California Independent System Operator Corporation

California ISO

The Role of Separate Capacity Offers in Spot Capacity Reserve Markets

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1 Introduction

The California ISO (CAISO) is currently developing policies and market based products to increase the flexibility of the CAISO system, and explicitly procure and price additional spot capacity in the CAISO markets. This naturally raises the issue of how these capacity products will be bid into the market so as to create an efficient mix of energy dispatch and capacity awards. One option under consideration is to allow capacity offer prices separate from energy bids on these products.

Separate offer prices can be used to exercise market power in spot capacity products. As the demand for spot market capacity increases, and capacity products become more localized, the potential for market power in capacity may increase. This increases the need to better understand whether or not capacity offer prices are necessary or appropriate in a competitive market.

The appropriateness of a separate capacity offer price depends on whether it represents a marginal cost to providing spot capacity. The costs of providing capacity can be thought of as falling into two general categories; direct costs and opportunity costs. From these possible costs it is shown:

- Separate capacity offers are not needed to cover *within market* opportunity costs of capacity.
- Prices available in other markets *outside* the market being bid into (i.e. the Real-Time market when bidding into the Day-Ahead market) can be covered by virtual bids without the use of a separate capacity offer price.
- Prices in export markets do not represent opportunity costs to internal generators providing capacity in CAISO markets.
- Potential lost option values due to having Day-Ahead capacity schedules instead of energy schedules may merit Day-Ahead capacity offer prices. This option value does not exist in the Real-Time market.[1] For capacity products re-optimized in Real-Time, it is likely that these option values, net of the option value of holding a capacity award, are zero.
- Direct marginal capacity costs may be costs incurred due to providing capacity but as yet none have been identified.

The efficient capacity offer prices depend on the size of any direct capacity costs. A better understanding of these costs and their potential size would inform the design of capacity products and offer price caps. Without demonstrated marginal costs to providing capacity it is difficult to justify a separate capacity offer prices.

[1] Lost option values can be considered an opportunity cost, but separate terminology is used here. When this paper refers to opportunity costs it means the opportunity cost of foregone profits from energy sales.

2 Overview of Spot Capacity Products

This paper discusses spot market (CAISO Day-Ahead or Real-Time market) capacity reserve products rather than forward capacity products or contracts. These spot capacity products are an ability to change energy output (or energy consumption) within a specified timeframe that is held in reserve so that they can produce energy (or reduce load) if needed. For example, if a generator can increase its energy output by 15 MW in 10 minutes, it can provide 15 MW of 10-Minute reserve capacity as long as it is not producing energy with that capacity. This is distinct from regulation, voltage support, or load/peak-load shifting services and products which are not providing passive reserve capacity.

CAISO has proposed new capacity and flexibility mechanisms in order to meet changing operational needs. These include a Flexible Ramping Product and Corrective Capacity.

> ***Flexible Ramping Product*** – This product will increase flexibility in the Real-Time Dispatch (RTD) to meet imbalances that may arise due to load and generation variability and uncertainty. This is done by procuring capacity (that can be ramped to within 5 minutes) in a current interval to be used in a future interval to resolve imbalances. The need for this flexibility is expected to grow as the CAISO transitions to a grid with greater integration of renewable generation and variable demand.[2]
>
> ***Corrective-Capacity –*** This capacity is meant to resolve certain reliability requirements on specific critical transmission constraints that allow for recovery to occur within 30-minutes. This requires that enough corrective-capacity effective on the transmission constraint be procured to make the post-contingency re-dispatch feasible. This differs from other capacity products in that it has a transmission component. Currently these reliability requirements are met with out-of-market operations.[3]

3 Determining the Value of Capacity

The market optimization minimizes total production costs given bids, transmission constraints, capacity requirements, the physical characteristics of resources and the demand for energy.

Changes in capacity requirements affect total production costs. The marginal value of capacity is the shadow value on the capacity requirement. This shadow value represents the amount total energy production costs would decrease if the capacity requirement were marginally relaxed (reduced). This can also be viewed as the amount production costs did not have to increase because a particular megawatt of capacity was able to help meet the capacity requirement.

