Comments on Bidding Rules Enhancements Straw Proposal
Department of Market Monitoring
May 19, 2015

The Department of Market Monitoring (DMM) appreciates this opportunity to comment on the ISO's proposal for Bidding Rules Enhancements. DMM supports the ISO's effort to address participant requests for additional bidding flexibility and a number of issues outstanding following the completion of the Commitment Cost Enhancements initiatives policy process. This initiative poses substantive questions that require further development prior to implementation. Following are DMM's comments on specific issues. Each comment is listed by ISO straw proposal section number.

Commitment Cost Mitigation (Section 6.2.1)*:*

The ISO's current method of mitigating commitment cost bids is to cap the bids for most gas resources at 125 percent of day-ahead estimated costs (or 150 percent of cost estimates made based on monthly gas futures prices for use limited units under the registered cost option). This current mitigation method provides substantial flexibility for market participants to incorporate into their commitment cost bids the uncertainty that may arise in a resource's actual commitment costs relative to the ISO's estimates of those costs. We support the ISO's proposals in the current initiative – along with prior enhancements made over the last year – to improve the methods for estimating a resource's actual commitment costs.

In early 2014, a situation occurred in the ISO system where many resources were dispatched to inefficient points in their operating range during a time when the gas supply for part of the state was very restricted. DMM supported the ISO's response to adopt a manual process to update gas prices used in the day-ahead market when natural gas prices increase by more than 25 percent compared to the previous day's results.

DMM supports the ISO's current proposal that minimum load and start-up costs for resources without day-ahead commitments should be allowed to submit new bids for these parameters, within the 125 percent cap for most resources, into the real-time markets. Given the level of volatility that has historically existed in western gas markets, this flexibility accounts for the volatility of natural gas prices in almost all situations.[1] However, we encourage the ISO to continue to work to improve the methods for estimating a resource's actual commitment costs, including updating the cost estimates with the best and most recently available gas price data.

FERC Order 809 (Section 6.2.3)

DMM addresses additional concerns related to potential changes in day-ahead market timing in section 6.3.3 below.

Inefficient accounting for minimum load costs after a PMIN rerate (Section 6.3.1)

The ISO has proposed a change to how minimum load costs are accounted for when units submit a temporary change to their minimum operating level (known as *PMIN rerates*). The current approach serves as an important and effective means of limiting the incentive to try to game PMIN rerates for increased bid cost recovery. However, we understand that there are some objections to the current approach due to the possibility of inefficient commitments.

The ISO's initial proposal is to scale the existing minimum load cost to the rerated PMIN by multiplying that cost by the share of the re-rate. In other words, if the rerated PMIN is 150 percent of the original PMIN, the rerated minimum load costs would be 150 percent of the original minimum load costs.

The ISO's initial proposal to scale minimum load costs is flawed, due to the fact that minimum load is generally an inefficient point for resources to operate, and so the resource is likely to be more efficient at its rerated PMIN. Additionally, minimum load costs can include other factors that are not related to operating level, such as costs for major maintenance.

Consequently, DMM has asked the ISO to consider an alternative option where the default energy bid is used to estimate the real costs to run at the level of the PMIN rerate. This estimate should be much closer to real costs that units face. Scaling the minimum load cost as proposed will lead to changed costs for PMIN rerates, but since it does not represent the real costs of the resource, will not lead to a more efficient set of commitment decisions. In addition to providing increased and unjustified bid cost recovery, the scaling option could distort the merit order of resources more than if there were no change in costs for PMIN rerates.

[1] Further detail can be found in the *Report on natural gas price volatility at western trading hubs,* Department of Market Monitoring, May 14, 2015: http://www.caiso.com/Documents/DMMReport-GasPriceAnalysis.pdf.

Resources without a day-ahead schedule cannot rebid commitment costs (Section 6.3.2)

DMM supports the ISO's proposal to allow resources not committed in the day-ahead market to rebid commitment costs with updated natural gas prices in the real-time market. This will help reduce the risk associated with using lagged natural gas for commitment costs in the real-time markets. Currently, default energy bids are updated to reflect the appropriate next day index for the flow date, but commitment costs are not.

