



May 31, 2024

The Honorable Debbie-Anne A. Reese  
Acting Secretary  
Federal Energy Regulatory Commission  
888 First Street, NE  
Washington, DC 20426

**Re: California Independent System Operator Corporation  
Docket No. ER24-\_\_\_\_-000**

**Tariff Amendment to Enhance Cost-verified Bidding above the  
Soft Energy Bid Cap**

Dear Secretary Reese:

The California Independent System Operator Corporation (“CAISO”) submits this tariff amendment to enhance cost-verified bidding above the CAISO’s \$1,000/MWh soft energy bid cap consistent with Order No. 831.<sup>1</sup> The CAISO’s amendment consists of two sets of enhancements.

First, the CAISO proposes to remove its current restriction that scheduling coordinators manually submit reference level adjustment requests to raise their default energy bids above \$1,000/MWh when the default energy bids would, by their own calculation, rise above \$1,000/MWh. Because each resource can bid up to the higher of its specific default energy bid or the soft energy bid cap, each resource will be able to bid above the soft energy bid cap in those intervals when its default energy bid is above the soft energy bid cap. Experience has demonstrated that restricting bid cap calculations to the soft energy bid cap is unnecessary and can inhibit resources from submitting cost-justified bids, particularly hydroelectric resources with intra-day opportunity costs. Removing this restriction will enable cost-justified bidding, which will promote more efficient dispatch on constrained days.

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<sup>1</sup> The CAISO submits this filing pursuant to section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d, and Part 35 of the Commission’s Regulations, 18 C.F.R. Part 35. Capitalized terms not otherwise defined herein have the meanings set forth in Appendix A to the CAISO tariff, and references herein to specific tariff sections are references to sections of the CAISO tariff unless otherwise specified.

Second, the CAISO proposes to enable storage resources to bid above the soft energy bid cap in the real-time markets. The CAISO will do so by providing methods to verify storage resources' unique opportunity costs in the real-time markets based on other resources' ability to bid above the soft energy bid cap. Enabling storage resources to bid above the soft energy bid cap will help the CAISO significantly on constrained days: storage resources will be more likely to charge and discharge at optimal times, leading to more efficient dispatch and less reliance on out-of-market actions to maintain state of charge heading into the net peak hours when the CAISO most depends on storage.<sup>2</sup>

The expedited stakeholder process for this initiative involved multiple rounds of written comments and meetings with stakeholders. Stakeholders broadly supported the CAISO's efforts to enhance the rules for bidding above the soft offer cap, recognizing the importance of allowing resources to reflect their true costs and the need for a near-term solution for summer 2024. The CAISO carefully considered stakeholder feedback while developing the final proposal, aiming to balance the need for an effective solution with implementation feasibility and potential risks flagged by some parties. The CAISO believes the proposed enhancements appropriately balance stakeholder perspectives while urgently addressing the identified issues.

The CAISO's enhancements represent its next steps to better enable resources to reflect their costs on the rare days when prices can spike and meeting demand is challenging. These enhancements are not the CAISO's final steps. The CAISO recognizes these processes can be optimized even further; however, the CAISO proposes these two enhancements now because they address the CAISO's most critical needs, they have a strong foundation in historical data, and because the CAISO can implement these enhancements before the peak-demand summer months. Meanwhile, the CAISO's price formation enhancements stakeholder initiative will continue to examine potential enhancements to default energy bids, cost-verification, and the unique considerations for different resource classes in the CAISO's markets.

The CAISO requests that the Commission approve the CAISO's tariff revisions as just and reasonable, effective August 1, 2024.

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<sup>2</sup> The CAISO respectfully requests that the Commission consider this as a single, unified filing. Although the tariff provisions and technology are not necessarily interdependent, approving one set of tariff revisions but not the other may help one resource class, but would exacerbate the current challenges for the other by causing even greater bid separation among the resource classes. For these reasons, the CAISO developed, filed, and will implement the solutions simultaneously.

