Comments of PJM Interconnection, L.L.C.

In response to the Commission’s Notice Inviting Post Technical Workshop Comments, issued in the above-referenced proceeding on January 16, 2015 (“Notice”), PJM Interconnection, L.L.C. (“PJM”) hereby submits these answers to the Commission’s questions outlined in the Notice.

1. Offer Caps

High natural gas prices during the winter of 2013-2014, as discussed at the price formation workshops, indicated that the current generic $1,000/MWh cap on energy offers (“offer cap”) might be insufficient to allow natural gas-fired generators to recover their costs when natural gas prices spike during constrained winter periods.

a. Should the $1,000/MWh offer cap be modified?

i. If the offer cap is modified, what form should the offer cap take? For instance, should a modified cap be set at a level greater than the current $1,000/MWh cap and apply even if a resource has costs greater than the new cap or should the offer cap be replaced with a structure that allows offers at the higher of marginal cost or the existing $1,000/MWh cap? Should it be a fixed cap or a floating cap that varies with the price of fuel (e.g., natural gas)? If a modified cap were set as a fixed offer cap, what should the new offer cap be? What should be the basis for determining the fixed offer cap?

ii. If the offer cap should not be modified or set such that marginal costs could be greater than $1000/MWh, how should the Commission ensure that suppliers with costs greater than the cap have the opportunity to recover those costs?

iii. Do the real-time and day-ahead market clearing processes allow sufficient time to verify the cost-basis of the marginal resources that exceed the offer cap? Does the settlement process allow sufficient time to verify costs of resources that receive uplift associated with offers that exceed the offer cap?
PJM Answer: In PJM, Market Sellers of generation resources can submit two types of offers into the Day-ahead Energy Market each Operating Day -- a market-based offer and a cost-based offer. Both offers are subject to an overall $1,000/MWh offer cap. PJM believes that the current $1,000/MWh energy offer cap, as it applies to cost-based offers and market-based offers, should be revised.

Cap on Cost-Based Offers

It is evident that the $1,000/MWh offer cap is no longer just and reasonable as applied to cost-based offers. Historically, cost-based offers had not approached the $1,000/MWh offer cap. However, in January 2014, severely cold weather caused gas prices to spike due to increased demand and gas pipeline deliverability issues. For the first time in PJM’s history, Market Sellers incurred gas costs that caused generator marginal costs to exceed the $1,000/MWh offer cap. Because their cost-based offers were capped at $1,000/MWh, Market Sellers of certain generation units were not allowed to reflect their marginal costs to produce energy in their cost-based offers. In the case of some Capacity Resources, which are required to offer into the Day-ahead Energy Market every day, Market Sellers of such resources were in effect being forced to either sell energy into the market at prices that did not reflect their marginal costs to produce that energy or take a forced outage on their unit. This was never the intent of the offer cap. In fact, it is contrary to basic principles of PJM’s energy market design because the purpose of the market design is to provide the financial incentives for physical asset owners to act in a manner that supports reliable system operations. An offer cap that would incentivize an asset owner to take a forced outage on their unit when it is most needed for system reliability is clearly inconsistent with the intent of the market design.

In response to these unprecedented conditions, PJM took emergency action to alleviate this untenable situation by filing two waivers with the Commission on January 23, 2014. The waivers sought authority to compensate Market Sellers for costs exceeding $1,000/MWh and to allow Market Sellers to submit offers that exceeded $1,000/MWh. Both waivers, which were

---

1 All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in PJM Open Access Transmission Tariff ("Tariff") and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement").


3 More specifically, the first waiver requested permission to permit Market Sellers of generation Capacity Resources with cost-based offers that had costs, determined and documented in accordance with PJM’s Cost Development Guidelines, that exceeded the applicable market clearing price (limited to the $1,000/MWh offer cap) to receive make-whole payments covering the difference between their actual costs and the market clearing price. See Request of PJM Interconnection, L.L.C. For Waiver and For Commission Action By January 24, 2014, Docket No. ER14-1144-000, (January 23, 2014). PJM also requested a separate waiver to allow Market Sellers to base their cost-based offers on their marginal costs, even if that caused their offer price to exceed the $1,000/MWh offer cap, and for such offers to set market clearing prices if applicable. See Request of PJM Interconnection, L.L.C. For Waiver, Request For 7-Day Comments Period, and Request For Commission Action By February 10, 2014, Docket No. ER14-1145-000 (January 23, 2014).
temporary and only sought relief for the remainder of the 2014 winter season, were granted by the Commission.\(^4\)

Following the winter of 2014, PJM’s stakeholders examined whether permanent changes to PJM’s offer cap rules were needed, however they were unable to come to agreement. Anticipating that winter 2015 would be as severe as winter 2014, PJM elected to file a Federal Power Act ("FPA") section 206 filing to make temporary changes to its offer cap rules so that it would not have to make emergency waiver filings with the Commission. Specifically, the proposed changes allow cost-based offers to be submitted and to set Locational Marginal Price ("LMP") up to $1,800/MWh for the 2015 winter period, and allow generators to recover actual incurred costs above that cap through uplift payments, with such costs being subject to an after-the-fact review by PJM and the Independent Market Monitor for PJM ("IMM").\(^5\) In the order accepting the December 15, 2014 Filing, the Commission determined that PJM “demonstrated that the current offer cap of $1,000/MWh in PJM is unjust and unreasonable for the winter months.”\(^6\)

On February 20, 2015, for the second consecutive year, PJM set its all-time winter peak demand, which was 143,826 MW (based on preliminary telemetered data). On the same date, 13 available generation units submitted cost-based offers of $1,000/MWh or greater and 11 other generation units also had cost-based offers above $1,000/MWh but were unavailable. The highest offer on an available generation resource was $1,795/MWh, plus applicable startup and no-load costs. While none of these units were selected by PJM to operate, and none set LMP, all of these units submitted cost-based offers greater than $1,000/MWh in accordance with PJM’s Cost Development Guidelines and the temporary market rule changes.\(^7\) Market Sellers submitted cost-based offers in excess of $1,000/MWh on several other days in February under similar operating conditions, although none were selected to operate.

Given the foregoing, PJM believes it is appropriate to eliminate the cap on cost-based offers. Resources should be allowed to recover their costs of providing energy and not be limited by any arbitrary cap. Not allowing resources that provide energy the opportunity to recover their costs of operating would result in unjust, unreasonable, and likely confiscatory rates. While some may argue that not having a cap on cost-based offers would invite offers that would unreasonably raise prices on consumers, PJM does not believe this would be true. In PJM, cost-based offers must be submitted in accordance with PJM’s Cost Development Guidelines, which in of themselves limit the type of costs that can be included in cost-based offers. Absent fraud or an inadvertent failure to adhere to the Cost Development Guidelines, the Cost Development Guidelines effectively cap cost-based offers at the approximate actual costs incurred by generation resources when operating.

\textit{Cap on Market-Based Offers}

\(^4\) See \textit{PJM Interconnection, L.L.C., 146 FERC \hspace{1mm} \| \hspace{1mm} 61,041(2014); PJM Interconnection, L.L.C., 146 FERC \hspace{1mm} \| \hspace{1mm} 61,078 (2014).}


\(^6\) See \textit{PJM Interconnection, L.L.C., 150 FERC \hspace{1mm} \| \hspace{1mm} 61,020, at P 33 (2015).}

\(^7\) Only two of the 21 units self-scheduled to run in real-time, but were not eligible for any make-whole payments from PJM.
PJM’s $1,000/MWh cap on market-based offers was established in 1997.\footnote{See e.g. Pennsylvania-New Jersey-Maryland Interconnection, Docket Nos. OA97-261-000 and ER97-1082-000 (filed April 1, 1997).} Given that this cap has been in place for 18 years, and more importantly the fact costs to operate generation resources have increased significantly, it follows that the cap on market-based offers should be increased.