Consider the example in Figure 1. The horizontal axis is the megawatt amount of a spot capacity product. The capacity requirement is a fixed amount. The marginal cost of capacity represents the increase in minimized production costs from procuring increasing amounts of capacity. The segments "X," "Y" and "Z" each represent a single megawatt. If the capacity requirement were relaxed by one

[2] For more information please see: http://www.caiso.com/Documents/StrawProposal_FlexibleRampingProduct.pdf

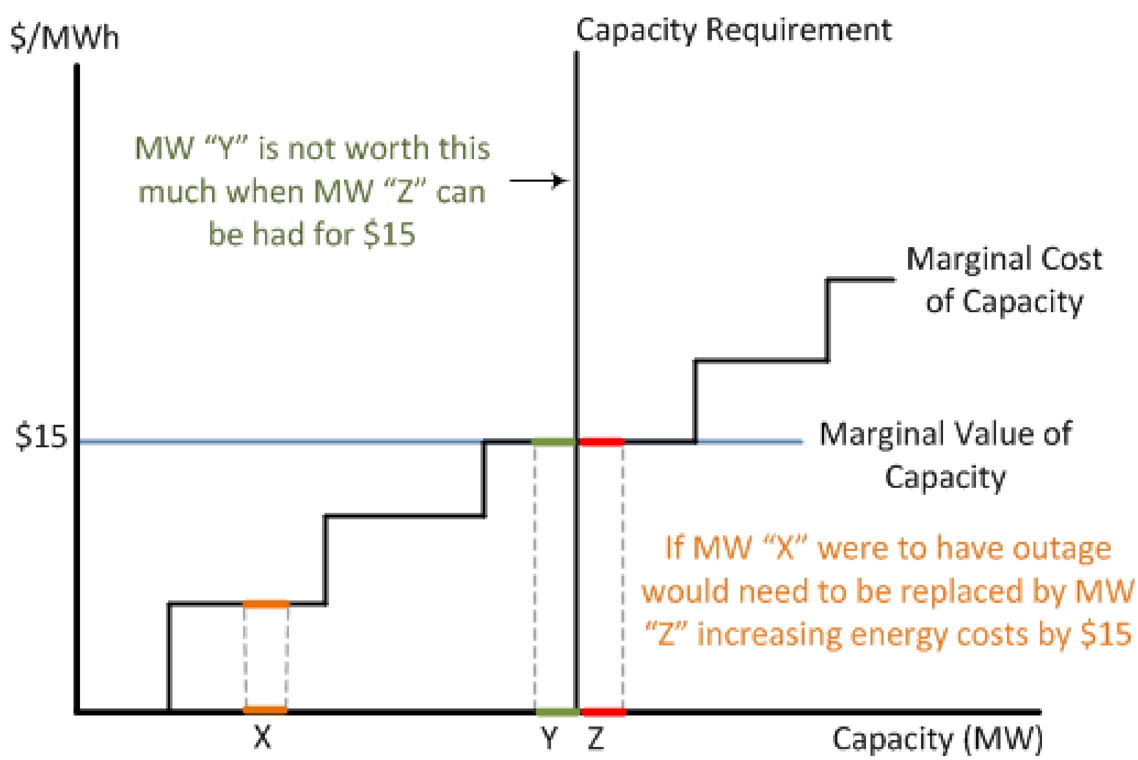
[3] For more information please see: http://www.caiso.com/Documents/StrawProposal-ContingencyModelingEnhancements.pdf

megawatt, then Y would not need to be procured and costs would decrease by $15. The shadow price on the requirement, and therefore the capacity price, is $15.

Figure 1 also shows that the value of capacity is not infinite or undefined simply because the demand is vertical. One would not pay $500 for megawatt "Y" when "Z" can be had for $15. It can also be seen that if megawatt "X" were to be unavailable, that megawatt "Z" would need to be procured at a cost of $15 to continue meeting the requirement. The $15 for megawatt "Z" is a cost not incurred because "X" is available. Megawatt "X" provides $15 of value even though its costs of providing capacity are lower.

Proposals to pay capacity only at its cost, or its opportunity cost,[4] rather than at the market clearing capacity price do not recognize this value. They would also remove the ability of resources to recover fixed costs through inframarginal rents and reduce incentives to increase or maintain resource flexibility.

Figure 1 – Value of Capacity



[4] This is a similar argument to paying energy "as bid" rather than the market clearing LMP.

