UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. ) Docket No. ER19-1486-000
) )
PJM Interconnection, L.L.C. ) Docket No. EL19-58-003
) Not Consolidated

Public Interest and Customer Organizations’ Partial Protest of and Comments on PJM’s Compliance Filing Regarding Energy and Ancillary Service Offset

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I. Introduction

Pursuant to Rule 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (“FERC” or the “Commission”),1 the Sierra Club, Natural Resources Defense Council (“NRDC”), the Sustainable FERC Project, Office of the People’s Counsel for the District of Columbia, Maryland Office of the People’s Counsel, Delaware Division of the Public Advocate, PJM Industrial Customer Coalition, Pennsylvania Office of Consumer Advocate, and New Jersey Division of Rate Counsel (collectively, “Public Interest and Customer Organizations” or “PICOs”) offer the following partial protest of and comments on PJM Interconnection, L.L.C.’s (“PJM”) August 5, 2020 Compliance Filing concerning modifications to the PJM Open Access Transmission Tariff to implement a forward-looking energy and ancillary services (“E&AS”) revenue offset.2

In its May 21, 2020 Order, the Commission found that its approval of reserve market changes “render[ed] PJM’s existing methodology for calculating the energy and ancillary services offset (E&AS Offset) in PJM’s capacity market unjust and unreasonable,” and required PJM to develop a forward-looking E&AS Offset in order to ensure that capacity prices going forward reflected the expected increases in energy and ancillary service revenues resulting from fundamental changes to PJM’s reserve market design.3

PICOs strongly support moving toward a forward-looking E&AS Offset for the PJM capacity market, which is necessary to avoid the unreasonable result of consumers having to pay

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1 18 C.F.R. § 385.213.
capacity prices that reflect historically lower E&AS revenues, even while E&AS revenues will increase as a result of PJM’s reserve market design changes. However, PICOs submit this partial protest and comments to note flaws in several components of PJM’s methodology that will undermine the Commission’s objective to improve the E&AS Offset’s accuracy.

First, PJM has arbitrarily added 10% to the cost-based energy market offers of the reference combustion turbine (“CT”) unit when simulating its bidding behavior and resulting energy and ancillary service revenues, which significantly reduces the net revenues earned by that unit and therefore inflates the net cost of new entry (“Net CONE”) that anchors the Variable Resource Requirement (“VRR”) Curve. Second, PJM’s proposed method for estimating ancillary service revenues will also tend to underestimate those revenues, producing an inflated VRR curve. Finally, PJM’s approach to constructing the hourly locational prices for the simulations relies on mismatched energy and fuel prices that undermine the accuracy of the offset in certain circumstances.

The undersigned organizations request that the Commission reject PJM’s proposal to use the 10% adder when developing the E&AS Offset for the reference CT unit. Because it is a simple matter to remove this adder from the simulations, this adder should be rejected as an element of PJM’s compliance filing. In contrast, the second and third issues raised in this partial protest will require more work by PJM and stakeholders. PICOs do not favor further delay of the Base Residual Auction (“BRA”) for the 2022/2023 Delivery Year and, thus, do not favor delaying that BRA while these flaws in the E&AS Offset methodology are addressed. However, it is imperative that these flaws in the E&AS Offset methodology be corrected in time for the BRA for the 2023/2024 Delivery Year. Therefore, the undersigned organizations urge the Commission to accept PJM’s filing with these aspects intact for purposes of conducting the BRA
for the 2022/2023 Delivery Year, but require PJM and stakeholders to develop an updated methodology addressing the ancillary service and gas/electric misalignment issues, in a manner that addresses the concerns raised in this partial protest, sufficiently in advance of the BRA for the 2023/2024 Delivery Year. PICOs suggest a compliance filing date for these further changes of no later than January 31, 2021, which would allow for an expedited but fulsome stakeholder process while still permitting enough time for those changes to be reviewed by the Commission ahead of the 2023/2024 BRA. Implementing an interim approach for the next BRA, while requiring a fully robust methodology for the subsequent BRA, appropriately balances competing interests and is well within the Commission’s Section 206 authority to fashion a just and reasonable replacement rate.

II. Legal Standards

As the Commission pointed out in its May 21 Order, “[h]aving found pursuant to a section 206 that PJM’s methodology for calculating the E&AS Offset is unjust and unreasonable, the burden falls on the Commission to determine the just and reasonable replacement rate.”4 As the D.C. Circuit has held, when FERC exercises its Federal Power Act (“FPA”) Section 206 authority to set a new rate, the Commission must show there was substantial evidence to support the reasonableness of its change in methodology.5

The FPA’s mandate that prices be just and reasonable requires balancing utility and consumer interests.6 Consumers’ wholesale electricity costs consist of the various revenue streams that suppliers receive from PJM’s markets. As such, the market rate is only just and

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4 May 21 Order at P 320 (citing 16 U.S.C. § 824e(a)).
reasonable if the total price is. Specifically, to maintain a just and reasonable rate, capacity market revenue must decrease as energy and ancillary services revenue increases.

The Commission’s May 21 Order directed PJM to propose Tariff modifications “to implement a forward-looking E&AS Offset that reasonably estimates expected future energy and ancillary services revenues for all Tariff provisions that rely on a determination of the E&AS Offset (e.g., Net CONE).” In assessing the reasonableness of models, prior FERC decisions have considered whether market designs “reasonably balance[] the multiple considerations . . . including reducing price volatility, susceptibility to the exercise of market power, [and] frequency of low reliability events.” FERC has reviewed such models keeping in mind that “net CONE value affects the position of the demand curve. . . [and] the proposed design should produce prices that are high enough to meet the reliability standard, but not so high as to add unnecessary costs.”

III. Argument

As the Commission concluded in the May 21 Order, when requiring PJM to switch to a forward-looking E&AS Offset:

[An] inaccurate estimate of Net CONE can distort capacity market prices, which in turn could distort the price signals sent to generation contemplating entry into the market, as well as generation contemplating market exit...Sending incorrect

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7 The FPA’s just and reasonable standard “entails an appropriate ‘balancing of the investor and the consumer interests.’” Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty., Wash., 554 U.S. 527, 532 (2008) (quoting FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)); FPC v. Hope Natural Gas Co., 320 U.S. at 602 (“Under the statutory standard of ‘just and reasonable’ it is the result reached not the method employed which is controlling...It is not theory but the impact of the rate order which counts.”).
9 May 21 Order at P 320 (emphasis added).
11 Id. at P 33.
12 May 21 Order at P 312.
price signals could result in over-procurement of capacity with higher prices passed through to load. For the Commission’s objective of shifting to a forward E&AS Offset to be fully achieved, it is critical to ensure that PJM’s methodology will result in a reasonably accurate offset, so as to send the correct price signals and avoid unnecessarily high prices and capacity procurement.

PJM has a long and well-documented history of capacity over-procurement. For example, over the most recent nine delivery years, actual installed reserve margins were 24% or more in all years but one, compared to reserve targets of around 16%. The continuation of PJM’s capacity oversupply situation undermines the very E&AS price signals that the Commission aims to send with its approval of PJM’s reserve market redesign. The problem stems from a vicious cycle. Capacity oversupply tends to reduce E&AS revenues and the E&AS Offset, thus increasing Net CONE values and increasing capacity clearing prices, which then results in capacity oversupply. And the cycle begins anew. The Commission should review this compliance filing not only with an eye to the accuracy of the E&AS Offset in and of itself, but also to ensure that the capacity market demand curve that results from that offset fits with and supports PJM’s overall market design and supports accurate E&AS price signals.

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14 Wilson Affidavit ¶¶ 10–12.
A. PJM’s compliance filing methodology would underestimate net revenues due to the 10% Adder

PJM proposes to artificially increase the cost-based offers of the reference CT unit for the purpose of modeling its dispatch and expected E&AS revenues by imposing an unsubstantiated 10% “adder” on all offer prices by that reference CT unit in all hours.\(^{15}\) PJM barely explains what costs this adder is supposed to reflect. In its affidavit on behalf of PJM, The Brattle Group (“Brattle”) describes those costs as “account[ing] for increased net costs of matching gas supplies with flexible day-of changes in operations,” which purportedly applies only to CTs because they are dispatched closer to the time of delivery than are other gas units.\(^{16}\) The nearly nonexistent evidence or explanation in support of this adder is staggering considering that by PJM’s own estimates, removal of the adder from the net revenue simulations increases dispatch of the reference CT by 40% and increases net revenues by 43%.\(^{17}\) An impact on the CT’s forecasted E&AS revenues of this magnitude causes Net CONE and the prices consumers pay for capacity to increase far above the level needed to incentivize investment in resource adequacy in the PJM region.

PICOs oppose the use of the 10% adder as an input to the E&AS net revenue simulations because it results in an inaccurate net revenue estimate, with cascading effects on the reasonableness of capacity clearing prices. Without substantial evidence to justify the need for the adder as proposed by PJM, its inclusion in the PJM Tariff would be unjust and unreasonable.

\(^{15}\) *PJM Interconnection, L.L.C.*, Compliance Filing at 29–30 & n.97 (“Proposed Tariff, Definitions O-P-Q (definition of Projected EAS Dispatch) (“For combustion turbine units only, the cost-based energy offer will include a 10 percent adder.”)), Docket Nos. ER19-1486 and EL19-58 (Aug. 5, 2020) (“PJM Compliance Filing”).

\(^{16}\) PJM Compliance Filing, Attach. C (Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on behalf of PJM Interconnection, L.L.C.) (“Brattle Affidavit”) ¶ 35.

