive forces accelerate or the market design evolves, but limiting the price cap at a level that is too low to reflect these economic realities would not be an effective way to avoid cost increases. Instead, it would discourage supply entry and increase exposure to reliability risks.

However, the price cap and high price events should be assessed differently in a scenario where they are the product of barriers to entry relative to need; if they are transitional outcomes

associated with rule changes that have not yet been accounted for in suppliers' development plans; or transient shocks to the market. If these factors are driving higher prices or price cap events, then the primary response is to address any identified market barriers. Prevailing market prices may remain high for a period regardless but should revert to lower competitive levels as soon as suppliers have sufficient opportunity to bring their projects forward.

Another consideration is alignment with the price caps in neighboring capacity markets. Other capacity markets' price caps are an indicator of the maximum prices deemed relevant to inform entry and exit decisions in those regions' various regulatory and investment contexts, and indicate the maximum price at which the PJM region may need to compete for capacity imports in the event that multiple regions are tight on capacity. As summarized in Table 8, the price caps employed in other neighboring markets are developed as a multiple of CONE or Net CONE, and range from \$524–\$631/MW-day (in 2028\$ and UCAP terms). The exception is MISO, which has a 4-season market where the maximum price cap can theoretically reach up to $4 \times \text{CONE}$ if all four seasons cleared with a shortfall. That is unlikely, however, so the effective cap is closer to $1 \times \text{CONE}$ or $2 \times \text{CONE}$ on an annualized basis if one or two seasons cleared short, respectively, while the others cleared at a low price). To provide sufficient economic incentives to attract net imports (and avoid net exports) to address any near-term capacity shortfalls, the PJM price cap would need to be in this range.

To the extent that resources' total annual capacity revenues are affected by seasonally higher prices in other markets or differences in UCAP accreditation methods, this would also be accounted for by sellers' assessment of whether to import or export.

The MISO auction is seasonal. The price cap in each season is set at 4 × CONE, meaning that each season would need to clear at the cap to produce an average clearing price equal to 4 × CONE on an annual basis.

TABLE 8: PRICE CAPS IN NEIGHBORING CAPACITY MARKETS (ESCALATED WITH INFLATION TO 2028\$, NOT ADJUSTED FOR UCAP DIFFERENCES)

| | Reference Price/ Net CONE (\$/MW-Day) | Gross CONE (\$/MW-Day) | Quantity at Cap (% of Target) | Price Cap Formula | Price Cap in 2028\$ (\$/MW-Day) |
|-----------------|---|------------------------|-------------------------------------|-------------------------------------|---------------------------------------|
| PJM 2025/26 BRA | \$246 | \$486 | 99% | MAX{Gross CONE, 1.5 × Net CONE} | \$486 |
| NYISO | \$229 | \$420 | 84% | 1.5 × Gross CONE | \$631 |
| ISO-NE | \$328 | \$513 | 98% | MAX{Gross CONE, 1.6 × Net CONE} | \$524 |
| MISO* | \$229 | \$367 | 99% | 4 × Gross CONE (Applied seasonally) | \$1,468 |
| IESO | \$353 | - | 98% | 1.5 × Net CONE | \$529 |

Sources and Notes: All prices in 2028\$/MW-day UCAP, calculated by adjusting most recent parameter year available for other markets by annual inflation and using neighboring markets' UCAP ratings (which could result in higher UCAP MW quantity ratings than PJM's updated accreditation methodology); PJM Net CONE and CONE from the 2025/26 Planning Year, adjusted to 2028\$ using forecast inflation, Gross CONE is the binding parameter that sets the price cap; NYISO Net CONE and CONE values adjusted from \$/ICAP kW-Year using published ICAP to UCAP Reference Point Translation Factor and applicable unit conversions; ISO-NE values in raw data assumed in ICAP MW and converted to UCAP MW using ISO-NE average EFORd; *MISO cap is based on 4 × CONE, but applied seasonally (i.e. to produce a 4 × CONE cap on an annual basis, all four seasons would need to clear at the price cap); MISO Net CONE and CONE reflect simple average of the Net CONE and CONE values per LRZ, assumed to be UCAP MW; IESO quantity at price cap includes contracted capacity; PJM, 2025/26 Planning Period Parameters for Base Residual Auction; ISO-NE, FCA 18 Demand Curve Values; ISO-NE, Market Rule 1—Section 13; MISO, MISO CONE and Net CONE Calculation for Planning Year 2025/2026; 187 FERC ¶ 61,202, Order Accepting Tariff Revisions, re Midcontinent Independent System Operator, Inc. proposed Reliability Based Demand Curves, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002; IESO, Capacity Auction: Pre-Auction Report; IESO, 2024 Annual Planning Outlook Report, Thompson and Spees, IESO Capacity Auction Reference Price and Maximum Auction Clearing Price Updates; Bank of Canada, Annual Exchange Rates; NYISO, Annual Update for 2024-2025 ICAP Demand Curves; NYISO, ICAP Demand Curve; NYISO, ICAP/UCAP Translation of Demand Curve.

Table 9 compares the range of RTO-wide price caps that may be considered based on our long-term simulation modeling, neighboring markets' caps, and relative to a \$350/MW-day Reference Price. These indicators suggest a price cap consistent with Curve 2 or Curve 3 would be sufficient to support reliability under long-run equilibrium conditions, when competitive forces can be expected to mobilize entry. However, these indicators provide an incomplete picture on the role and implications of a price cap in the event that of acute tight supply conditions prevent or severely limit the pace at which new entrants can respond to high prices.

TABLE 9: CONSIDERATIONS INFORMING THE PRICE CAP (\$/MW-DAY UCAP)

| Consideration | Cap Range | Suggests Price Cap: |
|---------------------------------------|--|--|
| Historical PJM Price Cap | \$450-\$625 (Nominal dollars, adjusted for ELCC) | Historical price cap range has been sufficient to maintain supply-side interest in new developments (except in most recent 2025/26 BRA, when other factors limited participation) |
| Proposed Temporary Cap | \$325 | PJM proposal filed with FERC (pending approval) to temporarily reduce price cap and mitigate customer exposure to price cap events under near-term tight supply conditions. Paired with price floor at \$175 to maintain supplier interest |
| Neighboring Markets' Price Caps | \$524-\$631 (2028\$) | Price cap high enough to align with neighboring capacity markets would be needed to compete for net imports when multiple regions are tight |
| Simulation Modeling | 150% - 191% × Reference Price | • <u>Curve 2</u> : Cap at 168%-191% × Reference Price supports 0.1 LOLE under long-run equilibrium conditions if price cap quantity is at 99% of reliability requirement |
| | @ \$350 Reference Price, cap would be \$605 for Curve 2, or \$525 for Curve 3 | • <u>Curve 3</u> : Lower cap at 150% × Reference Price would be right-shifted at minimum quantity |

Table 10 below illustrates the maximum 1-year cost exposure that customers could face in an RTO-wide price cap event, compared to prices that would be expected on a long-run average basis (at an assumed \$350/MW-day Reference Price). The table is a conceptual extreme in that it assumes that no customers are hedged against year-to-year capacity price spikes. Customers in regions with regulated planning are not heavily exposed to these prices, while customers in other states have a partial hedge on capacity prices through a combination of state contracts and standard offer service auctions. However, a subset of customers, particularly in retail choice states, are substantially exposed to these prices. Limiting the extent of customers' potential exposure to price cap outcomes is the primary reason to consider a price cap at the lower end of the potentially workable range.

TABLE 10: MAXIMUM 1-YEAR CUSTOMER COST EXPOSURE IN CAPACITY PRICE CAP EVENTS (ASSUMES NO CUSTOMERS ARE HEDGED AGAINST CAPACITY PRICES)

| | | Curve Parameters | | | Customer Costs | | |
|---------------|--------------------|--------------------------------|--|---|--------------------------------------|---|--|
| | Price @ Cap | Quantity @ Cap | Quantity @ Cap (for Maximum Cost Exposure) | Expected Avg. Customer Cost @ \$350 | Maximum Cost Exposure @ Cap | Ratio of Maximum to Average Cost Exposure | |
| | (\$/MW-day) [1] | (% of Reliability Req.) [2] | <i>(MW)</i> [3] | (\$ mln/yr) [4] | <i>(\$ mln/yr)</i> [5]: [1] x [3] | <i>(%)</i> [6]: [5] / [4] | |
| Current Curve | \$924 | 99.0% | 132,228 | \$17,491 | \$44,595 | 255% | |
| Curve 1 | \$890 | 97.8% | 130,562 | \$17,188 | \$42,413 | 247% | |
| Curve 2 | \$605 | 99.0% | 132,228 | \$17,189 | \$29,199 | 170% | |
| Curve 3 | \$525 | 99.6% | 133,069 | \$17,192 | \$25,499 | 148% | |

Sources and Notes: [1]: Price cap for each curve, expressed in \MW -day UCAP; [2]: Price cap quantity, expressed as a percent of the Reliability Requirement; [3]: Equal to the baseline simulated Reliability Requirement (133,564 MW) x [2]; [4]: Expected average customer cost under baseline modeling assumptions (i.e., True Reference Price equal to baseline value of \$350/MW-day UCAP for all curves); [5]: [1] × [3], with additional unit conversions; [6]: [5] / [4].

