Comments on Storage Bid Cost Recovery and Default Energy Bid Enhancements

Revised Straw Proposal

Department of Market Monitoring

September 23, 2024

Summary

DMM appreciates the opportunity to comment on the *Storage Bid Cost Recovery and Default Energy Bid Enhancements Revised Straw Proposal*.[1] DMM continues to recommend that the ISO address the real-time bidding incentives created by the current real-time bid cost recovery (BCR) design for batteries in Track 1 of this initiative. A primary purpose of BCR is to incentivize resources to submit bids that accurately reflect actual costs, so that the market optimization achieves efficient market outcomes. The current BCR design for batteries does the opposite, and instead creates incentives to bid inconsistent with real-time opportunity costs.

DMM understands that the ISO has identified potential challenges to implementing the straw proposal due to the multi-interval optimization. DMM encourages the ISO to explore alternate methods of identifying state-of-charge (SOC) insufficiency for a given interval, rather than shifting the Track 1 focus to implementation of an alternate solution that would only modify the inputs to the BCR calculation.

Another issue identified in the stakeholder process, is whether the ISO's current local market power mitigation might undermine or offset the efficiency and reliability benefits that would result from the ISO's proposed modifications to BCR calculations, to such a degree that they would not be worth undertaking without changes to the current storage default energy bids (DEBs). To address this issue, DMM has provided analysis of actual and potential impacts of bid mitigation on the dispatch of batteries using market data from Restricted Maintenance Operations (RMO) days in summer 2023 and 2024.

Based on this analysis, DMM does not believe that mitigation using the current default energy bids for storage resources would significantly limit the efficiency and reliability benefits of the ISO's proposed changes to BCR calculations. This analysis further indicates that implementing an approach based on the ISO's proposed changes should not be delayed or deferred until any enhancements are made to the current storage DEBs.

DMM's analysis also suggests that the overall financial impacts on individual resources resulting from mitigation under the ISO's proposed BCR changes would be limited. However, because some loss remains possible, DMM recommends considering an additional settlement provision targeted at preventing revenue losses in this situation. As noted by the Market Surveillance Committee (MSC), such provisions could be based on current settlement provisions that were developed to compensate batteries for any lost revenues due to exceptional dispatches issued to hold state-of-charge.

[1] *Storage Bid Cost Recovery and Default Energy Bid Enhancements Revised Straw Proposal for Track 1*, California ISO, September 4, 2024: https://stakeholdercenter.caiso.com/InitiativeDocuments/Revised-Straw-Proposal-Storage-Bid-Cost-Recovery-and-Default-Energy-Bids-Enhancements-Sep-04-2024.pdf

Track 1 should address inefficient bidding incentives created by the current design

Current BCR rules create incentives for batteries to bid below intraday opportunity costs in real-time, which can result in battery capacity being discharged prior to the peak net load hours. A primary purpose of BCR is to incentivize accurate bidding of expected costs to achieve efficient market outcomes. The current BCR design for batteries does the opposite, and instead creates incentives to bid inconsistent with real-time opportunity costs. These underlying inefficient incentives lead to the reliability and gaming concerns that have been discussed over the course of this stakeholder process.

DMM understands that the ISO has identified potential challenges to implementing the straw proposal due to the multi-interval optimization, and associated challenges with identifying intervals that have binding SOC constraints. DMM encourages the ISO to explore alternate methods of identifying SOC insufficiency for a given interval, rather than shifting the Track 1 focus to implementation of an alternate solution that would only modify the inputs to the BCR calculation. For instance, instead of relying on SOC constraint shadow prices from the multi-interval optimization, the ISO could explore the possibility of calculating the SOC available at the beginning of an interval to meet day-ahead schedules in that binding interval, or over a determined number of future intervals.

Throughout the stakeholder process, numerous entities have raised the issue of potential gaming or actions by "bad actors". Some stakeholders have proposed an approach that would narrowly target this potential source of BCR for battery storage resources. DMM agrees that the potential for gaming of BCR payments by batteries is concerning, and one purpose of the straw proposal and this initiative is to mitigate these gaming concerns. However, an interim approach that only targets gaming concerns would not address other important efficiency and reliability concerns created by current BCR rules. The ISO should address all three concerns: gaming, market efficiency, and reliability.