\(^{17}\) *See* M. Gary Helm, *E&AS Revenue Offset Update* at slide 21 (July 21, 2020) (attached hereto as Exhibit B).
We urge the Commission to reject PJM’s blanket use of this adder for purposes of developing the E&AS Offset.18

1. **Background on the 10% Adder**

The 10% adder is a relatively new addition to PJM’s estimates of Net CONE, and no BRA has ever been run using a VRR curve that reflects this adder. In 2018, The Brattle Group pressed this adder’s relevance in its evaluation of PJM’s potential changes to its methodology for constructing the VRR curve as part of the Quadrennial Review process. The Brattle authors observed that because CTs are committed and dispatched just a few hours before delivery, they “may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets, [which] . . . may increase the average cost of procuring gas above the price implied by day-ahead hub prices.”19 Brattle then went on to observe that “these costs are not transparent and may not follow regular patterns that are easily amenable to analysis,” and that its “interviews with generation companies provided mixed reactions.”20 While some fleet managers suggested they “might incur extra costs of up [to] $0.30/MMBtu,” managers of “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.”21 Brattle concluded by suggesting that PJM investigate this issue further and consider applying the 10% adder in its simulations.22

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18 While some of the undersigned organizations oppose the adder in the context of the energy market offer rules, that is not the focus of our arguments here, which instead point to the lack of evidence that the adder is in fact used to the extent that PJM assumes in the net revenue simulations.
20 *Id.*
21 *Id.* at 23–24.
22 *Id.* at 24.
Without any apparent investigation or consideration of how often any adder was actually used by owners of CTs (or, if and when added, whether it was due to actually incurred costs), PJM included the 10% adder in the methodology it proposed for the 2018 Quadrennial Review, which the Commission approved in April 2019. In its Quadrennial Review filing, PJM simply stated that doing so would be “reasonable and consistent with the approved energy market rules.” FERC approved the 10% adder, but did not engage intervenors’ arguments that while the energy market rules permit this adder, the more relevant inquiry for the sake of an accurate E&AS Offset is whether the adder is actually used and, if so, when and to what extent. Although FERC approved the use of the 10% adder in the VRR curve parameters, no BRA has been run under this new curve due to delays associated with the MOPR proceedings.

2. The 10% Adder has a Significant Effect on Net Revenues

As part of its stakeholder process to develop the forward-looking E&AS Offset to comply with the Commission’s May 2020 order in these proceedings, PJM raised questions as to whether it was appropriate to continue using the adder, and presented data on how estimated net revenues for the reference CT unit would be affected if that adder were removed. PJM’s analysis showed that the 10% adder has a significant effect on net revenues generated by the Optimal-Based dispatch.

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25 Quadrennial Review Order at P 129.
26 See Exhibit B at slide 21 (slide by PJM Lead Market Strategist asking “Is this a valid application of the 10% adder in the context of the E&AS Offset”).
Removing the 10% adder increased the CT’s run hours from an average of 3,795 across 2017-2019 up to an average of 5,325, a 40% increase. Net revenues increased from an average of $23,687 to $33,899, a 43% increase. As calculated in the attached affidavit of James F. Wilson, net revenue changes of this magnitude and direction would yield a $30/MW-day increase in Net CONE. For context, $30/MW-day is about half of the difference between the RTO Net CONE for the 2021/2022 BRA and the 2022/2023 BRA. In other words, this single assumption (blanket application of the 10% gas balancing adder) comprises about half the impact of the entire suite of changes that were debated for almost a year in the PJM stakeholder process and adjudicated by the Commission in Docket No. ER19-105.

Any simulation input with such a significant effect on net revenues and, ultimately, capacity prices must be fully supported by evidence and not simply assumed, particularly where to assume a certain value is counter to basic economic logic. To uncritically accept an unsubstantiated assumption of such importance is unreasonable.

3. **PJM does not offer any evidence in support of the 10% adder**

   In its August 5 compliance filing, PJM offered no evidence that a CT similar to the reference resource would add 10% to its cost-based energy market offers during every interval of the year, which is the assumption underlying PJM’s proposal. The sole support for PJM’s position is a statement by its consultants at The Brattle Group that it “remains appropriate for the CT to account for increased net costs of matching gas supplies with flexible day-of changes in

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27 *Id.* at slide 18 (“Dispatch Method Applied to Historical Day-Ahead LMPs”).
30 Wilson Affidavit ¶ 19.
31 PJM Compliance Filing at 29–31.
operations, as discussed in our [2018] Quadrennial Review report.” However, in 2018, Brattle did not find that blanket use of a 10% adder was appropriate. To the contrary, they noted that use of the adder was not widespread and recommended further investigation and consideration of its use before incorporating it into the E&AS Offset methodology.

Additionally, whether or not it is appropriate for a CT to account for any such increased costs is not the pertinent question. The relevant questions are whether CTs actually experience these increased costs at the level and with the frequency that PJM’s simulations assume they will and whether CTs then reflect these increased costs in their energy market offers. Especially in light of Brattle’s 2018 admonition, actual evidence of widespread use of a 10% adder is necessary to overcome the fact that it is economically irrational for a CT to inflate its cost-based offers unless absolutely necessary, given the potentially dramatic reduction to its net revenues. Here, PJM is assuming not only that a CT owner may inflate its energy market offer occasionally, but that a CT owner is inflating its energy market offer every time it submits an offer. That large leap of faith would also need to assume that sufficient competitive market conditions do not exist to discipline such offers, which, if true, would require consideration of additional market power mitigation measures. Without some empirical evidence that owners of CTs can, and will, routinely inflate their energy market offers by, on average, 10%, PJM cannot assert, and the Commission cannot conclude, that blanket application of the 10% adder improves “overall accuracy.”

The absence of evidence is particularly inexcusable because PJM has access to the information to show whether or not CTs comprehensively avail themselves of the 10% adder,

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32 Brattle Affidavit ¶ 35.
33 The Brattle Report at 23–24.
34 PJM Compliance Filing at 30.
including the actual energy market offers made by all resources, as well as the fuel price
information during the same intervals. PJM could have provided those data, but did not, to
support its position that it is reasonable or accurate to conclude that CTs include the full 10%
adder in every single energy market offer all the time. Because PJM did not provide those data
(despite acknowledging during the stakeholder process that it might not be appropriate to
maintain the adder in the simulations), one can only assume those data would not support its
position. PJM’s failure to provide such data stands in stark contrast to analysis showing exactly
the opposite – i.e., that CT owners often submit energy market offers below cost-based levels.
As noted in the Wilson Affidavit, PJM’s Independent Market Monitor recently released an
analysis showing that “gas units frequently offer at prices below their official marginal cost
estimates, suggesting that the gas units believe a competitive offer is lower than the calculated
cost-based level.”35 When analysis shows that owners of CTs regularly offer below their official
marginal cost estimates, PJM’s assumption that such owners always offer at 10% above such
estimates is not supported by substantial evidence and cannot be found to be just and reasonable.

Moreover, the stated basis for proposing the 10% Adder does not square with actual
practices. It seems far more likely that CTs incur gas balancing costs during only a subset of
hours each year:

While the reference resource might at times face uncertainties as PJM and the
Brattle Affidavit suggest, it is likely that most CTs would face such uncertainties
relatively rarely, if at all, especially under the recent and anticipated market
conditions. During most times of the year, electricity and natural gas prices are
stable, and the relationships between them are predictable. The uncertainties might
occur during unusual weather conditions (extreme cold or heat). However, even at
such times, there might only be a few regions in the PJM footprint that experience

35 Wilson Affidavit ¶ 21 (citing Monitoring Analytics, LLC, Protest of the Independent Market
Monitor for PJM at 10–12, Docket No. EL19-8-000 (Nov. 19, 2018) (finding that gas units
offered with negative markups in 28% of the unit-hours in 2017)).
pipeline constraints and difficulties scheduling natural gas intra-day; most of the footprint is served by multiple pipelines and storage facilities.36

As described in the Wilson Affidavit, it would be economically irrational for a CT operator to avail itself of the 10% adder in all hours. Instead, the operator “would exercise the opportunity to use the 10% adder provision selectively, in a manner that would increase, not decrease, their profits, by eliminating dispatch at times when it is unprofitable or only marginally profitable in expectation.”37 Indeed, “[i]t would be economically irrational for the reference resource to use the 10% adder unless it did indeed face additional costs, or perhaps was attempting to exercise market power.”38 There is simply no evidence that a rational CT operator would tack 10% on to every one of its energy market offers as a matter of course, as PJM appears to assume.

If PJM is unable to produce data (as opposed to assertions) to support the more targeted use of the 10% adder in the E&AS simulations, the appropriate adjustment is to entirely eliminate the adder from the simulations. Doing so is necessary to ensure that the replacement rate is just and reasonable.

4. The Commission’s prior approval of using the 10% adder in the E&AS Offset does not control this proceeding

In this compliance filing, PJM proposes to fundamentally transform nearly every element of how it estimates energy and ancillary service revenues for purposes of setting the VRR curve. Yet PJM proposes to retain use of the full 10% adder based, in significant part, on the Commission’s prior approval of its use.39 However, the Commission’s prior approval carries no

36 Wilson Affidavit ¶ 23.
37 Id. ¶ 19.
38 Id.
39 PJM Compliance Filing at 30.
weight when the changes at issue in this proceeding include a complete overhaul to the
calculation of the E&AS Offset.

First, PJM has changed the model used to calculate the E&AS Offset from the Peak Hour
Dispatch model previously used to the Projected EAS Dispatch model. The new model looks at
dispatch in all hours, not just the peak hours.\(^40\) As noted in the Wilson Affidavit, the narrow
circumstances in which a CT operator might avail itself of the 10% adder are those times when
demand is quite high and the gas pipeline system is nearing full utilization.\(^41\) While the Peak
Hour Dispatch model that PJM previously used would have consisted of hours in which it was at
least possible that some degree of the 10% adder could be used during certain peak hours, the
Project EAS Dispatch model is made up predominantly of hours where it is extremely unlikely
that the circumstances would create gas balancing costs. The change in the model makes the
lack of support for the 10% adder even more troubling.

Second, the factual circumstances that \textit{may} have induced some CT operators to include
balancing costs in their offers at the time of the Quadrennial Review have changed. As Mr. Wilson
observes, new gas pipelines have recently begun service, gas-electric coordination has improved,
and \“gas pipelines and marketers have developed new services to provide the intra-day flexibility
some generation resources need.\”\(^42\) The propriety of applying the 10% adder in the E&AS
simulations is not simply a determination that can be made for all time, but instead depends on the
facts on the ground -- would a CT operator avail itself of this adder during every hour of the year?
The evidence presented in this proceeding precludes that question being answered in the
affirmative. The use of the adder would likely change to reflect availability of gas service or

\(^{40}\) PJM Compliance Filing at 28–29.
\(^{41}\) Wilson Affidavit ¶ 23.
\(^{42}\) Id. ¶ 24.
market rules and dynamics, all of which change over time. PJM has never supported the use of the 10% adder for its E&AS simulations with actual evidence of its use “in real life,” and continues to avoid that responsibility with this filing.