B. Implications of Transient Acute Tight Supply Conditions

As discussed more fully in the *Brattle 2025 PJM CONE Report*, the PJM region presently faces a material risk that the RTO or some LDAs could face acute supply tightness over the coming auctions. Near-term accessible new gas-fired capacity may be insufficient to meet the projection of 31,600 MW of demand growth forecast by 2030, plus up to 18,000 MW of potential retirements by 2030 as previously forecasted by PJM. These supply needs can be at least partially met by a combination of near-term competitive response (e.g., uprates, demand response, net capacity imports, and thermal life extensions) and market reforms (e.g., reforms to capacity must offer rules, treatment of reliability must run (RMR) supply, and accelerated interconnections for some resources under the Reliability Resource Initiative (RRI)). Thewever, there remains a substantial risk that demand growth outpaces net increases in supply, considering potential for limited supply of gas turbines (available only at a pricing premium) and

PJM forecasts approximately 31,600 MW of RTO summer peak demand growth between 2024 and 2030. See PJM, 2025 PJM Long-Term Load Forecast Report, January 24, 2025, Table B-1. The retirement projection shows the projected retirements from 2025 through 2030 (inclusive) and comes from the February 2023 Energy Transition in PJM Report, see PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks, February 24, 2023, p. 5.

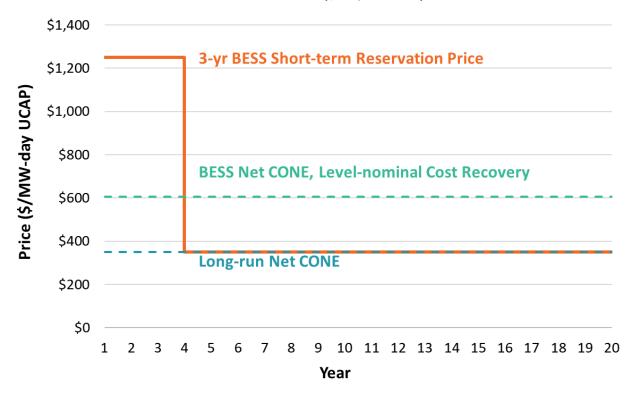
For must-offer requirement, see FERC, Order Accepted Tariff Revisions, Docket No. ER25-785-000, February 20, 2025; For treatment of RMR supply, see PJM, FERC Approves PJM Capacity Market Design Changes To Support Reliability, Affordability, February 20, 2025; For the RRI, see PJM, Reliability Resource Initiative Draws 94 Applications, March 21, 2025 and Howland, PJM fast-track interconnection process draws 26.6 GW in proposals, March 27, 2025.

longer timeframes required for resource interconnection processes and construction than have been required in the past. BESS resources may be possible to develop more quickly than gas plants to meet demand growth, but our analysis suggests they will be available only at a cost premium compared to the long-run Reference Price.

The role of the RPM price cap may be critical in the upcoming years if the market faces acute tight supply conditions. In the most extreme version of an acute tight supply scenario, with absolute barriers to supply entry, new capacity supply would not be possible to build regardless of the capacity market clearing price. In that scenario, the price cap should remain high enough to maximize response from short-term resources (life extensions, uprates, demand response, net imports) and to motivate investment in new resources as soon as barriers are resolved. However, prices above that level would be ineffectual to address near-term reliability shortfalls. If there is no ability for market response to these price signals, then further increases to the price cap would only serve to produce transfer payments from customers to incumbent generators for several years, likely beyond what they could reasonably have expected or counted on when they invested. If the acute tight conditions prevail for multiple consecutive years, then the size of the customer cost exposure and associated transfer payments would be similarly extended.

A slightly moderated and more realistic scenario is one where supply-demand conditions are tight, but there remains at least some capability for the market respond, albeit at prices that may be substantially higher than the long-run marginal cost of supply. The implications for the BRA price cap in this scenario are informed by the conceptual exercise illustrated in the following Figure 20. We examine a scenario in which market participants correctly predict that capacity market prices will be set at \$350/MW-day over the long run in line with the expected long-run marginal cost of supply ("Long-run Net CONE"). We further assume that for a short-term period of 3 years, it will not be possible to develop new gas-fired plants, and so capacity prices will be either set at the price cap or must rise high enough to attract BESS that can be built more quickly. The BESS resources would be attracted to enter at a capacity price of \$629/MW-day UCAP if they expect to earn that same price over the entire 20-year asset life of the project ("BESS Net CONE, Level-nominal Cost Recovery"). However, the same BESS resource will require a much higher price of \$1,329/MW-day UCAP in the first three years ("3-yr BESS Short-term Reservation Price") if future prices will return to the lower long-run price of \$350/MW-day UCAP over years 4-20 of the asset life after substantial volumes of new supply is able to come online (and assuming net E&AS offsets remain constant at current forward estimates, in nominal terms).

FIGURE 20: ILLUSTRATION OF SHORT-TERM RESERVATION PRICE NEEDED TO ATTRACT ENTRY FROM HIGHER-COST BESS IF FACED WITH 3 YEARS OF HIGH PRICES FOLLOWED BY LOW PRICES ALIGNED WITH LONG-RUN MARGINAL COST OF SUPPLY (\$350/MW-DAY) FOR REMAINING ASSET LIFE



Sources and Notes: Brattle 2025 PJM CONE Report.

In other words, a price cap in the range of \$1,300/MW-day (and an expectation that prices will remain at the price cap for at least three years running) could be required to attract higher-cost and shorter-lead BESS resources to enter the market if they are only able to secure high prices under one-year commitments and expect that future revenues will be undercut by lower-cost supply entry in the long term. Such a high price cap is outside the bounds of what can be considered a reasonable balance of VRR curve objectives, considering that it would: (a) be many multiples higher than needed to attract supply over the longer-term; and (b) expose customers to the potential for extreme pricing shocks.

If the price cap is maintained in the range of the 1.5–1.75 × Reference Price that we recommend and that is consistent with what is needed to support reliability on a long-run basis, the outcome in this scenario is that prices would clear at the price cap and that the BESS resources would not be developed under the one-year pricing commitments available. The market would then face a shortfall in supply relative to the reliability requirement for a temporary period, unless a backstop mechanism or out-of-market contracts were deployed to address the shortfall. Prices would still be high enough to elicit other short-term response and motivate gas-fired plants to develop as

quickly as possible, until reliability would be restored and new entrants would compete prices down to the long-run marginal cost of supply.

These scenarios illustrate a more general point about the role and limitations of a capacity market structured around one-year commitments. Annual capacity auctions reflect near-term market conditions and create opportunities for customers to access competitive pricing. The value proposition for customers is greatest when new, innovative players can enter the market with creative solutions that undercut the cost of incumbents. The biggest drawback of competitive markets that rely on merchant investors for a portion of supply entry is that customers can be exposed to the extremes of market conditions, particularly for any classes of customers that are not at least partially protected by longer-term supply commitments or retail pricing hedges.

C. Contingency Plan for Shortfalls

A well-functioning capacity market ideally produces few clearing results at the price cap and rarely or never relies on a reliability backstop or any out-of-market actions to ensure reliability. However, under expected near-term market conditions, we anticipate a material risk that a price cap aligned with long-term reliability needs may be insufficient meet reliability requirements for a temporary period until supply-demand conditions moderate. Modest increases to the capacity price cap would not be an effective means to fully mitigate this risk, as discussed above.

We therefore recommend that PJM and state agencies jointly review what to do in the event of a substantial shortfall. They may consider a combination of temporarily accepting some degree of lower reliability, other mechanisms to mitigate reliability risks, and/or reviews of the causes and necessary adjustments.

