UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	))	**Docket No. RM17-2-000**

COMMENTS OF THE DEPARTMENT OF MARKET MONITORING FOR THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The Department of Market Monitoring (DMM) for the California Independent System Operator (CAISO) files comments in the above-captioned proceeding. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) is proposing criteria for limiting how independent system operators can allocate real-time bid cost recovery to deviations. DMM strongly supports the NOPR position to not impose a requirement on ISOs to allocate real-time bid cost recovery to deviations. However, the definition of 'deviations' and allocation criteria specified in the NOPR could discourage CAISO from attempting to allocate any real-time bid cost recovery to deviations. Therefore, DMM recommends that the Commission allow individual ISOs discretion in how they may allocate bid cost recovery to deviations.

I. DMM strongly supports the proposal to not require ISOs to allocate bid cost recovery to deviations.

Goals of bid cost recovery allocation design

Each run of the CAISO's fifteen-minute market optimization software produces commitments and schedules that minimize total production costs over the time horizon of that market run. The optimal commitment and dispatch for each market run will generally include resources with discrete commitment costs, which result in average costs that decrease with output. As described in DMM's comments on the Fast Start Pricing NOPR, in this situation bid cost recovery is a necessary component of CAISO's efficient two-part pricing system.[1]

Therefore, the goal of bid cost recovery allocation should not be to eliminate all bid cost recovery. However, the methods used to allocate bid cost recovery can significantly impact market participant incentives to bid and physically perform in ways that affect spot market efficiency. The goal of bid cost recovery allocation design should be to contribute to creating or maintaining incentives for market participants to behave in ways that maximize spot market efficiency. In theory, allocating bid cost recovery to deviations could help to improve the efficiency of market participant behavior.

In theory, allocating bid cost recovery to deviations could increase efficiency.

Consider a simplified spot market structure in which there is one day-ahead market run for all 24 hours, followed by one real-time market run for each hour. Inputs to the day-ahead market run include resource availability, load forecasts, variable energy resource forecasts, and resource bids for each hour. The day-ahead market run creates optimal schedules given the set of inputs provided to the day-ahead market optimization.

The real-time market run for a given hour only considers inputs for that hour and only creates the optimal commitments and dispatch for that hour. This

---

[1] See Department of Market Monitoring, *Comments of the Department of Market Monitoring for the California Independent System Operator Corporation under RM17-3*, February 28, 2017, p. 1.

real-time run ignores the hours that follow the given hour when determining the optimal dispatch. The inputs for this real-time run may also change from what the inputs were for the day-ahead market optimization. If an input such as a variable energy resource's forecast or generation resource availability is different for an hour in the real-time market than it was for the day-ahead market run for that hour, the optimal commitment and schedules output by the real-time optimization software will be different than the optimal schedules output by the day-ahead market software. The schedules that have become optimal in real-time given the most updated inputs for that hour may include the commitment of different resources than were committed by the day-ahead market for that hour.

As a result of the change in the resources that should be committed or dispatched in real-time to minimize total production costs, there could be real-time bid cost recovery. This would arise if the prices set by marginal cost pricing did not result in resources fully recovering their commitment costs. Given the set of inputs provided to the real-time market optimization for that hour, this bid cost recovery is part of the efficient two-part pricing mechanism.

The change in inputs between the day-ahead market run and the real-time market run for that hour caused the optimal set of commitments to change between the day-ahead market and real-time market. Therefore, the change in inputs can be considered as having caused the real-time bid cost recovery. Moreover, if the inputs to the day-ahead market had more accurately reflected the inputs to the real-time market optimization for this particular hour, the day-ahead market optimization could have output a more efficient commitment and dispatch schedule for the actual operating of that hour. If the inputs to the day-ahead market had more accurately reflected the inputs to the real-time market for that hour, the total production costs over both the day-ahead market and real-time market for that hour could have been lower. Therefore, the change in inputs between the day-ahead market and the real-time market can cause a decrease in spot market efficiency.

Spot market efficiency will increase if the inputs to forward market runs *occurring further in advance of the moment of actual power flow* more accurately reflect the inputs to the market runs that occur closer to the moment of actual power flow – e.g. the single real-time market run for the hour in this example.[2] Allocating bid cost recovery to entities responsible for changes in inputs between two market runs for the same interval of actual power flow could create incentives for these entities to submit more accurate inputs to the market run that occurs further in advance of the actual power flow. In this way, allocating bid cost recovery to deviations in the inputs could theoretically increase the efficiency of the spot markets.

Allocating bid cost recovery to deviations is so complicated that it is likely to do more harm than good.

In practice, allocating bid cost recovery to deviations in inputs is extremely complicated. Given this complexity, seeking to allocate bid cost recovery to deviations is much more likely to create behavioral incentives that harm spot market efficiency. Therefore, DMM strongly supports the FERC NOPR proposal

[2] The day-ahead market run is the only forward market run in this simplified example.

to not require CAISO to allocate real-time bid cost recovery to changes in inputs between market runs that are calculating the optimal dispatch for the same interval of actual power flow.