**B. PJM Underestimates Ancillary Service Revenues**

PJM’s methodology for calculating a forward-look E&AS Offset is also flawed because it underestimates revenues from ancillary services, both now and especially in the future. Relying on Brattle’s recommendation, PJM proposes to use a historical average for operating reserve prices.43 As the Wilson Affidavit explains, this approach “will greatly understate future operating reserve revenues, especially if excess capacity declines and energy price expectations rise in future years.”44 This conclusion is based on the fact that operating reserve prices rise at a faster rate than corresponding energy prices. The Wilson Affidavit describes this market behavior as follows:

> When energy prices are low, there are many resources whose incremental energy production is not economic, so the opportunity cost to provide reserves is zero. As energy prices rise, it becomes increasingly likely that reserve prices will reflect these opportunity costs. At very high energy prices, energy and reserve prices may be relatively close, differing only by the fuel cost of the marginal provider of operating reserves.45

The Brattle Group’s own data offers further evidence of this phenomenon, despite its assertion that the relationship between energy prices and ancillary services prices is “roughly linear.”46 For example, when energy prices are in the $20 to $30/MWh range, synchronized reserve prices have clustered around $1/MWh. However, as energy prices increase to roughly $30 to $40/MWh—an increase of approximately 66% to 75%—ancillary services rise to around $2 to $5/MWh—an

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43 PJM Compliance Filing at 23 (citing Brattle Affidavit ¶ 22); see also id. at Attach A., Proposed Tariff Attachment DD Section 5.10(a)(v-1)(D).
44 Wilson Affidavit ¶ 28.
45 Id. ¶ 29.
46 Brattle Affidavit ¶ 22.
increase of two to five times above the previous price. In other words, ancillary services prices are increasing at roughly \textit{three to six times} the rate of energy prices.

As troublesome as this is, the impact of ancillary service revenue is only likely to increase in the coming years. Because of changes to the ORDC approved in this proceeding, operating reserve prices will be higher, even in hours when there is no shortage. The primary justification for the May 21 Order is the Commission’s finding that PJM’s old reserve market design under-priced reserves. As the Brattle Affidavit explains, “AS [ancillary service] revenues have been significant for some resources and are likely to become more so after PJM’s Reserve Pricing Reforms take effect.” In fact, PJM’s own simulations showed a \textit{tripling} of annual average synchronized and non-synchronized reserve prices after implementation of the approved reserve pricing changes. This trend will only accelerate the increase of ancillary services prices over energy prices. PJM’s continued reliance on historical average prices fails to comply with the Commission’s determination “that the just and reasonable replacement rate is adoption of a forward-looking E&AS Offset.” Instead, it will, according to the Wilson Affidavit, “greatly under state operating reserve revenues for the reference resource, especially if excess capacity declines and energy price expectations rise in future years.”

To address the likely increase in ancillary services revenues and to ensure a more accurate and more \textit{forward-looking} E&AS Offset, the Wilson Affidavit suggests that PJM “develop a functional relationship between energy price levels and operating reserve price levels for

\textsuperscript{47} Wilson Affidavit ¶ 42, Fig. 2.
\textsuperscript{48} \textit{Id.} ¶ 32.
\textsuperscript{49} May 21 Order at 74, 81–83.
\textsuperscript{50} Brattle Affidavit ¶ 21.
\textsuperscript{51} \textit{Id.} ¶ 23.
\textsuperscript{52} May 21 Order at 308.
\textsuperscript{53} Wilson Affidavit ¶ 33.
application within its simulation.” This functional relationship would recognize two well-acknowledged and previously discussed facts: (i) that increases in energy prices result in proportionately greater increases in operating reserve prices; and (ii) that reserve pricing changes are designed to increase operating reserve prices and revenues compared to historical averages. Without these changes to address anticipated increases in ancillary services revenue, PJM’s offset is unlikely to prevent the double-recovery of revenue the Commission sought to mitigate by requiring the forward-looking E&AS Offset.

C. The Accuracy of PJM’s Proposed Forward-Looking E&AS Offset is Undermined by Misalignment of Forward Prices For Natural Gas and Electric Energy

PJM’s proposed E&AS Offset methodology is also deeply flawed due to mismatched energy and fuel price information used by PJM to estimate forward-looking E&AS revenues. These flaws could ultimately lead to even less accurate estimates than the current approach based on historical averages.

Natural gas prices generally drive electricity prices in the PJM region. Therefore, in order for E&AS revenue estimates to be accurate, it is critical that the electricity and natural gas prices used in the model be reasonably consistent with one another by time and location. Brattle has recognized the importance of “alignment” of the electricity and fuel price dates in estimating E&AS revenues, and has urged PJM “to be sensitive to the alignment of forward price observation dates and forward contract delivery dates for power, natural gas, and other fuel commodities . . . [since alignment] of price observations will be essential to avoid systematic

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54 Id.
55 Id.
56 Id. ¶ 34–37.
errors in forecasts of E&AS margins.”\textsuperscript{57} Brattle therefore recommended using forward prices for electricity and natural gas “to the extent they are observable.”\textsuperscript{58}

Yet Brattle failed to follow its own admonition. It recommends only partial use of forward pricing, while failing to discuss the blending of limited forward pricing information with historical average data on the E&AS estimate analysis.\textsuperscript{59} Comparison of the Financial Transmission Rights (“FTR”) data provided by PJM based on historical averages shows that the monthly pattern in the FTR data does not align with the pattern in forward prices, and does not appear to have a logical explanation.\textsuperscript{60}

PJM’s proposal would have the E&AS revenues for the mid-Atlantic and eastern regions of PJM be simulated based on forward natural gas prices from eastern PJM, but the forward electricity prices would be from western PJM as adjusted based on the adjusted FTR auction results, which do not match. As a result, should natural gas forward prices in eastern PJM reflect expectations of increasing pipeline constraints and higher prices during future winter months, the E&AS Offset would reflect such expectations for natural gas prices, but likely would not reflect the corresponding expectation of higher electricity prices in those same areas.\textsuperscript{61} Such a “misalignment” would result in understating the likely E&AS net revenues for CTs located in eastern PJM.\textsuperscript{62}

Because natural gas is the marginal generation fuel in PJM for most hours, for any future year and location, electric and natural gas forward prices will often move together and generally

\textsuperscript{57} Brattle Affidavit ¶ 49.
\textsuperscript{58} Id. ¶ 11
\textsuperscript{59} Wilson Affidavit ¶ 39.
\textsuperscript{60} Id. ¶¶ 40–42.
\textsuperscript{61} Id. ¶ 43.
\textsuperscript{62} Id. ¶ 44.
reflect a fairly narrow spread between them. But under PJM’s proposal, this natural connection
is broken and the potential for misalignment is considerable. PJM’s proposal should be
changed to use additional, less liquid forward prices for the target year, subject to review of the
prices to be used and approval by the market monitor.

The Wilson Affidavit cites the lack of an eastern PJM electricity price as the most
important missing piece in developing a more accurate gas and energy alignment, but also notes
that “additional electricity and natural gas forward prices from other locations would also reduce
the scope for misalignment and likely improve the accuracy of the E&AS Offset calculations.”
The Wilson Affidavit also recommends the use of less liquid forward prices and the use of prices
for one or two years out when prices three years out are unavailable. This “innocent until
proven guilty” approach to the broader use of forward price information is unlikely to result in
market manipulation, and the forward prices could be subject to review by PJM and/or the
market monitor, with defined quantitative triggers to identify circumstances where the values are
suspect and warrant further review.

IV. Conclusion

For the foregoing reasons, the undersigned Public Interest and Customer Organizations
respectfully request that the Commission (i) reject the inclusion of the 10% adder for the reference
CT unit; (ii) accept the remainder of PJM’s filings for purposes of the BRA for the 2022/2023
Delivery Year; and (iii) direct PJM and stakeholders to expeditiously develop and file no later than
January 31, 2021, a proposal to reflect (a) a functional relationship between energy price levels

63 Id. ¶¶ 45.
64 Id. ¶¶ 45–47.
65 Id. ¶ 46.
66 Id. ¶ 47.
67 Id. ¶¶ 46–48.
and operating reserve price levels and (b) broader use of forward price information and improved alignment of gas and electric pricing, both consistent with the comments herein. The filing that occurs no later than January 31, 2021 should apply beginning with the BRA for the 2023/2024 Delivery Year.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at this 2nd day of September, 2020.

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EXHIBIT A
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. ) Docket No. ER19-1486-000
) )
PJM Interconnection, L.L.C. ) Docket No. EL19-58-003
) )

Not Consolidated

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE PUBLIC INTEREST AND CUSTOMER ORGANIZATIONS’ PARTIAL PROTEST OF AND COMMENTS ON PJM’S COMPLIANCE FILING REGARDING ENERGY AND ANCILLARY SERVICE OFFSET

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REGARDING ENERGY AND ANCILLARY SERVICE OFFSET

I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have thirty-five years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis, and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission (“Commission”), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

3. I have been involved in electricity restructuring and wholesale market design for over twenty years in the PJM region, New England, Ontario, California, MISO, Russia, and other regions. Since PJM Interconnection, L.L.C. (“PJM”) proposed the Reliability Pricing Model
(“RPM”) capacity construct in 2005, I have prepared numerous affidavits, reports, and analyses of RPM and RPM-related issues.

4. On August 5, 2020, PJM submitted proposed changes to its tariff (“PJM Compliance Filing”) to implement a forward-looking energy and ancillary services (“E&AS”) offset (“E&AS Offset”) in compliance with the Commission’s May 21, 2020 Order on Proposed Tariff and Operating Agreement Revisions in this docket.\(^1\) The PJM Compliance Filing attached an affidavit by Samuel A. Newell and James A. Read Jr. of The Brattle Group and Sang H. Gang of Sargent and Lundy (“Brattle Affidavit”).

