

# Opinion on Order 831 Rules for Bidding above the Soft Offer Cap

by

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## 1. Overview

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the CAISO's proposal<sup>2</sup> for revision of offer rules for the summer for 2024 for battery storage and hydropower resources under FERC Order 831. The existing rules for triggering an increase in the \$1000/MWh cap upon resource offers, the resources to which they are applicable, and the details of the calculations are summarized in Section 2, below. The present Order 831 offer rules for battery storage and hydro power as well as the need for revision were discussed most recently by the MSC during a public session of the Committee on April 24, 2024.

The current CAISO market design for managing dispatch over the day for energy-limited resources has a number of unresolved issues, most of which are not related to FERC Order 831 and cannot be addressed for this summer or even next winter.<sup>3</sup> The proposed changes would not

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<sup>1</sup> The participation of Dr. Bushnell, Dr. Harvey, and Dr. Hobbs in this Opinion were as paid consultants for the California ISO. All opinions expressed and implied in this document are solely those of the authors and do not represent or reflect the views of their employers.

<sup>2</sup> CAISO, "Rules for Bidding Above the Soft Offer Cap, Draft Final Proposal", May 2, 2024, [www.caiso.com/InitiativeDocuments/Draft-Final-Proposal-Price-Formation-Enhancements-Redline-May-7-2024.pdf](http://www.caiso.com/InitiativeDocuments/Draft-Final-Proposal-Price-Formation-Enhancements-Redline-May-7-2024.pdf).

<sup>3</sup> Storage scheduling and pricing issues have been a major focus of MSC public meetings and opinions. The MSC has previously written opinions commenting on the ISO's energy storage and distributed resources initiatives (ESDER) and the energy storage enhancements initiative. Within these opinions, we have addressed several specific issues, including bidding rules, market power mitigation (focusing on calculation of storage default energy bids), state of charge scheduling, state of charge management for resources that are procured for ancillary services, and exceptional dispatch.

- J. Bushnell, S.M. Harvey, and B.F. Hobbs, "Opinion on Energy Storage Enhancements Proposal," Market Surveillance Committee of the California ISO, Dec. 6, 2022, [www.caiso.com/Documents/MSCOpiniononEnergyStorageEnhancements.pdf](http://www.caiso.com/Documents/MSCOpiniononEnergyStorageEnhancements.pdf)

resolve all of these problems, but we believe that they would likely contribute to better management of energy-limited resources on very tight supply days during which Order 831 is triggered. These improvements will not necessarily be needed this summer or next winter, but they might be should such supply conditions occur.

The combination of a tightening supply-demand balance in the west and a CAISO resource mix that depends more on batteries than in prior years, means that the occurrence of a relatively low hydro year will result in less margin to compensate for market design flaws that unnecessarily deplete the available supply of energy-limited resources before the hour or hours in which it is most needed. These flaws include limitations on bidding that prevent prices from rising to appropriate scarcity levels during times when load is risk of curtailment (as during several events in 2022-2024), and restrictions on real-time storage offers that can prevent those offers from fully reflecting opportunity costs. In addition, as we emphasized in our ESDER4 opinion, the temporal horizon of the real-time market software is too short to endogenously estimate the opportunity cost of energy considering the full cycling time of resources and how they would be optimally charged and discharged over that cycle. The result can be systematic underestimations of the value of stored energy, and premature discharge of energy prior to when it would be most valuable to serve load.

These problems cannot be adequately addressed by the current mix of out-of-market actions. The ISO's provisions that allow battery operators to specify end-of-hour state of charge (SOC) limits have value only in limited circumstances, as evidenced by the fact that at the present time it is seldom used by battery resource operators. The battery operator's end-of-hour SOC constraint is also inapplicable to hydro resources. Meanwhile, although the CAISO's exceptional dispatch design is improved from last year, it does not apply outside the CAISO balancing area and has potentially serious limitations as the primary mechanism for managing energy-limited resources on days when Order 831 is triggered.

Hence, we agree with the CAISO that changes are needed for this summer to prevent premature discharge of batteries that occurred several times over the past two years. We also agree with the CAISO that it should not try to apply designs that limit the increase in the offer cap across the

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- J. Bushnell, S.M. Harvey, and B.F. Hobbs, "Opinion on Energy Storage and Distributed Energy Resources Phase 4," Market Surveillance Committee of the California ISO, Sept. 9, 2020, [www.caiso.com/Documents/MSC-OpiniononEnergyStorageandDistributedResourcesPhase4-Sep8\\_2020.pdf](http://www.caiso.com/Documents/MSC-OpiniononEnergyStorageandDistributedResourcesPhase4-Sep8_2020.pdf).

During public meetings of the MSC, additional storage issues have been discussed with staff and stakeholders including price formation in real-time advisory intervals and bid cost recovery (Nov. 22, 2022, Sept. 25, 2023). We also issued an opinion previously on Order 831 implementation, focusing on penalty values and allowable offer prices generally, without the focus on storage of the present opinion.

- J. Bushnell, S.M. Harvey, and B.F. Hobbs, "Opinion on Revisions to Import Bidding and Market Parameters for Compliance with FERC Order 831," Market Surveillance Committee of the California ISO, September 9, 2020, [www.caiso.com/Documents/MSC-OpiniononFERC831ImportBiddingandMarketParameters-Sep9\\_2020.pdf](http://www.caiso.com/Documents/MSC-OpiniononFERC831ImportBiddingandMarketParameters-Sep9_2020.pdf).

Western EIM to particular hours or shape the increase over hours. The CAISO has indicated it cannot apply these kinds of limitations for this summer. Furthermore, it does not appear to us that they are a good idea for any summer.

The changes that the CAISO proposes for summer 2024 will not undermine local market power mitigation, nor will they correct the flaws of the existing local market power mitigation design which undermine the use of energy-limited resources to meet load. We agree with stakeholders that the fundamental flaws in the application of local market power mitigation to energy-limited resources need to be corrected, particularly in the context of a CAISO and Western EIM resource mix which is becoming more energy-limited. However, correction of those flaws cannot be undertaken this summer.

There are a number of other possible improvements in the way resource operators and CAISO operators manage the energy limitations of batteries and other energy-limited resources that also cannot be implemented for this summer. This does not change the need to make the changes which the CAISO believes that it can implement by late this summer.

This Opinion is organized as follows. In Section 2, we provide a background summary of Order 831 and the CAISO's present implementation of it, together with an overview of the CAISO's proposal to revise that implementation for the summer of 2024. Then in Section 3, we describe in detail some pricing and scheduling inefficiencies that have been caused over the past two years by not allowing batteries to bid above the soft cap of \$1000/MWh, and by the 75 minute lag between changes in real-time offers and when they go into effect.

In those two sections, we emphasize that the inability of storage resources to fully reflect opportunity costs associated with future prices is an important reason for premature discharge of those resources in some circumstances, but not the only such reason. The root of the opportunity cost problems is that Order 831 was adopted by FERC before there were material amounts of battery capacity in the US, and the Order did not focus on the temporal opportunity cost of resources with short-term energy limits. In particular, the Maximum Import Bid Price (MIBP) introduced by the CAISO in its Order 831 compliance filings was originally designed to measure the opportunity cost of a thermal resource selling its output in another market at the same point in time. However, it is usually the case that the relevant opportunity cost of an energy-limited resource is not the value of its output in another market at the same point in time but the value of its output in a future hour.<sup>4</sup> The resulting mischaracterization of opportunity costs for batteries can significantly distort scheduling of battery charge and discharge and have contributed to the

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<sup>4</sup> In rare cases, the opportunity cost of not selling elsewhere might be relevant to a storage resource, just as it can be for a thermal resource, if that opportunity is higher than the opportunity cost of selling later in the same market. For instance, late in the evening when prices are generally decreasing over time, a storage unit with 1 MWh SOC might conceivably earn more revenue by selling that energy in a neighboring market immediately rather than waiting and selling it later in its own market. However, when opportunity costs for storage are referred to, usually it is foregone revenues in its own market at a later time that are referred to.

inefficiencies summarized in Section 3. However, this mischaracterization is not the only issue contributing to inefficient management of storage, as we discuss in that section. Another example is the time lag in the real-time markets in the implementation of changes in bids and offers, which means that even if resources realize that their discharge offers understate opportunity costs and are causing them to discharge when they shouldn't, the offers cannot be corrected until 75 or more minutes later. In sum, these inefficiencies have led to appreciably higher system costs than necessary, and under tight system conditions could endanger system reliability. We agree with the ISO that this situation should be addressed to the extent feasible this summer. Therefore, the ISO's consideration of reforms to the Order 831 soft cap system is timely.

Then in Section 4 we consider whether use of existing tools available to operators could address these problems, which has been suggested by some stakeholders. These tools include self-scheduling, maintaining a targeted end-of-hour charge, exceptional dispatch by ISO operators, and physical withholding by the resource operators. We conclude that none of those tools by themselves are sufficient to significantly address the problem.

Section 5 addresses the question as to whether it would be desirable to tailor the amount by which storage bids can be raised above the soft cap by the hour of the day. We conclude that even if it were possible to do so in the summer of 2024 that it would not be a desirable feature of a soft bid cap system. We agree with the CAISO Department of Market Monitoring (DMM) that the weights used to shape the Maximum Import Bid Price (MIBP) prices for thermal resources should be calculated using prices for the same day. In other words, the weights were intended to, and should be designed to, "shape" the hourly prices for that day, not to scale hourly prices in a way that the average over all hours is greater or less than the associated multi-hour index price. However, we do not agree that this shaping should be based solely on Integrated Forward Market (IFM) prices. There are no IFM prices for Western EIM trading points outside the CAISO. Consideration needs to be given to informing the calculation of shaping weights for Western EIM regions based on Fifteen Minute Market (FMM) prices relevant to those regions, and which also have the advantage of reflecting more recent conditions.

Section 6 concerns how the CAISO's proposal would affect market power mitigation. First, we consider whether local market power mitigation (LMPM) would be undermined under the ISO's proposal, and remaining features of LMPM for batteries that will continue to present potential risks to system efficiency and reliability. We describe some lessons from past experience with mitigation of battery discharges, and recommend that additional data be reported in the future on the impact of LMPM on battery price offers and operations to inform discussions of further reforms to the Order 831 soft caps that might be considered after 2024. We also conclude that the market price impacts of raising the offer cap for storage will not necessarily increase average prices. We believe that although higher prices might result in intervals in which batteries are presently discharging prematurely, we would expect that greater battery supply in intervals where there is true scarcity would decrease market prices at those times, yielding an overall improvement in market efficiency.

Section 7 begins with a brief overview of the overall benefits that the proposed design would provide to the summer 2024 markets. Subsequent subsections then describe several particular ways in which the proposal's ability to correct the efficiency problems we discuss above are limited. The changes made by the proposal will not address the potential for batteries to be drained of their state of charge before they can adjust their offer prices. They will also not address the potential for battery offer prices to be subjected to inappropriate local market power mitigation that causes them to be dispatched despite their offer prices. Moreover, while the changes might mitigate the impacts of excessive load conformance adjustments and erroneous exceptional dispatch, the changes will not eliminate them. These limitations will need to be addressed in subsequent initiatives by the CAISO in 2025 or later.

Finally, Section 7 closes with some discussion of several other concerns and questions. One is the interaction of higher storage offer caps with reliability demand response (RRDR), which we believe will help to prevent inefficiently early discharge of storage by triggering RRDR earlier. Another is whether there should be changes to day-ahead market offer caps; we do not see a clear need to raise the offer cap for batteries in the IFM. As we have pointed out in prior opinions relating to storage resources, the IFM solves the allocation of battery charging and discharging over the day and efficiently calculates opportunity costs automatically. Another issue is the concern expressed by some stakeholders about potential scarcity that could be created in real-time as a result of price-taking exports in HASP. We believe that this is less of a problem than some stakeholders suggest, but its potential impact is related to decisions by CAISO operator regarding EIM transfers. A final issue we will discuss concerns bid cost recovery for storage resources. We conclude that the proposed changes for summer 2024 will not address the existing issues with BCR for storage, nor any additional issues that may arise if the CAISO operators rely heavily on exceptional dispatch.

## **2. Order 831 Background**

The Federal Energy Regulatory Commission (FERC) issued Order 831 in 2016 in an effort to better align bidding caps with supply costs during extreme conditions. Prior to the order, supply offers in ISO markets had been capped at \$1000/MWh. The order came in the wake of extremely cold periods that coincided with spikes in natural gas prices, which in turn plausibly raised the marginal cost of supply from some natural gas units to above the \$1000 cap. The focus at that time was therefore naturally on providing gas units the ability to submit offers that reflected their short run marginal cost during periods of extreme natural gas prices. As an additional check on potential market power, the order required some form of cost-verification of offers above \$1000/MWh.<sup>5</sup>

The CAISO submitted a filing to comply with order 831 in September 2019. The CAISO's 831 implementation needed to consider several complexities, largely due to its position as the sole

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<sup>5</sup> Order No. 831, pp. 140.

ISO within its region, combined with the prominent role played by hydroelectric facilities and, later, battery storage units within the western electricity market. These factors imply that opportunity costs, rather than directly measured fuel costs, could reasonably drive the supply costs of certain units above \$1000.

