California Independent
System Operator Corporation

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

Department of Market Monitoring

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I. Introduction

Market rules incorporated in the CAISO's February 9, 2006, MRTU filing include two options for Generating Units, Non-Dynamic and Dynamic System Resources to specify their Start-Up and Minimum Load Costs. On a semi-annual basis, these resources may choose between the following two options:

- **Cost-Based.** This option will apply a formula which calculates start-up and minimum load costs for the resource based on resource operating characteristics (e.g., start-up fuel consumptions) and associated fuel costs;

- **Bid-Based.** A resource that selects this option must submit start-up and minimum load bids that will be in effect for six months. These bids need not be related to actual operating costs.

The CAISO's initial assessment was that extremely high start-up and minimum load bids under this second bid-based option would be deterred by the fact that since these bids would be in effect for a minimum six month period, a generator submitting such bids would run the risk of pricing a unit out of the market during many hours when it would profitable to operate the unit. However, the Department of Market Monitoring (DMM) is considering whether bids under the bid-based option should be subject to some type of cap in order to protect against the potential exercise of local market power through submission of very high start-up and minimum load bids. This white paper provides a preliminary discussion of a range of potential options for capping start-up and minimum load bids under the bid-based option, and presents results of DMM's preliminary quantitative assessment of these various options.

II. Background

Local Market Power

Under MRTU, a unit's energy bids may be subject to local market power mitigation (LMPM) limits whenever the unit receives an incremental dispatch due to congestion on an uncompetitive transmission constraint or other local reliability requirement. However, no such mitigation is applied to start-up and minimum load bids of units under the bid-based option. This creates the potential for the exercise of local market power through start-up and minimum load bids submitted under the bid-based option in a number of ways:

- Under some market conditions and bidding strategies, extremely high start-up and minimum load bids would have the effect of allowing a unit to be economically withheld, so that Locational Marginal Prices (LMPs) may be set by other units within a generator's portfolio with relatively high Default Energy Bids (DEBs).
- Under other market conditions and bidding strategies, a generator could profit directly by having a unit with extremely high start-up and minimum load bids dispatched for reliability reasons.
- For units with Resource Adequacy (RA) contracts, extremely high start-up and minimum load bids could have the effect of withholding RA capacity from the Residual Unit

Commitment (RUC) process. Units are selected in the RUC process based on three components: start-up, minimum load and RUC availability bids. Thus, although RA units are required to have a RUC availability bid of zero and do not receive a RUC availability payment, capacity under RA contracts could be effectively withheld from the RUC process as a result of extremely high start-up and minimum load bids.

The CAISO's initial assessment was that such behavior would be deterred by the fact that start-up and minimum load bids submitted under the bid-based option would remain in effect for a minimum six month period, so that a generator submitting extremely high start-up and minimum load bids would run the risk of pricing a unit out of the market during many hours when it would be profitable to operate the unit. However, under MRTU, a generator can always self-commit a unit in order to avoid pricing a unit out of the market during hours when it may not be profitable to exercise local market power through the unit's very high start-up and minimum load bids. Thus, the ability to self-commit a unit provides generation owners with a mechanism that can be used to "switch" extremely high start-up and minimum load bids "on" or "off" as needed in order to implement strategies for exercising various degrees of local market power that may exist throughout the year.

Another factor affecting the degree to which local market power might be exercised through very high start-up and minimum load bids involves the nature of various reliability contracts in effect for the various resources within a constrained area. Historically, the ability to exercise local market power in major constrained areas has been limited by having a significant amount of capacity under Reliability Must Run (RMR) contracts, which provide for cost-based compensation for start-up and minimum load energy. However, starting in 2007, RMR contracts are being greatly reduced and replaced by Resource Adequacy (RA) contracts for units being used to meet Local Resource Adequacy (LRA) requirements. While current LRA provisions require that local RA units make their capacity available to the CAISO, RA contracts are not required to include any provisions to limit a unit's start-up and minimum load bids.

Thus, while the degree to which local market power might be exercised through very high start-up and minimum load bids under MRTU depends on a variety of conditions that may be difficult to assess at this time, the potential for such bidding strategies clearly exists under current MRTU market rules.

Experience of Other ISOs

Two other ISOs (New England and PJM) have LMPM provisions similar to those proposed by the CAISO under MRTU, including a six month bid-based option for start-up and minimum load bids. CAISO's Department of Market Monitoring (DMM) staff has contacted market monitors at these ISOs in order to obtain any information about the potential problems that have been encountered with excessively high start-up and minimum load bids, and other market features that may affect the potential for exercising local market power through such bids (such as the amount and nature of local reliability contracts in the most severely constrained areas). However, no specific information has been provided.

In the New York ISO (NYISO), start-up and minimum load bids are submitted on a daily basis and are not capped, but are subject to conduct-impact tests performed as an automatic part of the Day Ahead and Real Time Markets. In most load pockets, only a small percentage of hours were mitigated for start-up and minimum load parameters as documented in the New York ISO *2005 State of the Market Report.*[1] There are load pockets, however, for which the percentage of hours with mitigation was over 10 percent and as much as 60 percent during the summer of 2005.[2]

Gas Prices

Under the bid-based option, one factor generators would presumably consider is the potential price of gas over the six month period over which they would not be permitted to adjust their bid. Presumably, generators selecting the bid-based option would typically bid at a level that exceeded their actual projected start-up and minimum load costs, and would take into account potential increases in the price of gas over the six month period.

Similarly, while all of the options for setting start-up and minimum load bid caps in this paper are designed to allow most or all generators to bid significantly in excess of actual start-up and minimum load costs, each of these options requires some assessment of the projected start-up and minimum load costs of gas fired units, taking into account the potential future price of gas over the period for which the cap may be in effect. At a minimum, some assessment must be done based on projections of gas prices at the time caps are set. In addition, some mechanism may be necessary to periodically recalculate or reset caps in the event that gas prices increase dramatically over levels initially used in setting caps.

The analysis of start-up and minimum load costs provided in the following sections of this paper is based on a price of $8.50/mmBtu based on the approximate forward price of gas in early 2008 as reported in trade publications.[3] All other data used in the analysis are based on unit characteristics that have been filed by generators with the CAISO and are maintained in the CAISO's Master file.[4] Under MRTU, generators will file similar start-up fuel data. These data must be combined with gas and electric price data in order to project actual start-up costs.

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[1] http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2005_NYISO_SOM_Final.pdf

[2] The NYISO market monitor notes that these statistics may be somewhat misleading in terms of the percentage of hours subject to mitigation, particularly when the mitigated unit(s) have long time requirements for start-up and/or minimum load, since the mitigation would impact all the start-up hours and all the hours at minimum load. However, DMM notes that since minimum load costs may be paid for all hours when units are operating at minimum load – even if a unit is committed by the ISO to meet reliability requirements during a limited number of hours of the day – these statistics still suggest that the financial impacts of extremely high start-up and minimum load bids could be significant in some load pockets.