PJM believes the overall cap on market-based offers should be higher than observed cost-based offers. While the market-based offer cap has been fixed at $1,000/MWh in the past, a better approach may be to set a market-based offer cap on an annual basis at some percentage above the highest cost-based offer from previous Delivery Years. For example, based on the nearly $1,800/MWh cost-based offer observed in February 2015, a market-based offer cap could be set at 150\% * $1,800 = $2,700/MWh for the 2015/2016 Delivery Year. As described below in response to Question 1.d, setting a market-based offer cap at $2,700/MWh may also be an appropriate cap for market-based offers for generation resources so that such offers are aligned with the maximum allowable offers of Demand Resources.

Finally, the real-time and day-ahead market clearing processes do not allow sufficient time to verify the cost-basis of the marginal resources that exceed any fixed offer cap. Verifying such costs must occur after such markets close, as PJM did in the winter of 2014 for units that had cost-based offers in excess of $1,000/MWh, and for which the Commission gave PJM temporary authority to do for costs incurred above $1,800/MWh for winter 2015. It is important to note that any costs that are recoverable based on this after-the-fact review must be credited through uplift payments in PJM’s market design.

b. What are the advantages and disadvantages of having offer caps be set at the same level across all RTOs/ISOs? Would different offer caps across the RTOs/ISOs exacerbate interface pricing issues at RTO/ISO borders? If so, how? Would an offer cap that takes the form of the higher of marginal cost or $1,000/MWh create the same issues as setting different offer caps across RTOs/ISOs?

PJM Answer: Offer caps should be implemented on a uniform basis across all RTOs/ISOs. Having different offer caps in different RTOs/ISOs would exacerbate interface pricing and seams related issues because a discontinuity could create dispatch and pricing anomalies and transmission congestion coordination discontinuities at the market borders, especially during periods of extreme weather. For example, if gas prices become elevated due to gas pipeline constraints on a pipeline that serves generators in both PJM and New York Independent System Operator (“NYISO”), or both PJM and Midcontinent Independent System Operator (“MISO”), then a lower offer cap in one market could artificially create a discontinuity in coordination of congestion management because one market would reflect the true congestion costs in prices and the other may not because of the offer cap limitation. This could create anomalous dispatch or pricing results at the market borders. Implementing offer caps in the form of the higher of marginal cost or $1,000/MWh would appear to have the same issues as setting different offer caps because fuel supply conditions, and therefore fuel prices, are likely to vary across the RTOs, which would result in differing effective offer caps.

c. What impact would adjusting the offer cap have on other aspects of RTO/ISO price formation (e.g., mitigation rules or shortage pricing rules)? Would other market rule changes be necessary if offer cap levels were adjusted? Do other
challenges associated with modifying offer cap rules exist? If so, what are they? If offer cap rules are adjusted, how quickly could RTOs/ISOs incorporate adjusted offer cap rules into their software and the market clearing process?

**PJM Answer:** Adjusting the offer cap would have an effect on other aspects of price formation in PJM. Specifically, allowing the energy offer cap to rise would correspondingly raise the level of shortage prices in PJM. As PJM explained in an answer supporting the December 15, 2014 Filing:

Shortage pricing in PJM is based on simultaneous optimization of energy and reserves and the energy price during reserve shortage conditions is a function of energy offers and Reserve Penalty Factors. If the Commission were to limit energy prices to $2,700/MWh when Reserve Penalty Factors are applicable and cost-based offers are greater than $1,000/MWh, it would depress reserve prices below the appropriate levels needed to capture operator actions in market clearing prices. This would in effect reduce the incentive for resources to follow PJM’s dispatch instructions during the most critical operating periods and create out-of-market uplift payments that undermine the pricing signals.9

PJM did not alter its shortage pricing rules in the December 15, 2014 Filing, and does not believe that shortage prices should be purposefully reduced below an amount that is commensurate with higher energy prices allowed by any higher offer cap. Prices established during shortage conditions need to maintain the incentive for Market Participants to follow PJM dispatch instructions to provide either reserves or energy, and artificially reducing shortage prices below the levels they would otherwise reach if offer caps are increased would negatively impact these incentives.

PJM does not believe that other market rule changes would be necessary due to the adjustment of offer caps, nor does PJM believe that such adjustment would cause other challenges as long as the shortage pricing rules are not altered and offer caps are established consistently across the RTOs/ISOs.

As to implementation timeframes, PJM can incorporate new offer cap rules into its software in a matter of days. However, if rules related to shortage pricing are altered so that they do not automatically rise with higher energy prices, that would likely take several months to implement.

d. Should the same offer cap that applies to generation also apply to load bids? What are the advantages and disadvantages of applying an offer cap to load bids?

**PJM Answer:** PJM believes that offer caps for generation resources and Demand Resources should be the same, and both should be higher than the current $1,000/MWh offer cap for generation resources. PJM currently has different offer caps for generation resources and Demand Resources. While the aforementioned $1,000/MWh offer cap applies to all offers from generation Capacity Resources (notwithstanding the temporary approved revisions for the winter of 2015), Demand Resources have a stratified offer cap that is dependent upon the lead

---

9 Motion For Leave to Answer and Limited Answer of PJM Interconnection, L.L.C., Docket No. EL15-31-000 at 4 (filed January 5, 2015).
time required to dispatch the resource. Under PJM’s current rules, Demand Resources with a lead time in excess of one hour but less than two hours have an offer cap of $1,100/MWh, Demand Resources with a lead time of more than 30 minutes but less than or equal to one hour have an offer cap of $1,274/MWh and Demand Resources with a lead time of 30 minutes or less have an offer cap of $1,549/MWh.10 Historically, Demand Resource offers were largely submitted as one large block at a single offer cap. The intent of the stratified offer caps was to provide some amount of separation between Demand Resource offers so that they could be dispatched in economic order as opposed to creating administrative mechanisms to dispatch only the portion of the large block of offers at the same price. The second purpose was to recognize that more flexible resources are more valuable to PJM and thus the most flexible resources have the highest offer cap.11 Effective June 1, 2015, PJM will increase its Reserve Penalty Factors, which will cause a corresponding increase in the Demand Resource offer caps while maintaining the existing stratification. There is currently no planned adjustment to the generation offer cap. PJM would prefer to have identical offer caps for both generation resources and Demand Resources. PJM suggests that a reasonable market-based offer cap on both generation and Demand Resources cap would be equal to the higher of the previously described $2,700/MWh amount or the resource’s applicable cost-based offer (with the caveat that PJM believes there should be no cap on any resource’s cost-based offers).

PJM does not see any reason to impose a cap on load bids (referred to as “Demand Bids” in PJM’s market rules). Because load cannot exercise market power via the submission of Demand Bids in the Day-ahead Energy Market, PJM does not see any reason why a cap would need to exist on such bids.

2. Transparency

At the Uplift and Operator Actions Workshops, some panelists addressed issues concerning insufficient transparency of uplift and operator actions. Improved transparency could inform resource entry and exit and market rule discussions; improved transparency could also improve market understanding, predictability, and confidence.

a. What should RTOs/ISOs do to improve transparency of uplift credits and charges, unit commitment, and other operator actions? Please comment on the type of information that would be useful, why it is necessary, whether it should be shared with specific resources or available to all, the timing of its release, and whether it is feasible to release the information in real-time.

PJM Answer: PJM strives to ensure that its markets are as transparent as possible and that its operators’ actions are understood by Market Participants. That being said, PJM’s rules related to confidentiality that protect market sensitive information,12 combined with the discretion that operators must possess in order to reliably operate the Transmission System, means that

---

10 See e.g. Proposed Tariff Revisions of PJM Interconnection, L.L.C., Docket No. ER14-822-000, at 27 (December 24, 2013) (“DR Operational Filing”) (accepted by the Commission in PJM Interconnection, L.L.C., 147 FERC ¶ 61,103 (2014)).


12 See Operating Agreement, section 18.17.
Market Participants will likely never be able to see and understand every factor that operators consider when dispatching the system, and accordingly that contribute to uplift.