In order to account for the opportunity costs of transactions outside the CAISO system, the CAISO 831 implementation of Order 831 can trigger an increase in offer caps when trades in bilateral hubs imply that western prices in some hours are expected to rise above \$1000. This principle is implemented using a formula for a Maximum Import Bid Price (MIBP). The CAISO's implementation also includes a "hard offer cap group," consisting of resources for which cost verification is impractical or not applicable, such as imports, exports, virtual supply, and demand bids. Offers from resources in this group are capped at \$2000/MWh when 831 conditions are triggered.<sup>6</sup>

The MIBP is the current tool used to reflect the opportunity cost of power sales outside of the CAISO market. It takes the maximum of two multi-hour block bilateral index prices (Mid-C, Palo Verde) and shapes them to an hourly price profile using hourly CAISO pricing data from a previous high price day. The shaping is necessary because a multi-hour (e.g., 16 hour) block of power traded at, for example \$500/MWh, represents an average over prices expected to be much lower than \$500 in some hours and much higher than that in other hours. The goal of the shaping formula should be to shape the prices applicable for the current day, and to allow estimation of the maximum hourly values that would be broadly consistent with the multi-hour price average. As DMM comments have indicated,<sup>7</sup> the current implementation does not do this and we agree that it should be adjusted.

The MIBP is the main trigger for allowing bids from transfers, virtuals, and demand response to bid above \$1000. However, offers from hydro and storage units can be traced back to a specific resource, and therefore under the terms of Order 831, those resources are required to have any offers above \$1000 to be subject to cost verification. Unfortunately, given that the "costs" of such units are dominated by opportunity costs in the form of prices associated with later sales opportunities, such verification is difficult to design, both conceptually and practically.

The current CAISO process for cost-verification "builds on the ISO's process for calculating default energy bids (DEBs)."<sup>8</sup> A DEB, typically reserved for local market power mitigation, can

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<sup>6</sup> California ISO, "Price Formation Enhancements: Rules for bidding above the soft offer cap, Issue Paper." April 12, 2024, page 5.

<sup>7</sup> CAISO Department of Market Monitoring, "Comments on Price Formation Enhancements: Rules for Bidding above the Soft Offer Cap Draft Final Proposal," May 8 2024, [www.caiso.com/Documents/DMM-Comments-on-PFE-Rules-for-Bidding-above-the-Soft-Offer-Cap-Draft-Final-Proposal-May-8-2024.pdf](http://www.caiso.com/Documents/DMM-Comments-on-PFE-Rules-for-Bidding-above-the-Soft-Offer-Cap-Draft-Final-Proposal-May-8-2024.pdf).

<sup>8</sup> California ISO, "Price Formation Enhancements: Rules for bidding above the soft offer cap, Issue Paper," op. cit., page 6.

be calculated automatically using pre-determined formulas linked to external indices of natural gas and bilateral electricity prices. The DEB therefore is a natural reference source for costs.

However, several aspects of DEB implementation make its application to Order 831 conditions problematic. First, currently all DEBs are capped at \$1000, even if the underlying DEB formula implies a value above this threshold. This alone makes DEBs a useless tool for cost verification under Order 831 events that, by definition, are triggered by estimated marginal costs above this \$1000/MWh threshold. While there is an established process for natural gas facilities to submit a “Reference Level Change Request” (RLCR) and have their DEB adjusted above \$1000 in a timely manner, this process has not been implemented for hydro or storage units. This means that under current policy, offers from hydro and storage units remain effectively capped at \$1000, even when Order 831 conditions are triggered and the DEB formula would imply values higher than that level, so that higher offers could be allowed.

A second problematic aspect of the reliance upon DEBs for Order 831 implementation is that storage DEBs themselves likely suffer from several problems and are in need of reform. We discuss these aspects in more detail in Section 7, below.

The CAISO proposal makes two primary changes to the current Order 831 implementation. First, it will remove the \$1000 cap on DEBs that current limit the applicability of hydro and storage DEBs to Order 831 conditions.<sup>9</sup> Second, it would create an alternative reference formula, or “proxy cost,” for storage units that can be used to cost justify offers above \$1000. This formula would apply the 4<sup>th</sup> highest “shaped” price from the MIBP profile as a cap on offers across all hours from storage units.<sup>10</sup> These units would also remain subject to local market power mitigation, however, so if the highest DEB is below these levels, offers from mitigated units would be set by the DEB formula and not by the 4<sup>th</sup> highest MIBP.

As we discuss below, the current limits on bidding from storage and hydro units can cause these resources to drain their stored energy prematurely and potentially threaten reliability. These problems are detailed in the following section, which reviews the experience of the last two years. However, our reading of this experience is that, although these offer cap limits are one important reason for this premature drainage problem, there are other problematic features of the ISO markets that that also contribute and therefore also need to be addressed.

### **3. The Problem: Review of Experience 2022-2024**

The concern that the CAISO and Western EIM need to address in this initiative are the dual problems of 1) resources with daily energy or state of charge limits being dispatched in the hours leading up to the net load peak instead of high cost resources that are not energy-limited,

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<sup>9</sup> “Draft Final Proposal,” op. cit., page 14.

<sup>10</sup> Ibid., page 18.

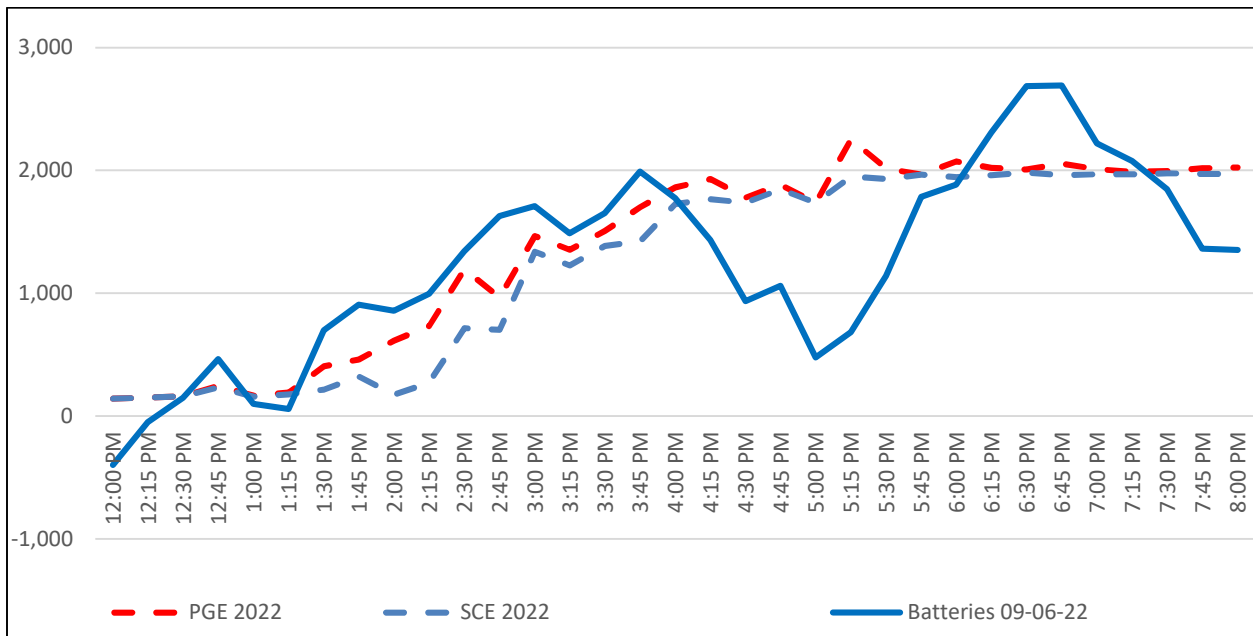
with the result that the energy-limited resources have too little state of charge to cover their day-ahead market schedules over the net load peak; and 2) energy-limited resources that have been dispatched in hours leading up to the net load peak or that are otherwise very tightly energy-limited in their available supply over the net load peak hours being dispatched during the early hours of the net load peak instead of high cost resources that are not energy-limited (including demand response), leaving inadequate energy to cover their day-ahead market schedules over the remaining hours of the net load peak.

We provide context for this concern with a review of issues with the availability of supply from energy storage resources in September 2022, January 2024, August 2023 and July 2023. There are many gaps in the publicly accessible data, but the available data do illustrate the challenges created by the lower bid cap for storage resources on days when Order 831 is in effect due to high costs.

### 3.1 September 6, 2022

Figure 1 below shows the PG&E and SCE LAP prices and battery dispatch on September 6, 2022. The key points illustrated by the figure are:

- battery dispatch rose to 1000 MW before LAP prices rose to \$1000,
- prices in PG&E and SCE LAPs were above \$1000 before the SMEC reached \$1000 and before the triggering of the increase in bid caps under Order 831, and
- battery dispatch was low at 1:15 p.m. then rose at 1:30 p.m. and continued to rise until out-of-merit dispatch by operators began to reduce battery dispatch at 3:30 p.m.



**Figure 1.** LAP Prices and Battery Dispatch on September 6, 2022

Source: Calculated from 5 minute data at [www.aiso.com/TodaysOutlook/Pages/default.aspx](http://www.aiso.com/TodaysOutlook/Pages/default.aspx).



The timing of the market created challenges for managing energy-limited resources in real-time. If battery operators did not respond immediately to the surge in dispatch and raise offers at 1:45 pm, with those offers going into effect at 3 pm, the next time they could raise offers was at 2:45 p.m. Those 2:45 offers would not go into effect until 4 pm, which was too late for offer price increases to avoid depleting a battery's state of charge. Figure 1 shows that batteries were being dispatched at 1500 MW or above between 3 and 4 pm).

The result of the early afternoon dispatch of batteries, combined with the lack of charging of batteries, was that CAISO batteries overall went into the net load peak later that afternoon with too little state of charge to be dispatched at capacity for 4 hours. In addition, some individual batteries likely went into the net load peak period with too little state of charge to cover their day-ahead market schedules over the net load peak.

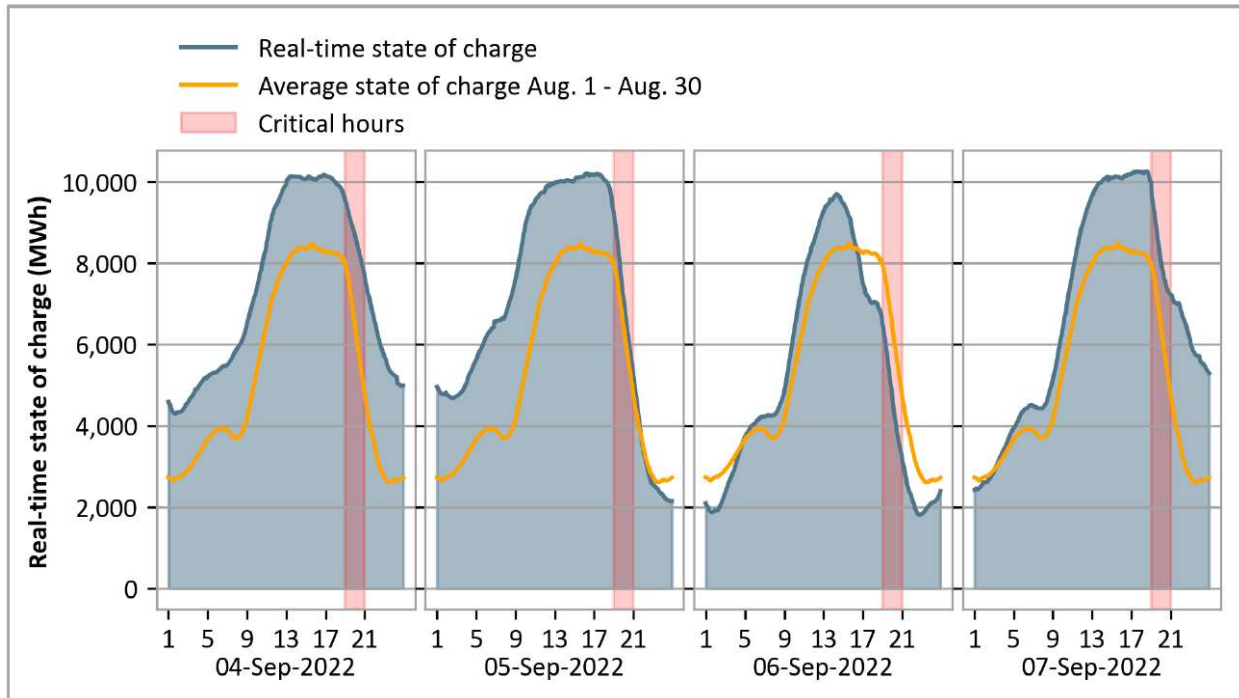
The summer report for September also indicates that the ancillary service state of charge constraint bound for some resources, forcing them to charge, although there is no discussion of the megawatts of battery capacity that were in this position approaching and during the net load peak hours.<sup>11</sup> Resources dispatched to charge by the ancillary services constraint must have been very low on state of charge to trigger that ancillary services constraint.