Allocating bid cost recovery to changes in inputs in a way that would incentivize behavior that would increase ─ rather than decrease ─ spot market efficiency is extremely complicated in CAISO markets because CAISO does not have the simple two-market structure described in the example of the subsection above. CAISO has the day-ahead market similar to the day-ahead market described in the example above. However, CAISO does not use the single real-time market run for a given real-time interval that ignores all subsequent time intervals. Instead, CAISO uses a sophisticated multi-interval optimization in real-time.

This real-time multi-interval optimization does not just consider the inputs to the most immediate ("binding") time interval when determining the optimal commitment and dispatch for the binding interval. The real-time multi-interval optimization also considers the inputs to all the subsequent time intervals over the next 4.5 hours and determines the optimal commitment and dispatch over all of these "advisory" intervals in that 4.5 hour time window. As a result, the CAISO day-ahead and real-time spot market structure does not consist of a single forward market (such as a day-ahead market) before the real-time market run for a specific interval of actual power flow. Instead, the day-ahead market is just the first of many forward markets.

Consider the actual power flow interval between 9:00 and 9:15 AM on an illustrative sample day (e.g. April 11). The first forward market for 9:00-9:15 power flow is the day-ahead market that runs at 10:00 AM on April 10. The next forward market for power flow on 9:00-9:15 on April 11 starts around 4:30 AM on April 11. The real-time market optimization run that starts at 4:30 AM on April 11 considers inputs for all time intervals between 4:30 and 9:00. The run outputs the optimal commitment and schedules for all of those intervals, given the inputs provided to the optimization at 4:30. If an input that is relevant for 9:00-9:15 power flow is different in the 4:30 real-time market run than the input was in the day-ahead market run, the 4:30 market run could determine that the optimal commitment for 9:00-9:15 power flow is different than the commitment that the day-ahead market determined was optimal for 9:00-9:15 power flow.

Yet another forward market run for 9:00-9:15 power flow starts around 5:30 AM. Additional forward market runs that reassess the optimal commitments and schedules for the 9:00-9:15 power flow occur just about every fifteen minutes until the final real-time market run that makes commitment decisions begins around 8:45.

In CAISO markets, deviations in inputs (such as resource bids and availability and load and variable energy resource forecasts) between the day-ahead market run at 10:00 AM on April 10 and the final forward market run at 8:45 AM on April 11 are not uniquely relevant in determining the cause of bid cost recovery for actual power flow between 9:00 and 9:15 on April 11. This is because changes in inputs between any earlier forward market and a later forward market for the same interval of actual power flow can cause the optimal resource commitment to be different between the two forward markets. Therefore a change in inputs between any of the forward markets can cause real-time bid cost recovery. As a result, assigning any particular change in inputs between the large number of forward markets as the cause for bid cost recovery in a particular interval of actual power flow is extremely complicated.

Due to this difficulty in accurately assigning cost-causation for bid cost recovery, DMM strongly supports the principle that, "at the highest level, the allocation of uplift costs should, to the extent possible…avoid discouraging market participant behavior that lowers total production costs".[3] For CAISO to allocate bid cost recovery in a way that maximizes spot market efficiency, the most appropriate goal may be to try to simply allocate bid cost recovery in a way that has the lowest impact on spot market behavioral incentives.

CAISO currently accomplishes this goal for real-time bid cost recovery by allocating most real-time bid cost recovery to metered load. Almost all metered load is unresponsive to the final price paid by a load serving entity to the wholesale market for a marginal increment of load. As a result, bid cost recovery can currently be allocated to metered load without materially reducing the total consumer and supplier surplus that would have been achieved by the spot market in the absence of the bid cost recovery allocation.[4] Allocating bid cost

---

[3] 158 FERC ¶ 61,047, *Notice of Proposed Rulemaking: Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. RM17-2-000, January 19, 2017, ¶ 2, pp. 1-2.

[4] As load becomes increasingly able to respond to wholesale market prices, CAISO may be able to improve spot market efficiency by adjusting bid cost recovery allocation to best allocate it in a way that has the lowest impact on spot market behavioral incentives.

recovery to deviations could do more harm than good. DMM therefore supports the NOPR not requiring CAISO to allocate bid cost recovery to deviations.

II. The Commission should allow discretion in how CAISO may allocate bid cost recovery to deviations.

As discussed in the section above, appropriately allocating bid cost recovery to deviations between the various CAISO forward markets could, in theory, improve incentives for market participants to provide more accurate inputs to the various forward market runs. DMM is not currently advocating for CAISO to allocate bid cost recovery to deviations due to the harm to market efficiency that could occur from doing so incorrectly. However, there is the potential for CAISO and stakeholders to identify some methods for allocating some bid cost recovery to forward market run deviations that could improve spot market efficiency. If the definition of 'deviations' and allocation criteria specified in a final Commission Order is too specific to allow CAISO to accurately allocate bid cost recovery according to cost-causation principles, it would discourage CAISO from attempting to allocate any real-time bid cost recovery to deviations. Therefore, DMM recommends that the Commission allow more discretion than seems to be proposed in the NOPR in how individual ISO's may allocate bid cost recovery to deviations.

The definition of 'deviations' is too specific.