DMM believes it is important to address the fundamental design flaw underlying storage BCR rules, rather than treating the market efficiency and reliability impacts of BCR rules as a lower priority than the gaming issue, and taking up efficiency and reliability issues at a later time. Implementing an approach that effectively addresses these efficiency and reliability issues now should not foreclose the possibility of additional discussion on specific circumstances where real-time BCR for batteries may be warranted.

The ISO's straw proposal to eliminate real-time BCR due to insufficient SOC would address current inefficient bidding incentives, and establish a more appropriate default rule of not paying BCR due to insufficient SOC. Starting from this new default position, the ISO and stakeholders may then wish to consider the specific and narrow circumstances in which BCR may be warranted in a future phase of this initiative.

Effects of local market power mitigation

Default energy bids for battery storage resources are currently based on day-ahead prices during the fourth-highest priced hour (plus additional adders).[2] These DEBs may not reflect real-time intraday opportunity costs on days when real-time prices exceed day-ahead prices by a significant margin.

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[2] For a battery with four hours of storage, real-time DEB is based on the 4th highest locational marginal price (LMP) in the day-ahead market at the resource's location, plus estimated charging costs, variable O&M, and a 10 percent adder.

Because of this, local market power mitigation (LMP) could cause storage resources to be discharged (or forgo charging) at a price below a battery owner's estimate of their intraday opportunity costs, or below the actual ex post opportunity costs (i.e., based on actual real-time prices). Such sub-optimal dispatch can be economically inefficient and reduce system reliability. In addition, this can cause a storage resource to have its state-of-charge depleted before reaching hours with day-ahead discharge schedules, and result in losses associated with buying back the day-ahead schedules. Currently, such losses would be covered by BCR payments. However, if the ISO eliminates BCR resulting from state-of-charge limitations, these losses would not be recovered through BCR payments.

At the September 11 stakeholder meeting, DMM presented analysis of the potential magnitude of the impact of bid mitigation of battery dispatch based on actual market data for the nine days during summer 2023 and 2024, when the ISO called for Restricted Maintenance Operations (RMO).[3]

To highlight the impact that mitigation has actually had on battery dispatch, DMM first provided an hourly summary of the metrics that DMM uses to track the impact of bid mitigation based on actual bids submitted by market participants. As shown in Figure 1 below, these metrics categorize battery capacity offered in the market as follows:

- The blue bars in Figure 1 show the quantity of bids that were subject to potential mitigation, but which are not changed due to mitigation.[4]
- The green bars show cases in which mitigation caused bids to be lowered, but did not cause any increase in the level at which the battery was dispatched.
- The red bars show cases in which mitigation caused bids to be lowered and resulted in an increase in the level at which the battery was dispatched.

As shown in Figure 1, these metrics show that in practice, mitigation has had a very limited overall impact on battery dispatch. Moreover, mitigation has had the greatest impact during the three peak net load hours 19 to 21, during which prices and reliability needs are highest.

Eliminating BCR for batteries buying back day-ahead schedules would create an incentive for batteries to submit higher priced bids during the mid-day and afternoon hours, prior to peak net load hours when they have been scheduled to discharge through the day-ahead market. To assess the potential impact of bid mitigation under this scenario, DMM used the same data used to assess the actual impact of mitigation, but assumed the following:

- All batteries bid at the $1,000/MWh bid cap during all hours.

[3] *Analysis of battery bid cost recovery and bid mitigation issues*, Department of Market Monitoring, September 11, 2024: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Battery-Bid-Cost-Recovery-and-Mitigation-Data-DMM-Sep-11-2024.pdf

[4] Units are *subject to mitigation* if they can relieve congestion on a constraint that is determined to be structurally non-competitive. However, bids from these resources are not *lowered* unless the bid is higher than the unit's default energy bid or a competitive market price.

- All batteries choose the storage DEB option, which includes an estimate of intraday opportunity cost based on day-ahead prices.[5]

Under this scenario, the potential impact of mitigation can be assessed as follows:

- Each unit's mitigated bid is the maximum of the unit's DEB or the competitive LMP.
- If the unit's mitigated bid is *greater* than the unit's LMP, then mitigation has no impact on the unit's dispatch.
- If the unit's mitigated bid is *less* than the unit's LMP, then mitigation could cause the unit's bid to be dispatched.