4 Opportunity Costs of Within Market Unsold Energy

When a generator has capacity held in reserve it does not produce energy. If the resource could have profitably sold energy into the same market that procured its capacity[5] it incurs an opportunity cost from lost energy sales within that market.

For example, generator G1 has a Locational Marginal Price (LMP) of $50, and marginal production costs of $45. G1's profit from selling energy would be the difference between the LMP and its marginal cost.

(4.1) Profit from Energy = LMP - MC = $50 - $45 = $5

If G1 is held for capacity, it foregoes this $5 profit. This is the opportunity cost of providing capacity. The capacity price must be at least $5 for G1 to be willing to provide capacity and not produce energy.

The capacity price will cover this opportunity cost. This can be seen if we assume G1 is marginal in the capacity market (that G1 is price setting). The capacity price will be the reduction in energy production costs from marginally relaxing the capacity requirement (the shadow price). Capacity from G1 would be used to generate energy, increasing generation costs by $45, but it would displace energy costing $50, for a savings of $5. The capacity price will, at the very least, cover the within market opportunity costs of foregone energy sales without the inclusion of a separate capacity offer used in the determination of the shadow value. Within-market opportunity costs do not support non-zero offer prices for capacity.

5 Opportunity Costs of Outside Markets

It may be argued that a capacity offer price can be used to represent the opportunity cost of not selling power into another market. This capacity offer price would represent an amount the generator would need to be paid per megawatt of capacity awarded in addition to any within market opportunity costs in order to provide capacity.[6] Such an argument may go as follows:

> A generator resource, G2, is bidding into the CAISO Day-Ahead Market (DAM) and has a marginal production cost of $35. G2 expects it can sell power into another market for P^{other} equal to $38[7] and earn a profit of $3. As G2 would want to at least earn this $3 if it sells energy into the CAISO DAM, it increases its energy bid to $38. Assume however that G2 is selected to provide a capacity product forgoing energy sales, and that it sets the capacity price.
>
> The market clearing LMP for G2 is $39. Its capacity price would be the difference between the LMP and G2's energy bid ($39-$38) which is $1. This is less than the $3 it could have earned in the other market and less than the $4 it would have earned had it sold energy. The lost $3 profit opportunity is due to the perceived low within market opportunity cost caused by the inclusion of the other market opportunity costs.

[5] That is, if it sold capacity into the CAISO Day-Ahead market, but could also have sold energy into the CAISO Day-Ahead market.

[6] This offer would represent a marginal cost to using a megawatt as capacity that would not be incurred if the megawatt were used as energy or received no awards at all.

[7] This is the expected price after accounting for Non-CAISO transmission costs. For this example assume no CAISO congestion.

> A separate capacity offer of \$3, equal to the opportunity cost of the other market, would make the resource whole with a price of \$4 (\$1+\$3).

However, a separate capacity offer is not the only way to capture the expected price of an outside market. Instead, an energy bid equal to the marginal cost of energy and an export bid equal to the expected price in the export market could be submitted.[8] Working from the example above, G2 could submit an energy bid of \$35 and an export demand bid of \$38. Assume there is no congestion (that the LMP is \$39 at both the generator and the export node). If G2 were to provide energy its profit would be the difference between its LMP and marginal cost.

$$(5.1)\quad \textit{Profit if Energy} = LMP - MC = \$39 - \$35 = \$4$$

If G2 were to instead provide capacity, its profits would be the difference between its LMP and energy bid. Because G2 submitted an energy bid equal to its marginal cost, its capacity profit will also equal the difference between the LMP and marginal cost.

$$(5.2)\quad \textit{Profit if Capacity} = LMP - \textit{Energy Bid} = \$39 - \$35 = \$4$$

The export bid would not clear the market because G2's willingness to pay, \$38, was below the export price, \$39. G2's profit of \$4 is the same as if it had submitted a separate capacity offer price.