PJM believes that as a general rule, PJM should be able to provide enough information related to where and how uplift is created on the system so that Market Participants can see it as a market signal and take action, without revealing any individual Market Participant’s confidential and/or market sensitive information. Currently, the information on uplift publically released is aggregated to a high enough level that Market Participants cannot see where uplift is being created and why. While this protects Market Participants’ confidential information, it is not granular enough to provide an accurate market signal to Market Participants. PJM believes that a revised approach that would improve transparency would be to allow PJM to release uplift data aggregated at the Zonal level. That way, Market Participants could see in which Zones and under what circumstances uplift is being incurred, thus sending a more accurate market signal to Market Participants, but would not give unit specific information that could allow a competing Market Participant to calculate a particular unit’s approximate offer. For example, if a Zone has 100 generation units in it, and $10 million in uplift is allocated to that Zone in a given month, Market Participants would be able to see the uplift allocated to that Zone relative to other Zones, but would not be able to determine which individual units were causing the uplift (since the $10 million could conceivably be caused by all 100 units equally, just one unit, or many other combinations). The problem with putting this, or other concepts, into practice is the fact that Market Participants are hesitant to disclose information they believe to be commercially sensitive. If such information is designated as commercially sensitive, PJM cannot deem it otherwise per the terms of section 18.17 of the Operating Agreement. PJM looks forward to the Commission’s guidance on how to strike a balance between the need to provide transparency to the market and protect individual Market Participants’ confidential information.

Practically speaking, uplift information cannot be released in real-time by PJM because they are outside-the-market payments, and are almost always calculated after markets clear. Certainly, providing a complete accounting of uplift payments for a particular area over a particular timeframe, such as an Operating Day, could not be done accurately in real-time.

b. What types of information should not be shared publicly? Why? What are the concerns with commercially sensitive information?

PJM Answer: PJM believes that all non-commercially sensitive information and non-CEII information should be shared publically. Further, as explained previously, PJM believes that certain information that may currently be considered to be commercially sensitive by Market Participants may not be commercially sensitive. This determination is relevant because under section 18.17.1(e) of PJM’s Operating Agreement, PJM only has authority to post non-aggregated energy market bid and offer data under the following circumstances:

(e) Notwithstanding anything to the contrary in this Agreement or in the PJM Tariff, to allow the tracking of Market Participants’ non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the nonaggregated bid data and Offer Data submitted by Market Participants (for participation on the PJM Interchange
Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection. However, to protect the confidential, market sensitive and/or proprietary bidding strategies of Market Participants as well as the identity of Market Participants from being discernible from the published data, the posted information will not reveal the (a) name of the resource, (b) characteristics of a specific resource, (c) identity of the load, (d) name of the individual or entity submitting the data, (e) identity of the resource owner, or (f) location of the resource at a level lower than its Zone. The Office of the Interconnection also reserves the right to take any other precautionary measures that it deems appropriate to preserve the confidential, market sensitive and/or proprietary bidding strategies of Market Participants to the extent not specifically set forth herein.

PJM believes the key questions that must be asked to determine whether information is actually commercially sensitive is whether the release of this information truly provides a competitive advantage to someone else, and whether releasing the information will increase the likelihood of manipulative behavior.

Assuming information is commercially sensitive; it should not be shared publically because it has the potential to erode the integrity of competitive markets by giving certain Market Participants competitive advantages over others, and potentially harming some Market Participants financially. If Market Participants believe their commercially sensitive information is at risk of being disclosed publically, they likely will hesitate to transact in RTOs/ISOs. PJM’s Operating Agreement has clear guidelines related to when commercially sensitive information may or may not be shared and under what circumstances.13

c. Commission Staff’s August 2014 report on uplift noted several issues with the consistency and granularity of uplift data provided as part of the Electric Quarterly Reports. What steps could be taken to improve the quality of uplift data required to be reported as part of the Electric Quarterly Reports?

**PJM Answer:** PJM’s Electric Quarterly Reports (“EQRs”) contain data regarding the service agreements it enters into (i.e., “contract data”); and, because PJM does not engage in power sales, it does not report “transaction data” in its EQRs. PJM complies with all applicable requirements for its EQRs. PJM also provides Market Participants with a supplemental, pre-formatted report through its markets settlements system. This report has been created to aid PJM’s Market Participants with filing their EQRs. The supplemental report provides hourly data specific to uplift in the following categories: Customer Share of Day-ahead Operating Reserve Credits, Customer Share of Balancing Operating Reserve Credits, and Customer Share of Synchronous Condensing Credits. PJM is amenable to providing additional information in these reports, as deemed appropriate by the Commission, but would object to filing EQR reports, or portions of EQR reports, on behalf of any of its Market Participants. Otherwise, PJM does not have any specific suggestions with respect to improving the quality of uplift data reported as part of EQRs.

13 See e.g. Operating Agreement, section 10.3, section 18.17.
3. Pricing Fast-Start Resources

Commission Staff’s December 2014 paper about operator-initiated commitments discussed how RTOs/ISOs relax the minimum operating level of resources to make certain block-loaded fast-start resources appear dispatchable to the pricing software, and thus eligible to set the market clearing price as the marginal resource. The paper also discussed how some RTOs/ISOs have modified the locational marginal price (LMP) framework to include start-up and no-load costs of certain fast start resources (e.g., New York Independent System Operator, Inc.’s (NYISO’s) Hybrid Pricing).

a. During the Operator Actions Workshop, panelists explained that relaxing resource minimum operating limits can lead to incentive and operational issues such as over-generation. What tradeoffs are involved with relaxing the minimum operating limits of block-loaded resources to zero for purposes of price setting? Should relaxing the minimum operating level be limited to block-loaded fast-start resources, or should relaxation be available to a larger set of resources?

PJM Answer: In PJM, resource minimum operating limits are relaxed for both combustion turbines (CTs) and demand side resources when these resource types bid into the Day-ahead Energy Market without a dispatchable range (i.e. economic min=economic max). By relaxing the operating limits for these block-loaded resources, a dispatchable range is created so the dispatch and pricing software can consider the full set of resources running at PJM’s discretion as being eligible to set LMP. Regardless of the degree of relaxation that is applied to the minimum operating limits, there is a trade-off between allowing block-loaded resources to set price and maintaining power balance outside of the dispatch software solution. PJM believes that the level of relaxation is critical and the “right” answer is dependent upon the operating circumstances.

To further illustrate how the trade-off between over-generation and power balance affects the solution, consider the following example:

100,000 MW Load
5000 MW of inflexible CTs online
Relaxation degree – 100% (i.e. economic minimum relaxed to 0)

Under these conditions, the optimization engine will dispatch all online resources until it has enough generation to meet the load. In this example, suppose 99,900 MWs are dispatched from flexible resources that are less expensive than the CTs and the remaining 100 MWs are obtained from the CTs since the dispatchable range could vary anywhere between 0 and 5000 MWs. While power balance is met under this scenario in the dispatch engine because it considers the CTs to be 100% flexible, the reality is that PJM now has dispatched 104,900 MWs. This is because it economically dispatched 99,900 MW of steam units while having 5,000 MW of CTs online. The sum of these values means that PJM would be over-generating by 4,900 MW. This scenario will likely cause system control problems and result in an erratic dispatch signal because the next dispatch solution would need to lower the system to attempt to regain power balance.
Instead let’s assume a relaxation degree of 10% (i.e. economic minimum relaxed to 4500)

In this scenario, the engine has to honor the economic minimum parameter of 4500 MWs from the CTs. Therefore, at most, 95,500 MWs are dispatched from flexible resources and the remaining 4500 MWs are obtained from the CTs, presuming they are dispatched to minimum. In this case, PJM would have dispatched 95,500 MW of flexible generation and would still have 5,000 MW of CTs online. Under this scenario, PJM would have dispatched a total of 100,500 MW. While this result still leads to over-generation, the quantities are more manageable from a system operations perspective.

The two scenarios illustrate why relaxing the minimums on block-loaded units and allowing them to set LMP can have negative consequences to system operations. Regardless, PJM feels that this is an integral part of the LMP calculation in order to achieve accurate prices and minimize price suppression and uplift. However, the percentage used to create a dispatchable range on block-loaded resources must be set with both goals in mind.

