UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. EL19-8-000

PROTEST OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits this protest to the filing submitted by PJM Interconnection, L.L.C. ("PJM") on October 29, 2018 ("October 206 Filing").

The Market Monitor agrees with PJM on one point, that the current rules pertaining to the inclusion of maintenance costs in cost-based offers are unjust and unreasonable. PJM and the Market Monitor differ in that PJM argues for higher levels of maintenance costs in cost-based offers, although no maintenance costs belong in cost-based offers. PJM misrepresents the history of maintenance costs in PJM cost-based offers. The rules are not discriminatory. The PJM customers and PJM management and the PJM Board all approved the current approach to major maintenance in PJM Manual 15 (Cost Development Guidelines) ("Manual 15") in 2012 as applying consistent treatment across generating technologies.

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1 18 CFR § 385.211 (2018).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

The October 206 Filing nowhere claims to make markets more competitive, or to improve the definition of competitive offers or to more effectively address market power. Instead, PJM asserts that Manual 15 is internally inconsistent. But rather than attempting to respect prior stakeholder decisions on this topic and proposing to both make the rules internally consistent and consistent with competitive outcomes, PJM proposes a set of ad hoc rules designed to increase energy offers above the competitive level and to permit generators to choose whether costs are short marginal costs or fixed costs. PJM never asserts that maintenance are short run marginal costs.

The history of PJM's proposal began with the Market Monitor's routine reviews of generators' cost-based offers. The Market Monitor informed Market Sellers when cost-based offers exceeded short run marginal costs.[3] Generators seeking to price above short run marginal costs complained to PJM. In support of generators, PJM began an effort to gain control of cost-based offer reviews through Fuel Cost Policies, review of variable operations and maintenance costs, and calculation of opportunity costs.[4] As a result, PJM realized that the current market rules did not include all the maintenance costs that some generators sought to include in cost based offers, so PJM initiated a stakeholder process to change the rules.

The PJM customers evaluated PJM's arguments and the evidence in the current PJM stakeholder process and rejected PJM's proposal multiple times.[5] The Commission should

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3 *See*, for example, Market Monitor Report, MC Webinar (September 28, 2015), <http://www.monitoringanalytics.com/reports/Presentations/2015/IMM_MC_Webinar_Report_20150928.pdf> , and Market Monitor Report, MC Webinar (April 25, 2016), <http://www.monitoringanalytics.com/reports/Presentations/2016/IMM_MC_Webinar_Market_Monitor_Report_20160425.pdf>.

4 *See* FERC Docket ER16-372 and Opportunity Costs Issue Tracking at <https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={867315DA-0DED-4A9A-B571-DE4B2C8BF80E}>.

5 "Item 01 – Draft Minutes – MRC – 7.26.2018," Markets and Reliability Committee (August 23, 2018) <https://www.pjm.com/-/media/committees-groups/committees/mrc/20180823/20180823-item-01-

reject PJM's proposed tariff revisions, which are counter to the Commission's goal of competitive markets.[6] The Commission should instead require PJM to replace the current rules with clear tariff requirements that support effective market power mitigation to the intended competitive level, which is short run marginal cost, as the Commission determined 14 years ago and reiterated in 2015:[7]

> The Commission has stated previously that in a competitive electricity market, suppliers are 'expected to produce at the point where prices exceed their short-run marginal costs,'[8] and it found that mitigation based on marginal cost is reasonable for generators that are usually dispatched in-merit to provide energy.[9] The Commission also stated that defining the appropriate cost basis for mitigated offers is not an 'exact science,' but nonetheless the Commission stated that mitigated offers should 'reasonably reflect offers in a competitive market.'[10]

In this protest, the Market Monitor provides background discussion, an alternative proposal, and protests PJM's 206 filing. The background explains the purpose of PJM cost-based offers, the components of cost, and the PJM Market Rules pertaining to cost-based offers in Section I.A.; provides evidence of and consequences of market inefficiencies due to the inclusion of maintenance costs in cost-based offers in Section I.B.; explains the

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draft-minutes-mrc-20180726.ashx> and "Consent Agenda Item A – Draft Minutes – MC – 9.27.2018," Members Committee (October 22, 2018) <https://pjm.com/-/media/committees-groups/committees/mc/20181025/20181025-consent-agenda-item-a-draft-20180927-mc-meeting-minutes.ashx>.

6 The Commission states that "[t]he Commission's core responsibility is to "guard the consumer from exploitation by non-competitive electric power companies." <https://www.ferc.gov/industries/electric/indus-act/competition.asp?csrt=13497500850217223907>

7 *Southwest Power Pool*, 152 FERC ¶ 61,226 at P 68 (2015) ("SPP SRMC Order").

8 *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 25 (2005) ("FMU Order").

9 *Id.* at P 27.

10 *Id.* at P 114.

recommendation that the Commission require cost-based offers equal to short run marginal costs in Section I.C.; and documents the history of the PJM Cost Development Guidelines in Section I.D. The Market Monitor presents its alternative proposal in Section II.

The Market Monitor identifies issues with PJM's filing in Section III. PJM claims to identify issues in Manual 15 though the definition of cost-based offers should reside in the PJM OATT (Section III.A.). PJM's proposal does not address the fact that cost-based offers are limited to incremental costs (Section III.B.). PJM's proposed language does not provide the clarity needed for ongoing development and review of cost-based offers (Section III.C.). The Commission's determination regarding a major maintenance component in Southwest Power Pool's mitigated offers is not a precedent for PJM's cost-based offers (Section III.D.). PJM incorrectly argues that the current rules impede cost recovery (Section III.E.).

I. BACKGROUND

A. The Purpose of Cost-Based Offers is Market Power Mitigation to Ensure Competitive Energy Market Outcomes.

The purpose of cost-based energy offers is to prevent the exercise of market power in the PJM energy market. PJM administers market power mitigation in the energy market by replacing a generator's market-based offer with its cost-based offer when the generator owner fails the structural test for local market power, the Three Pivotal Supplier ("TPS") test, or is required for reliability. The effectiveness of market power mitigation in delivering competitive market outcomes is based entirely on cost-based offers as the measure of the competitive offer level. When market power is not mitigated, energy prices exceed the competitive level, uplift payments exceed the efficient level, and economic withholding allows generators to collect capacity payments without running, while raising prices for other generators and for load. The competitive offer level is the short run marginal cost of the generator for the relevant market hour.

There are three types of costs identified under PJM rules: short run marginal costs, avoidable costs, and fixed costs. Annual costs that would be avoided if energy were not produced over an annual period are avoidable costs. Fixed costs are associated with an investment in a facility including the return on and of capital. From the perspective of the time of power production, avoidable costs and fixed costs are both fixed. Short run marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production.

Short run marginal cost is the cost of inputs consumed and the net cost of byproducts created at the time of power production. A generator requires a specific quantity of short run inputs to start and achieve a specific output level. The primary input is fuel. A generator creates a specific quantity of byproducts, such as emissions and ash, for which the generator incurs a cost and may earn offsetting revenues. Market revenues fully provide for short run marginal costs as long as the market price equals or exceeds the level of short run marginal costs at the time of production, and uplift payments make up any shortfall. Emissions allowance costs and opportunity costs are short run marginal costs.

An avoidable cost divided by output is a measure of average cost. Dividing an avoidable cost or a fixed cost by output does not convert such costs into marginal costs. Unlike marginal costs, avoidable costs are not automatically recovered when the energy price equals or exceeds average cost at the time of production. Since avoidable costs are not actually incurred at the time of power production, only part of avoidable costs are recovered when the energy price equals or exceeds average cost at the time of production and there is therefore no guarantee of covering avoidable costs by including them in the energy offer as there is for short run marginal costs.

In the short run, energy prices provide a signal to produce or not produce energy. In the short run, generators' decision making is limited to when to start, when to shut down, when to increase output and when to reduce output. In the long run, energy prices, ancillary service prices, and capacity prices provide signals to invest or shut down. In the long run, generators' decision making includes staffing, maintenance, and fuel supply agreements, among other avoidable costs. Maintenance costs are actual costs that must be covered by market revenue if a unit is to remain in operation. But at the time of the decision to produce or not produce energy, maintenance costs are fixed costs or sunk costs. Capacity payments and energy market net revenues need to cover maintenance costs, and other avoidable costs, for units to remain in operation. Investors also expect that market revenues will cover fixed costs, including a return on and of capital, and will not invest if that is not true. The legitimacy of and necessity to cover maintenance costs does not mean that they are short run marginal costs.