[3] The *Energy Market Report* by Insight Research currently provides quotes for gas delivered to Malin and the Southern California Border (SoCal) for three month periods. Platt's *Gas Daily* provides monthly quotes for NYMEX gas futures contracts at Henry Hub, along with forward assessments of gas daily basis for Southern California (SoCal) by seasons. These data can be combined to project an expected delivered price for gas in California over the 6 to 12 month period that might be required to set and adjust (if necessary) any caps for start-up and minimum load bids.

[4] Start-up costs based on gas and auxiliary electric power for cold starts. The cost of auxiliary power, which represents a relatively small portion of start-up costs, is calculated at an assumed price of electricity equal to the

II. Start-up Bid Cap Options

For the sake of discussion, the CAISO has developed a series of three options for limiting the bids for start-up payments under the bid-based option. Variations of each of these approaches may be developed based on further discussion and analysis. In addition, each approach for capping start-up bids may be coupled with any of the three different options for capping minimum load bids discussed in a later section of this white paper.

Option A

This option is based on the fact that start-up costs are correlated with unit start-up times, as depicted in Figure 1. Under this approach, a relatively small number of unit categories would be established based on start-up times (e.g., fast start units, long start units, and extremely long start units), and a separate start-up bid cap would be set for all units within that category. The start-up bid cap for each category would be set based on the unit with the highest or upper range of start-up costs of all units in the category.

Startup costs are also correlated with unit size (or maximum generating capacity), depicted in Figure 2. Thus, under this option, start-up cost bids for each unit (*u*) are limited by the unit's maximum rated capacity ($PMax_u$) multiplied by a start-up cost cap (expressed in terms of $/MW of each unit's maximum capacity or PMax).

The specific formula used under this approach is summarized below:

$$\text{Maximum Start-up Bid}_u = PMax_u \times \text{Start-up Cap}_{UStart}$$

Where:

$PMax_u$ = Maximum capacity of unit

$\text{Start-up Cap}_{UStart}$ = Highest start-up cost ($/MW of PMax) of all units within start-up category.

Data shown in Figures 3 and 4 suggest that if this approach were adopted, it may be appropriate to exclude a limited number of units as outliers when setting start-up bid caps for some categories of start-up times. Any units that were excluded as outliers when setting bid caps would still be assured of full recovery of start-up costs under the cost-based option provided under current MRTU market rules. In addition, another option would be to allow generators the option of seeking to establish a special negotiated rate in excess of any cap placed on the bid-based option, upon a demonstration that the cap should not be applicable to their unit due to any special circumstances.

gas price multiplied by an assumed "market heat rate" of 10,000 BTU/KWh. Minimum load heat rates are based on each unit's reported average heat rate at its reported minimum operating level (PMin).

Figure 1. Gas Unit Start-Up Cost and Start Times*

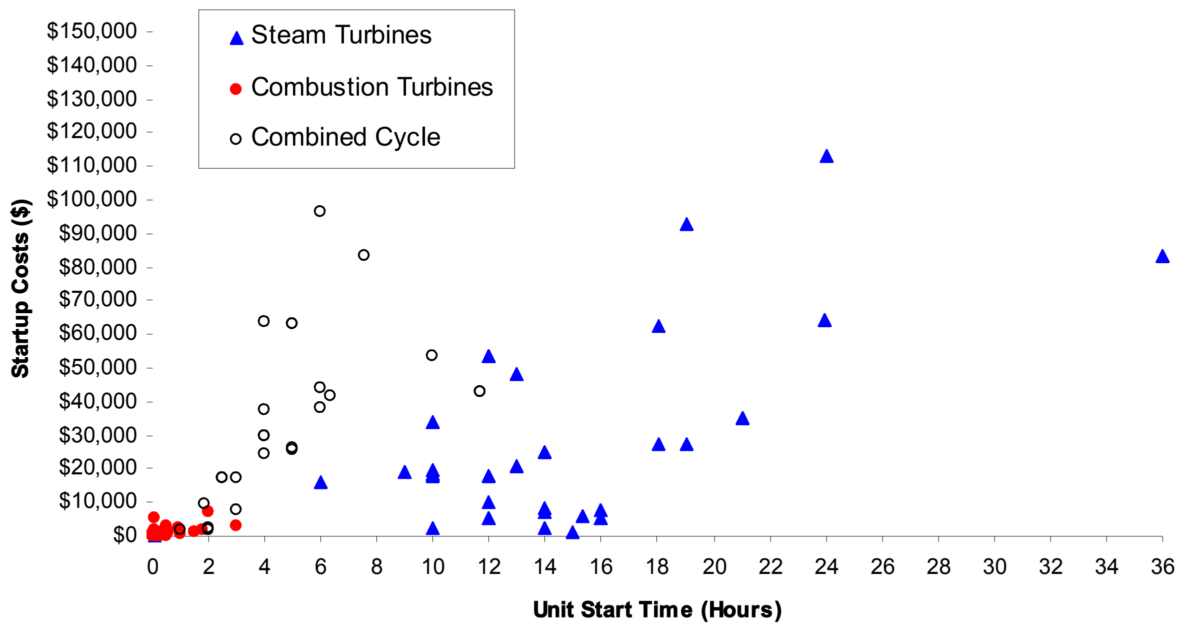
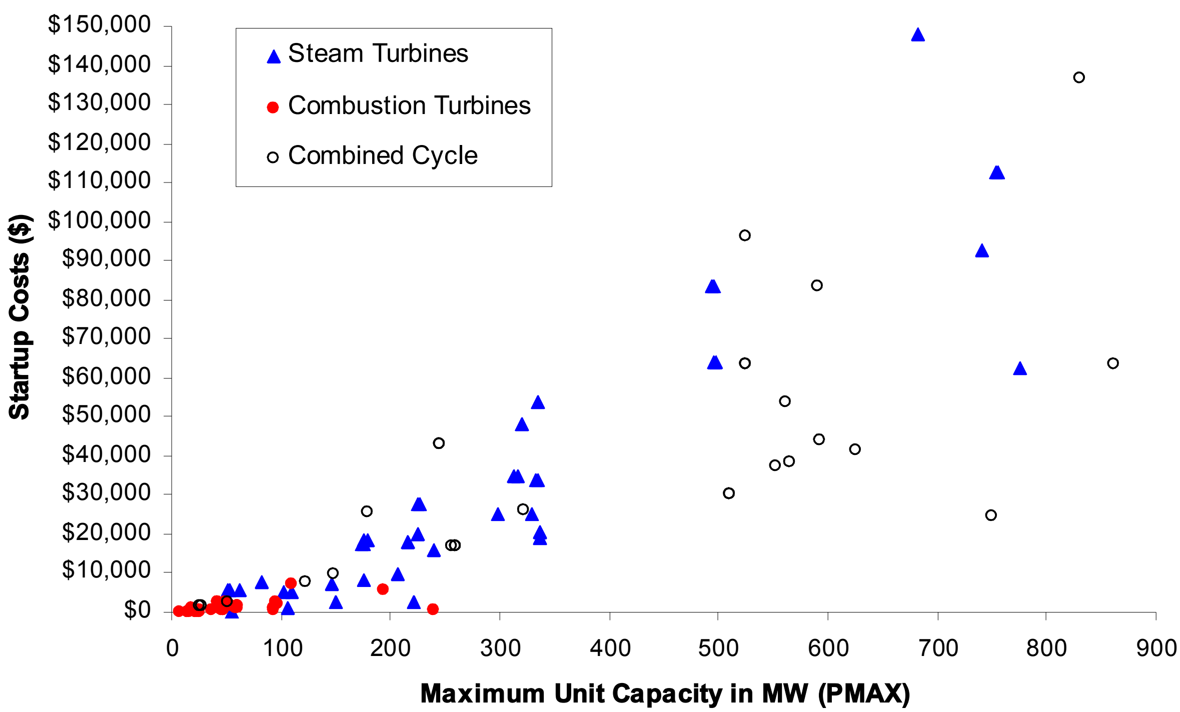


Figure 2. Gas Unit Start-up Costs and Maximum Unit Capacity (PMAX)*



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu.