PJM has already implemented changes to its dispatch and pricing software that relax minimum operating levels on resources other than block-loaded, fast start units. PJM has expanded this process beyond block-loaded resources in order to provide the maximum opportunity for the cost of resources that are operating to control transmission constraints to be reflected in both day-ahead and real time LMPs. While this relaxation does not need to be applied as often for other resources as it does for block-loaded units, it is still important to do so when necessary in order to ensure that LMPs reflect the costs of resources operating to meet demand while respecting transmission constraints as much as possible.

b. What are the merits of expanding the set of costs included in the energy component of LMP (i.e., start-up and no-load costs)? What factors should be considered when expanding the set of costs included in the energy component of LMP? If the start-up and no-load costs of block-loaded fast-start resources are included in the LMP, how should they be included? For example, should start-up costs only be included during intervals when the resource starts up?

**PJM Answer:** The primary and overriding factor that needs to be considered in whether to include certain costs in the LMP calculation is maintaining consistency between dispatch instructions and the resulting nodal prices. This consistency is what drives the incentives for asset owners to follow dispatch instructions of the system operator and thereby act in the manner that best supports system reliability. As such, PJM does not believe additional costs, such as start-up and no-load costs, should be included in the energy component of LMP.

In order to factor in the start-up cost into LMP, an assumption about how long the resource is going to run must be known so that the start-up cost can be amortized over that period. This assumption about run time introduces uncertainty in the cost of the unit used to set LMP and subsequently introduces error in the LMP calculation and potential divergence between the dispatch instructions provided to the resource and the resulting price at the resource’s location. Including the start-up cost in only the intervals where the resource starts up likely would not impact the LMP calculation because resources are typically not able to follow dispatch during their start-up phase and therefore are not eligible to set LMP. If such units were somehow to be made eligible to set LMP during their start-up phase, and the entire start-up cost
was included in only the relatively small number of intervals when the resource was starting up, the impact on LMP and potential divergence between LMP and dispatch instructions would be exacerbated significantly.

No-load cost, unlike hourly start-up cost that varies based on run time, is an hourly value that is constant from hour to hour. However, PJM has observed that no-load costs associated with CTs are small and not a significant contributor to uplift. Therefore, introducing no-load cost in the LMP calculation would be a major change that provides little benefit in reducing uplift. Further, this change in LMP calculation would also introduce a divergence between dispatch signals and LMPs, and potentially incentivize resources to chase LMPs and not follow dispatch. This additional risk is not commensurate with the benefit because no-load costs for block-loaded units do not significantly contribute to uplift. For these reasons, PJM believes that LMPs should be calculated consistently in both the dispatch engine as well as the pricing algorithm in order to ensure that the pricing results provide the correct incentives for resources to follow PJM's dispatch instructions.

Therefore, PJM does not believe that additional costs should be included in the LMP solely in an effort to minimize uplift payments. Rather, PJM feels the Commission’s focus should be on incorporating operator actions into pricing in order to reduce uplift, while at the same time maintaining the consistency between LMPs and dispatch instructions in real-time.

c. Should off-line resources be eligible to set the LMP? If so, should start-up and no-load costs be included in the price, or just incremental energy costs?

**PJM Answer:** PJM does not allow off-line resources to set LMP and does not believe they should be able to set LMP. Allowing offline resources to set LMP would result in a set of LMPs that are inconsistent with actual operating conditions because they incorporate resources that are not online. Like including startup and no-load into LMP, allowing off-line resources to set LMP would drive a wedge between the dispatch solution and the price calculation. It is critical that the dispatch solution and market clearing prices be calculated using the same model and that model must reflect the true operating conditions on the system as closely as possible. Consistency between dispatch instructions and nodal prices is the cornerstone of the energy market and the mechanism by which the incentives provided by the market serve to reinforce reliable grid operations.

4. **Settlement Intervals**

Panelists at the Shortage Pricing/Mitigation and Operator Actions Workshops generally supported sub-hourly, rather than hourly, settlement intervals as providing better incentives for resources to perform during shortage events and to make investments to enhance resource flexibility.

a. What are the advantages and disadvantages of moving to sub-hourly settlements for the real-time market as they relate to price signals, market efficiency, and operations?

**PJM Answer:** The advantages of moving to sub-hourly settlements are accurate pricing, compensation based on actual system conditions, improved market incentives, elimination of transaction pricing differential and improved overall settlement accuracy. The compensation for
sub-hourly settlements will reflect the value for when the action was provided. The alignment of performance and pricing intervals in settlement will promote market incentives for Market Participants to be responsive to actual system conditions. By doing so, this will result in more efficient real-time commitment and dispatch decisions of both internal resources as well as import and export schedules. The elimination of pricing differential between actual versus post condition derived from hourly integrated pricing settlements could promote resource performance and willingness to increase cycle flexibility during constrained operation conditions. PJM does not see a disadvantage to sub-hourly settlements, but PJM’s stakeholders have raised concern that a movement to sub-hourly settlements may be costly and difficult to accomplish in a short period of time.

b. What metering and RTO/ISO software changes would be needed to change settlement intervals from hourly to sub-hourly for the real-time market, and how long would these changes take to implement? Are there significant costs to RTOs/ISOs, and to market participants, of such changes? Are there any other impediments to adjusting settlement intervals?

PJM Answer: Based on PJM’s preliminary analysis, changing settlement intervals from hourly to sub-hourly in the real-time market would require software changes to PJM’s Power Meter application, ExSchedule application, Market Settlement Calculation system and the Market Settlement Reporting System to accommodate sub-hourly settlements. Power Meter is the application in which Market Participants submit revenue quality meter data for generating unit output and tie line flows to PJM. ExSchedule is the application in which Market Participants submit interchange transaction schedules to PJM.

New external user interfaces in the Power Meter application would be required for sub-hourly revenue metered data submittal. ExSchedule data transfer to the Market Settlement Calculation would need to be updated. Calculations in the Market Settlement Calculation application would need to be modified. New reports and alteration to existing reports would be needed for the Market Settlement Reporting system. Data storage and system performance would need to be enhanced to accommodate the existing billing statements’ issuance timelines.

The impact on Market Participants would depend on their existing metering infrastructure and data reporting process. Today, there are a large number of Market Participants that struggle to report accurate, timely, hourly revenue meter data to PJM. The common challenges are an insufficient number of personnel, data size, dated physical meters and antiquated systems. Given the numerous challenges PJM’s Market Participants face; only a limited number of Market Participants have the current capability to provide sub-hourly meter data to PJM. In anticipation of this potential challenge, PJM’s initial design of sub-hourly settlements will maintain the existing hourly spot market, congestion and loss calculations and will require the development of a new sub-hourly delta calculation that will reconcile the pricing differential for generation, interchange and transaction settlements with new supporting settlement reports.

Additional information is needed for PJM to formulate a reasonable cost estimate on the sub-hourly settlements implementation. Anecdotally, the cost for the implementation of sub-hourly settlements would be similar to the cost of a moderately complex market integration. Given the aforementioned Market Participant challenges, the acceleration of revenue meter data submittal could potentially be costly for Market Participants.
c. What are the advantages and disadvantages of changing from hourly to sub-hourly settlements in the day-ahead market?

**PJM Answer:** Because today's day-ahead markets are based on hourly schedules and prices, a movement to sub-hourly settlements would only make sense if the day-ahead market models were changed to produce sub-hourly schedules. To date, PJM has not received feedback from Members that the current hourly day-ahead market format is not adequate to allow Market Participants to hedge their purchases and sales at day-ahead prices. As a result, other than alleviating the complexity of reconciling the balancing market settlement calculations, there do not appear to be significant advantages to a more granular day-ahead scheduling process given the general hedging purpose of the day-ahead market. Additionally, the model complexity of a sub-hourly day-ahead market is exponentially greater than an hourly market, so moving to that model would likely result in longer day-ahead market clearing times, which is counter to what is needed for better gas/electric coordination. The disadvantage of moving to a more granular day-ahead market is that it would be significantly more complicated. Thus, the potential benefit of being able to estimate energy consumption needs day-ahead on a sub-hourly basis may be outweighed by the additional cost of implementation and the additional burden on Market Participants.