## I. Background

### A. Order No. 831

The Commission issued Order No. 831 in 2016. Order No. 831 had two primary requirements for ISO/RTOs: “(1) cap each resource’s incremental energy offer at the higher of \$1,000/megawatt-hour (MWh) or that resource’s verified cost-based incremental energy offer;” and “(2) cap verified cost-based incremental energy offers at \$2,000/MWh when calculating locational marginal prices (LMP) (hard cap).”<sup>3</sup>

The Commission issued these requirements because it was concerned that certain ISO/RTO offer caps at the time could prevent resources from recouping short-run marginal costs by excluding them from energy bids. The example cited by the Commission in Order No. 831 was when natural gas prices suddenly “increase dramatically,” such as during cold snaps.<sup>4</sup> When several resources have short-run marginal costs above \$1,000/MWh but cannot reflect those costs within their incremental energy offers due to the offer cap, the ISO/RTO may not dispatch the most efficient set of resources because it cannot distinguish among the resources’ actual costs.

Although the Commission sought for resources to include short-run marginal costs in their energy bids, Order No. 831 required offers above \$1,000/MWh be cost-verified to ensure they “reasonably reflect a resource’s actual or expected costs.”<sup>5</sup> Each ISO/RTO or its market monitor thus must verify bid costs above \$1,000/MWh. Order No. 831 also expressly intended for cost verification requirements to work with market power mitigation procedures “because market power concerns are heightened when a resource’s short-run marginal costs exceed \$1,000/MWh.”<sup>6</sup> Order No. 831 thus required all incremental energy offers equal to and above \$1,000/MWh be cost-based, “which essentially requires mitigation of all incremental energy offers above \$1,000/MWh.”<sup>7</sup> The Commission explained:

While in this Final Rule we increase the offer cap for cost-based incremental energy offers, we also subject offers above

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<sup>3</sup> Order No. 831 at P 1.

<sup>4</sup> *Id.* at P 2; Reuters, “Severe US Cold Snap Prompts Peak Power And Natural Gas Demand,” Jan. 17, 2024, <https://www.reuters.com/business/energy/us-natural-gas-demand-hits-record-high-amid-severe-cold-snap-2024-01-17/>.

<sup>5</sup> Order No. 831 at P 140.

<sup>6</sup> *Id.* at P 139.

<sup>7</sup> *Id.* at P 142.

\$1,000/MWh to additional market power mitigation in the form of the verification requirement. The verification requirement is designed to ensure that a cost-based incremental energy offer above \$1,000/MWh is not an attempt by the associated resource to exercise market power. The verification requirement is part-and-parcel with the increase of the offer cap for cost-based incremental energy offers. We find that it would be inappropriate to raise the offer cap without imposing a verification requirement. The verification requirement thus serves as an additional backstop market power mitigation measure.<sup>8</sup>

Order No. 831 recognized that pre-market cost verification is not always possible. It thus found that “if a resource’s incremental energy offer above \$1,000/MWh is not verified but that resource is nonetheless dispatched, that resource would be eligible to receive an uplift payment to recover its verified costs.”<sup>9</sup> The Commission also found that neither virtual transactions nor exchange transactions—imports and exports—necessarily required cost verification because they generally offer additional supply and increase competition; however, the Commission noted it would consider proposals by ISOs/RTOs to verify their costs where warranted.

## **B. CAISO Compliance with Order No. 831**

The Commission accepted the CAISO’s tariff revisions to comply with Order No. 831 and related tariff revisions to implement commitment cost and default energy bid enhancements. In compliance with the Commission’s directives regarding the offer cap structure requirement of Order No. 831, the CAISO implemented a two-tier cap structure: (1) a soft energy bid cap of \$1,000/MWh, which applies to all energy bids<sup>10</sup> except for virtual bids and bids for non-resource-specific system resources (*i.e.*, import bids that come from a resource not identified as a specific resource located outside of the CAISO

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<sup>8</sup> *Id.* at P 143.

<sup>9</sup> *Id.* at P 146.

