Storage Bid Cost Recovery and Default Energy Bid Enhancements

Revised Straw Proposal for Track 1

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1. Introduction

Grid-scale energy storage assets have been deployed quickly onto the California Independent System Operator's (ISO) footprint in recent years, going from about 500 MW in 2020 to approximately 10,000 MW by July 2024. These assets have the potential to advance California's goals to further renewable integration by absorbing excess renewable energy during periods of low demand in order to later inject that energy back into the grid when demand increases.

Energy storage has unique operational characteristics compared to conventional thermal generators and variable energy resources (VERs). The nature of energy storage assets is defined by their flexibility, responsiveness, and by the fact that they are energy-limited resources whose fuel availability is endogenous to the electric market. As such, the ability of energy storage resources to provide energy products and services when scheduled is determined by its ability to secure the state of charge (SOC) needed to support its awards and schedules. Energy storage resources bids reflect these unique operational characteristics and do not result merely from their costs to produce energy in a given interval. Rather, they also reflect storage resources' desire to be dispatched at a given time based on their opportunity costs in future intervals.

In 2022, the ISO noted that the then-applicable provisions related to bid cost recovery (BCR) for energy storage did not align with the overall objectives and intent of the BCR construct. Specifically, the ISO noted that a combination of ancillary service awards or self-provisions for regulation-down in the real-time market, coupled with relatively high energy bids, resulted in unusually high BCR payments to storage resources.[1] The ISO found, and Federal Energy Regulatory Commission (FERC) agreed, that storage resources' high bids did not represent the resources' actual bid costs but rather reflected economic unwillingness to discharge, essentially avoiding energy dispatches in certain intervals. Further, it was found that the absence of bid cost recovery payments for providing ancillary services would not create incentives for these resources to bid in ways that would undermine the market's efficiency. If anything, the opportunity to receive bid cost recovery payments drove the incentive for high bids that undermines market efficiency.[2]

In filing for this change, the ISO noted that it would initiate a stakeholder process after the FERC filing to assess whether other potential changes may be more appropriate to address the BCR issue.[3] This position was then echoed by FERC, which noted the ISO offered to monitor the impacts of the bid cost recovery provisions to electric storage resource settlements and continue to engage with stakeholders to examine whether any other longer-term enhancements might be made to the tariff to address this issue.[4]

As the penetration of energy storage resources continued to grow within the ISO's footprint, additional concerns related to how BCR provisions apply to energy storage resources were raised by stakeholders. In 2023, the Department of Market Monitoring (DMM) published a special report on battery storage,

[1] CAISO, "Tariff Amendment to Prevent Unwarranted Bid Cost Recovery Payments to Storage Resource, and Request for Effective Date One Day After Filing" ("ASSOC Filing"), September 2022, at 10.

[2] CAISO, ASSOC Filing, September 2022, at 12.

[3] CAISO, ASSOC Filing, September 2022, at 13.

[4] *California Independent System Operator Corp.*, 181 FERC ¶ 61,146 at P 14 (2022).

which noted that there are a number of situations where batteries may receive inappropriate or inefficient BCR.[5]

Earlier this year, the ISO committed to initiate a stakeholder process to consider enhancements to bid cost recovery as it applies to storage resources because the concerns about unwarranted bid cost recovery payments to storage exist regardless of the recently proposed changes to allow energy storage resources to bid above the soft energy cap under certain circumstances.[6] As such, this initiative seeks to address this matter expeditiously given the ISO's commitment to the Board of Governors, the Western Energy Markets (WEM) Governing Body, and FERC.

2. Changes from the Straw Proposal

This revised straw proposal includes several significant changes, new alternative proposals, and details and examples not included in the straw proposal. Most of these changes are in direct response to stakeholder comments.

Several stakeholders noted that the timeline and schedule for Track 1 as presented in the Issue Paper & Straw Proposal (IPSP) would be insufficient to have the robust discussions needed to develop a durable holistic solution to storage BCR challenges. A new timeline, aiming for a November joint Board of Governors and WEM Governing Body meeting, is included in Section 3.

Several stakeholders requested the ISO provide additional clarity on the issue at hand, including numerical examples. A series of numerical examples have been included in Appendix A.

Some stakeholders offered alternative solutions that could enhance or replace the Proposed Solution put forth by the ISO in the IPSP. A summary of the stakeholder feedback received on each of the potential solutions, as well as a description of these alternative solutions is included in Section 5.

Several stakeholders have noted that instances in which resources have been subject to local market power mitigation (LMPM) in intervals prior to their day-ahead (DA) schedules may merit specific BCR provisions that ensure they are made whole. A discussion on mitigation in the context of the Proposed Solution and other alternative proposals is included in Section 6.1.

Several stakeholders have noted that features of the ISO's market design could drive outcomes and dispatch instructions that result in the buy- or sell-back of day-ahead schedules, specifically calling out multi-interval optimization (MIO). A discussion of MIO in the context of the Proposed Solution and other alternative proposals is included in Section 6.2.

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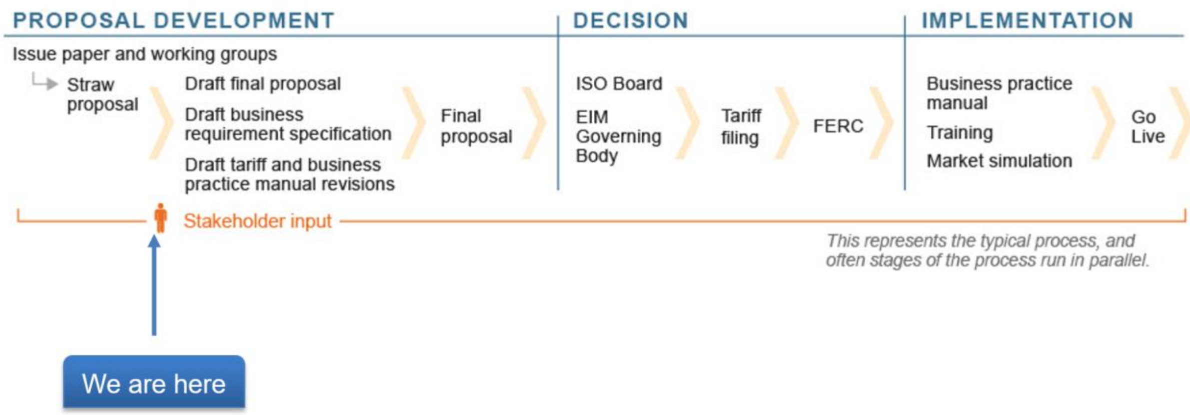
[5] DMM, "Special Report on Battery Storage", July 2023, at 20.
[6] CAISO, Board of Governors Memo regarding the Tariff Amendment on Price Formation Enhancements, May 2024, at 6.

3. Stakeholder Process

With the publication of these materials, the ISO is at the Straw Proposal stage in the Storage BCR & DEB Enhancements Initiative. Figure 1 shows the typical process for a stakeholder initiative.

Figure 1: Stakeholder Process Milestones



The purpose of this Revised Straw Proposal is to describe and compare the different potential solutions to the issues within the scope of Track 1 of this initiative, as well as provide examples detailing how the potential solutions would work and specify the areas where further development and discussion is needed for each of these potential solutions. The ISO will publish this Revised Straw Proposal, hold a meeting to discuss it with stakeholders, and later solicit written feedback to prepare the next iteration of this paper. Afterward, the ISO will publish a draft final proposal, set a stakeholder meeting to discuss it, and solicit stakeholder feedback once more, per the schedule below.

Table 1. Updated Track 1 Timeline [7]

Milestone	Date
Workshop issue slides posted	July 1, 2024
Stakeholder workshop on issue	July 8, 2024
Workshop stakeholder comments due	July 18, 2024
Second Stakeholder workshop on issue	July 22, 2024
Issue Paper & Straw Proposal (IPSP) posted	July 26, 2024
Stakeholder meeting on IPSP	August 5, 2024
IPSP stakeholder comments due	August 8, 2025
Stakeholder meeting on Alternative Proposals	August 19, 2024
Comments on Meeting on Alternative Proposals	August 26, 2024
Revised Straw Proposal (RSP) posted	September 4, 2024
Stakeholder meeting on RSP	September 9, 2024
RSP stakeholder comments due	September 23, 2024
Draft Final Proposal (DFP) posted	September 30, 2024
Stakeholder meeting on DFP	October 7, 2024
DFP stakeholder comments due	October 21, 2024
Joint Board of Governors and Governing Body Meeting	November 7, 2024

4. Track 1 Issues: Unwarranted Storage BCR

As underscored in Section 1, the ISO is aware of some issues in the current BCR construct as it applies to battery energy storage. These issues warrant expeditious resolution.

BCR is the process by which the ISO ensures scheduling coordinators (SCs) are able to recover start-up, minimum load, transition, and energy bid costs. In order to recover start-up and minimum load costs, a unit must be committed by the CAISO. For purposes of determining BCR eligibility, the ISO uses a concept called commitment period. A commitment period consists of the consecutive time periods within a trading day when a resource is on-line, synchronized to the grid, and available for dispatch. A commitment period is comprised of the self-commitment period and CAISO commitment period. The portion of a commitment period where a resource submits energy self-schedule or ancillary services (AS) self-provision is called a self-commitment period. Resources are not eligible for BCR of start-up,

[7] All dates are tentative until confirmed through a notice in the ISO's Daily Briefing.

minimum load, or transition costs during self-commitment periods, but are eligible for BCR of awarded Energy and AS. The portion of a commitment period that is not a self-commitment period is called a CAISO commitment period. Resources are eligible to receive BCR for start-up costs, minimum load costs, transition costs, awarded Energy and AS during a CAISO commitment period.

To calculate BCR, the commitment costs and the energy and AS bid costs are used as inputs to calculate a resource's net difference between costs and revenues in separate pre-calculations for the Integrated Forward Market (IFM), the Residual Unit Commitment (RUC) process, and the Real-Time Market (RTM) (*i.e.,* IFM Net Amount, RUC Net Amount, and RTM Net Amount). If the difference between the total costs and the market revenues is positive in the relevant market, then the net amount represents a Shortfall. If the difference is negative in the relevant market, the net amount represents a Surplus. For each resource the IFM, RUC, and RTM Shortfalls and Surpluses are then netted over all hours of a trading day, with the IFM Shortfalls and Surpluses netted separately from the RUC and RTM Shortfalls and Surpluses. Thus, RUC or RTM surpluses over the entire trading day are used to offset a RTM or RUC shortfall, respectively, incurred over the entire trading day. For either IFM or the combined RUC and RTM netting, if the net amount over the trading day is positive (a Shortfall), then the resource receives a BCR uplift payment equal to the net trading day amount.

As such, BCR is designed to provide "uplift payments" to a resource when revenues from the sale of energy and AS do not cover the resource's start-up, minimum load, and energy bid costs over the course of a day.[8] The rationale behind BCR is to incentivize efficient bidding by allowing for the recovery of commitment costs. Without BCR, resources would have an incentive to add a risk premium to their offers, leading to inefficient market outcomes, with higher overall costs for energy.[9]

BCR was initially designed with conventional thermal assets in mind. For conventional thermal assets, commitment costs include star-up and minimum load costs, among others. This is because when a thermal power plant starts up, it incurs certain costs such as fuel costs to reach the desired output level. In addition, thermal resources may also have minimum load requirements, meaning that they have a limited turndown range that requires them to run at a specific percentage of their maximum continuous rating. Since conventional resources with a day-ahead schedule may incur in some costs prior to the intervals when they are expected to generate electricity (*i.e.,* during the commitment period), BCR is a necessary mechanism to recover those costs over the trading day.