1. Short Run Marginal Costs and Maintenance Costs

The Market Monitor annually calculates short run marginal costs for current generating technologies on the basis of the rate of consumption of materials needed to produce power from different generating technologies (e.g. water, water treatment chemicals, emission abatement chemicals, etc.) and the current cost of such materials. Table 1 provides the Market Monitor's estimates of short run marginal costs for combustion turbines (CT), combined cycle plants (CC), coal plants (CP), diesel engines (DS), nuclear plants, wind turbines, and solar installations.

Table 1 Short Run Marginal Costs by Unit Type for 2018 Technology

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$37.89	9,241	$0.38
CC	$26.91	6,296	$1.09
CP	$33.72	9,250	$4.03
DS	$165.66	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

The short run marginal costs in Table 1 consist of fuel and variable operations and maintenance (VOM). The VOM includes consumables other than fuel used at the time of electric production. The cost of the fuel used by units to start and produce electricity is the largest part of short run marginal cost, generally in excess of 90 percent of the total. A start increases fuel costs by the amount of fuel used to start. An additional MWh increases fuel costs by the amount of fuel used to produce that MWh. These events occur in the short run. The inputs that the company can optimize in the short run are the short run marginal costs. These are the costs of fuel, water and other inputs consumed in the short run.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time in order to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

The number of starts or operating hours is one of the inputs used in a unit owner's decision to perform maintenance. Maintenance projects last weeks and are typically scheduled for off peak periods when energy prices are lower. Companies may optimize the timing of the maintenance by advancing it or delaying it with respect to the OEM recommendation. Companies may not perform maintenance at all if the long run expectation is that revenues will not exceed maintenance costs. Maintenance intervals, as repeated in the OEM documents referenced by PJM, are recommended to increase availability, but are not required for short run operation.[11] The fact that after some number of run hours and/or starts, a unit will likely need maintenance does not make maintenance a short run marginal cost. Maintenance is a real cost which results from operating the unit

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11 October 206 Filing at P35.

and maintenance cost must be covered if a unit is to remain in business, but it is not a short run marginal cost.

2. Incremental Costs in the PJM Market Rules

The PJM Market Rules require that cost-based offers not exceed the level of incremental costs defined in Operating Agreement Schedule 2. Operating Agreement Schedule 2 refers to Manual 15, which employs up to a 20 year historic calculation of maintenance costs as an input to incremental cost. The Commission has found incremental cost to be an insufficiently clear term.[12] Unlike the Market Monitor, and unlike the Commission, PJM does not interpret incremental costs to mean short run marginal costs.[13]

PJM interprets incremental costs to mean "expenses incurred as a result of electric production." PJM allows generators to include as incremental costs any cost that varies with generator output, run hours, starts, or forced outages. The fact that some maintenance costs vary with generator run hours or starts does not mean that they are short run marginal costs. When a generator runs more, the floors get dirtier and light bulbs burn out more quickly. Floor sweeping and light bulb replacement costs vary with run hours but that does not make them short run marginal costs. The same is true of filter changes and turbine inspections. Maintenance costs are intermediate to long run variable costs. Variable costs are not short run marginal costs. By allowing maintenance costs in cost-based offers because they are variable costs, PJM allows cost-based offers to exceed the competitive level, undermining market power mitigation. PJM never asserts that maintenance costs are part of competitive offers in the energy market. The Market Monitor and PJM agree that maintenance costs are not short run marginal costs.[14]

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12 SPP SRMC Order at P70.

13 FMU Order at PP 25, 27 &s 114.

14 PJM presentation to the MRC on September 27, 2018 "Variable Operations & Maintenance Costs (VOM) Updated Proposal," (September 27, 2018).

3. Maintenance Costs in Manual 15

Manual 15 and Schedule 2 of the OA include rules related to maintenance costs. The two documents do not use consistent terminology or provide clear, consistent guidance to users. Schedule 2 lists incremental maintenance costs, peak-prepared-for maintenance costs, and Maintenance Adders, without defining the meaning and purpose of each. Manual 15 provides for the inclusion of maintenance costs in energy market cost-based offers. Manual 15 includes provisions for maintenance costs mainly based on FERC's system of accounts, which predate markets and do not define costs consistently with market economics. The maintenance calculation relies on a 10 to 20 year history of maintenance costs, intended to capture multiyear maintenance cycles. OA Schedule 2 makes no mention of FERC accounts or 20 year cost histories.

The long history used to calculate total maintenance can lead to distorted values when high historical maintenance costs that resulted from running for a large number of hours are divided by a relatively small number of MWh when the unit does not currently run often. This calculation inflates maintenance costs included in cost-based offers in dollars per MWh. The historical maintenance cost calculation can result in maintenance costs exceeding $500 per MWh, and logically can result in maintenance costs over $999 per MWh. This result is clearly wrong; the production of an additional MWh does not result in an increase in maintenance costs of $500 at the time of production. For some Market Sellers, the 10 or 20 year history extends beyond what is required by their document retention practices, so they cannot support their maintenance costs with actual data.

Manual 15 includes methods to allocate maintenance costs to start costs, no load costs, and incremental cost curves. These factors are called cyclic starting and peaking factors. There is no analytical basis for these factors in Manual 15. The impact of these factors is significant. Manual 15 allows for a cyclic peaking factor of three, which means that a unit with a $300 per equivalent operating hour (EOH) maintenance cost can add $180 per MWh to a 5 MW peak segment [((3 * 300)/5) = 180]. It is not appropriate to define short run marginal costs based on the desired dispatch for a unit. Use of these factors artificially makes units less flexible at a time in the history of power markets when flexibility is more important than ever. Use of actual short run marginal costs will provide the right signal to the market about the effective use of these units and will correctly reflect the actual costs of such use. If operating more flexibly results in higher maintenance costs, those costs should and will be reflected in the market price of capacity to the extent not recovered in the energy market. The use of arbitrary starting and peaking factors is not appropriate because long term maintenance costs are not short run marginal costs.

Some generators execute Long Term Service Agreement (LTSA) contracts with turbine original equipment manufacturers (OEM) to jointly manage the cost of and risks associated with turbine operation and maintenance. The OEMs take responsibility for maintenance in return for payment from the unit operators. LTSAs are generally structured to require payment of costs to the OEM in dollars per start, dollars per service hour or dollars per MWh. LTSAs effectively require the operator to prepay for maintenance before it is required. LTSAs are contracts that allow a unit owner to amortize maintenance expenses over time in a defined way linked to the operation of the unit. The method used by LTSAs to collect these payments does not make these payments short run marginal costs. A contract cannot convert long term maintenance costs into short run marginal costs. That is why PJM stakeholders voted in 2012 to not permit LTSA costs to be included in cost-based offers.

B. Maintenance Costs Allow PJM Prices to Exceed Competitive Levels.

The inclusion of maintenance costs in cost-based offers allows cost-based offers to exceed competitive offers. Higher cost-based offers directly increase energy market prices when units are offer capped for local market power or reliability, when cost-based offers are greater than $1,000 per MWh and when high cost-based offers are the reason for high price-based offers.

Negative markups exist when price-based offers are less than cost-based offers. Negative markups reflect the difference between unit offers at what unit owners believe are competitive levels (price-based offers) and cost-based offers. If price-based offers are less than cost-based offers it means that unit owners recognize that the cost-based offer is greater than the competitive offer.

The level of maintenance costs approved by PJM exceeds short run marginal costs in general, and dramatically exceeds short run marginal costs for combustion turbines. Maintenances costs directly affect energy market prices and uplift.

1. Negative Markup

Table 2 shows the percentage of marginal units that had markups above, below, or equal to zero for coal, gas and oil fuel types. In 2017, 45.45 percent of coal units had negative markups.