Figure 2 shows results for this analysis for the same nine days in summer 2023 as shown in Figure 1, when Restricted Maintenance Operations (RMO) was in effect.

- The yellow bars in this figure represent the volume of bids that could be dispatched due to mitigation under this hypothetical scenario.
- The green bars in this figure represent the volume of bids that would not result in additional dispatch due to mitigation.

Figure 3 shows results for the first eight RMO days in summer 2024. Results for all 17 of these days from 2023 and 2024 were provided in the appendix of DMM's presentation at the September 11 meeting.

Results of this analysis show that even if batteries bid very high (e.g., $1,000/MWh), mitigation would likely have had minimal impact on dispatch prior to the peak net load hours on critical days. Based on this analysis, DMM does not believe the ISO's current local market power mitigation process would undermine or offset the efficiency and reliability benefits of fixing the BCR calculations, as proposed by the ISO. While DMM continues to recommend that the storage DEB based on intraday opportunity costs be enhanced, DMM believes this analysis also shows that the proposed changes to BCR rules should not be deferred or delayed until such enhancements are made.

[5] Currently, about 1,200 MW of battery capacity have a cost-based DEB option that has a very low default value (e.g., $.38/MWh). When resources fail to designate the storage DEB as their top choice of DEB methodology in the MasterFile, a DEB will instead be generated using the cost-based methodology applied to all other non-gas resources. This will produce a DEB for storage resources that is less than $1, far below a reasonable estimate of intraday opportunity costs. Although the competitive LMP will serve as a floor for mitigated bids, failure to designate the storage DEB can increase the likelihood that bids will be lowered due to mitigation and lead to incremental dispatch. DMM is notifying these scheduling coordinators to ensure they are aware of all DEB options for battery resources.

Figure 1. Actual impact of bid mitigation

Hourly averages for all 9 RMO days in summer 2023 (15-minute)