Figure 3. Gas Unit Start-up Costs and Start-up Times*

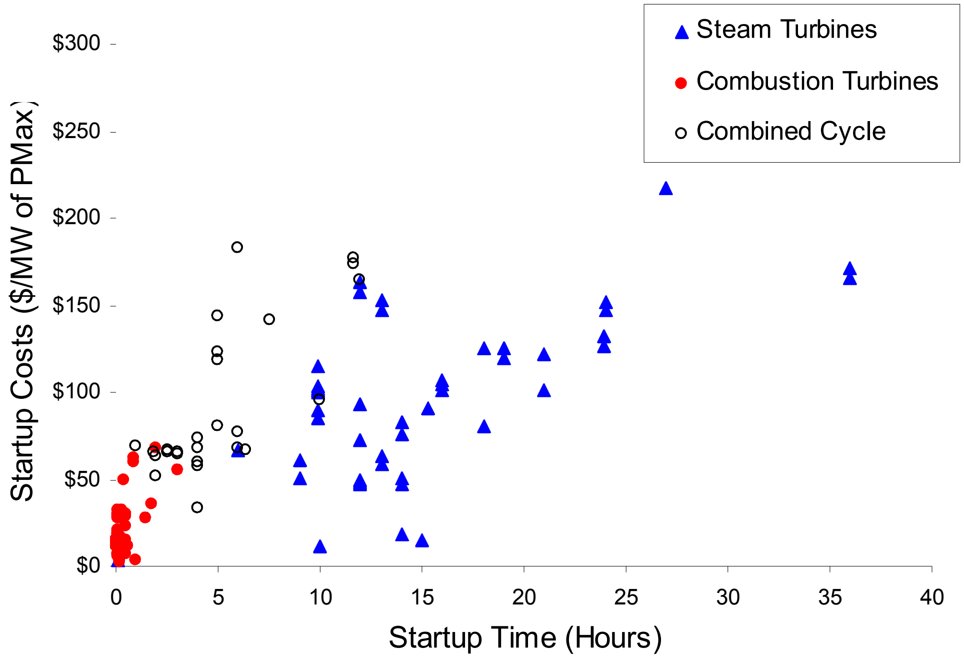
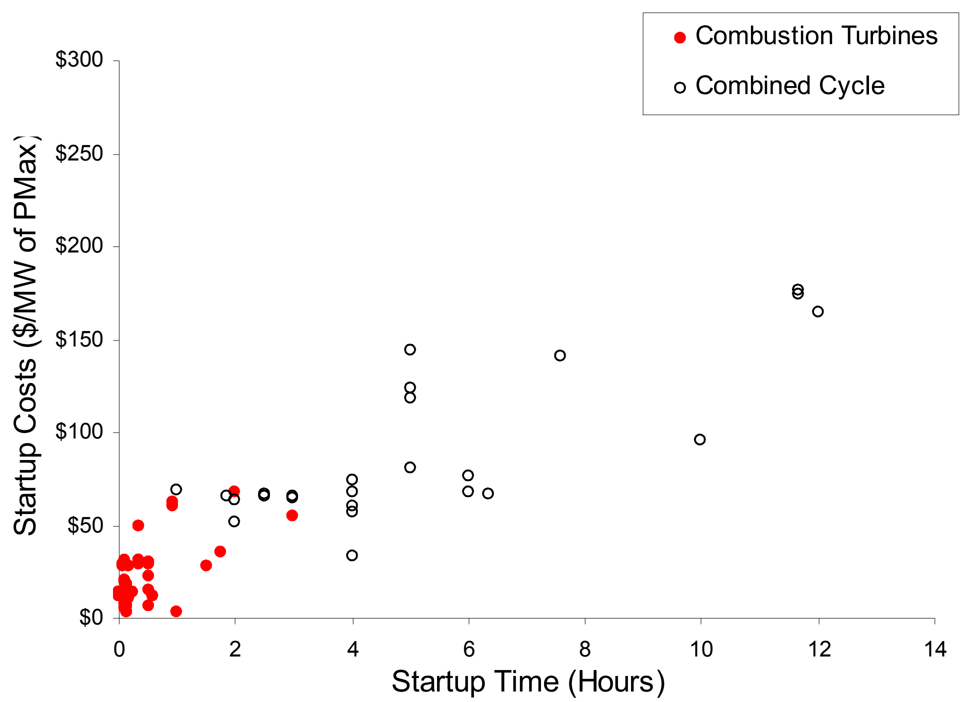


Figure 4. Gas Unit Start-up Costs and Start-up Times*
(CTs and Combined Cycle, < 13 Hour Start Time)



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

In addition, data depicted in Figures 1 through 4 suggest that start-up costs (in $/MW of PMax) may be more closely correlated with the type of generating technology unit (i.e., combustion turbines, combined cycle units, and steam turbines). Thus, another variation of this option would be to categorize units by generating technology (rather than start-up time) for purposes of setting start-up bid caps. With this approach, the specific level of the cap for units within each category of technology would be set by the highest start-up cost of all units within that category. More detailed data on start-up costs for each of these technology types is provided in the section on Option C for setting start-up bid caps.

As shown in Table 1 and Figures 5 and 6, analysis of actual start-up cost data suggest that if this approach were adopted, it may be appropriate to categorize units into four categories of start-up times, such as:

- Less than 1 hour
- 1 to 8 hours
- 8 to 23 hours
- More than 23 hours

Table 1 shows summary data for each of these categories. As shown in Table 1, while the weighted average start-up cost of units in each of these categories varies by a significant amount (Column D), the difference in the maximum start-up cost of units in the three categories representing units with start-up times of one hour or more is relatively small (Column C).

Table 1. Option A: Potential Start-up Bid Cap Categories and Costs

A Unit Start-up Time	B Approx. Capacity (MW)	C Maximum Start-up Cost ($/MW of PMax)	D Weighted Average Start-up Cost ($/MW of PMax)	E Maximum as Percent of Weighted Avg. Cost (Col. C ÷ Col.D)
> 1 hour	2,840	$60	$20	296%
1 to 8 hours	9,921	$144 [1]	$83	221%
8 to 23 hours	11,484	$174	$102	171%
>= 23 hours	4,239	$217	$161	135%

[1] Maximum for units with 1 to 8 hour start-up time excludes one aggregate cogeneration unit listed as Gas Turbine with $222/MW start-up cost. If included, this unit would make maximum start-up cost for this category higher than maximum start-up cost for categories representing units with longer start times.