<sup>10</sup> The types of energy bids include supply bids (including import bids), demand bids (including export bids), and virtual bids. Existing tariff section 30.2; tariff appendix A, existing definitions of “Energy Bid,” “Supply Bid,” “Import Bid,” “Demand Bid,” “Export Bid,” and “Virtual Bid.”

balancing authority area);<sup>11</sup> and (2) a hard energy bid cap of \$2,000/MWh, which applies to all energy bids.<sup>12</sup>

Under the current tariff process, a supplier that intends to submit an energy bid above the soft energy bid cap must submit a reference level change request to the CAISO to adjust the price in a resource's default energy bid (*i.e.*, the resource's cost-based incremental energy offer).<sup>13</sup> Once the CAISO can validate and approve a requested change to a resource's default energy bid, the supplier can submit an energy bid up to the price of the modified default energy bid.<sup>14</sup> The CAISO employs a "reasonableness threshold"<sup>15</sup> to determine whether to approve requested adjustments to the default energy bid made through the automated process.<sup>16</sup>

Figure 1 illustrates the relationship between gas-fired resources' default energy bids, reasonableness threshold, and potential bids. Bid 1 is below the soft energy bid cap and is not subject to cost-verification, but bids 2 and 3 would require the gas resource to request a default energy bid adjustment to reflect those values. A default energy bid reflecting bid 2 would be approved through

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<sup>11</sup> Resource-specific system resources are resources external to the CAISO balancing authority area (*i.e.*, system resources) that in some respects are treated like resource-specific resources located within the CAISO balancing authority area. For example, resource-specific system resources may submit three-part bids (*i.e.*, start-up bids, minimum load bids, and bids for energy above minimum load). Existing tariff section 30.5.2.4. These resources are guaranteed recovery of these costs through the bid cost recovery process (see existing section 11.8, et seq.) and are subject to local market power mitigation (see existing tariff section 39.7, et seq.). Therefore, the CAISO can cost-verify offers for energy above minimum load for these resources as it does for internal resources.

<sup>12</sup> Tariff sections 30.7.12.1, 30.7.12.3, and 39.6.1.1.1 – 39.6.1.1.2; tariff appendix A, existing definitions of "Soft Energy Bid Cap" and "Hard Energy Bid Cap."

<sup>13</sup> As discussed above, default energy bids are the CAISO's resource-specific cost-based mechanism for applying energy bid mitigation. Default energy bids have a static value throughout the day. Default energy bids do not represent an hourly cost curve; they are represented as a single calculated number in day-ahead and real-time (*e.g.*, the fourth highest day-ahead LMP). The process for submitting a request to adjust the prices in a resource's default energy bid is set forth in tariff section 30.11.2.

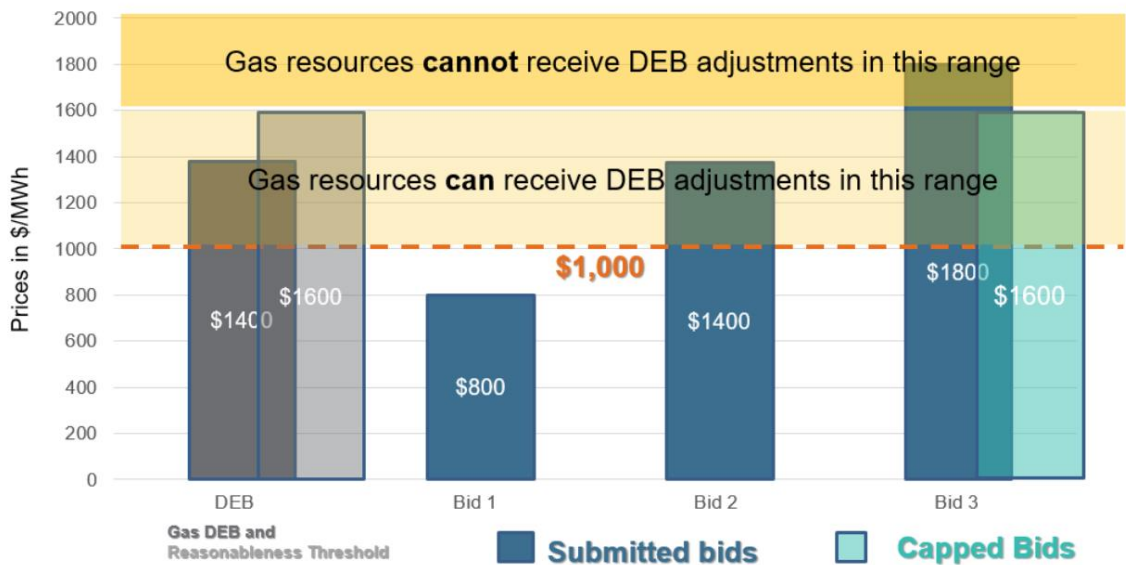
<sup>14</sup> Successful cost-verification process does not "lift the cap" on the default energy bid, but supplants the capped default energy bid with a new adjusted default energy bid, which represents that resource's new energy bid cap.

