BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, Dynegy Inc.,	)	
Eastern Generation, LLC, Homer City	)	Docket No. EL16-49-000
Generation, L.P., NRG Power Marketing	)	
LLC, GenOn Energy Management, LLC	)	
Carroll County Energy LLC,	)	
C.P. Crane LLC, Essential Power, LLC	)	
Essential Power OPP, LLC, Essential	)	
Power Rock Springs, LLC, Lakewood	)	
Cogeneration, L.P., GDF SUEZ Energy	)	
Marketing NA, Inc., Oregon Clean	)	
Energy, LLC, and Panda Power	)	
Generation Infrastructure Fund, LLC	)	
v.	)	
PJM Interconnection, L.L.C.	)	
	)	ER18-1314-000, -001
PJM Interconnection, L.L.C.	)	
	)	EL18-178-000
PJM Interconnection, L.L.C.	)	(Consolidated)

COMMENTS OF THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION TO PJM'S FIRST COMPLIANCE FILING CONCERNING THE MINIMUM OFFER PRICE RULE

The Pennsylvania Public Utility Commission (PAPUC) herein files these Comments in response to the Compliance Filing of PJM Interconnection, L.L.C., (PJM) Concerning the Minimum Offer Price Rule filed on March 18 2020, regarding capacity market rule changes to PJM's Open Access Transmission Tariff (OATT or Tariff) addressed in the Federal Energy Regulatory Commission's (FERC or Commission) Order dated December 19, 2019.[1]

I. SUMMARY OF PAPUC COMMENTS

The PAPUC comments to PJM's Compliance Filing are summarized in the following three main points:

A. Minimum Offer Price Rule (MOPR) prices should not be "maximum offer prices" but prices that reflect actual costs of competitive entry.

B. Price escalation factors should be rejected, absent clear historical and empirical evidence of their applicability. For newer declining cost technologies, annual price adjustments should be adopted to reflect current and projected nominal costs at the time of development.

C. The Commission should ensure adequate flexibility for all economic parameters to capture unique characteristics of each unit under the Resource Specific Exemption (RSE) process.[2]

In its comments herein, the PAPUC draws attention to a few key deficiencies in the Compliance Filing. First, initial Gross Cost of New Entry (Gross CONE)[3] should reflect the future cost of a new generation unit of an efficient operator. Non-verified adders, while permitted to establish maximum offer prices for marginal operators, should be eliminated for the purposes of estimating Gross CONE for minimum offer prices.

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[1] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) (December 19 Order).
[2] A resource-specific exception "allows Capacity Market Sellers to demonstrate that the costs of their resources are less than the applicable default MOPR floor price and thus re-set the resource's applicable MOPR floor price down to a level that represents the resource's actual costs (excluding the impact of any State Subsidies)." *PJM Interconnection, L.L.C.*, Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for an Extended Comment Period of at Least 35 Days, Docket No. ER18-1314 (March 18, 2020) at 3 (Compliance Filing).
[3] "The gross CONE values reflect an estimate of the 'nominal-levelized' annual cost to construct and develop a new greenfield construction for the resource type." Compliance Filing at 53.

Gross CONE assumptions should also mirror the characteristics of generation resources that seek to enter the market in PJM's generation queue. Lastly, energy offer adders used for the purpose of determining NetCONE[4] to calculate *maximum* offer prices, should also be rejected, as such adders often do not reflect the true cost structures of new, efficient operators. In summary, MOPR prices should establish *minimum* prices, not *maximum* prices, in order to avoid over-mitigation of PJM's competitive market, impose unjust and unreasonable costs on consumers, and insert barriers to competitive entry.

Second, the PAPUC is concerned that PJM's traditional price escalation factors do not reflect historical cost trends for changes in Gross CONE. Specifically, PJM has not established any historical relationship between the cost of new wind, solar, or battery generation technologies and their proposed escalation indices. In fact, the opposite trend is evident: PJM's existing and proposed price indices rise over time, while the Gross CONE of the above-referenced generation technologies declines over time. This trend is observed in even the more traditional gas-fired generation units and can be explained with technology advancements, economies of scale in production and plant size, and improvements in productivity and efficiency. PJM's escalation factors fail to capture these key drivers of future costs, and the proposed four-year review period is insufficient to correct the omissions given the magnitude of the declining costs. The PAPUC offers some alternatives for consideration by the Commission to correct these deficiencies.