Now consider the case where the LMP is less than the expected price in the other region, say the LMP equals \$36. The profits if providing energy or capacity can be calculated as above using the new \$36 LMP. The profit from exporting energy is the difference between the price in the other market and the export LMP.[9]

$$(5.3)\quad \textit{Profit if Energy} = LMP - MC = \$36 - \$35 = \$1$$

$$(5.4)\quad \textit{Profit if Capacity} = LMP - \textit{Energy Bid} = \$36 - \$35 = \$1$$

$$(5.5)\quad \textit{Export Profit} = P^{other} - LMP^{export} = \$38 - \$36 = \$2$$

The total profit G2 earns is its profit from selling energy or capacity, plus its export profit.

$$(5.6)\quad \textit{Total Profit} = \textit{CAISO Profit} + \textit{Export Profit} = \$1 + \$2 = \$3$$

The \$3 profit is the same profit G2 would earn if it were to sell energy directly to the outside market (\$38 - \$35). By representing the expected price of outside markets as an export demand bid, G2 can manage it price opportunities in both markets.

[8] An export bid states the price at which one is willing to buy energy at an export node.

[9] The export LMP is the cost of exporting energy from the CAISO markets at a particular export node.

Table 1 shows the profits of providing capacity (or energy) and export profits from the export bid method under a variety of LMP and congestion scenarios. It compares these profits to the maximum possible profit in each scenario. Under all these scenarios the export bid method captures the maximum profit.

Table 1 – Representing Outside Market Prices with Export Bids

Marginal Cost	=	**$35**	**- submit as energy bid**
$\text{Price}^{\text{Other Market}}$	=	**$38**	**- submit as virtual export bid**

Export Scenario	A	B	C	D	E	F	G	H	I	J	K	L
Generator LMP	$36	$37	$38	$39	$36	$37	$38	$39	$36	$37	$38	$39
Export LMP	$36	$37	$38	$39	$37	$38	$39	$40	$35	$36	$37	$38
Congestion	$0	$0	$0	$0	$1	$1	$1	$1	-$1	-$1	-$1	-$1
Profit - Capacity	$1	$2	$3	$4	$1	$2	$3	$4	$1	$2	$3	$4
Profit - Exports	$2	$1	$0	$0	$1	$0	$0	$0	$3	$2	$1	$0
Total Profit	**$3**	**$3**	**$3**	**$4**	**$2**	**$2**	**$3**	**$4**	**$4**	**$4**	**$4**	**$4**
Possible Profit	$3	$3	$3	$4	$2	$2	$3	$4	$4	$4	$4	$4

Profit - Capacity = $(LMP^{gen} - 35)*(1 \text{ if } LMP^{gen}>=35, 0 \text{ otherwise})$

Profit - Exports = $(38 - LMP^{exp})*(1 \text{ if } LMP^{exp}<=38, 0 \text{ otherwise})$

Notice that when the congestion cost is $1 in scenarios E and F that G2 earns only $2 instead of $3. This is because the cost of exporting energy is not the same as the marginal cost of generation, it is the LMP at the export node. The $1 difference in the marginal cost of congestion (MCC) between the generator and export nodes reduces the profitability of exports. The marginal cost of exporting energy is therefore $36, and the profit that could be earned in the other market is:

$$(5.6)\quad \textit{Export Profit} = P^{other} - LMP^{export} = \$38 - \$36 = \$2$$

G2 may be considering the price it could earn in a different temporal market rather than a different geographic market. If G2 expects it could sell energy in the Real-Time market for $38, it would not want to sell energy for less in the Day-Ahead market. This situation is analogous to the different geographic market case. G2 can submit a virtual demand bid which is an offer to buy a financial position at the Day-Ahead price and have it liquidated at the Real-Time price. Viewed another way, it is a way to financially export from the Day-Ahead market into the Real-Time market. The opportunity costs of the Real-Time market can be managed in the same manner as an export market.

Table 2 shows the distribution of profits from the virtual demand bid method under different pricing scenarios. As with the export bid method, the virtual demand bids, coupled with marginal cost energy bids, captures the maximum profit.

Table 2 – Representing Real-Time Prices with Virtual Demand Bid in Day-Ahead Market

Marginal Cost	**$35**	**- submit as energy bid**
Price$^{\text{Other Market}}$	**$38**	**- submit as virtual demand bid**

Virtual Scenarios	**A**	**B**	**C**	**D**
LMP	$36	$37	$38	$39
Profit - Capacity	$1	$2	$3	$4
Profit - Virtuals	$2	$1	$0	$0
Total Profit	**$3**	**$3**	**$3**	**$4**
Possible Profit	$3	$3	$3	$4

Profit - Capacity = (LMP - 35)*(1 if LMP>=35, 0 otherwise)

Profit - Virtuals = (38 - LMP)*(1 if LMP<=38, 0 otherwise)

6 "Single" Clearing Prices in LMP Market Design

The CAISO markets employ a Location Marginal Price (LMP) market design. This design enforces the law of one price that all prices for a commodity will be equal, after accounting for transportation and transaction costs. The prices at all nodes within CAISO only differ by the costs of congestion and losses. In this way the CAISO market creates a "single" spot clearing price that adjusts for the costs of congestion and losses at each node.