Figure 5. Gas Unit Start-up Costs and Start-up Times*

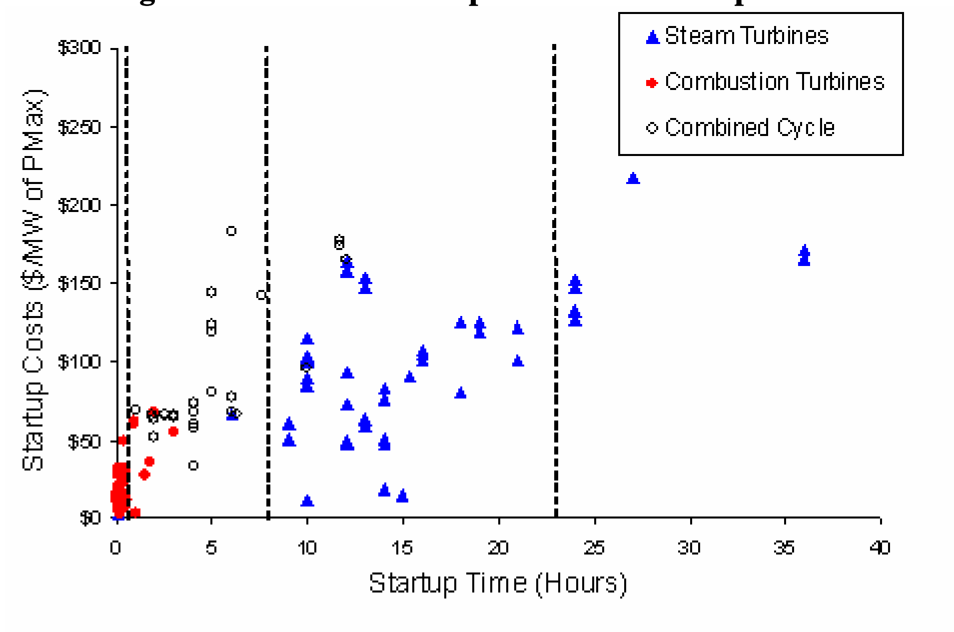
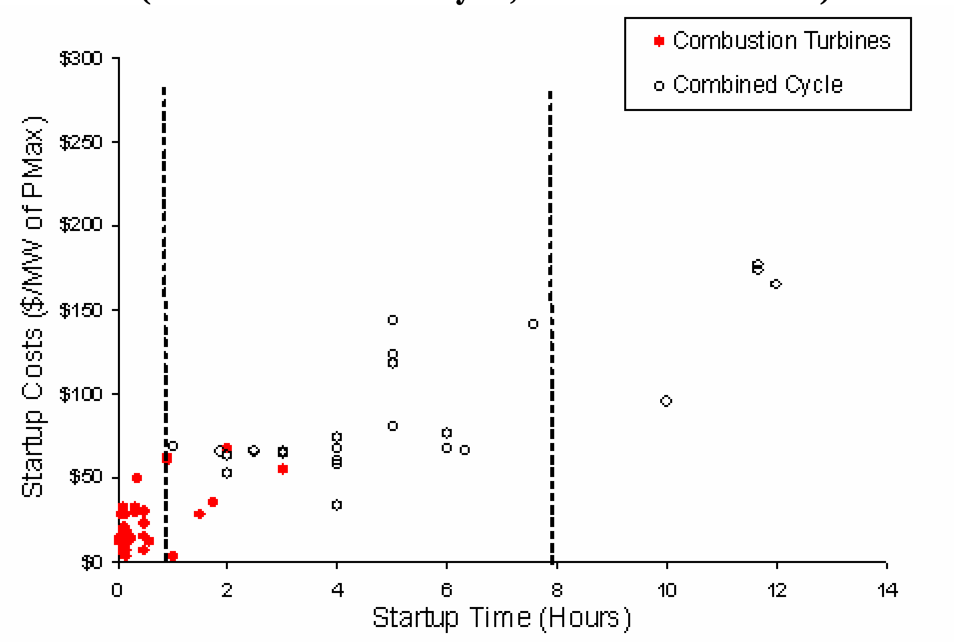


Figure 6. Gas Unit Start-up Costs and Start-up Times*
(CTs and Combined Cycle, < 12 Hour Start Time)



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

Option B

The basic concept underlying this option is that start-up bids for each unit would not be allowed to exceed some factor (e.g., 200 percent) of their actual projected start-up costs.

The specific formula used under this approach is summarized below:

$$\text{Maximum Start-up Bid}_u = \text{Start-up Cost}_u \times 200\%$$

Where:

Start-up Cost_u = Projected start-up cost (in total $) for units based on start-up fuel inputs filed by generator with the CAISO and projected price of gas over the six month period the cap is in effect.

Under this option, a relatively specific formula would be established to determine the potential future price of gas over the period for which the cap would be in effect based on a combination of data from different industry sources.[5]

Option C

Like Option A, the basic concept underlying this option is to establish a relatively small number of unit categories, each of which would have a separate start-up bid cap for all units in that category. However, under this option, units would be categorized by generating technology (combustion turbines, combined cycle units, and steam turbines) rather than start-up time. In addition, the cap for each category of units would be set based on the start-up cost for a typical unit within the category, multiplied by a factor (e.g., 200 percent) that ensured that the cap exceeded the actual start-up cost of most capacity within the category by a significant degree.

The specific formula used under this approach is summarized below:

$$\text{Maximum Start-up Bid}_u = \text{PMax}_u \text{ x Start-up Cap}_{\text{UType}}$$

Where:

PMax_u = Maximum capacity of unit

$\text{Start-up Cap}_{\text{UType}}$ = Projected start-up cost ($/MW of PMax) of typical unit within technology category × 200%

[5] As noted in Footnote 3, the *Energy Market Report* by Insight Research currently provides quotes for gas delivered to Malin and the Southern California Border (SoCal), while Platt's *Gas Daily* provides monthly quotes for NYMEX gas futures contracts at Henry Hub, along with forward assessments of gas daily basis for Southern California (SoCal) by seasons.

The main technology categories (*UType*) would include combustion turbines, combined cycle units, and steam turbines. Figures 7 through 9 show start-up cost curves for each of these technologies, which depict the percentage of total capacity within each category along with its corresponding start-up cost.

