UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators	))))))	Docket No. RM16-5-000

COMMENTS OF THE
INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to the notice of proposed rulemaking issued in this docket on January 21, 2016 ("NOPR"), Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submits these comments on the Commission's proposal to revise its regulations to require that each regional transmission organization (RTO) and independent system operator (ISO) cap each resource's energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer.[1]

I. COMMENTS

A. Topics Requested by the Commission for Comment

The Market Monitor agrees that offers should not be held below actual short run marginal cost, even when that cost exceeds $1,000 per MWh. There should be no absolute hard cap on the level of short run marginal cost in the absence of market power. The LMP

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1 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 154 FERC ¶ 61,038. Current PJM market rules include a $1,000/MWh system offer cap (up to $2,000 for cost based offers) and a $1,000/MWh total compensation cap, including uplift. *See* PJM Operating Agreement ("OA") Schedule 1 §§ 1.10.1A(d) (energy offer cap) & 3.2.3(m)&(n) (total compensation cap).

markets function efficiently when units offer at short run marginal cost, whether low or high, and LMP reflects the short run marginal costs of the marginal units. The Market Monitor supports the Commission's proposal to permit offers above $1,000 per MWh only when such offers are cost based because the proposal permits verifiable short run marginal costs to set price while providing protection against the exercise of aggregate market power. The Market Monitor requests that the Commission clarify that such cost-based offers include the same limits on offer parameters as all other cost-based offers.

There is no reason that $1,000 per MWh should continue to be the dividing line between offers based on short run marginal costs and offers that may include markups. The $1,000 per MWh level could be reduced to $500 per MWh, for example, and it would be fully consistent with the Commission's logic in this NOPR. The data on offers included in the 2015 State of the Market Report for PJM, for example, shows that in 2015 only 0.17 percent of all offers were above $400 per MWh.[2]

The Market Monitor recommends that the $1,000 per MWh cap be interpreted to include a unit's operating rate which combines its incremental offer and no load offer on a per MWh basis.[3] Otherwise it would be possible for a unit to keep its incremental market-based offer below $1,000 while the operating rate was greater than $1,000 including the no load component of its offer. This could result in circumventing the Commission's $1,000 per MWh offer cap on market-based offers, permitting the exercise of market power and resulting in an increase in uplift payments. For example, if a marginal unit had a $999 per MWh market-based offer that incorporated a substantial markup over short run marginal costs and the unit were the marginal unit with a high no load offer, the unit would set LMP at $999 per MWh and recover no load costs in uplift payments. If the Commission does not

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2 2015 State of the Market Report for PJM Vol II (March 10, 2016) at 15, 77.

3 *See* OA Schedule 1 § 3.2.3(m)&(n). This rule limits total compensation to units including uplift consistent with the approach recommended here.

include both incremental and no load costs in the interpretation of the $1,000 per MWh cap, it will create the opportunity for units to circumvent the $1,000 per MWh offer cap (or other cap). Such an outcome would be an unintended, negative consequence of the Commission's intent to improve price formation.

The short run marginal costs of a unit in markets with three part offers are the basis for start up costs and no load costs in addition to incremental costs. Three part offers include start up costs, no load costs and incremental costs. Each of the three parts of all cost-based energy offers consist entirely of short run marginal costs. The Commission should incorporate all parts of the offer in offer caps. The Commission should explicitly direct that all three parts of offers that exceed $1,000 per MWh be required to be verifiable short run marginal costs. The start up, the no load and the incremental should all be required to be cost based when the operating rate exceeds $1,000 per MWh.

The Commission should order that the definition of an offer exceeding $1,000 per MWh should include no load and incremental costs.[4] Both elements of the offer are based on exactly the same short run marginal costs to produce power. A minimum level of no load costs is required to ensure that incremental offer curves are monotonically increasing, but with that limit, the dividing line between the no load and incremental components of the offer is arbitrary and reflects only the judgment of the seller. For example, a unit may be block loaded and all short run marginal costs of operation would be in the incremental rate offered for that one output level. The same unit could be offered with a range of output in which case the short run marginal costs of operation could be divided into no load and incremental components.

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[4] While start up costs should also be included, such inclusion requires an assumption of the run hours and MWh output over which the start up costs should be spread. This is impossible to do accurately. Using the minimum run time would give units an incentive to increase minimum run times, with the associated unintended consequences. The check on start up costs would be that they would also be subject to ex ante and ex post verification with associated penalties for failure to comply.