[4] "Net CONE represents the amount of capacity market revenues that a resource would need to justify the investment." Compliance Filing, Attachment D at 4.

Third, the PAPUC recommends that Commission allow maximum flexibility under PJM's proposed RSE offer process, including flexibility with respect to each of the six financial parameters.

II. COMMENTS

A. MOPR Prices Should Not Be "Maximum Offer Prices" But Prices That Reflect Actual Cost Of Competitive Entry.

1. The Commission Should Not Allow The Use Of Speculative Cost Adders In Setting The Minimum Offer Price Of A Given Resource.

The establishment of a minimum price should reflect the actual cost of a given resource to enter the market. However, PJM's calculations and cost projections for various technologies contain undocumented and speculative costs in the form of "cost adders" that should be removed in order to ensure that MOPR prices do not mitigate truly competitive project outcomes. The PAPUC does not take a position as to the appropriateness of cost adders in the calculation of NetCONE for the Variable Resource Requirement Curve used for purposes of mitigating market power or determining the reliability requirements that necessitate the calculation of *maximum* prices. The purpose of NetCONE therein is to calculate the maximum price offer for a given resource, whereas the MOPR in this proceeding serves an entirely different purpose – the establishment of *minimum* prices used to mitigate the impact of state subsidies. This distinction was acknowledged by the Commission when it envisioned the establishment of separate prices for the MOPR and the Market Seller Offer Cap:

> We therefore find that it is just and reasonable for PJM's Tariff to use one definition of a competitive offer to set the

> default capacity market seller offer cap for supplier-side market power mitigation and a different one for the purpose of setting the default offer price floor.[5]

In recognition of this distinction, the default offer price floor should reflect *actual* costs of projects, as adjusted for projected unit cost *increases or decreases* by technology, and changes in unit efficiencies over time. In calculating actual costs, adders should be excluded, because the detailed cost build-up for each technology may already embed such costs in the estimates. Competitive projects that clear the auctions should not be penalized for effectively minimizing such speculative cost elements. Examples of cost adders include the contingency fee of 10% of engineering, procurement, and construction ("EPC")[6] and "owner-furnished equipment" (OFE) costs adders[7] embedded in PJM's Gross CONE calculations. For instance, PJM's estimates for the EPC contingency for a combustion turbine (CT) plant are \$16.0 million to \$20.2 million,[8] and \$69.2 million to \$77.3 million for a combined cycle (CC) plant.[9] Similarly, PJM assumes an owner's contingency of 8% of Owner's Costs.[10] PJM's estimates for the owner's

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[5] December 19 Order at ¶ 152.

[6] SAMUEL A. NEWELL ET AL., THE BRATTLE GROUP, PJM COST OF NEW ENTRY (April 19, 2018) at 25, https://www.pjm.com/~/media/library/reports-notices/reliability-pricing-model/20180425-pjm-2018-cost-of-new-entry-study.ashx. "'Contingency' covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, similar to the EPC contractor fee." *Id.*

[7] "Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, etc." *Id*. at 28.

[8] *Id.* at 22.

[9] *Id*. at 23.

[10] *Id*. at 28.

contingency for a combustion turbine (CT) plant are $4.2 million to $4.7 million,[11] and $8.1 million to $9.5 million for a combined cycle (CC) plant.[12] From a technical perspective, if such costs are based on historical actual plant, equipment and labor costs, such contingencies should already be embedded in other cost elements. If project costs are based on perfect execution, theoretical plant, equipment and labor costs, then contingency costs are perhaps more realistic and appropriate. As PJM has not provided sufficient information to justify its contingency cost adjustments, such adjustments should be rejected and NetCONE values recalculated, absent additional testimony justifying the appropriateness of these cost adders.

PJM also proposes to include a 10% cost adder in the method used to estimate net energy revenue offsets, in order to be consistent with the 10% margin sellers are allowed to include in their energy market offers.[13] As with the other adders, these are not verified cost elements, but speculative costs that may not apply in every situation. In previous filings, PJM has attempted to justify this adder by referencing various uncertainties confronting a seller who prepares an energy market offer, including assumptions regarding the applicable gas index hub, day-ahead versus intra-gas use, and assigned LMP.[14]

However, PJM has provided no explanation why such speculative costs should be used here to set *minimum* offer prices. Even Brattle's report, upon which PJM has relied