5. New Products to Incent Flexibility

Flexible resources that are capable of ramping up and down and/or starting up quickly provide value to the electric system. Panelists at the Operator Actions Workshop said that market designs which reward flexibility may stimulate investment in flexible capacity and provide resources more incentive to submit flexible offers. One panelist at the Operator Actions Workshop commented that existing market rules can create disincentives for resources to submit supply offers that reflect the full flexibility (for example, ramp rate, minimum run time, minimum operating level, maximum operating level, minimum down time) of their resources. In addition, panelists at the workshops discussed the need for locational reserve products to better reflect local needs for flexibility.

a. How do RTOs/ISOs currently ensure that they will have sufficient flexibility during real-time? Specifically, to what extent are residual unit commitments used to acquire anticipated needed flexibility?

**PJM Answer:** PJM currently does not schedule to a ramp-specific constraint and, outside of ancillary service needs, does not make supplemental unit commitments outside of the Day-ahead Energy Market solely for the purpose of ramping capability. By scheduling resources to meet the ramping needs in the Day-ahead Energy Market, in addition to the required Operating Reserve criteria, and procuring an additional set of ramping capability in real-time in the form of Regulation, Primary Reserves and Synchronized Reserves, PJM does not have any problems meeting the ramping needs of its system in real-time. In other words, the clearing of the Day-ahead Energy Market results in the commitment of sufficient resources to provide the ability for those resources to change output by at least the magnitude required to meet the hourly changes in demand. In PJM’s experience, this day-ahead commitment of resources, together with the procurement of the above ancillary services, have procured sufficient resources with enough flexibility to meet changes in demand and interchange that are observed in real-time. PJM has therefore not experienced any need to commit resources outside of the Day-ahead Energy Market or the ancillary service markets solely for the purpose of providing flexible ramp capability to the system.
b. How are flexible resources compensated for the value that they provide to the system? Does that compensation reflect the value? Why or why not? If compensation to flexible resources does not reflect their value, how should RTOs/ISOs compensate flexible resources for the service they provide?

**PJM Answer:** PJM compensates resources for operational flexibility through a combination of payments from the energy and ancillary services markets. However, there is no discrete compensation for flexibility in the form of generic ramping capability alone. In the energy markets, resources that can ramp more quickly have a greater ability to capitalize on energy market price signals when they rise and fall throughout the Operating Day, and therefore have a greater revenue potential than resources that cannot ramp as quickly. Additionally, PJM has multiple day-ahead and real-time ancillary service markets that procure and compensate resources for their ramping capability. The PJM dispatch algorithms are time-coupled, which also ensures that sufficient resources are scheduled on a look-ahead basis to secure adequate reserves and ramping capability. Compensation for this is managed through the reserve markets.

In discussions with other RTOs, PJM understands that some regions do not deploy Synchronized Reserves to address slow ramping situations; however, PJM does deploy Synchronized Reserves to address slow ramping because it is economical to do so. In PJM’s view, this approach is superior to creating a separate ramp product that is unnecessary if Synchronized Reserve is available and not deployed. Further, PJM has a Day-ahead Scheduling Reserves Market that clears simultaneously with the Day-ahead Energy Market, which procures 30-minute reserves. PJM also has Primary and Synchronized Reserve Markets that clear simultaneously with the Real-time Energy Market and procure 10-minute real-time reserves and a Regulation Market that also clears in real-time to maintain system control needs. All of these markets are additional ways that resources with ramping capability are compensated for their flexibility. PJM believes that moving to sub-hourly settlements would increase the incentives for more flexible operation because physical assets would be rewarded more explicitly for following dispatch signals as closely as possible by settling their output on more granular time intervals.

c. What are the tradeoffs between sending a price signal through a short-duration shortage event versus establishing a ramping product that is priced separately?

**PJM Answer:** PJM utilizes time-coupled look-ahead dispatch to co-optimize energy and reserves. This approach avoids transient shortage and ramp limitations. In the case of resource underperformance, PJM deploys Synchronized Reserve to address slow ramping because it is more economical to do so. In PJM’s view, this approach is superior to creating a separate ramp product that is unnecessary if Synchronized Reserve is available and not deployed.

PJM does not believe that transient shortage conditions are an issue that needs to be addressed in PJM. This is because by definition they are transient, and in PJM are infrequent and random, meaning the very short-term price signals they send do not provide any useful information that would drive investment or reflect the true state of the system.
d. What are the tradeoffs among procuring flexibility through unit commitments (e.g., headroom requirements) rather than through the ten-minute reserve products or through ramp products?

PJM Answer: PJM believes that all products required by the RTO/ISO to maintain reliability should be defined as clearly as possible rather than using a “catch-all” requirement such as headroom. Precisely defining a reserve requirement and market clearing price for each reserve requirement are needed to provide transparency to the market so that the market knows precisely what type(s) of reserves are needed and what the value of those products are. This approach also allows for the costs needed to meet each requirement to be minimized, thus reducing the overall production cost of the system. This is because when all products are explicitly defined, they can be optimized together in commitment and dispatch, thereby assuring that all product requirements are met at the lowest possible cost. Simply committing more resources than would otherwise be necessary without explicitly determining which product(s) are required would lead to a sub-optimal commitment and dispatch because the resources are not being scheduled for a specific need.

e. Does allowing combined-cycle natural gas resources to submit different offers for different configurations facilitate more efficient price formation? What are the advantages and disadvantages to generators of bidding these configurations?

PJM Answer: Allowing combined cycle natural gas resources to submit different offers for different configurations facilitates more efficient price formation because it allows for the actual cost per MWh to be reflected in the market clearing price for each combined cycle resource. Not doing this may result in market clearing prices that are not accurate when the combined cycle resource is marginal because the incremental offer may not be reflective of the resource’s current operating configuration.

There are no clear disadvantages to allowing Market Sellers to submit different offers for different configurations for their combined-cycle resources. Allowing them flexibility in submitting their offers allows for the most accurate modeling and pricing of the resource. While PJM does allow combined cycle units to submit multiple configurations in the form of splitting their plants into multiple units, PJM has not implemented the detailed system changes to allow combined cycle units to be modeled in the reliability and market systems. PJM has been reviewing the changes needed to accommodate this combined cycling modeling with other RTOs as well as vendors. The cost of the changes is significant (approximately $5-15 million) and to date, PJM Market Participants have not indicated that implementing these features are a high priority. Therefore, PJM has not spent the considerable resources necessary for implementation.

6. Operating Reserve Zones

A lack of sufficiently granular reserve zones could be muting efficient price signals. At the Shortage Pricing/Mitigation workshop, the NYISO panelist noted that NYISO is considering establishing a new reserve zone and the PJM Interconnection, L.L.C. (PJM) external market monitor indicated that he believed PJM’s shortage pricing rules were not sufficiently locational. For instance, last year PJM experienced shortages in the
American Transmission System, Inc. (ATSI) footprint that did not trigger shortage pricing because the ATSI zone is not a reserve zone.

a. How does the establishment, elimination or reconfiguration of reserve zones affect price formation? What should the triggers be? From experience, do the RTOs/ISOs have the appropriate reserve zones defined? Are additional, fewer, or different reserve zones needed?

PJM Answer: For a RTO/ISO that, like PJM, uses a joint optimization of energy and reserves to both dispatch the system and calculate market clearing prices, the location and level of the reserve requirements is an integral component to price formation. Reserve requirements that are either set at inappropriate levels or in a location that is inconsistent with how the grid is being operated can cause dispatch signals and prices to deviate from levels that would optimally maintain reliability. For pricing and dispatch instructions to align, it is imperative that reserve zones be established based on how the grid is operated. This includes short-term instances where a transient occurrence on the system, such as a transmission line outage, causes the realignment of reserve zones. The RTO/ISO must have the flexibility to keep reserve zones and requirements consistent with what is needed to maintain system reliability. Any deviations from that ideal level will create pricing inefficiencies and potentially lead to resources being manually dispatched outside of the market and associated uplift payments.