The RPM already incorporates a Reliability Backstop mechanism to address such situations, although it has never been triggered and has been a lesser focus in prior VRR Curve Reviews (other than as an indicator for the appropriate minimum quantity of the VRR Curve). Under the current Reliability Backstop mechanism, if any BRA clears below the reliability backstop threshold (99% of the system Reliability Requirement) on a system-wide basis, this triggers an investigation to review the reasons for the shortfall and to potentially recommend corrective actions to address it (e.g. addressing barriers to entry or increasing VRR curve pricing parameters). If the RPM clears below the 99% threshold on an RTO-wide basis for three consecutive BRAs, this would trigger a Reliability Backstop Auction where seller offers are solicited for a 6-month bid window,

sellers compete on price, and they can receive terms of up to 15-years to provide new capacity.⁵⁸ Currently the backstop mechanism provisions apply only on an RTO-wide basis; it is not triggered if an individual LDA is short.

The current Reliability Backstop mechanism has the following limitations for addressing anticipated acute supply challenges:

- The backstop is not triggered by shortages that may affect individual LDAs but that do not
 affect the entire RTO. This leaves a gap in which specific LDAs may be affected by supply
 barriers or unanticipated high supply costs, and that an immediate investigation or other
 backstop response may not be automatically triggered to address the problem;
- The Backstop Procurement is not triggered until a shortfall is observed for three consecutive years, meaning that the region would face at least two (and probably more) years of shortfalls before the needed supply would be brought forward under the backstop;
- The compressed forward period of upcoming BRAs, when combined 6-month timeline to solicit bids under the Backstop Procurement Auctions, is long enough that it would be unlikely for any winning resources to be able to reach online status for the relevant delivery period; and
- The procurement and payment structure of the Backstop Procurement is somewhat ambiguously specified and may result in higher-cost procurements that the minimum that might be required to fill the reliability gap under an all-source competitive auction for capacity-only commitments at the lowest possible price and term.⁵⁹

With respect to the first role of the Reliability Backstop of triggering an investigative review, we recommend to expand its applicability to include LDAs. On an LDA-specific basis, the trigger for an investigation would be any price cap event (which may correspond with a volume in the range of 95%-99% of the LDA Reliability Requirement, as discussed further in Section VII.A below). For both RTO-wide and LDA shortage events, it is important to diagnose the causes of the event so that PJM and state agencies can take appropriate actions, which will likely fall into one of the following three categories:

⁵⁸ There are other triggering conditions as well, see PJM, 2022 OATT, Attachment DD, Section 16.

⁵⁹ The Tariff description leaves room for interpretation and judgement but implies that the contracts could be awarded under bundled contract structures (inclusive of energy and ancillary revenues) that would make it more challenging to determine the offers with the lowest net cost compared to a capacity-only payment structure. As another ambiguity, the Tariff references a contractual term of up to 15 years (to be specified by the seller) but does not specify how different offer terms would be considered in selecting winning offers.

- **Design flaw or barrier to entry.** If the reason for a price-cap and shortfall event is that there is a market design flaw or a barrier to competitive market entry, then these issues should be addressed directly either through PJM rule changes (or by providing state agencies or other entities the information needed to address permitting or other challenges that may exist outside the scope of PJM markets).
- VRR curve pricing parameters lower than the incremental cost of supply. If the reason for
 a price cap event is that the cost of incremental supply is above the prices supported in the
 RPM construct, then an accelerated adjustment to increase the price cap or Reference Price
 is required to attract entry.
- Shifts to market fundamentals. In some cases, the cause of a price cap event may have been a large contraction to supply (e.g. a large resource exiting, a large increase to local demand). If that shift is very large compared to LDA size or came as a surprise, then there may simple have been insufficient anticipation by the market to predict high prices and propose alternative projects. In these cases, no rule change or pricing adjustment may be needed to attract supply interest to address the shortfall in subsequent RPM auctions.

With respect to the more impactful aspect of the Reliability Backstop mechanism associated with Backstop Procurements, our recommendations are more limited. Our primary recommendation is that PJM and state agencies should consider whether the current Reliability Backstop mechanism offers sufficient protections in the present market context, considering the possibility that acute supply conditions may affect one or more upcoming auctions and that modest adjustments to the price cap would not be an effective means to limit the associated reliability risks. While a comprehensive redesign of the Reliability Backstop mechanism is out of the scope of the Quadrennial Review process, we offer high-level thoughts on aspects of the mechanism that could be adjusted. These or other adjustments to the backstop should be developed with the understanding that the BRA auctions are the primary means of signalling the need for new capacity entry, such that the trigger of the backstop is understood to indicate the presence of a design deficiency or barrier to entry that should be separately and directly addressed.

Design components of an enhanced Backstop Procurement mechanism that could be considered may include:

Reliability Threshold Triggering a Procurement: We would recommend that any backstop
procurement would be applied only at or below the quantity at which the RTO or VRR curves
reach the price cap (99% of Requirement system-wide, but a lower 95-99% of Requirement
in the LDAs). Setting the Backstop Procurement volume at a lower volume would indicate
more tolerance to absorb modest reliability shortfalls, which is likely justified considering that

- market response or investigative review may be sufficient to address most shortfall events (particularly those that are associated with surprises or short-term market variations).
- Consecutive Years Requirement: We recommend that states and PJM review the
 appropriateness of triggering the Backstop Procurements only after three consecutive years
 of shortfall if that creates unacceptable reliability exposures. One option would be to trigger
 a Backstop Procurement in any year the clears short of some defined minimum acceptable
 reserve margin.
- **Procurement Volume**: If a Backstop Procurement is conducted, we would recommend that it procure only up to the minimum acceptable reliability level, which should be at or below the quantity of the RTO or LDA price cap. This would retain the role of the BRA and VRR curve to reflect the willingness to pay for in-market capacity supply up to the price cap and revert to backstop procurements only in the event that in-market signals are insufficient. The result of the procurement is then to support reliability at a minimum level, without introducing excess volumes that may undermine BRA and VRR-based pricing signals in future years.
- Product and Term: If a one-year term at the price cap is insufficient to attract supply, one option would be to procure incremental supply under a 2 to 15-year commitment (with a goal to secure commitments under both the lowest price and shortest term to minimize the total magnitude of financial commitments). To limit the total size of financial commitments produced, the commitments would be structured as capacity-only payments for a specified volume of UCAP supply, leaving the capacity seller to retain risks associated with capacity ratings, energy market risks, and ancillary service market risks.
- Format of Competitive Procurement: Structuring any backstop procurement to prioritize both lower price and shorter term could incentivize sellers to offer at the lowest price and term (i.e. a uniform clearing price and term). One way to structure the clearing would be to select resources based on price at any prices up to the cap (normal BRA clearing), or based on the shortest term for incremental resources offering supply at the price cap.
- Sellers Eligible for Multi-year Commitments: Eligibility would likely be limited to new resources and existing resources that demonstrate costs commensurate with the offered price and term, subject to expanded monitoring and mitigation to address market power, including the possibility that even new resources may be in a position to exercise market power in very tight market conditions or LDAs with limited supply options. Solutions to address these circumstances may differ from the approaches to reviewing supplier offer costs that are effective in the BRA auctions.
- Other capacity sellers: Earn 1-year commitment at the price cap (same as today).

We caveat these options by noting that relying frequently or extensively on backstop procurements would indicate that in-market incentives for new supply entry are inadequate, signalling that there is likely a deficiency in the market design or barrier to entry that should be addressed. The above-market costs associated with any such procurements would ultimately be allocated to consumers of the affected regions over the duration of the commitments (even to customers who have hedged), another reason to limit the size and scale of any such backstops.

VII. Implementation Considerations for MRI-Based VRR Curves

The MRI-based approach to setting VRR Curves on a system-wide basis can be adapted for use in each of the LDAs, as well as in a sub-annual RPM construct. Consistent with the rationale for our recommendation to adopt a system-wide MRI-based VRR curve, applying MRI-based curves in the LDAs and within a sub-annual market construct has the potential to enhance economic efficiency and send price signals that reflect the marginal value of incremental capacity, tailored to specific locations and each sub-annual period.