5. I prepared this affidavit at the request of the Sierra Club, Natural Resources Defense Council (“NRDC”), the Sustainable FERC Project, Office of the People’s Counsel for the District of Columbia, Maryland Office of the People’s Counsel, Delaware Division of the Public Advocate, PJM Industrial Customer Coalition, Pennsylvania Office of Consumer Advocate, and New Jersey Division of Rate Counsel. My assignment was to evaluate the proposed E&AS Offset mechanism, with a focus on the E&AS Offset for the RPM reference resource, and recommend any needed changes.

\(^1\) *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153 (May 21, 2020) (“May 21 Order”).
II. Summary and Recommendations

6. For many years I have been in favor of changing to a forward-looking E&AS Offset, and it is especially important with the implementation of the Reserve Pricing Reforms approved in this docket, as recognized in the May 21 Order.2 After reviewing PJM’s proposal, I have identified three areas where changes to the proposed methodology are needed for it to accurately estimate the E&AS net revenues of the RPM reference resource, as discussed further later in my affidavit:

1. PJM proposes to raise the offer prices of the reference resource by a 10% adder in its simulations to estimate E&AS net revenues. This assumption, which would substantially lower E&AS Offset values and raise Net CONE values, is unsupported; the 10% adder should be rejected.

2. PJM proposes to base the reference resource’s estimated operating reserve revenues on historical averages. However, the Reserve Pricing Reforms are expected to raise operating reserve prices and revenues, and reduced excess capacity in future years could also lead to higher operating reserve revenues. PJM should modify the proposal to ensure that the E&AS Offset mechanism will capture the likely increases in operating reserve revenues.

3. PJM’s proposal makes only limited use of forward price information (three locations for electricity, six for natural gas), and contains instances of potentially significant “misalignment” between electricity and natural gas prices. PJM should

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2 May 21 Order at P 310.
modify the proposal to use additional forward price information, subject to review of the actual forward prices to be used by PJM or the market monitor to ensure any instance of manipulation would be detected.

7. If these three problem areas are not addressed, the forward-looking E&AS Offset mechanism may not generate reasonably accurate estimates of the net revenues of the reference resource, and could even lead to less accurate estimates than the current approach based on historical averages.

8. The remainder of my affidavit is organized as follows. The next section briefly summarizes the chronic over-procurement of capacity in PJM, the harm caused by this over-procurement, and the role of the E&AS Offset and Net CONE parameter in the over-procurement. The following section discusses in greater detail the three areas of the proposal that warrant changes.

III. Context: Chronic Over-Procurement of Capacity in PJM

A. PJM’s RPM Mechanism Has Over-Procured Capacity for Many Years

9. In a recent report, I documented the over-procurement of capacity through PJM’s RPM mechanism and explained the causes of the over-procurement.3 I found that over the most

recent nine RPM delivery years, actual installed reserve margins were 24% or more in all years but one, compared to targets of around 16%.\(^4\)

10. I identified three primary causes of the past over-procurement (and these causes continue to lead to over-procurement):\(^5\)

1. Excessive load forecasts. While PJM made changes to its load forecasting methodology last year, I have evaluated the results in detail and conclude that the over-forecasting problem has not yet been fixed.

2. A conservative capacity demand curve (“VRR curve”) shape that over-procures capacity even when RPM clears at prices at or somewhat above Net CONE.

3. Excessive Net CONE values (the price parameter of the capacity demand curve). This was not fixed in the last Quadrennial Review, which retained the combustion turbine (“CT”) as the reference resource (combined cycle units are more common and economical),\(^6\) and introduced a “10% adder” to the E&AS net revenue estimate that lowered the E&AS Offset and raised Net CONE values.\(^7\)

11. The forward-looking E&AS Offset mechanism at issue in this proceeding, depending upon its design, can help to correct this over-procurement, or instead exacerbate it.

\(^4\) Over-Procurement Report at 1.
\(^7\) 2018 Quadrennial Review Affidavit at 28–30.
B. Capacity Over-Procurement Thwarts Commission Objectives and Harms Consumers and Markets Over the Long Run\(^8\)

12. The over-procurement of capacity through RPM harms consumers and markets by retaining older, inefficient capacity and attracting new capacity that is not needed, thus increasing consumer cost. The over-procurement also leads to excess capacity in E&AS markets, which depresses the prices for energy and ancillary services. This harms consumers and markets by preventing the E&AS markets from accurately reflecting the value of all resource types and all resource attributes, such as flexibility and ramp speed. This also weakens incentives for price-responsive demand and demand response, which must expand for the markets to operate efficiently.

13. Thus, the capacity over-procurement thwarts the Commission’s objectives to achieve more accurate prices in E&AS markets that reflect the value of these services at all times, and to see greater revenue recovery in these markets rather than through administrative capacity mechanisms.

C. The Forward-Looking E&AS Offset Should Reflect Market Expectations of Reduced Excess Capacity and Higher E&AS Revenues, If/When This Occurs

14. The harm caused by the over-procurement of capacity is an important consideration in the design of a forward-looking E&AS Offset mechanism. Should the market anticipate reduced over-procurement and less excess capacity in the coming years, expectations for future E&AS revenues will rise. The forward-looking E&AS Offset mechanism should be designed to capture

any such change in the market outlook and to reflect it in the Net CONE values for the next RPM
base residual auction, not after several years, as occurs under the current methodology that relies
upon historical averages.

IV. Evaluation of PJM’s Proposed Forward-Looking E&AS Mechanism

15. Through my review of PJM’s proposal I identified three areas where some
adjustments to the proposed methodology are needed, as discussed in this section of my affidavit.

A. The 10% Adder to the Reference Resource’s Cost for Simulation Purposes

16. PJM’s energy market rules allow generation resources to include a 10% adder in
their cost-based energy market offers. In its 2018 Quadrennial Review filing, PJM stated that this
rule is to account for “uncertainties” in the determination of energy market participation costs.9

17. In its 2018 Quadrennial Review filing, PJM proposed to raise the offer prices for
the reference resource in its E&AS Offset simulations in all hours by the 10% adder, asserting that
the reference resource would confront the same uncertainties. Prior to the 2018 Quadrennial
Review there had been no adder in the E&AS Offset simulations.

18. In the stakeholder process that preceded PJM’s filing in this proceeding, PJM
considered and discussed with stakeholders whether or not to apply the 10% adder. Ultimately

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9 PJM Interconnection, L.L.C., Periodic Review of Variable Resource Requirement Curve Shape
PJM proposed to apply the 10% adder for the reference CT resource, but not for any other resource types.\textsuperscript{10}

19. In the simulations PJM presented in the stakeholder process, the assumption that the reference resource would raise its offers by the full 10% adder in all hours reduced the CT’s run hours by 29%, and its net revenues by over $10,000/MW-year (30%).\textsuperscript{11} The negative impact of the 10% adder on the reference resource’s net revenues reflects the fact that in most locations and at most times, PJM’s energy markets are quite competitive, and a resource that raises its offer prices above cost would reduce its dispatch and profits. Presumably, generation resources would exercise the opportunity to use the 10% adder provision selectively, in a manner that would increase, not decrease, their profits, by eliminating dispatch at times when it is unprofitable or only marginally profitable in expectation. It would be economically irrational for the reference resource to use the 10% adder unless it did indeed face additional costs, or perhaps was attempting to exercise market power.

20. The Brattle Affidavit states (p. 11): “The 10% adder remains appropriate for the CT to account for increased net costs of matching gas supplies with flexible day-of changes in operations, as discussed in our Quadrennial Review report.” However, the cited Brattle Quadrennial Review report did not assert that the 10% adder was “appropriate;” it merely suggested that PJM “investigate this further and consider applying” the 10% adder:

\textbf{Consider Including a Gas Balancing Cost Adder for CTs:} 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


\textsuperscript{11} M. Gary Helm, \textit{E&AS Revenue Offset Update} at slide 18 (July 21, 2020).
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.12

21. PJM has not to date performed the recommended investigation. No analysis was provided in the 2018 Quadrennial Review regarding whether existing CTs commonly do raise their offers above costs, and if so, why, how frequently, and under what circumstances. This information is available and could easily have been reviewed to determine whether the 10% adder assumption is realistic. Recent analysis by PJM’s market monitor suggests that the assumption is not realistic: the market monitor found that gas units frequently offer at prices below their official marginal cost estimates, suggesting that the gas units believe a competitive offer is lower than the calculated cost-based level.13

22. In its 2018 Quadrennial Review filing that proposed the 10% adder, PJM suggested that the following “uncertainties” might lead the reference resource to take advantage of the allowed 10% adder: “assumptions regarding the applicable gas index hub, Day-ahead versus intra-day gas arrangements, and assigned Locational Marginal Pricing.”14 However, an operating power

13 Monitoring Analytics, LLC, Protest of the Independent Market Monitor for PJM at 10–12, Docket No. EL19-8-000 (Nov. 19, 2018) (finding that gas units offered with negative markups in 28% of the unit-hours in 2017).
14 2018 PJM VRR Review at 23.
plant would rarely be uncertain about whether it will choose to sell into the day-ahead or real-time market, where it will get its gas, and at what LMP node its power will be priced.

23. While the reference resource might at times face uncertainties as PJM and the Brattle Affidavit suggest, it is likely that most CTs would face such uncertainties relatively rarely, if at all, especially under the recent and anticipated market conditions. During most times of the year, electricity and natural gas prices are stable, and the relationships between them are predictable. The uncertainties might occur during unusual weather conditions (extreme cold or heat). However, even at such times, there might only be a few regions in the PJM footprint that experience pipeline constraints and difficulties scheduling natural gas intra-day; most of the footprint is served by multiple pipelines and storage facilities.

24. Since the time of the 2018 Quadrennial Review, when use of the 10% adder for E&AS simulations was approved, several new pipelines have begun service in the PJM footprint, which has improved the availability of natural gas to many power plants. There have also been improvements in gas-electric coordination, and gas pipelines and marketers have developed new services to provide the intra-day flexibility some generation resources need. While there may be locations where, under some circumstances, CTs incur substantial additional costs for intra-day balancing that are not otherwise captured in PJM’s simulations, PJM has provided no analysis showing that this is the case, or how often it happens, or where in the footprint it happens.