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[11] *Id*. at 22.
[12] *Id*. at 23.
[13] *PJM Interconnection, L.L.C.*, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER19-105-000 (October 12, 2018) at 2 (PJM Periodic Review Filing).
[14] *Id.,* Attachment C at 6.

for review of the 10% cost offer adder in the past, has noted its speculative use, as follows:

> PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. *However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices*. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM's Operating Agreement to the variable operating costs of the CTs in the simulations."[15]

Therefore, Brattle's findings establish that, depending on the competencies of the plant operator, the 10% cost offer adder may not be necessary. This finding, coupled with the goal of designing "minimum" offer prices for generation resources, supports the exclusion of cost adders that serve as barriers to competitive entry for an efficient market participant.[16] Such adders have the potential to overstate operational costs and understate

[15] *Id.*, Attachment G, Exhibit No. 2 at 23–24 (emphasis added).

[16] PAPUC acknowledges, again, that for reliability circumstances, a 10% adder may be appropriate for maximum prices for the purposes of market power mitigation and establishing the NetCONE values incorporated into VRR curve, if the goal is to achieve a conservative outcome for reliability purposes. As noted before, the Commission has been clear that the MOPR prices have a different function and definition than the MSOC. *See* December 19 Order at ¶ 152; *Calpine Corp. v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,035 (2020) at ¶ 194 (April 16 Rehearing Order).

net energy and ancillary revenues for efficient operators – the very sort of operators who should operate in a competitive market and are more likely to clear in the BRA.

2. The Commission Should Not Allow The Use Of PJM's Proposed Adjustment Factor In Setting The Minimum Offer Price Of A Given Resource.

In Section 6.8 (a) of the Tariff, PJM allows an Adjustment Factor equal to 1.10 to provide a margin of error for understatement of costs. This Adjustment Factor is then added to an additional adjustment referencing the 10-year average Handy-Whitman Index (HWI) in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.[17] Given the Commission's new directive to expand PJM's calculations of Avoidable Cost Rates (ACR)[18] to all resources, any proposed escalation of costs and adders should be affirmed by empirical data. Historically, the HWI index has significantly over-stated projections of Gross CONE values, as further discussed below. Moreover, PJM has provided no quantitative analysis for the additional 10% Adjustment Factor, in addition of the HWI inflation factors for these resources. The 10% Adjustment Factor should be rejected for the purposes of MOPR calculations, absent further historical empirical evidence applicable to each technology.

[17] Compliance Filing at 77 n.244. *See also* Compliance Filing, Attachment C, Section 6.8.
[18] Net ACR is a value that "estimates how much revenue the resource requires (in excess of its energy and ancillary service revenue) to provide capacity in the given year." *Id.* at page 66.

3. The Commission Should Require Downward Adjustments To PJM's Gross CONE Values For Onshore Wind Facilities.

PJM has selected a clear high-end outlier for its baseline Gross CONE value for onshore wind facilities. In the Compliance Filing, PJM has proposed to use the U.S. Energy Information Administration (EIA) 2019 value of $1,677/kW, which is 14% higher than any alternative published value, and falls even outside the range of values of Lazard ($1,100/kW-$1,500/kW).[19] It appears that the key driver for PJM's higher Gross CONE figures for onshore wind is related to the selection of wind farm project size. PJM's Gross CONE value for onshore wind is based on EIA Case 21, which assumes a 17 x 2.8 MW configuration (50 MW).[20] However, PJM's current interconnect queue as of May 6, 2020, for onshore wind projects shows an average project size of 205MW over 80 projects.[21] Absent PJM providing further evidence of the proper and more realistic wind farm size for future projects, the PAPUC recommends using a Gross CONE for onshore wind facilities for a 200 MW facility, using the same reference document utilized by PJM (EIA Case 20), adjusted for removal of any undocumented contingency fees, as discussed above. Doing so would reflect an unadjusted Gross CONE value of $1,265/kW[22], which lies squarely between the estimates provided by Lazard.

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[19] *Id.*, Attachment E, Appendix A to Keech Affidavit.

[20] *Id.*, Attachment E, Appendix A to Keech Affidavit, Descriptions and Costs of Reference Resources & Sources of Technology Costs.

[21] PJM New Services Queue, https://www.pjm.com/planning/services-requests/interconnection-queues.aspx (last visited May 6, 2020).