Storage resources, in contrast, are fundamentally different from conventional thermal assets. As recognized by FERC in its Order Accepting the ASSOC Constraint filing, storage resources have neither start-up nor minimum load costs, and generally have fast ramp rates, thus lacking the conventional drivers for BCR (*i.e.,* commitment). Although they may have other opportunity costs, they generally lack the intertemporal constraints that warrant bid cost recovery. Energy storage resources' bids do not result merely from their costs to produce energy in a given interval; instead, they also reflect storage resources' desire to be dispatched at a given time based on their opportunity costs in future intervals. As a result, the bids submitted by storage resources are not equivalent to those submitted by conventional thermal assets as they do not only represent actual bid costs but also include an implied opportunity cost.

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[8] CAISO, ASSOC Filing, September 2022, at 3.
[9] *Ibid.*

Moreover, the BCR construct, in general, does not adequately consider attributes common among storage resources, such as SOC constraints, which determine whether an asset can support its awards and schedules. This results in materially different treatment with regards to conventional generators. For example, if a conventional thermal asset is unable to perform and fulfill its day-ahead schedule due to unavailability (*i.e.,* an outage), the expected energy from that asset is categorized as SLIC Energy, thus making it ineligible for BCR. In contrast, when a storage resource is unable to meet its day-ahead schedule due to physical limitations, like having a SOC that cannot support the schedule, the market can instruct the storage asset to a 0 MW dispatch due to the SOC being binding, resulting in the buy-back or sell-back energy to be categorized as Optimal Energy (OE) which is eligible for BCR. Given these conditions, some BCR payments to storage resources have materialized despite not being aligned with the intent of BCR. In particular, the ISO is aware of a significant rise in BCR payments related to the buy- and sell-back of day-ahead schedules driven by limited or insufficient SOC.

This differentiated treatment of unavailable energy between conventional and storage assets creates two concerns:

- **Concern 1:** Storage assets are not exposed to real-time (RT) prices for deviating from day-ahead schedules.
- **Concern 2:** Storage assets are incentivized to bid strategically to maximize the combined BCR and market payment.

A buy-back of a discharge day-ahead schedule can occur when a storage asset's real-time SOC is too low to support it. Conversely, a sell-back of a charge day-ahead schedule can occur when a storage asset's real-time SOC is too high to support it.

In the RTM, SCs bids can bid in a manner that would unduly maximize BCR payments through buy-back or sell-back of the day-ahead schedule. This behavior results in inefficient outcomes that could materially hinder the reliability of the ISO's grid because energy storage resources would be unavailable when needed in real-time. This construct also results in economic inefficiency, as it removes exposure to real-time prices, thus minimizing incentives to reflect real time market conditions in supply offers. Finally, the current BCR paradigm as it applies to storage resources can lead to undeliverable day-ahead market awards, since scheduling coordinators may bid in a manner that would artificially inflate BCR payments to maximize pursuit of unwarranted real-time BCR revenue without exposure to real time conditions and prices.

For buy-backs of the day ahead schedule, the storage asset starts the RTM with a day ahead schedule with bids to discharge. In the RTM, grid conditions may materially differ from the day ahead market. If storage resources submit bids that do not reflect RT conditions and opportunity costs, this may lead to dispatch being possible prior to the intervals with a day-ahead schedule. It is crucial to underscore that, given the current BCR construct, storage resources are insulated from RT price exposure and, as such, have little incentive to bid in a manner that reflects those conditions and would allow for the preservation of SOC to meet day-ahead schedules in future intervals. As a result, if resources are dispatched early in the day such that their day-ahead schedule for the peak period is now infeasible, those assets must buy-back the now infeasible day-ahead schedule. The buy-back results in the storage resource receiving BCR to make the resource whole for the hours that were bought back. Importantly, the cost being recovered is based on the difference between the RT bid and the RT locational marginal price (LMP). As such, this resource could execute a bidding strategy that seeks to maximize that difference in the periods when a buy-back is triggered, leading to unduly high BCR payments. By bidding at low prices that tend towards the bid floor, a storage asset may make more money by triggering BCR and failing to support its day-ahead schedule than by bidding in a manner that would ensure delivering said day-ahead schedule or being efficiently available for redispatch in the RTM.

For sell-backs of the day ahead schedule, the mechanism works in reverse. Here, the storage asset starts the RTM with a day ahead schedule with bids to charge. In the RTM, grid conditions materially differ from the day ahead market. As noted before, storage resources are insulated from RT prices and as such have no incentive to bid in a manner that would reflect RT conditions and opportunity costs, potentially resulting in dispatch to charge earlier in the day relative to their day-ahead schedules. Thus, if earlier dispatch resultant from the bids causes the asset to charge earlier than its day-ahead schedule, their initial day-ahead schedule to charge is now infeasible, triggering a sell-back of said day-ahead schedule. Since the BCR construct today calculates the difference between the RT bid and the RT LMP, the resource could bid strategically to maximize this difference just as in the prior case. As such, a resource could execute a bidding strategy that seeks to trigger sell-backs, then bid consistently high (at or near the bid cap) in order to maximize its BCR revenue. This, just like the prior example, can result in circumstances where the asset is better off by triggering BCR and bidding strategically to maximize it than by bidding in a manner that would ensure support of its day-ahead schedule or being efficiently available for redispatch in the RTM.

The dynamics described above and exemplified in Appendix A create incentives that are not aligned with the intent of BCR, as assets might be incentivized to bid and operate in the RT market in a manner that would trigger buy- or sell-backs of their day-ahead energy schedules in order to capture outsized BCR payments. In addition, the current BCR construct as it applies to energy storage assets results in inefficient outcomes that could materially hinder the reliability of the ISO's grid. The BCR construct results in inefficiency as it removes exposure to real-time prices, thus minimizes incentives to reflected real-time market conditions in supply offers while also potentially creating incentives to pursue unwarranted real-time BCR revenue at the expense of day-ahead awards without any exposure to RT conditions and prices.

Considering the sensitive nature of the information contained herein, the ISO is actively monitoring storage BCR impacts to ensure unwarranted payments do not increase to untenable levels following the dissemination of this information or any of the examples contained in these materials.

5. Revised Straw Proposal Relative to Track 1

This section provides an overview of the three potential solutions currently under consideration: the proposed solution put forth by the ISO in the IPSP, an alternative solution first put forth by the California Energy Storage Alliance (CESA) and further developed by Pacific Gas & Electric (PG&E) and the Western Power Trading Forum (WPTF), and an alternative solution put forth by Vistra Corp (Vistra).

5.1. ISO Proposed Solution

As noted previously, when a storage resource is unable to meet its day-ahead schedule due to physical limitations, like having a SOC that cannot support the schedule, the market instructs the storage asset to a 0 MW dispatch due to the SOC being binding, resulting in the energy to be categorized as OE, which is eligible for BCR. The ISO's proposed solution to the issue discussed in Section 3.1 involves redefining dispatch unavailable due to SOC constraints in the binding interval as "non-optimal energy," which would be ineligible for BCR. The ISO proposes to identify whether storage resources can support their awards and schedules in the real-time binding interval on a resource-by-resource basis.

If a given storage resource's SOC at the start of the binding interval is equal to its minimum or maximum value, with consideration of the ASSOC constraint, the end-of-hour SOC constraint, upper and lower charge limits, and the attenuated SOC constraint, then the market would rerate or derate the PMax or PMin to 0 in order to capture that the asset is completely full or empty. This, in turn, would lead to the reclassifying any energy associated with buy-backs or sell-backs in that binding interval as non-optimal due to physical limitations as it is not available for dispatch. As a result the ISO would exclude the energy associated with that interval from the BCR calculation.

The proposed solution would align the treatment of unavailable energy from a storage asset to that of a conventional thermal asset, which has its expected energy categorized as SLIC energy when it is unable to perform and fulfill its day-ahead schedule due to unavailability (*i.e.,* an outage), thus making it ineligible for BCR.

Recently, the ISO has identified significant challenges with the design of the proposed solution due to the impact of multi-interval optimization (MIO). These issues, as well as the complications they present for the proposed solution and other alternatives, are covered in detail in section 6.2.

5.1.1. Stakeholder Feedback on the ISO Proposed Solution

In comments submitted August 16th, the California Public Utilities Commission's Energy Division (CPUC ED) expressed support for the Proposed Solution, noting that the issue at hand merits urgent resolution as it introduces inefficiencies into the market and could increase costs for ratepayers. In comments submitted August 26th, the DMM also expressed support for this proposal, noting that it, contrary to any of the alternative proposals put forth by stakeholders, would address opportunities for strategic bidding, market inefficiencies, and diminished reliability. DMM argues that this is because the Proposed Solution would fix the core issue that current BCR rules create: an incentive for batteries to bid below expected opportunity costs in real-time and in a manner that can result in battery capacity being discharged prior to the peak net load hours.

Similarly, in their August 26th comments, the California Public Utilities Commission's Public Advocates Office (Cal Advocates) also supported this proposal as it simultaneously addresses each of the three risks underscored by DMM. Cal Advocates noted that the Proposed Solution is the most effective and viable option to address the need to protect ratepayers from the high costs and risks that the current BCR rules create. In contrast, Cal Advocates argued that the alternative proposals from the CESA and Vistra fail to simultaneously mitigate the risks identified by DMM. In this context, Cal Advocates also stated that adoption of the Proposed Solution on an interim basis would be acceptable if the ISO includes broader reform of BCR rules for energy storage in the scope of a subsequent track of the initiative.

Other stakeholders have taken a different position, noting that the proposed solution is overly punitive and fails to recognize the fact that storage assets do not have total control over their RT SOC given certain characteristics of the ISO's markets and optimization processes. Stakeholders such as the California Community Choice Association (CalCCA), CESA, Customized Energy Solutions (CES), and WPTF reflected these positions in their comments submitted on August 8th. In comments submitted August 26th, Vistra noted that the proposed solution is overly punitive and that other proposals put forth by stakeholders should be adopted in the interim.

5.2. CESA Alternative Solution

As noted previously, several stakeholders have stated that the timeline and schedule for Track 1 of this initiative may be insufficient to allow for the robust conversations needed to develop a durable and holistic solution to the issues in scope. In this context, CESA suggests implementing an alternative solution in the interim which would address Concern 2 (*Storage assets may have an incentive to bid strategically to maximize the combined BCR and market payment*). The alternative solution proposed by CESA would imply modifying the formula used to calculate BCR to use the day-ahead Locational Marginal Price (LMP) instead of the RT Bid, as follows:

- From: (RT dispatch – DA schedule) * (RT bid – RT LMP).
- To: (RT dispatch – DA schedule) * (***DA LMP*** – RT LMP).[10,11]

[10] One stakeholder requested clarification on whether the BCR calculation only applies to hours in which there is a day-ahead schedule. No, BCR Shortfalls and Surpluses are calculated for all intervals, regardless of whether there is a day-ahead schedule or not. This stakeholder also asked why the formula does not breakout RT dispatch into fifteen-minute market (FMM) and five-minute real time dispatch (RTD) terms. For simplicity of explanation, this scenario assumes all buy- or sell-back occurs in the RTD. Unwarranted BCR from buy- or sell-back of day-ahead schedules may occur in between the 1) day-ahead schedule and the FMM; 2) day-ahead schedule and the RTD; and/or 3) FMM and the RTD. BCR resulting from the change between the day-ahead schedule and the FMM would be defined as: (FMM dispatch – DA schedule) * (RT bid – FMM LMP). BCR resulting from the change between the FMM and the RTD would be defined as: (RTD dispatch – FMM dispatch) * (FMM LMP –RTD LMP). BCR resulting from the change between the day-ahead schedule and the RTD dispatch remains defined as: (RT dispatch – DA schedule) * (RT bid – RTD LMP). Netted, these three formula would provide BCR.