1. **Whether a hard cap on cost-based incremental energy offers used for purposes of calculating LMPs should be included in any final rule in this proceeding and, if so, whether the hard cap should equal $2,000/MWh or another value.**

Based on recent and foreseeable events, gas is the only fuel likely to result in offers greater than $1,000 per MWh. The most likely exception to this is oil, depending on conditions in world oil markets. The short run marginal costs of a gas fired unit are primarily a function of the cost of natural gas, and the higher the gas cost, the smaller the share of non-fuel costs.[5] Removal of any cap on short run marginal cost therefore relies on the competitiveness of the gas markets. If the gas markets exhibit structural market power and/or the ability of gas sellers to exercise market power during extreme market conditions, removal of the offer cap in the power markets will allow the impact of market power in the gas markets to flow through into the power markets. To the extent that companies are vertically integrated and include a gas marketing function, there could be additional incentives to exercise market power in the gas markets to exercise market power in the power markets. For this reason, in order to have confidence in the functioning of the power markets in the absence of a hard cap on short run marginal cost, it is essential that market participants have confidence in the competitiveness of the gas markets.

2. **The ability to timely verify the costs within incremental energy offers above $1,000/MWh prior to the day-ahead or real-time market clearing process, including whether the verification of physical offer components is also necessary.**

As noted in the NOPR, from the beginning of PJM markets, the offers of units are entirely the responsibility of the owners of the units making the offers in PJM markets. The result is to place responsibility for offers where it belongs. If the unit does not clear or the

5 When gas costs are $10 per MMBtu or above, gas costs typically comprise more than 95 percent of short run marginal costs for gas fired units.

unit exercises or attempts to exercise market power, the responsibility lies appropriately and entirely with the owner. Unit owners are subject to rules governing offers including the definition of short run marginal costs and the definition of certain offer parameters. In PJM, the Market Monitor does not have the authority to tell a unit owner what its fuel cost is or what its offer should be. But the Market Monitor does have the authority to verify cost-based offers, to discuss issues with unit owners and to refer unit owners to the Commission for violating the rules and for the attempted or actual exercise of market power.

Fuel cost policies are an essential part of the verification of cost-based offers in PJM.[6] The purpose of fuel cost policies is to ensure that market power is not exercised through the inclusion of fuel costs or other elements of the offer that are not cost based. The importance of fuel cost policies has risen substantially with the increased reliance on gas fired units in PJM and the impact of gas price volatility in setting prices in PJM markets during high demand periods. The goal of fuel cost policies is to create an algorithmic, verifiable and systematic approach to defining fuel costs. The Market Monitor includes as an Attachment the IMM Fuel Cost Policy Guidelines that the Market Monitor has provided to market participants for the development of algorithmic, verifiable and systematic fuel policies. For example, if a unit buys gas at a defined trading location on the pipeline system, the gas costs for the day-ahead offers could be equal to the Weighted Average Price (WAP) of trades executed on the Intercontinental Exchange, Inc. (ICE) prior to the offer entry.

The Market Monitor has had the responsibility for fuel cost policies in the PJM markets. The Market Monitor is currently engaged in an ongoing and somewhat lengthy

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6 "Incremental fuel cost" is listed among the components of costs for generating units powered by machines. OA Schedule 2. The PJM Cost Development Guidelines (PJM Manual 15) defines incremental fuel cost in greater detail and specifies the requirement that participants develop an approved fuel cost policy. PJM Manual 15 § 2.3 at 9–12.

process of working with PJM members to develop unit specific fuel cost policies for all gas fired generating units in PJM.[7]

The existence of a unit specific fuel cost policy approved by the Market Monitor for market power issues and approved by PJM for tariff compliance should be a required condition of making an offer in excess of $1,000 per MWh.[8]

The nature of information in the gas markets means that while it is reasonably straightforward to calculate gas costs for most days, it is most difficult to calculate gas costs on the very high demand days on which the gas costs matter most and on which gas costs are most likely to imply a power price in excess of $1,000 per MWh. On very high demand days, the gas market is least transparent and it is more likely that there would be no completed trades reported on ICE or only low gas volumes traded, and/or that the bid-ask spread would be so wide as to be meaningless. The gas market becomes primarily bilateral on such days and correspondingly opaque.

While out of scope for this NOPR, both this issue of transparency and the issue of market power in the gas market suggest that a longer term solution should reconsider the structure and design of the gas market and the potential for an independent system operator for the gas market.

In all cases, the cost of gas used in offers in the day-ahead market is based on the best available information about what the cost of gas will be during the operating day. The only condition under which the cost of gas is certain prior to submitting a day-ahead offer is when the gas is actually purchased prior to offer submission.