A. Locational VRR Curves Based on Marginal Reliability Impact

To accompany the system-wide MRI-based VRR curve, we recommend PJM implement MRI-based curves in the LDAs. We recommend implementing MRI-based curves at the LDA level for similar reasons as we recommend MRI-based VRR curves in the system. This will provide consistent price signals to consumers that reflect a rationalized expression of the value of reliability at different reserve margins for different locations on the system. We describe here two options for how to construct MRI-based local curves:

- Option 1: Additive LDA MRI-based Curves (Long-Term Recommendation). The first option matches the approach used by ISO-NE, wherein the local clearing prices in each LDA are interpreted as additive to the system price. 60 Additive MRI-based LDA curves employ the same scaling factor for both the system and LDA curves, which ensures a consistent willingness to pay for reliability value of all resources, regardless of their location. This approach as a strong conceptual basis and hence is our recommended approach over the long term for PJM; but would require more time to implement considering that the RPM auction clearing engine would need to be updated.
- Option 2: Non-additive LDA MRI-based Curves (Recommended for Initial MRI Curve Implementation). The second approach is non-additive and is more similar to the approach currently used currently in PJM and by MISO in its locational MRI-based curves. Under this methodology, separate MRI-based curves are developed for the LDAs and the system, each

ISO New England, <u>ISO New England Inc and New England Power Pool Participants Committee</u>, <u>Docket No. ER16-000</u>, <u>Demand Curve Design Improvements</u>, April 15, 2016.

of which uses its own scaling factor to ensure that the curve passes through a consistent Anchor Point for each LDA.⁶¹ Under this methodology, the local MRI-curve is binding only when import limits bind and cause LDA price separation above the system price (same auction clearing mechanism that PJM uses today).

As we explain further below, we recommend PJM adopt the non-additive approach (Option 2) alongside implementation of a system-wide MRI-based curve in the 2028/29 auction due to its relative ease of implementation. However, over the long term, we recommend PJM consider transitioning to the additive approach (Option 1), alongside the transition to a sub-annual capacity auction.⁶²

OPTION 1: ADDITIVE LDA MRI-BASED CURVES (LONG-TERM RECOMMENDATION)

The additive MRI-based curves approach maintains consistent willingness to pay for reliability value across all resources by using a single scaling factor to translate the MRI curves in each location, including the system, from units of reliability into units of price (\$/MW-day UCAP). This approach follows the method used by ISO-NE to calculate locational demand curves in their capacity market. While the system-wide MRI curve reflects avoided EUE from reduced system-wide shortfall events, the LDA MRI curves reflect the additional avoided EUE associated with locating capacity in a particular LDA, rather than locating that capacity elsewhere in the unconstrained system. Under this approach, an LDA would clear at a higher price to the extent that there is additional reliability value for a resource being built within a specific import-constrained LDA. The difference in reliability value by location is driven by transmission constraints between LDAs and the system, since local capacity may be able to serve internal demand that a resource outside the LDA would not be able to serve.

Figure 21 illustrates the additive nature of the resulting price formation that would be created by the system-wide MRI curve (reflecting system-wide reliability value), plus the LDA-specific MRI curve (reflecting the additional reliability value created by locating supply within a constrained area).

⁶¹ MISO, <u>Business Practices Manual No. 011: Resource Adequacy</u>, February 21, 2025, pp. 207–213.

The additive approach is particularly amenable to seasonal capacity markets as one can retain the same willingness to pay for reliability across seasons and locations. Additionally, the auction optimization process is simplified when the willingness to pay is consistent across seasons and locations, which could facilitate the implementation of a seasonal market.

⁶³ ISO New England, <u>ISO New England Inc and New England Power Pool Participants Committee</u>, <u>Docket No. ER16-000</u>, <u>Demand Curve Design Improvements</u>, April 15, 2016.

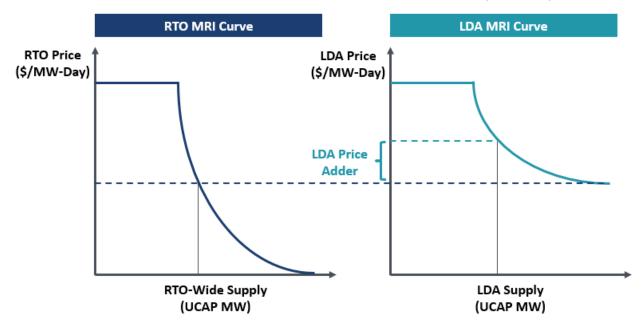


FIGURE 21: ADDITIVE LDA MRI-BASED CURVE METHODOLOGY (OPTION 1)

Table 11 provides more detail on the steps used to calculate additive MRI-based curves (adapted somewhat from the ISO-NE approach to align with PJM's current LDA reliability modeling approach).

TABLE 11: STEPS TO CALCULATE ADDITIVE LDA MRI CURVES

Step 1: Set the system-wide reliability target using the 0.1 Annual LOLE in each region using the system-wide reliability model, and establish the RTO-wide "scaling factor" for the system-wide MRI-based VRR Curve

Step 2: Establish the RTO-wide "scaling factor" as aligned with the system-wide MRI-based VRR Curve

Step 3: For each LDA, similarly calculate the location-specific MRI curves across varying reserve margins by adding or subtracting capacity from that location. The EUE events considered in the LDA MRI curve should only capture the *additional* reliability value accomplished by locating capacity within the LDA beyond what is achieved by locating the capacity within the parent LDA or broader RTO system⁶⁴

Step 4: Calculate the LDA MRI-based demand curves by multiplying the LDA MRI curve by the system-wide scaling factor

In the versions of the LDA MRI curves presented here, the reliability results have not been adjusted to ensure that only the additional reliability value is reflected. After making this adjustment, the resulting MRI-based curves would produce a somewhat lower price than shown in the following figure.

Following this approach, each LDA would have an MRI curve aligned with local reliability modeling data for that specific LDA, but reflecting a uniform value of reliability across the footprint. Figure 22 provides an illustration of additive MRI curves for each LDA in gray compared to the current VRR curve that may result from this approach. The resulting curves are substantially lower and left-shifted compared to the current VRR Curve, though this comparison does not mean that prices would necessarily be lower in total considering that the local plus parent or RTO curves together would affect the local clearing price. The additive LDA curves approach would produce substantially more stabilized price formation in the LDAs, considering that a modest LDA pricing premium would be realized even if the in-LDA supply is relatively high, and the much flatter slope of the LDA MRI curves would more gradually introduce locational price premiums.

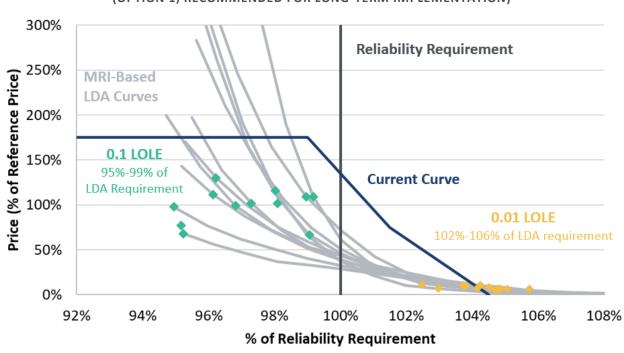


FIGURE 22: ADDITIVE MRI-BASED CURVES FOR PJM LDAS (OPTION 1, RECOMMENDED FOR LONG-TERM IMPLEMENTATION)

Sources and Notes: Indicative curves constructed based on LDA reliability modeling data provided by PJM staff.

The additive LDA MRI curve approach could offer efficiency benefits by producing a standardized willingness to pay for all units of reliability in the auction, accounting both for system-wide and local reliability value. Moreover, the additive approach will align well with the implementation of a seasonal market as discussed further in Section VII.B.

However, several challenges would be presented with implementing this additive MRI concept on an LDA-specific basis. If PJM were to implement this approach, the consequence would be to

transition away from the current concept of a Net CONE-based approach to managing reliability needs in each location (i.e. with the height of LDA VRR Curves tied to the locationally-adjusted long-run marginal cost of supply) and toward a different approach that relies more centrally on placing a uniform value on reliability across the footprint. Since the revised LDA VRR Curves would no longer be tied to a location-specific Net CONE as the primary determinant of pricing parameters, the result would be that locations with a much higher cost of supply may absorb poorer reliability before prices could rise high enough to attract local supply investment.

The RPM clearing approach would also need to be updated to implement an additive MRI curves approach. Hence, we recommend that PJM implement non-additive LDA MRI-based curves for the 2028/29 BRA (which would not require revisions to the clearing approaches) but consider eventually transitioning to the additive approach alongside implementation of a potential subannual market.

OPTION 2: NON-ADDITIVE LDA MRI-BASED CURVES (RECOMMENDED FOR INITIAL MRI CURVE IMPLEMENTATION)

To remain more closely aligned with the current LDA VRR Curves and current auction clearing approaches, non-additive LDA MRI curves can be used. Under this approach, locational price separation would continue to occur as they do today (when capacity import limits bind). In considering how to adapt an MRI-based curve concept to the LDAs, we considered three suboptions as illustrated in Figure 23 below. Each of these curve options is constructed using a distinct scaling factor for each LDA.