Table 2 Percent of marginal units with markup below, above and equal to zero (By fuel type): 2017[15]

	2016			2017		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	58.25%	22.45%	19.30%	45.45%	22.22%	32.32%
Gas	22.46%	16.52%	61.02%	36.06%	13.01%	50.93%
Oil	11.80%	84.58%	3.61%	25.13%	73.87%	1.01%

Figure 1 shows the frequency distribution of hourly markups for all gas units offered in 2016 and 2017.[16] The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions. Of the gas units offered in the PJM market in 2017, nearly 28 percent of gas unit-hours had a maximum markup that was negative. More than six percent of gas fired unit-hours had a maximum markup above $100 per MWh.

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15 2017 State of the Market Report for PJM, Vol. 2, Section 3: Energy Market, Table 3-39.

16 2017 State of the Market Report for PJM, Vol. 2I, Section 3: Energy Market, Figure 3-30.

Figure 1 Frequency distribution of highest markup of gas units: 2016 and 2017

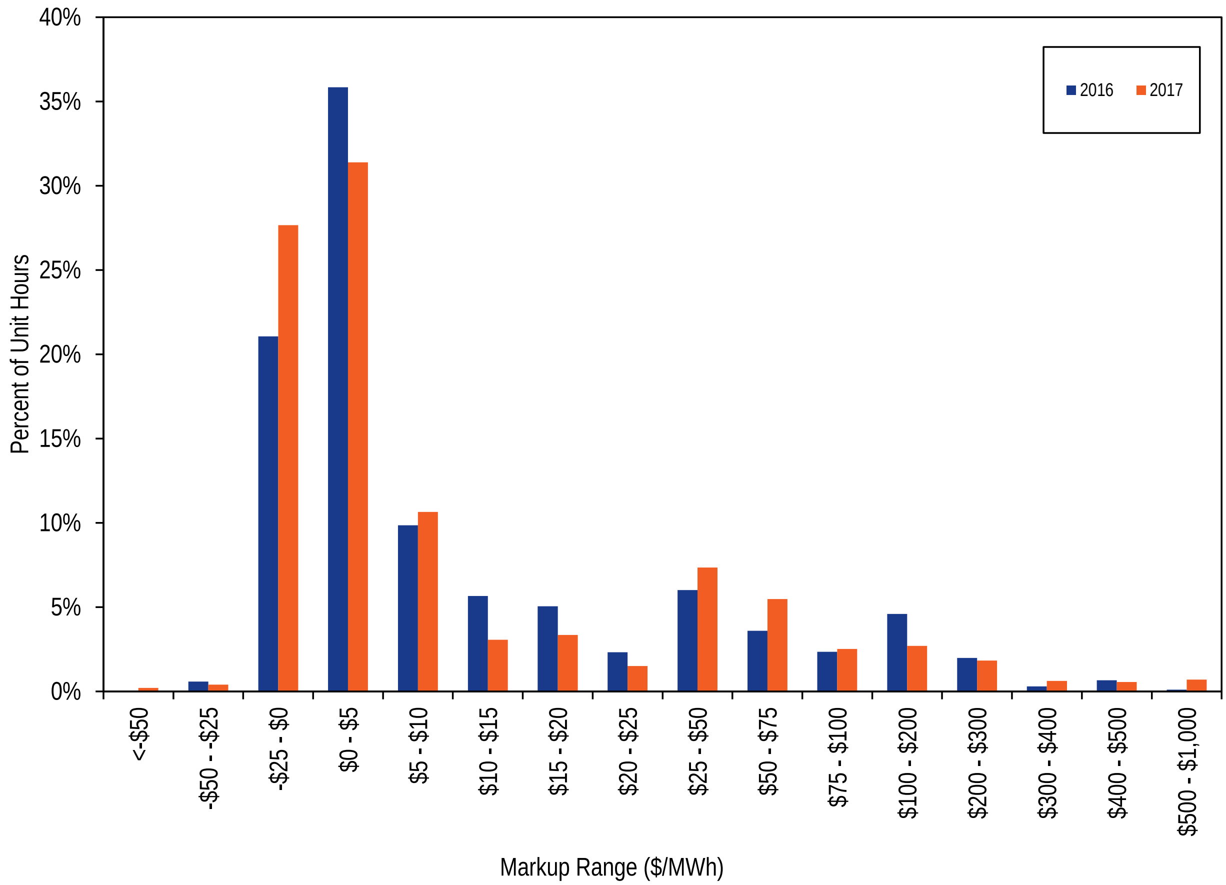

Figure 2 shows the frequency distribution of hourly markups for all coal units offered in 2016 and 2017.[17] Of the coal units offered in the PJM market in 2017, nearly 41 percent of coal unit-hours had a maximum markup that was negative.

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17 2017 State of the Market Report for PJM, Vol. 2, Section 3: Energy Market, Figure 3-31.

Figure 2 Frequency distribution of highest markup of coal units: 2016 and 2017

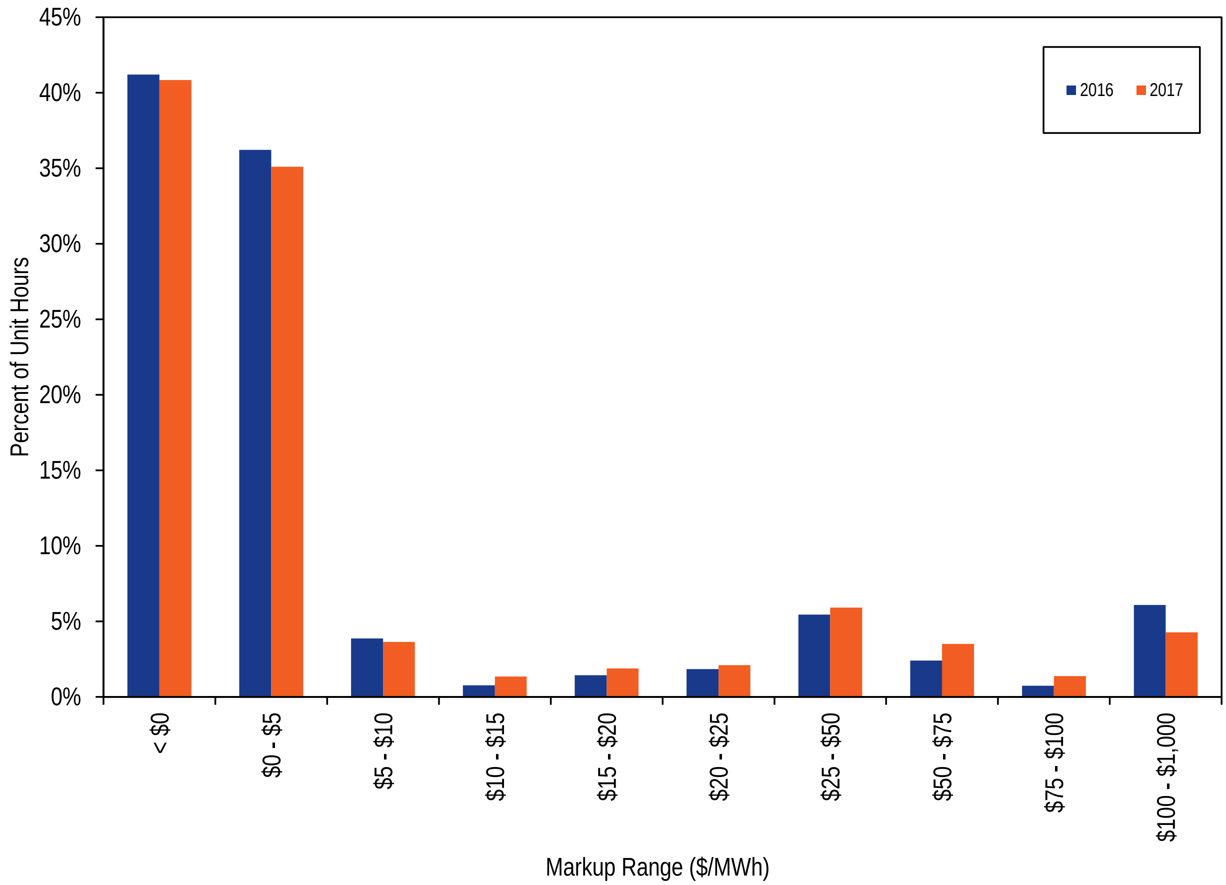
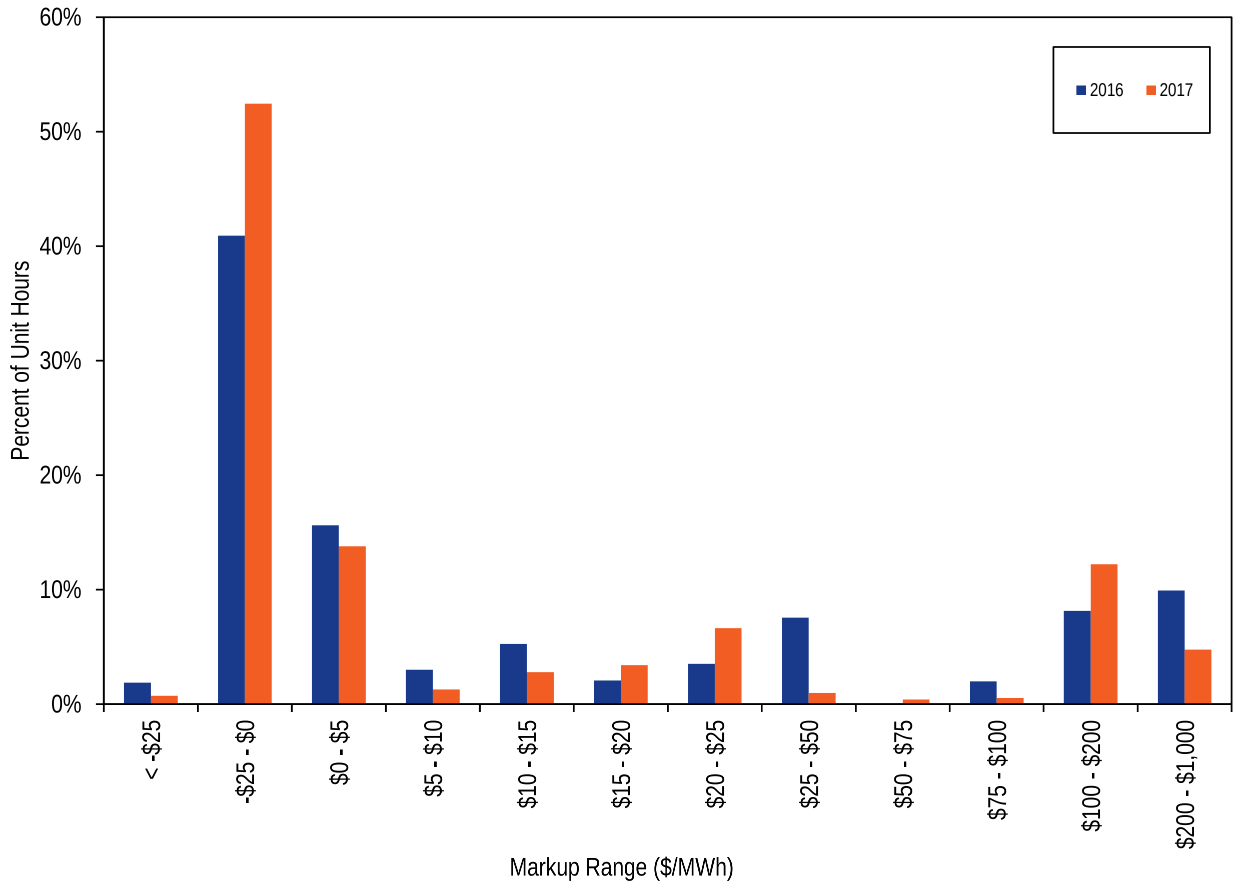