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7 As a result of the winter 2014 events and consideration of increased offer caps for cost-based offers, the Market Monitor determined that prior fuel cost policies were not adequate to protect the market and took steps, working in conjunction with participants, to improve them. Although significant progress has been made, the reforms are incomplete.

8 *See* OATT § 12A; OATT Attachment M § IV.E-1.

For this reason, it is essential that any verification process include the requirement that all offers follow the rules, that all offers follow the associated approved fuel cost policy, that all offers reflect the best information available to unit owners at the time that offer decisions are made, that all offers are subject to rigorous and timely after the fact review and that the Commission impose significant penalties for violating the rules if that is determined during the after the fact review. The after the fact review is not to check the actual cost of gas purchased for offers above $1,000 per MWh in cases where the offers passed the ex ante screen and were permitted to set LMP. The after the fact review in that case is to determine whether unit owners relied on the best available information about the expected cost of gas at the time the offer was submitted. However, in cases where the offer above the $1,000 per MWh threshold is not accepted by the Market Monitor or by PJM, the after the fact review to determine eligibility for uplift payments should be based on actual incurred gas costs and whether they were reasonable. The result would be that any uplift payments for offers above $1,000 per MWh would be based on the actual gas cost incurred. Given the relative opacity of the gas markets on high demand days, it is critical that unit owners have a strong incentive to follow the rules.

The ex ante review process can provide reasonable assurance that cost-based offers reflect the best information about the cost of gas expected during the operating day when costs will actually be incurred. But the ex ante review process requires strong compliance incentives because of the nature of information in the gas market on high demand days. In addition, in PJM the volume of data to be processed in a short time is quite large, including about 420 gas fired units and about 35 gas trading points.

The Market Monitor will work with PJM to ensure that the mechanics of the ex ante review process work as effectively as possible in the PJM day-ahead market processes. The Market Monitor will review offers ex ante and provide the results of that review to PJM. The Market Monitor will attempt to communicate with the unit owner if the Market Monitor believes that an offer is not based on the cost of gas. The Market Monitor will make recommendations to PJM about whether a cost-based offer in excess of the defined threshold is consistent with the fuel cost as defined in the fuel cost policy or whether it is not and therefore whether it passes the market power mitigation screen. It is PJM's decision about whether to accept an offer if the Market Monitor determines that it is not based on the cost of gas. Regardless of PJM's decision, the Market Monitor will perform a timely ex post review and make referrals to the Commission as required.

3. Whether the Market Monitoring Unit or RTO/ISO may need additional information to ensure that all short-run marginal cost components that are difficult to quantify, such as certain opportunity costs, are accurately reflected in a resource's cost-based incremental energy offer and to the extent that RTOs/ISOs currently include an adder above cost in cost-based incremental energy offers, whether such an adder is appropriate for incremental energy offers above $1,000/MWh.

The Market Monitor currently calculates opportunity costs at the request of members and does not need additional information about the details of opportunity costs. If a unit offer greater than $1,000 per MWh were to include an opportunity cost in excess of that calculated by the Market Monitor, the Market Monitor would not verify the offer ex ante and would, depending on the after the fact review, refer the unit owner to the Commission.

However, the provision of additional information about the components of offers is needed to make the ex ante review process work effectively. For clarity and to make the ex ante review process more effective, the Market Monitor requests that the Commission order that for all offers, units be required to identify all separate elements of the offers including the fuel or fuels burned, the fuel cost, the emissions costs by type if any, the level of variable operation and maintenance expense, whether an opportunity cost adder is included and the level of that adder, whether some or all of the permitted ten percent adder is included and the amount added, and whether some or all of any permitted FMU adder is included and the amount added.[9] The Market Monitor also requests that the Commission require that all supporting data be provided to the Market Monitor in a timely manner.[10]

The Market Monitor recommends that the ten percent adder be limited to the current cap of ten percent included in the $1,000 offer cap. The cost of gas reflects the best information available to unit owners and incorporates the uncertainty about expected gas costs when offers are made. The ability to include real-time information in offers will be further improved if the Commission approves the ability to make hourly changes to offers based on changes in the cost of gas.

Regardless of how the Commission rules on inclusion of a ten percent adder in the ex ante offers, any such adders should be excluded from an ex post evaluation of actual gas costs for inclusion in uplift. Only actual, after the fact demonstrated gas costs should be included in uplift payments.

