California Independent
System Operator Corporation

MRTU Market Power Mitigation:
Bid Caps for Start-Up and Minimum Load Costs

Draft Revised Proposal

Department of Market Monitoring

August 8, 2007

I. Revised Proposal and Options

This paper provides further revisions and refinements to the options and proposal for startup and minimum load bid caps under MRTU, which were last presented in a June 25, 2007 whitepaper by the Department of Market Monitoring (DMM).[1] This revised list of options and proposal reflects feedback from stakeholders and management that it may be appropriate to have a lower cap for units that are more likely to have locational market power, while having a higher cap for other units. However, the revised proposal continues to reflect options that may be feasibly implemented under the current MRTU software design, which precludes the more dynamic approaches used in other ISOs in which mitigation is performed as part of the market software only when system and market conditions suggest that units may have locational market power. Thus, each of the options under consideration are designed to be feasible to implement by a manual process of reviewing and limiting startup and minimum load bids entered into the Master File, as discussed in the May 16, 2007 whitepaper on this issue.[2]

In the June 25 whitepaper, DMM proposed unit specific bid caps for start-up and minimum load bids equal to 300% of the cost-based values for these parameters. Several stakeholders expressed concern that the proposed caps were too high, particularly for units located in constrained areas where market power is likely to be prevalent. In response to these concerns, DMM has modified the proposal to include lower bid caps for units located in Local Capacity Areas (LCAs) and higher bid caps for units outside of those areas. Additionally, to address the concern that lower bid caps may unduly expose suppliers to spot market gas price risk, should gas prices rise significantly during the minimum 6-month period of the bids, DMM has proposed several options for providing relief in such situations. The specifics of the current proposal include the following:

Different Caps for LCA and non-LCA Units

- For units within Local Capacity Areas, bids caps would be set at 200% of start-up and minimum load costs, as projected using plant operating characteristics and an index of NYMEX gas futures prices described in the May 16 whitepaper.

- For units outside of Local Capacity Areas, bids caps would be set at 400% of projected start-up and minimum load costs.

Provision for Gas Price Increases

The May 16 whitepaper provided an analysis of NYMEX gas futures prices on a forward looking six month period relative to actual increases in daily spot market gas prices over the subsequent

[1] *MRTU Market Power Mitigation: Proposal for Bid Caps for Start-Up and Minimum Load Costs*, Department of Market Monitoring, June 25, 2007 *(http://www.caiso.com/1c08/1c08b3ec1a150.pdf)*

[2] *MRTU Market Power Mitigation: Options for Bid Caps for Start-Up and Minimum Load Costs*, Department of Market Monitoring, May 16, 2007 (May 16 Whitepaper), p. 17 (*http://www.caiso.com/1b87/1b87a5451d380.pdf*)

six months over the last five years. That analysis indicates that there is a relatively small chance that spot market gas prices may reach 150% to 200% of the index of NYMEX gas futures prices proposed for use in setting bid caps.[3]

Thus, with a cap of 200% of projected costs, there may be a small chance of scenarios where significant increases in the spot market price of gas occur, such that a unit's actual startup and minimum load costs may exceed the 200% cap applicable to LCA units at some point during the six month period that the unit's bid remains in effect. While the chance of this may be relatively low, DMM believes some provision for such scenarios should be incorporated in the proposal to mitigate the potential reliability and operational problems that may be associated with such scenarios, and ensure that the proposal is found to be just and reasonable by FERC.

Three options under consideration to mitigate this potential scenario are:

- **Cost Recovery through Uplift Payments.** Under this approach, if spot market gas prices ever increased to the point where the unit's actual start-up or minimum load cost exceeded the 200% cap, then the owner of the unit could apply to receive an additional payment covering the difference between the bid and the actual start-up or minimum load cost. The unit's actual start-up or minimum load cost would be calculated using the same spot market gas index used in calculating start-up or minimum load costs under the cost-based option, and the generator's uplift payments would be increased as part of the settlement process if necessary to cover these costs.

- **Option to Modify Bid.** Under this approach, generation owners would be provided the option of increasing their startup or minimum load bids for a unit. The modified bid may still be subject to a cap, but would be based on updated monthly gas futures prices (e.g., the maximum NYMEX monthly futures price for the remainder of the six month period that the bid would be in effect).[4]

- **Option to Switch to Cost-Based Option.** Under this approach, the owner would have the option of switching back to the cost-based option for the remainder of the six month period that the bid would be in effect.