Variations of the approach that we considered include:

• Option 2a (Recommended) is constructed such that the curve passes through the Reliability Requirement at the LDA-Specific Reference Price for each LDA. Option 2a curves (like all MRI-based curves that we considered) are flatter than the current VRR curve, which would tend to reduce price volatility in the LDAs over the long run. Although these curves intersect the price cap at approximately 96%–99% of the local Reliability Requirements, the additive reliability events at the price cap remain fewer than 0.1 LOLE events in each curve. This indicates that a somewhat lower volume of supply can be absorbed in the LDAs before excess reliability risks are introduced, and thus justifies intersecting with the price cap at a lower percentage of the LDA Reliability Requirement. In the low-price and high-quantity region of this curve, the LDA MRI curves are flatter and have a wider foot compared to the Current VRR Curve. However, unlike in the additive MRI curves approach described above, this portion of the LDA curves is unlikely to materially affect auction clearing outcomes (considering that

parent LDA and RTO prices would infrequently be low enough that this portion of the LDA demand curve would be relevant in setting prices).

- Option 2b was another option that we considered for an LDA MRI-based curve, and is constructed such that each curve intersects the price cap at 99% of each LDA's Reliability Requirement. The logic of this curve would be to align with a concept in which the priority is to align with the LDA Reliability Requirement and rarely fall below 99% of that Requirement (i.e., using 99% as the equivalent of a "minimum acceptable" reliability threshold that should not be violated for economic reasons). Option 2b curves are right-shifted relative to Option 2a, and would be more likely to produce outcomes above the LDA Reliability Requirement. However, these curves are less grounded in economic logic than the system-level version of the curves defined by 99% of Requirement, since the cap tied to 99% of the LDA Reliability Requirement does not necessarily map to similar reliability levels at the price cap for each LDA. On balance, we view Option 2a as a more attractive approach that would allow LDA prices to reach the cap more gradually in most LDAs and at a pace that is more aligned with reliability risks.
- Option 2c is set such that each curve intersects the price cap at the quantity corresponding to a 0.1 LOLE.⁶⁵ Option 2c curves are similar to Option 2a but are more left-shifted and could absorb a more substantial shortfall compared to the LDA Reliability Requirement. This approach has some conceptual appeal if 0.1 LDA LOLE were treated as a minimum acceptable level of LDA reliability risk. However, the 2c curves are misaligned with the LDA Reliability Requirement, considering that they would produce pricing below the LDA Reference Price at the LDA Reliability Requirement.

Considering the tradeoffs amongst these options, we recommend PJM adopt Option 2a curves in the LDAs for the 2028/29 BRA alongside the system-wide MRI-based curve, and eventually evaluate the potential to transition to additive curves in the future.

⁶⁵ The price cap value is shown at 1.5 × Reference Price in Figure 23.

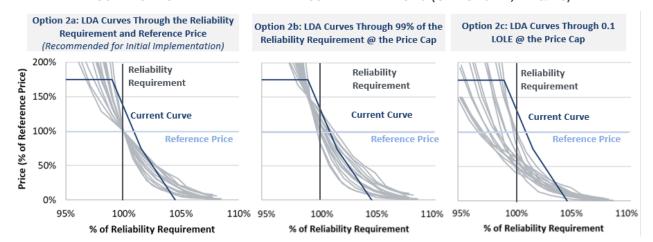


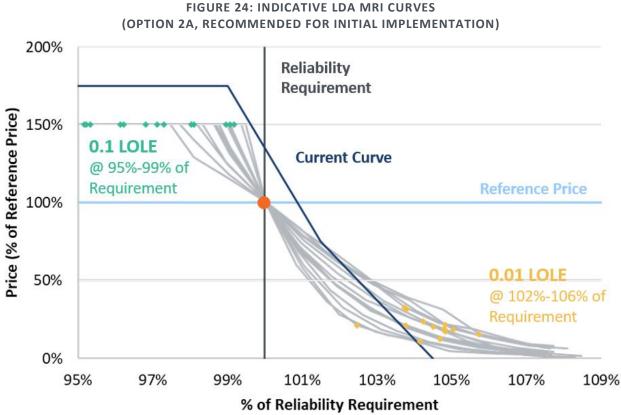
FIGURE 23: NON-ADDITIVE LDA MRI CURVE VARIATIONS (OPTIONS 2A, 2B & 2C)

Sources and Notes: For each MRI curve option, all LDAs have distinct scaling factors. For option 2a, the scaling factors are calculated such that the curves go through the Reliability Requirement at the Reference Price. For option 2b, the scaling factors are calculated such that the curves pass through the price cap at 99% of the Reliability Requirement. For option 2c, the scaling factors are calculated such that the curves pass through the price cap at the quantity associated with 0.1 local LOLE. The price cap is assumed to be equal to 1.5 × Reference Price for all LDAs. Reliability modeling data is provided by PJM staff.

All LDAs will have distinct MRI-based VRR Curves using this approach, with differences in shape due to differences in reliability modeling for each LDA. Some LDAs may be able to retain adequate levels of reliability at a level further below their reliability requirement and thus those LDAs will intersect the price cap at a lower reliability level. Figure 24 below illustrates the resulting locational VRR curves across all LDAs, compared against the Current Curve. As shown in the figure, the candidate MRI-based curves are flatter than the Current Curve, would be somewhat left-shifted, and would reach the LDA price caps at a somewhat lower quantity in most LDAs. These more gradual pricing outcomes signaled by the LDA MRI-based curves are more attuned to the reliability risks introduced by variations in LDA supply quantities. Despite the potential for lower volume outcomes when considering the outcomes as a percentage of Reliability Requirement, all MRI-based LDA curves reach the price cap before LDA-specific risks are high (as indicated by the green dots, plotted where LDA reliability events reach 0.1 LOLE).

We recommend that each LDA Reference Price would be set equal to or higher than the parent LDA or system Reference Price, acknowledging the one-way interaction in which LDA VRR curves can only produce higher prices when import constraints are binding (but cannot produce lower prices). For a similar reason, we recommend setting the price cap of the LDA curves equal to the greater of either: (a) the parent LDA/RTO price cap; or else (b) 1.5 × the LDA Reference Price. We recommend the 1.5 × multiplier for LDAs even if a higher multiple is adopted for the RTO-wide MRI curves in order to mitigate exposure to locational price spikes that may be associated with year-to-year variability or unanticipated shifts in supply and demand. However, we reiterate our

recommendation (from Section VI.C above) that it would be beneficial to update the Reliability Backstop mechanism to ensure that any LDA price cap event would automatically trigger an investigative review to understand the causes of the outcome. If the event is driven by a surprise such as an unexpected change to the Capacity Emergency Transfer Limit (CETL) parameter, no change to the price cap would be relevant as supply response would be expected for the next auction. However, if the local price cap event is driven by increased supply costs in the LDA, that would indicate expedited increase in pricing parameters. Other price cap events may be associated with barriers to entry or other challenges that would need to be addressed through more targeted solutions as discussed above.



Sources and Notes: Indicative LDA curves are constructed option 1 of the LDA MRI curves shown above in Figure 23. All curves have the same price cap as a percentage of their reference price. The scaling factors is distinct for each LDA and is calculated such that the curve runs through the Reliability Requirement at the Reference Price.

B. Adapting MRI-Based VRR Curve to a Potential Subannual Capacity Market Construct

In addition to the economic advantages of an MRI-based demand curve described in Section IV, an MRI-based VRR Curve could also be readily adapted to provide economically rationalized

signals should PJM transition to a sub-annual capacity market construct. In 2023, PJM introduced a proposal to transition from an annual auction construct to a sub-annual market with two seasons: winter and summer. ⁶⁶ In a sub-annual market, both resource accreditation and reliability needs would be season-specific, which would provide more visibility into reliability needs, enable more resources with different seasonal capabilities, and offer economic efficiency benefits as discussed in Section III.E above. Further, co-optimized auction clearing across seasons can ensures that resources are able to recover their going-forward costs over the year and allow an economically-optimized selection of resources that supports seasonal resource needs.

As a starting point approach to developing a seasonal MRI-based curve, we recommend considering the MISO approach. MISO has already demonstrated the development of a four-season MRI-based capacity demand curve, which will be first used in the 2025/26 planning year capacity auction.⁶⁷ Though MISO's approach applies across four seasons, the same concept can be adapted to apply to an arbitrary number of sub-annual periods.