The cost of exporting from the CAISO markets is the LMP at the export node, not the marginal cost of an internal generator. Energy can be exported at this price regardless of the energy or capacity awards of the internal generator. Because the opportunity to export to outside markets is unaffected by the decisions made at the internal generator, the prices in outside markets are not opportunity costs to internal generators.[10] Energy is exported from the CAISO market, not specific generators.

The benefit of having an internal generator, in this situation, is that it is a hedge against an increase in the export LMP when scheduling an export. The generator is naturally "long" on energy prices while the export bid is "short" on energy prices.[11] The price received by the generator offsets, or hedges, the cost of exporting energy. If the generator is bidding its marginal cost, then the hedge is intact whether it provides energy or capacity (as the value of both would increase as the LMP increases).

[10] It is possible for participants to export from the CAISO markets without owning or contracting with any internal generator.

[11] The generator is "long" on the LMP because its value increases as the LMP increases. The export demand bid is "short" on the LMP because its value decreases as the LMP increases.

7 Capacity Offers and Virtual Bids

Virtual demand bids and separate capacity offer prices can both be used to manage price opportunities between the Day-Ahead and Real-Time markets. The Real-Time price can be captured with a virtual demand bid whether a generator has capacity, energy or no awards in the Day-Ahead. Because the Real-Time price opportunity is not forgone due to the ability to submit virtual bids, it may be argued that the Real-Time price is not an opportunity cost for the generator.

Capacity offers and virtual demand bids also have different implications for market power in capacity products. If a generator has market power in capacity, it could increase its capacity offer above true marginal costs in order to exercise this market power. This could directly increase capacity prices and indirectly increase energy prices. In the case of the CAISO proposal to create corrective capacity, it could also directly affect energy prices.[12] The submission of virtual demand bids to represent expected Real-Time prices does not pose this market power concern.

New market power mitigation measures would need to be developed before capacity offers could be allowed for localized markets or constraints with limited competition for the supply of capacity.[13]

More generally, offer prices above the true marginal costs of providing capacity could also introduce inefficiency by increasing prices above marginal costs or causing otherwise economic capacity from not clearing the market even in the absence of resources exercising market power.

8 Option Value of Day-Ahead Schedules

While decisions may be made on expectations about the future, those expectations may not be met. Because of this, the ability (option) to respond to outcomes that differ from expectations may be valuable. A Day-Ahead energy schedule provides the option to sell back that schedule in Real-time. Day-ahead capacity awards may also create Real-Time options if they are re-optimized in Real-Time.

Consider a generator that expects the Real-Time LMP will be $38. However, the actual LMP may be different than this expectation. The generator estimates that the Real-Time LMP can be anywhere between $30 and $46 with equal probability, as shown in Figure 2. For simplicity assume that the Day-Ahead LMP will be $35 with certainty. Assume also that capacity awards are held fixed in Real-Time and not re-optimized. The generator has a marginal energy cost of $35 which it bids into the market while also submitting a virtual demand bid of $38 (per the method shown in Section 5).

The Day-Ahead profit will be $0 whether the generator provided energy or capacity. The profits it can earn on its virtual demand position will be the difference between the Real-Time and Day-Ahead LMPs, a $3 expected profit. Even though the generator expects to earn a $3 profit on its virtual demand position, any realized LMP less than $35 will result in a loss.