The Market Monitor opposes the inclusion of any other potential adders that are not based on verifiable information on short run marginal costs.

4. Whether the Market Monitoring Unit or RTO/ISO may need additional information or new authority to require revisions or corrections to a cost-based incremental energy offer to ensure that a resource's cost-based incremental energy offer is an accurate reflection of that resource's short-run marginal cost.

The Market Monitor believes that the current PJM rule requiring that unit owners are solely responsible for their offers is a core element of the PJM market design and should remain so. It would not be appropriate for the Market Monitor to substitute its judgment for the judgment of the unit owner. There is a substantial agency problem were the Market

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9 The Market Monitor maintains a web based application for generation owners to provide the required data.

10 *See Southwest Power Pool, Inc.*, 141 FERC ¶ 61,048 at PP 420–423 (2012).

Monitor substitute its judgment for that of the unit owner. If the unit owner exercises or attempts to exercise market power, that is the unit owner's responsibility.

The role of the Market Monitor should be to agree with unit owners on clear, algorithmic and verifiable fuel cost policies to minimize any disagreement about the level of costs included in cost-based offers. The purpose of fuel cost policies is to ensure that market power is not exercised. The Commission has the authority to resolve any disputes between unit owners and the Market Monitor on fuel cost policies related to the potential to exercise market power.

The Commission should require that all generation owners have approved fuel cost policies and provide all supporting data in a timely manner in order to be eligible to make an offer in excess of $1,000 per MWh.

5. Whether the proposal should apply to imports and whether a cost verification process for import transactions is feasible.

Almost all (more than 99.99 percent) imports into PJM were price takers in 2015. It is not feasible to have a verification process for imports because imports may be sourced as purchases from the spot market of a neighboring balancing authority and are generally not sourced from a specific generating unit. An offer cap of $1,000 per MWh should continue to apply to imports that are not price takers. Imports that are price takers should receive the relevant clearing price in PJM that results from the price formation process in PJM markets including the result of offers greater than $1,000 per MWh. Imports are not disadvantaged by this approach, the incentives for imports to respond to prices remain as they are currently and no new ability to exercise market power is created by permitting imports to set price above $1,000 per MWh.

Imports from pseudo-tied units are not technically imports as the power from such units is treated as internal generation and incorporated in PJM's Area Control Error. All such units should be explicitly subject to exactly the same rules governing ex ante and ex post verification of costs associated with offers in excess of $1,000 per MWh as internal units.

Currently, emergency imports can set price in PJM. The Market Monitor recommends that there be a verification process established for such offers. While they do not occur frequently, such emergency offers currently provide an unmitigated opportunity to exercise market power in PJM markets. The small number of such offers makes an ex ante verification process feasible. Such offers should be subject to clear rules governing the short run marginal cost basis for ex ante offers, including opportunity costs, and also subject to an after the fact verification process and significant penalties for offers not linked to short run marginal costs. Such emergency import offers should also be subject to the rule that they can set price only if they pass the ex ante verification process. If they do not, they are eligible to receive uplift payments if the offer passes the ex post verification process.

6. **Whether excluding virtual transactions above $1,000/MWh could limit hedging opportunities, present opportunities for manipulation or gaming, create market inefficiencies, or have other undesirable consequences, and whether alternatives exist which would allow virtual increment offers and decrement bids to be submitted and cleared at prices above $1,000/MWh.**

Offer caps for virtuals should not be increased above $1,000 per MWh. Increasing offer caps for virtuals would create opportunities for the exercise of market power and the manipulation of markets and permit unit owners to avoid the requirement that offers greater than $1,000 per MWh be cost based.

If the Commission wishes to permit some virtuals to offer or bid above $1,000 per MWh, the Market Monitor recommends that such increment offers or decrement bids be limited to liquid trading hubs to minimize the potential to exercise market power or manipulate the markets. The Market Monitor recommends that market participants be required to explain why such offers are appropriate and be subject to ex ante and ex post review. The Market Monitor also recommends that UTC transactions be excluded from any such offers. As UTCs are about spreads between nodes, there is no reason to relax any current rules governing UTC offer behavior.

If the Commission wishes to permit some virtuals to offer or bid above $1,000 per MWh, these offers and bids should also be subject to after the fact review for whether they resulted in the exercise of market power or market manipulation.

7. The impact the proposal would have on seams.

The impact on seams would be consistent with efficient markets. If the competitive price in PJM were above $1,000 per MWh and below $1,000 per MWh in another area, power would flow from that area to PJM. If the price in another area were above $1,000 per MWh and below $1,000 per MWh in PJM, power would flow to that area from PJM. Both are expected and appropriate outcomes consistent with efficient markets.