[22] U.S. ENERGY INFORMATION ADMINISTRATION, CAPITAL COST AND PERFORMANCE CHARACTERISTIC ESTIMATES FOR UTILITY SCALE ELECTRIC POWER GENERATING TECHNOLOGIES (February 2020) at 20-3, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

B. Price Escalation Factors Should Be Rejected, Absent Clear Historical And Empirical Evidence Of Their Applicability. For Newer Declining Cost Technologies, Annual Price Adjustments Should Be Adopted To Reflect Current And Projected Nominal Costs At The Time Of Development.

PJM has historically used various indices to escalate MOPR parameters for purposes of calculating going-forward costs and accounting for inflation. As an example, PJM's OATT applies the following annual escalators to MOPR parameters:

1. Applicable ACR rates, using the Handy-Whitman Index of Public Utility Construction Costs or a comparable index to update the base values for the Delivery Year, and for future Delivery Years.[23]

2. CONE values, using the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index year annual average rate of change.[24]

In the Compliance Filing, PJM has proposed to expand use of the BLS Composite index Gross CONE escalator factors beyond CONE values for Combustion Turbine (CT) and Combined Cycle Natural Gas (CCNG) plants to include solar, wind, and battery resources, among others.[25] Specifically, PJM has proposed to use a BLS composite index, slightly modified for use for other resources as follows:

> As prescribed by the Tariff, this index is "a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 25%)." As Mr. Keech explains, for all other resource types, PJM will replace the "BLS Producer Price Index Turbines and Turbine Generator Sets" index with the BLS's "Producer Price Index for Goods

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[23] PJM Open Access Transmission Tariff, 3551–53 (Effective Date: 9/23/2019 - Docket No. ER19-2417-001, pages 17–19) (last accessed May 12, 2020) https://www.pjm.com/directory/merged-tariffs/oatt.pdf.

[24] PJM Open Access Transmission Tariff, 3499 (Effective Date: 1/17/2019 - Docket No. ER19-105-001, page 6) (last accessed May 12, 2020) https://www.pjm.com/directory/merged-tariffs/oatt.pdf.

[25] Compliance Filing at 55.

> Less Food and Energy, Private Capital Equipment" index, with no change to the relative weight of each index.[26]

PJM has presented no data or testimony establishing that such indices reflect historical escalation factors or going forward cost trends for any of these resources. Using the same references provided by PJM in their Compliance Filing, historical data clearly shows that Gross CONE values are consistently declining for solar and wind resources. Specifically, new Crystalline Solar PV resources nominal levelized cost of energy (LCOE) have declined from $359/MWh to $41/MWh between 2009 and 2019.[27] During the period for which PJM has applied the previous BLS composite index, these solar resources costs have *declined* from $64/MWh to $40/MWh, or 38% between 2015 and 2019.[28] During this same period, the BLS Composite index applied to CCNG plants *increased* between 2.46% and 12.36%, depending on the PJM zone. Even adjusting for inflation, the real installed costs of solar have declined substantially since 2010. Between 2010 and 2018, the installed cost of utility scale solar tracking PV systems has dropped from 2018 Real $6.34/W-AC to $1.59/W-AC on a capacity weighted basis. [29] PJM Compliance Filing references also forecast potential declines in Solar Utility PV CAPEX costs.[30]

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[26] *Id.*
[27] LAZARD, LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS – VERSION 13.0 (November 2019) at 7, https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf (LAZARD).
[28] *Id.*
[29] MARK BOLINGER ET AL., LAWRENCE BERKELEY NATIONAL LABORATORY, SOLAR ENERGY TECHNOLOGIES OFFICE, U.S. DEPARTMENT OF ENERGY, UTILITY-SCALE SOLAR: EMPIRICAL TRENDS IN PROJECT TECHNOLOGY, COST, PERFORMANCE, AND PPA PRICING IN THE UNITED STATES – 2019 EDITION (December 2019) Report at 21, Figure 10, https://emp.lbl.gov/publications/utility-scale-solar-empirical-0 (UTILITY-SCALE SOLAR).
[30] NATIONAL RENEWABLE ENERGY LABORATORY, U.S. DEPARTMENT OF ENERGY, Annual Technology Baseline: Electricity, https://atb.nrel.gov/.