25. PJM also proposes to use a new, more accurate Projected EAS Dispatch Model for the E&AS Offset simulations, which PJM describes as “more consistent with commercial
expectations” of these revenues. 15 This change to a more accurate and detailed dispatch model further weakens any case for the 10% adder, that is purportedly included to reflect errors and uncertainties in the representation of CT costs and operations.

26. Applying the 10% adder in the E&AS Offset simulations would increase Net CONE and exacerbate the over-procurement discussed in the previous section of my affidavit. If it reduces the reference resource’s net revenues by $10,000/MW-year, as suggested by PJM’s simulations noted above, that would raise Net CONE values in unforced capacity terms by roughly $30/MW-day.16 This would raise the RPM VRR curve and clear additional capacity at additional cost, exacerbating the over-procurement problem.

27. Lacking anything more than anecdotal evidence that resources similar to the reference resource face costs not reflected in PJM’s simulations, the 10% adder should not be applied in the simulations. If further investigation identifies that the 10% adder would be realistic under certain circumstances, it could be appropriate to include it in the simulation under those specific circumstances. For example, if investigation establishes a basis for it, the 10% adder could be included in subregions whenever the applicable natural gas price in the simulation (hub price plus basis) rises to over 50% above the two-week rolling average, suggesting that pipeline constraints may be occurring and gas balancing flexibility may be reduced.

15 PJM Compliance Filing at 5, 28–33.
B. Estimating Reference Resource Operating Reserves Revenues

28. Forward prices are not available for ancillary services revenues, such as operating reserves. The Brattle Affidavit recommended, and PJM accepted, simply using historical average operating reserve prices.\textsuperscript{17} This will greatly understate future operating reserve revenues, especially if excess capacity declines and energy price expectations rise in future years.

29. As a general rule, when energy prices rise in a wholesale electricity market, operating reserves prices rise not in a proportional manner, but at a faster rate. This is because, as the Brattle Affidavit acknowledges (p. 7), the primary cost of providing operating reserves is the foregone opportunity to provide energy. When energy prices are low, there are many resources whose incremental energy production is not economic, so the opportunity cost to provide reserves is zero. As energy prices rise, it becomes increasingly likely that reserve prices will reflect these opportunity costs. At very high energy prices, energy and reserve prices may be relatively close, differing only by the fuel cost of the marginal provider of operating reserves.

30. The Brattle Affidavit suggests that the relationship between ancillary services prices and energy prices “appears to have been roughly linear, approximately passing through the origin,”\textsuperscript{18} but provides no analysis to support this assertion. And, in fact, The Brattle Group provided contrary information in the stakeholder process, shown in Figure 1.\textsuperscript{19} The Brattle Group’s graphic suggests that when energy prices are in the $20 to $30/MWh range, synchronized

\textsuperscript{17} PJM Compliance Filing, Attach. C (Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on behalf of PJM Interconnection, L.L.C.) (“Brattle Affidavit”) ¶ 25; PJM Compliance Filing, Proposed Tariff, Attachment DD Section 5.10(a)(v-1)(D).

\textsuperscript{18} Brattle Affidavit ¶ 22.

\textsuperscript{19} The Brattle Group, \textit{Recommendations for Forecasting Gas, Energy and Ancillary Services Prices} at slide 6 (Item 2B) (July 30, 2020).
reserve prices have clustered around $1/MWh; but when energy prices rise to the $30 to $40/MWh range, synchronized reserve prices often rise to the $2 to $5/MWh range and higher.

31. Accordingly, should excess capacity decline in the future, leading to higher expectations for energy prices, operating reserves prices and revenues should be expected to rise faster than energy prices and revenues for the reference resource. The forward-looking offset mechanism should reflect this reality.

32. Perhaps more important, ancillary services revenues are expected to become more significant as a result of the Reserve Pricing Reforms in this docket. A key feature of the Reserve Pricing Reforms is the Operating Reserve Demand Curve (“ORDC”), which sets higher operating reserve price levels, including in hours when there is no shortage. The Brattle Affidavit acknowledges (¶ 21) that “AS revenues have been significant for some resources and are likely to
become more so after PJM’s Reserve Pricing Reforms take effect.” The Brattle Affidavit also notes (¶ 23) that PJM’s simulations of the reforms showed a tripling of annual average synchronized and non-synchronized reserve prices.

33. PJM should develop a functional relationship between energy price levels and operating reserve price levels for application within its simulation. The functional relationship should reflect that 1) increases in energy prices result in proportionately greater increases in operating reserve prices, and 2) the Reserve Pricing Reforms will increase operating reserve prices and revenues compared to historical averages. Using historical average reserve prices, as PJM proposes, would greatly understate operating reserve revenues for the reference resource, especially if excess capacity declines and energy price expectations rise in future years.

C. Underuse of Forward Prices, Risk of Misaligned Fuel and Energy Prices

34. This section of my affidavit explains flaws in the proposed E&AS Offset mechanism that could lead to highly inaccurate estimates of E&AS net revenues as forward energy and fuel price expectations change over time. These flaws could lead to E&AS Offsets calculated based on mismatched energy and natural gas assumptions; the resulting estimates could be even less accurate than the current mechanism using 3-year historical averages. I also propose improvements to the mechanism that would address the identified flaws to some extent.

35. The forward E&AS Offset mechanism simulations require forward electricity prices (“LMPs”) and also fuel prices for each hour and each location represented in the simulations. The scope of this affidavit is the E&AS Offset for the gas-fired CT reference resource, so the focus is on natural gas prices. Unfortunately, the available energy and natural gas forward price information is much less granular in terms of time and location than needed for the simulations, especially for the relevant delivery year three years into the future. Thus, the hourly, locational
price data required for the simulations must be constructed and shaped based on a combination of the available forward price information and also some historical patterns.

36. For the estimates of E&AS revenues in the simulation to be accurate, it is critical that the electricity and natural gas prices used for each specific time and location be reasonably consistent with one another. Natural gas prices are a key driver of electricity prices in the PJM region, so at times when natural gas prices are high in some region of the PJM footprint, they typically will drive electricity prices high in the same vicinity during the same period of time. If the simulation uses electricity and natural gas prices for an hour and location that are not based on consistent sources, the results could be unrealistically high or low estimates of the reference resource’s net revenues for the hour.

37. The Brattle Affidavit (¶ 49) recognizes the importance of consistency or “alignment” of the electricity and fuel price dates to be used in simulating energy and ancillary services revenues:

In recommending the use of forward energy prices to forecast net E&AS revenues, we urge PJM to be sensitive to the alignment of forward price observation dates and forward contract delivery dates for power, natural gas, and other fuel commodities. The price of natural gas in particular is one of the principal drivers of electric energy prices. Therefore, forward electricity prices on any given date will reflect forward natural gas prices on that same date, not forward gas prices set well before or after that date. Alignment of price observations will be essential to avoid systematic errors in forecasts of E&AS margins. Consistency across commodities is similarly important when shaping future prices into hourly and daily patterns.

38. The Brattle Affidavit (¶ 11) also recommends using forward price information to the extent “observable,” as they would in supporting a client in an investment decision:

To estimate expected net E&AS revenues in the delivery year, we recommend that PJM adopt the principles and methods we would use when supporting a client in an investment or contract decision for a similar timeframe. One of those principles is to rely on market prices to the extent they are observable. In this case, we
recommend using forward prices for electric energy and natural gas applicable to PJM market participants.

39. However, the Brattle Affidavit then violates these principles, and recommends using forward prices from only three locations for electricity and six locations for natural gas. This recommendation is apparently due to concerns about the potential for manipulation due to low liquidity, although the Brattle Affidavit does not argue that such manipulation is at all likely to occur. The Brattle Affidavit also does not discuss the limited geographic scope of the recommended electricity or natural gas price points. The recommended, highly limited use of forward prices creates a need to rely on historical information, and leads to a substantial risk of misalignment between locational energy and natural gas prices.

40. For electricity, the Brattle Affidavit recommended only the Northern Illinois Hub (applicable to only the COMED zone), the AEP-Dayton hub (applicable to zones in Ohio, Kentucky, and western portions of West Virginia and Virginia), and the PJM Western Hub (applicable to other PJM Western locations). All other zones, including all zones in the mid-Atlantic and eastern areas of PJM, are to be “mapped” to the forward prices from the PJM Western Hub, with the price differences estimated using results from long-term Financial Transmission Rights (“FTR”) auctions. The FTR prices are annual, so PJM proposes to create the monthly “shaped” values using historical average monthly congestion price differentials.

20 Brattle Affidavit ¶ 51.
21 Id. ¶ 66.
22 Id. ¶¶ 51, 67.
23 Id. ¶¶ 15–17.
24 PJM Compliance Filing, Proposed Tariff Attachment DD Section 5.10(a)(v-1)(C)(3).
41. However, the monthly pattern in the FTR data provided by PJM, based on historical averages, does not align well with the monthly pattern in the corresponding forward prices. Figure 2 below shows that the basis from PJM Western Hub to PJM Eastern Hub reflected in forward prices for peak hours in 2021-2022, 2022-2023 and 2023-2024 (the first three bars in each month group) exhibit a consistent, and understandable, monthly pattern that is very similar for all three delivery years: the basis is about $3/MWh for the summer peak months of July and August, over $6/MWh for the winter peak months of January and February, and lower for other, off-season months.

42. Figure 2 also shows the corresponding basis in the long-term FTR prices shaped with historical data provided by PJM,\textsuperscript{25} from Western Hub to the PSEG zone in eastern PJM (the fourth and last bar in each monthly group). This data logically should match the pattern shown in the forward prices, but instead it exhibits a very different pattern. The shaped FTR prices not only fail to match market expectations as reflected in forward prices, the pattern exhibited in the FTR price data (highly negative in September and March; highly positive in January but not February, as examples) also seems to defy any logical explanation.