PJM has two reserve regions, one encompassing the entire RTO and then a subset of that region including the Mid-Atlantic portion of PJM’s footprint and the Dominion Zone. PJM operates in this configuration because it is consistent with how the system operators control the system and maintain reserves throughout PJM’s footprint. As a result, it sets market clearing prices in a manner that is consistent with the Transmission System’s operating conditions regardless of whether or not the system has adequate reserves or is in shortage conditions.

A common argument regarding shortage pricing is that a RTO/ISO should define many small reserve zones to ensure that shortage prices can occur in various locations across the footprint. The creation of additional reserve zones and reserve requirement constraints to the joint optimization of the energy and reserve markets will impact the dispatch and commitment of resources on the system, as well as the system production cost – most often by increasing it. If reserve zones are created without an actual need for reserves in the area, resources that are economic to provide energy at the lowest cost will be withheld in order to provide reserves for a reason that has no discernible reliability benefit. This results in increased system production costs without a commensurate increase in system reliability. Additionally, under stressed system conditions where reserve quantities are tight, system operators may need to manually dispatch resources inconsistently with the reserve market’s signals because the reserve market’s signals are not aligned with the reliability needs of the Transmission System on the whole. Adverse impacts such as these can be avoided if reserve zones are aligned with how the grid is operated.

b. Are processes in place for adding, removing, or changing reserve zones adequate for efficient price formation?

PJM Answer: In order to ensure market prices reflect actual system conditions under all conditions, the RTO/ISO needs the flexibility to create new reserve zones and redefine existing reserve zones as needed and as the transmission system’s topology dictates. The less flexibility there is in reconfiguring reserve zones, the more likely it is that situations will be encountered where administrative rules limit the RTO/ISO’s ability to define a set of reserve
zones that align with reliability needs and produce optimal market clearing prices. Currently, there are adequate rules in PJM to accomplish this, and those rules should not be altered.

7. Uplift Allocation

Uplift allocation rules might impact resource participation decisions in RTO/ISO markets. For example, uplift allocation rules might incent participation in day-ahead markets or drive decisions on how to use financial products.

a. Do uplift allocation rules reflect cost causation or mute potential investment signals? If so, how?

**PJM Answer:** Current uplift allocation rules likely mute potential investment due to the lack of transparency regarding where uplift is being accrued. For example, if a resource that is being dispatched by a RTO/ISO to control a transmission constraint is not setting LMP and is collecting uplift, and the cause and magnitude of the uplift is not made transparent to the market, the socialized uplift costs provide no information to potential investors that a locational problem on the system exists. If the uplift is recurring, the price signal is muted and the location and magnitude of costs being incurred to control the transmission constraint is hidden from the market. In PJM’s experience, transparent locational price signals have incented innovation and investment. Uplift in general can mute potential investment because it removes infra-marginal rents from resource owners when LMPs are suppressed due to a resource being run out of merit order. Rules that limit the transparency on where, why and how much uplift is being incurred further compound the problem because Market Participants have no ability to respond to the uplift being incurred.

b. What philosophy should govern uplift allocation? Do any of the RTOs/ISOs have a best practice? What is it and why is it a best practice?

**PJM Answer:** Uplift can be allocated in many ways, all of which have their own positive and negative aspects. PJM has a stakeholder group, the Energy Market Uplift Senior Task Force (“EMUSTF”) that has been discussing potential changes to how uplift is allocated in PJM. The focus of the EMUSTF has been cost causation, although it has become evident that determining causality for all instances in which uplift is created with any degree of detail or certainty is virtually impossible. In PJM’s opinion, uplift should be allocated in a manner that does not unduly harm a single sector of Market Participants, create perverse incentives or inhibit beneficial market activity. Unfortunately, there does not appear to be a single “best practice” for allocating uplift that is uniform across all RTOs/ISOs, and coming to agreement on a methodology that meets agreed upon principles of uplift allocation and achieves consensus in PJM’s stakeholder process has been elusive. Currently, there are ten proposals on how to allocate uplift being considered at the EMUSTF based on different principles and philosophies. Given the contentiousness of the issue of uplift allocation, it would be beneficial to all RTOs/ISOs and market participants if the Commission provides some direction on the main or guiding principle(s) that should govern allocation of uplift.

c. Should uplift allocation categories reflect the reasons for committing a unit and incurring uplift? Would disclosing these reasons through publicly available data improve uplift transparency and provide information to facilitate modifications of the allocation of uplift costs?
**PJM Answer:** Allocating uplift based on the reason a unit was committed is one methodology that can be used, and in fact is one of the methodologies PJM currently uses to allocate uplift. More transparency around why uplift is being incurred provides more detailed information that potential investors may utilize to address the underlying problem and eliminate the uplift. However, the need for transparency must be balanced against the need to ensure Market Participants’ confidential and market sensitive information remains non-public.

8. **Market and Modeling Enhancements**

At the Uplift and Operator Actions Workshops, panelists highlighted various drivers of persistent, concentrated uplift and operator actions, including constraints that are not incorporated into market models. Panelists also noted that certain constraints are difficult to model accurately or to incorporate into both the day-ahead and real-time market models. These include local voltage constraints and reliability constraints such as N-1-1 contingency constraints.

a. Assuming that RTOs/ISOs should improve their market models to better reflect the cost of honoring reliability constraints in energy and ancillary services market clearing prices, what types of constraints should RTOs/ISOs include in their market models, and what types of constraints should be handled by manual commitments? Of those reliability constraints that should be in the market models, which reliability constraints should RTOs/ISOs prioritize?

**PJM Answer:** If one assumes that RTOs/ISOs should improve their market models to better reflect the cost of honoring reliability constraints in energy and ancillary services clearing prices, the types of constraints that RTOs/ISOs should include in their market models include those that cause significant congestion costs and are likely to be sustained over time. On the other hand, the types of constraints that are of a lower priority for inclusion in the market model and could be handled by manual commitments are those that are likely to be more transient in nature and unlikely to be repetitive or sustained over time.

PJM’s Day-ahead Energy Market model does a good job of reflecting real-time congestion with a few exceptions. Manual dispatch decisions are taken into consideration in Day-ahead Energy Market models if the condition is repetitive and PJM’s real-time operations staff communicates the dispatch to the day-ahead market operations staff. Some of the types of modeling issues that can differ in the Day-ahead Energy Market model compared to the Real-time Energy Market model include:

1) Localized Reactive or voltage limits: Currently, the Day-ahead Energy Market model cannot accurately reflect these localized reactive constraints unless a surrogate voltage interface is defined in advance, allowing generation to set LMPs. If an interface is not defined, staff will manually commit generation in order to provide lagging or leading MVAR support, typically resulting in uplift billed to the Transmission Zone.

2) Virtual Transactions: Virtual Transactions are modeled in the Day-ahead Energy Market but are not experienced in real-time operations. These Virtual Transactions may result in congestion or eliminate congestion that would otherwise been realized in real-time, which can result in a divergence between prices in the Real-time and Day-ahead Energy Markets.
3) Generator flexibility: Committing larger inflexible generators will address reliability issues but they may not be able to set LMP because of their inflexible parameters or large economic minimum operating points. This can happen when a unit is committed in the day-ahead market at a lower megawatt configuration and is then required to increase its output marginally in real-time, yet also needs a mechanical reconfiguration to obtain the next incremental minimal block of megawatts. Additional megawatts that are above the day-ahead award, or unable to set the cost in real-time, will thus potentially become uplift.

The highest priority reliability constraints that the RTOs/ISOs should capture in the market models are those that are likely to be sustained over time. This is because those constraints are the ones for which price signals could drive investment in resources that would resolve the constraint and reduce congestion on the system.

b. In 2013, ISO New England Inc. (ISO-NE) increased its replacement reserve requirement to “reduce the need to schedule additional resources above the load and reserve requirements” in its Reserve Adequacy Analysis. PJM has a similar proposal to increase day-ahead and real-time reserve requirements when extreme weather is expected. In what circumstances can such practices improve efficiency of price formation?

**PJM Answer**: PJM’s proposed rules will improve efficiency of real-time and day-ahead energy reserve pricing because they more accurately reflect operator actions when PJM requires more day-ahead or real-time reserves than normal.\(^{14}\)

c. Do transmission constraint relaxation penalty factors improve the efficiency of price formation? If so, should these penalty factors be allowed to set the energy price if a transmission constraint is relaxed?