The concept in a sub-annual MRI curve, as with the annual MRI curve, is to establish an economically rationalized willingness-to-pay (or "scaling factor") that is uniform across reserve margins and across capacity seasons. The season-specific VRR Curves' horizontal placement are then tied to the season-specific peak load, while the shape and slope are associated with season-specific reliability drivers. However, the \$/MWh scaling factor would remain identical across the seasons, meaning that the same value of reliability is expressed across all seasons and capacity volumes. Each season's MRI curve would be subject to a capacity price cap, as would the total annual capacity price.⁶⁸

In RPM auction clearing, sellers' season-specific ELCC UCAP ratings would be accounted for, with individual sellers able to submit offers to sell capacity either for an individual season or for the full annual period. Seasonally co-optimized auction clearing would be utilized to maximize cleared reliability value minus total resource cost across the annual period, with prices set at the

⁶⁶ PJM, <u>Capacity Market Reform: PJM's Proposal</u>, Resource Adequacy Senior Task Force, June 14, 2023.

See 187 FERC ¶ 61,202, Order Accepting Tariff Revisions, re Midcontinent Independent System Operator, Inc. proposed Reliability Based Demand Curves, June 27, 2024, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002; and Spees, Newell, Bai. Written Testimony regarding MISO's Reliability-Based Demand Curve, September 28, 2023.

The annual price cap would apply to the average price realized across all seasons, which we would recommend should continue to remain within the traditional range of 1.5-2 × Reference Price that currently applies in PJM and other capacity markets. However, the maximum price in any one season may be appropriate to increase to a higher level, to account for the scenario in which one season is the primary driver of reliability needs (while other seasons have low or zero prices) and so that one season's pricing signals may need to be sufficient to attract new resource investments for a period.

intersection of supply and demand on a season-specific basis.⁶⁹ As a result, the seasonal MRI-based VRR Curves will help to balance and guide the resource mix in a fashion that is economically rationalized based on the value of reliability and marginal cost of improving reliability (i.e. against sellers' resource costs).

The result will be to incentivize the marketplace to identify the lowest-cost and highest-value resources to improve reliability. If the summer season is tight and reliability needs are acute there, then capacity prices will be higher in the summer than in the winter season and sellers will be incentivized to bring forward more summer-focused capacity resources such as solar; if the winter season is tight, then resources with higher and more firm fuel capabilities will be attracted; if reliability needs in both seasons are balanced, then resources with strong annual ELCC ratings will be prioritized. This in-market signaling would also reduce the current level of criticality placed on accurately predicting the resource mix in PJM's reliability modeling, since the market can be more adaptable to a different balance of summer and winter risks (while offering more visibility a certainty that both seasons' capacity needs will be met). Implementing a co-optimized, subannual market would require enhancing the RPM auction clearing engine, and would be aligned with the additive MRI-based VRR curve approach described in Section VII.A above (i.e., Option 1A). The use of a single scaling factor to develop summer and winter MRI-based VRR curves for the system and for all LDAs would allow the market to reflect a consistent willingness to pay for reliability across all sub-annual periods and all locations in the PJM RTO.

Figure 25 provides an indicative representation of summer and winter MRI-based curves that could be used in PJM. Each season's curve is derived from PJM's modeling of season-specific reliability risks, with x-axis quantities adapted to account for season-specific ELCC ratings of the resource mix. Since these curves are curves are developed based on the same willingness to pay for reliability (i.e., the use of the same scaling factor in all seasons), the relative flatness of the winter curves reflects that, at the same sub-annual reserve margin, 1 MW of additional capacity provides greater reliability improvements in the summer rather than the winter. The winter curve is left-shifted compared to the annual curve due to the lower winter peak load and associated supply needs, while the summer curve is right-shifted for the same reason. The two curves are

The surplus-maximizing objective function would maximize the area under the cleared demand curves (system and LDA) minus the cost of cleared supply (allowing sellers to clear under a season-specific or annual offer structure, but without duplicate clearing). Prices would be derived from the shadow price on the supply-demand constraint in each season and LDA (which stipulates that cleared supply ≥ cleared demand). The result would be to produce distinct prices for each capacity season, with LDA-specific price adders also for each season. All sellers would earn a capacity payment equal or greater than the offer price, though for annual offers the sellers would be presumed to be indifferent regarding which season produces higher prices as long as the total annual offer cost is recovered.

tens of GW apart from each other, which illustrates the scale of imprecision that must currently be averaged into the current composite annual RPM construct.

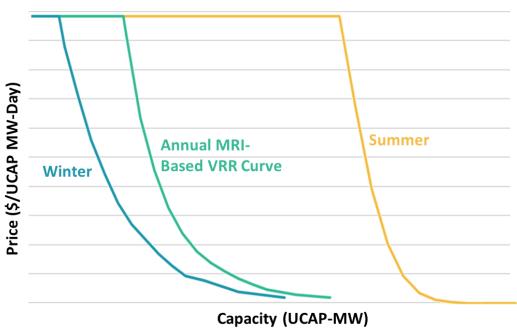


FIGURE 25: INDICATIVE SUB-ANNUAL AND ANNUAL MRI-BASED VRR CURVES

Notes: Indicative calculation, derived from PJM seasonal MRI modeling and seasonal UCAP accreditations.

Whether in an annual or sub-annual market, the implementation of MRI-based VRR curves will promote economic efficiency and enable PJM to meet its reliability needs in a cost-effective manner. Collectively, the recommendations outlined in this report will strengthen the ability of the RPM to attract and retain sufficient capacity to meet reliability objectives on a long-run average basis, while ensuring the market remains resilient to uncertainties, both in the near-term and beyond.

Appendix

In this appendix we provide additional detail on the structure and input assumptions of the Monte Carlo simulation model used to evaluate the VRR curve performance across a range of sensitivities. This methodology allows us to simulate the distribution of clearing outcomes that might be realized over many years, rather than making recommendations about the VRR curve size and shape based solely on near-term forecasts of supply and demand in the PJM market.

A.1 Overview of Model Structure and Assumptions

To evaluate PJM's current VRR Curve and possible alternative curves, we conducted Monte Carlo simulations using an updated and enhanced version of the model used in the 2022 Quadrennial Review. This methodology provides us with distributions of price, quantity, and reliability outcomes for each evaluated VRR curve, which we then analyze in light of the performance objectives of the RPM and the VRR curve. This model exclusively simulates outcomes in the three-year-forward BRA and does not analyze the supply and demand changes that result from the short-term Incremental Auctions held between the BRA and the beginning of the Planning Year.

The Monte Carlo simulation model we employ in this analysis evaluates capacity market outcomes probabilistically, given realistic variability in supply and demand. The model operates under the long-run equilibrium assumption that merchant generation will enter and/or exit the market until clearing prices equal Net CONE on average. Due to unavoidable variability in supply-demand conditions, it is not possible to ensure that procured capacity will land exactly at the Reliability Requirement in every year. For each model run, we therefore simulate 10,000 capacity market outcomes (or "draws"). The supply-demand balance varies in each draw due to the application of randomized supply and demand variability tuned to historical levels. To simulate rational economic entry and exit, infra-marginal supply is added or subtracted from the market in each draw to facilitate model convergence to a long-run average clearing price equal to the Reference Price across the final 1,000 market simulations. Using these results in equilibrium, we assess the performance of the demand curve.

Every input parameter utilized in the model is derived directly from auction parameters, historical market data, and historical offer prices. ⁷⁰ By ensuring that all model inputs and parameters are derived directly from observable data, we aim to accurately capture the range of outcomes that may be reflected in the upcoming review period relevant for VRR curve implementation. Reliability results (i.e., LOLE, LOLH, and EUE calculations) are tabulated based on cleared quantity values and reliability modeling provided by PJM. See Table 12 summarizes primary inputs used in the Monte Carlo simulation model under base modeling assumptions.

TABLE 12: MODEL INPUTS UNDER BASE CASE ASSUMPTIONS

| Parameter | Unit | Value |
|------------------------------------|--|---------|
| PJM System Parameters | | |
| Peak Load | (MW) | 142,286 |
| Forecast Pool Requirement | (UCAP %) | 93.9% |
| UCAP Reserve Margin | (UCAP %) | -6.1% |
| Reliability Requirement | (UCAP MW) | 133,564 |
| Supply and Demand Variability | | |
| BRA Total Supply | (Std. Dev as % of BRA Total Supply) | 4.4% |
| BRA Reliability Requirement | (Std. Dev as % of BRA Reliability Requirement) | 3.7% |
| BRA Net Supply | (Std. Dev as % of BRA Reliability Requirement) | 2.8% |

Sources and Notes: Peak Load and Reliability Requirement do not include demand from FRR entities. System parameters match the values used in the 2025/26 Base Residual Auction, from PJM, 2025/26 Planning Period Parameters, 2023. See Sections A.2, A.3, and A.4 for explanation of the derivation of total supply variability, reliability requirement variability, and net supply variability.