43. For natural gas, the Brattle Affidavit recommended six locations: Chicago, Michcon (Michigan), Dominion South and Columbia-Appalachia TCO (both represent western Pennsylvania and Ohio in the Marcellus/Utica production region), TETCO M3 (New Jersey and eastern Pennsylvania) and Transco Zone 6 non-NY (Maryland to New Jersey).\(^{26}\) Figure 3 below shows the same peak hour electricity forward prices as in Figure 2 for 2021-2022 (in $/MWh) and the corresponding natural gas basis (in $/MMBtu), from the Dominion South point to Transco Zone 6 Non-NY. The monthly patterns of electric and natural gas forward prices make sense

together: natural gas forwards reflect higher basis during the winter months of January and February, which match the higher electricity forwards during those months; natural gas prices are lower in other months, suggesting that the higher electricity forwards in July and August are mainly driven by other factors, such as high electricity demand in those months.

44. Under PJM’s proposal the E&AS revenues for the mid-Atlantic and eastern regions of PJM would be simulated based on forward natural gas prices from eastern PJM (Transco Zone 6 non-NY, shown in Figure 3, and TETCO M3), but the forward electricity prices would be from Western PJM (Western Hub) as adjusted based on the shaped FTR auction results discussed above, which may not match, as shown in Figure 2. As a consequence, should natural gas forward prices in eastern PJM reflect expectations of increasing pipeline constraints and higher prices during winter months in future years, the E&AS Offset simulation would reflect these natural gas price
expectations, but likely would not reflect the corresponding expectations of higher winter electricity prices in these areas. This “misalignment” – modeling high natural gas prices, but not the corresponding high electricity prices that would result under these circumstances – would lead to understating the likely E&AS net revenues for the reference resource in eastern PJM (CONE Area 1).

45. Forward electricity and/or natural gas prices for a particular region can change over time relative to other regions due to electric or natural gas transmission development, substantial generation additions or retirements, or many other causes. Natural gas and electric forward prices will often move together (for example, due to gas pipeline construction that affects natural gas forwards), but may also move separately. However, for any future year and location, electric and natural gas forwards will generally reflect a fairly narrow range of spark spreads (ratio of electric to natural gas price) or implied heat rates, because natural gas is the marginal generation fuel in PJM in most hours. Under PJM’s proposal, the natural connections between electricity and natural gas price movements are broken, due to limited use of forward price information, filled in with historical information that may exhibit very different patterns.

46. The potential for misalignment largely results from the very limited used of forward prices, and especially the rejection of all forward electricity prices from points east of the PJM Western Hub. The proposal would be improved by broader use of forward prices. While perhaps an electricity forward price for the eastern areas of the PJM footprint is the most important missing piece, additional electricity and natural gas forward prices from other locations would also reduce the scope for misalignment and likely improve the accuracy of the E&AS Offset calculations.

47. The methodology should be changed to use additional, less liquid forward prices for the target year. Where forward prices for the delivery year three years out are unavailable or
highly illiquid, forward prices for one or two years out could be used. The use of such less liquid forward prices could be subject to review by PJM and/or the market monitor, and quantitative triggers could be defined to identify circumstances where the values are suspect and warrant further review. The triggers could be based on the implied heat rates or spark spreads reflected in the electricity and natural gas forward prices, which, when outside of historical ranges, would raise questions about one or both prices. Should a further review suggest that the forward prices should not be used, the methodology could fall back to PJM’s proposed approach for the affected price point.

48. Such an “innocent until proven guilty” approach to forward price information is appropriate in this situation, because market participants generally lack the ability and incentive to profit from manipulating these values. Attempts to manipulate the prices would be fairly transparent; the impact would lead to prices that deviate from expected patterns; and the potential benefit (higher RPM prices due to the resulting higher Net CONE values) would be uncertain.

49. This concludes my affidavit.
Attachment JFW-1
James F. Wilson  
Principal, Wilson Energy Economics

4800 Hampden Lane Suite 200  
Bethesda, Maryland 20814 USA

Phone: (240) 482-3737  
Cell: (301) 535-6571  
Email: jwilson@wilsonenec.com  
www.wilsonenec.com

SUMMARY
James F. Wilson is an economist with over 35 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the Energy Journal, Electricity Journal, Public Utilities Fortnightly and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982  
BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Analysis of provisions to enhance resource fuel security in day-ahead and real-time wholesale electricity markets.
- Evaluated peak electric load forecasts and enhancements to load forecasting methodologies.
- Evaluated a probabilistic analysis to determine the electric generating capacity reserve margin to satisfy resource adequacy criteria.
- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
• Panelist on a FERC technical conference on capacity markets.
• Affidavit on the potential for market power over natural gas storage.
• Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.
• Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
• Participated in a panel teleseminar on resource adequacy policy and modeling.
• Affidavit on opt-out rules for centralized capacity markets.
• Affidavits on minimum offer price rules for RTO centralized capacity markets.
• Evaluated electric utility avoided cost in a tax dispute.
• Advised on pricing approaches for RTO backstop short-term capacity procurement.
• Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
• Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
• Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
• Participated on a panel teleseminar on natural gas price forecasting.
• Affidavit evaluating a shortage pricing mechanism and recommending changes.
• Testimony in support of proposed changes to a forward capacity market mechanism.
• Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
• Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
• Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
• Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE
Principal
• Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
• Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
• Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
• Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism’s design; prepared a detailed report. Evaluated the impacts of the mechanism’s flaws on prices and costs and prepared testimony in support of a formal complaint.
• Analyzed impacts and potential damages of natural gas migration from a storage field.
• Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
• Prepared affidavit evaluating a pipeline’s application for market-based rates for interruptible transportation and the potential for market power.
• Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
• Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
• Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
• Evaluated market power issues raised by a possible gas-electric merger.
• Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission (“FERC”) policy.
• Prepared an expert report on damages in a natural gas contract dispute.
• Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
• Prepared testimony evaluating natural gas procurement incentive mechanisms.
• Analyzed the need for and value of additional natural gas storage in the southwestern US.
• Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
• Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
• Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
• Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
• Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
• Advised a major US utility with regard to the Federal Energy Regulatory Commission’s proposed Standard Market Design and its potential impacts on the company.
• Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
• Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
• Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
• Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
• Reviewed the reasonableness of an electric utility’s wholesale power purchases and sales in a restructured power market during a period of high prices.
• Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
• Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
• Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
• Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
• Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
• Authored a report on the role of regional transmission organizations in market monitoring.
• Prepared market power analyses in support of electric generators’ applications to FERC for market-based rates for energy and ancillary services.
• Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
• Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
• Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
• Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

Project Manager

• Reviewed, critiqued and submitted testimony on a New Jersey electric utility’s restructuring proposal, as part of a management audit for the state regulatory commission.
• Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
• Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
• Provided analytical support to the Secretary of Energy’s Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
• Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
• Designed an auction process for divestiture of a Northeastern electric utility’s generation assets and entitlements (power purchase agreements).
• Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

Project Director, Moscow, Russia
Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (the Program on Natural Monopolies, a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

• Advised on industry reforms and the establishment of federal regulatory institutions.
• Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
• Developed policy conditions for the IMF’s $10 billion Extended Funding Facility.

Independent Consultant stationed in Moscow, Russia, 1991–1996
Projects for the WORLD BANK, 1992-1996:

• Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
• Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
• Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
• Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
• World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
• Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:
• Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
• Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992


• For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
• Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
• Analyzed long term coal and rail alternatives for a midwest electric utility.
• Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
• Performed a financial and economic analysis of a proposed hydroelectric project.
• For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
• Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
• Evaluated uranium contracting strategies for an electric utility.
• Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
• Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
• Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS


In Re: Joint Application of Longview Power II, LLC and Longview Renewable Power, LLC to Authorize the Construction and Operation of Two Wholesale Electric Generating Facilities and One High-Voltage Electric Transmission Line in Monongalia County, Public Service Commission of West Virginia Case No. 19-0890-E-CS-CN, Direct Testimony on behalf of Sierra Club, January 3, 2020; testimony at hearings January 30, 2019.


PJM Interconnection, L.L.C., FERC Docket No. EL19-63 (RPM Market Supplier Offer Cap), Affidavit in Support of the Complaint of the Joint Consumer Advocates, April 15, 2019.


PJM Interconnection, L.L.C., FERC Docket No. EL18-178 (MOPR and FRR Alternative), Affidavit in Support of the Comments of the FRR-RS Supporters, October 2, 2018; Reply Affidavit on behalf of Clean Energy and Consumer Advocates, November 6, 2018.


In the Matter of the Application of DTE Gas Company for Approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 Months ending March 31, 2019, Michigan Public

Constellation Mystic Power, L.L.C., FERC Docket No. ER18-1639-000 (Mystic Cost of Service Agreement), Affidavit in Support of the Comments of New England States Committee on Electricity, June 6, 2018; prepared answering testimony, August 23, 1018.


PJM Interconnection, L.L.C., FERC Docket No. ER18-1314 (Capacity repricing or MOPR-Ex), Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, May 7, 2018; reply affidavit, June 15, 2018.


In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company’s Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.


Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88 (Capacity Performance transition auctions), Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.


Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.


In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 13-2385-


Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081 (minimum offer price rule), Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.


PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.


PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.


Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.


PUBLISHED ARTICLES

Forward Capacity Market CONEfusion, Electricity Journal Vol. 23 Issue 9, November 2010.


Restructuring the Electric Power Industry: Past Problems, Future Directions, Natural Resources and Environment, ABA Section of Environment, Energy and Resources, Volume 16 No. 4, Spring, 2002.


**Economic Policy in the Natural Monopoly Industries in Russia: History and Prospects** (with V. Capelik), Voprosi Ekonomiki, November 1995.


**OTHER ARTICLES, REPORTS AND PRESENTATIONS**


**Panel: Demand Response**, Organization of PJM States Spring Strategy Meeting, April 9, 2018.


**Panel: Transitioning to 100% Capacity Performance: Implications to Wind, Solar, Hydro and DR**; moderator; Infocast’s Mid-Atlantic Power Market Summit, October 24, 2017.


**IMAPP “Two-Tier” FCM Pricing Proposals: Description and Critique**, prepared for the New England States Committee on Electricity, October 2016.


Panel on Load Forecasting, Organization of PJM States Spring Strategy Meeting, April 13, 2015.


One Day in Ten Years? Resource Adequacy for the Smart Grid, revised draft November 2009.


Market Power: Definition, Detection, Mitigation, pre-conference workshop, with Scott Harvey, January 24, 2001.


Market Monitoring Workshop, presented to RTO West Market Monitoring Work Group, June 2000.


The Regional Transmission Organization’s Role in Market Monitoring, report for the Edison Electric Institute attached to their comments on the FERC’s NOPR on RTOs, August, 1999.