Figure 3 shows the frequency distribution of hourly markups for all offered oil units in 2016 and 2017.[18] Of the oil units offered in the PJM market in 2017, nearly 53 percent of oil unit-hours had a maximum markup that was negative.

[18] 2017 State of the Market Report for PJM, Vol.2, Section 3: Energy Market, Figure 3-32.

Figure 3 Frequency distribution of highest markup of oil units: 2016 and 2017



The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. Competitive price-based offers reveal actual unit marginal costs and that the PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs. PJM's proposed changes would exacerbate this issue.

The frequency of negative markups shows that cost-based offers exceed the competitive offer level for many generating units. PJM mitigates the offers of sellers with market power to the lesser of the market-based or cost-based offer. As a result, generating units that fail the TPS test may have their offers set to a level greater than the competitive level and be committed on noncompetitive offers with the result that prices are affected by market power. Overstated maintenance costs, in some cases at extremely high levels, can also be a mechanism for the exercise of aggregate market power when markets are tight.

The maintenance costs are used as support for the high price-based offers. Overstated maintenance costs can also be a mechanism for the exercise of aggregate market power when costs are asserted to be greater than $1,000 per MWh. Offers greater than $1,000 per MWh can only be based on costs.

2. PJM Maintenance Cost Approval

As part of its March 6, 2017, offer flexibility compliance filing, PJM proposed a review process for variable operations and maintenance (VOM) costs. In 2017, PJM began requesting information from Market Sellers regarding the calculation of VOM costs and approving such costs without input from the Market Monitor.

Manual 15 allows for the calculation of maintenance cost in dollars per MMBtu, dollars per equivalent operating hour (EOH) and dollars per start. Manual 15 allows the use of maintenance costs, excluding long term maintenance costs and LTSA costs, in dollars per MWh in the peaking segments of incremental cost curves for combustion turbines and combined cycles. The Market Monitor converted all VOM costs in dollars per EOH and in dollars per MMBtu into dollars per MWh.

Table 3 shows the range of PJM approved VOM costs for combustion turbines and engines.[19] Table 3 shows the number of units and economic maximum (MW) by ranges defined as multiples of the Market Monitor's benchmark of $0.25 per MWh. Table 3 shows that PJM approved VOM costs exceeded the Market Monitor's benchmark, and that 77 units had VOM costs greater than 100 times the Market Monitor's benchmark.[20] The average PJM approved VOM cost for combustion turbines and engines was $48.42 per MWh. The average is skewed by high outliers.

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19 2017 State of the Market Report for PJM, Vol. 2 Section 3: Energy Market, Table 3-48. The $0.25 benchmark was increased in 2018 to $0.38 per MWh.

20 The number of companies and units below the Market Monitor's benchmark means that this information cannot be provided under the PJM confidentiality rules.

Table 3 PJM approved VOM Costs for combustion turbines and diesels.

VOM Cost Range	Number of units	Economic Max (MW)
Between $0.01 and $0.25 per MWh	Confidential	Confidential
Between $0.25 and $2.50 per MWh	96	9,788
Between $2.50 and $25.00 per MWh	160	10,075
More than $25.00 per MWh	77	2,540

Table 4 shows the range of PJM approved VOM costs for combined cycles.[21] Many, but not most, combined cycles have approved VOM costs consistent with short run marginal costs. Table 4 shows the number of units and economic maximum (MW) by ranges defined as multiples of the Market Monitor benchmark of $1.00 per MWh.[22] Table 4 shows that 34 units had approved VOM costs within the Market Monitor benchmark, and that 14 units had VOM costs greater than four times the Market Monitor benchmark. The average PJM approved VOM cost for combined cycles was $3.59 per MWh. The average is skewed by high outliers but the outliers cannot be individually posted based on PJM confidentiality rules.

Table 4 PJM approved VOM Costs for combined cycles

VOM Cost Range	Number of units	Economic Max (MW)
Between $0.01 and $1 per MWh	34	15,424
Between $1 and $2 per MWh	28	13,932
Between $2 and $4 per MWh	9	2,629
More than $4 per MWh	14	2,614

Table 5 shows the range of PJM approved VOM costs for coal units.[23] The majority of coal units use VOM costs consistent with short run marginal cost, and, as Table 2 shows, the majority offer below their approved level. Table 5 shows the number of units and economic

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21 2017 State of the Market Report for PJM, Vol. 2, Section 3: Energy Market, Table 3-49.

22 2017 State of the Market Report for PJM, Vol. 2 Section 3: Energy Market, Table 3-48. The $1.00 benchmark was increased in 2018 to $1.09 per MWh.

23 2017 State of the Market Report for PJM, Vol. 2, Section 3: Energy Market, Table 3-50.

maximum (MW) by ranges defined as multiples of the Market Monitor benchmark of $4.00 per MWh.[24] Table 5 shows that 72 units had approved VOM costs within the Market Monitor benchmark, and that 52 units had VOM costs greater than the Market Monitor benchmark and lower than four times the Market Monitor benchmark. The average PJM approved VOM cost for coal units was $4.35 per MWh. The average is skewed by high outliers but the outliers cannot be posted based on PJM confidentiality rules.