**PJM Answer**: Transmission constraint relaxation penalty factors improve the efficiency of price formation by serving as a cap on the shadow price associated with a specific binding constraint. They limit the magnitude of congestion that is included in the PJM’s total LMP and therefore ensure that the cost of congestion is not artificially high when there is no appreciable relief beyond a certain threshold or artificially low when considerable relief MWs are available at a specified cost. These limits also serve to beneficially mitigate extreme volatility of congestion prices in real-time operations. Allowing the shadow price of a particular transmission constraint to increase without limit in a near-term dispatch can cause extreme dispatch signal volatility and price spikes that no physical asset owner can possibly react to, thereby increasing congestion costs to load with no beneficial impact on dispatch efficiency. Since these penalty factors only affect the shadow price limits associated with constraints, and do not directly impact the energy price, they should not be used to set the energy component of PJM’s total LMP, regardless of whether a transmission constraint is relaxed.

d. Are there any new constraints that represent other physical characteristics of the system (with corresponding penalty factors), such as N-1-1 reliability constraints, that could be included in the model to improve the efficiency of price formation? If so, what types of constraints should be included and how should the penalty factors be determined?

---

**PJM Answer:** Under certain conditions, PJM will operate to N-2 constraints as part of real-time and day-ahead operations. This is accomplished by modifying contingency sets in both the Day-ahead and Real-time Energy Markets while controlling to the appropriate rating set. Additionally, PJM operates to known stability constraints by creating interfaces that can be modeled in both the Real-time and Day-ahead Energy Markets.

e. Should RTOs/ISOs create new products that procure the capacity necessary to address reliability constraints that cannot be captured in market models? If so, what should these products look like, and what process should RTOs/ISOs use to design these products?

**PJM Answer:** PJM does not believe it is necessary to create any such additional reliability products for the PJM Region. Having a robust locational capacity market, such as PJM’s Reliability Pricing Model (“RPM”), is sufficient to procure capacity required to address reliability constraints.

f. In some cases, creating new products to satisfy system needs (e.g., ramp capability, local reliability product, or additional reserves to account for operational uncertainty) may amount to procuring a level of spinning or non-spinning reserves above the mandatory reliability requirement. If the “new product” can be satisfied by an existing ancillary service product (e.g., ten minute reserves), is it necessary to create a new and separate product with its own price and co-optimization? Rather than developing a new product, could RTOs/ISOs change the cost allocation of any additional ancillary services procured above the mandatory reliability requirement?

**PJM Answer:** PJM does not believe it is necessary to create a new and separate product to satisfy system needs, with its own price and co-optimization, for the PJM Region. PJM has utilized the existing ancillary service market construct to procure additional reserves under emergency operating conditions. PJM has introduced the “pay for performance” concept as part of its current Regulation market construct and RPM “Capacity Performance” initiative in an effort to either reduce overall Regulation requirements or enhance reliability and market efficiency via increased generator flexibility. As explained above in the answers to Questions 5b and 5c, PJM deploys Synchronized Reserve during those infrequent times when sufficient resource flexibility is not available to meet changing system conditions, and does not believe that a change in its cost allocation methodology is necessary for this service given that the purpose of such deployments is consistent with the requirement for the service.

9. **Shortage Prices**

In the questions below, the term “shortage pricing” refers generically to any pricing action taken in response to a shortage event. Not all RTOs/ISOs use this phrase in the same way. In responding to the questions below, please define terms and distinguish between “shortage pricing” and “scarcity pricing,” if such a distinction is intended.

a. What principles should be used to establish shortage price levels? Should there be one price for any shortage or a set of escalating prices for greater

---

levels of shortage? Is it important to have shortage price levels consistent across adjacent RTOs/ISOs to avoid seams issues?

**PJM Answer:** The appropriate levels associated with shortage pricing should serve to enhance operational reliability by aligning real-time market prices with system conditions, incent uncommitted resources and imports from external areas to sell power during periods of reserve shortage, incent Capacity Resources to perform beyond their capacity commitments (when possible), facilitate demand response and price-responsive demand and provide correct investment signals. Shortage prices are best set by an operating reserve demand curve ("ORDC") which establishes reserve shortage penalty factors that are reflected in energy and reserve prices when shortages of reserves exist. As described in depth in PJM’s Energy Reserve Filing, PJM proposes to implement a multi-step ORDC in order to reflect the relative quantity of reserves to meet normally applicable real-time reserve requirements and reserves needed in excess of those requirements, and to establish different Reserve Penalty Factor levels for reserve shortages.16

It is critical to have an escalating set of shortage pricing penalty factors in order to accurately communicate the price associated with varying levels of reliability issues caused by increasing reserve shortages. Additionally, it is imperative that shortage prices be able to reach a high enough level so that they capture the cost of all controlling actions taken to maintain reliability. Prices that are unable to reach this level undermine wholesale market price signals and create inefficient market outcomes resulting in unnecessary uplift. PJM’s Reserve Penalty Factors will increase to $850/MWh on June 1, 2015, which in turn will establish a maximum shortage price of $2,700/MWh. Given the cost-based offers recently experienced, PJM recognizes this shortage price level is not adequate to accurately price reserve shortage conditions. Therefore if the Commission appropriately raises the energy market offer cap above $1,000/MWh, then shortage price levels must also be raised to allow prices to properly reflect reserve shortage conditions. For example, if the energy market offer cap is raised to $2,700/MWh, it would require a commensurate increase in the Reserve Penalty Factors to ensure that all available reserves are procured prior to the system going short. Raising these parameters would result in an increase in prices in PJM during a reserve shortage as well. To ensure this, the new Reserve Penalty Factors would need to be set to a level approximately equal to the offer cap to capture the maximum opportunity cost a resource would reasonably incur during all operating conditions. Using an offer cap and a set of penalty factors all valued at $2,700/MWh, the resultant shortage price under PJM’s current energy and reserve market configuration would need to rise to approximately $13,500/MWh.

Ideally, the offer cap and associated shortage prices and mechanisms should be consistent across neighboring areas to eliminate border pricing differences that result in interchange swings during the most tenuous operating circumstances. Having consistent shortage pricing levels across adjacent RTO/ISO borders would certainly improve efficiency across seams. Therefore, PJM believes it is important that shortage pricing levels be consistent across RTOs/ISOs.

b. What are the advantages and disadvantages of implementing shortage pricing in the day-ahead market as well as in the real-time market? If shortage pricing is established only in the real-time market but not in the day-ahead market, are other policies needed to facilitate price convergence between the day-ahead

---

and real-time markets during periods of shortage? If so, what are these other policies? If not, why not?

**PJM Answer:** PJM has not implemented shortage pricing in the Day-ahead Energy Market because there are price-sensitive load and transactions in the Day-ahead Energy Market that are unwilling to purchase in this market at shortage prices and would prefer to take the risk that real-time prices will be lower than day-ahead prices. In lieu of implementing shortage pricing in the Day-ahead Energy Market, PJM has rules that allow Virtual Transactions and price-sensitive demand to not only offer into the Day-ahead Energy Market up to the energy offer cap of $1,000/MWh, plus two times the Reserve Penalty Factor (which will equal $2,700/MWh starting June 1, 2015) but also allow them to be eligible to set the day-ahead clearing price at this level. Should such Virtual Transactions clear and therefore set price in the Day-ahead Energy Market above the $1,000/MWh level, that would signal the existence of shortage conditions in the Day-ahead Market and facilitate price convergence in real-time. Therefore, PJM does not believe that an explicit, shortage pricing mechanism is necessary in the Day-ahead Energy Market.

10. **Transient Shortage Events**

At the Shortage Pricing/Mitigation Workshop, panelists stated different positions regarding pricing transient, or short-duration, shortage events. Transient shortage events are shortage events that last only a short time, perhaps as short as one or two five-minute dispatch intervals. For instance, PJM’s market clearing process will not invoke shortage pricing if it can resolve the shortage within a certain time. However, even transient shortage events need a price signal to provide incentives to develop capabilities to respond to the shortage.

a. **Should there be a minimum duration for a shortage event before it triggers shortage pricing? Why or why not?** How would one determine that minimum time, and how does it relate to the settlement interval?