[11] One stakeholder stressed the importance of clarifying the origination of this formula for BCR. This formula is a derivation from the formula found in the BPM Configuration Guide for RUC and RTM Bid Cost Recovery Settlement (CC6620). The ISO used the derivation to highlight the CESA alternative solution's change in simple, digestible terms. The ISO appreciates the stakeholder feedback that the derived formula caused confusion and shares the following proof as clarification:

CC6620 describes a RT interval as eligible for BCR when the following is true: BAARUCNetAmount + BAARTMNetAmount > 0. To simplify, all other bids and awards are assumed to be zero. Therefore, BAARUCNetAmount is zero because there are no awards from the RUC process.

Stakeholders argue that this proposal would eliminate the impact of a resource's bid on BCR payments, alleviating the concerns regarding unduly inflated BCR payments. In addition, some stakeholders have noted that their software used -$150 bids in hours with day-ahead schedules to "firm them up", a practice that could yield unwarranted BCR under the status quo but would not contribute to unduly high BCR if RT Bids are not part of the BCR calculation.

This proposal's main advantage is that it would eliminate the impact of a resource's bid on BCR payments in the intervals it is applied, potentially addressing the concerns related to strategic bidding. On the other hand, this alternative also has some drawbacks, notably, this proposal would not address Concern 1, continuing the current insulation of storage resources from RT prices. Stakeholders have acknowledged that this alternative would not resolve Concern 1, but they argue it would allow more time to develop a holistic solution that addresses said concern appropriately. Moreover, this modification to the RT BCR formula would continue to pay BCR to resources that are not available in real-time, but it may limit its magnitude as the payment is now calculated by the price difference between day-ahead and RT as shown in the examples in Appendix A.

In comments submitted August 26th, several stakeholders noted that this alternative merits further consideration and development. CESA offered additional clarification regarding their proposal, stating that this alternative proposal should only apply in the intervals where the generic SOC constraint is binding. Specifically, CESA proposes that their alternative solution should apply in 5-minute intervals where the buy-back or sell-back is caused by the generic SOC constraint binding.[12] Given the complexities of using the SOC as the trigger variable, CESA also offered an alternative set of trigger conditions that do not employ the SOC. For this alternative, CESA notes that if an interval fulfills three conditions it should trigger the alternative BCR calculation. In the case of a buy-back of a discharge schedule, the interval must have (1) a day-ahead schedule or base schedule to discharge, (2) a RT dispatch to discharge that is lower than the day-ahead or base schedule, and (3) a RT dispatch that does not charge the resource. In the case of a sell-back of a charge schedule, the interval must have (1) a day-ahead schedule or base schedule to charge, (2) a RT dispatch to charge that is lower than the day-ahead or base schedule, and (3) a RT dispatch that does not discharge the resource. If the conditions above cannot be used, CESA notes that it may be more appropriate to consider the SOC at the end of the

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BAARTMNetAmount is defined in CC6620 as: BAARTMNetAmount = RTM cost – RTM revenue. In this scenario, "cost" is MWh change multiplied by bid and "revenue" is MWh change multiplied by price. These terms are reflected as: RTM Cost = (RT dispatch – DA schedule) * RT bid; and RTM Revenue = (RT dispatch – DA schedule) * RT LMP. Therefore, BAARTMNetAmount is expressed as:

BAARTMNetAmount = (RT dispatch – DA schedule) * RT bid – ((RT dispatch – DA schedule) * RT LMP)

Rewritten: BAARTMNetAmount = (RT dispatch – DA schedule) * (RT bid – RT LMP)

[12] In this context, the "generic SOC constraint" should be interpreted as the minimum and maximum limits of the resource, as opposed to other SOC constraints such as the ASSOC Constraint or the End-of-Hour (EOH) SOC constraint.

binding 5-minute interval as opposed to at the beginning as it may more accurately identify if dispatch was limited by the generic SOC constraint.

When a buy-back has occurred, CESA recommends using the higher of either the day-ahead LMP, the RT Default Energy Bid (DEB), or the RT Bid in the interval's BCR calculation. Conversely, when a sell-back has occurred, CESA recommends using the lower of the day-ahead LMP, the RT DEB, or the RT Bid. As such, CESA updated proposal would modify the aforementioned RT BCR calculation as follows:

- For a buy-back: (RT dispatch – DA schedule) * (***[Max(DA LMP, RT DEB, RT Bid)]*** – RT LMP).
- For a sell-back: (RT dispatch – DA schedule) * (***[Min(DA LMP, RT DEB, RT Bid)]*** – RT LMP).

There are some key questions on the proposal that need to be worked through. Notably, since CESA's proposal would use the day-ahead LMP instead of the real-time bid, it is unclear how this could be implemented for storage assets in the Western Energy Imbalance Market (WEIM) that are outside the ISO's footprint and not part of the Extended Day-Ahead Market (EDAM). In this paper, such resources are referred to as WEIM-only resources. There is no day-ahead LMP for WEIM storage assets. This concern does not include EDAM Balancing Authority Areas (BAAs), which will have a day-ahead LMP. The day-ahead PNode LMP could be used for storage assets in the WEIM, but this is a price relative to the ISO's BAA and therefore it is not reflective of the offers of the WEIM assets.

In addition, it is unclear whether this proposed modification to the RT BCR formulae should apply in all intervals or only intervals when SOC constraints are binding. CESA's proposal explicitly states that it should only apply when the SOC constraints are binding. However, because BCR is calculated over the course of the whole day, modifying the formulae for only a subset of intervals would not fully remove the impact a resource's bid has on BCR payments. Specifically, BCR surplus calculated in other intervals, which impacts total BCR payout for the day, would still be derived using a resource's bid. Moreover, this could be specifically in intervals where the resource's dispatch used SOC that directly implicated the resource not being able to deliver its day-ahead schedule. Overall, the ISO believes that a modification to the RT BCR formulae as proposed by CESA should be applied across all intervals so as to ensure consistency on the surplus and shortfall estimations throughout the day. In addition, applying the modified formulae for all intervals would also materially minimize issues related to MIO, which are explored in detail in Section 6.2. For these reasons, the examples included in Appendix A consider (1) the status quo, (2) the proposed solution, (3) the initial CESA proposal when applied to all intervals, (4) the initial CESA proposal when applied only to intervals with a binding SOC constraint, (5) the updated CESA proposal when applied to all intervals, and (6) the updated CESA proposal when applied only to intervals with a binding SOC constraint. Reflecting all of these scenarios in the examples herein is meant to allow a better understanding of the potential impacts of applying these solutions for a subset of intervals and for all intervals.

5.2.1. Stakeholder Feedback on CESA Alternative Solution

Stakeholders have noted the merits of CESA's proposal, highlighting that it warrants further development and consideration. In comments submitted August 26th, CalCCA underscored that, while they do not take a position on a preferred approach at this time, the CESA and Vistra proposals warrant further consideration, as they could offer improvements to the Proposed Solution's blunt mechanism for excluding storage resources from BCR. San Diego Gas & Electric (SDG&E) stated in their August 26th comments that alternative solutions proposed by stakeholders, such as CESA's Alternative Proposal, offer creative temporary or short-term approaches to mitigating the quantity of BCR payments that result from bidding behavior or operator action and should be evaluated further in the Revised Straw Proposal. Other stakeholders have expressed support for the continued development of CESA's Alternative Proposal, submitting their own modified versions of it through written comments. These variations are detailed in the two subsequent subsections herein.

In contrast, some stakeholders have expressed that CESA's Alternative Proposal is not viable given the fact that it focuses solely on resolving Concern 2. In their August 26th comments, Cal Advocates noted that CESA's Alternative Proposal would continue to compensate storage at the potentially high differential between day-ahead and RT prices, a factor that could be potentially exacerbated by the fact that RT prices under stressed grid conditions may increase further due to the elimination of the soft-offer cap for storage, leading to increased ratepayer exposure. In addition, Cal Advocates stated that the lack of clarity on how to apply CESA's Alternative Proposal to storage assets in the WEIM should be sufficient to disqualify this proposal from consideration.

Finally, the DMM expressed that none of the alternative proposals presented by stakeholders would address the real-time bidding incentives created by the current BCR design, which can lead to inefficient dispatch based on bids below real-time marginal cost. In this context, the DMM noted that the ISO should not rush to implement interim measures that only address strategic bidding concerns or other limited scenarios created by the actions of scheduling coordinators.

5.2.2. PG&E's Modifications to CESA's Proposal

The modifications proposed by CESA in their August 26th comments are not dissimilar from other enhancements to CESA's initial alternative proposal put forth by other stakeholders. PG&E, for example, recommended focusing CESA's Proposal to the hours with day-ahead schedules. PG&E's reasoning is that storage resource's RT bids for hours with a day-ahead schedule are inherently different from RT bids for hours without a day-ahead schedule since the former represent the opportunity cost of buying back that day-ahead schedule while the later represent the resource's unwillingness to be discharged unless prices reach a given threshold.

PG&E generally agrees with the CESA proposal in that it addresses Concern 2; nevertheless, PG&E proposed a slight modification to CESA's initial proposal; which changes the BCR calculation for discharging as follows:

- CESA's Initial Proposal: (RT dispatch – DA schedule) * (RT bid – RT LMP)
- PG&E's proposed modification: (RT dispatch – DA schedule) * (**Max[RT bid, DA LMP]** – RT LMP)

This modified version of CESA's initial proposal is very similar to the updated CESA Proposal, with the exception that it would not consider the RT DEB. This is because PG&E does not currently support any storage RT BCR proposal based on DEB values. PG&E notes that its modified version of CESA's Proposal is more conservative as it better limits the BCR recovery amounts.

Regarding the questions on how a proposal using the day-ahead LMP in the BCR calculation should apply to resources in the WEIM footprint, PG&E argues that WEIM Only and CAISO/EDAM batteries should be handled differently for RT BCR given the fact that WEIM Only Day-Ahead schedules are essentially self-scheduled while CAISO/EDAM day-ahead schedules are a product of the Integrated Forward Market. As a result, PG&E reasons that a WEIM Only battery bidding in the RT markets should be presumed to have full control of its SOC in forming its bids relative to its base schedule. As such, given the fact that the base schedule of a WEIM Only asset was not the product of any CAISO market process, these resources shouldn't be eligible for RT BCR due to buy-back of what can be deemed a self-schedule.

5.2.3. WPTF's Modifications to CESA's Proposal

WPTF also proposed modifications to CESA's initial proposal. Specifically, WPTF proposes that for an interval to be deemed ineligible for RT BCR the following conditions must be met:

- The resource's SOC at the beginning of the interval needs to be at min or max SOC value.
- The resource has a day-ahead or base schedule that cannot be supported.

The second condition added by WPTF is essentially the same as proposed by PG&E, to focus on intervals with a day-ahead schedule. The only difference is that WPTF's proposal would also apply to WEIM Only resources, hence the reference to the base schedule. WPTF further notes that, in order to address mitigation issues, a third condition could be added; namely, that the resource was not mitigated in a prior interval. Issues regarding mitigation are explored in Section 6.1.

As such, WPTF proposes an interim solution that would first identify intervals where (1) the resource's SOC in the 5-minute market is at the min or max SOC value going into that interval, and (2) the resource has a day-ahead or base schedule that it cannot support due to the SOC value; then replace the RT Bid component of the RT BCR calculation for those intervals with RT DEBs, day-ahead LMPs, and/or RT bids.