Figure 2 below, reproduced from the CAISO Department of Market Monitoring's 2022 Battery Report, shows the changes in state of charge over four days of the September 2022 heat wave. One can see that the state of charge started being drawn down far before the net load peak on September 6, and that the CAISO went into hours ending 18-21 with much less charge than on prior September days and less than it had on average during milder conditions in August. The graphic suggests that the state of charge began declining during hour ending 14.<sup>12</sup>

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<sup>11</sup>There is a brief reference to this on p. 153, California ISO, "Summer Market Performance Report, September 2022," November 2, 2022.

<sup>12</sup>Figure 145 in the September 2022 report (ibid.) similarly shows that overall battery state of charge was two or three thousand megawatts lower at the beginning of hour 19 on September 6 than on September 5 or 7, even with extensive operator intervention to reduce dispatch in the prior hours. See California ISO, ibid., pp.149-153.



**Figure 2.** Resource Adequacy Batteries State of Charge September 4-7, 2022

Source: California ISO, Department of Market Monitoring, “Special Report on Battery Storage,” July 7, 2023, p. 34, Figure 3.2.2.

It is not clear why the CAISO batteries were dispatched so heavily during the early afternoon of September 6, 2022. The September summer report stated that the “(n)et schedule interchange tends to reach its lowest levels during the midday hours when plenty of renewable production is available to meet ISO’s needs and any surplus supply can be economic to export. As the system reaches the net load peak and solar production decreases, net scheduled interchange tends to increase.”<sup>13</sup>

However, this is not what happened on September 6, 2022 during the period batteries were being drained. The CAISO was constrained up relative to the desert southwest (EIM east) in FMM and RTD between 13:30 and around 15:20.<sup>14</sup> EIM transfers fell in RTD from 2672 MW at 12:10 to 911.75 MW at 14:50. It is noteworthy that transfers were 3323 MW in FMM at 14:50., around 2400 MW higher than in RTD. This large difference between the FMM and RTD transfers

<sup>13</sup> California ISO, *ibid.*, p. 136

<sup>14</sup> See [www.caiso.com/Documents/Real-TimeDailyMarketWatchSep06-2022.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchSep06-2022.html).

likely contributed to the draining batteries beginning at 13:30.<sup>15</sup> Subsequently, prices were low in EIM east until around 15:00 while prices were high in PGE and batteries being drained in the CAISO.

There was no similar increase in prices early in the afternoon on September 5, so there was no similar draining of battery state of charge.

Had batteries possessed the ability to offer supply above the soft bid cap during the afternoon on September 6, 2022, that would only have potentially impacted the dispatch of perhaps a few hundred megawatts of batteries that were offered at the soft cap during those hours.<sup>16</sup> The main problem impacting the dispatch of batteries during that afternoon was the long lag time in batteries being able to change their offer prices when their dispatch changed at 13:30. Moreover, it is not clear what other resources were available for dispatch had the batteries been able to increase their offer prices.

The CAISO has portrayed the upper end of the offer curve for the Western EIM on September 6, 2022 during hour ending 19 during the net load peak. That graphic shows what appears to be a thousand or so megawatts of hydro and batteries offered at the soft cap, along with around a couple thousand MW of gas and a few hundred megawatts of reliability demand response and other generation.<sup>17</sup> We do not know how much of the gas would actually have been available to replace batteries and hydro in the CAISO dispatch, as we do not know where the gas was located, and the CAISO and eastern EIM were transmission constrained for imports from EIM North. We similarly do not know how much of the hydro offering at \$1000 was located in the CAISO, rather than the Pacific Northwest where it would not have been dispatched in any case because prices were far lower.

Figure 1 above shows a substantial decline in the dispatch of batteries after 15.45 and hitting a minimum at 17:00. The cause of this decline is not entirely clear from the September summer report. Some decline might have been due to increased ancillary services schedules.<sup>18</sup> The CAISO also mentions some exceptional dispatch ending hour 17 and 18, but this was only around 350 MW.<sup>19</sup> The September report also indicates that the end-of-hour state of charge constraint was binding on about half of the batteries for hour ending 18, but it appears to have

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<sup>15</sup> Figure 129 in the September 2022 Summer report, *op. cit.*, also shows overall WEIM transfers falling rapidly from over 2000 MW starting sometime after 13:00 and hitting a low of around 100 MW around 16:00.

<sup>16</sup> See California ISO, Department of Market Monitoring, “Comments on Price Formation Enhancements,” April 30, 2024, Figure 2.

<sup>17</sup> See California ISO, “Price formation enhancements: Rules for bidding above the soft offer cap straw proposal discussion,” Market Surveillance Committee Meeting, April 24, 2024, slide 23.

<sup>18</sup> See September 2022 Summer report, *op. cit.*, p. 148, Figure 144.

<sup>19</sup> See *ibid.*, pp. 150-152, Figure 148.

bound only on 1 or 2 batteries for hour ending 17.<sup>20</sup> Perhaps some batteries simply had no charge left by 15:45, or, alternatively, net battery output was reduced by some batteries charging to meet the ancillary service state of charge constraint, offsetting other batteries being dispatched. While it is uncertain what happened to arrest the decline in state of charge between 15:45 and 17:00, it is clear that battery state of charge was prematurely depleted and then something happened to reduce battery dispatch to around zero.

The impact of the premature dispatch of batteries on September 6 was that the CAISO was unable to meet its contingency reserves with its available resources and had to arm up to 800 MW of load for shedding in order to meet WECC requirements.<sup>21</sup>

This premature dispatch is shown in Figure 1 based on publicly available 5-minute output data for batteries on September 6, 2022. One can clearly see the decline in battery output from 15:45 to 17:45 and that the output of batteries was materially below a rough estimate of 2500 MW estimate of battery capacity during much of the period from 17:45-21:00 in which the CAISO had to rely on arming load for load shedding for reserves, allowing it to dispatch a portion of its contingency reserves to meet load.<sup>22</sup>

There is no discussion in the September Report of what factors caused the varying output of batteries over the period in which the CAISO was dispatching contingency reserves to meet load. Perhaps the issue was that individual batteries were not following dispatch instructions or net output was being reduced by batteries that were charging as a result of the ancillary service state of charge constraint. It is also possible that the reduced battery output reflected the impact of the operator exceptional dispatch and end-of-hour constraint decisions. There was no discussion in the September report of how well the operators managed the availability of storage resource output over this period.

### **3.2 January 16, 2024**

The January, 2024 cold spell in the Pacific Northwest was more of a typical Order 831 event where the Order is triggered by very high gas prices. As discussed in the CAISO report on that event, gas prices for the 4 day weekend gas package reached levels around \$25/mmbtu at a variety of locations in the west.<sup>23</sup> There was considerable variation in reported gas prices for the weekend package, with reported prices at Stanfield averaging \$21.85, but ranging up to \$35.<sup>24</sup> Because the reported price was a 4-day weekend package over a holiday weekend, the package price is not necessarily reflective of the cost of buying gas for January 13 or 14.

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<sup>20</sup> See September 2022 Summer report, op. cit., Figure 150, p. 154.

<sup>21</sup> See *ibid.*, p. 169 (Figure 164, “Arming load is the last step before rolling blackouts.”)

<sup>22</sup> See *ibid.*, Figure 164, p. 169

<sup>23</sup> See California ISO, “Winter conditions report for January 2024,” March 6, 2024, particularly pp.19-23.

<sup>24</sup> See NGI Daily Gas Price Index, January 16,2024.

The MSC does not have access to data on daily gas prices on January 13 or 14 (gas prices for individual days, as opposed to the publicly available 4-day weekend block price which reflects a sort of average value over multiple days), and there is no discussion of daily gas prices in either the PowerEx or CAISO reports on the cold wave.<sup>25</sup> We may know more about gas prices and costs on the individual days when DMM publishes its report covering first quarter 2024. Figure 4 in the CAISO January report shows that the departure from normal temperatures at the BPA locations was larger on the 13<sup>th</sup> and 14<sup>th</sup> than on the 15<sup>th</sup> and 16<sup>th</sup>, so the price of gas for those individual days was likely higher than the price for the weekend package. A generator could buy gas for the weekend to meet its load on the 13<sup>th</sup> and 14<sup>th</sup> but then it would incur a loss selling the gas it did not need on the 15<sup>th</sup> and 16<sup>th</sup>, so the effective cost of gas for the day would be higher than the price of the weekend package. Power prices were materially lower over most of the day on January 16 than on prior days, consistent with warming temperatures.<sup>26</sup>

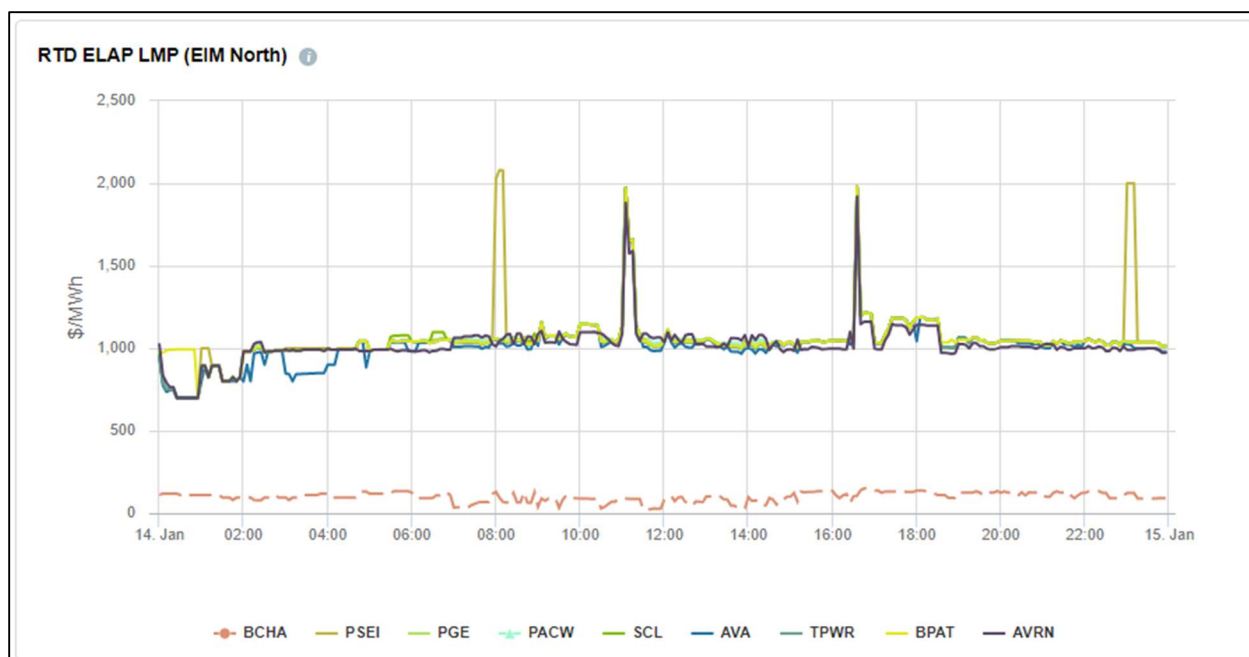
3 shows the EIM North RTD prices over the day on January 14, 2024. There was only a short period of low prices. Prices were at the soft cap all day after about 3 a.m., so we cannot discern from this data when the most stressed hours actually were and what opportunity costs would have been appropriate to use in particular hours. This subject could be studied for possible refinements for 2025 and 2026, but for now there is no basis for assuming that the maximum import bid price (MIBP) offer shape is appropriate to Pacific Northwest conditions.

EIM North prices were at \$1000 across the entire day on Jan 14, 2024, while prices in the CAISO were less than \$200 or even negative.

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<sup>25</sup> California ISO, “Winter conditions report, for January 2024,” *op. cit.*, and PowerEx, “Analysis of the January 2024 Winter Weather Event,” March 6, 2024.

<sup>26</sup> [www.caiso.com/Documents/Real-TimeDailyMarketWatchJan16-2024.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchJan16-2024.html).



**Figure 3.** RTD LMPs for EIM North, Jan. 13, 2024

Source : [www.caiso.com/Documents/Real-TimeDailyMarketWatchJan14-2024.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchJan14-2024.html)

Neither the PowerEx nor CAISO reports<sup>27</sup> discuss the extent to which the management of energy-limited hydro was impacted by the soft bid cap. But the CAISO has published some information on the Western EIM supply curve and dispatch. First, the CAISO winter report shows what appears to be pretty flat gas-fired generation output over the days in EIM north over the period January 13 to 15.<sup>28</sup> This flat output is consistent with gas-fired generation being infra-marginal and operating at capacity throughout the critical days. However, it could also be consistent with some high cost-gas-fired generation not being offered because of the offer cap. Perhaps gas-fired generation lacked the cost-basis to justify a bid above the soft cap as required by Order 831.<sup>29</sup> Second, the CAISO supply stack graphic for the Western EIM for hour 19 on January 15 shows only a small amount of gas-fired generation offered at the bid cap, with mostly batteries and hydro offered around the cap. It appears that on January 15 virtually all of the gas-

<sup>27</sup> Ibid.

<sup>28</sup> See California ISO, “Winter conditions report, for January 2024,” op. cit., Figures 34-36, pp. 41-42.

<sup>29</sup> On the other hand, while the focus of this opinion is on batteries and hydro there was no discussion in the January report of whether there were requests for reference level adjustments or of whether they were granted, nor of how the automatic adjustments worked. Similarly, the graphic portrayed of headroom on start-up and minimum load offers is aggregated over the western EIM and does not focus on conditions in the Pacific Northwest.

fired generation was offered at prices of \$500 or below.<sup>30</sup> However, gas prices may have been higher on January 13 and 14 and the 1000 offer cap may have been binding for more gas-fired generation supply than on January 15.