The technical resource used by PJM, *USEIA Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generation Technologies*, acknowledged these declining solar unit cost trends, specifically noting:

> Solar prices have been dropping due to reductions in equipment costs as well as the required construction labor. As solar modeling software advances, projects are able to optimize layouts and ground coverage for lowest levelized cost of energy, thereby allowing for reduced civil expenditures on a per kilowatt basis. Solar modules that are arriving on the market have a net potential of 1500 V rather than the previous standard of 1000 V. This increased net potential allows for lower wiring losses, which increases the net energy yield and lower wiring material costs to reduce the capital cost. Additionally, strides have been made to make modules more efficient to increase their power rating and lighter in weight to allow for reduced transportation and installation cost. Electrical components have been dropping in price, especially the inverters. As solar development advances and matures, EPC contractors and developers have also been bearing less contingency and overhead, further reducing a solar project's overall price.[31]

It is clear that these types of technology improvements, economies of scale and labor hour reductions are not captured in the proposed BLS Composite index. Furthermore, while installed costs for solar have been dropping, module efficiencies have been increasing every year. In general, module efficiencies have improved consistently, with improvements of 1-2% every 4 years. For instance, in 2017, the module efficiency was listed as 17.4%,[32] which translates into a relatively robust increase in energy

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[31] U.S. ENERGY INFORMATION ADMINISTRATION, CAPITAL COST AND PERFORMANCE CHARACTERISTIC ESTIMATES FOR UTILITY SCALE ELECTRIC POWER GENERATING TECHNOLOGIES (February 2020) at 24-4, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[32] GALEN L. BARBOSE ET AL., LAWRENCE BERKELEY NATIONAL LABORATORY, U.S. DEPARTMENT OF ENERGY, TRACKING THE SUN: INSTALLED PRICE TRENDS FOR DISTRIBUTED PHOTOVOLTAIC SYSTEMS IN

revenues of 5.7% to 11.5% every 4 years. Such an abrupt update to module efficiencies every 4 years, as proposed by PJM, would result in significant overstatement of NetCONE values for solar PV units in the intervening years.

Similarly, for new onshore wind resources, nominal LCOE costs have declined from $135/MWh to $41/MWh from 2009 to 2019.[33] During the period for which PJM has applied the previous BLS composite index (2015-2019), these wind resources have declined in cost from $55/MWh to $41/MWh,[34] or 25%, while the existing CCNG BLS Composite index has *increased* between 2.46% to 12.36%. Wind generation efficiencies have also been steadily increasing, as turbine height, blade length and other related wind technologies have evolved. Capacity factors have increased from approximately 25% in 1998 to a range of 34%-47% in 2017, depending on the wind resource quality.[35] PJM's reference resources also forecast potential increases in wind capacity factors.[36] Such substantial increases in efficiency must be accounted for on a more concurrent basis than every 4 years.

THE UNITED STATES - 2018 EDITION (September 2018) at 15, Figure 7, https://emp.lbl.gov/publications/tracking-sun-installed-price-trends.

[33] LAZARD, *supra* note 27, at 7.

[34] *Id.*

[35] U.S. DEPARTMENT OF ENERGY, OFFICE OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, 2018 WIND TECHNOLOGIES MARKET REPORT (2018) at 44, Figure 41, https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf (2018 WIND TECHNOLOGIES MARKET REPORT).

[36] NATIONAL RENEWABLE ENERGY LABORATORY, U.S. DEPARTMENT OF ENERGY, Annual Technology Baseline: Electricity, https://atb.nrel.gov/.

Similarly, the capital cost of battery energy has declined precipitously, from over $1,100/kwh in 2010[37] to approximately $230/kwh in 2018.[38] Further, advances in new battery technologies may lead to battery capital costs as low as $30/kwh - $50/kwh by 2030.[39] For battery packs, Bloomberg concluded the following:

> From the observed historical values, we calculate a learning rate of around 18%. This means that for every doubling of cumulative volume, we observe an 18% reduction in price. Based on this observation, and our battery demand forecast, we expect the price of an average battery pack to be around $94/kWh by 2024 and $62/kWh by 2030. It's necessary here to highlight that this is the expected average price. Of course, some companies will undershoot and go to the market with lower prices, sooner. Others will be higher. Different cell and pack designs, a range of cathode chemistries on offer, economies of scale and regional differences will ensure there is a range in the market."[40]

Given this clear fact pattern and consistent price trends of more than a decade, it is unreasonable for PJM to assume that prices will increase for battery, solar and wind technologies. Further, it is also unreasonable to assume that efficiencies to these developing technologies will no longer improve. PJM's proposal to limit review of prices and efficiency assumptions at least every four years, will translate to unjust and unreasonable prices for consumers and will create unjustified barriers to market entry.