Table 5 PJM approved VOM Costs for coal units

VOM Cost Range	Number of units	Economic Max (MW)
Between $0.01 and $4 per MWh	72	29,080
Between $4 and $16 per MWh	52	16,157
Between $16 and $40 per MWh	0	0
More than $40 per MWh	0	0

The current approval process instruction from PJM to generators states that generators "can include repair, replacement, inspection and overhaul expenses related to steam turbines, generators, boilers, heat recovery steam generators, main steam, feed water, condensate, condensers, cooling towers, transformers, control systems, and fuel systems."[25] This instruction goes beyond the concept of costs that "result from electric production." The equipment described in PJM's instructions needs preventive maintenance to prevent damages or performance issues. The equipment needs corrective maintenance to correct damages or restore normal performance levels. The equipment may be improved by maintenance projects that increase availability and performance. Some of these maintenance activities and/or projects are done based on a schedule provided by the manufacturer. Others are done based on the expertise of the plant staff. Many of these maintenance activities are not performed based on generator output, run hours, or starts.

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24 2017 State of the Market Report for PJM, Vol. 2 Section 3: Energy Market, Table 3-48. The $4.00 benchmark was increased in 2018 to $4.03 per MWh.

25 VOM Template 2018, PJM Markets and Operations, <https://pjm.com/-/media/markets-ops/energy/fuel-cost-policy/vom-template.ashx?la=en>, accessed November 15, 2018.

None of them are short run marginal costs. PJM's instructions are not consistent with the OA or Manual 15.

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are set to cost to mitigate market power or when units are required for reliability. The Market Monitor's recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test, or are needed for reliability, and are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

3. Impact on Energy Market Prices

To estimate the change in energy market prices due to maintenance costs, the Market Monitor replaced actual marginal unit VOM with the Market Monitor's short run marginal cost benchmark for marginal units with VOM in excess of the benchmark in the first six months of 2018. Table 6 provides the contribution to locational marginal price (LMP) of the components of offers with the actual offer VOM and the benchmark for the first six months of 2018. In the first six months of 2018, VOM accounted for 5.5 percent of PJM LMP. With offers at short run marginal cost, the amount falls to 2.5 percent of LMP. Table 6 does not include any change to market dispatch and commitment due to withholding facilitated by the use of cost-based offers above competitive levels. The October 2016 Filing's proposal will exacerbate these effects.

Table 6 Variable operations and maintenance cost contribution to real-time LMP, current and adjusted to short run marginal cost: January through June, 2018

Element	VOM Contribution to LMP	Percent	Adjusted VOM Contribution to LMP	Percent
Gas	$16.09	37.9%	$16.09	37.9%
Coal	$7.22	17.0%	$7.22	18.8%
Markup	$5.06	11.9%	$5.06	17.0%
Oil	$3.40	8.0%	$3.40	8.0%
Ten Percent Adder	$2.96	7.0%	$2.96	6.4%
NA	$2.73	6.4%	$2.73	5.5%
VOM	$2.34	5.5%	$1.11	2.6%
Increase Generation Adder	$1.10	2.6%	$1.10	1.4%
LPA Rounding Difference	$0.63	1.5%	$0.63	1.4%
Ancillary Service Redispatch Co	$0.60	1.4%	$0.60	0.5%
CO2 Cost	$0.22	0.5%	$0.22	0.5%
Municipal Waste	$0.20	0.5%	$0.20	0.2%
Opportunity Cost Adder	$0.08	0.2%	$0.08	0.2%
NOx Cost	$0.07	0.2%	$0.07	0.1%
Other	$0.04	0.1%	$0.04	0.1%
Market-to-Market Adder	$0.01	0.0%	$0.01	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Constraint Violation Adder	$0.00	0.0%	$0.00	0.0%
Wind	($0.01)	0.0%	($0.01)	(0.0%)
LPA-SCED Differential	($0.10)	(0.2%)	($0.10)	(0.2%)
Decrease Generation Adder	($0.20)	(0.5%)	($0.21)	(0.5%)
Total	$42.44	100.0%	$41.21	100.0%

With 385,863 GWh of real-time load in the first six months of 2018, the difference in LMP translates to $474,610,901 more in real-time energy cost to load due to maintenance costs for six months. If the effect were similar for the remaining six months of the year, the impact of maintenance on LMP would be approximately $950 million a year. This would be the impact if prices settled at real-time LMP. It does not include effects on uplift, or increases in prices from economic withholding such that the market does not commit a unit due to the inclusion of maintenance in any part of the three part offer.

4. Potential Impacts to Uplift Payments

Increased offers due to the inclusion of maintenance costs directly increase uplift payments. In 2017, 7,756 GWh were made whole via day-ahead operating reserves (day-ahead uplift). The average payment was $9.88/MWh. An increase of $1/MWh results in an increase of $8 million in uplift. In 2017, 6,357 GWh were made whole via balancing operating reserves (real-time uplift). The average payment was $9.00/MWh. An increase of $1/MWh results in an increase of $6 million in uplift. Summing day-ahead and balancing payments, an increase of $1/MWh in offers would result in an increase of $14 million in uplift.

Based on these data, the effect of maintenance costs on uplift is in the tens of millions of dollars per year. That is in addition to the approximate $950 million impact the Market Monitor calculates due to the VOM component of LMP, which does not include the effect of economic withholding.

5. Market Based Rate Authority

In approving market based rates for PJM Market Sellers, the Commission may rely on a presumption that the RTO market power mitigation plan adequately mitigates market power. PJM's practice of allowing cost-based offers to exceed competitive levels call into question the presumption of adequate mitigation on which the Commission relies.[26]

C. The Market Monitor Recommends that the Commission Require PJM to Limit Cost-based Offers to Short Run Marginal Costs.

The Market Monitor recommends that the Commission require that the PJM OATT define cost-based offers to equal short run marginal costs and that short run marginal costs be defined as the cost of inputs consumed and the net cost of byproducts created at the time

26 Order 697-A, Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 123 FERC ¶ 61,055 (April 21, 2008).

of power production. The Market Monitor recommends that the Commission clarify that maintenance costs are not short run marginal costs and are avoidable costs.

D. Manual 15 (Cost Development Guidelines) History

Manual 15 contains the rules that govern the development of cost-based offers. The current guidelines date back to the years in which PJM was a tight power pool comprised of regulated, cost of service utilities. These guidelines were not developed for the purpose of market power mitigation. These guidelines were developed to standardize cost accounting procedures among the regulated utilities participating in the PJM power pool to facilitate cost sharing and coordinated dispatch.

The 1989 version of the PJM Cost Development Guidelines manual shows the goal of these rules and the responsibility of the task force responsible:[27] "The primary responsibility of the Task Force is to review the determination and application of the various operating and maintenance costs applied in system operation and accounting to determine, where prudent and justifiable, the applicability of standardized procedures."

Regarding maintenance costs, at least since 1989, the PJM Cost Development Guidelines method for the development of maintenance costs is to utilize FERC accounts as the source of costs that can be included in cost-based offers. The FERC accounting system and the Cost Development Guidelines predate the existence of power markets. The FERC accounting system was not created to separate short run marginal costs from avoidable costs. It was not created to provide a guideline on the development of competitive offers in a market. Even the inclusion of PJM's interpretation of incremental costs, "expenses incurred as a result of electric production" was introduced in the Cost Development Guidelines on April 6, 2011, more than a decade after the creation of the PJM market.[28]

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27 *See* Attachment.

28 Manual 15 § 2.6.

PJM has maintained the same cost-development guidelines document for at least forty years. The creation of markets and all the subsequent market design enhancements never prompted PJM to abandon the repeatedly edited document. PJM has failed to create guidelines for the development of cost-based offers that reflect competitive offers.