We agree with the ISO proposal to only allow resources without day-ahead schedules to update commitment costs, but recommend that the ISO specify how this would apply to different configurations of multi-stage generating units. In addition, DMM suggests that the ISO maintain the requirement that real-time commitment costs not differ across hours within a date. To implement real-time rebidding consistent with this requirement, the ISO would need to limit rebidding to the time period between calculation of commitment costs with updated natural gas prices and T-75 of the first interval of the trading date.

Gas price index may not reflect real-time gas purchase costs (Section 6.3.3)

Participants have indicated that daily natural gas price volatility is one of the main reasons why bidding rules should to be enhanced to allow for more flexibility. This stakeholder process considers methods to help reduce exposure to gas price volatility. Overall, DMM is supportive of only incremental changes to the bidding rules, as we feel that almost all of the historic volatility would be covered by the ISO's current bidding rules procedures.

Natural gas prices are a key input in the ISO markets as most prices are set by natural gas-fired resources. There are two ways in which the spot natural gas prices are directly used in the ISO markets.

- An index of various natural gas prices is used to calculate default energy bids (DEBs) used to mitigate energy bids when local market power mitigation screens are triggered. Default energy bids include a 10 percent adder that is applied to all fuel and variable cost components, including variable gas costs. Generated bids may also be calculated using the gas price index.
- Natural gas prices are also used to calculate start-up and minimum load commitment costs under the proxy cost option that applies to most gas-fired generating units. Resources on the proxy cost option have the ability to bid in their start-up and minimum load costs up to 125 percent of their proxy costs.

Currently, the natural gas price index used by the ISO in the day-ahead market to calculate default energy bids and commitment costs for units under the proxy cost option is based on prices for the next day gas market and is usually lagged by one day. For instance, when the ISO's day-ahead market begins to be run at 10 a.m., default energy and commitment cost bids are based on an index of multiple gas prices that were published for next day gas trading that occurred on the prior day. The use of a gas index based on the average of multiple gas prices is designed to increase the accuracy of gas prices used and prevent potential manipulation. The ISO normally uses prices based on the previous day's trading since all but one of the sources of published gas prices for next day gas trading do not become available until after the time that the ISO's day-ahead market begins to run. However, this creates a one day lag between the flow date of the next day gas prices used in this index and the flow date corresponding to the operating day for which the ISO's day-ahead market is being run.

The ISO recently modified market rules to address issues created when natural gas prices in next day trading, which occur on the day the day-ahead market runs, appear to have increased significantly above the gas prices that it would normally use for the day-ahead electricity market. Specifically, when the natural gas prices reflected in current trading in the InterContinental Exchange (ICE) market exceeds the previous day's gas price index by 25 percent or more, the ISO now updates default energy and commitment cost bids used in the day-ahead market using these ICE prices.

DMM's analysis of over 5 years of ICE trading data shows that on almost 99 percent days the maximum recorded daily spot market gas price is within 110 percent of the prior day's next day gas price, the price used by the ISO to calculate commitment costs. [2] Our analysis further shows that in the 0.4 percent of days when 125 percent headroom would not cover the maximum recorded trade, the vast majority of trades, 90 percent, were within 125 percent of the prior day's next day average price, the current cap on proxy costs. Thus, we see that the ISO's current rules have covered most natural gas risk over the last 5 years. This reinforces the fact that the next day gas price is an exceptionally good proxy for spot natural gas prices.[3]

The ISO has already worked to reduce some of this risk by removing the next day price lag through its manual update procedure when next day gas prices increase by 25 percent from the previous day. Most of the remaining days not covered under the current provisions are concentrated in early February 2014.