Third, more recently, the CAISO published a portrayal of the Western EIM supply curve for hour ending 19 on January 14, 2024. This figure shows what appears to be a few thousand megawatts of hydro offered at the soft cap, a few hundred megawatts of gas-fired generation offered at the bid cap, and around a thousand megawatts of batteries offer at the soft cap.<sup>31</sup> The batteries were presumably located in the CAISO so could not have been dispatched to meet Pacific Northwest load, but we do not know if all of the hydro and gas was in the Pacific Northwest or if some was located in the CAISO and not relevant for meeting load in the Pacific Northwest. The compressed scale of the figures makes it hard to tell if the amount of gas offered at the cap was much different between January 14 and 15. However, RTD prices were not always at the cap on January 15, suggesting that supply was less stretched on January 15 than on the 14<sup>th</sup>, except for the transmission-constrained BPA balancing area.<sup>32</sup>

The PowerEx report includes a graphic portraying emergencies declared by several balancing areas during the cold spell. This graphic indicates that one balancing area had emergencies in the morning rather than in the evening, another had an emergency starting a little after noon on January 13 and continuing into the evening, and yet another had emergencies lasting most of the day on January 14 and 15. The pattern of system emergency hours portrayed in the PowerEx graphic is another indication that basing the shaping of the MIBP solely on CAISO IFM prices is not always appropriate for EIM balancing areas.

### **3.3 August 16, 2023**

Figure 4 below shows that between 15:45 to around 16:55 on August 16, 2023, prices rose to over \$700 and up to the bid cap in RTD in all of the CAISO LAPs and in virtually all EIM East balancing areas. RTD prices were lower in the Pacific Northwest, which was apparently constrained down relative to the CAISO and EIM East. The minimum state of charge constraint was apparently binding for about 20 resources during this price spike.<sup>33</sup> The binding minimum charge constraint had the effect that the batteries could not be dispatched even when prices rose to the price cap because load could not be met.

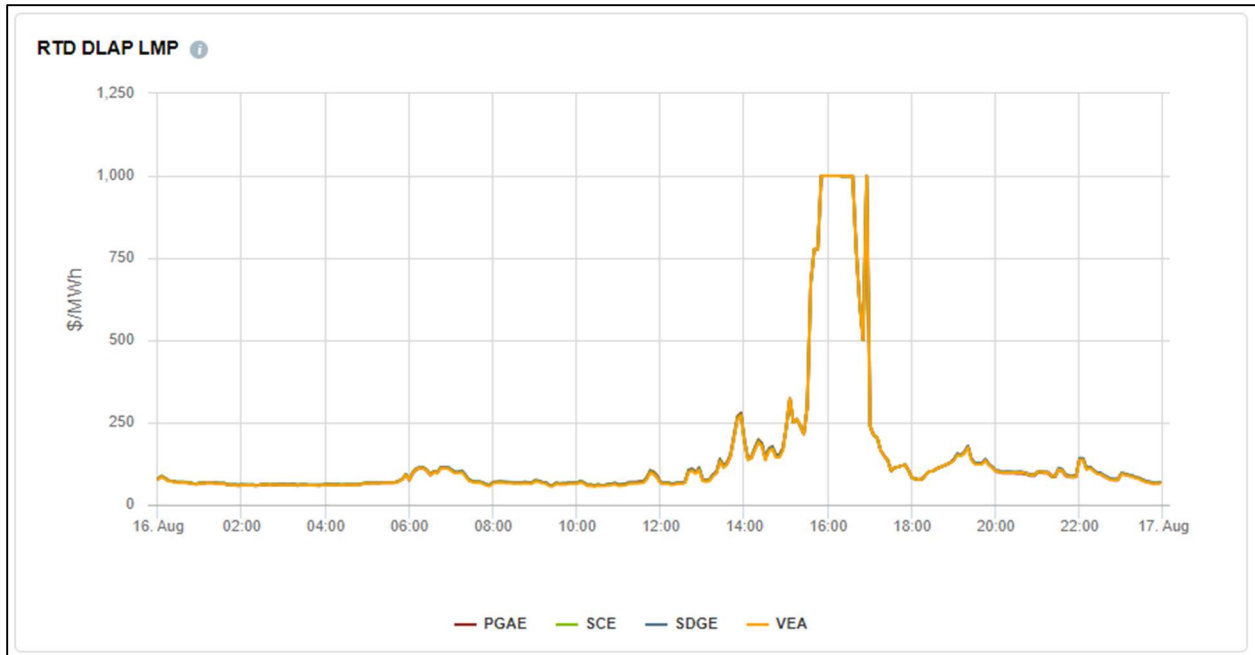
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<sup>30</sup> See *ibid.*, Figure 63, p. 67.

<sup>31</sup> See California ISO, “Price formation enhancements: rules for bidding above the soft offer cap straw proposal discussion,” Market Surveillance Committee Meeting, April 24, 2024, slide 27.

<sup>32</sup> See [www.caiso.com/Documents/Real-TimeDailyMarketWatchJan14-2024.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchJan14-2024.html) and [www.caiso.com/Documents/Real-TimeDailyMarketWatchJan15-2024.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchJan15-2024.html)

<sup>33</sup> See August Summer report, *op. cit.*, pp. 86-88, Figure 82, and [www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html)



**Figure 4.** RTD Prices in Four CAISO DLAPs, August 16, 2023

Source: [www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html)

There is essentially no discussion of the causes of this price spike in the August 2023 summer report. The CAISO was not transmission constrained relative to most of EIM East during this period so the application of the end-of-hour SOC constraint resulted in a large increase in EIM transfers over the hour in both the FMM and RTD, and RTD prices rose in both the CAISO and EIM east. The impact of the CAISO operators applying the end-of-hour constraint was the same as if the offer prices of the impacted batteries had been increased above \$1000. The impact of the CAISO end-of-hour constraint is also similar to the impact of exceptional dispatch with a binding state of charge floor.

The price spike beginning at 15:45 was not associated with congestion between the CAISO and EIM east. While there were high RTD load conformance adjustments in this period, the timing of the changes in load conformance does not appear to be closely aligned with the increases and decreases in RTD, so that the load conformance adjustments cannot be clearly identified as the cause of the price spike. Moreover, prices mostly remained below \$300 in FMM.<sup>34</sup>

In any case, battery operators could not have seen this sudden price spike and would have no reason to have adjusted their offers an hour before so as to maintain their state of charge. An eyeball estimate based on DMM’s tabulation of offers for August 16, 2023 suggests that less

<sup>34</sup> [www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html)



than 1000 MW of battery capacity was offered around the bid cap, and therefore might have been offered above \$1000 had a higher bid cap been in effect.<sup>35</sup>

There is no reason to believe that batteries offering supply at prices below \$1000 would have submitted higher offers had the price cap been higher.<sup>36</sup> This suggests that no more than 1000 MW of batteries might have submitted higher offer prices that would have limited their dispatch had the bid cap been higher.

Without CAISO discussion of what caused this price spike, it is hard to assess how higher offer prices on 1000 MW or so of batteries would have changed the outcome. There is no discussion of the use of exceptional dispatch, and reports of the use of the minimum state of charge constraint are very sparse. Figures 83 and 84 on page 88 of the August Summer Report appear to indicate that the megawatts constrained by a minimum state of charge constraint rose a couple thousand megawatts at the beginning of hour ending 17 (in line with the timing of the price spike in RTD), and that the number of battery resources with a binding constraint rose from one or two to around 20.

It is possible that it was binding minimum state of charge constraints that caused the price spike by suddenly reducing the battery capacity available for dispatch. If so, this would be an illustration of the complexity of managing battery state of charge with inflexible out of market constraints such as exceptional dispatch rather than offer prices. It also illustrates the risk that operators' use of exceptional dispatch constraints to manage state of charge would inadvertently cause clearing prices to rise to the hard cap. The capacity not available because the CAISO operator applied the state of charge constraint to 20 or so batteries meant that this capacity was not available at any price. Had Order 831 been in effect, the price would perhaps have gone to \$2000.<sup>37</sup> Without more discussion it is impossible to draw conclusions regarding how this price spike would have been impacted by greater battery offer price flexibility.

One might have expected prices to also rise in FMM as a result of the binding end-of-hour state of charge constraint for hour ending 17, but this is not the case. The CAISO August report does not discuss when the end of hour constraint became effective in RTPD. If the constraint was inserted after the FMM had already been initialized for the first three intervals of FMM for hour ending 17, this would account for FMM prices only rising for the 16:45 FMM interval, then falling again when the constraint was no longer binding for a number of resources for hour ending 18.<sup>38</sup>

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<sup>35</sup> See California ISO, Department of Market Monitoring, "Comments on Price Formation Enhancements," April 30, 2024, Figure 4.

<sup>36</sup> Ibid.

<sup>37</sup> See August Summer report, op. cit., pp. 86-88, Figures 82 to 84

<sup>38</sup> The MSC does not have ready access to FMM battery output data to confirm that battery output was higher in FMM than in RTD.

The real-time market impact of the application of CAISO operator constraints on batteries would have been that they sold their output at low prices in FMM, then bought the power back at \$1000/MWh prices in RTD. This difference would have been several hundred dollars per MWh. While bid-cost recovery (BCR) would ensure that the resources would have been made whole for losses over the day as a result of the out-of-market dispatch, but the resources would still lose any profits from balancing provided earlier or later in the day.

With the new exceptional dispatch BCR rules in effect, as we understand the BCR calculation, the resources that are dispatched down out-of-merit would have their BCR calculated relative to an optimal dispatch based upon the high RTD prices. This optimal dispatch is compared to profits actually earned as a result of being dispatched down. If the resources were managing their own state of charge with their offer prices and been dispatched down because of their offer prices, they would not be eligible for BCR.

An hour or so later on August 16, FMM prices rose to the \$2000 cap over most of the FMM intervals from 18:00 to 19:00 due to a 4000+ MW load conformance in FMM.<sup>39</sup> This load conformance caused FMM load to exceed the supply that was available at any price, resulting in power balance violations or the market clearing being based on reliability demand response (RRDR).

The RTD price ranged from \$75 to \$125 in the CAISO during that hour.<sup>40</sup> In fact, RTD prices did not reach \$250 the rest of the day. There were no elevated prices in RTD due to lack of battery supply nor were their high prices due to an exercise of market power through high offer prices.

There appears during this hour to have been perhaps questionable decision making on the part of the CAISO associated with the load conformance adjustment. This adjustment had the effect of buying power at \$2000 in FMM and selling it back at \$125 in RTD.

It is possible that this load conformance was intended to preserve battery state of charge by increasing HASP net imports or perhaps causing additional units to be committed, possibly to ensure the delivery of ramp capability (the modeling of additional constraints in the FRU nodal dispatch occurred in later that year in September). If that was the case, we speculate that the intent may have been to reduce net imports in HASP and commit more units to pass the RSE, or perhaps the magnitude of the adjustment was in response to the software bugs that led to operating problems in July that had not yet been resolved (or perhaps even identified). The August report did not discuss the market impact of the large load conformance adjustments on this day or their rationale. But, in our opinion, the very costly outcome appears to indicate that much too much load conformance adjustment was applied.

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<sup>39</sup> [www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html](http://www.caiso.com/Documents/Real-TimeDailyMarketWatchAug16-2023.html). Note that the load conformance values are not in publicly available data.

<sup>40</sup> Ibid.

### 3.4 July 2023

The CAISO had some large power balance violations in late July that apparently were in part due to lack of battery supply.<sup>41</sup> It is difficult to draw lessons from these events because we now know that the outcomes on these days were in part a result of software bugs that were only identified much later.

Because the report on July 2023 was compiled before the cause of the problem was identified, we will not review that discussion. We note that the end-of-hour constraint was not used and there does not appear to have been any use of exceptional dispatch to manage battery state of charge.<sup>42</sup> However, there were periods in which the CAISO was unable to balance net load and suggestions that this was due to inadequate battery state of charge.

### 3.5 Review of Experience: Conclusion

There have been challenges for battery operators and CAISO operators in managing state of charge on the type of day when Order 831 triggers. The megawatts of battery supply constrained by the soft offer cap are generally less than 1000 MW. Most batteries are offering well below the bid cap on days when Order 831 triggered. For most batteries it does not appear that the bid cap is the key issue in managing state of charge, it seems more likely to us that the problem is the long time lag involved in changing offer prices. This lag can create situations where, by the time the battery operator can increase its offer price to reduce dispatch of the battery, it is too late. This problem will not be fixed by changes to the Order 831 soft cap. This limitation of the current CAISO market design also applies to the operators of hydro resources.

The record of CAISO operator actions in managing state of charge is also mixed. Exceptional dispatch and operator state of charge constraints were apparently applied too late to avoid the need to arm load for possible curtailment on September 6, 2022. Conversely, CAISO out-of-market SOC management tools were not being used at all on the July 2023 heatwave days on which there were large power balance violations, apparently due in part to limits arising from battery state of charge. On the other hand, perhaps the application of CAISO out-of-market constraints to too many batteries on August 16, 2023 caused a price spike in RTD.