1. Stakeholder Process

In 2011, a problem statement was presented at the Cost Development Subcommittee to "Eliminate Conflicting Language in Manual 15's Treatment of Capital Expenses for CT's and ACR Eligibility."[29]

The proposal description was "to remove the inclusion of overhaul and inspection costs from CTs and CCs in the variable operating and maintenance cost aligning the treatment of these types of units with other generation types." Overhaul and inspection costs are the bulk of long term, major maintenance costs for combustion turbines, including combined cycle plants. This description makes clear that the exclusion of long term maintenance costs was meant to align the rules for all generators. The rule change was the opposite of discriminatory. By ignoring the rule change in 2012, PJM has not followed the market rules by allowing major maintenance in cost-based offers, regardless of the technology or fuel type of the generating unit.

The proposal to remove these maintenance costs from energy offers was approved in 2011 and incorporated in the Cost Development Guidelines on February 8, 2012 (Manual 15 Version 18). The changes are found in Sections 5.6 and 6.6 of Manual 15. In order to align the new rule with the PJM capacity market delivery year, the rule was set to be effective and became effective starting with the 2015/2016 delivery year on June 1, 2015.

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[29] *See* "CC/CT Overhaul Recovery Manual 15 Changes History," Monitoring Analytics presentation to the Markets Implementation Committee, July 25, 2017, <http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MIC_CT-CC_Overhaul_Recovery_M_15_Changes_History_20170725.pdf>.

In 2017, PJM began a stakeholder process to discuss VOM and propose rules that would clarify which variable operations and maintenance costs are includable in cost-based offers.[30] The only motive cited in the problem statement written by PJM to initiate the stakeholder process was the differing interpretation of allowable costs between PJM and the Market Monitor. Rather than establishing a goal of defining competitive offers, PJM disagreed that the incremental costs includable in cost-based offers should be restricted to short run marginal costs.

The stakeholder process began in May 2017. PJM proposed that all maintenance costs "incurred as a result of electric production" be includable in cost-based offers. The Market Monitor proposed that cost-based offers be based only on short run marginal costs, and since maintenance costs are not short run marginal costs, maintenance costs should not be included in cost-based offers. Both proposals failed in the stakeholder process. PJM offers its proposal in this proceeding.

II. ALTERNATIVE PROPOSAL

The Market Monitor also offers its proposal to rectify the unjust and unreasonable language in Operating Agreement Schedule 2 and to align the PJM Market Rules with the Commission's expectations.[31] [32] The Market Monitor's proposal would limit cost-based offers to the competitive level, short run marginal cost, and eliminate the use of Manual 15, so that all provisions that substantially affect rates would be included in OA Schedule 2.

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30 *See* PJM Issue Details: Variable Operation and Maintenance Costs <*https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={49DFD7B6-1E99-488F-BC00-D6750114DF15}*>.

31 *See* FMU Order at P 25.

32 "Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets," Docket AD14-14 (October 2014) at 4.

The revised Schedule 2, Section 1.1(a) should specify all determinants of incremental energy costs, start costs, and no load costs.[33] For example, the Market Monitor proposes to replace the current language with:

**SCHEDULE 2 –
COMPONENTS OF COST**

1.1 Permissible Components of Cost-based Offers.

(a) Each Market Participant obligated to sell energy on the PJM Interchange Energy Market at cost-based rates will only include the following determinants or their equivalent in the calculation of costs for energy supplied to or from the PJM Region:

i. For incremental energy cost curves

Fuel cost, heat rate, emissions allowance cost, operating cost, opportunity costs

ii. For no load costs

Fuel cost, no load heat input, emissions allowance cost, operating cost

iii. For start costs

Start fuel cost, heat input, station service power cost, operating cost

The levels of cost-based incremental energy costs, no load costs, and start costs, as well as their determinants shall not exceed Short Run Marginal Costs. Short Run Marginal Costs are the cost of inputs consumed and the net cost of byproducts created at the time of power production.

The language in Schedule 2, Section 1.2 directing the use of Manual 15 should be struck and replaced with equations detailing the correct calculation of cost-based offers. Removing the reference to the Cost Development Guidelines from OA Schedule 2 and replacing it with equations detailing the correct calculation of cost-based offers is necessary to eliminate the issue that both PJM and the Market Monitor raise, that the current rules are

33 OA Schedule 1, Sections 1.1 and 6.4.2 also contain provisions related to cost-based offers that must be revised.

unjust and unreasonable. Manual 15 is not subject to review under the just and reasonable standard.

III. PROTEST

A. The Problem Identified by PJM is the Use of the Cost Development Guidelines.

PJM's filing demonstrates that the use of Manual 15 is a problem. PJM does not identify any specific language in Operating Agreement Schedule 2 that it finds unjust, unreasonable, or discriminatory. PJM wants to change Manual 15, but PJM has not received the stakeholder support necessary to make PJM's preferred changes. It is clear from the Market Monitor's analysis that the rules in Manual 15 significantly affect rates. In addition, the level of concern among stakeholders and the opposition by stakeholders is evidence that it is widely understood that the rules in Manual 15 significantly affect rates and therefore that these rules belong in the OATT or Operating Agreement. Under the rule of reason, all of the relevant details for cost development should be included in the PJM tariff. The rule of reason requires that "all practices that significantly affect rates, terms and conditions fall within the purview of section 205(c) of the FPA, and, therefore, must be included in a tariff filed with the Commission."[34] These rules are core to market power mitigation and directly affect the rates paid by customers.

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34 *See, e.g., Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,296, 62538 (2018) ("PJM's December 2015 adjustments to the benefits factor curve, including PJM's actions to implement through its manuals an entirely different curve that capped RegD participation in certain hours, illustrate how the methodology for establishing the benefits factor is not a mere implementation detail, but instead significantly impacts RegD resources' participation in the Regulation market and, ultimately, Regulation market clearing. Although we find that PJM must include the methodology for calculating the benefits factor curve in its Tariff, we agree with PJM that it must retain the operational flexibility to effectively control ACE without unnecessary delay. Requiring PJM to maintain the benefits factor calculation methodology in its Tariff permits PJM to set forth implementation and operational details, which may vary over time and may not be reasonably susceptible to specification, in PJM manuals."); *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076, at P 656 (2007) ("Our policy is that all practices that significantly affect rates, terms and conditions fall

B. PJM Ignores the Fact that Schedule 2 and the OA Limit Cost-based Offers to Incremental Costs.

PJM filed tariff revisions proposing to add the term Maintenance Adder to Schedule 2 in 2017.[35] The use of this term without reference to incremental costs created an opportunity for PJM to argue for a new definition of allowable maintenance costs. The Commission has not issued an order on PJM's revision to include the new term in OA Schedule 2, but PJM assumes it as accepted language in making additional revisions in the October 206 filing. The new term, Maintenance Adder, is redundant with the previously existing terms, Peak-prepared-for maintenance cost and incremental maintenance cost. It is also redundant with the term Other incremental operating costs, because PJM's definition of Maintenance Adder includes variable operation and maintenance expenses. The addition of the redundant term Maintenance Adder does not change the fact that OA 6.4.2(a)(ii) allows only incremental costs to be included in cost-based offers. The term Maintenance Adder should be rejected by the Commission.

1. Generator Costs, as Defined by PJM, are Not Clear

PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," proves too much. Most costs incurred at a generating station result

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within the purview of section 205(c) of the FPA, and, therefore, must be included in a tariff filed with the Commission. Further, we have found that our 'rule of reason' test requires a case-by-case analysis...."); *see also Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 (1993), citing City of Cleveland v. FERC, 773 F.2d 1368, 1376 (D.C. Cir. 1985) ("[There] is an infinitude of practices affecting rates and service. The statutory directive must reasonably be read to require the recitation of only those practices that affect rates and service significantly, that are realistically susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous. It is obviously left to the Commission, within broad bounds of discretion, to give concrete application to this amorphous directive."); Public Service Commission of New York, et al. v. FERC, 813 F.2d 448, 454 (D.C. Cir. 1987) (held that the Commission properly excused utilities from filing policies or practices that dealt only with matters of "practical insignificance" to serving customers).

35 *See* PJM Compliance Filing, Docket ER16-372 (March 6, 2017) at 7.

from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's definition does not clearly define which costs associated with electric production are includable in cost-based offers. The lack of clarity leaves the definition of incremental costs to the discretion of PJM and generators. The result would be to make review of cost-based offers unverifiable. The Commission should reject PJM's proposed definition of marginal costs.