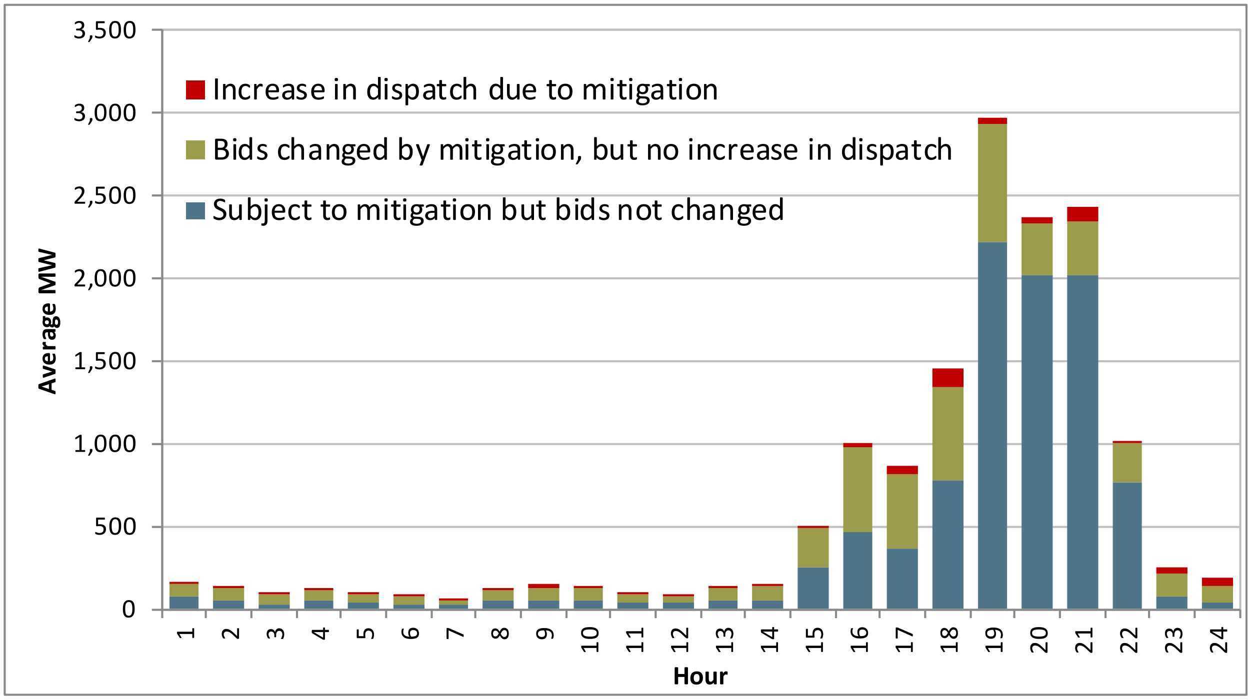


Figure 2. Potential impact of bid mitigation with higher energy bids

Hourly averages for all 9 RMO days in summer 2023 (15-minute)

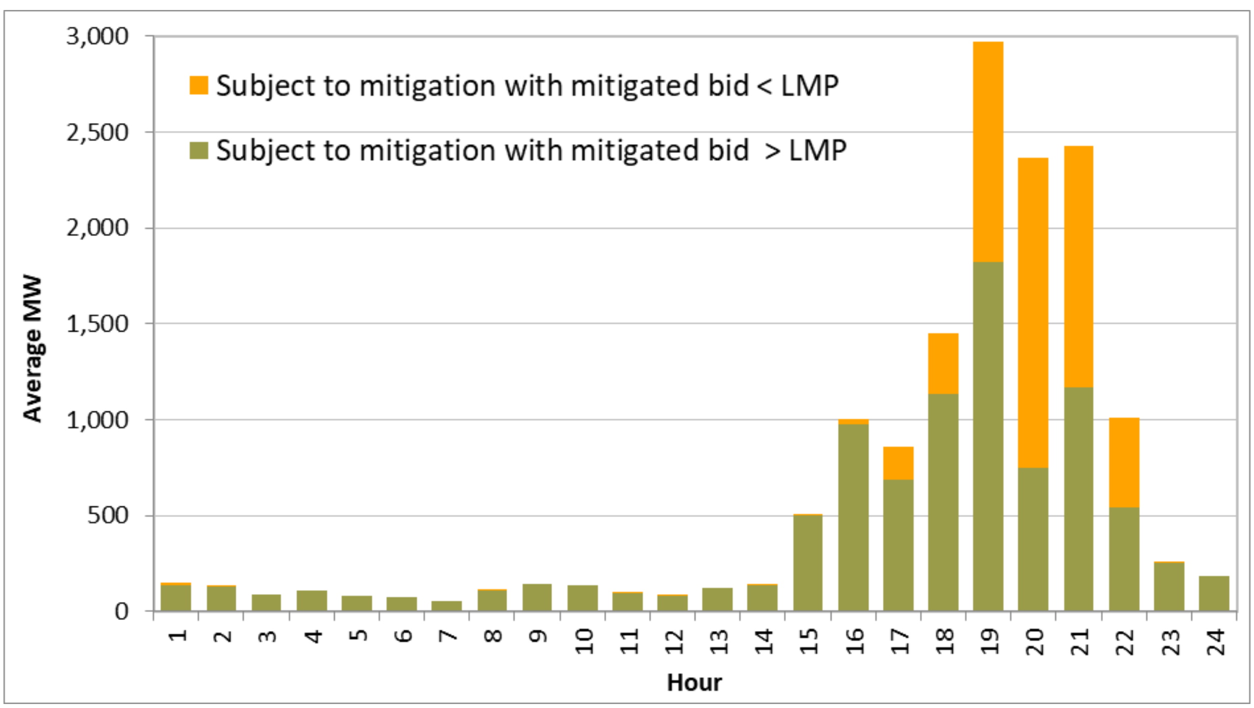
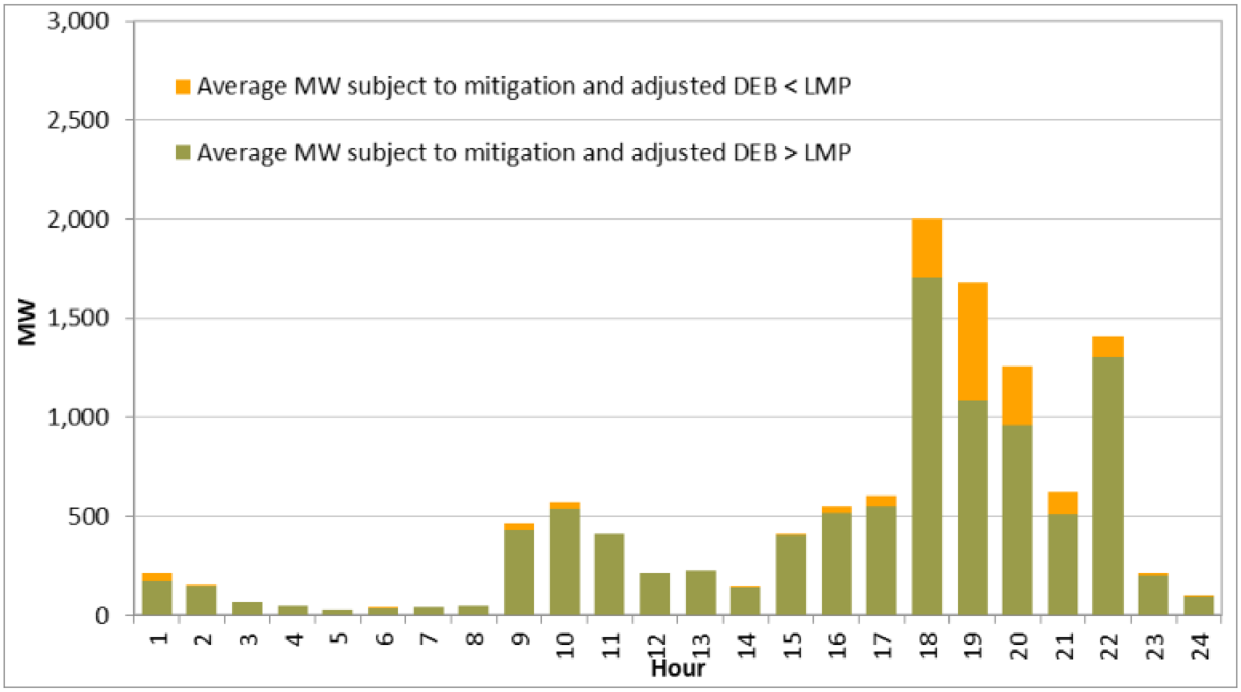