We know little about the impact of energy limits and the soft cap on the dispatch of hydro in general and particularly in the Western EIM outside California. We are also in the dark about how the CAISO dispatch and the offer cap impacted the need of some balancing areas to declare emergencies during the January cold wave. Fragments of data published by the CAISO show that some hydro and gas was offered at the soft cap on those days, but, unfortunately, we do not know where the capacity was located nor the nature of the energy limits impacting those hydro resources.

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<sup>41</sup> See California ISO, “Summer Market Performance Report July 2023,” Sept 18, 2023, pp. 111-115

<sup>42</sup> See *ibid.*, pp. 89, 107-108.

Another complication is that the ability of storage resources to submit offer prices above \$1000 does not help manage state of charge or other energy limits if all of the resources that are not fully dispatched have binding energy limits. In this situation, changes in relative offer prices only change which energy-limited resources are depleted first. It is not clear from the CAISO discussion of the system dispatches during September 2022, August 16, 2023, or in the Pacific Northwest in January 2024 whether any alternative resources were available to replace the output of energy-limited resources during the high price intervals

One lesson is that it appears to be important that batteries and other resources with binding energy limits be able to offer at prices above the price trigger for reliability demand response resources. It is pointless for operators to activate reliability demand response in order to maintain state of charge on batteries or energy-limited hydro if the offer price cap will constrain batteries and energy-limited hydro to submit offers that are lower than the offers of reliability demand response. This offer price pattern will cause the market software to deplete battery state of charge in order to avoid dispatching the reliability demand response offered at \$1900 or above when Order 831 is triggered. Our assumption is that in such circumstances, rotating blackouts impose costs in excess of \$2000/MWh, and so it is worthwhile to use RDRR to maintain charge/hold back water if that storage can be used later to reduce the risk and amount of load curtailed during such a load shedding event.

#### **4. Existing Out-of-Market Mechanisms for Managing Energy Constraints**

Some stakeholders suggest that given the limited time available to implement changes for summer 2024 and the limited set of design choices that can be implemented by August, the CAISO should not make any changes to the soft bid cap design for energy-limited resources and instead rely solely on the current out of market mechanisms for managing daily energy constraints. In particular, it has been suggested that the CAISO rely on the end-of-hour energy constraint for battery operators and exceptional dispatch by California ISO operators to manage daily energy limits.

These two tools may indeed need to be used this summer, and the exceptional dispatch tool has been improved since last summer. But it should be recognized that the current resource operator and CAISO operator software and market tools for managing state of charge and energy limits do not appear to be well suited for use as the primary mechanisms for managing state of charge and energy limits so as to maintain reliability with a resource mix that includes a large number of energy-limited resources on days with tightly binding daily limits.

In our view, the end-of-hour state of charge constraint is rarely if ever used because of fundamental flaws that cannot conceivably be corrected by August 1, 2024, if ever. Exceptional dispatch is a workable method for managing the energy limits of one or two very large resources but is far more complex for operators to use to efficiently manage the dispatch and state of charge of a hundred or more energy-limited batteries and hydro resources that comprise a material portion of the resource mix.

One fundamental complexity when managing a large number of energy-limited resources is that it is not sufficient to analyze the energy balance of individual resources but of the overall resource mix. Another critical challenge will be meeting variations in net load without recurrent power balance violations from using an exceptional dispatch tool that effectively removes supply from the dispatch curve.

Furthermore, as discussed below, it is our understanding that the end-of-hour state of charge constraint is not available to hydro resources, and CAISO operators lack the authority to exceptionally dispatch resources located outside the CAISO balancing area. Therefore, neither exceptional dispatch nor the state of charge constraint alone is likely to satisfactorily deal with the problems discussed in Section 3, above.

We discuss the various tools that have been suggested by stakeholders in more detail below, including self-scheduling (Section 4.1), maintaining a targeted end-of-hour charge (Section 4.2), exceptional dispatch (Section 4.3), and physical withholding (Section 4.4).

#### **4.1 Self-scheduling**

Self-schedules can be used to ensure that batteries or hydro resources would be dispatched in particular hours to the extent they have supply, but it does not ensure that the batteries or hydro resources would have sufficient supply to cover their day-ahead market obligations in the net load peak hours.

#### **4.2 Resource operator end-of-hour state of charge**

The resource operator end-of-hour state of charge constraint is not a workable tool for battery resources to rely on to manage their state of charge. While it may be helpful to some batteries, it has serious flaws as a primary mechanism for energy-limited resources to use to maintain their state of charge during stressed system conditions.

- Use of the tool by CAISO batteries violates Flexible RA requirements for CAISO resources
- The end-of-hour resource constraint is not available for use by energy-limited hydro resources.
- The design has deep flaws for managing state of charge from the standpoint of the resource operator, which is why it is rarely used.
- The use of the end-of-hour constraint would have larger impacts on prices when Order 831 is triggered than would raising the offer cap for the same resources.

We elaborate below on the last three considerations.

**4.2.1 Hydro resources.** It is our understanding that there is no resource operator end-of-hour state of charge or similar constraint available for use by hydro resources. Hence, this constraint does nothing to help utilities in the Pacific Northwest or Rockies manage the dispatch of their energy-limited hydro resources.

**4.2.2 Resource operator risks.** As was explained at the April 24, 2024 MSC meeting, the end-of-hour constraint can bind not only to prevent undue dispatch of an energy-limited battery, it can also bind so as to requiring charging at any price. In setting the end-of-hour constraint during the afternoon, battery operators have to factor in their expected charging during the hour. If charging economics are less favorable than expected during an hour in which an end-of-hour constraint has been applied, the end-of-hour constraint can force batteries to charge at very high prices. This feature makes it very risky for battery operators to use this constraint in most circumstances. This is consistent with our understanding that the constraint is rarely used.

For example, suppose a battery has a 325 MW state of charge going into hour ending 15 and the resource expects to charge 50 MW during the hour with low priced solar output. Suppose to be conservative, the resource operator puts in a 360 MW end-of-hour state of charge constraint to prevent the resource from being unduly dispatched below 360 MW. If prices are high during the hour and the battery only charges 20 MW during the first part of the hour, the constraint would not only prevent dispatching the resource below the 360 MW target, but would force charging to reach the 360 MW target even at very high prices by the end of the hour.

This feature of the end-of-hour constraint creates great risks for battery operators using this constraint to manage their state of charge. This risk of battery operators would be borne by the CAISO in using exceptional dispatch if the CAISO operators set the minimum state of charge below the current state of charge in anticipation of storage occurring.

**4.2.3 Price impacts.** If battery resources use the end-of-hour constraint to manage their state of charge and the constraint binds, their supply will effectively be offered at the penalty price for the end-of-hour constraint. This penalty price would be higher than the soft bid cap during Order 831 hours and higher than the offer prices that battery operators might select to better manage their dispatch. The market impacts of using this constraint are therefore likely even larger than of allowing batteries to offer supply at prices somewhat in excess of the soft cap.

There seems to be confusion in the discussion of the end-of-hour constraint, with a perception that prices will somehow be lower because the resource using the constraint cannot set the price. However, when the supply of the resource using the constraint is withdrawn from the market, the next highest resource would set the price. Therefore, the effect is essentially the same as if the storage resources were offered at a higher price.

**4.2.4 Conclusion: End-of-hour state of charge.** We do not think it is a good option to rely solely on the SOC constraint mechanism for maintaining the availability of energy-limited resources, either for summer 2024 or in the long run. Moreover, although no data were presented in the ISO's September 2022 summer report on the use of the SOC constraint or the extent to which it was binding on operations, our understanding from discussions with CAISO staff is that this functionality is not being used and was not used by a material number of resources, if any, on September 6, 2022. Given the limitations of this design, we see no reason for this to miraculously improve during Summer 2024. Moreover, were this functionality actually to be used by a material number of battery operators, it would create the potential for recurrent

unintended power balance violations as well as market prices being set by hard cap during tight system conditions.

### **4.3 Exceptional dispatch**

The changes in the CAISO exceptional dispatch design implemented in late 2023 and available for summer 2024 represent a material improvement in the exceptional dispatch design and will improve the CAISO operators' ability to backstop reliability during stressed system conditions when battery state of charge is being prematurely depleted. In particular, exceptional dispatch constraints that are based upon a minimum state of charge, rather than a fixed output, allow operators to put the constraints in place before the constraint needs to bind, avoiding the need for operators to track the state of charge of many resources in order to decide when to impose a constraint.

However, there are a number of limitations and challenges to relying on exceptional dispatch as a primary mechanism for maintaining the availability of energy-limited resources during stressed system conditions.

- We understand that CAISO operators do not have the ability to use exceptional dispatch outside the California ISO balancing area.
- Exceptional dispatch needs to be implemented in a coordinated fashion across all energy-limited resources in order to avoid simply changing which resources have their state of charge drained.
- When resources with offers at the soft bid cap are exceptionally dispatched to reduce their dispatch, the supply of these resources is effectively moved to the top of the dispatch stack at the hard cap. If the operators need to dispatch these resources to balance net load, they can do this by selectively raising the exceptional dispatch level of individual resources. Relying on manual adjustment of exceptional dispatch cap has the potential for unintended power balance violations while also providing a distraction for operators. This may have happened during hour ending 17 on August 16, 2023 (Section 3.3, supra.) due to use of the end of hour constraint by CAISO operators.
- The use of exceptional dispatch to manage state of charge is even more complex during the period prior to the net load peak when batteries might be charging and discharging. If the minimum state of charge is set at or below the current state of charge, it would allow any charging to be dispatched, rather than used to build up state of charge for the net load peak. If the minimum state of charge is set below the current state of charge then it will cause charging, even at high prices
- If there are software issues such as those during July 2023 (Section 3.4), operators may not even be aware of the need to use exceptional dispatch.

Exceptional dispatch based on minimum state of charge or zero dispatch will change the sequence of battery dispatch if batteries with low offer prices are exceptionally dispatched to reduce their dispatch, in effect moving them to the top of the dispatch stack. There is a potential for unintended impacts every time this is done. However, there is no real alternative to this

CAISO operator impact when CAISO operators depend on either exceptional dispatch or the hour state of charge constraint to manage state of charge. The exceptional dispatch state of charge constraint, like the end-of-hour state of charge constraint, effectively moves the remaining supply offers of the resource to the bid ceiling when it binds. It therefore has the same market impact as if the resource offered at or above the hard bid cap.

When exceptional dispatch is used to stop the dispatch of a set of batteries, and the exceptional dispatch constraints bind on the batteries, but no relaxation is necessary to meet load, then exceptional dispatch will generally produce the same prices as if the affected batteries had raised their offers above the clearing prices. However, if only the offers of some batteries are increased so that some batteries are dispatched at the soft cap while other resources set prices, then which resources are dispatched will vary depending on to which resources the exceptional dispatch is applied. This can result in a different set of resources being dispatched than if resources had increased their offer prices. If only a few batteries are being heavily dispatched, application of exceptional dispatch to these batteries will preserve their state of charge but may result in increased dispatch of other batteries if most of the supply stack around the dispatch price consists of batteries. But if exceptional dispatch is applied to a large number of batteries, there is a potential for the operators to leave too little capacity available at any price to balance variations in net load.

Conversely, if prices are high enough that a large proportion of batteries are being dispatched, applying exceptional dispatch to these batteries is less likely to simply increase the dispatch of those batteries, but there is again potential for the operators to leave too little capacity available at any price to balance variations in net load. The use of exceptional dispatch or end-of-hour state of charge constraint as the primary tool to manage battery state of charge type constraints will be challenging with considerable potential for creating unintended price spikes.

Hence, once the exceptional dispatch constraints begin to bind, CAISO operators will need to carefully manage the relaxation of the constraints across batteries as needed to meet load while avoiding both prices being set by the power balance constraint as a result of exceptional dispatch constraints and undue draining of state of charge. If CAISO operators need to adjust exceptional dispatch limits from interval to interval to balance net load, exceptional dispatch may result in somewhat higher or lower prices than if prices were set by offers above the soft cap.

Managing the dispatch and state of charge using exceptional dispatch is a complicated task that the CAISO operators have not yet carried out effectively. There are indications that the complexities of using end-of-hour constraints in the same manner as exceptional dispatch to manage battery state of charge on August 16, 2023 caused the price spike in hour ending 17 (Section 3.3), although the CAISO has not explained the cause of this price spike.

Summer 2024 could provide lessons in how well the new functionality works in practice, and identify needed changes or supporting operator tools, particularly if the western markets encounter hot, extremely high net load conditions.



The new exceptional dispatch functionality will not necessarily produce lower real-time imbalance prices than a design in which storage resource operators were able to manage their state of charge with offer prices that we expect will typically be less than the bid cap. On the other hand, absent state of charge dependent offers for batteries,<sup>43</sup> the reality is that batteries have to rely in part on exceptional dispatch by CAISO operators to manage their state of charge when system conditions are different than expected.