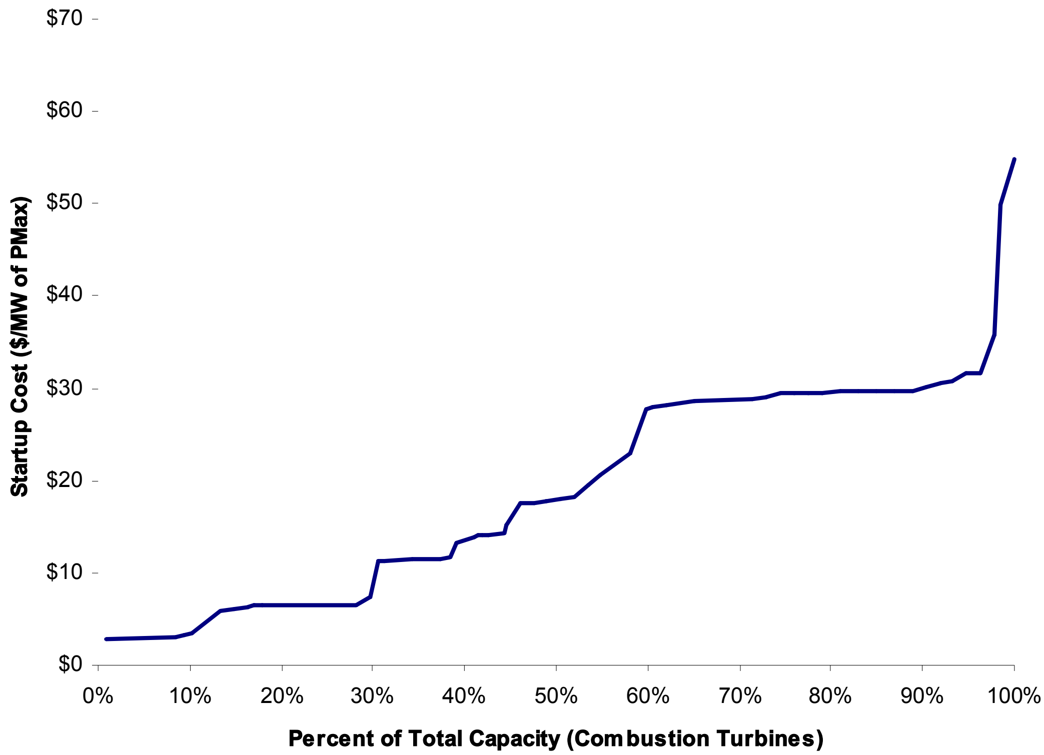
Table 2 shows summary data for each of these technology categories. As shown in Table 2, while the maximum and weighted average start-up cost of CTs varies by a significant amount from other technologies, the maximum and average start-up costs for combined cycle units are only slightly lower than costs for steam turbines.

Under this approach, the cap for each technology might be set by multiplying the weighted average start-up costs shown in Column D by 200 percent, resulting in the start-up caps shown in Column E. As shown in Column F, with this approach, the resulting caps would exceed the start-up costs of 89 percent of CTs, and 100 percent of combined cycle and steam turbine capacity.

Table 2. Option C: Potential Start-up Bid Cap Categories and Costs

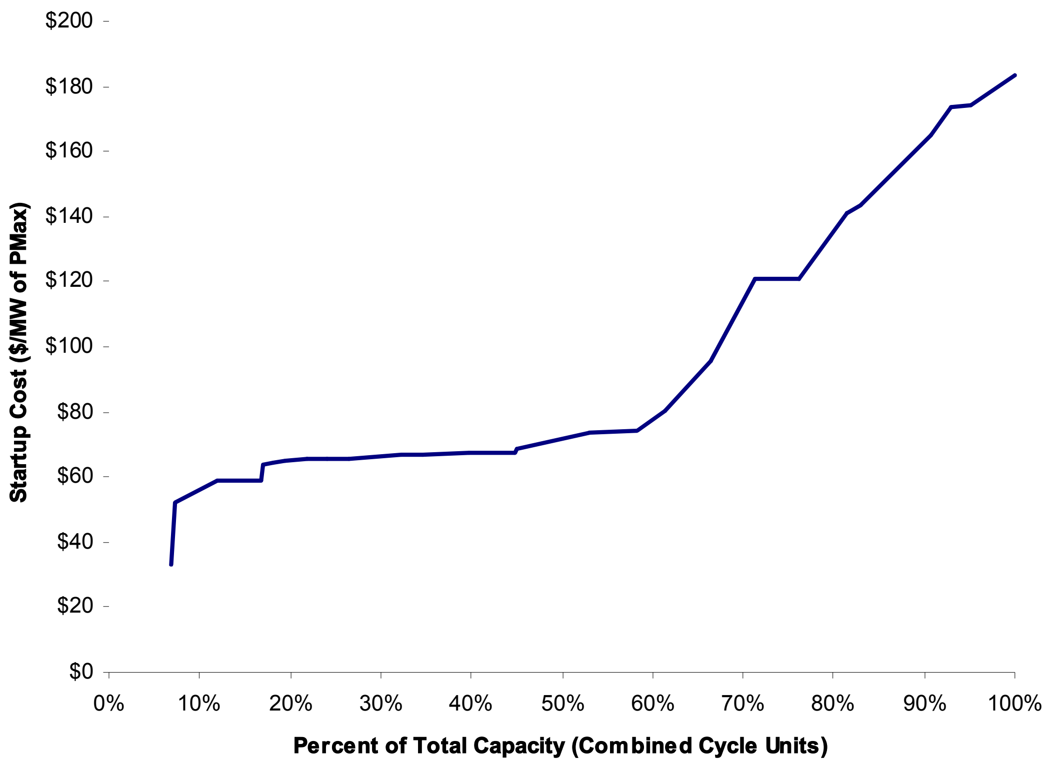
A Unit Type	B Approx. Capacity (MW)	C Maximum Start-up Cost ($/MW of PMax)	D Weighted Average Start-up Cost ($/MW of PMax)	E Weighted Average Start-up Cost × 200%	F Percent of Capacity With Cost < Avg. Cost × 200%
Combustion Turbine	3,088	$55	$19	$38	89%
Combined Cycle	10,927	$183	$95	$190	100%
Steam Turbine	14,135	$217	$113	$226	100%

Figure 7. Start-up Cost Curve – Combustion Turbines*



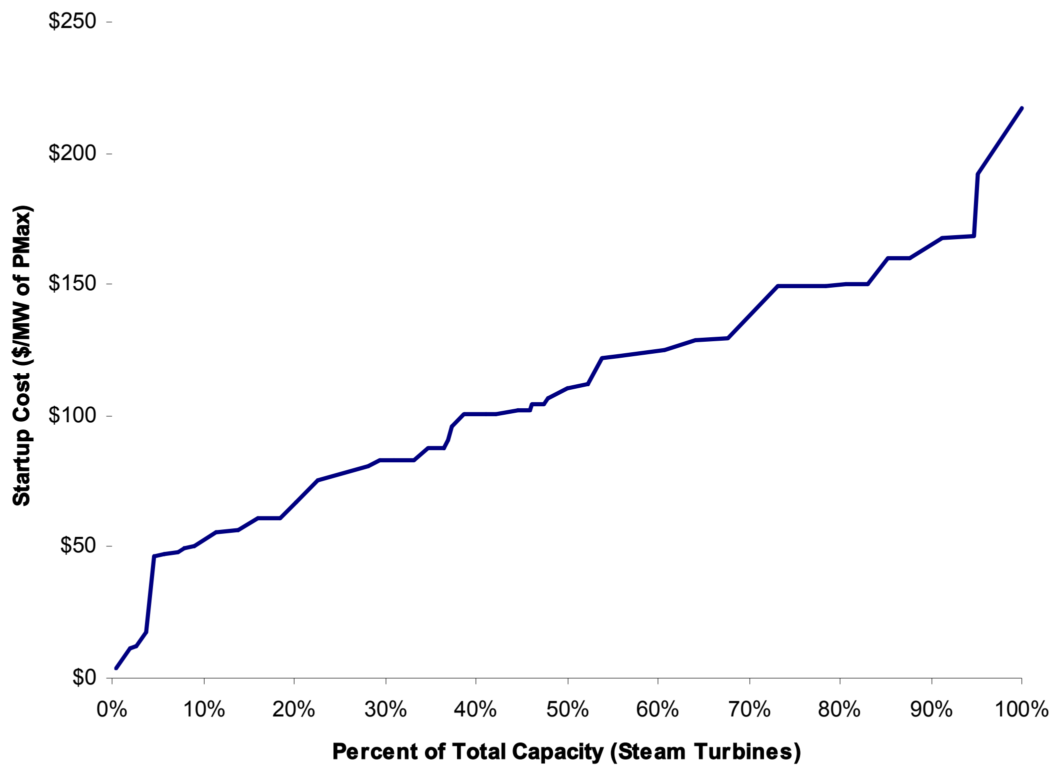
* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