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[37] CHARLIE BLOCH ET AL., ROCKY MOUNTAIN INSTITUTE, BREAKTHROUGH BATTERIES: POWERING THE ERA OF CLEAN ELECTRIFICATION (January 2020) at 16, https://rmi.org/wp-content/uploads/2019/10/rmi_breakthrough_batteries.pdf.

[38] *Id.* at 76.

[39] *Id.* at 76–77.

[40] Logan Goldie-Scot, *A Behind the Scenes Take on Lithium-Ion Battery Prices*, BLOOMBERGNEF (March 5, 2019) https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/.

The PAPUC offers several practical and reasonable solutions to resolve these inaccuracies. As to unit costs, PJM could use any one of its referenced reports[41] to adjust the Gross CONE values on a percent of change basis annually when annual updates to actual values are published. To the extent PJM is concerned that such annual updates may not be provided, PJM can use the reference documentation provided herein to establish pricing trends and make more reasoned extrapolations of future prices. Extrapolations for annual declines in unit Gross CONE values could be assumed, as discussed below.

For projections of Gross CONE for Solar PV technologies, the installed prices have declined drastically, as noted above. The long-term average geometric mean of annual price declines has ranged from 25% in nominal LCOE,[42] to 19% in 2018 constant dollar installed capacity cost terms.[43] Additionally, the PAPUC recommends that annual energy gains for solar generation be incorporated into the annual NetCONE determinations. Historical efficiency gains in solar energy generation of 5.7% to 11.5% every 4 years have been documented above. PJM should include a reasonable estimate of future solar energy efficiency gains in their subsequent compliance filing, as such revenue improvements can have substantial impacts on NetCONE MOPR values between quadrennial review periods, because variable costs are essentially zero.

[41] Compliance Filing, Attachment E, Appendix A to Keech Affidavit, Sources of Technology Costs.
[42] LAZARD, *supra* note 27, at 7.
[43] UTILITY-SCALE SOLAR, *supra* note 29, at 21, Figure 10.

As for projected declines in wind turbine installed costs, both historical trends and DOE projections anticipate wind generation costs to decline. As noted by DOE:

> This is a decrease of nearly $1,000/kW from the peak in average costs in 2009 and 2010, but is roughly on par with the costs experienced in the early 2000s—albeit with much larger turbines and improved performance. Early indications from a sample of projects currently under construction suggest that somewhat lower costs are on the horizon, with some developers reporting costs in the $1,100–$1,250/kW range."[44]

There has been a relatively linear long-term decline in constant dollar installed cost of wind generators documented by DOE, reflecting a 6.1% geometric average decline in costs between 2009 and 2018,[45] and more recent data, reflecting a geometric average of 4.7% decline in LCOE of wind turbines between 2016 and 2019.[46] Based on this data, maintaining a fixed Gross CONE value is very likely to overstate Gross CONE by over 15% by Year 4. Therefore, the PAPUC recommends that PJM be directed to determine a reasonable de-escalation value, consistent with historical trends, so as not to overstate Gross CONE values between quadrennial review periods.

As for projections of wind turbine efficiency improvements, the PAPUC recommends that PJM include an annual efficiency adjustment, consistent with the long-term trends of new wind generation units noted in the 2018 DOE Wind Technologies Market Report study,[47] subject to further update at least every four years. Average annual historical efficiency improvements have ranged from 0.5% to 1.2%, depending on

[44] 2018 WIND TECHNOLOGIES MARKET REPORT, *supra* note 35 at x–xi.
[45] *Id*. at 51, Figure 46.
[46] LAZARD, *supra* note 27, at 7.
[47] 2018 WIND TECHNOLOGIES MARKET REPORT, *supra* note 35 at 44 (Figure 41), 51 (Figure 46).

wind quality.[48] Wind efficiency assumptions can have a substantial impact on NetCONE values, as variable costs of generation are essentially zero.

Given the documented historical decline in battery prices and the forecast for further declines in battery costs, the PAPUC recommends that PJM include an annual price de-escalation value in its next MOPR compliance filing. Historical battery costs have declined at a geometric mean of 26.6% per year between 2010 and 2018 on a constant dollar basis,[49] while future battery cost projections may be as low as $30/kwh to $50/kwh by 2030. Failure to account for these likely declines in installed battery prices can lead to substantial overstatement of battery Gross CONE values by Year 4, given the consistent and steady drop in battery prices.