5.3. Vistra Alternative Solution

In comments on the IPSP, Vistra noted that the ISO should improve its rules to ensure storage awards or dispatches due to outages or bid parameters should not be considered as optimal energy eligible for BCR, similarly to how use of the EOH SOC parameter makes intervals prior to and associated with this parameter ineligible for BCR.[13] In this context, Vistra proposed:

[13] Per Tariff Section 11.6.6, where Scheduling Coordinators elect to submit end-of-hour state-of-charge targets, storage resources participating as Non-Generator Resources will be ineligible for RTM Bid Cost Shortfalls in the two hours preceding the scheduled Operating Hour.

- **Component 1:** Classify energy associated with Instructed Imbalance Energy as non-optimal, thereby excluding it from the BCR calculation in intervals where there is an active:
    - Outage card that reduces its Pmax (Availability derate), Pmin (Load Max derate), Maximum Continuous Stored Energy (Maximum Energy derate), or Minimum Continuous Stored Energy (Minimum Energy rerate).
    - Bid parameter that reduces its Maximum Continuous Stored Energy (Maximum Energy derate) or Minimum Continuous Stored Energy (Minimum Energy rerate).
    - EOH SOC bid parameter constraining the solution to achieve a minimum SOC at the end-of-hour as requested by the SC.
- **Component 2:** If a given storage resource's SOC at the start of the binding interval is equal to its minimum or maximum SOC value, that binding interval bid cost recovery formula will use the DEB instead of the bid-in offers.
    - Include a sunset date for this element to ensure there is accountability for a future filing to provide a replacement make whole payment framework needs to be in place prior to the sunset date.

Vistra argues that this proposal would appropriately classify energy associated with awards or instructions that are due to outages or due to SC action to drive the market outcome. In addition, Vistra argues that this proposal would mitigate Concern 2 by limiting bid cost assessments to the asset's DEB.

In comments submitted August 26th, Vistra noted that only the portion unavailable would be classified as derated or rerated energy ineligible for BCR if an asset is not fully out of service. Vistra also noted that under their proposal, when any SOC bid parameter is used, the settlement interval would be considered ineligible for BCR such that all energy is reclassified as non-optimal.

In comments submitted August 26th, Vistra also offered the following modifications to Component 2 of its initial proposal:

- Only apply the new settlement rule in intervals where:
    - Resource is Limited Energy Storage Resource.
    - Resource received an IFM award or has a base schedule in that settlement interval.
    - Resource received an Instructed Imbalance Energy award from Fifteen Minute Market or Five Minute Market that is in the opposite direction of its IFM award or base schedule.
    - Resource had 0% or 100% SOC (i.e., equal to minimum or maximum continuous stored energy used by the market in the RTD binding interval.
- Settlement rule would limit unwarranted BCR by changing the BCR settlement only in the triggered interval to the RT DEB.

5.3.1. Stakeholder Feedback on Vistra's Alternative Solution

Similarly to CESA's Alternative Proposal, some stakeholders have noted that Vistra's alternative proposal warrants further development and consideration. In comments submitted August 26th, CalCCA underscored that, while they do not take a position on a preferred approach at this time, the CESA and Vistra proposals warrant further consideration, as they could offer improvements to the Proposed Solution's blunt mechanism for excluding storage resources from BCR.

SDG&E also noted in their August 26th comments that alternative solutions proposed by stakeholders offer creative temporary or short-term approaches to mitigating the quantity of BCR payments that result from bidding behavior or operator action and should be evaluated further in the Revised Straw Proposal. SDG&E does however note that, while they do not endorse or oppose any alternative solution at this time, they are concerned that using the DEB in a modified BCR calculation is premature given the ISO's expressed intention to re-evaluate the formulation of the storage DEB in a later track of this initiative. As such, while SDG&E supports a comprehensive evaluation of the alternative proposals at this time, given the need for an expedited Track 1 solution, it would be premature to use the DEB for the purposes of a modified BCR calculation.

In contrast, some stakeholders have expressed that Vistra's Alternative Proposal is not viable. In their August 26th comments, Cal Advocates argued that application of the DEB would be no more effective in mitigating unwarranted BCR than using the day-ahead LMP since DEBs tend to be lower than RT prices under stressed grid conditions. As such, large differentials between RT prices and the storage DEB would expose ratepayers to large BCR payments and shield storage resources from the same high RT prices. As a result, Cal Advocates states that Vistra's Alternative Proposal poses the same risks to ratepayers as CESA's Alternative Proposal.

PG&E has also stated that Vistra's Alternative Proposal is not viable since it relies on the DEB value for BCR, which they argue would only make sense in the RT intervals with no day-ahead schedule. Finally, the DMM expressed that none of the alternative proposals presented by stakeholders would address the real-time bidding incentives created by the current BCR design, which can lead to inefficient dispatch based on bids below real-time marginal cost. In this context, the DMM noted that the ISO should not rush to implement interim measures that only address strategic bidding concerns or other limited scenarios created by the actions of scheduling coordinators.

6. Challenges related to the Potential Solutions

6.1. Issues Regarding Local Market Power Mitigation

Local Market Power Mitigation (LMPM) is the process by which the ISO seeks to mitigate non-competitive behavior and market power. Market power is having the ability to substantially distort competitive market outcomes. ISO market power mitigation measures intend to mitigate non-competitive behavior while avoiding unnecessary interference with competitive price signals. The measures identify conditions where scheduling coordinators can exercise market power and mitigate their bids to their DEB or the competitive LMP, whichever is greater.[14] Today, an asset's DEB cannot exceed $2,000. For storage resources participating as a non-generator resource, the DEB is calculated by adding 10% to the maximum of 1) the sum of the expected energy cost and the variable storage operation cost; and 2) the storage opportunity cost.

Local market power mitigation occurs when transmission constraints determine bids in a specific area as non-competitive. Here, the ISO conducts a three potential pivotal supplier test which seeks to determine if the largest three suppliers control too much counter-flow supply. Non-competitive areas are where available counter-flow capacity from internal resources not controlled by the identified potentially pivotal suppliers is less than the demand for the counter-flow capacity.[15] Once a bid is mitigated in a fifteen minute interval, the mitigated bid applies only in that run. The original unmitigated bid will be evaluated again for the corresponding fifteen minute interval of the next run, if it lies within the market horizon. For the real time dispatch, the market power mitigation process is conducted on three five minute advisory intervals after the binding five minute interval. Like the fifteen minute interval, the mitigated bid only applies to that five minute interval with the original unmitigated bid evaluated in future runs.

Stakeholders have noted that there are instances that would still warrant BCR, specifically underscoring mitigation. Some stakeholders have noted that instances in which resources were mitigated in intervals prior to a buy- or sell-back of a day-ahead schedule may merit specific BCR provisions. The Market Surveillance Committee (MSC) echoed this concern in the meeting held July 30th, noting that, depending on how material this impact would be in the short-run, the ISO should consider applying the same approach used for the Hold Exceptional Dispatch (ED). Today, when the ISO issues a Hold ED to a storage asset, per Tariff Section 11.5.6.1.2, the ISO calculates the opportunity cost starting from the first Operating Interval when the resource met and followed the ED through the end of the operating day. The ISO calculates the difference between the resource's maximum potential RTM Energy revenues without the Hold ED and the resource's maximum potential RTM Energy revenues with the Hold ED. If the resource's maximum potential RTM Energy revenues without the Hold ED are higher than the resource's maximum potential RTM Energy revenues with the Hold ED, then the resource will receive the positive difference between these two values, which is its opportunity cost. The ISO calculates the resource's opportunity costs based on its Master File characteristics, bids, SOC, day-ahead schedules, and the applicable LMP. Given the similarities of this instances, where a given instruction may affect the potential revenues of an asset throughout the day, the MSC has noted that calculating a revenue counterfactual as the Hold ED does could alleviate the issues of resources being mitigated.

In comments submitted August 8th, several stakeholders noted that the ISO should more thoroughly consider the potential impacts of LMPM in the Revised Straw Proposal. CES noted that under the current

[14] Methodology for bid mitigation can be found for the day-ahead market in Tariff Section 31.2.3 and for market power mitigation in the real-time market in Tariff Section 34.1.5 and Market Operations Business Practice Manual Section 7.4

[15] More information can be found in Tariff Section 39 and Market Operations Business Practice Manual Section 6.5

LMPM mechanism, a unit that is identified as possibly being able to exercise market power will have its bids adjusted downwards to the higher of its DEB or the next competitive bid price. CES further highlighted that for storage assets, this process may also result in downward price adjustments of charging bids as well as discharge bids. In this context, CES underscored that this application of LMPM may reduce the price at which the asset is willing to buy energy, potentially resulting in the resource not being able to achieve the necessary SOC to meet their day-ahead schedules later on. General recommendations to further consider the potential implications of LMPM were also voiced by SDG&E, Terra-Gen, Vistra, and WPTF as part of their respective August 8th comments.

In comments submitted August 26th, DMM noted that local market power mitigation could cause storage resources to be discharged or forgo charging at a price below their actual real-time opportunity cost as determined by expected real-time prices. DMM also referenced the data the ISO presented during the August 19th stakeholder meeting to attempt to assess the potential magnitude of the issue. DMM noted that the data the ISO referenced from previous DMM reports was estimated using the actual bids submitted to the market.

DMM underscored that current BCR rules imply that historical bids are not likely to include an accurate representation of real-time intra-day opportunity costs, and that if the ISO were to eliminate BCR associated with buying back or selling back day-ahead schedules due to binding state-of-charge constraints, that new policy would likely incentivize resources to increase bids in some hours to better reflect intraday opportunity costs. Such a modification and a change in bidding behavior could lead to a larger potential impact of mitigation than suggested by historical analysis, especially in hours with significant real-time intraday opportunity costs. In this context, DMM recommends the ISO refine their analysis of the potential impacts of mitigation under the proposed storage BCR changes to assess hourly impacts, and account for changed bidding incentives under the proposed BCR rule changes.

DMM noted that the ISO will likely need to address the mitigation issue even if incremental dispatch caused by mitigation is relatively uncommon and if further analysis suggests it is likely to be uncommon moving forward. This is because some battery resources may be subject to LMPM with increased frequency, particularly those located within Local Reliability Areas (LRAs). As a result, those assets are likely to be disproportionately affected when mitigation does result in incremental dispatch. To underscore the importance of this issue, DMM noted that the ISO may need to address the potential issues of mitigation within Track 1, before the longer-term effort to enhance the storage DEBs is completed.

Regarding the potential solution suggested by the MSC, DMM noted that such a settlement approach would ensure that when batteries are subject to mitigation, they are equitably compensated for any lost revenues that can result when the current storage DEB option does not reflect actual real-time opportunity costs. Nevertheless, DMM argued, this settlement approach will not completely prevent inefficient dispatch in real-time that can be caused when bids are mitigated based on current DEBs. As a result, implementation of such a settlement approach should not negate the need to develop more accurate battery DEBs in Track 2, but could be a workable solution to consider in Track 1. If this solution is pursued, DMM recommends to have it be limited to resources that have actively elected in MasterFile to use the storage DEB methodology where available.

Other stakeholders have noted that the concerns related to mitigation do not merit additional consideration or delay for the implementation of a near-term solution. Cal Advocates argued in comments submitted August 26th that the analyses presented by the ISO and those conducted by DMM indicate that incremental RT energy associated with bids that were lowered in the LMPM process was very low in 2022 and 2023. As such, Cal Advocates reasons, mitigation of storage resource bids may not significantly impact storage BCRs and consideration of these matters should not delay the implementation of the Proposed Solution. Focusing on near-term implementation, PG&E noted in their August 26th comments that any short-term or interim proposal to address unwarranted BCR may not address periods of mitigation due to implementation complexity. If this is the case, PG&E requested the ISO to state at what point of the subsequent Tracks this topic will be addressed.