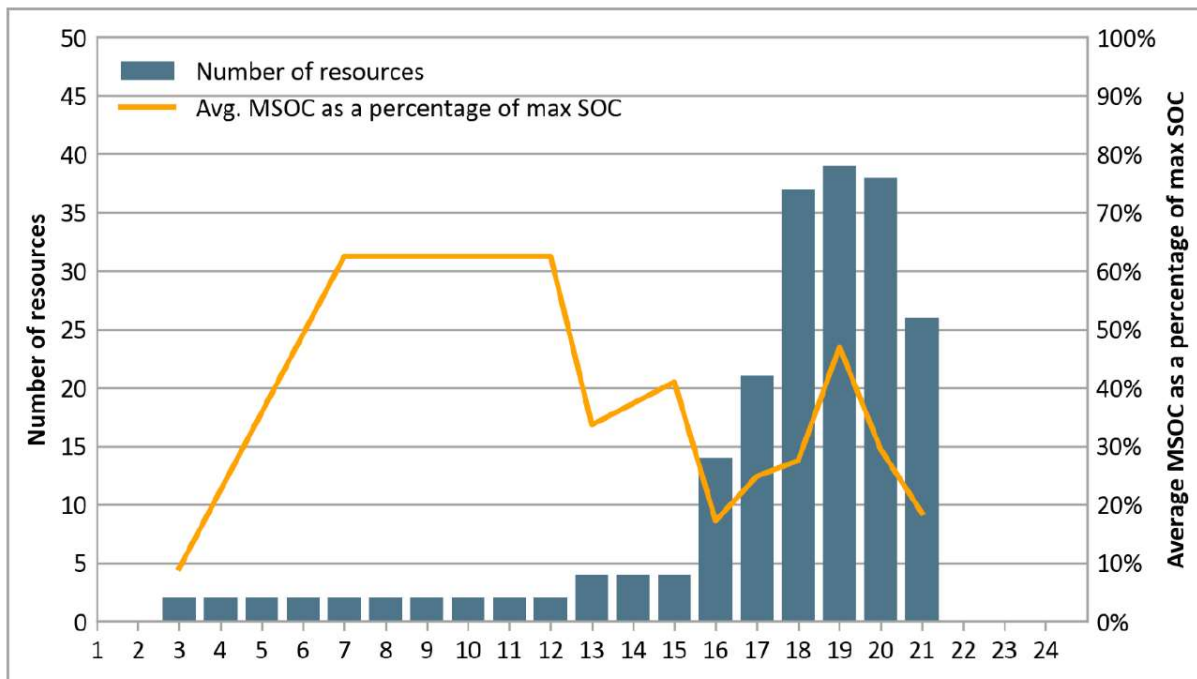
Above, we have discussed in the context of August 16, 2023 the potential for inflated BCR costs when CAISO operators withhold too much output with exceptional dispatch and drive real-time prices to the bid cap. When stakeholders consider the merits of relying on exceptional dispatch rather than offer prices to manage state of charge, they keep in mind that the resources dispatched down out-of-merit with exceptional dispatch when prices are high will receive BCR for the foregone revenues, while resources that are not dispatched because of high offer prices will suffer the revenue losses from not being utilized.

If the CAISO balancing area encounters high load, tight supply conditions this summer it may be necessary at times to drain some battery state of charge to meet load, while avoiding unnecessary depletion. In that situation it will be demanding a lot of operators to carry out this task in a cost-effective manner by adjusting price-taking exceptional dispatch minimum state of charge requirements from interval to interval in RTD.

Ad hoc exceptional dispatch that preserves the state of charge on one battery or other energy-limited resource by draining another will not maintain reliability under highly stressed system conditions. While the CAISO has not prepared any data showing the dispatch of individual resources relative to their SOC on September 6, 2022, there is a suggestive analysis by the Department of Market Monitoring, shown in the figure below. This analysis suggests that operators ran into exactly this situation on September 6, when a combination of exceptional dispatch and end-of-hour constraints on one resource triggered increased dispatch of others. It appears that this may have resulted in end-of-hour constraints being applied to more units in the next hour and additional ED being used to cap the dispatch of yet more batteries.

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<sup>43</sup>A capability that the CAISO had considered but ultimately dropped as part of their 2021-2023 energy storage enhancements initiative.



**Figure 5.** Minimum State of Charge Requirement on September 6, 2022

Source: California ISO, Department of Market Monitoring, “Special Report on Battery Storage,” July 7, 2023, Figure 3.2.1 p. 33.

A similar Figure 150 in the September summer 2022 report indicates that the end-of-hour RTD minimum state of charge constraint only bound on one or two storage resources through hour ending 17 but bound on around on 18 out of 36 storage resources to which the constraint was applied in hour ending 18.<sup>44</sup> This is consistent with end-of-hour constraints and exceptional dispatch being applied too late and in an ad hoc manner.

We have not discussed the management of state of charge during July 2023 (Section 3.4) because the software bugs appear to have had a major impact on operator visibility of what was happening on the system. However, this should be a cautionary reminder that if state of charge management depends entirely on operator controlled exceptional dispatch, rather than storage resource offers, this can magnify the market and reliability impacts of software issues.

Hopefully, CAISO’s operations has developed tools for summer 2024 that will enable the CAISO to use its exceptional dispatch capability more effectively than similar out of market constraints have been used in the past. There is no assurance, however, that this will be the case. Exceptional dispatch will be very challenging to use for the purpose of balancing variations in net load (and in load conformance) without triggering power balance violations as a result of

<sup>44</sup> See California ISO, Summer Market Performance Report for September 2022, op. cit., p. 154.

withholding too much battery supply. Allowing batteries to offer somewhat above the soft cap would allow market based state of charge management and reduce the likelihood of imperfect exceptional dispatch driving prices to the hard cap.

#### **4.4 Physical withholding**

In light of the realities that the end-of-hour state of charge constraint is unavailable to hydro resources and that CAISO operators do not have the ability to exceptionally dispatch energy-limited resources located outside the CAISO BAA, some stakeholders seem to have suggested that these gaps be filled by physical withholding of supply by energy-limited resource without other options manage their energy limits on Order 831 days.

Aside from the adverse reliability impacts of physical withholding, such withholding would have an even more adverse market impact than offers above the soft cap. Physically withheld supply would not be available at any price. This is one of the reasons it is normally not permitted in most ISO markets.

### **5. Varying Bid Caps by Hour of the Day**

There has been discussion with stakeholders of the desirability of restricting the hours in which the bid cap is lifted or of shaping the increase in the bid cap over the day. The CAISO has stated that it cannot implement this functionality for summer 2024.

However, we do not think this type of functionality is desirable in any case. Hence, the inability of the CAISO to implement this type of functionality for summer 2024 is not a reason to delay implementation of the proposed Order 831 changes.

We discuss this functionality with respect to MIBP hourly shaping and with respect to bid cap levels during the CAISO net load peak hours.

#### **5.1 Shaping**

Some stakeholders have suggested that the bid cap for energy-limited resources be shaped over the day in the same manner as the MIBP. We do not agree with this view in setting the bid cap for energy-limited resources. The opportunity cost of energy-limited resources is not the opportunity cost of selling power in another market in the same hour as would be the case for a thermal resource. Instead, the opportunity cost of an energy-limited resource is the value of the power in a future hour.

Hence, the opportunity cost of an energy-limited resource does not vary over the hours of the day in the same way as those of a thermal resource for which the MIBP hourly shaping of opportunity costs were designed.

The offer prices of energy-limited resources need to rise prior to the hours with the highest prices (such as the hours of the net load peak), to avoid prematurely depleting state of charge or

reaching a daily energy limit. It is too late to increase offer prices after the net load peak hours have arrived.

The opportunity cost of a battery, for example, could vary over the day in part based on the amount of time available to charge before supply becomes too tight to charge as the net load peak hours approach. The opportunity cost may also decline in hours after the evening net load peak, but this might not always be the case. For example, the PowerEx report shows that a balancing area in the Pacific Northwest remained in a state of emergency through the night of January 14-15.<sup>45</sup>

## **5.2 Opportunity costs during CAISO net load peak hours**

Another set of stakeholders have the view that the bid cap should be set lower in net load peak hours in the CAISO balancing area. It appears to us that this recommendation reflects an overly simplistic and California centric view of opportunity costs. We first discuss this recommendation in the context of batteries in the CAISO and then turn to whether this recommendation is appropriate for the western EIM as a whole.

**5.2.1 Battery Opportunity Costs.** There appears to be an underlying premise for the suggestion that 4-hour batteries will go into the net load peak hours with 4 hours state of charge. This premise appears to be the basis for conclusions that opportunity costs would be low in the 4 net load peak hours and that the LMP in the 4<sup>th</sup> highest priced hour is always a reasonable proxy for battery opportunity costs.

However, battery resources may not be able to manage their state of charge so that they go into the net load peak hours with 4 hours of charge. The current rules for governing the frequency and time lag for offer price changes can result in a battery being unable to raise its offer prices until it has been dispatched for two hours or more, significantly depleting its state of charge.

This is essentially what happened on September 6, 2022 when batteries began being dispatched heavily at around 1:30 (Section 3.1, supra.). If battery operators did not realize this was more than a transitory change and raise their offer prices at 1:45, the next chance to raise their offer prices would have been at 2:45, going into effect at 4pm. One can see in Figure 1, above, that the heavy net dispatch of batteries was between 1:30 and 4pm, a period when many batteries had offer prices well below the offer cap.<sup>46</sup>

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<sup>45</sup> See PowerEx, “Analysis of the January 2024 Winter Weather Event,” March 6, 2024. We infer based on FMM and RTD prices that this balancing area was BPA.

<sup>46</sup> See California ISO, Department of Market Monitoring, “Comments on Price Formation Enhancements,” op. cit., Figure 4.

Moreover, battery owners had no way of forecasting this increased dispatch. Even now it is not clear what happened to drive the large increase in battery dispatch over this period.<sup>47</sup>

If the CAISO had implemented state of charge-dependent offers as proposed in the December 2021 and April 2022 straw proposals for Energy Storage Enhancements along with other elements of the straw proposal in November 2023, the problem of batteries being dispatched to materially deplete their state of charge before they could adjust their offer prices would be addressed for summer 2024. However, the CAISO dropped the proposal for this market design feature in July 2022.<sup>48</sup>

Hence, such a design will not be in operation for the foreseeable future. The CAISO faces the reality for the next few years that storage operators will only be able to adjust their offer prices in response to increased dispatch with a long lag. The likely consequence at times will be that storage will enter the net load peak hours with too little state of charge to be dispatched at capacity for 4 hours.

The alternative of batteries whose state of charge has been depleted charging going into the net load peak to restore their state of charge also does not work. This is because if the other batteries are not offering at a price above other resources, restoring SOC in this manner would simply deplete state of charge on one battery to fill another with a net loss of charge.

Hence, if a battery has 2 hours state of charge to cover 4 hours of day-ahead market schedules on a day when prices may go to \$2000, it makes considerable sense for the battery operator to submit offers that reduce dispatch if prices fall to lower levels, such as below \$1000/MWh, for a few intervals. Saving state of charge in this manner for higher priced intervals in future hours is efficient.

Another factor that can create a need for high offer prices during the net load peak hours is resources whose state of charge has declined to the point that the ancillary service charging constraint is binding. On September 6, some batteries apparently had a state of charge that fell to such a low level that this constraint was triggered and they had to charge to support their ancillary service awards.<sup>49</sup> There are similar references to batteries in this situation on July 20 and July 25, 2023 in the July 2023 Summer Report.<sup>50</sup> These resources clearly had very little state of charge to use for energy dispatch. Any additional energy dispatch of these resources would have depleted the state of charge and triggered charging to meet the ancillary services

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<sup>47</sup> See discussion in Section 3.1, *supra*.

<sup>48</sup> See California ISO, “Energy Storage Enhancements Second Revised Straw Proposal,” p. 5. There was a reference to shifting this design into another initiative, but this does not appear to have happened.

<sup>49</sup> There is a brief reference to this on p. 153 of California ISO, “Summer Market Performance Report, September 2022,” *op. cit.* There is no data in that summer report on how many units or MW of capacity were impacted.

<sup>50</sup> See *ibid.*, pp. 118-119

state of charge requirement in the next interval. On the other hand, the alternative of alternately discharging and charging at high prices would consume power, and incur net costs because of round trip losses.

Before any rules setting lower price caps in net load peak hours for batteries are considered, there needs to be analysis of the actual level of state of charge across the battery fleet at different points in time during days when Order 831 triggered and there was also significant dispatch of batteries. A metric showing the MW of batteries with less than 3 hours, 2 hours, and 1 hour SOC over the day would be helpful in understanding the issues involved in managing state of charge. This kind of information could guide changes to the way the bid cap is set in the net load peak for implementation in 2025 or 2026. For example, perhaps the battery bid cap should always be increased to \$2000 when reliability demand response is activated, to ensure that the demand response can be used to avoid draining state of charge-limited batteries. This is another reason why the CAISO would have been better off going into summer 2024 if state of charge-dependent offer prices were available.

**5.2.2. Opportunity Cost Patterns Outside the CAISO.** Much of the discussion of opportunity costs in the four net load peak hours is California centric, focused on the needs of regions with large amount of 4-hour batteries and a solar output-driven net load peak. Individual hydro resources with short term energy limits may have a different temporal pattern of peak opportunity costs than batteries in the CAISO. These opportunity costs could be driven by the timing of water inflows, mandatory releases, and reservoir levels. It should not be assumed that all hydro resources will always have enough water in storage to release at capacity over the four highest price hours, rather than perhaps the two highest price hours.