We set the Reliability Requirement and the initial volume of total supply offers consistent with historical market data from the 2025/26 BRA. These values are updated in each model draw based on the supply and demand variability parameters, which are based on the observed variability in BRA supply and demand from the 2015/16 to 2024/25 Planning Years.

In each draw, the model selects a single capacity market supply curve. Each supply curve having the same shape as a historical BRA supply curve, but with offer prices adjusted for inflation and with price-quantity blocks that have been smoothed. The model cycles through 17 supply curves, derived from the historical supply curves used from the 2009/10 to 2025/26 Base Residual Auctions. Each block in the supply curve is sized as a percent of total supply offers, which is subject to variability in each draw. On the demand side, the quantity points on the VRR Curve are

For additional detail on the derivation of the \$350/MW-day UCAP base Reference Price, see the Brattle 2025 PJM CONE Report.

calculated relative to the Reliability Requirement, which is also subject to variability in each model draw. Figure 26 shows a stylized depiction of how the model estimates a distribution of price and quantity distributions driven by supply and demand variability.

The intersection of supply and demand determines the clearing price, quantity, and reliability in each draw. These clearing results are tabulated across the final 1,000 draws, once the model has reached equilibrium market conditions, and these draws provide the estimated distribution of market clearing results. The shape of the VRR curve under consideration will affect the price and quantity distributions compared to other tested curves.

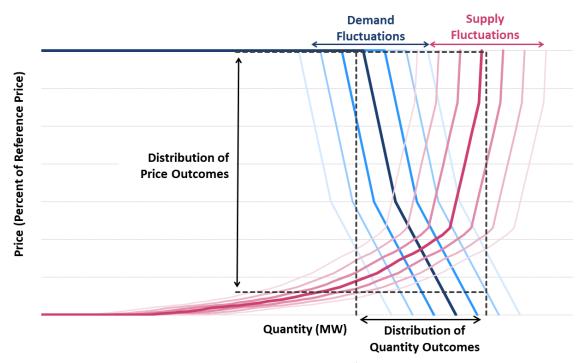


FIGURE 26: SUPPLY AND DEMAND VARIABILITY

Sources and Notes: Illustrative variations are not intended to reflect the exact variation magnitudes used in our simulations.

A.2 Reliability

We model reliability outcomes based on the cleared UCAP reserve margin in each draw and reliability modeling data provided by PJM that captures the LOLE, LOLH, and EUE values at a range of different UCAP reserve margins. Linear interpolation is used to calculate reliability when the cleared UCAP reserve margin falls between two data points provided by PJM. The relationship between UCAP reserve margin and the various reliability metrics is asymmetrical. For simplicity, the following paragraph describes LOLE, but the relationship is the same for LOLH and EUE. Below the Reliability Requirement, LOLE increases more steeply (indicating worsening reliability outcomes), but at reserve margins above the Reliability Requirement, LOLE decreases more gradually (meaning improving reliability). An implication of this asymmetry is that a demand curve that results in a distribution of clearing outcomes centered on the Target Point (i.e. the Reliability Requirement) with equal variance above and below the target will fall short of the 0.1 LOLE target on an average basis.

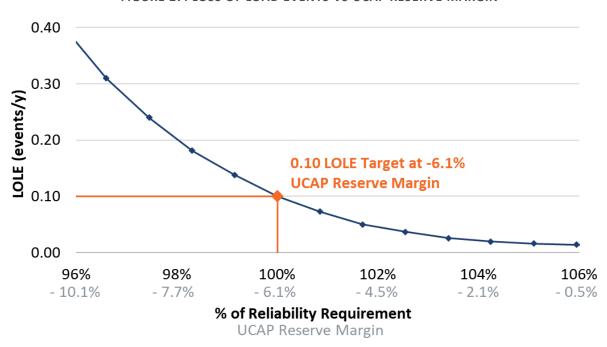


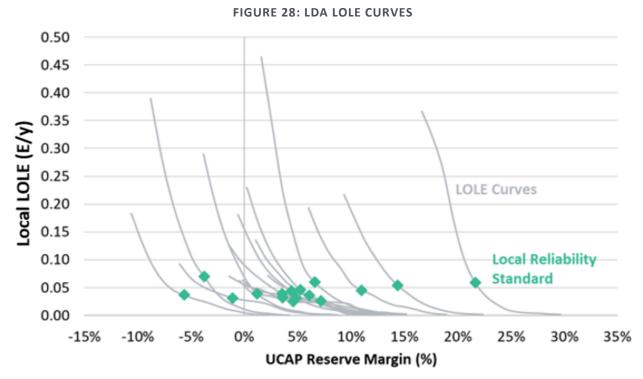
FIGURE 27: LOSS OF LOAD EVENTS VS UCAP RESERVE MARGIN

Sources and Notes: Reliability data provided by PJM reliability modeling staff; PJM is a summer-peaking region, but most reliability risks occur in the winter due to infrastructure complications primarily associated with gas generation, which leads to a negative summer reserve margin at the 1-in-10 LOLE target.

We did not model the reliability results for individual LDAs as part of this Quadrennial Review. However, in any given LDA, the relationship between the local reserve margin (calculated based on local supply and imports) and local reliability mirrors that of the overall system. In both the LDAs and the system as a whole, there is a convex, downward-sloping relationship between UCAP reserve margin and reliability, which reflects the diminishing marginal reliability impact of capacity as reserve margins increase.

Unlike the system-wide LDA curves, the Reliability Requirement of individual LDAs is not calculated by adding/subtracting perfect capacity around the 1-in-10 LOLE target. Instead, local reliability curves are calculated in relation to the locational reliability standard in each LDA,

defined as 40% of the RTO-wide load-normalized EUE.⁷¹ As a result of this calculation, the local reliability standard for each LDA falls at slightly different reserve margins, as shown in Figure 28.



Sources and Notes: Reliability data provided by PJM reliability modeling staff; Local reliability standard calculated using data provided by PJM and following the logic from PJM, Manual 20A, Effective Date June 27, 2024.

A.3 Demand

In the model, the base value for the Reliability Requirement is set to match the Reliability Requirement from the 2025/26 BRA at 133,564 MW. In each model draw, this Reliability Requirement is updated by applying normally-distributed randomized variability. The magnitude of this variability parameter is tuned to the historical variation in the RTO Reliability Requirement relative to a linear trend, consistent with the methodology used in the prior Quadrennial Review.

Table 13 shows the historical Reliability Requirement values, as well as the linear prediction and the deviation from the trend, which sets the BRA Reliability Requirement variability parameter.

The LDA-specific Local Reliability Standard is set at 40% × RTO-wide load-normalized EUE. Load-normalized EUE is the (very small) percentage of annual energy demand that cannot be served due to resource adequacy events, defined as the estimated MWh of EUE, divided by the forecasted annual net energy consumption (MWh EUE/MWh Load). Since the LDA-specific EUE measures only shortages in the LDA, but not the shortages that may coincide with system-wide events, LDA-specific normalized EUE is a measure that is partly (but not entirely) additive to system-wide normalized EUE. See: PJM, Manual 20A, Effective Date June 27, 2024.

The average historical deviation from the trend is 5,540 UCAP MW, or 3.7% of the average BRA Reliability Requirement from 2015/16 to 2024/25.