The ISO agrees that consideration of instances of mitigation may be warranted, but if and how to incorporate this exception will be largely dependent on further analysis and on the solution pursued. If the Proposed Solution is pursued, a specific exception for mitigation may be warranted, although this could materially impact the complexity of the solution, a tradeoff that is particularly relevant if it is pursued on an interim basis. If a solution akin to the CESA Alternative Solution is pursued, a modification that includes an exception for mitigation may not be necessary given that said solution does not eliminate BCR but only modifies the calculation of it. Nevertheless, if a solution similar to CESA's Alternative Solution is pursued, further discussion of mitigation may be warranted in the development of a holistic revision to the storage uplift construct. The ISO will continue to analyze the prevalence and impact of mitigation following the recommendations from stakeholders and the DMM in written comments. The ISO will provide those findings as discussions around the different potential solutions continue to develop.

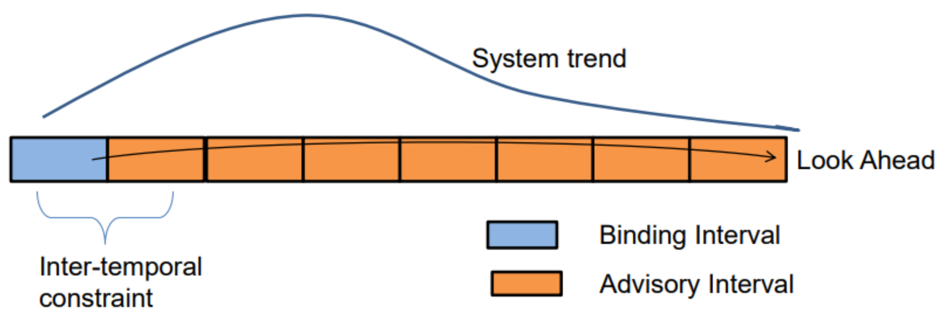
6.2. Issues Regarding Applicable Intervals and Multi-Interval Optimization

As noted in Section 5, all of the potential solutions described in this paper commence with the assumption that the ISO will be able to identify intervals where the SOC constraint is binding to later reclassify the energy associated with that interval, or to modify the BCR calculation applicable to that interval. As this initiative's efforts have progressed, the ISO has found that this condition is not met often in the binding interval, primarily due to the multi-interval optimization (MIO) process.

MIO allows the RTM to position resources to handle changes in the future horizon. For storage resources, the MIO charges or discharges a storage asset due to projected conditions in the future, linking solutions over intervals to ensure the asset's limited SOC is utilized when it is most valuable. As a result, the MIO may charge or discharge a storage resource to prepare for a future energy award, to avoid hitting the resource's maximum SOC constraint, to adjust for future interval economic conditions stemming from supply, demand or net interchange forecasts, or to rebalance an exceptional dispatch.

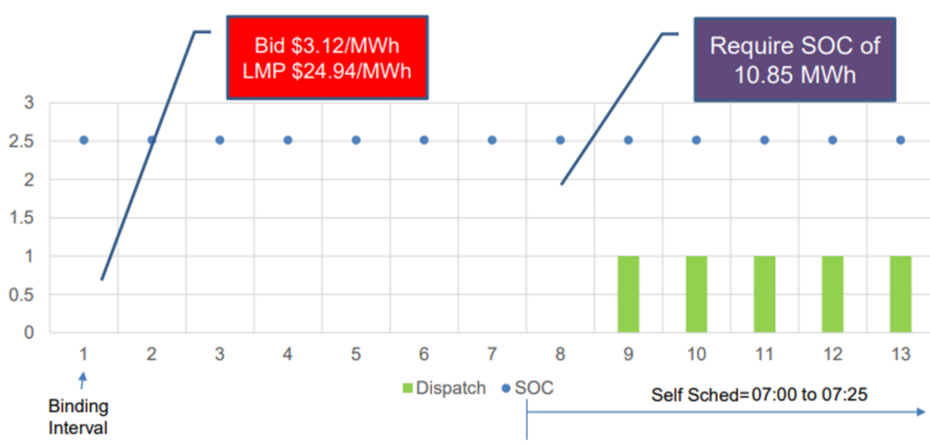
Future intervals are considered "advisory intervals" while the current interval is the "binding interval." The 15-minute market can look ahead almost 2 hours past the binding interval, while the 5-minute market can look ahead up to thirteen 5-minute intervals past the binding interval.

Figure 2. Visual Representation of the MIO Look-Ahead



The MIO dispatch may be uneconomical (*i.e.,* out-of-merit) in the binding interval, in order to meet a future scheduled advisory interval. For example, the following resource has a future self-schedule that requires 10.85 MWh of state of charge. The resource needs to charge to meet that state of charge. However, the resource's bids to charge are below the LMP and are uneconomical. Without the multi-interval optimization, the resource does not charge and does not have the state of charge necessary to meet its self-schedule.

Figure 3. Example of MIO for a Storage Resource



With the MIO, the resource charges continuously from intervals 1 through 8 in order to meet the self-schedule discharge as best as possible. Looking at a single interval, this charge is uneconomic, as the resource has bid $3.12/MWh, much lower than the LMP of $24.946/MWh. Note, the resource does not reach a state of charge of 10.85 MWh, as the optimal solution accounts for the uneconomic charging bids during intervals 1 through 8. Instead, the MIO allows the resource to optimally fulfill its self-schedule, given current market conditions. Further information regarding the MIO can be found in Tariff Section 34.5 and Market Operations Business Practice Manual Section 7.8.

Figure 4. Example of MIO for a Storage Resource

Given the MIO process, it is possible for a storage resource to reach a binding interval with an SOC that is close to either of its limits (0% or 100%) and have that remaining SOC preserved in that and several future intervals. This is because MIO might find that the economic solution over the look ahead horizon is to conserve SOC with an uneconomic dispatch in the binding interval so that the asset can be dispatched later (in what is at that time an advisory interval) when the market revenue will exceed the loss in the binding interval. This outcome can theoretically happen to any resource, but given batteries' responsiveness, ramp rates, and limited fuel supply (*i.e.,* SOC), this is especially prevalent for storage assets. As a result, it is possible for a storage asset to be near having a binding SOC constraint in the binding interval but for it to not actually reach either of the SOC limits for several intervals.

This situation materially affects the feasibility of applying a solution that exclusively focuses on the binding interval and whether it has a binding SOC constraint. The Proposed Solution has a fundamental assumption that the dispatch is optimal for the binding interval, meaning that the SOC would be depleted to meet the day-ahead schedule and the storage asset would be at the SOC limit in the next interval, allowing for the Proposed Solution to be triggered. Nevertheless, if the optimal dispatch over the time horizon results in an uneconomic dispatch in the binding interval to preserve the SOC for a subsequent interval, this can be repeated over many RTD runs, thus preserving the SOC for one or several intervals before the Proposed Solution can kick in. Given the fact that both the CESA and Vistra alternatives, as well as the modifications proposed by PG&E and WPTF, would rely on first identifying intervals with a binding SOC constraint, these solutions may also run into the issue of being seldom triggered due to MIO. This materially erodes their effectiveness at resolving Concern 2.

In this context, the ISO is considering that continued development of the Proposed Solution would require modification of its logic to consider advisory intervals. This effort would be similar to recent modifications applied to the ASSOC Constraint. Alternatively, if a solution akin to CESA's proposal is pursued (*i.e.,* one that focuses on modifying the RT Bid component of the RT BCR calculation), this issue could be circumvented by simply applying the modified formula for all intervals, not just intervals with a binding SOC constraint. This alternative may allow for a solution that addresses Concern 2 and is implementable in the near-term. The ISO is committed to continue exploring the merits and tradeoffs of all solutions described in the paper herein, as well as means to enhance them to ensure addressing Concern 2 in the near-term.

7. Governance Classification: Joint Authority

This initiative proposes changes to "California ISO Settlements and Billing", "Bid and Self-Schedule Submission in California ISO", and "Market Power Mitigation Procedures" in the ISO tariff as they relate to bid cost recovery and default energy bid provisions for storage resources. The ISO believes that the WEM Governing Body has joint authority with the ISO Board of Governors over the proposed tariff rule changes.

The ISO Board of Governors and the WEM Governing Body have joint authority over any:

> "[P]roposal to change or establish a tariff rule applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in the WEIM/EDAM. The WEIM/EDAM Governing Body will also have joint authority with the Board of Governors to approve or reject a proposal to change or establish any tariff rule for the day-ahead or real-time markets that directly establishes or changes the formation of any locational marginal price(s) for a product that is common to the overall WEIM or EDAM markets. The scope of this joint authority excludes, without limitation, any other proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid. Note: For the avoidance of any doubt, the joint authority definition is not intended to cover balancing authority-specific measures, such as any parameters or constraints, the CAISO may use to ensure reliable operation within its balancing authority area."[16]

All of the tariff rule changes proposed in this initiative would be "applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in the WEIM/EDAM." None of the proposed tariff rules would be applicable "only to the CAISO balancing authority area or to the CAISO-controlled grid." Accordingly, this initiative falls entirely within the scope of joint authority.

This proposed classification reflects the current state of this initiative and could change as the stakeholder process proceeds. Stakeholders are encouraged to submit a response to this proposed decisional classification in their written comments, particularly if they have concerns or questions.

8. Next Steps

The ISO will hold a stakeholder meeting on this Revised Straw Proposal on September 9, 2024. Comments on this Revised Straw Proposal, as well as the September 9, 2024 stakeholder meeting, will be due September 23, 2024.

[16] Charter for EIM Governance § 2.2.1

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9. Appendix A: Examples of Unwarranted Storage BCR

The examples contained herein are updated versions of the simplified examples shared during the stakeholder process and as part of the IPSP. Graphs in this section seek to provide context to the examples. After each example, a table is presented to compare the outcomes under different BCR approaches; namely: (1) the status quo, (2) the proposed solution, (3) the initial CESA proposal when applied to all intervals, (4) the initial CESA proposal when applied only to intervals with a binding SOC constraint, (5) the updated CESA proposal when applied to all intervals, and (6) the updated CESA proposal when applied only to intervals with a binding SOC constraint.

Example 1: Simplified Buy-Back with Static Bids

Consider a resource that submits day-ahead discharge bids for $75 for all hours of the day-ahead market. In the day-ahead market, LMPs are in the range of $50-$100. This results in the battery asset having a discharge schedule for most of the period covering HE 18 – HE 22. In real-time, the battery asset submits only slightly higher bids to discharge; specifically submitting $80 bids for all intervals of the RTM in a manner aligned with its day-ahead bids. In the RTM, grid conditions are materially different, with prices going above $80 earlier in the day relative to the storage asset's day-ahead schedule. This results in premature dispatch of the asset, triggering a buy-back for the day-ahead discharge awards during the period of HE 18 – HE 22. In this circumstance, the buy-back effectively eliminates exposure to RT conditions, resulting in BCR that fully makes the resource whole. Importantly, under this bidding strategy, the BCR does not attribute the asset additional revenue for not following the day-ahead schedule, but it does make it whole despite the fact that it was not able to perform due to its submission of bids that did not reflect or consider RTM conditions. This, however, could change by pursuing a bidding strategy that seeks to maximize the amount of BCR paid out when triggering the buy-back.