Figure 8. Start-up Cost Curve – Combined Cycle Units*



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

Figure 9. Start-up Cost Curve – Steam Turbines*



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

IV. Minimum Load Bid Cap Options

Option A

Under this option, minimum load bids would be limited by each unit's minimum operating level ($PMin_u$) multiplied by the prevailing CAISO system energy bid cap.

Maximum Minimum Load $Bid_u = PMin_u \times$ MinLoadCap

Where:

$PMin_u$ = Minimum operating level of unit

MinLoad Cap = CAISO System Energy Bid Cap (e.g., $500 to $1,000/MWh)

Option B

Under this option, minimum load bids for each unit would not be allowed to exceed some factor (e.g., 200 percent) of their actual projected start-up costs.

The specific formula used under this approach is summarized below:

Maximum Minimum Load $Bid_u = PMin_u \times PMinCost_u \times 200\%$

Where:

$PMin_u$ = Minimum operating level of unit

$PMinCost_u$ = Projected minimum load operating cost (in $/MWh) for units based on the heat rate at minimum operating level, combined with the projected price of gas and the default variable O&M adders for each technology type.[6]

Option C

The basic concept underlying this option is to establish a relatively small number of generating technology categories, each of which would have a separate minimum load bid cap for all units in that category. Under this option, the three major generating technology categories would be combustion turbines, combined cycle units, and steam turbines.

[6] $4 for CTs and Reciprocating Engines, $2 for all other unit types.

The cap for each of these types of units would be set based on the minimum load cost for a typical unit within the category, multiplied by a factor (e.g., 200 percent) that ensured that the cap exceeded the actual minimum load cost of most capacity within the category by a significant degree.

The specific formula used under this approach is summarized below:

$$\text{Maximum Minimum Load Bid}_u = \text{PMin}_u \text{ x } \text{MinLoadCap}_{\text{Utype}}$$

Where:

PMin_u = Minimum operating level of unit

$\text{MinLoadCap}_{\text{Utype}}$ = Projected minimum load cost ($/MWh of PMin) of typical unit within technology category (*UType*) × 200%

The main technology categories (*UType*) would include combustion turbines, combined cycle units, and steam turbines. Figures 10 through 12 show minimum load heat rates for each of these technologies, which depict the percentage of total capacity within each category along with its corresponding minimum load heat rate.

Table 3 shows summary data for each of these technology categories. As shown in Table 3, steam turbines have the highest maximum and weighted average minimum load heat rates. Although CTs have a higher maximum heat rate at minimum load than combined cycle units, the weighted average minimum load heat rates of these two technologies is very close. In practice, it should also be noted that CTs are rarely scheduled or run at minimum load, or are done so only for short period of time.

Under this approach, the cap for each technology might be set by first multiplying the weighted average minimum load heat rates shown in Column D by 200 percent. As shown in Column E, with this approach, the resulting heat rates would exceed the minimum load heat rates of 95 percent of steam turbine capacity and 100 percent of combined cycle capacity. Column F shows how these heat rates would then be converted into a cap (in $/MWh of minimum load) using a gas price of $8.50/mmBtu and $2 to $4 for variable O&M.

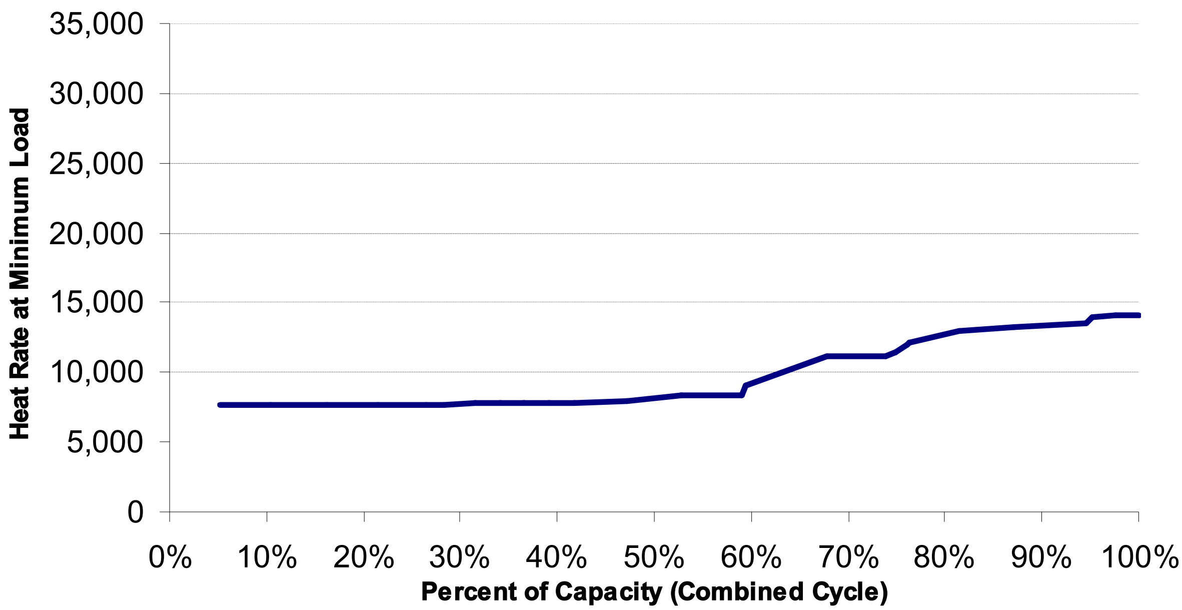
Table 3. Option C: Potential Minimum Load Bid Cap Categories and Costs

A Unit Type	B Approx. Capacity (MW) [1]	C Maximum Min Load Heat Rate (BTU/KWh)	D Weighted Average Heat Rate (BTU/KWh)	E Percent of Capacity with Heat Rate < Avg. Heat Rate × 200%	F MinLoad Cost @ Avg. Heat Rate x 200% [2] ($/MWh)
Steam Turbines	14,265	34,006	14,435	98%	$249
Combined Cycle	11,027	14,101	8,822	100%	$154
Combustion Turbine	3,432	29,500	12,816	97%	$226

[1] Total capacity of each technology type differ from those shown in Table 2 since CAISO Master File data does not include minimum load heat rate and start-up cost data for all units.