Moreover, the temporal pattern of hydro opportunity costs in the Pacific Northwest will likely converge with the pattern in the CAISO and desert southwest when there is no south-to-north transmission congestion. But this will not necessarily be the case when there is significant congestion in that direction as during the January 2024 cold spell. We saw in the discussion of the January cold wave in Section 3.2 that some BAAs in the Northwest entered emergencies in hours outside the typical CAISO net load peak hours. As a result, prices remained at the soft bid cap during almost every hour on January 14, 2024. Moreover, as mentioned above, the BPA balancing area remained in a state of emergency through the night of January 14-15.

Hence, there is no basis for assuming that the net load peak in the Pacific Northwest will be the same as in California, particularly during the winter when there is south-to-north transmission congestion in WECC.

It should also be kept in mind that the current price shaping for the MIBP is based on CAISO prices, not prices in the Pacific Northwest. It should not be taken for granted that the net load shape pattern is the same across the Western EIM as in the CAISO, nor over all periods of the year. Moreover, cascade hydro resources may face a distinct set of opportunity cost patterns over the day, driven by the value of the water in downstream run-of-river generation. The cost of releasing water upstream at 22:00 will depend on the value of the water at downstream storage limited-generation sites over the subsequent few hours. The opportunity cost of releases from

cascade hydro resources could rise over the hours ending 19 to 22 because prices later in the night would be low.

### **5.3 Conclusion concerning shaping of opportunity costs**

The Western EIM Order 831 design needs to account for reliability needs of all balancing areas in the western EIM, not just the needs of solar dependent regions. Moreover, the design needs to enable resource operators and the CAISO to manage the energy limits of all energy-limited resources, not just 4-hour batteries located in the CAISO.

The CAISO should not be California centric and assume the hours with the highest value for energy-limited resources will always be when the sun goes down in California during the summer. The Pacific Northwest and the Rockies in particular may need to conserve hydro for the morning peak or for a different time in the evening, or even overnight.

The current MIBP is based on IFM prices on high priced days. In our September 9, 2020 Order 831 opinion, we noted the complexities of calculating appropriate shaping factors for very tight supply days.<sup>51</sup> Although we have focused on the offer cap for energy limited resources, the discussion of January 14 and of shaping of prices over the day outside the CAISO is relevant to the calculation of the MIBP. Shaping based on IFM prices for the CAISO balancing area is not necessarily appropriate when applied to bilateral prices at trading hubs in the Pacific Northwest on days with transmission congestion between the Pacific Northwest and the rest of the Western EIM. Consideration might be given to calculating weights for bilateral contract shaping based FMM prices at these hubs.

We agree with DMM that the hourly shape of the MIBP should be based on prices from the same day. In other words, the MIBP should *shape* multi-hour prices from the associated bilateral index and not *scale* those prices so that the average MIBP is higher (or lower) than the index. However, it is not appropriate to use IFM prices to shape offer price caps for the Pacific Northwest. The CAISO should consider using hourly shaping factors based on FMM prices, which could be calculated for all Western EIM trading points, and also reflect more up-to-date information on market conditions. We agree that there is a need for the CAISO to revisit the shaping factor.

Hence, the time of day when the highest value occurs together with the level of appropriate opportunity cost caps may differ across EIM regions. It would at least be very complex, and perhaps not possible, to develop a single set of peak hours and opportunity cost caps that would be appropriate over the year and across the Western EIM.

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<sup>51</sup> J. Bushnell, S. Harvey, B.F. Hobbs, “Opinion on Revision to Import Bidding and Market Parameters for Compliance with FERC Order 831,” op. cit..

In light of these challenges in setting appropriate time varying offer caps for varying types of energy-limited resources across the western EIM, there needs to a compelling reason to take on this complexity, rather than setting a single bid cap over the day.

If batteries and other energy-limited resources have financially binding IFM schedules covering their output while at the same time energy-limited resources elsewhere in the western EIM have financially binding base schedules, many stakeholders have pointed out that it is not economic for energy-limited resources with financially binding forward schedules to exercise market power by raising their offer prices above their true opportunity costs. If a resource's increase in its offer prices reduces the resource's dispatch below its day-ahead market schedule, the seller would be buying back their IFM or base schedules at real-time prices.

## **6. Market Power Related Issues**

The proposed Order 831 changes will have a minor impact on the CAISO/Western EIM market power mitigation design. The only change in the local market power mitigation design will be to uncap default energy bids that exceed \$1000 using the current DEB formula. There are no changes in the way default energy bids are calculated. There are also no changes in the way local market power mitigation is triggered. In our view, these kinds of changes are needed as the resource mix in both the CAISO and Western EIM shifts to include more energy limited resources whose output must be managed over the day, but these are not tasks that can be completed for summer 2024.

The following issues are discussed in this section. First, in Section 6.1, we consider whether local market power mitigation (LMPM) would be undermined under the ISO's proposal, and remaining features of LMPM for batteries that will continue to present potential risks to system efficiency and reliability. We describe some observations from past experience with mitigation of battery discharges, and recommend that additional data be reported in the future on the impact of LMPM on battery price offers and operations to inform discussions of reforms that might be considered in 2025 and 2026. Then in Section 6.2, we focus on the market price impacts of raising the offer cap for storage. There we point out that although higher prices might result from either offer prices or exceptional dispatch being used to limit the dispatch of batteries that would otherwise discharge prematurely, we expect that greater battery supply in intervals where there is true scarcity would decrease market prices in those intervals, yielding an overall improvement in market efficiency.

### **6.1 Local market power mitigation**

Some stakeholders have expressed uncertainty as to whether local market power mitigation will remain in effect with the increase in the Order 831 offer cap. Our understanding is that local market power mitigation will remain in effect. The only change impacting local market power mitigation will be to allow the use of default energy bids that exceed the \$1000 bid cap. This change will primarily impact the default energy bids of hydro resources when Order 831 triggers,



with minimal impact on battery default energy bids (which are calculated using a different methodology).<sup>52</sup>

The uncapping of default energy bids for hydro resources should enable more efficient management of hydro resources with short term energy limits during stressed system conditions such as occurred in the Pacific Northwest during January 2024. Several stakeholders have pointed out that the current hydro default energy bid is fixed over the day, which may not be appropriate. We agree that it would be useful to reassess the determination of hydro default energy bids and potentially implement changes over the next few years. Since a large portion of the dispatchable hydro in the Western EIM is located in the Pacific Northwest, it is essential that any assessment of opportunity costs for hydro not be focused solely on the pattern of prices in the CAISO, but take account of the temporal pattern of opportunity costs in the Pacific Northwest as well. It is readily apparent from the pattern of FMM and RTD prices over the days of January 13 to 16, 2024 as well as the set of hours particular balance areas were in a state of emergency, that the highest prices and most stressed system conditions were not necessarily during the hours of the CAISO net load peak. There might not even be a fixed temporal pattern of opportunity costs in the Pacific Northwest when there is south to north congestion, particularly on winter days.

We recognize on the other hand that while the proposed Order 831-related changes will not undermine effective local market power mitigation, flaws in the current local market power mitigation design as it is applied to storage resources will continue to result in inefficient mitigation of offer prices that may have adverse impacts on reliability, and raise consumer costs, reducing the benefits from the proposed changes. Nevertheless, we support the proposed changes for summer 2024, as well as for winter 2024-2025 as a step in the right direction.

The impact of local market power mitigation applied to energy limited resources with binding energy limits is fundamentally different from mitigation of thermal generation. If thermal generation is mitigated below its actual cost, the resource operator will incur financial losses, which can perhaps be recovered in the BCR payments, or, if the losses are not recovered, that mitigation may impact future contracts and resource economics. Moreover, there are processes for adjusting default energy bids of thermal resources in response to short term fuel cost changes. Hence, the mitigation of thermal resources will typically not impact short-run reliability, nor will it raise consumer costs over the operating day.

However, this is not the case for mitigation of energy limited resources with binding energy limits. Offer price mitigation that inappropriately reduces offer prices of energy limited resources early in the day, can result in the resources not being available to meet load at the net load peak, raising prices and potentially having adverse reliability impacts.

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<sup>52</sup> See California ISO, “Price Formation Enhancements, Rules for Bidding Above the Soft Offer Cap,” May 2, 2024 pp.14-18, California ISO, “Rules for bidding above the soft offer cap, Draft Final Proposal,” May 2, 2024, pp. 16-17, 21.

For example, suppose an energy limited resource is mitigated at 2 p.m. so that it is dispatched at \$200 instead of a gas resource offering at \$225. While this dispatch would reduce consumer costs if the mitigated resource were a gas unit, that is not the case if the mitigated resource is an energy limited resource. The dispatch of the energy limited resource based on mitigated offers at 2 p.m. will reduce the available supply later in the day. If that energy is not available at the net load peak, prices may be set by reliability demand response at \$950 or \$1900 or perhaps even by the power balance penalty. Inappropriate mitigation can therefore adversely impact reliability while at the same time raising consumer costs.

As the CAISO and Western EIM resource mix evolves to become more dependent on energy limited resources, it will become more important to avoid applying inappropriate mitigation to storage resources prior to the net load peak hours. This applies both to batteries and energy limited hydro resources in the Pacific Northwest, particularly during low hydro years, such as what appears to be the case for summer 2024.

The September 2022 summer report mentioned that one factor contributing to the premature dispatch of storage resources was the application of LMPM mitigation.<sup>53</sup> We understand that there were similar issues during 2023.

The California ISO Department of Marketing monitoring battery report has some data on mitigation of batteries in 2022; for instance, Figure 2.10.1 in the CAISO Department of Market Monitoring Battery report for 2022 shows, based on an eyeball estimate, that 450 MW average per hour triggered mitigation. That figure is calculated over all 2000 hours in the quarter. Since there is generally no congestion at night to trigger mitigation, nor likely during the high solar hours, the mitigation was likely concentrated in fewer than ½ of all hours, implying around 900 MW per hour. Since there also might not be congestion to trigger mitigation on low load days, the amount of mitigation triggered on high load days might be as much as 2000 MW an hour or more.

An eyeball estimate further suggests that only about 175 MW per hour of mitigation resulted in changes to offer prices. This lower level of migration is consistent with the DMM data in their April 30 comments showing that many battery operators submit low, even price taking bids, even on high load days. If the mitigation is triggered only in the hours and days with congestion as noted above, this average megawatts per hour over all hours might translate into 500 to 700 MW of offers being mitigated on high load days, which might be a material proportion of the supply offered above low prices. Moreover, since default energy bids are calculated based on day-ahead market prices, there might also be more mitigation on days during which net load is higher than expected; this increases the importance of allowing higher offer prices to be submitted in order to conserve battery supply for the net load peak.

Figure 2.10.1 also suggests that only about 10 MW per hour of batteries are dispatched based on offers reduced by mitigation. That is a low amount but it is on average over 2000+ hours, so that

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<sup>53</sup> See California ISO, “Summer Market Performance Report for September 2022,” op. cit., p. 149.

level would result in about 20,000 MWh over the quarter.<sup>54</sup> The mitigation may have been concentrated in a limited number of hours on tight supply days, which is precisely when mitigation can contribute to adverse reliability impacts. For example, if the mitigation was concentrated on six afternoon hours on the 10 worst days in the quarter, this would be more than 350 megawatts an hour of mitigated dispatch on those 10 tight supply days.

The CAISO January cold spell report did not discuss the extent of mitigation of energy limited hydro resources during the January cold spell, so we cannot assess its impact.<sup>55</sup>

To inform stakeholder of future design changes relating to local market power mitigation as applied to resources with daily energy limits, it is desirable that the CAISO report the MW of energy limited resources dispatched based on mitigated prices by hour for the CAISO and for the three EIM regions (North, East and California) on tight supply days. This would enable stakeholders to assess the urgency of changes to the current local market power mitigation design by 2025 or 2026. If the CAISO does not currently have the system functionality to compile this information, it would be desirable to develop that functionality. As the CAISO and the Western EIM resource mix evolves and it becomes more important to manage daily energy limits, it is important to understand the extent to which the application of local market power is impacting the ability of market participant to manage those energy limits.

## 6.2 Higher bid caps

The proposed changes would raise the offer cap for batteries and hydro resources on Order 831 days. While there is concern that this will lead to higher energy prices overall, this will not necessarily be the outcome. A higher offer cap could potentially result in higher market prices in some hours in which resources would have otherwise been dispatched at the previous soft cap. There will be no price impact if resources other than batteries are dispatched at the soft cap. Part of the rationale for raising the offer cap is that there is also a potential for *lower* prices in the tightest supply hours if the changes to the cap shift output from energy-limited resources toward those tight supply hours rather than dispatching at a low price in another hour in which their output could be replaced by the output of high cost thermal generation.

A higher offer cap would also enable batteries possessing material market power to submit higher offers. However, this should not translate into an appreciably greater potential for the exercise of material market power for the following reasons:

- Resources will still be subject to local market power mitigation
- Resources located in California (or in the future in the EDAM) would generally have financially binding forward schedules from the IFM . EIM entities need to submit base schedules covering their load (in order to pass the RSE). If the resources in the base

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<sup>54</sup> This is an eyeball estimate based on California ISO, Department of Market Monitoring, “Special Report on Battery Storage,” July 7, 2023, p. 27 (Figure 2.10.1).