<sup>15</sup> The CAISO calculates this threshold by increasing the fuel price component of a resource's reference level by fixed percentages so the reasonableness threshold accounts for differences between a supplier's actual or expected costs for a specific resource and the gas prices that the CAISO market systems would otherwise use. Section 30.11.1 of the CAISO tariff.

<sup>16</sup> Suppliers also can leverage a manual process to request that the CAISO use a different fuel or fuel equivalent cost in calculations using a resources reference levels, like the default energy bid.

the reference level change request process because it is within the range of the reasonableness threshold. A requested default energy bid reflecting bid 3 would be capped by the reasonableness threshold. The supplier may submit a request for after-market cost recovery for any difference between the capped bid and its actual fuel costs or fuel-equivalent costs, like the value requested in bid 3, provided they meet the corresponding requirements for eligibility.<sup>17</sup>

**Figure 1: Automated Default Energy Bid Adjustments for Gas-fired Resources Today**



The CAISO also allows resources to submit “manual” reference level change adjustment requests when they believe costs will materialize beyond what the automated processes will approve.<sup>18</sup> However, the manual process has limitations. First, it depends on unique, serial requests and approvals for every resource. Each request must be submitted before 8:00 AM on the relevant trade date.<sup>19</sup> If numerous resources submitted custom requests at the deadline, it would be challenging to review and approve them before the market processes begin. The process was designed for rare or unexpected costs; not pervasive issues like opportunity costs. Second, the CAISO’s criteria for reviewing and approving manual requests is based on fuel and fuel-equivalent prices; not real-time opportunity costs.<sup>20</sup>

<sup>17</sup> See tariff sections 30.11, *et seq.* and 30.12, *et seq.*

<sup>18</sup> Tariff section 30.11.4; see *also* section O.1.3 of the Business Practice Manual for Market Instruments, <https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments>.

<sup>19</sup> Tariff section 30.11.4.2.

<sup>20</sup> Tariff section 30.11.4.3.

Although each default energy bid is a bespoke tool to mirror the costs for a specific resource in the market, the CAISO included a requirement for resources to submit reference level change requests to adjust their default energy bids above the soft energy bid cap even when the default energy bids would rise above the soft energy bid cap by their own calculation. In other words, the CAISO expressly capped all default energy bids at \$1,000/MWh, regardless of their natural calculation and inputs.<sup>21</sup>

### **C. Maximum Import Bid Price**

Order No. 831 did not require ISOs and RTOs to subject virtual transactions and imports above \$1,000/MWh to the verification requirement.<sup>22</sup> However, the Commission stated ISOs and RTOs could file additional tariff revisions under section 205 of the Federal Power Act to address any issues that arise from permitting virtual transactions up to \$2,000/MWh and the absence of a verification requirement for imports.<sup>23</sup> Because the CAISO frequently relies on energy from imports, it implemented additional protections for import and virtual bids above the \$1,000/MWh soft energy bid cap.