Figure 1 Simplified Buy-Back Example (static bids): LMPs

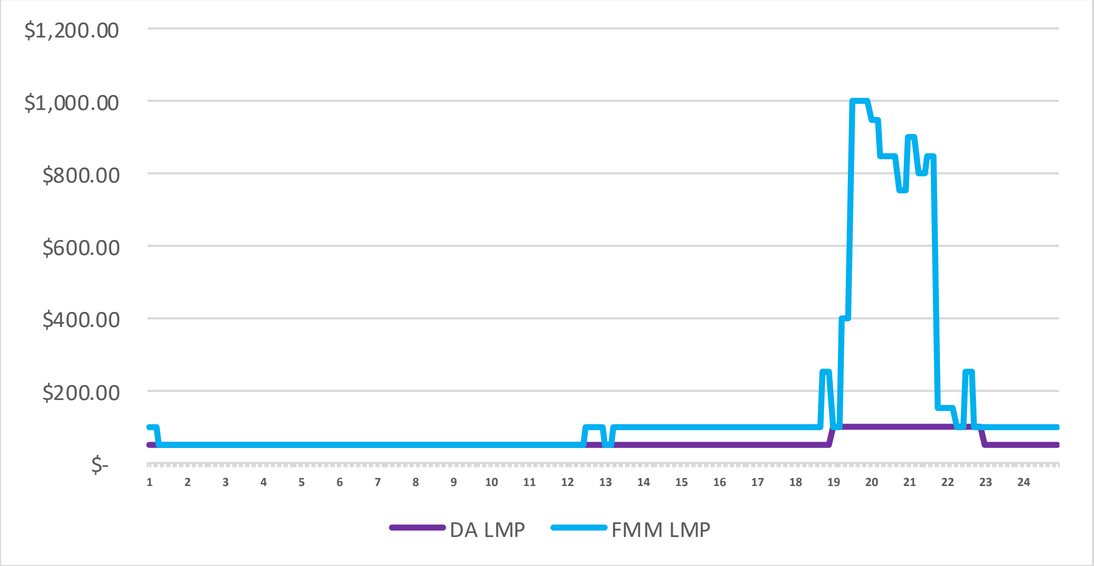

Figure 2 Simplified Buy-Back Example (static bids): Discharge bids

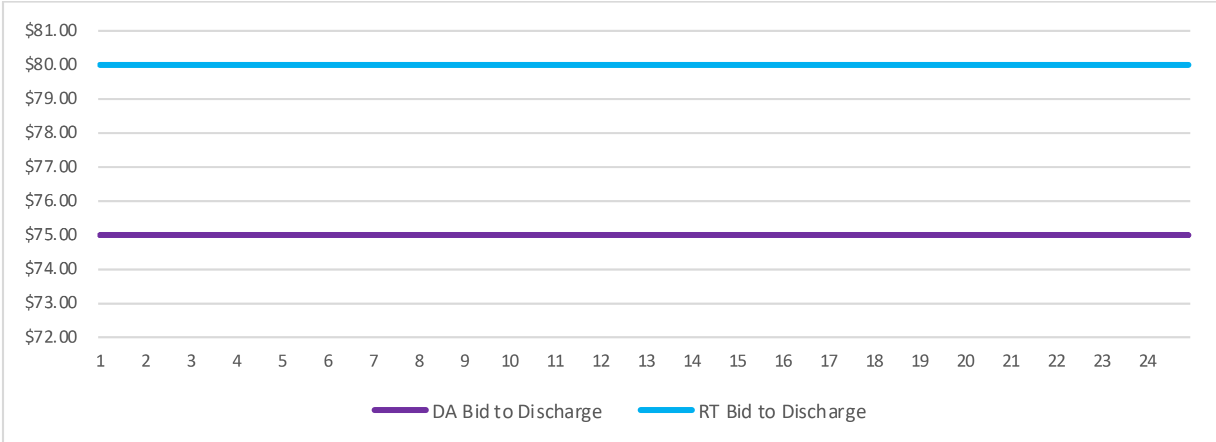

Figure 3 Simplified Buy-Back Example (static bids): Schedules and Dispatch

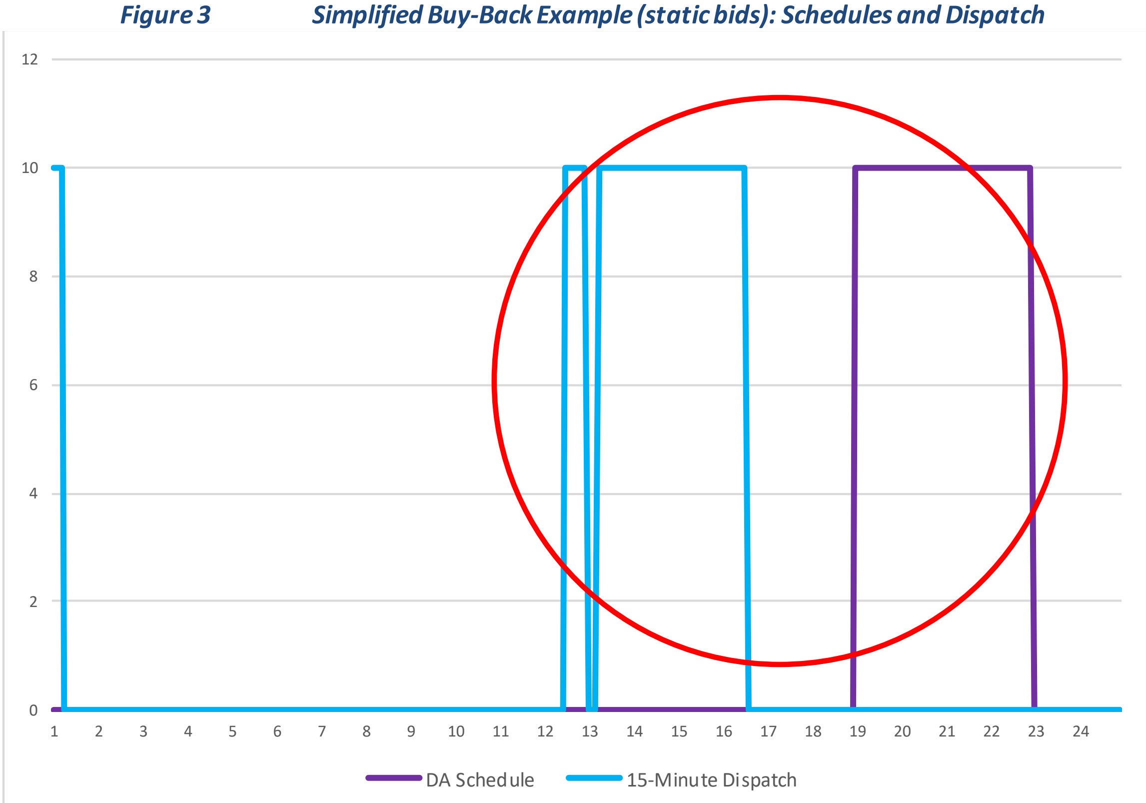

Table 1. Summary of Daily Totals across Different Potential Solutions

Status Quo	RT BCR Shortfall (+)/surplus (-)	$ 227,800.00
	RT BCR distribution (+ = payment to resource)	$ 227,800.00
	Additional revenue from not following DA schedule	$ 800.00
Proposed Solution	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$(227,000.00)
Initial CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ 203,500.00
	RT BCR distribution (+ = payment to resource)	$ 203,500.00
	Additional revenue from not following DA schedule	$ (23,500.00)
Initial CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 218,200.00
	RT BCR distribution (+ = payment to resource)	$ 218,200.00
	Additional revenue from not following DA schedule	$ (8,800.00)
Updated CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ 203,500.00
	RT BCR distribution (+ = payment to resource)	$ 203,500.00
	Additional revenue from not following DA schedule	$ (23,500.00)
Updated CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 218,200.00
	RT BCR distribution (+ = payment to resource)	$ 218,200.00
	Additional revenue from not following DA schedule	$ (8,800.00)

Example 2: Simplified Buy-Back with Modified Bids

Consider the same resource under the same circumstances decides to modify its bids to -$150, the bid floor, for the intervals when it had a discharge day-ahead schedule. Given that the asset has been discharged prematurely, the day-ahead schedule is bought back but now with consideration of the -$150 bid within the calculation. This bidding strategy can result in additional revenues from not following the day-ahead schedule, as shown below. This underscores that the current BCR framework not only disincentives the consideration of RTM conditions for RT bidding by unduly eliminating exposure to RT prices, but also presents the opportunity to pursue a bidding strategy that could result in additional, unwarranted revenue.