C. PJM's Proposed Tariff Revisions Do Not Provide the Clarity Needed by Market Sellers, PJM, and the Market Monitor.

PJM first raised its disagreement regarding allowable costs in cost-based offers more than two years ago in response to complaints from generators that the Market Monitor expected cost-based offers to include only short run marginal costs. The disagreement created uncertainty for Market Sellers regarding the expectations for compliance and undermines the enforceability of the rules.

1. Market Sellers Need Clear Rules to Implement Tariff Compliant Cost Development Practices.

Generators rely on their accounting systems to record maintenance expenses at the plant. Many generators use this accounting information to calculate the maintenance costs included in cost-based offers. But, because the PJM Market Rules, and those proposed in the October 206 Filing, allow a subset of maintenance costs in cost-based offers, compliance requires item by item review of maintenance accounts under the PJM approach. The categorization of costs as maintenance at the plant does not generally involve a determination of whether such costs are includable as incremental costs under OA Schedule 2. Under the PJM approach, a subsequent compliance review is required to remove certain costs.

Manual 15 asks generators to use maintenance expenses for the past 10 to 20 years. The Market Monitor is not aware of any generator that has performed an item by item review of its 20 year maintenance accounts to determine compliance of each item with PJM's interpretation of OA Schedule 2. PJM does not perform an item by item review of historical maintenance costs. PJM's current interpretation and the October 206 Filing proposal suggest that Market Sellers would review 20 years of maintenance project invoices to determine what portion was "incurred as a result of electric production." That is implausible and PJM has not explained how this approach would or could actually be implemented.

The Market Monitor has reviewed the items in some generators' maintenance accounts. The reviewed maintenance accounts included items that are clearly not short run marginal costs, such as maintenance to building structures, replacement of equipment not directly involved in power production, maintenance supervision and labor, spare parts, and insurance. In fact, there are no maintenance costs that are short run marginal costs. PJM has not provided lists of compliant and noncompliant costs sufficient to permit Market Seller's review of their maintenance account items or sufficient to permit the Commission to make a compliance determination. Applying a compliance review based on such a list, unless it allows for everything in the FERC maintenance accounts, would be an intrusive and costly change to generator accounting practices and to any serious monitoring and enforcement efforts, even if the PJM proposal were evaluated on its own terms. This problem persists with any proposal that would allow maintenance costs in cost-based offers. Restricting cost-based offers to short run marginal costs avoids the accounting difficulties and compliance risks associated with attempting to include maintenance costs in cost-based offers.

2. PJM's Proposed Revisions Allow for Multiple Interpretations.

PJM has changed its interpretation of the PJM Market Rules.[36] PJM's proposed revisions in this filing provide no clarity to prevent future changes of interpretation. PJM simply adds language stating that "Maintenance Adders may include expenses incurred as

36 *See* October 206 Filing at 17.

a result of electric production…" PJM also adds some includable items such as long term service agreement expenses. The language is otherwise unclear.

PJM does not address the use of FERC accounts. PJM does not state which repairs or what replacements constitute maintenance as a result of electric production. For example, PJM's proposed language does not provide state whether replacement would include replacement of an entire turbine, replacement of turbine blades, or only replacement of filters. PJM does not state whether replacement includes replacement of light bulbs or computer equipment. PJM's proposed language does not state whether repairs include only repairs to turbines, engines and generators or also include repairs to balance of plant equipment like transformers, breakers, metering equipment, controls, etc.

Schedule 2 contains two terms that refer to maintenance costs: Peak-prepared-for maintenance cost and Incremental maintenance cost. The term Maintenance Adders was proposed by PJM but not approved by the Commission as part of Schedule 2. The term Maintenance Adder is defined in the Operating Agreement. PJM or generators may argue for the inclusion of other costs under the undefined terms.

PJM is proposing a new term called Operating Costs while leaving the existing term Other incremental operating costs. The latter is not defined in the tariff. The Commission should direct PJM to include only one, properly defined, operations cost component.

3. Data is Not Required to Interpret the Tariff.

In the October 206 Filing, PJM provides a justification for changing its interpretation of the rules based on its review of data on costs, which began in August 2017.[37] This cannot be PJM's primary justification for its proposal, because PJM initiated the rule change in the

37 October 206 Filing at 17-18.

stakeholder process before it began its review of variable operations and maintenance costs.[38]

Regardless of PJM's reasons, reviewing the costs requested by Market Sellers for use in their cost-based offers should not change PJM's interpretation of what is allowable. In the correct model of tariff implementation, PJM and the Market Monitor learn about the specifics of unit costs from Market Sellers and then determine which are short run marginal costs, avoidable costs, and fixed costs. The definitions of the types of costs are not contingent on the requests and desires of Market Sellers. The fact that some PJM Market Sellers requested PJM's approval to include costs that violate the PJM Market Rules does not justify changing the rules.

PJM argues that coal and nuclear resources include avoidable maintenance costs in their cost-based offers.[39] This is not generally true, as shown in Table 5. PJM does not address the fact that Market Sellers routinely offer below their offer cap, especially coal and nuclear resources.[40] The observed offer behavior indicates that coal generators offer competitively most of the time. But, as the Market Monitor has reported consistently, some

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38 *See* Agenda Item 6, Markets Implementation Committee (May 3, 2017), presenting the problem statement and issue charge to initiate the stakeholder process, <https://www.pjm.com/-/media/committees-groups/committees/mic/20170503/20170503-agenda.ashx>, and "Fuel Cost Policy Update: Annual Review," PJM Presentation to the Markets Implementation Committee (June 7, 2017), documenting the first deadline for VOM policies of August 1, 2017, <https://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-item-16a-fuel-cost-policy-update.ashx>.

39 *See* October 206 Filing at 17.

40 *See* Table 2. The statistics for nuclear generators are not provided to protect confidentiality. However, it is well understood that a de minimis level of nuclear power costs vary with output level and that nuclear fuel costs do not vary with output.

coal resources overstate costs and receive higher than competitive compensation when they have market power.[41]

D. The Commission's Determination Regarding SPP's Maintenance Cost Component is Not a Precedent for PJM.

PJM cites the Commission's recent approval of a major maintenance cost component for mitigated offers for Southwest Power Pool. The SPP major maintenance component is not a precedent for PJM. In SPP, almost all generating units are subject to cost of service regulation which ensures full recovery of all costs. PJM requires a consistent efficient market framework for the markets that SPP does not require. The SPP market rules are also not comparable to PJM's, because SPP's tariff supports mitigated offer development with a level of specificity that is missing from the PJM Market Rules. For all these reasons, the Commission should evaluate PJM's proposal, and alternate proposals in this docket, without deference to rules established for other RTOs.

1. The SPP Members Chose to Share Costs in this Way.

Despite their recognition that maintenance costs are not short run marginal costs, the Southwest Power Pool (SPP) members, vertically integrated regulated utilities, chose to share costs by including maintenance costs in mitigated offers.[42] The SPP thermal generation fleet is almost exclusively owned and operated by fully regulated utilities that provide distribution, transmission, and generation to their customers. The SPP market facilitates efficient regional power dispatch and cost savings. The SPP market does not substitute for cost of service regulation as the PJM market does.

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41 *See* 2018 State of the Market Report for PJM, January through September, Section 3: Energy Market, p. 145-146 and Section 4: Uplift, p. 224.

42 *See* Submission of Tariff Revisions to Implement a Major Maintenance Cost Component to Mitigated Start-Up Offer and Mitigated No-Load Offer, Southwest Power Pool, Docket ER18-1632 (May 15, 2018).

The PJM members clearly did not make a choice to share costs by including maintenance costs in cost-based offers.[43] Over twenty years ago, when PJM was also a power pool among vertically integrated utilities, its members chose to share costs according to the FERC accounting system. (This is how the maintenance cost language came to be part of Manual 15.) That was before markets. The PJM states chose a different model, regulation through competition. The PJM market has a fundamentally different purpose than the SPP market. The PJM market facilitates regulation through competition in a restructured power market with separated distribution, transmission, and generation businesses. Regulation through competition requires a set of markets for energy, capacity, and ancillary services that provide consistent efficient, competitive price signals, even in the presence of market power. Regulation through competition requires mitigation to short run marginal costs for sellers with market power in order to ensure competitive outcomes. PJM's proposal will take PJM back to the era of the PJM power pool when transactions were based on the "split savings" method in order to achieve a more efficient dispatch among the participating companies. The PJM power pool rules were not intended to create a competitive market and market power was not mitigated when competition was unlikely.