Thus, DMM finds that only incremental changes to the ISO's current bidding rules are warranted and generally supports the ISO's efforts as a part of this stakeholder process. Specifically:

- DMM supports the ISO's proposal to allow resources not committed in the day-ahead market to rebid in their proxy costs with updated natural gas prices in the real-time market. This will help reduce the risk associated with using lagged natural gas for commitment costs in the real-time markets. Currently, default energy bids are updated to reflect the appropriate next day index. See additional comments on this provision in section 6.3.2 comments above.

[2] Further detail can be found in the *Report on natural gas price volatility at western trading hubs,* Department of Market Monitoring, May 14, 2015: http://www.caiso.com/Documents/DMMReport-GasPriceAnalysis.pdf.

[3] Ibid.

- DMM suggests that if the ISO moves the closing of the day-ahead market forward to be consistent with FERC Order No. 809, the ISO should preserve its manual process to update the gas price index with ICE prices when natural gas prices spike. As DMM's analysis of ICE data indicates, updating the natural gas prices during these periods reduces the risks associated with natural gas price volatility. Thus, the ISO should consider specifying, as part of that process, how the ISO intends to preserve the manual gas price index update process with an earlier day-ahead market closing and run period.
- DMM suggests that the ISO consider dropping the threshold for when the ISO invokes the update to its special price spike procedures. The current threshold is set at a 25 percent change in next day index prices from the previous index price. For instance, dropping the threshold that triggers the manual update process from 25 percent to 15 percent would have included an additional 5 days in our sample period, representing 16 percent of the days with high gas price volatility in our sample.
- DMM supports further consideration and discussion of the ISO's general concept to allow for cost recovery for resources that don't cover their fuel costs due to gas price volatility. However, DMM believes this approach would need to be limited by strict and clear conditions that are spelled out in detail as part of this stakeholder initiative, rather than at a later point as part of the implementation process. Design details should include specific reporting and documentation requirements required from generators, and data verification and calculational rules that would be employed by the ISO. In addition, the ISO would also need to commit to ensuring that the necessary resources and processes were in place to implement this change. DMM notes that this may require additional expertise in gas procurement and auditing that do not currently exist within the ISO. Thus, we recommend that the ISO carefully flesh out this option as early as possible to ensure clarity and completeness.

Greenhouse gas costs for natural gas suppliers (Section 7.2)

The regional gas price indices used in the ISO's optimization should represent, to the extent possible, the true marginal costs of gas purchased by the resource. As such, to the degree that resources with greenhouse gas compliance obligations are given a greenhouse gas obligation rebate on gas transport prices set by retail tariffs, the ISO's gas price indices should recognize that. The current rebates are *de minimus* so the cost of instituting new greenhouse gas adjusted fuel regions may not be justified, but this could change in the future. DMM would support the addition of greenhouse gas adjusted fuel regions.

Adjusting gas transportation adders (Section 7.3)

The proposed change would allow calculation of regional gas price indices that better reflect the true incremental cost of gas within the PG&E system. DMM is supportive of this change. For SCE and SDG&E regions, gas transport costs are based on historical volume. DMM recommends that the ISO ask market participants to keep their gas regions, which are entered into master file, up to date so that they accurately reflect the current costs faced by the resource. If necessary, the ISO should validate these entries.

Improvements to the energy price index calculation (Section 7.4)

In response to specific questions posed in the straw proposal, DMM recommends the following:

1. The electricity price index (EPI) should be assigned based on the retail electricity provider of the resource, rather than the natural gas fuel region.

2. Rather than setting the EPI to the maximum of a retail electricity price and an estimated wholesale price, resources incurring wholesale electricity costs for auxiliary power should be assigned an EPI based on an estimated wholesale electricity cost at their location and resources incurring retail electricity costs should be assigned an EPI based on the retail electricity costs they incur.

3. Resources paying for auxiliary power under the SDG&E tariff should be assigned an EPI based on SDG&E's tariff rather than SCE's tariff.