Figure 3. Potential impact of bid mitigation with higher energy bids
Hourly averages for 8 RMO days in summer 2024 (15-minute)



Batteries can be protected against lost revenues due to bid mitigation through a targeted settlement rule such as the one used for exceptional dispatches to hold state-of-charge.

DMM supports development of targeted ex post settlement rules that would compensate batteries in cases when mitigation did cause a loss in revenue by reducing discharge capability in later higher priced hours.

Losses associated with buying back day-ahead schedules due to insufficient state-of-charge are appropriate when the lack of stored energy is the result of bids submitted by the scheduling coordinator. In hours leading up to when batteries are scheduled to operate in the day-ahead market, this potential exposure to real-time prices creates the incentive for batteries to submit bids reflecting their best estimate of intraday opportunity costs based on expected real-time prices and system conditions.

However, even if battery bids reflect a reasonable estimate of intraday opportunity costs, the ISO's local market power mitigation process can cause a battery's bids for earlier hours to be lowered below the battery's estimate of intraday opportunity costs. This can cause market dispatches that leave the battery without sufficient stored energy to meet day-ahead schedules, leading the battery to incur from buying back day-ahead schedules in later hours. Such cases may warrant additional settlement measures.

The ISO, the Market Surveillance Committee (MSC), and DMM have all noted the potential impacts of bid mitigation as described above. The MSC has proposed using the ex post settlement approach that has been developed for settlement of exceptional dispatches to hold state-of-charge, in cases where local market power mitigation causes incremental dispatch of storage resources. This proposed settlement should work to cover losses associated with insufficient stored energy due to bid mitigation in prior hours when battery storage DEBs do not fully reflect the actual (ex post) intraday opportunity costs.

The ISO should seek to enhance battery DEBs to more accurately reflect potential real-time intraday opportunity costs in a later stage of this initiative.