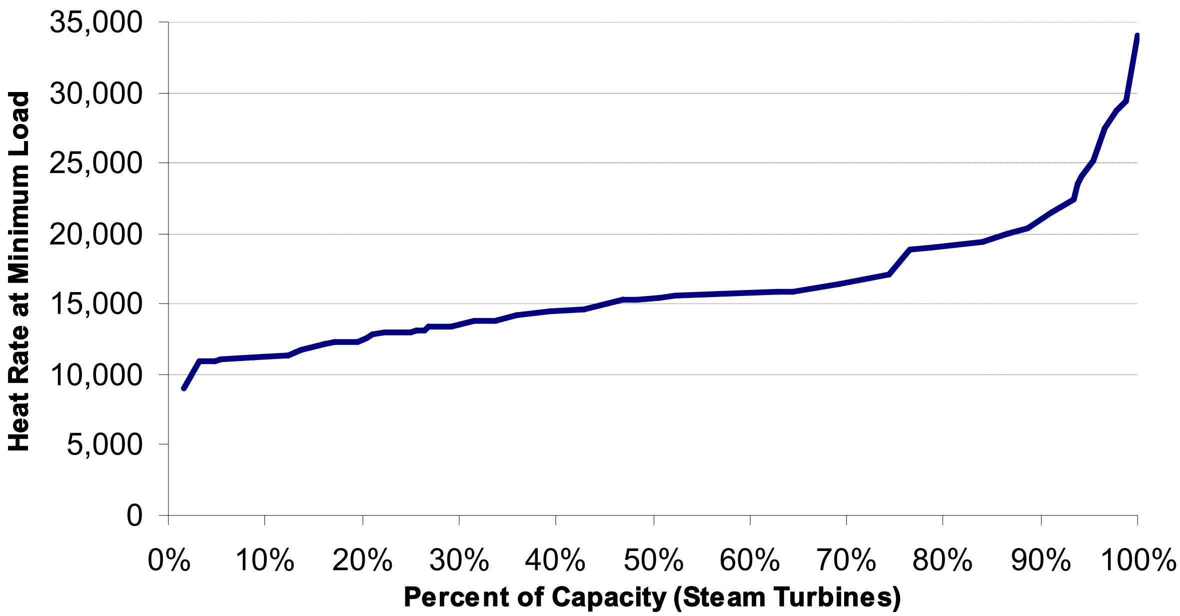
[2] Based on weighted average heat rate in Column D × 200 percent. Assumes $8.50/mmBtu gas price, $4/MWh variable O&M for CTs, and $2/MWh variable O&M for other units.

Figure 10. Minimum Load Heat Rates – Combined Cycle Units*



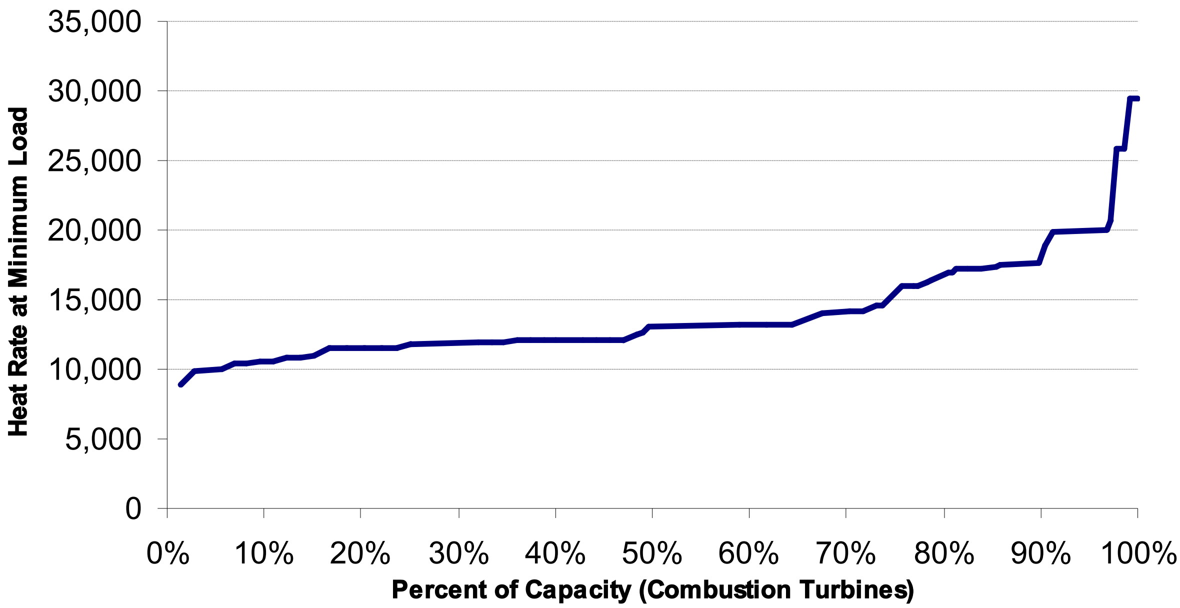
* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

Figure 11. Minimum Load Heat Rates – Steam Turbine Units*



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

Figure 12. Minimum Load Heat Rates – Combustion Turbines*



* Based on data from CAISO Master File, assuming gas price of $8.50/mmBtu

V. Summary and Conclusions

Start-Up Bids

A comparative summary of the analysis of the three options for establishing start-up bid limits described in Section IV is provided in Table 4.

While Option A was primarily designed to assess potential start-up bids caps based on the maximum start-up cost of all units within various categories of start-up times, another variation of this option would be to base these bid limits on the maximum start-up cost of all units of a similar generation type (e.g., combustion turbines, combined cycle units, and steam turbines). Thus, Table 4 also shows results for this variation of Option A, derived as part of the analysis of Option C (see Table 2, column C, page 12). Since the start-up times tend to be within the same range for units of the same generating technology, these two variations of Option A yield very similar results. For example, almost all CTs have start-up times of less than one hour, so the cap for start-up costs for CTs would be $55 to $60/MW of PMax under either of these variations of Option A. Similarly, most combined cycle units have start-up times of 1 to 8 hours, resulting in a start-up bid cap of $144 to $183/MW of PMax under either of these variations of Option A. Finally, most steam turbines have start-up times of 8 to 24 hours, resulting in a start-up bid cap of $174 to $217/MW of PMax under either of these variations.

Table 4. Summary of Options: Startup Bid Caps

Unit Category		Option A: Maximum Cost by Category	Option B: Actual Startup Cost x 200% (Weighted Average/ Maximum)	Option C: Cost for Typical Unit x 200%
Unit Start Time (Hours)	< 1 hour	$60		
	1 to 8 hours	$144		
	8 to 23 hours	$174		
	>= 23 hours	$217		
Generator Type	Combustion Turbine	$55	$38 / $110	$38 (89%)
	Combined Cycle	$183	$190/ $396	$190 (100%)
	Steam Turbine	$217	$225 / $434	$225 (100%)

[1] Percentages indicated capacity with actual start-up costs equal or less than potential cap under Option C.