B. Additional Comments

Scarcity pricing would be affected by an increase in the offer cap above $1,000 per MWh. There are two aspects to the scarcity pricing rules that are affected by the increase in the offer cap. At a minimum, the existing scarcity pricing penalty factors should be added to the highest accepted offer above $1,000 per MWh that is marginal. But in addition, the level of the scarcity pricing penalty factors should reflect the value of reserves which is a function of the current price of energy and the opportunity cost of providing reserves.

The Market Monitor recommends that PJM be required to make a detailed proposal to dynamically set the scarcity price based on energy prices and the value of reserves, review the proposal with PJM members and the Market Monitor, and make an appropriate filing with the Commission.

The offer cap for Demand Resources should be set at $1,000 per MWh unless there is a cost-based justification for a higher offer.[11] Demand Resources currently have the ability to define a strike price as high as $1,849 per MWh which they are guaranteed to be paid

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11 Throughout this pleading Demand Resources refers to emergency and pre-emergency load response.

when called regardless of LMP, and which can set price.[12] Regardless of whether Demand Resources set price, all payments to Demand Resources are uplift. Given the strong steps taken in the Capacity Performance design to help ensure that all capacity resources are treated comparably, the decision on this NOPR should address this inconsistency and require the same offer caps for demand resources as for generation resources. The offers of Demand Resources should be subject to ex ante and ex post verification. In addition to the comparability argument, demand resources could be used, when owned by an entity that also owns generation, to exercise market power by setting prices high for the entire portfolio.

12 FERC accepted proposed changes to have the maximum offer price (the strike price) for 30 minute demand response to be $1,000/MWh+1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + [Shortage Penalty/2] and for 120 minute demand response to be $1,100/MWh. OATT Attachment K Sec 1.10.

II. CONCLUSION

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

Respectfully submitted,

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Dated: April 4, 2016

Attachment

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Monitoring Analytics

DATE: **September 24, 2015**

TO: **PJM Members**

FROM: **Joseph Bowring**

SUBJECT: **Fuel Cost Policy Guidelines: Gas Replacement Cost**

Generation owners that choose to offer their gas fired units based on replacement cost should follow these guidelines:

- Replacement cost should be derived from a verifiable, algorithmic, systematic approach. The MMU must be able to replicate the calculations after the fact, by following the procedure outlined in the fuel cost policy. The fuel cost policy may include multiple approaches to the calculation of replacement cost that vary with verifiable, identifiable system and market conditions.
- Replacement cost should be for an identified gas region for which there is a reported regional index of delivered prices.
  - Units in a location without a reported regional index of delivered prices should select the closest reported regional index and include any applicable transportation costs to the unit location. For example, units located behind a gas LDC should include the reported index most representative of the LDC city-gate and defined additional tariff transportation costs.
- Generation owners should use the available reported data consistent with the data used to construct the regional indices as their base replacement cost. For example a price that is within the current day's applicable index trading range on ICE prior to the day-ahead energy offer submission.
  - The regional index values (e.g. Platts and ICE) are not posted until late in the day.
  - The base replacement cost may be adjusted using an algorithmic, verifiable and reproducible method.
- For days when price discovery is limited, e.g. if there are no bid/offers on ICE for a generator's location, the base replacement cost must be based on the closest publicly available reportable regional index plus any applicable transportation charges.
- Alternative regional indices may be utilized if a generation owner can demonstrate the applicability of such index. For example a generation owner may use a Gulf Coast index if they own firm transportation from that region to their unit's location. If a generation owner uses a method relying on firm transportation, the MMU will request a copy of the contract.
- If the base replacement data are not publicly available, the value used must be verifiable and supportable. Examples of methods are: a screen shot from ICE or NYMEX demonstrating that no data are available; documented offers from three independent third parties, e.g. IM; email; recorded conversation; or an electronic NAESB confirmation of a purchase made prior to energy offer.

- All documentation supporting fuel cost components used must be saved. The MMU will request such documentation periodically or when the MMU has questions about specific offers.
- The fuel cost policy must include a calculation of the development of the replacement fuel cost used in an actual eMKT offer for a specific unit and date in order to illustrate the method. The date should be one where gas price volatility created uncertainty around the purchase cost. The calculation should include the index starting price and any additional transportation or other charges with all components shown separately. This example should illustrate the methodology used to adjust the base replacement cost and be verifiable.