Figure 4 Simplified Buy-Back Example (dynamic bids): LMPs

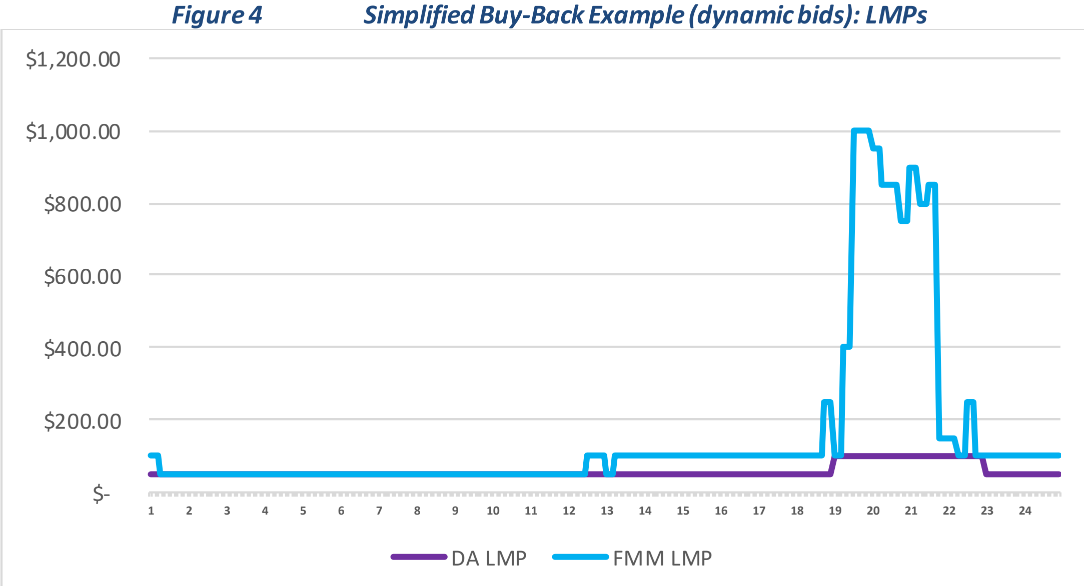

Figure 5 Simplified Buy-Back Example (dynamic bids): Discharge Bids

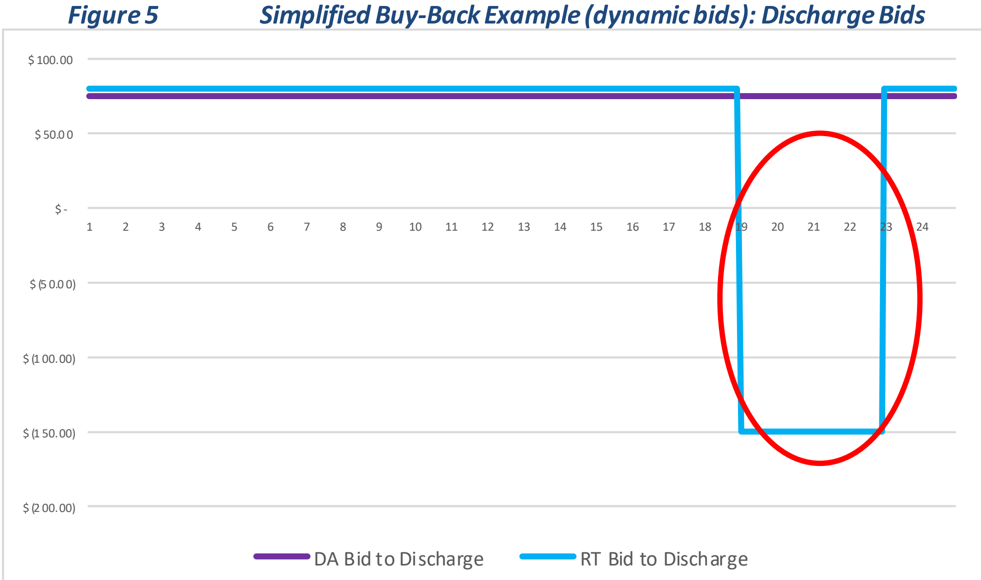

Figure 6 Simplified Buy-Back Example (dynamic bids): Schedules and Dispatch

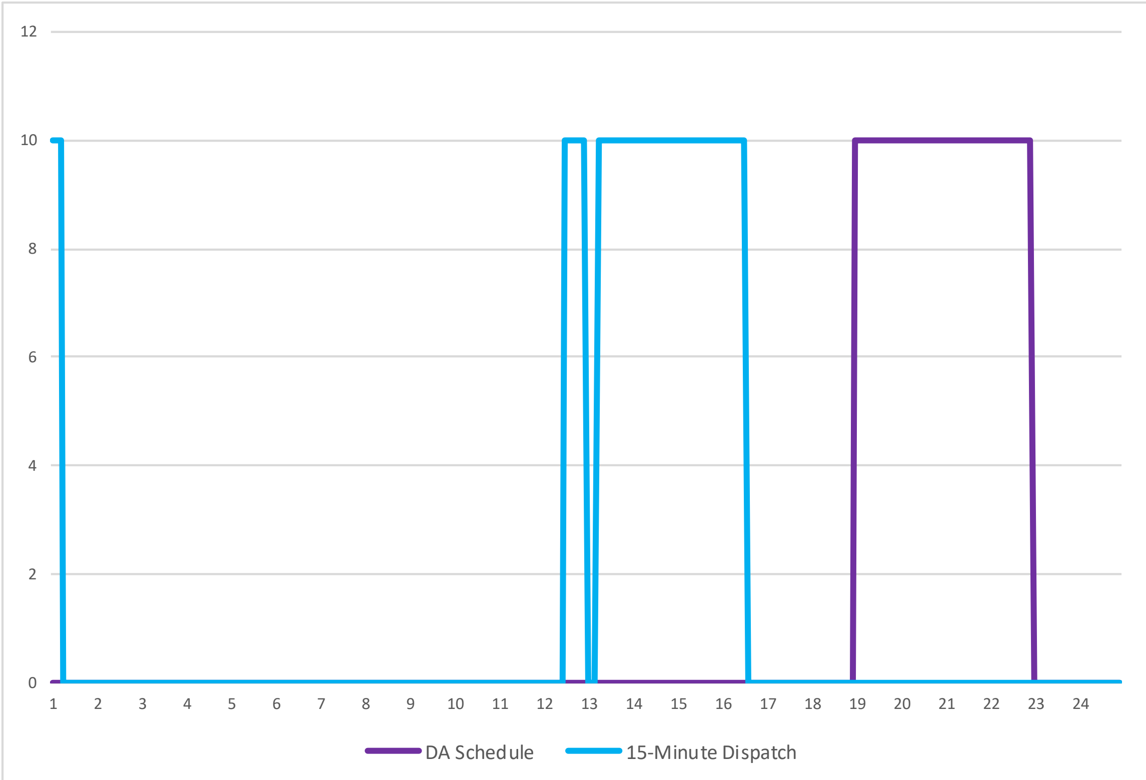

Table 2. Summary of Daily Totals across Different Potential Solutions

Status Quo	RT BCR Shortfall (+)/surplus (-)	$ 338,200.00
	RT BCR distribution (+ = payment to resource)	$ 338,200.00
	Additional revenue from not following DA schedule	$ 111,200.00
Proposed Solution	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$(227,000.00)
Initial CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ 203,500.00
	RT BCR distribution (+ = payment to resource)	$ 203,500.00
	Additional revenue from not following DA schedule	$ (23,500.00)
Initial CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 218,200.00
	RT BCR distribution (+ = payment to resource)	$ 218,200.00
	Additional revenue from not following DA schedule	$ (8,800.00)
Updated CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ 203,500.00
	RT BCR distribution (+ = payment to resource)	$ 203,500.00
	Additional revenue from not following DA schedule	$ (23,500.00)
Updated CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 218,200.00
	RT BCR distribution (+ = payment to resource)	$ 218,200.00
	Additional revenue from not following DA schedule	$ (8,800.00)

Example 3: Simplified Sell-Back with Static Bids

Consider a resource that submits day-ahead charge bids for $10 for all hours. In the day-ahead market, the LMPs reach a level equal or lower than $10 around HE 12 through HE 15, resulting in a day-ahead charging schedule for that period. In the RTM, grid conditions are different, with LMPs being equal or less than $10 earlier in the day relative to the storage asset's day-ahead schedule. Since the storage asset does not have an incentive to modify its bids given the changing system conditions, the asset continues to submit $10 charge bids. This results in the asset being charged prematurely relative to its day-ahead schedule during HE 10 – HE 13. Given this premature charging, a sell-back of the charging schedule occurs, triggering BCR that makes the resource whole without attributing it additional revenues. This, nevertheless, just like the buy-back example, can change by pursuing a bidding strategy focused on maximizing the BCR paid out as a result of the sell-back.