PJM also proposes to annually increase Gross CONE values of CCNG plants by the BLS composite index, as described herein. However, a brief review of historic estimates of Gross CONE values shows that PJM's Handy Whitman and BLS composite escalation factors have been a poor proxy for long term Gross CONE values. Pursuant to the latest filings, EMAAC and SWMAAC Updated 2022/2023 CONE Values for CCNG plants without major maintenance are $116,000 MW-Yr, and $120,200 MW-Yr,[50] respectively, and $126,400 MW-Yr and $130,600 MW-Yr, respectively, including major maintenance.[51] The oldest documented EMAAC and SWMAAC prices for PJM date

[48] *Id.*
[49] Goldie-Scot, *supra* note 40.
[50] PJM Periodic Review Filing, Attachment E, Exhibit No. 2 at 52.
[51] *Id.* at 68. Major maintenance costs were historically included in Gross CONE values. Gross CONE values were recently modified by the Commission to exclude major maintenance costs. In an effort to have a more comparable cost, both calculated Gross CONE values are provided herein to present a more equivalent analysis. *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 (2019) at ¶¶ 135–36.

back to the 2011 BRA when Gross CONE values were $175,250/MW-Yr in CONE Area 1 (EMAAC) and $154,870/MW-Yr in CONE Area 2 (SWMAAC). Thus, overall Gross CONE values for CCNG plants have *actually declined between Delivery Years 2014 and 2022 by 16% to 28%*, for CONE Areas 1 and 2. During this period of time, PJM has used the Handy-Whitman Index, which escalated Gross CONE values a cumulative 20% for CONE Areas 1 and 2 between Delivery Years 2014-2017.

Subsequently, PJM started using the BLS Composite index, which increased Gross CONE values for Delivery Years 2019-2022 by an additional cumulative 2.46% to 12.36% between 2015 and 2019 BRAs for CCNG units. While some downward resets to Gross CONE costs were implemented in the 2016 and 2018 Delivery Years during the Triennial Review process, the trends here are clear. As a result of economies of scale, competition, and technology advancements, nominal costs of CCNG Gross CONE do not increase over time in correlation with any established composite indices as proposed by PJM. Therefore, the PAPUC recommends that the Commission reject using annual escalation factors to calculate Gross CONE costs for CCNG plants in subsequent BRAs. The PAPUC recommends such costs be held constant until the next formal review of CCNG Gross CONE costs, unless PJM provides compelling facts to demonstrate that economies of scale, industry competition, technology innovation or other major cost factors will be altered over the next 4 years.

Lastly, PJM fails to also account for long term efficiency gains in CCNG resources between quadrennial reviews. In PJM's 2011 Triennial review, PJM established a heat rate value of 6,722 Btu/kWh, without duct firing, which corresponds to a heat rate of 6,914 Btu/kWh, with duct firing.[52] In PJM's recent Quadrennial review, the reference CCNG resources were updated for efficiencies of 6,312 Btu/kWh, without duct firing and 6,553 with duct firing.[53] Thus, CCNG long term efficiencies are improving by 5% to 6% every 7 years, or an average of 0.7% to 0.9% per year, depending on duct burning status. The PAPUC recommends that PJM include an annual efficiency improvement factor based on historical technology trends, absent compelling evidence that such efficiency improvements will cease.

In summary, PJM's proposal to use existing, or even slightly modified BLS escalators in establishing Gross CONEs for various generation technologies for subsequent BRAs is not just and reasonable. PJM has not established any correlation between historical Gross CONE values and their proposed escalation indices. In fact, the exact opposite is the case. The escalators have projected increased estimated future costs, while actual Gross CONE values have declined, some quite drastically. The new BLS Composite indices will not change this fact. Over the 2010 to 2018 period, the existing BLS Composite Index has resulted in a cumulate price increase of 19.4%.[54] PJM has proposed to replace the "BLS Producer Price Index Turbines and Turbine Generator

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[52] JOHANNES PFEIFENBERGER ET AL., THE BRATTLE GROUP, SECOND PERFORMANCE ASSESSMENT OF PJM'S RELIABILITY PRICING MODEL (August 26, 2011) at 79, Table 15, https://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110826-brattle-report-second-performance-assessment-of-pjm-reliability-pricing-model.ashx.
[53] SAMUEL A. NEWELL ET AL., THE BRATTLE GROUP, PJM COST OF NEW ENTRY (April 19, 2018) at 14 (Table 5), https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.
[54] U.S. BUREAU OF LABOR STATISTICS, BLS Series Reports (Indices WPUFD41312, PCU333611333611, WPUID612, ENU340005052371, ENU240005052371, ENU390005052371, ENU420005052371), http://data.bls.gov/cgi-bin/srgate (last visited May 11, 2020).