Real-time bids are the primary determinant of real-time market software dispatches for batteries above or below the batteries' day-ahead schedules. As discussed in prior DMM comments, without real-time BCR payments that cover losses from day-ahead schedule buybacks or sellbacks, when state-of-charge constraints are binding, batteries would need to rely on real-time bid prices to manage the risk of losses associated with insufficient SOC to deliver day-ahead schedules in later hours.[6]

In order to dispatch batteries efficiently, bids should reflect the potential intraday opportunity costs of charging or discharging batteries differently in the real-time market (particularly for day-ahead schedules in hours beyond the real-time advisory lookout). Therefore, default energy bids for batteries used when bid mitigation is triggered also need to reflect potential opportunity costs of discharging batteries, or forgoing charging of batteries, in the real-time intervals leading up to the day-ahead schedules. More generally, DEBs for batteries need to vary hourly, and reflect the changing real-time opportunity costs of dispatching in a given hour before reaching a dispatch opportunity in a future hour.

Currently, batteries can opt to have default energy bids for the real-time market that include an opportunity cost component based on the fourth highest resource locational marginal price from the day-ahead market, plus a 10 percent adder.[7] The option may be effective and efficient in many instances. However, in real-time, these DEBs may be insufficient to capture intraday opportunity costs associated with potentially higher real-time prices based on changing real-time conditions.

Further, the current DEB design is a static value over all hours of the operating day and does not consider changing intraday opportunity costs throughout the day. This can lead to a DEB that is too high in some hours, and too low in other hours. DMM recommends the ISO develop DEBs that could vary hourly, with higher values in the intervals leading up to the peak pricing hours, and lower values in later intervals as intraday opportunity costs fall.

However, DMM believes that the analysis of the impacts of mitigation DMM has performed as part of this stakeholder process shows that the overall impact of bid mitigation is limited, so that the proposed changes to BCR rules should not be deferred or delayed until such DEB enhancements are made.

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[6] *Comments on Storage Bid Cost Recovery and Default Energy Bids: July 8, 2024 Workshop*, Department of Market Monitoring, July 18, 2024: https://www.caiso.com/documents/dmm-comments-on-storage-bcr-and-default-energy-bids-july-8-2024-workshop-jul-18-2024.pdf

[7] For a four-hour energy storage resource. For an N hour energy storage resource, it would be the N^{th} highest day ahead LMP. See Appendix D, Market Operations Business Practice Manual, p 310: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments

Real-time locational marginal prices—not bid costs—were the primary driver of BCR from insufficient SOC to meet day-ahead awards in the first half of 2024.

Throughout the stakeholder process, some entities have raised the issue of potential gaming or actions by "bad actors". Some stakeholders have proposed an approach that would narrowly target this potential source of BCR for battery storage resources. Such an approach could seek to mitigate gaming concerns by basing bid costs used in BCR calculations on each resource's DEB or day-ahead LMP, rather than their actual bid price.

At the September 11 meeting, DMM presented a slide showing analysis that most BCR in 2024 has been driven by real-time market prices, rather than bid costs.[8] Alternative approaches to the BCR calculation that target the calculation of bid costs may reduce BCR payments to batteries in some circumstances. However, DMM believes this analysis suggests that these types of alternative approaches are not likely to be highly effective at reducing the relatively high BCR payments being received by batteries. Most importantly, DMM believes such approaches would be ineffective at addressing the fundamental bidding incentives, market inefficiencies, and potential reliability impacts of current BCR rules for batteries.

In these comments, DMM is providing additional explanation of the analysis of BCR components presented at the September 11 meeting, and the implications of this analysis.

Figure 4 below breaks out the major components of the BCR calculation over the first half of 2024, for days with instances where battery SOC was insufficient to meet a day-ahead schedule. This figure corresponds to the figure on slide 3 of DMM's September 11 presentation.

As shown in Figure 4, the two major components of battery BCR are bid costs and market revenues. To determine if BCR is paid, a resource's net revenue is calculated over the day—based primarily on the summation of all accepted bid costs and all the market revenues received by the unit. If net revenue is positive, then no BCR payment is needed. If net revenue is negative, a net revenue shortfall, then BCR is paid to cover the shortfall. As shown in Figure 4, BCR payments for these units on these days was driven primarily by negative net real-time energy revenues—not by bid prices.

The remaining portion of these comments provide a simplified series of examples designed to help explain and interpret the results shown in Figure 4.