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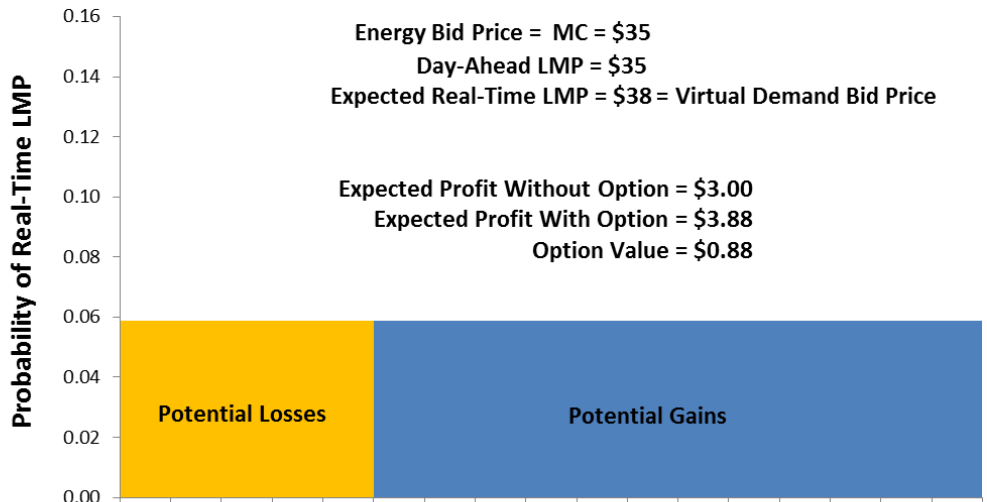
[12] Because the corrective constraint is transmission based and there is a direct link between the congestion components in the capacity price (LMCP) and energy price (LMP).

[13] The local market power mitigation proposal in in the "Contingency Modeling Enhancements: Second Revised Straw Proposal" are not structured to account for market power from capacity offers. Please see the paper at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ContingencyModelingEnhancements.aspx

Figure 2 – Option Value of Waiting Until Price is Known



RT LMP	$30	$31	$32	$33	$34	$35	$36	$37	$38	$39	$40	$41	$42	$43	$44	$45	$46
VD Profit	-$5	-$4	-$3	-$2	-$1	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	$11
BuyBack Profit	$5	$4	$3	$2	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Overall Profit	$0	$0	$0	$0	$0	$0	$1	$2	$3	$4	$5	$6	$7	$8	$9	$10	$11

If the generator has a Day-Ahead energy schedule, it can buy back that schedule if the Real-Time LMP is below the Day-Ahead LMP. The profit from this energy buy back will offset the losses on its virtual position. The expected overall profit given that the Day-Ahead energy schedule can be bought back is $3.88. However, if the generator was awarded capacity, it would not have the option to sell buy back energy in Real-Time to offset unfavorable LMP outcomes.[14] The expected profit if awarded capacity would be $3.00. The difference between the expected profits, $0.88, is the option value of the Day-Ahead energy schedule.[15] The generator would want to be paid this option value in order to give up an energy schedule and provide capacity. A capacity offer price of $0.88 would make the expected profits from providing capacity or energy the same, assuming the capacity is fixed in Real-Time.

The above example is a simplified illustration of how there may be a lost option value to providing capacity in the Day-Ahead. The actual size of this option value would also be affected by positive option values to capacity schedules. The option value of capacity schedules is not only from the ability to sell back capacity at a profit but also from the ability to capture the Real-Time LMP from energy schedules. Assuming a Real-Time capacity price of $0, the option value of a capacity schedule would be the blue area ($3.88) in Figure 2 multiplied by the probability the capacity schedule is converted to energy. In this example, if the probability of conversion to energy in Real-Time is greater than 23%, than the

[14] There is no opportunity to profitably buy back capacity awards as the capacity price cannot be negative. It may also be the case that capacity awards are held going into Real-Time and only incremental awards are allowed.

[15] This option value is not introduced by the use of virtual demand bids. Even if the generator only submitted a physical energy bid and there was no capacity product there would still be an option value of $0.88 to having an energy schedule. The example shows that using virtual bids to manage opportunity costs from the Real-Time market does not cover the lost option value from the capacity award.

capacity schedule option value will be greater than the energy schedule option value. In such a case the capacity schedule would not be imposing lost option values, in net, on the generator.