TABLE 13: HISTORICAL VARIABILITY IN BRA RELIABILITY REQUIREMENT

| Year | Historical BRA Reliability Requirement [A] (UCAP MW) | Linearized BRA Reliability Requirement [B] (UCAP MW) | Residual Above (Below) Linear Trend [C] (UCAP MW) | |
|---|---|--|---|--|
| 2015 | 162,777 | 170,766 | (7,989) | |
| 2016 | 166,128 | 166,491 | (363) | |
| 2017 | 165,007 | 162,215 | 2,792 | |
| 2018 | 160,607 | 157,939 | 2,668 | |
| 2019 | 157,092 | 153,664 | 3,429 | |
| 2020 | 154,355 | 149,388 | 4,967 | |
| 2021 | 153,161 | 145,113 | 8,048 | |
| 2022 | 132,257 | 140,837 | (8,580) | |
| 2023 | 131,820 | 136,561 | (4,741) | |
| 2024 | 132,056 | 132,286 | (230) | |
| Average BRA Reliability Requirement | | [1]: Average [A] | 151,526 | |
| Standard Deviation of Residuals | | [2]: Std. Dev. [C] | 5,540 | |
| BRA Reliability Requirement Variability | | [3]: [2]/[1] | 3.7% | |

Sources and Notes: All quantities in UCAP MW; [A]: From PJM, 2015/26 to 2024/25 Base Residual Auction Planning Parameters; [B]: Expected value of [A] based on linear trend; [C]: [A] – [B]

A.4 Supply

Unlike the demand curve, the capacity market supply curve is not administratively determined and under the control of PJM. Instead, the supply curve consists of price-quantity pair supply offers by market participants. For our modeling, we use supply curve shapes derived from historical RPM offers from the 2009/10 to 2025/26 Planning Years. These supply curves reflect a wide range of capacity resources offered into the market and account for participant offer levels in response to changing market conditions, rule changes, supply-side constraints, and resource accreditations over time. To prepare these curves for our model, we construct smoothed and normalized supply curves from the 2009/10 to 2025/26 Base Residual Auction offer data. For all supply curves, we smooth price-quantity pairs into 1,000-MW standard blocks, adjust prices for inflation so that all prices are in 2028\$, and normalize MW quantity bids so that the final supply curves quantities are represented as a percentage of BRA Total Supply for each year. The model

employs a cyclical process to select one normalized, smoothed supply curve for use in each model draw. This supply curve is then adjusted to account for the model convergence parameter (represented by the quantity of infra-marginal supply), as well as total supply variability, which is tuned to historically observed levels. The resulting supply curves are shown in Figure 8 above.

By using a range of supply curves, the model captures a substantial range of different possible market conditions that could be faced in RPM, including that may be affected by different market conditions, retirement cost drivers, and other market conditions. In addition to capturing these historical changes via the shape of the supply curves, we adjust the total supply quantity in each draw by adding normally-distributed randomized variability. Similar to the demand variability, the magnitude of this variability parameter is based on historical variability in totally supply offers in the BRA relative to a linear trend. The average historical deviation from the trend is 7,792 UCAP MW, or 4.4% of the average BRA Total Supply from 2015/16 to 2024/25, as summarized in Table 14.

TABLE 14: HISTORICAL VARIABILITY IN BRA TOTAL SUPPLY

| Year | Historical BRA Total Supply [A] (UCAP MW) | Linearized BRA Total Supply [B] (UCAP MW) | Residual Above (Below) Linear Trend [C] (UCAP MW) | |
|---------------------------------|--|--|--|--|
| 2015 | 178,588 | 186,823 | (8,235) | |
| 2016 | 184,380 | 184,488 | (108) | |
| 2017 | 178,839 | 182,153 | (3,315) | |
| 2018 | 179,891 | 179,818 | 73 | |
| 2019 | 185,540 | 177,483 | 8,056 | |
| 2020 | 183,352 | 175,149 | 8,203 | |
| 2021 | 186,505 | 172,814 | 13,691 | |
| 2022 | 167,698 | 170,479 | (2,781) | |
| 2023 | 157,281 | 168,144 | (10,863) | |
| 2024 | 161,088 | 165,809 | (4,722) | |
| Average BRA Total Supply | | [1]: Average [A] | 176,316 | |
| Standard Deviation of Residuals | | [2]: Std. Dev. [C] | 7,792 | |
| BRA Total Supply Variability | | [3]: [2]/[1] | 4.4% | |

Sources and Notes: All quantities in UCAP MW; [A]: From auction data provided by PJM; [B]: Expected value of [A] based on linear trend; [C]: [A] – [B]

A.5 Net Supply Variability

In addition to calibrating the supply and demand variability to the historically observed levels, we tune the net supply variability (i.e., the correlation between supply and demand) to historically observed levels. In the RPM, there is a partial correlation between supply and demand. This correlation in supply and demand is associated with market participants' individual efforts to align their decision-making with anticipated market conditions (i.e., plan ahead to offer more supply when conditions are tight, or defer/retire supply when the market is long). Similarly FRR entities tend to enter and exit the market with a relatively balanced volume of supply and demand. Separately estimating supply and demand variability without accounting for this correlation would overstate the resulting variability in net supply (i.e. total supply minus Reliability Requirement) that produces the effect of market price volatility.

Due to this relationship, we apply a correlation factor between the supply and demand variability to ensure that modeled net supply variability matches the historically observed net supply variability. We estimate the deviation of Net Supply from a linear trend in the same manner as with the other variability calculations, using data from the 2012/13 to 2024/25 Base Residual Auctions to capture a wide range of observed Net Supply values. The historical deviation of Net Supply from the linear trend is 4,145 UCAP MW, as shown in Table 13. This value is equivalent to 2.8% of the average BRA Reliability Requirement from 2012/13 to 2024/25, which sets the BRA Net Supply variability size as implemented in our model.

TABLE 15: HISTORICAL VARIABILITY IN BRA NET SUPPLY (SUPPLY LESS RELIABILITY REQUIREMENT)

| Year | Historical BRA Reliability Requirement [A] (UCAP MW) | Historical BRA Total Supply [B] (UCAP MW) | Historical BRA Net Supply [C] (UCAP MW) | Linearized BRA Net Supply [D] (UCAP MW) | Residual Above (Below) Linear Trend [E] (UCAP MW) |
|---|--|--|--|---|---|
| 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 | 133,732 149,989 148,323 162,777 166,128 165,007 160,607 157,092 154,355 153,161 132,257 131,820 | 145,373 160,898 160,486 178,588 184,380 178,839 179,891 185,540 183,352 186,505 167,698 157,281 | 11,641 10,909 12,163 15,810 18,253 13,831 19,284 28,447 28,996 33,344 35,442 25,461 | 9,907 11,879 13,851 15,823 17,795 19,767 21,739 23,712 25,684 27,656 29,628 31,600 | 1,734 (970) (1,688) (13) 457 (5,936) (2,456) 4,736 3,313 5,688 5,814 (6,139) |
| 2024 132,056 161,088 29,032 Average BRA Reliability Requirement Standard Deviation of Residuals BRA Net Supply Variability | | 33,572 [1]: Average [A] [2]: Std. Dev. [E] [3]: [2]/[1] | (4,540) 149,793 4,145 2.8% | | |

Sources and Notes: All quantities in UCAP MW; [A]: From PJM, 2012/13 to 2024/25 Base Residual Auction Planning Parameters; [B]: From auction data provided by PJM; [C]: [B] – [A]; [D]: Expected value of [C] based on linear trend; [E]: [C] – [D]

List of Acronyms

| BESS | Battery Energy Storage Systems |
|---------|---|
| BGE | Baltimore Gas and Electric Company |
| BRA | Base Residual Auction |
| СС | Combined Cycle |
| CETL | Capacity Emergency Transfer Limit |
| СЕТО | Capacity Emergency Transfer Objective |
| CIFP-RA | Critical Issue Fast Path-Resource Adequacy |
| COD | Commercial Online Date |
| CONE | Cost of New Entry |
| СРІ | Consumer Price Index |
| СТ | Combustion Turbine |
| DPL | Delmarva Power and Light Company |
| E&AS | Energy and Ancillary Services |
| ELCC | Effective Load Carrying Capability |
| EMAAC | Eastern Mid-Atlantic Area Council |
| EUE | Expected Unserved Energy |
| FRR | Fixed Resource Requirement |
| GW | Gigawatt |
| IA | Incremental Auction |
| ICAP | Installed Capacity |
| IESO | Ontario's Independent Electricity System Operator |
| IMM | Independent Market Monitor |
| IRM | Installed Reserve Margin |
| ISO-NE | Independent System Operator of New England |
| LDA | Locational Deliverability Area |
| LOLE | Loss of Load Events |
| LOLH | Loss of Load Hours |
| MAAC | Mid-Atlantic Area Council |
| MISO | Midcontinent Independent System Operator |

| MOPR | Minimum Offer Price Rule |
|-------|--------------------------------------|
| MRI | Marginal Reliability Impact |
| MSOC | Minimum Office Seller Cap |
| MW | Megawatt |
| MWh | Megawatt Hour |
| NYISO | New York Independent System Operator |
| PJM | PJM Interconnection |
| RPM | Reliability Pricing Model |
| RTO | Regional Transmission Organization |
| UCAP | Unforced Capacity |
| VRR | Variable Resource Requirement |

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