**PROFESSIONAL ASSOCIATIONS**

- United States Association for Energy Economics
- Natural Gas Roundtable
- Energy Bar Association

July 2020
EXHIBIT B
E&AS Revenue Offset Update

M. Gary Helm, Lead Market Strategist

MIC Special Session – Reserve Price Formation Order
July 21, 2020
• FERC filing extension to August 5 approved
• Updated resource parameters
• Completed historical dispatch on reference resources
• Completed initial forward price development and dispatch
  – Updating forward price methodology and dispatch parameters
• Engaged Brattle to assist in methodology development
  – Conducting review of forward price development
  – Conducting review of resource parameters
Optimal-based Dispatch at Forward LMPs

- CT
- CC
- Coal
- Storage

Assumed Output Model Applied to Forward LMPs

- Nuclear
- Solar (Fixed and Tracking)
- Wind (Onshore)
- Wind (Offshore)
The net energy and ancillary services revenue estimate shall be determined by a simulated energy dispatch of a 367 MW combustion turbine (with heat rate of 9,134 BTU/kWh, 20 MW/min ramp rate, variable operations and maintenance expenses of $1.10/MWh, plus major maintenance costs of $20,840/start and a 2 hour minimum run time) using an hourly zonal day-ahead forecasted LMP, developed from forward prices, forward gas prices, plus an ancillary services revenue to be determined.
# Reference Resource (CT) Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max Capacity</td>
<td>367 MW</td>
<td>Average capacity of CONE Area units at ISO conditions (59°F, 14.7 psia)</td>
</tr>
<tr>
<td>Min Stable Level</td>
<td>244 MW</td>
<td>Turn down ratio = 1.5, <a href="#">Minimum Unit-Specific Operating Parameters for Generation Capacity Resources</a></td>
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<tr>
<td>Ramp Rate</td>
<td>20 MW/min</td>
<td>PJM</td>
</tr>
<tr>
<td>Heat Rate</td>
<td>9134 Btu/kWh</td>
<td>Average heat rate of CONE Area units at ISO conditions (59°F, 14.7 psia)</td>
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<tr>
<td>Min Run</td>
<td>2 hr</td>
<td><a href="#">Minimum Unit-Specific Operating Parameters for Generation Capacity Resources</a></td>
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<tr>
<td>Min Down</td>
<td>1 hr</td>
<td>Sargent &amp; Lundy</td>
</tr>
<tr>
<td>Time to Start</td>
<td>21 min</td>
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</tr>
<tr>
<td>VO&amp;M</td>
<td>$1.10/MWh</td>
<td></td>
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<tr>
<td></td>
<td>$20,840/start</td>
<td>Major maintenance ($5.83/MWh)</td>
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<tr>
<td>Start Fuel</td>
<td>491 MMBtu/start</td>
<td>Average fuel use of CONE Area units</td>
</tr>
<tr>
<td>Fuel Pricing Points</td>
<td>Zonal fuel mapping from 2018 CONE Study, See Manual 18, Section 3.3.2</td>
<td></td>
</tr>
<tr>
<td>NOx</td>
<td>0.0093 lb/MMBtu</td>
<td>2018 CONE Study; historical allowance prices escalated for forward</td>
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<tr>
<td></td>
<td>55 lb/start</td>
<td></td>
</tr>
<tr>
<td>SO2</td>
<td>0.0006 lb/MMBtu</td>
<td>EPA; historical allowance prices escalated for forward</td>
</tr>
<tr>
<td>CO2</td>
<td>117 lb/MMBtu</td>
<td>EPA; RGGI ECR trigger price applied to RGGI units</td>
</tr>
<tr>
<td>Forced Outages (EFORd)</td>
<td>6.331%</td>
<td><a href="#">PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020</a></td>
</tr>
<tr>
<td>Maintenance Outages</td>
<td>First two weeks in October</td>
<td></td>
</tr>
</tbody>
</table>
The net energy and ancillary services revenue estimate shall be determined by a simulated energy dispatch of a 1,188 MW combustion turbine employing duct-firing (with heat rate of 6,501 BTU/kWh, 20 MW/min ramp rate, variable operations and maintenance expenses, inclusive of major maintenance costs, of $2.11/MWh and a 4 hour minimum run time) using an hourly zonal day-ahead forecasted LMP, developed from forward prices, applicable forward gas prices, plus an ancillary services revenue to be determined.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Max Capacity</strong></td>
<td>1,188 MW w/ Duct Burner; 1,060 MW w/o Duct Burner</td>
<td>Average capacity of CONE Area units at ISO conditions (59°F, 14.7 psia)</td>
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<tr>
<td><strong>Min Stable Level</strong></td>
<td>460 MW</td>
<td></td>
</tr>
<tr>
<td><strong>Ramp Rate</strong></td>
<td>20 MW/min</td>
<td>PJM</td>
</tr>
<tr>
<td><strong>Heat Rate</strong></td>
<td>6,501 Btu/kWh w/ Duct Firing; 6,269 Btu/KWh w/o Duct Firing</td>
<td>Average heat rate of CONE Area units at ISO conditions (59°F, 14.7 psia)</td>
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<tr>
<td><strong>Min Run</strong></td>
<td>4 hr</td>
<td>Minimum Unit-Specific Operating Parameters for Generation Capacity Resources</td>
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<tr>
<td><strong>Min Down</strong></td>
<td>3.5 hr</td>
<td></td>
</tr>
<tr>
<td><strong>Time to Start</strong></td>
<td>135 min</td>
<td>Sargent &amp; Lundy</td>
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<td><strong>VO&amp;M</strong></td>
<td>$2.11/MWh</td>
<td>Sargent &amp; Lundy</td>
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<tr>
<td><strong>Start Fuel</strong></td>
<td>8242 MMBtu/start</td>
<td>Average fuel use of CONE Area units</td>
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<td><strong>Fuel Pricing Points</strong></td>
<td>Zonal fuel mapping from 2018 CONE Study, See Manual 18, Section 3.3.2</td>
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<tr>
<td><strong>NOx</strong></td>
<td>0.0074 lb/MMBtu</td>
<td>2018 CONE Study; historical allowance prices escalated for forward</td>
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<td></td>
<td>160 lb/start</td>
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<tr>
<td><strong>SO2</strong></td>
<td>0.0006 lb/MMBtu</td>
<td>EPA; historical allowance prices escalated for forward</td>
</tr>
<tr>
<td><strong>CO2</strong></td>
<td>117 lb/MMBtu</td>
<td>EPA; RGGI ECR trigger price applied to RGGI units</td>
</tr>
<tr>
<td><strong>Forced Outages (EFORd)</strong></td>
<td>3.045%</td>
<td>PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020</td>
</tr>
<tr>
<td><strong>Maintenance Outages</strong></td>
<td>First two weeks in October</td>
<td></td>
</tr>
</tbody>
</table>
The net energy and ancillary services revenue estimate shall be determined by a simulated energy dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance expenses, inclusive of major maintenance costs, of $9.50/MWh) using an hourly zonal day-ahead forecasted LMP, developed from forward prices, Central Appalachian coal forward prices, plus an ancillary services revenue to be determined. Modeled as an economic unit with an eco max/eco min of 650/433 MW. The time to start is 5 hours and the minimum runtime and minimum downtime are 6 hours.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Notes</th>
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<tbody>
<tr>
<td>Max Capacity</td>
<td>650 MW</td>
<td>EIA (Case 1)</td>
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<tr>
<td>Min Stable Level</td>
<td>433 MW</td>
<td>Turn down ratio = 1.5, Minimum Unit-Specific Operating Parameters for Generation Capacity Resources</td>
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<tr>
<td>Ramp Rate</td>
<td>5 MW/min</td>
<td>PJM</td>
</tr>
<tr>
<td>Heat Rate</td>
<td>8638 Btu/kWh</td>
<td>EIA (Case 1)</td>
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<tr>
<td>Min Run</td>
<td>6 hr</td>
<td>Minimum Unit-Specific Operating Parameters for Generation Capacity Resources</td>
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<tr>
<td>Min Down</td>
<td>6 hr</td>
<td></td>
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<tr>
<td>Time to Start</td>
<td>5 hr</td>
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<tr>
<td>VO&amp;M</td>
<td>$9.5/MWh</td>
<td>PJM</td>
</tr>
<tr>
<td>Start Fuel</td>
<td>Coal: 124 MMBtu, Oil: 8746 MMBtu</td>
<td>PJM</td>
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<tr>
<td>Fuel Pricing Points</td>
<td>Coal: Central Appalachia, Oil: New York Harbor Heating Oil</td>
<td></td>
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<tr>
<td>NOx</td>
<td>0.06 lb/MMBtu</td>
<td>EIA (Case 1); historical allowance prices escalated for forward</td>
</tr>
<tr>
<td>SO2</td>
<td>0.09 lb/MMBtu</td>
<td></td>
</tr>
<tr>
<td>CO2</td>
<td>Coal: 206 lb/MMBtu, Oil: 159 lb/MMBtu</td>
<td>EIA (Case 1), EPA; RGGI ECR trigger price applied to RGGI units</td>
</tr>
<tr>
<td>Forced Outages (EFORD)</td>
<td>11.776%</td>
<td>PJM 2015 - 2019 Weighted Average EFORD by Fuel Type, Class Average Values Effective June 1, 2020</td>
</tr>
<tr>
<td>Maintenance Outages</td>
<td>None modeled at this time, to be determined</td>
<td></td>
</tr>
</tbody>
</table>
The net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch of a 1 MW / 4 MWh resource with a 91% charge and discharge efficiency* against an hourly zonal day-ahead forecasted LMP, developed from forward prices, plus an ancillary services revenue to be determined. The resource is assumed to be dispatched between 90% and 10% state of charge.