Each of the three options described above, if adopted, would be optional for generators that are eligible for these provisions, and would only be triggered upon request of the generator. For example, under the third option, if a generator believed that an increase in spot market gas prices was relatively short, the generator may not want to switch to the cost-based option for the remainder of the six month period.

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[3] See May 16 Whitepaper, pages 5-13. Specifically, the analysis of gas prices over this 63 month period provided in the May 16 whitepaper showed that: about <u>98.5% of the time</u>, spot market prices would be <u>within 150%</u> of the gas price index used in setting start-up and minimum load bids. About <u>99.67% of the time</u>, spot market prices would be <u>within 200%</u> of the gas price index used in setting start-up and minimum load bids.

[4] With this approach, further details may need to be worked out governing the gas price used in determining the limit for the new bid submitted by the generator. For example, during relatively short-term spikes in the price of gas, using updated monthly futures prices could still result in a cap that was somewhat lower than daily spot market prices. On the other hand, basing the limit on the daily spot market price could result in situations where very short term spikes in spot market gas prices would allow a generator to adjust its bid to an extremely high level relative to costs after spot market gas prices dropped back down.

Eligibility for Gas Price Increase Provision

Eligibility for the gas price provisions described above could be limited in at least three different ways:

- **Eligibility Limited to Units Bidding at the 200% Cap.** With this approach, generators would be allowed to apply for relief, under whatever provision is adopted from the three described above, only if they had initially submitted a bid at the 200% cap. The rationale for this approach is that unless the generator submitted a bid that was capped by the 200% limit, the cap did not limit the generator's ability to manage the gas price risk associated with the six month bid-based option. On the other hand, with a bid cap of 200%, this approach might create a significant incentive for a unit to submit a bid at the 200% cap. For example, rather than bid 150% of projected costs, a generator may bid at the 200% limit in order to mitigate all the gas price risk associated with the bid-based option.

- **Eligibility Triggered if Spot Market Price Reaches 200% of Gas Price Index.** With this approach, generators would be allowed to apply for relief, under whatever provision is adopted from the three described above, only if spot market gas prices reached 200% of the gas price index that was applicable when they initially submitted their bid at the start of the six month period. Under this option, even generators that submitted bids below the 200% cap would be eligible for relief. This approach could avoid the potential perverse incentive that could be created by the option described above: i.e., that with a bid cap of 200%, a generator may bid at the 200% limit (e.g., rather than 150%) in order to mitigate all the gas price risk associated with the bid based option. In effect, this approach subjects the generator to the risk that gas price increases may increase its costs above its bid price, but truncates this risk in the event that gas prices rise to 200% of the gas price index in effect at the time the unit submitted its bid.[5]

- **Eligibility Triggered if Actual Costs Reach Bid Price.** With this approach, a generator would be allowed to apply for relief, under whatever provision is adopted from the three described above, only if the unit's actual startup or minimum load costs reached their bid price.[6] This approach completely mitigates all gas price risk associated with the bid-based option. In addition, since this option could provide a significant incentive for generators to select the bid-based option and could be frequently triggered, it is possible that this approach could involve significant administrative processes and manual calculations and adjustments (to Master File values, uplift settlements, etc.). Thus, if this option were adopted, it may be necessary to couple this option only with the third option described in the previous section: i.e., that any generator applying to modify its bid due to a gas price increase would simply be allowed to switch to the cost-based option for the remainder of the six month period.

[5] For example, if a generator bid 150% of the cap, the generator would bear the risk associated with spot gas price increases between 150% to 200% of the futures price used in setting the generator's bid cap. However, if spot prices reached 200% of the futures price used in setting the generator's bid cap, the generator could opt to switch to the cost-based option for the remainder of its six month period.

[6] This approach – like the other two options – implicitly assumes that the generator is purchasing gas for startup and minimum load on the daily spot market, or, alternatively, that the spot market price of gas reflects the generator's opportunity cost (i.e., if the generator is long on gas, any additional gas not consumed could be sold at the spot market price).

With all of the above approaches, spot market gas prices used to determine eligibility would be based on the same spot market gas price index used by the CAISO for calculating Default Energy Bids (DEBs), and cost-based startup and minimum load costs.

II. Initial DMM Recommendation

Table 1 provides an initial comparison of the three options for addressing scenarios where significant increases in the spot market price of gas occurs at some point during the six month period that the unit's bid remains in effect, such that a unit's actual startup and minimum load costs may exceed the unit's bid and/or the applicable cap. Table 2 provides a similar comparison of the three options for determining units that would eligible for any of these provisions.