<sup>55</sup> See California ISO, Winter Conditions Report for January 2024, March 6, 2014.

schedule have unduly high offer prices, the EIM entity would be meeting a portion of this load with power purchased from others at a high price..

It is important to recognize that most offers in most hours are not constrained by the offer cap; rather, they are constrained by competition. Figures 2 and 4 in the DMM April 30 comments provide a good illustration of the way offer prices vary over the day across the battery fleet, with only a small portion of the capacity offered at the soft cap.<sup>56</sup> Raising the offer cap does not mean all offers will be at the higher bid cap because most offers are not constrained by the cap today.

## **7. Benefits and Limitations of the Proposed Design**

In this section, we first briefly summarize the overall improvements that the proposed design would provide to the summer 2024 markets in Section 7.1. That section also mentions several particular ways in which the proposal’s ability to correct the efficiency problems we discuss above are limited, which are then discussed in detail in Sections 7.2 to 7.5. These limitations will need to be addressed in subsequent initiatives by the CAISO in 2025 or later.

Finally, in Sections 7.5-7.8 we review four other general questions about the proposal. One is the interaction of higher storage offer caps with reliability demand response (RRDR), which we believe will help to prevent inefficiently early discharge of storage by triggering RRDR earlier (Section 7.5). Another issue is whether there should be changes to day-ahead market offer caps; we do not see a clear need to raise the offer cap for batteries in the IFM (Section 7.6). As we have pointed out in prior opinions relating to storage resources, the IFM solves the allocation of battery charging and discharging over the day and efficiently calculates opportunity costs automatically. In Section 7.7, we examine a concern expressed by some stakeholders about potential scarcity that could be created in real-time as a result of price-taking exports in HASP. We believe that this is less of a problem than some stakeholders suggest, but its potential impact is related to decisions by CAISO operator regarding EIM transfers. The final issue we discuss (Section 7.8) concerns bid cost recovery for storage resources. We conclude that the proposed changes for summer 2024 will not address the existing issues with BCR for storage, nor any additional issues that may arise if the CAISO operators rely heavily on exceptional dispatch.

### **7.1 Benefits of the proposed design**

The core benefit of the proposed design will be to enable energy limited resources to set offer prices at levels that will better enable them to conserve their state of charge by limiting their dispatch to the highest price intervals when other supply is unavailable. One of the problems with the current situation is that this other supply may come from resources that, during Order 831 events, are offering their supply at prices above the current soft cap. Alternatively, this alternative supply could be from other resources also offering at the soft cap but which are not

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<sup>56</sup> See California ISO, Department of Market Monitoring, “Comments on Price Formation Enhancements,” April 30, 2024.

dispatched instead of batteries because of their location relative to the distributed load bus and the impact of marginal losses on least cost dispatch. The changes in the CAISO's proposal will improve the ability of storage resources to offer their energy-limited supply at prices above those of other substitutes when those substitutes are available, thereby preserving stored energy for periods in which supply is truly scarce.

However, these proposed changes will not address all of the problems impacting the dispatch of energy limited resources during tight system conditions. As discussed below, the changes will not address the potential for batteries to be drained of their state of charge before they can adjust their offer prices. They will also not address the potential for battery offer prices to be subjected to inappropriate local market power mitigation that causes them to be dispatched despite their offer prices. Moreover, while the changes might mitigate the impacts of excessive load conformance adjustments and erroneous exceptional dispatch, the changes will not eliminate them.

## **7.2 Timelines for offer price changes**

The changes do not address the SOC management difficulties faced by battery operators that arise from the long time lag in offer prices changes. This was discussed in the context of Figure 1 in Section 3.1 which illustrate how, on September 6, 2023, batteries were dispatched for a couple of hours before they could change their offers. By the time they could modify their offers to prevent being discharged, it was too late. The long lag in being able to change offer prices might be one reason why some battery supply is offered at the cap, so it will not be depleted before the resource operator can raise its offers.

The current offer price design and time lags put battery operators in a difficult position. On the one hand, they do not want to offer so high that the battery resource cannot earn profits from balancing variations in the load. But on the other hand, they also do not want their inability to adjust offer prices quickly to result in having their state of charge depleted by sustained high dispatches to the point that they cannot cover their day-ahead market schedule.

Without state of charge dependent offers for battery operators to use in managing their dispatch, there will be a continuing need for operators to intervene with the use of exceptional dispatch to prevent undue depletion of battery state of charge. This results in the complexities and market risks that we described in Section 4.3, above.

The proposed Order 831 changes should help cushion the price impacts of imperfect adjustments in exceptional dispatch minimum state of charge, but how much benefit there will be is impossible to assess at this point.

## **7.3 Local market power mitigation**

The proposed changes will not correct the undue mitigation of the offer prices of energy limited units. These problems involved both the calculation of default energy bids and the mitigation trigger.

The proposal will not change the default energy bids (DEBs) for batteries, so offer prices above the cap could still be mitigated to the level of the DEB. The DEB is calculated with a 1.1 multiplier relative to IFM prices, but that IFM price is based on expected conditions, not conditions on a day during which net real-time load is higher than expected and batteries are being heavily dispatched.

Moreover, the trigger for the LMP is based on the three pivotal supplier test being applied to all resources, with all resources mitigated if any set of resources fail that test. Hence, small batteries can have their offers mitigated because large thermal generators fail the three pivotal supplier test.

These designs need to evolve to reflect the increasing reliance of the CAISO and the Western EIM overall on energy limited resources. The premise behind the CAISO's local market power mitigation has always been to apply mitigation only when the benefits – in terms of significantly reducing the risk of the exercise of market power – outweigh the potential costs of inaccurate or overly aggressive mitigation. The issues discussed in this opinion illustrate how the costs of overly aggressive mitigation of storage can be much higher than for traditional resources, and that the benefits are more ambiguous.

We support the suggestion of a variety of stakeholders that there needs to be a reconsideration of the way hydro and battery default energy bids are calculated. This assessment needs, at a minimum, to consider: a) differences in the pattern of Pacific Northwest prices relative to the CAISO and EIM East when EIM North is transmission constrained; b) other differences across the footprint of the Western EIM in the Rockies and Southwest; c) the likelihood that not all resources will necessarily have sufficient state of charge to discharge over the 4 highest hours; and d) the desirability of setting the real-time DEB of batteries in the CAISO above the offer of reliability demand response when the resource's remaining SOC is less than what is required to meet the resource's IFM schedules. A similar DEB design could be implemented in the Extended Day-Ahead Market (EDAM).

A necessary first step in addressing these design limitations is to understand how often energy limited resources are mitigated in afternoon and evening hours on these tight supply days when energy limits are likely to bind, rather than over all hours on all days.

#### **7.4 Load conformance**

To the extent that the design would trigger an increase in both the hard cap and penalty prices in additional hours, this could inflate the cost of large load conformance adjustments by CAISO operators that are unrelated to actual load.

For example, on August 16, 2023, FMM set prices at the Order 831 bid cap during FMM interval 18, 18:30 and 18:45 when there were power balance violations due to load conformance adjustments in FMM in excess of 4000 MW. The price nearly reached the hard cap in interval 18:15, with the price perhaps set by reliability demand response.

If the proposed design serves to trigger Order 831 in additional hours, then large load conformance adjustments in those hours could cause FMM to clear at the \$2000 penalty price in additional hours.<sup>57</sup> This is a fundamentally a problem of CAISO operator use of very large load conformance adjustments in FMM; this is neither a problem of market power, nor of Order 831 market design. It is noteworthy that over the period 18:00 to 19:00 on August 16, 2023, the prices in RTD, with load less inflated by load conformance than the FMM price, were less than \$100 in a number of intervals and had a maximum price of \$127.8 at 18:55.

## **7.5 Reliability demand response (RRDR)**

The CAISO's assessment of the bid caps for batteries on September 6 and August 16, 2023 indicates that the bid cap set by the 4<sup>th</sup> highest MIBP value would have been \$2000 and thus exceeded the offer price of reliability demand response.

This is a good feature as it is desirable to avoid outcomes in which CAISO operators activate reliability demand response in order to reduce net load and preserve battery state of charge, but the offer cap for RDRR then results in depletion of battery state of charge in order to avoid dispatching higher offer price reliability demand response.

This is a good feature but we do not know how general this relationship between the battery bid cap and RRDR offer prices will be.

## **7.6 Changes to day-ahead market offer caps**

We do not perceive that there is a clear need to raise the offer cap for batteries in the day-ahead market. As we have pointed out in prior opinions relating to storage resources,<sup>58</sup> the IFM solves the allocation of battery charging and discharging over the day. The IFM optimization assesses both the need for the battery output in the early hours of the day and over the net load peak.

Similarly, it is our understanding that the IFM enforces hydro energy limits over the 24 hours of the day-ahead market, so they are internalized in the software optimization. Energy limited resources do not need to reflect these constraints in their offer prices; this is because if these constraints bind in the IFM optimization, the opportunity cost of the energy-limited resources will automatically be reflected in IFM prices. The issue in our minds is whether there is a need for energy-limited resource operators to withhold supply from the IFM at a price in excess of \$1000. It is not apparent to us that there is such a clear need for this ability to withhold supply from the IFM at high prices that it needs to be implemented for this summer.

This is very different from the case of RTPD which only looks out 2 hours and the actual real-time dispatch, RTD which has a time horizon of only one hour. Because the optimization in RTPD and RTD does not look out over the remainder of the day, energy-limited resource

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<sup>57</sup> If a hydro offer above \$1000 with a DEB above \$1000 would trigger Order 831 caps, this could create more load conformance driven price spikes at \$2000 instead of \$1000.

<sup>58</sup>See Footnote 3, above.

operators need to try to manage their energy limit with their offer prices. Because of the time lags in offer adjustments and because resource operators have limited visibility into prospective system conditions, the CAISO needs to be able step in with ad hoc out-of-market actions. Examples of such actions include the end-of-hour state of charge constraint and exceptional dispatch, when resource operators are not able to manage their state of charge.

The CAISO has raised battery default energy bids in the IFM so as to resolve other issues with the local market power design. An example of such an issue is mitigating offers only in some hours while optimizing over the entire day; as a result, charging bids and discharge offers were not set over the day on a consistent basis and could result in highly inefficient utilization of storage. But this issue does not require a further increase in the bid cap. If the IFM optimization is operating correctly, batteries will be scheduled over the 24 hours of the IFM solution consistent with their opportunity costs as automatically calculated in the IFM software, and it is not necessary for resources to guess their opportunity costs and reflect them in order prices in order to receive the market clearing price.

Hence we do not see a need to make changes to storage offer caps in the IFM for this summer. If there is a need, it should be clearly spelled out so that a design can be developed to address that need.

## **7.7 Risk of Draining batteries to support hourly exports**

Some stakeholders appear to be concerned by scarcity that could be created in real-time as a result of price-taking exports in HASP. We believe that this is less of a problem than some stakeholders suggest, but its potential impact is related to decisions by CAISO operator regarding EIM transfers.

If hourly exports are scheduled to sink in the WEIM, the hourly exports would back units down in the RSE that might help a BAA pass the RSE. However, the units backed down in the RSE could be dispatched up in FMM and RTD to avoid draining batteries, if batteries had appropriate offer prices in RTD. The same issue would still exist if no exports were scheduled; in either case, battery offer prices need to be high enough in RTD so that they would be dispatched after other resources in the Western EIM.

This might be more of an issue in the future if the CAISO were exporting power to entities not participating in the Western EIM, but for now there are few hourly exports to such entities.

However, there is a potential FMM price impact if CAISO operators do not allow EIM transfers in the binding FMM interval.<sup>59</sup> If this is the case, FMM prices in the CAISO could be artificially high as a result of the restriction on EIM transfers into California, as would the cost of the

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<sup>59</sup> See California ISO, Market Performance and Planning Forum, December 14, 2024, p. 80; California ISO, Department of Market Monitoring, Q3 2023 Report on Market Issues and Performance, February 21, 2024, pp. 63-69; and California ISO, Department of Market Monitoring, Q4 2023 Report on Market Issues and Performance, April 24, 2024, pp. 74-88.



exports. Batteries would not be drained in RTD in any case because CAISO operators do not restrict EIM transfers in RTD. We agree with the suggestion of Michelle Kito of the CPUC at the beginning of the April 24, 2024 MSC meeting that there needs to be discussion of whether the CAISO plans to allow operators to restrict EIM transfers in HASP and RTPD, and if so, how, and the related issue of whether the software flaws that led to problems last July have been fully corrected. If those software flaws have not been fully corrected but have been addressed with an ad hoc fix, the CAISO should provide a description of that fix so there can be consideration of potential unintended consequences before summer.

## **7.8 BCR for storage resources**

The proposed changes for summer 2024 will not address existing issues with BCR for storage, nor any additional issues that may arise if the CAISO operators rely heavily on exceptional dispatch. Exceptional dispatch that triggers \$1000 or \$2000 price spikes while at the same time withholding substantial battery output has the potential to generate outsized BCR costs. We agree with the suggestion of the California ISO Department of Market Monitoring that a review and restructuring of the current design for BCR payments to batteries is needed.