* This is used to represent an 83% roundtrip efficiency in the dispatch model
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max Capacity</td>
<td>Modeled as 1 MW / 4MWh resource</td>
<td></td>
</tr>
<tr>
<td>Charge Efficiency*</td>
<td>91%</td>
<td>EIA (Case 18)</td>
</tr>
<tr>
<td>Discharge Efficiency*</td>
<td>91%</td>
<td></td>
</tr>
<tr>
<td>State of Charge</td>
<td>Between 90% and 10%</td>
<td></td>
</tr>
<tr>
<td>Forced &amp; Maintenance Outages</td>
<td>None at this time, to be determined</td>
<td></td>
</tr>
</tbody>
</table>

*This is used to represent an 83% roundtrip efficiency in the dispatch model*
The net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [hourly zonal day-ahead forecasted LMP, developed from forward prices, times 8,760 hours, adjusted for forced & maintenance outages] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of major maintenance costs, plus an ancillary services revenue to be determined.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max Capacity</td>
<td>Modeled as 1 MW resource, operating 8760 hours per year</td>
</tr>
<tr>
<td>VO&amp;M</td>
<td>$\text{Multi: } 7.66/\text{MWh}$</td>
</tr>
<tr>
<td></td>
<td>$\text{Single: } 9.02/\text{MWh}$</td>
</tr>
<tr>
<td>Forced Outages (EFORd)</td>
<td>1.101%</td>
</tr>
<tr>
<td>Maintenance Outages</td>
<td>None at this time, to be determined</td>
</tr>
</tbody>
</table>
The net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the hourly zonal day-ahead forecasted LMP, developed from forward prices, applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue to be determined. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource.
The net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the hourly zonal day-ahead forecasted LMP, developed from forward prices, applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue to be determined.
The net energy and ancillary services revenue estimate shall be the product of [the hourly zonal day-ahead forecasted LMP, developed from forward prices, times 8,760 hours times at an assumed 45% of rated output], plus an ancillary services revenue to be determined
**Onshore Wind, Fixed Tilt Solar PV, Single-Axis Tracking Solar PV:**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output</td>
<td>Hourly capacity factor profiles applied to a 1MW resource</td>
</tr>
<tr>
<td>VO&amp;M</td>
<td>$0/MWh</td>
</tr>
<tr>
<td>Forced &amp; Maintenance Outages</td>
<td>None at this time, to be determined</td>
</tr>
</tbody>
</table>

**Offshore Wind:**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output</td>
<td>1MW resource at 45% capacity factor for 8760 hours per year</td>
</tr>
<tr>
<td>VO&amp;M</td>
<td>$0/MWh</td>
</tr>
<tr>
<td>Forced &amp; Maintenance Outages</td>
<td>None at this time, to be determined</td>
</tr>
</tbody>
</table>
## Dispatch Methods Applied to Historical Day-Ahead LMPs

### Optimal-Based

<table>
<thead>
<tr>
<th>Resource</th>
<th>Net Revenue ($/MW-year)</th>
<th>Run Hours*</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2017</td>
<td>2018</td>
</tr>
<tr>
<td>Reference CT (No 10% Adder)</td>
<td>$31,772</td>
<td>$44,431</td>
</tr>
<tr>
<td>Reference CT (10% Adder)</td>
<td>$21,793</td>
<td>$32,881</td>
</tr>
<tr>
<td>MOPR CC</td>
<td>$74,736</td>
<td>$91,781</td>
</tr>
<tr>
<td>MOPR Coal</td>
<td>$3,653</td>
<td>$20,893</td>
</tr>
<tr>
<td>MOPR Battery</td>
<td>$18,556</td>
<td>$25,370</td>
</tr>
</tbody>
</table>

* Discharge Hours

### Assumed Output

<table>
<thead>
<tr>
<th>Resource</th>
<th>Net Revenue ($/MW-year)</th>
<th>Run Hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>MOPR Nuclear (Single)</td>
<td>$175,720</td>
<td>8,760</td>
</tr>
<tr>
<td>MOPR Nuclear (Multi)</td>
<td>$187,502</td>
<td>8,760</td>
</tr>
<tr>
<td>MOPR Onshore Wind</td>
<td>$81,041</td>
<td>8,760</td>
</tr>
<tr>
<td>MOPR Offshore Wind</td>
<td>$117,670</td>
<td>8,760</td>
</tr>
<tr>
<td>MOPR Fixed-Tilt Solar PV</td>
<td>$38,865</td>
<td>4,717</td>
</tr>
<tr>
<td>MOPR Tracking Solar PV</td>
<td>$63,096</td>
<td>4,749</td>
</tr>
</tbody>
</table>
Ancillary Services

• Considering two options:
  – Analyze the percent of historical revenues from selling energy and ancillary services across resource classes. Develop a revenue adder for reserve and regulation market revenues that can be added to the projected energy market revenues.
  – Analyze the historical correlation between energy and ancillary market prices. Develop forward-looking hourly reserve and regulation market prices based on the forward hourly energy prices. Perform a co-optimized energy, regulation and reserve dispatch against the forward prices.

• Continue to assume fixed reactive services revenues, consistent with March MOPR filing

• Account for which services each resource type is able and likely to provide
Methodology Update – Price Development

• Based on (Manual 15, Long Term Method 12.5.1 – 12.5.5)
  – RT monthly LMP forwards for delivery year (calendar year)
    • Power – West Hub, with 3-yr historical hourly basis to other hubs
    • Gas – Henry Hub, with 3-yr historical daily basis to other hubs
  – Shaped with historical DA LMPs from most recent 3 years
    • Conducted for each of 3 years individually

• Considering Brattle recommendations regarding pricing hubs and basis determination
  • (Note: See corresponding Brattle presentation)
Use of 10% adder

- Accounts for uncertainty in the values of the costs used to determine cost-based offers in the energy market
- Accounts for real-time gas charges, balancing fees when dispatching CT for Net CONE development
- Is this a valid application of the 10% adder in the context of the E&AS Offset?
- Dispatch impact: CT run hours increased 40% when 10% adder was removed from historical run
<table>
<thead>
<tr>
<th>Decision Item</th>
<th>Choices</th>
<th>Current Thinking</th>
<th>Reasoning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Price method</td>
<td>• Heat Rate Output Scalar</td>
<td>Forward Input Scalar</td>
<td>Use of forward prices scaled for historical shape.</td>
</tr>
<tr>
<td></td>
<td>• Forward Input Scalar</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Forward sample</td>
<td>• Single day</td>
<td>Multiple days</td>
<td>Provides a large sample to address anomalous data, but not too historic</td>
</tr>
<tr>
<td></td>
<td>• Multiple days</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power hub</td>
<td>• West hub</td>
<td>West, NI, AEP-Dayton</td>
<td>Most liquid. Historical basis provides reasonable expectation of future local price</td>
</tr>
<tr>
<td></td>
<td>• Local hub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas hub</td>
<td>• Henry hub</td>
<td>DomS, Chicago, MichCon</td>
<td>Liquid, match to Electric hub.</td>
</tr>
<tr>
<td></td>
<td>• Local hub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Basis method</td>
<td>• Historical</td>
<td>Historical</td>
<td>Most liquid. Match electric and gas hubs. Use monthly differentials</td>
</tr>
<tr>
<td></td>
<td>• FTR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day of Week</td>
<td>• Adjust</td>
<td>Under investigation</td>
<td>Prevents mismatch of days of week when conducting hourly scaling</td>
</tr>
<tr>
<td>Adjustment</td>
<td>• Do not adjust</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market for scalar</td>
<td>• Day-Ahead/Real-Time</td>
<td>Day-ahead, investigating</td>
<td>Majority of units committed in day-ahead, thus volatility shape more applicable</td>
</tr>
<tr>
<td></td>
<td>• Day-ahead</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scalar sample</td>
<td>• One-year</td>
<td>Three year</td>
<td>Provides a large sample to address anomalous data, but not too historic</td>
</tr>
<tr>
<td></td>
<td>• Three-year</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Decision Matrix – Dispatch

<table>
<thead>
<tr>
<th>Decision Item</th>
<th>Choices</th>
<th>Current Thinking</th>
<th>Reasoning</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatch method</td>
<td>• Peak-hour based</td>
<td>Optimal based</td>
<td>Removes peak hour limitations. More applicable to dispatchable unit operations</td>
</tr>
<tr>
<td></td>
<td>• Optimal based</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Offers modeled</td>
<td>• Cost</td>
<td>Cost-based</td>
<td>Simple, transparent and reasonable. Use of 10% adder approved as part of quadrennial review. Is 10% adder applicable here?</td>
</tr>
<tr>
<td></td>
<td>• Cost-based plus 10%</td>
<td>Cost-based plus 10%?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Price-based</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance Outages</td>
<td>• Two-weeks in October</td>
<td>Two-weeks</td>
<td></td>
</tr>
<tr>
<td>Forced Outages</td>
<td>• Account for in EFORd</td>
<td>EFORd</td>
<td></td>
</tr>
<tr>
<td>Optimization</td>
<td>• 24-hour look ahead</td>
<td>24-hour look ahead</td>
<td>Closer to Day-ahead optimization</td>
</tr>
<tr>
<td></td>
<td>• None</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Daily start limitations</td>
<td>• Yes</td>
<td>No</td>
<td>Allows for economic operation</td>
</tr>
<tr>
<td></td>
<td>• No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emissions adders</td>
<td>• Yes</td>
<td>Yes</td>
<td>Included for units in allowance trading programs (NOx, SO2, CO2)</td>
</tr>
<tr>
<td></td>
<td>• No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas mapping</td>
<td>• PJM</td>
<td>PJM</td>
<td>Matches decisions agreed to in Quadrennial Review</td>
</tr>
<tr>
<td></td>
<td>• IMM</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
PJM intends to outline acceptable deviations from the default methodology for developing the forward E&AS offset through the unit-specific exception process.

- What deviations from the default methodology do participants feel are necessary?
- What evidence should be shown to demonstrate that such deviations match commercial expectations?
Next Steps

- Test forward price development with updated methodology
- Run dispatch with updated forward prices and parameters
- Develop acceptable ranges for unit specific process
July 21
Draft proposal and discussion

July 30
Updated proposal and discussion

August 5
Compliance filing due

2020

Stakeholder Feedback and Input
• Brattle recommendations
• Forward prices
• Dispatch parameters and methods
• Present indicative values
Facilitator:
Michele Greening,
michele.greening@pjm.com

Secretary:
Nick DiSciullo,
nicholas.disciullo@pjm.com

SME/Presenter:
Gary Helm, gary.helm@pjm.com

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