Sets" index with the BLS's "Producer Price Index for Goods Less Food and Energy, Private Capital Equipment" index, with no change to the relative weight of each index.[55] Had this change been implemented earlier, the cumulate price increase would have been even higher at 21.5% between 2010 and 2018.[56]

PJM should be directed to either adopt a method of annual updates to Gross CONE values based on actual year-to-year changes to resource technology costs referenced in EIA or other acceptable reports, or determine an appropriate historic geometric mean or arithmetic mean calculation to approximate these declining cost trends. Lastly, PJM should include annual resource efficiency adjustments for certain advancing technologies to avoid over mitigation of competitive offers, as reflected in the NetCONE calculations.

C. The Commission Should Ensure Adequate Flexibility For All Economic Parameters To Capture Unique Characteristics Of Each Unit Under The Resource Specific Exemption (RSE) Process.

While the PAPUC has opposed the application of a MOPR to non-subsidized resources as a matter of competitive market policy, the Commission has decided to apply the MOPR to unsubsidized gas-fired CTs and CCNGs,[57] and additionally may apply the MOPR to other unsubsidized resources participating in utility default service procurements.[58] Therefore, it is essential that the Commission provide maximum

[55] Compliance Filing at 55.
[56] U.S. BUREAU OF LABOR STATISTICS, BLS Series Reports (Indices WPUFD41312, PCU333611333611, WPUID612, ENU340005052371, ENU240005052371, ENU390005052371, ENU420005052371), http://data.bls.gov/cgi-bin/srgate (last visited May 11, 2020).
[57] April 16 Rehearing Order at ¶302.
[58] *Id.* at ¶386.

flexibility under PJM's proposed Resource Specific Exemption offer process, including flexibility with respect to each of the six financial parameters and not just the twenty-year life parameter. These financial modeling assumptions include: (i) nominal levelization of gross costs, (ii) asset life of 20 years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use of first year revenues, and (vi) weighted average cost.

The Commission has in the past recognized the use of the real levelization method of determining Net CONE values.[59] Although the Commission found nominal levelization as just and reasonable, the Commission, in the same breath acknowledged the flexibility for generators to use real levelized methods in the unit specific review process. As to asset life, the PAPUC supports PJM's proposal to allow offers of up to 35 years in the RSE process.[60] As to residual value, PJM should provide flexibility for the recognition of residual values, especially with regard to unique situations were real estate or Capacity Injection Rights (CIRs) can be sold at the end of a project life, or upon refiring or repowering of a generation unit.[61] Moreover, the PAPUC agrees with PJM that a generation resource developer should have the flexibility to provide unit specific

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[59] *PJM Interconnection, L.L.C., reh'g denied*, 137 FERC ¶ 61,145 at ¶ 33 (2011) (2011 MOPR Rehearing Order) ("[I]n our partial acceptance of PJM's compliance filing, project sponsors seeking an offer price floor lower than the MOPR screen will have recourse to a unit-specific, cost-justification review process that may include alternative levelization methods, among other proposed cost assumptions. Accordingly, while we continue to find the nominal levelized method to be just and reasonable for the initial screening of offers, we will grant rehearing (as discussed below) with respect to unit-specific offers *and permit project sponsors the opportunity to justify the use of a real levelized method with respect to their specific processes*.") (emphasis added).

[60] Compliance Filing at Attachment B, Section 5.14(h)(3)(B).

[61] While not all CIRs have value, sale of CIRs in certain transmission constrained areas is more likely, as recently reflected in Queues AF1-101 and AB2-091. PJM New Services Queue, https://www.pjm.com/planning/services-requests/interconnection-queues.aspx (last visited May 6, 2020).

cost data which accurately reflects, in all material respects, the seller's reasonably expected costs of new entry.

IV. CONCLUSION

For all the foregoing reasons, the PAPUC respectfully requests that its Comments be considered by FERC in this proceeding. We urge the Commission to adopt our recommendations and direct PJM to implement them.

Respectfully submitted,

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Dated: May 15, 2020

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I am on this date serving a copy of the foregoing document upon each person designated on the official service list compiled by the Federal Energy Regulatory Commission in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Respectfully submitted,

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