The Flexible Ramping Product will be available to the energy market in Real-Time, in part for the purpose of responding to price spikes. It is reasonable to expect that as Real-Time LMPs increase the probability of converting Flexible Capacity awards into energy schedules increases.[16] Corrective Capacity is one source of counterflow to corrective constraints, the other is energy. It also seems reasonable that as Real-Time LMPs increase, the probability of Corrective Capacity converting to energy would increase (as energy becomes a relatively cheaper source of counterflow to the corrective constraint).[17]

A simple model was run to estimate the potential size of these option values. Expected Real-Time LMPs were estimated using the LMPs from previous days as explanatory variables.[18] The differences between the expected and actual LMPs (the errors) were used as the distribution of Real-Time LMPs. This distribution, the expected Real-Time LMP, and the Day-Ahead LMP were used to estimate potential options values for Day-Ahead energy and capacity schedules.

This method is likely to error in the direction of over estimating the option values for two reasons. First, the model of expected Real-Time LMPs is naïve in that it only considers previous LMPs in the estimation. A more sophisticated model that includes other factors affecting LMPs, such as weather forecasts or natural gas prices, could better predict Real-Time LMPs. Because the model is less precise its errors are larger, which increases the estimated option values. This is particularly true after LMP spikes (either up or down) where the model overestimates the likelihood of similar spikes in subsequent days.

Second, the Day-Ahead LMP is the only cost information used. The option to buy back energy schedules only has value if the difference between the Day-Ahead LMP and the Real-Time LMP is greater than the difference between the Day-Ahead LMP and marginal costs (the profit from energy or capacity awards). Modeling marginal costs as if they are equal to the Day-Ahead LMP will also bias the estimated option values higher as it lowers the threshold at which the buyback is profitable.

The majority of the time (over 2/3 of the observations) the estimated option value of a Day-Ahead energy schedule was $0/MWh. The likely upward bounds of the potential lost Day-Ahead Energy Schedule option value was about $6/MWh, assuming the capacity schedule is held fixed in Real-Time. If the capacity schedules were to be re-optimized in Real-Time, the potential option value of no Day-Ahead energy schedule, net of the option value of having a capacity schedule, is likely near $0/MWh. The probability of converting the capacity to energy given Real-Time LMPs higher than Day-Ahead LMPs would need to be less than about 35% for the net option value to start rising above $0/MWh.

[16] A demand curve for Flexible Capacity is a potential design option. This would make it more likely that high Real-Time LMPs would induce Flexible Capacity to be converted to energy schedules.

[17] A higher LMP indicates a higher opportunity cost of not producing energy, i.e. the cost of capacity has gone up.

[18] A simple autoregressive model was run for each Location-Trade Hour daily LMP series. The number of lags used was determined for each series using the Akaike Information Criterion (AIC) for model selection. Two years of data were used for the three major DLAPs in CAISO, forming 72 Location-Hour LMP series.

9 Direct Costs of Providing Capacity

Given that a separate capacity offer is not required to cover opportunity costs, the appropriateness of such an offer depends on whether there are any option value costs or direct marginal costs to providing capacity. While it has yet to be demonstrated to what extent direct capacity costs exist, a set of potential direct costs are:

- Operations and maintenance costs related to readiness
- Staffing costs (when no energy schedules)
- Gas scheduling and transportation reservation costs
- Scheduling Costs

It is also unclear whether or not these costs are marginal. If they are fixed costs that are incurred if any capacity is to be provided, it may be expected that they would be recovered through inframarginal rents or forward capacity contracts.[19] Including non-marginal costs in a separate capacity offer would distort the tradeoffs used to determine prices within the market optimization, moving the market away from marginal cost pricing.

Without a better understanding of any direct costs of providing capacity, it would be difficult to understand how these costs should be incorporated into the design of spot capacity products and pricing.

10 Implications

Separate capacity offer prices are not needed to cover the opportunity costs of foregone energy sales. Within market opportunity costs are covered by the capacity prices as determined in the CAISO market processes without the need for separate capacity offers. Opportunity costs of Real-Time energy sales due to Day-Ahead awards can be covered with virtual bids.

The potential lost option value from Day-Ahead energy schedules when awarded capacity may be a reason for separate capacity offer prices in Day-Ahead markets. However, estimates suggest this potential lost option value is close to $0/MWh.

In the absence of demonstrated direct marginal capacity costs it would be difficult to justify separate spot capacity offer prices.

[19] It is also worth pointing out that the role of inframarginal rents in covering fixed costs and influencing investment is an important reason to pay capacity at the prevailing capacity price rather than at cost or at opportunity cost only.