**PJM Answer:** There should be a minimum duration for a shortage event before it triggers shortage pricing. Only persistent shortages should influence price. Furthermore, if there is no reliability concern present on the Transmission System, prices should not be at levels that would suggest otherwise. For these reasons, PJM’s Intermediate Term Security Constrained Economic Dispatch (IT SCED) was designed so that it must be unable to resolve the shortage for a defined period of time before the shortage is recognized in the Real-Time Security Constrained Economic Dispatch (RT SCED) and LMP. PJM also believes that the minimum duration for shortage pricing should be at least as long as the settlement interval, but could also be longer than the settlement interval. Rather, the minimum duration for shortage pricing should be established on the basis of what is likely and required to stimulate investment. Therefore, even in the case where the settlement interval in PJM would be reduced to something less than an hour, PJM still believes that its current implementation of shortage pricing using the IT SCED will be applicable even with a shorter settlement interval.

As stated previously, one of the principles of shortage pricing is to provide the correct investment signals to the market. Transient shortages do not provide robust price signals because their transient nature means that investment is not really necessary. In real-time, there is not sufficient time for the market to respond to the signal. In the long-term, the short-lived price signal is not strong enough to create the appropriate investment incentive.
b. Do RTO/ISO rules regarding transient shortage events result in appropriate price signals? Why or why not? To the extent possible, please provide empirical evidence supporting your answer.

**PJM Answer:** Transient shortage events should not be priced at the same level as sustained shortage events. The Transmission System is not dynamic enough to respond every 5 minutes. Therefore, short-lived shortage prices can lead to over-generation control problems because of interchange response to the transient price signal, as well as physical limitations associated with resource ramping capability. PJM has actually observed this behavior and it has caused issues with maintaining system control as well as suppression of energy market prices.

c. Should treatment of transient shortages be consistent across all RTOs/ISOs? Why or why not?

**PJM Answer:** Ideally, treatment of transient shortages should be consistent across all RTOs/ISO because inconsistency could lead to interchange inefficiency when one neighboring area has volatile, brief spikes in pricing and another does not.

11. Interchange Uncertainty

Due to the lag between price signals and interchange scheduling for import and export transactions, trade between RTOs/ISOs can result in volatile prices and variable system conditions because the ability of importers to schedule flows across the seam can lag behind actual system needs, creating uncertainty in interchange and contributing to operational issues. Several RTOs/ISOs have instituted new rules, such as NYISO’s and PJM’s Coordinated Transaction Scheduling (CTS), which attempt to better coordinate interchange schedules and price signals in order to improve inter-RTO/ISO flows.

a. What can the RTOs/ISOs do to reduce interchange uncertainty? Does CTS help to reduce the uncertainty in interchange created by the lag between price posting and interchange schedules? Does the ability to reduce uncertainty depend on whether all interchange spread bids are incorporated into the RTO/ISO dispatch model (as proposed for the CTS implementation between NYISO and ISO-NE) rather than simply allowing interchange spread bids on a voluntary basis (as proposed for the CTS implementation between NYISO and PJM)? Are there other steps that should be taken to reduce interchange uncertainty?

**PJM Answer:** Interchange uncertainty is primarily the result of the short lead time interchange schedule submission requirements, 20 minutes prior (T-20) to the start of the transaction, associated with scheduling interchange in most RTOs/ISOs, as well as the short minimum schedule duration time of 15 minutes. These two features of real-time interchange make it impossible to forecast and respond to changes in interchange values due to the constant change in both the direction and magnitude of interchange. The CTS product between NYISO and PJM (and possibly an identical product currently under discussion between MISO and PJM) is targeted at mitigating one of these problems by requiring a longer submission requirement, transaction flow minus seventy five (T-75) minutes, so that the transactions can be evaluated by the RTO/ISO in conjunction with generation resources to determine the most efficient resource profile to meet the forecasted load. Due to the optional nature of CTS on both the NYISO and MISO seams in PJM, it will not reduce all of the uncertainty that interchange can present, but will provide an incremental reduction in this uncertainty.
In an attempt to further minimize interchange uncertainty and address the lack of visibility Market Participants have related to the magnitude of interchange that is needed, PJM worked with stakeholders in 2014 to identify a solution that would provide more predictability about interchange levels to PJM’s dispatch group when making future commitment decisions. As a result of these stakeholder discussions, PJM has the ability to implement an interchange cap when defined triggers are encountered. Specifically, during emergency conditions, PJM may elect to implement a net interchange cap that represents the maximum level of RTO-wide net interchange beyond which the scheduling of additional non-dispatchable transactions using Spot Market Import or non-firm hourly point to point transmission service will be disallowed. The inclusion of a net interchange cap provides PJM’s dispatch group more certainty around the total level of interchange they can expect so more accurate generation commitments can be made to meet future system conditions in peak hours of the day.

b. What information do market participants need to better respond to interchange price signals?

PJM Answer: In order to respond to price signals in a more timely fashion, Market Participants need visibility into the RTOs/ISOs' forward price projections as well as an indication of the magnitude of interchange that is needed. Without having forward price indicators, Market Participants are left to guess what prices will be in the future or wait until real-time prices reach certain thresholds that trigger a particular interchange transaction, which in most cases is too late or triggers too much response.

12. Next Steps

a. Are there other price formation issues that, if addressed, would improve energy and ancillary services price formation in RTO/ISO markets? What are they?

PJM Answer: As previously discussed, there are numerous price formation issues that would improve price formation in RTO/ISO energy and ancillary service markets. Specifically, shortage prices should not be artificially limited but should fully capture costs and control actions. Further, the settlement timeframe should be shortened from hourly to sub-hourly so that the settlement timeframe does not encourage adverse resource response or interchange incentives. In addition, there should be uniformity across RTOs/ISOs with regard to both shortage pricing levels and offer caps, as well as whether and how to include transient shortage events in shortage pricing. Given the specialized business rules and market designs that currently exist, direction from and action by the Commission will likely be required in order for RTOs/ISOs to coordinate on these items. PJM does not believe there are any other issues that need to be addressed in order to improve price formation in RTO/ISO markets.

b. What are the highest-priority price formation issues to address? Is the priority of issues different in different RTO/ISO markets? If so, what are the priorities for each RTO/ISO and are the RTOs/ISOs currently addressing those issues sufficiently?

---

**PJM Answer:** PJM believes there are several highest-priority price formation issues that need to be addressed in the PJM Region. The first is better capturing operator action in pricing. However, capturing these actions into pricing creates trade-offs between uplift and prices and also uplift and revenue adequacy. Moreover, balance needs to be maintained to ensure that uplift is minimized when prices accurately represent the current system conditions while at the same time not shifting the costs from uplift to revenue adequacy by utilizing constraints that weren’t captured in the Financial Transmission Rights (“FTR”) market. Additionally, prices need to reach appropriate increased levels at the proper time. Often, prices go high too late, and the system would have benefited from the response that high or shortage pricing levels encourage further in advance of the actual shortage conditions. Furthermore, pricing levels should not be artificially limited in order to reach stakeholder consensus or for social acceptability. Rather, they should be set to represent the true needs of the system. Therefore, a permanent solution to the overall energy market offer cap issue is needed.

PJM takes no position on the priority of issues in other RTOs/ISOs.

Respectfully submitted,

Craig Glazer  
Vice President – Federal Government Policy  
PJM Interconnection, L.L.C.  
1200 G Street, N.W.  
Suite 600  
Washington, D.C. 20005  
(202) 423-4743  
craig.glazer@pjm.com

Steven Shparber  
Counsel  
PJM Interconnection, L.L.C.  
2750 Monroe Blvd  
Audubon, PA 19403  
(610) 666-8933  
steven.shparber@pjm.com
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 Audubon, PA, this 6\textsuperscript{th} day of March, 2015.

Steven Shparber  
Attorney for  
PJM Interconnection, L.L.C.