2. The PJM Market Requires Efficient Entry and Exit Signals.

Unlike SPP, the PJM market requires efficient entry and exit signals for generators to support competition. Allowing generators with market power to offer costs in excess of short run marginal costs in the energy market distorts both efficient dispatch and efficient investment signals. Consider a generator with market power in the energy market that is

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43 "Item 01 – Draft Minutes – MRC – 7.26.2018," Markets and Reliability Committee (August 23, 2018) <https://www.pjm.com/-/media/committees-groups/committees/mrc/20180823/20180823-item-01-draft-minutes-mrc-20180726.ashx> and "Consent Agenda Item A – Draft Minutes – MC – 9.27.2018," Members Committee (October 22, 2018) <https://pjm.com/-/media/committees-groups/committees/mc/20181025/20181025-consent-agenda-item-a-draft-20180927-mc-meeting-minutes.ashx>.

not competitive in the capacity market. The overstatement of short run marginal costs allows the generator to inefficiently recover avoidable costs in the energy market and to correspondingly lower their capacity offer below a competitive level in order to maintain capacity revenues. The energy market clears at prices above competitive levels, and the capacity market clears at prices below competitive levels. Uneconomic capacity remains in the market due as a result of its market power. The outcome is clearly inefficient.

The inefficient outcome is intended by PJM. PJM proposed to its stakeholders that for "generating units that did not clear or have a capacity commitment for the current Delivery Year, costs shall include those that are allowed" under several categories of the Avoidable Cost Rate in Tariff Attachment DD, Section 6.8.[44] PJM's May 2018 proposal clearly meant to allow Market Sellers with uneconomic capacity resources to use market power in the energy market to impose inefficient capacity costs on customers.

SPP provides no precedent for PJM's proposal. SPP does not require efficient entry and exit signals from the market because its thermal generation fleet predominantly relies on cost of service regulation as the source of revenues. The Commission should recognize the significant differences in market design between SPP and PJM in evaluating PJM's proposal.

3. The SPP Major Maintenance Process Requires a Level of Scrutiny and Detail Not Included in PJM's Proposal.

While the Market Monitor disagrees with SPP's decision to allow costs that exceed short run marginal costs in its mitigated offers, SPP's mitigated offer development process maintains more scrutiny and its tariff includes more detail than PJM's vague proposal and

44 "Item 3A3 – VOM OA Schedule 2," PJM draft proposal for the Markets Implementation Committee (May 2, 2018), <https://www.pjm.com/-/media/committees-groups/committees/mic/20180502/20180502-item-03a3-vom-oa-schedule-2.ashx>, last accessed November 17, 2018. Also see <https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={49DFD7B6-1E99-488F-BC00-D6750114DF15}>.

vague OA Schedule 2 language. SPP's process also relies on its Market Monitoring Unit, rather than the RTO, to evaluate mitigated offers.

E. PJM Incorrectly Argues that the Current Rules Raise Cost Recovery Issues.

PJM claims that the current rules raise the risk of under recovery of costs for CCs and CTs because they are not allowed to include major maintenance in their cost-based offers. PJM has no basis for this statement. In reality, CCs and CTs have the highest levels of avoidable cost recovery in the PJM market, while nuclear and coal units have the lowest. Table 7 shows the extent of avoidable cost recovery by quartile for each generation technology in PJM. It shows that CCs and CTs recover avoidable costs several times over. Most coal and nuclear plants just recover avoidable costs, and some do not recover avoidable costs. The data do not support PJM's arguments that CCs and CTs face discriminatory cost recovery prospects in the PJM market.

Table 7 Avoidable Cost Recovery by Quartile: 2017[45]

		Recovery of avoidable costs from energy and ancillary net revenue			Recovery of avoidable costs from all markets		
Technology	Total Installed Capacity (ICAP)	First quartile	Median	Third quartile	First quartile	Median	Third quartile
CC - Combined Cycle	56,286	1%	182%	362%	283%	424%	545%
CT - Aero Derivative	5,997	0%	10%	41%	295%	341%	386%
CT - Industrial Frame	21,317	0%	11%	27%	340%	427%	481%
Coal Fired	52,495	0%	10%	38%	74%	87%	117%
Diesel	412	0%	25%	212%	386%	443%	583%
Hydro	9,236	225%	319%	411%	331%	400%	561%
Nuclear	33,732	73%	85%	89%	85%	100%	102%
Oil or Gas Steam	8,178	0%	0%	6%	139%	161%	183%
Pumped Storage	31,091	397%	397%	973%	440%	749%	1023%

The new units in PJM that replaced the retiring units have been, almost without exception, combined cycles, the same units that PJM is claiming are at risk of under recovery of maintenance costs. Table 8 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets from 2011 through 2017. In 2017, 86 percent of combined cycles recovered their avoidable costs from all

45 2017 State of the Market Report for PJM, Vol. 2 , Section 7: Net Revenues, Table 7-29.

markets and 99 percent of all combustion turbines recovered their avoidable costs from all markets. In contrast, 52 percent of all coal units recovered their avoidable costs from all markets and 68 percent of all nuclear units recovered their avoidable costs from all markets.

Table 8 Proportion of units recovering avoidable costs: 2011 through 2017. [46]

	Units with full recovery from energy and ancillary net revenue							Units with full recovery from all markets						
Technology	2011	2012	2013	2014	2015	2016	2017	2011	2012	2013	2014	2015	2016	2017
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	62%	85%	79%	79%	95%	88%	93%	86%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	23%	100%	96%	76%	98%	100%	99%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	18%	99%	98%	83%	100%	100%	100%	99%
Coal Fired	-	-	25%	78%	18%	19%	19%	-	-	54%	83%	69%	40%	52%
Diesel	48%	42%	37%	69%	56%	33%	46%	100%	100%	77%	100%	100%	100%	100%
Hydro	74%	61%	95%	97%	81%	79%	95%	81%	77%	97%	98%	100%	100%	97%
Nuclear	-	-	79%	100%	53%	16%	21%	-	-	95%	100%	89%	58%	68%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	9%	92%	78%	86%	85%	91%	88%	88%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

PJM's market rules contain outdated provisions that allow a frequently mitigated generating unit (FMU) to use cost-based offers that exceed short run marginal costs when its market revenues do not exceed its avoidable costs. No generating units have qualified for FMU status since November 1, 2014.[47] If PJM's cost recovery concerns were valid, units would qualify as FMUs. PJM's cost recovery concerns have no basis.

Most importantly, PJM is not a cost of service regulator. It is not PJM's responsibility to guarantee long run cost recovery. It is PJM's responsibility to set up market design rules that allow competition and to mitigate resources to ensure competition in the presence of structural market power.

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46 2017 State of the Market Report for PJM, Vol. 2, Section 7: Net Revenues, Table 7-30.

47 2018 State of the Market Report for PJM: January through September, Section 3: Energy Market, p. 154.

IV. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this protest as it resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: November 19, 2018

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 Eagleville, Pennsylvania,
this 19th day of November, 2018.

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ATTACHMENT

Charter

The Cost Development Task Force (CDTF) was established in October, 1975, by the PJM Operating Committee (OC). Task Force membership includes one representative appointed by each of the Members and Associates of the Operating Committee, and one representative from the Interconnection Office.

The primary responsibility of the Task Force is to review the determination and application of the various operating and maintenance costs applied in system operation and accounting to determine, where prudent and justifiable, the applicability of standardized procedures.

Other Task Force responsibilities are as follows:

A. Aid unit commitment project by serving as IO/company interface during definition of a complete set of scheduling parameters.

B. Respond to PJM or regulatory agency audits by supplying technical expertise in the area of cost development as required based on concerns raised during these audits of PJM operation. Responsibilities include answering questions relating to cost development procedures, and expanding cost development guidelines, if necessary.

C. Ongoing assignments resulting from OC acceptance of unified cost development guidelines:

   1. Develop annual maintenance cost escalation factors.

   2. Review annual unit maintenance factors.

   3. Assign/accept maintenance factors for immature units.

   4. Assign/accept estimated fuel cost and maintenance factors for units whose operating parameters or characteristics have changed.

   5. Review requests for exemptions from standard cost guidelines based on unusual unit operation.