[8] See slide 3 in *Analysis of battery bid cost recovery and bid mitigation issues*, Department of Market Monitoring, September 11, 2024: https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Battery-Bid-Cost-Recovery-and-Mitigation-Data-DMM-Sep-11-2024.pdf

Figure 4. Components of BCR settlement calculations during hours when batteries had insufficient SOC to support day-ahead schedules 2024

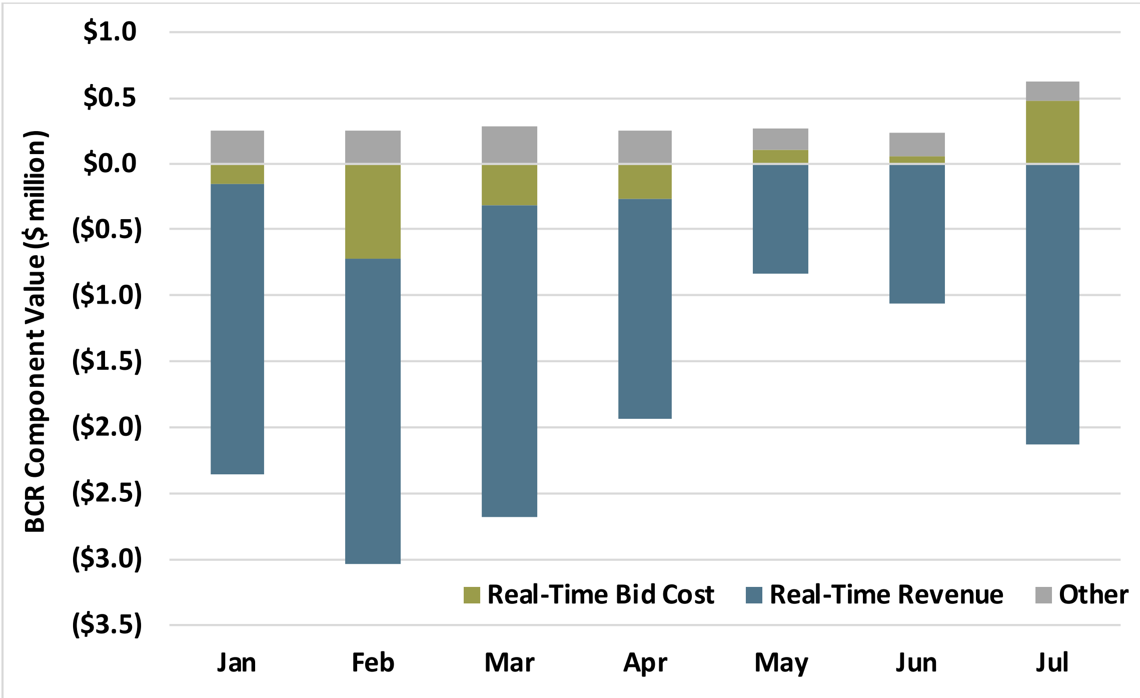


Table 1 and Figure 5 below show example cases to illustrate how the BCR components are represented in Figure 4.

Case A is a 1 MW dispatch with a bid of $30 and LMP of $50. A $30 bid means there is a $30 cost for that 1 MW, which reduces net revenue. The resource is paid $50, which increases net revenue. Total net revenue is -$30 + $50 = $20, which is greater than zero. If this was the only real-time schedule, then no BCR payment is needed, as there is no shortfall.