In addition, as shown in Table 4, Options A and C would both result is very similar start-up bid caps for each of the major generation types. Under Option C, the caps for steam turbines and combined cycle units (derived by multiplying the costs for a typical unit by 200 percent) would exceed the cap under Option A (representing the maximum cost within each category) by a very small amount. For CTs, the $38/MW cap under Option C would be somewhat lower than the

$55/MW cap under Option A, but would still exceed the actual start-up cost of 89 percent of all CT capacity.

Under Option B, caps would be derived by multiplying the start-up cost of each unit by 200 percent. Thus, the overall average cap for all units within each type of technology is equal to the cap of each type of technology under Option C, and is very close to the caps for each category of Option A.

Table 5 provides an initial summary assessment of each option in terms of three criteria that might be used to assess the overall effectiveness of each option:

- *Effective Mitigation of Market Power*. Options A and C would provide a similar level of market power mitigation, since both of these options would establish a uniform cap on start-up bids for all units within the same category (see Table 4). Such uniform caps would provide greater mitigation of potential market power for units with higher start-up costs, and less mitigation for units with lower start-up costs. Meanwhile, since caps under Option B would be set equal to 200 percent of each unit's actual start-up cost, this option provides a more uniform level of mitigation for all units. As shown in Table 4, the average cap under Option B would be comparable to the uniform caps under Options A and C. Thus, DMM has initially suggested that each of these options would provide a *medium* to *high* level of mitigation. In order to differentiate between relative level of mitigation offered by these options, additional analysis assumptions would need to be made about which specific units or type of units may be most likely to select the bid-based option and seek to exercise locational market power through high start-up bid costs.[7]

- *Limit Implementation Complexity*. All three options appear to be relatively simple to implement, since each option would ultimately involve limiting the start-up bid value entered by CAISO staff in the CAISO Master File for each unit. However, while Options A and C would involve limiting bid values submitted by participants to a uniform value for each category of unit, Option B would require performing a special – but still simple – calculation based on each unit's own start-up cost data. All options would require some method of determining gas prices to be used (reflecting projected gas prices over a forward looking six month period), and might involve a mechanism for adjusting bid caps if gas prices exceed forecasted levels used in this initial calculation by a significant level.

[7] For example, if it is assumed that units with relatively high start-up costs (in comparison with other units within their category) might be most likely and able to exercise locational market power through high start-up bid costs, Options A and C might provide a greater degree of mitigation, since the caps under these options would be less than 200 percent of these units' actual start-up costs.

- *Avoid Over Mitigation and/or Need for Negotiated Option.* As shown in Table 4 and discussed above, this analysis indicates that bid caps under all options would tend to exceed actual start-up gas costs of each unit by a significant amount. One exception is Option C, which would result in a $38/MW cap for CTs, which would exceed the actual start-up cost of just about 89 percent of all CT capacity. As previously discussed, this may create a need to establish an option under which generators might seek a special negotiated start-up bid if they felt the cost-based option was not appropriate or sufficient for their unit.

Table 5. Comparison of Options: Startup Bid Caps

Option Performance	Option A: Maximum Cost by Category	Option B: Actual Startup Cost x 200%	Option C: Cost for Typical Unit x 200%
Effectively Mitigation of Market Power	Medium to High	Medium to High	Medium to High
Limit Implementation Complexity	High	Medium	High
Avoid Over Mitigation and/or Need for Negotiated Option	High	Very High	High

Minimum Load Bids

Table 6 provides a comparative summary of the analysis of the three options for establishing minimum load bid limits described in Section IV. As shown in Table 6:

- Option A would clearly result in the highest minimum load bid cap ($500/MWh in year one of MRTU, increasing to $1,000/MWh).
- Option B would result in average minimum load bid caps for combined cycle and steam turbine units of $154 to $249, respectively, and maximum bid caps for units in these two categories of $244 and $582, respectively.[8]
- Option C would result in the lowest minimum load bid caps, with a cap of about $154 for combined cycles and $249 for steam turbine units.

Table 7 provides an initial summary assessment of each option in terms of the same three criteria that might be used to assess the overall effectiveness of each option described in the previous section.

- *Effective Mitigation of Market Power*. Option C would provide the highest level of overall market power mitigation, followed by Option B. Option A would provide a relatively low level of market power mitigation, since the initial $500 cap under this option would be 2 to 3 times higher than under Option B, and would be about 4 times higher than the average minimum load cost of most capacity.

- *Limit Implementation Complexity*. Option A appears to be extremely easy to implement, since it involves limiting the start-up bid value entered by CAISO staff in the CAISO Master File for each unit by the same value (e.g., the $500 bid cap on energy). Option C would involve limiting bid values submitted by participants to a uniform value for each category of unit, while Option B would require performing a special – but still simple – calculation based on each unit's own start-up cost data. Again, all options would require some method of determining gas prices to be used (reflecting projected gas prices over a forward looking six month period), and might involve a mechanism for adjusting bid caps if gas prices exceed forecasted levels used in this initial calculation by a significant level.

- *Avoid Over Mitigation and/or Need for Negotiated Option.* As shown in Table 6 and discussed above, this analysis indicates that bid caps under all options would tend to exceed actual minimum load costs of each unit by a significant amount. The only notable exception to this is Option C, which could result in bid caps greater than the actual minimum load costs of just about 98 percent of steam turbine capacity.

[8] Calculations of the average and maximum bid caps for minimum load energy under Option B based on heat rate calculations performed as part of the analysis of Option C, shown in Table 3 (Columns C and D). Results for CTs not discussed since CTs should not typically be dispatched at minimum loads for extended periods.

Table 6. Summary of Options: Minimum Load Bid Caps

Unit Category		Option A Energy Bid Cap	Option B Actual minLoad Cost x 200% (Weighted Average/ Maximum)	Option C Cost for Typical Unit x 200%[1]
Generator Type	Combined Cycle	$500 / $1,000	$152 / $244	$152 (100%)
	Steam Turbine	$500 / $1,000	$249/ $582	$249 (98%)
	Combustion Turbine	$500 / $1,000	$226 / $506	$226 (97%)

[1] Percentages indicated capacity with actual start-up costs equal or less than potential cap under Option C.

Table 7. Comparison of Options: Minimum Load Bid Caps

Option Performance	Option A: Maximum Cost by Category	Option B: Actual minLoad Cost x 200%	Option C: Cost for Typical Unit x 200%
Effectively Mitigation of Market Power	Low	Medium to High	Medium to High
Limit Implementation Complexity	Very High	Medium	High
Avoid Over Mitigation and/or Need for Negotiated Option	High	High	Medium to High

Next Steps

The discussion and analysis of the range of potential options for capping start-up and minimum load bids under the bid-based option presented in this paper is designed to serve as a starting point for further discussion of various options.

The specific quantitative results presented in this paper are designed to provide an indication of the relative cap that might result under the various options based on currently available data. However, DMM notes that data currently in the CAISO Master File would require further review and may be subject to modification in order to further refine calculations under any specific option.[9]

[9] One such example is the actual generation type of various units. These data are not currently used directly for any settlement calculations, but DMM's review suggests that numerous units may be miscategorized, or that additional categories may be needed for purposes of the type of analysis in this paper.