For the purposes of allocating bid cost recovery to deviations, the NOPR "propose(s) that deviations are megawatt hour differences between a market participant's scheduled deliveries or receipts at particular points – as determined by the day-ahead market clearing process – and those amounts actually delivered or received in real-time that are not related to real-time economic or reliability-related operator dispatch instructions."[5] As described in Section I above, changes to inputs between various CAISO multi-interval optimization forward market runs could cause bid cost recovery. Therefore, limiting the definition of 'deviations' to changes between day-ahead market schedules and metered output would prevent CAISO from allocating bid cost recovery to the deviations that actually caused the bid cost recovery in many situations.

Consider a wind resource that schedules its forecast of 100 MW of output in the day-ahead market (run at 10:00 am on April 10) for actual power flow from 9:00-10:00 on April 11. In the real-time market run that starts around 4:30 am on April 11, that wind resource now forecasts output of only 10 MW for 9:00-10:00. As a result, this real-time market run may commit a gas resource that takes several hours to start up. The start-up instruction from this real-time market run to the gas resource is a binding start-up instruction, so the commitment costs for the resource will be owed to the gas resource regardless of how inputs change to the rest of the real-time forward market runs for actual power flow from 9:00-10:00. Finally, assume that by the final real-time market runs for actual power flow at 9:00 on April 11, the forecast for the wind resource has gone back up to 100 MW and the resource's metered output is 100 MW.

This example illustrates how defining 'deviations' too narrowly can result in inefficient allocation of bid cost recovery. The wind resource has no deviations between its day-ahead market schedule and its metered output. Therefore,

[5] NOPR, ¶ 4, p. 3.

under the NOPR definition of deviations, this resource would not be allocated bid cost recovery for the commitment costs of the gas resource. This would occur even though the wind resource's deviations between forward markets clearly caused the commitment of, and bid cost recovery for, the gas resource. The deviation of the wind resource forecast for actual flow from 9:00-10:00 on April 11 between the day-ahead market and the 4:30 real-time market multi-interval optimization run caused the commitment of the gas resource. The deviation of the wind resource forecast from 10 MW (during the forward run starting at 4:30) back up to 100 MW (for the final real-time market runs for power flow from 9:00-10:00) increased the need for bid cost recovery payments to the gas resource because the 100 MW wind output causes the binding real-time market prices on which the gas resource settles to be lower than if the wind resource had produced the 10 MW forecasted at the time (4:30) the decision was made by the real-time market software to commit the gas resource.

Criteria for real-time uplift categories, netting, and hourly settlement are too specific.

The criteria specified in the NOPR for hourly cost allocation, netting, and differentiating between local and system could also result in bid cost recovery allocation rules that incentivize inefficient bidding behavior or physical performance in CAISO spot markets.

For example, consider again the wind resource from the subsection above that, at the time of the day-ahead market run at 10:00 on April 10, forecasts 100 MW of output for actual power flow from 9:00-10:00 on April 11. Again assume that by the 4:30 real-time forward market run for 9:00 power flow on April 11, the wind resource forecasts only 10 MW of output for 9:00-10:00. Again, this causes the commitment of the gas resource. To differentiate this example from the example in the subsection above, now assume that the wind resource's forecast output for 9:00-10:00 remains at 10 MW and the wind resource's actual metered output is 10 MW.

This example illustrates how the netting criteria specified in the NOPR would create incentives for inefficient behavior. If the entity that controls the wind resource also controls a different dispatchable resource, that entity would have some incentive to have the dispatchable resource deviate up to 90 MW above its instructed output level from 9:00-10:00. Under the NOPR proposal to net a market participant's "helping" and "harming" deviations, the market participant could offset its 90 MW of "harming" downward wind resource deviation with up to 90 MW of "helping" upward dispatchable resource deviation. However, because the multi-interval optimization committed the gas resource hours in advance of the 9:00-10:00 actual power flow, the market participant's 90 MW of upward dispatchable resource deviation does not help to reduce bid cost recovery at all. In fact, the upward deviation may increase the need for bid cost recovery by suppressing real-time market prices used to settle the gas resource that was committed at 4:30.

The examples above illustrate the complexity of accurately assigning bid cost recovery to the deviations that caused it. A final Order that is too specific in defining 'deviations' and the criteria for allocating bid cost recovery to deviations could unintentionally result in market rules that create incentives for market participant behavior that reduces the efficiency of CAISO spot markets. Therefore, DMM recommends that the Commission allow more discretion than seems to be proposed in the NOPR in how individual ISO's may allocate bid cost recovery to deviations.

Respectfully submitted,

/s/ Ryan Kurlinski

Eric Hildebrandt, Ph.D.
Director, Market Monitoring
Ryan Kurlinski
Manager, Analysis & Mitigation
Mike Castelhano, Ph.D.
Market Monitoring Analyst Lead
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: 916-608-7150
rkurlinski@caiso.com

Independent Market Monitor for the
California Independent System Operator

Dated: April 10, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service lists in the above-referenced proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 10th day of April, 2017.

/s/ Anna Pascuzzo

Anna Pascuzzo