Figure 7 Simplified Sell-Back Example (static bids): LMPs

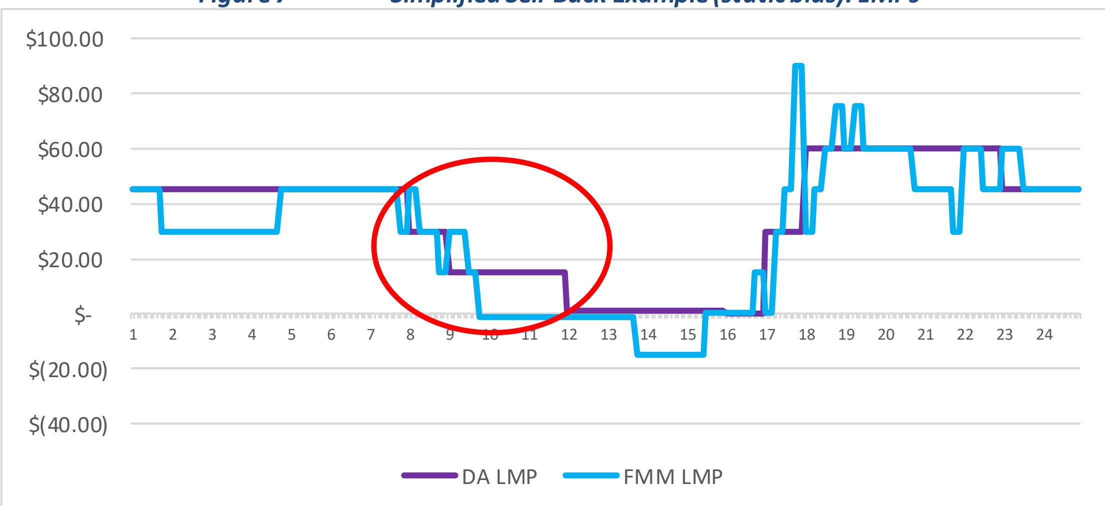

Figure 8 Simplified Sell-Back Example (static bids): Charge bids

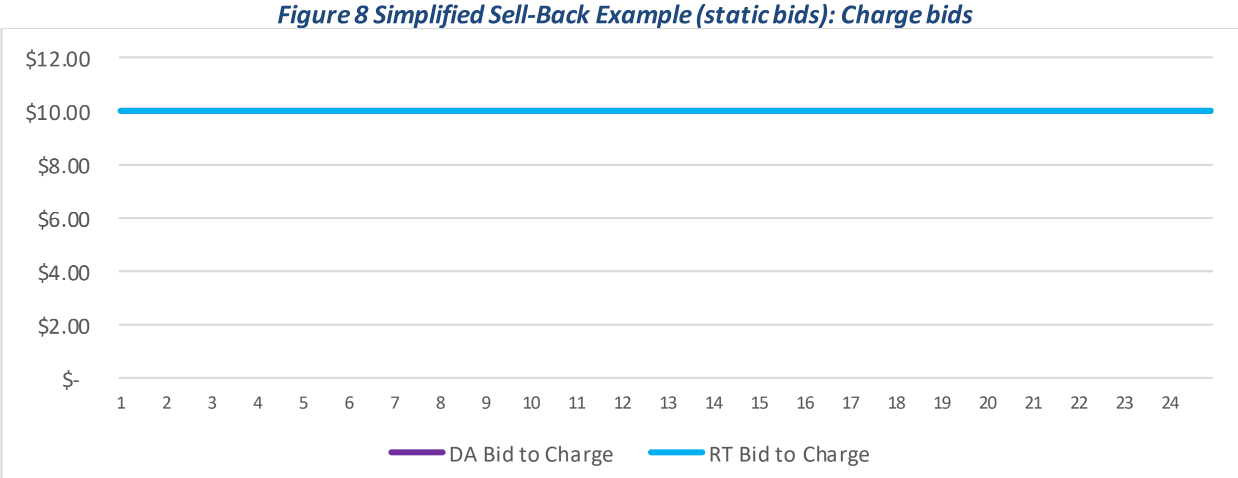

Figure 9 Simplified Sell-Back Example (static bids): Schedules and Dispatch

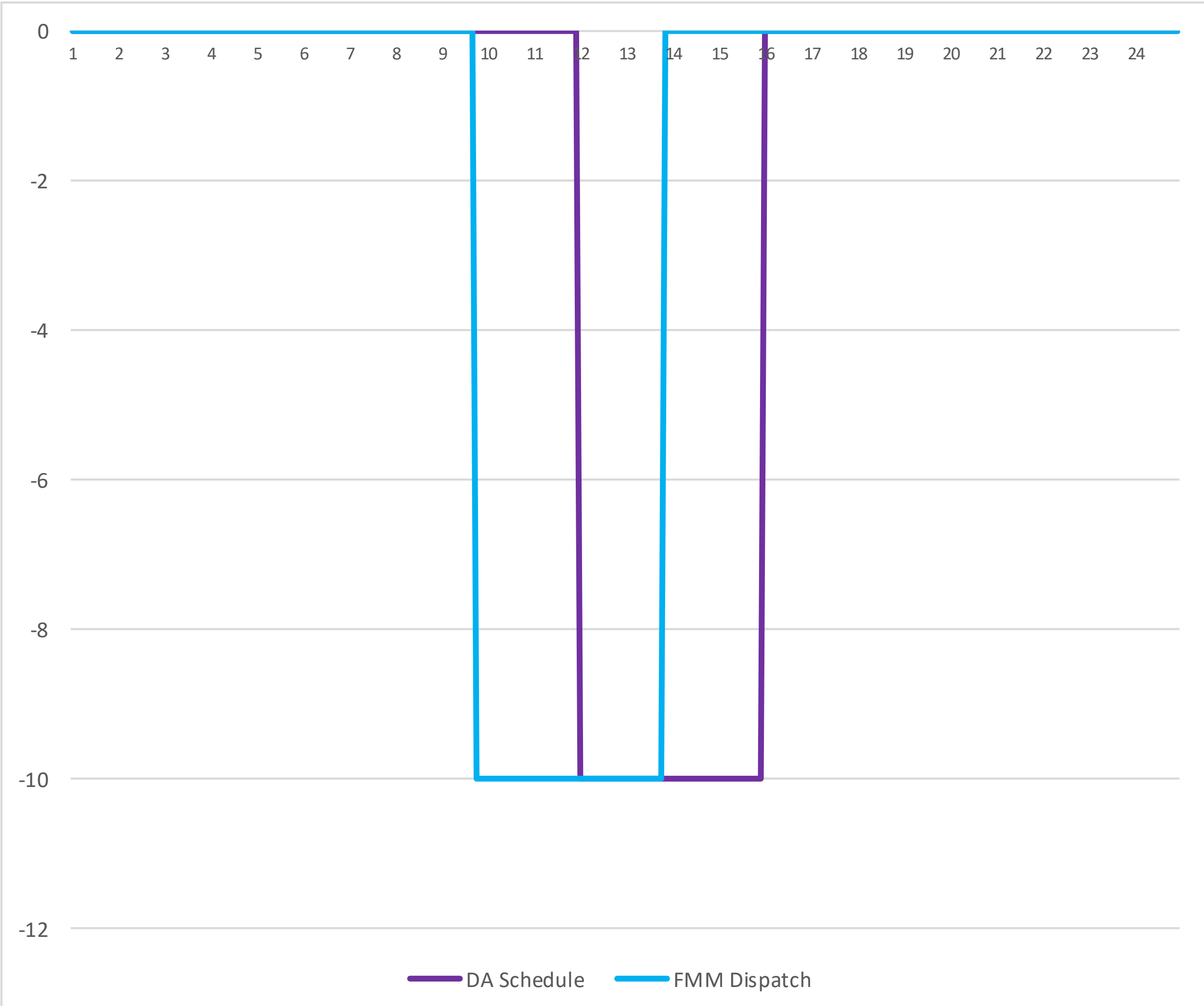

Table 3. Summary of Daily Totals across Different Potential Solutions

Status Quo	RT BCR Shortfall (+)/surplus (-)	$ 2,630.00
	RT BCR distribution (+ = payment to resource)	$ 2,630.00
	Additional revenue from not following DA schedule	$ (100.00)
Proposed Solution	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$(2,730.00)
Initial CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$ (2,730.00)
Initial CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 290.00
	RT BCR distribution (+ = payment to resource)	$ 290.00
	Additional revenue from not following DA schedule	$ (2,440.00)
Updated CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$ (2,730.00)
Updated CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 290.00
	RT BCR distribution (+ = payment to resource)	$ 290.00
	Additional revenue from not following DA schedule	$ (2,440.00)

Example 4: Simplified Sell-Back with Modified Bids

Consider the same resource under the same circumstances decides to modify its bids to the hard offer cap, $2,000, for the intervals when it had a charge day-ahead schedule. Given that the asset has been charged prematurely, the day-ahead schedule is sold back but now with consideration of the $2,000 bid within the calculation. This bidding strategy can result in additional revenues from not following the day-ahead schedule, as shown below. This highlights, once more, that the BCR framework today both disincentives the consideration of RTM conditions for RT bidding by unduly eliminating exposure to RT prices, and presents the opportunity to pursue a bidding strategy that could result in additional, unwarranted revenue.

Figure 10 Simplified Sell-Back Example (dynamics bids): LMPs

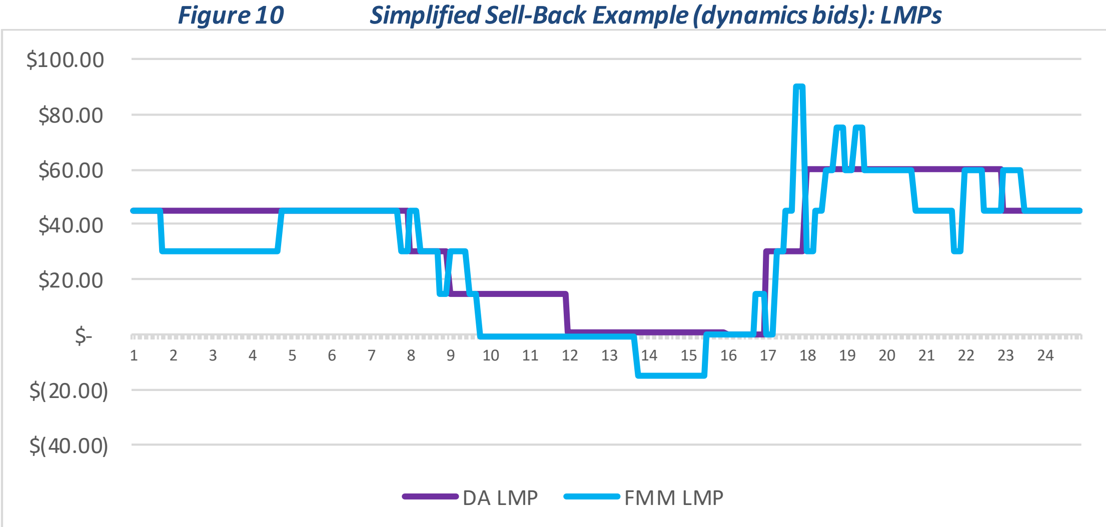

Figure 11 Simplified Sell-Back Example (dynamics bids): Charge Bids

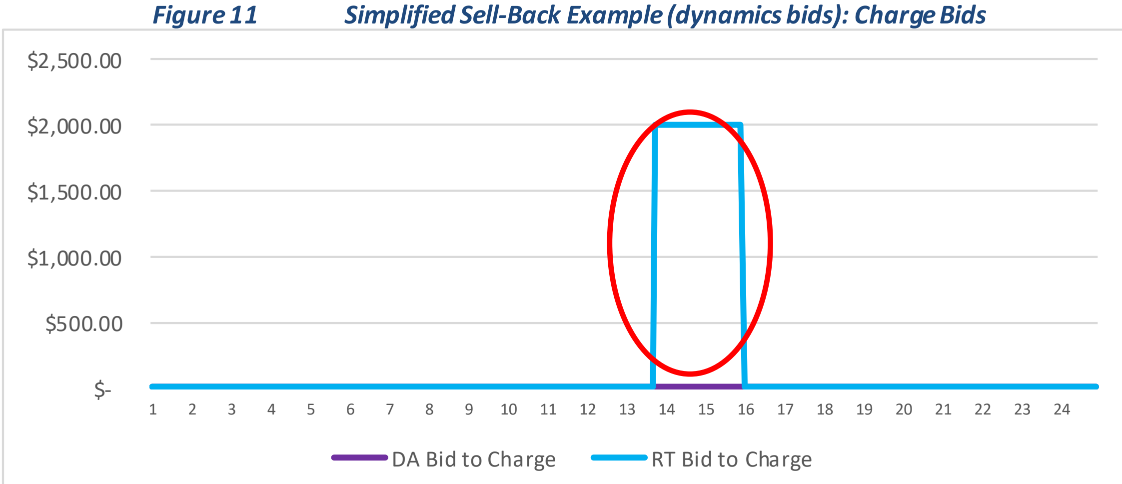

Figure 12 Simplified Sell-Back Example (dynamics bids): Schedules and Dispatch

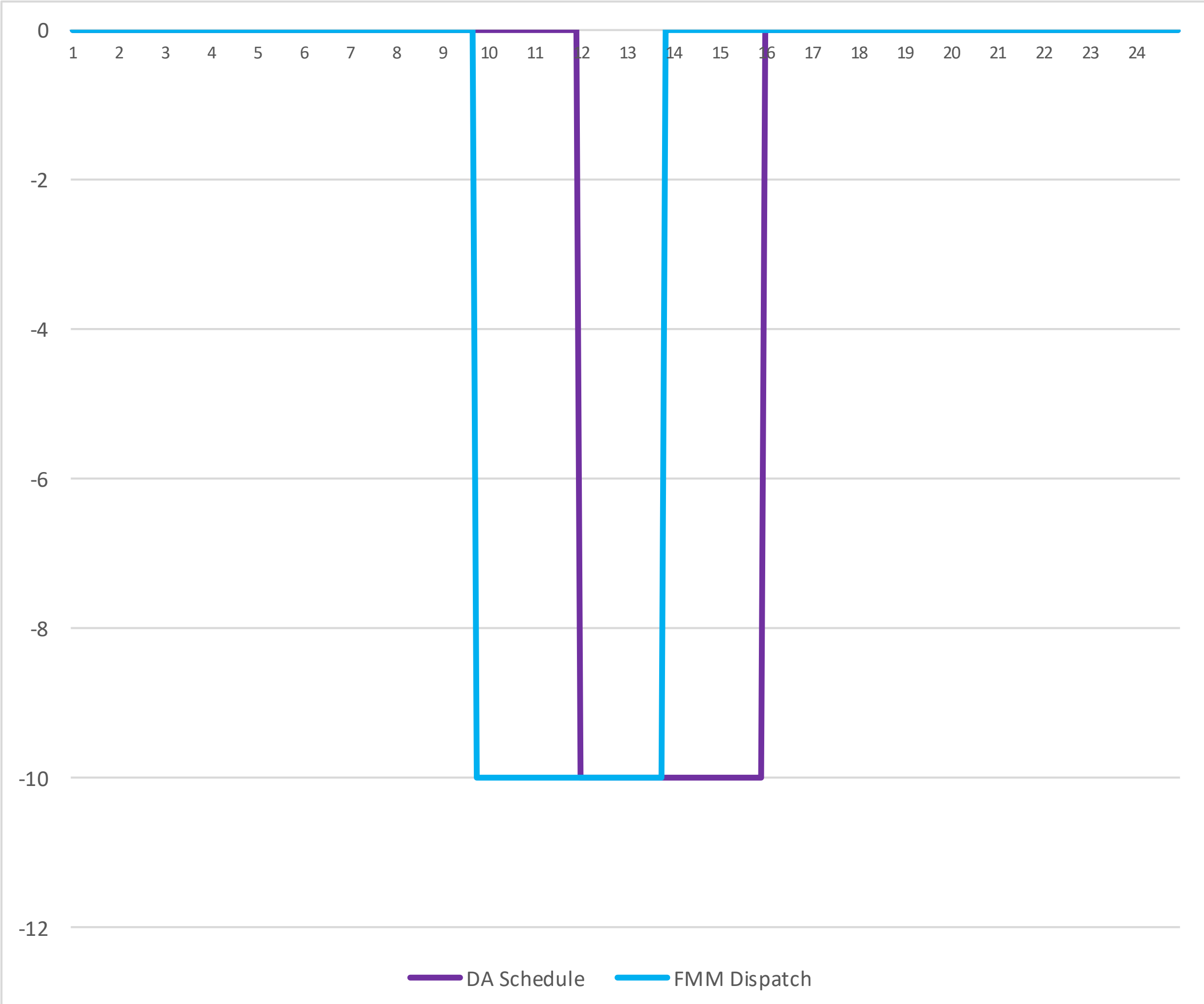

Table 4. Summary of Daily Totals across Different Potential Solutions

Status Quo	RT BCR Shortfall (+)/surplus (-)	$ 520,030.00
	RT BCR distribution (+ = payment to resource)	$ 520,030.00
	Additional revenue from not following DA schedule	$ 517,300.00
Proposed Solution	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$(2,730.00)
Initial CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$ (2,730.00)
Initial CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 290.00
	RT BCR distribution (+ = payment to resource)	$ 290.00
	Additional revenue from not following DA schedule	$ (2,440.00)
Updated CESA Solution / All Intervals	RT BCR Shortfall (+)/surplus (-)	$ -
	RT BCR distribution (+ = payment to resource)	$ -
	Additional revenue from not following DA schedule	$ (2,730.00)
Updated CESA Solution / Only Binding Intervals	RT BCR Shortfall (+)/surplus (-)	$ 290.00
	RT BCR distribution (+ = payment to resource)	$ 290.00
	Additional revenue from not following DA schedule	$ (2,440.00)