4. The wholesale EPI is currently calculated for peak hours by multiplying the average price from some peak hours in the relevant season (either summer or winter) from the last year by a future price conversion factor. The off-peak price is calculated by multiplying the average price for all off-peak hours in the previous year by the monthly future price conversion factor. Recommended changes to the current wholesale energy cost estimate used for the EPI include the following:

   i) The wholesale EPI should be based on analysis of prices from the resources specific appropriate commitment period rather than the 5-minute real-time market in all cases. For example, a resource committed by the day-ahead market would have an EPI based on the day-ahead wholesale price, rather than the 5-minute real-time price.

   ii) The current calculation of the off-peak wholesale EPI is based on the average off-peak wholesale price at the pricing node from the prior year. In some cases, the earliest interval included may be almost two years prior to the trade date. DMM recommends that a more recent time period would be more representative of congestion driven price differences between the pricing node and trading hub where future price conversion factors are calculated.

   iii) The wholesale price for days containing peak hours is estimated by averaging prices from the top 8 peak hours within each day of the relevant season in the prior year and multiplying the seasonal average by the future price conversion factor. DMM suggests that an average of all peak hours would be more representative. As with off-peak price calculations, DMM recommends that a more recent time period would be more representative of congestion driven price differences between the pricing node and trading hub where future price conversion factors are calculated.

iv) Future price conversion factors are restricted to be between 100 and 150 percent. The restriction appears arbitrary and only allows price increases. DMM recommends that the future price conversion factor be symmetrical and allow for downward price changes (e.g. 50 to 150 percent).

5. In addition, the ISO could increase transparency in this area by publishing an analysis of the quality of the existing wholesale EPI price forecasts. Should the current wholesale EPI calculation, or a revised version, fail to forecast wholesale electricity prices within a reasonable range, a thorough analysis could suggest changes to the calculation algorithm.

Currently, the EPI for EIM resources is calculated using the formula used for CAISO resources choosing the registered cost option. This formula is described in section G.1.1 of the Market Instruments BPM as an estimated electricity price calculated by multiplying the projected monthly future gas price multiplies by a factor of 10. DMM recommends that the EPI for EIM resources should instead be calculated in a manner consistent with ISO balancing area resources.

Resource characteristics review (Section 8)

Under the current ISO tariff, resource characteristics submitted to the ISO by market participants "shall be accurate and actually based on physical characteristics" as defined in tariff section 4.6.4:

> ***4.6.4 Identification Of Generating Units***
> *Each Participating Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the CAISO. All information provided to the CAISO regarding the operational and technical constraints in the Master File shall be accurate and actually based on physical characteristics of the resources except for the Pump Ramping Conversion Factor, which is configurable.*

DMM has previously expressed concern that the ISO does not have an adequate process for reviewing or validating unit characteristics entered into the Master File, and that participants may submit values that limit the availability and flexibility of resources based on economic preferences rather than actual technical unit characteristics.

The ISO's proposal seeks to address this issue by modifying the tariff to explicitly allow participants to enter two sets of Master File values: one based on actual physical characteristics, and another set of "market" characteristics based on the scheduling coordinator's preference for resource constraints to be used by the market software.

DMM is supportive of this approach as an alternative to the status quo if the necessary design and implementation details are further developed as part of the stakeholder process. Allowing participants to enter market characteristics on the basis of economic profit maximization or to simply minimize plant usage and wear and tear could promote physical withholding and allow gaming. As a result, DMM believes it would be reasonable to set guidelines limiting the degree to which a unit's market characteristics could be more constrictive than their actual physical characteristics. To impose such limitations, however, the ISO would need a process and criteria for determining or reviewing actual physical characteristics.

In addition, the existing proposal indicates that this effort will be coordinated with other efforts affecting or based on resource requirements such as the reliability service initiative and other initiatives relating to resource adequacy. DMM believes this coordination is very important, and that this process should ensure that resources under resource adequacy obligations are clearly required to provide the capacity and flexibility to the market for which resource adequacy compensation or credit is being provided.