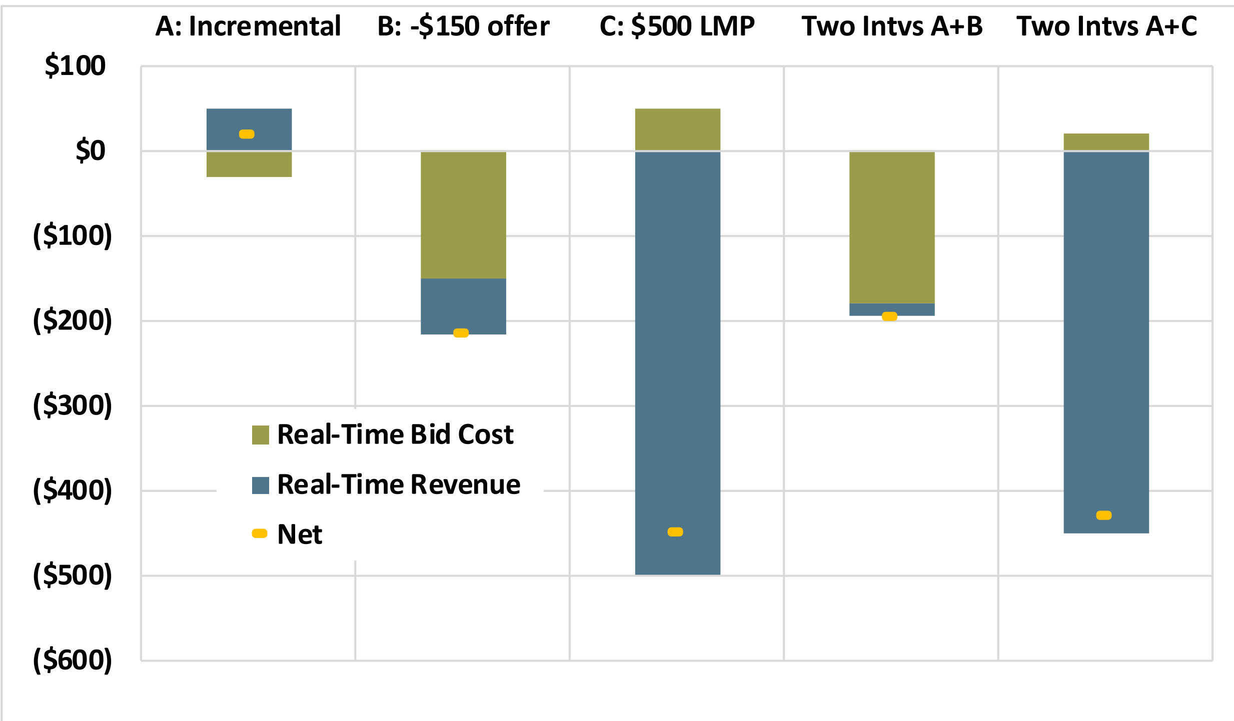
Case B shows a -1 MW real-time schedule with a -$150 bid and LMP of $65. In this case, the bid cost is the larger driver of negative net revenues which require a BCR payment. A bid of -$150 represents that the resource is willing to pay up to $150 to produce 1 MW. This bid indicates that the resource receives a benefit of $150 for producing 1 MW, and that not producing 1 MW results in the loss of $150. When the resource receives a dispatch of -1 MW, the $150 benefit is foregone as reflected in the bid cost, and the resource does not receive the $150 benefit of producing. This reduces net revenue by $150. The resource pays the $65 LMP for the reduction of 1 MW, further reducing net revenue. The total net revenue is -$150 + -$65 = -$215.

Case C shows a -1 MW real-time schedule with a $50 bid and $500 LMP. In this case, the revenue is the larger driver of negative net revenues which require a BCR payment. A dispatch of -1 MW avoids a bid cost of $50, which increases net revenue. However, the resource pays the LMP of $500 for the reduction of 1 MW, which reduces net revenue. The total net revenue is: $50 + -$500 = -$450.

Table 1. Example BCR component calculations

Case	RT MW	Bid	LMP	Real-Time Bid Cost Green bar	Real-Time Revenue Blue bar	Net
A: Incremental	1	$30	$50	-$30	$50	$20
B: -$150 offer	-1	-$150	$65	-$150	-$65	-$215
C: $500 LMP	-1	$50	$500	$50	-$500	-$450
Two Intvs A+B				-$180	-$15	-$195
Two Intvs A+C				$20	-$450	-$430

Figure 5. Chart of BCR calculation components for example cases



Bid cost recovery is calculated from net revenues summed over all the intervals in the day. The three cases described above (A, B, and C) can be combined to illustrate other cases where a resource first discharges a MW and then has insufficient charge to meet a day-ahead schedule.

- The sum of cases A and B illustrates an example where the resource discharges in an earlier interval (A), and receives BCR due primarily to bid costs associated with buying back a discharge in a later interval (B).
- The sum of cases A and C illustrates an example where the resource discharges in an earlier interval (A), and receives BCR due primarily to negative revenue associated with buying back a discharge in a later interval (C) at a high real-time price.