Based on this initial comparison and discussion, DMM would tend to favor the following approach for addressing the potential for spot market gas price spikes for units subject to the 200% cap:

- **Option to Switch to Cost-Based Option.** Generation units under the bid-based option would have the option of switching back to the cost-based option for the remainder of the six month period that the bid would be in effect.

- **Eligibility Triggered if Actual Costs Reach Bid Price.** A generator would be allowed to file to switch to the cost-based option only if the unit's actual startup or minimum load costs (calculated using the CAISO's spot market gas price index) reached or exceeded their bid price.

As noted in the discussion provided in Tables 1 and 2, this option of allowing generators to switch to the cost-based option if actual costs reach their bid price removes a very high degree of the gas price risk inherent in the bid-based option unless generators submit relatively high bids (e.g., 150% to 200% of above the cost projection used to set the 200% cap). Although this could conceivably result in more units selecting bid-based option, this would also reduce the overall level of bids submitted by avoiding potential incentive to bid at or near the 200% cap that could be created under the other two options considered. Also, since this approach requires that units switch to the cost-based option for the remainder of the six month period, local market power would be effectively mitigated for the remainder of this time period in the event this option was triggered. Thus, this option seems to provide a lower overall risk of excessive local market power, while also reducing the gas price risk inherent in the six month bid-based option.

Table 1. Comparison of Potential Provisions for Gas Price Increases

Comparison Criteria	**Uplift for Costs in Excess of Bid**	**Modify Bid based on New Gas Price**	**Switch to Cost-based Option for remainder of six-month period**
Local Market Power Mitigation * * Note: Effectiveness of each option may also depend on criteria for eligibility as discussed in Table 2	Medium – Could result in excessive costs due to distortion of unit commitment process (e.g., unit could be committed based on bid cost, but paid higher cost through uplift).	Low – If triggered, unit could have a higher bid which would remain in effect even if gas prices dropped.	High – If triggered, unit would switch to cost-based option.
Limits Gas Price Risk associated with Cap for Generators	Medium to High (depending on criteria for eligibility as discussed in Table 2)	Medium to High (depending on criteria for eligibility as discussed in Table 2)	Medium to High (depending on criteria for eligibility as discussed in Table 2)
Feasibility and Ease of Implementation	Relatively easy if frequency and volume of uplifts are low.	May be complex due to need to determine limits for new modified bid.	Only requires switch to cost-based option in Master File. Normal business process may need to be accelerated to reduce 7-11 day period for updating Master File.

Table 2. Comparison of Potential Criteria for Determining Eligibility

Comparison Criteria	**Option 1** **Only Units Bidding at 200% Cap** **<u>and</u>** **Actual Cost of Units Reach 200% Cap**	**Option 2** **Any Unit for which Actual Costs of Unit Reach 200% Cap**	**Option 3** **Any Unit for which Actual Costs Reach Six-month Bid**
Local Market Power Mitigation	May cause some units to submit relatively high bids due to gas price risk associated with this option. May also provide an incentive for units to bid at the 200% cap (e.g., rather to 150%) in order to eliminate gas price risk.	Reduces (relative to Option 1) the incentive to submit relatively high bids due to gas price risk. However, this option may still provide an incentive for units to bid at the 200% cap (e.g., rather to 150%) in order to eliminate gas price risk entirely.	Reduces (relative to Option 2) the incentive to submit relatively high bids due to gas price risk – since gas price risk would be eliminated entirely. However, may result in more units selecting bid-based option, but could reduce level of bids submitted relative to Options 1 and 2. Also, if this option was coupled with the option of letting units switch to cost-based rates, then local market power would be effectively mitigated for remainder of 6-month period under this option.
Limits Gas Price Risk associated with Cap for Generators	High to Medium. Eliminates gas price risk for units bidding at cap, but gas price risk for other unit's increases as unit's bid is lowered.	Medium. Eliminates gas price risk for units bidding at cap, but gas price risk for other unit's increases as unit's bid is lowered (but less risk than Option 1).	High. Completely eliminates gas price risk for all units under bid-based option, except for risk associate with administrative lag needed to update Master File. (i.e., 7 to 11 days under normal business process).
Feasibility and Ease of Implementation	High feasibility, but may require 7-11 days to update Master File under normal business process. Frequency of Master File changes should be very low.	Feasibility same as first option. Frequency of Master File changes may be higher than under first option.	Feasibility same as first option Frequency of Master File changes may be higher than other two options.