The CAISO cannot verify the actual costs of import bids from non-resource-specific imports because the CAISO does not have the cost information associated with the bid. Therefore, the CAISO revised the existing bid validation rules and related tariff provisions to accept non-resource adequacy import bids, export bids, demand bids, and virtual bids priced above the soft energy bid cap only when the CAISO has cost-verified a bid or has calculated a maximum import bid price that exceeds the soft energy bid cap. Together, the CAISO's import bidding rules enable the CAISO to verify import bid costs consistent with Order No. 831, and ensures these resources—which do not have resource adequacy obligations—have sufficient incentive to offer supply into the CAISO's markets.<sup>24</sup>

The CAISO calculates hourly maximum import bid prices for the day-ahead market and real-time market, separately, including for on-peak and off-peak hours.<sup>25</sup> The CAISO calculates the hourly maximum import bid price as

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<sup>21</sup> Tariff section 39.7.1 (“Default Energy Bids used for purposes other than for calculating Reasonableness Thresholds will be subject to the Soft Energy Bid Cap, unless the CAISO has approved a Reference Level Change Request pursuant to Section 30.11 in support of an Energy Bid above the Soft Energy Bid Cap”).

<sup>22</sup> Order No. 831 at PP 172, 192.

<sup>23</sup> *Id.* at PP 176, 197.

<sup>24</sup> See *California Independent System Operator Corp.*, Tariff Amendment to Enhance Import Bidding, Docket No. ER21-1192, pp. 19 *et seq.* (Feb. 22, 2021), <https://www.aiso.com/Documents/Feb22-2021-TariffAmendment-PricingParameters-OrderNo831-ER21-1192.pdf>.

<sup>25</sup> Section 30.7.12.5.3 of the CAISO tariff.

110 percent of the greater of the published bilateral electric index prices for the Mid-Columbia or Palo Verde trading hub locations, multiplied by an hourly shaping ratio. The hourly shaping ratio decomposes the bilateral block prices into an hourly granularity. The Commission approved using the maximum import bid price based on these hub prices because they are the primary liquid trading hubs for bilateral electric transactions in the Western Interconnection. Thus, they provide representative electric prices for the bilateral market outside of the CAISO balancing authority area.

#### **D. Concerns that Resulted in this Tariff Amendment**

The CAISO launched an expedited stakeholder initiative in response to stakeholder concerns that the current rules for resources bidding above the \$1,000/MWh soft offer cap may prevent resources from accurately reflecting their costs in their energy offers when those costs exceed the soft energy bid cap. Particularly, the CAISO and stakeholders were concerned that the large and growing fleet of storage and hydroelectric resources (1) cannot adjust their default energy bids to reflect intra-day opportunity whether those costs are above the soft energy bid cap or not, and (2) cannot validate opportunity costs that rise above the soft offer cap but are otherwise already defined by the default energy bid, respectively.

Consider Figure 2 compared to Figure 1, above. Figure 2 represents hydroelectric resources' ability to submit bids above the soft energy bid cap today. Unlike the gas-fired resources in Figure 1, their bids are capped at the soft energy bid cap regardless of what their default energy bids would be.

The CAISO calculates a reasonableness threshold for all resources using the same fuel or fuel equivalent cost formula, which may not capture the full scope of costs defined in the default energy bid formulas for resources like hydroelectric generators or battery storage resources. The CAISO does not have reasonableness thresholds or other criteria against which to validate requested default energy bid adjustments due to changes in costs other than fuel and fuel-equivalent costs.<sup>26</sup>



**Figure 2: Hydroelectric Resources Today**



Intra-day opportunity costs represent resources' foregone profits of producing energy now rather than producing energy later. For those resources that operate based on finite resources like reservoirs or state of charge, intra-day opportunity costs reflect a real cost to produce energy in a particular moment. Supplying energy earlier generally means the resource cannot supply energy later. This is a significant concern for the CAISO, which depends on such limited resources to meet its net peak demand. These challenges compound because they overlap: high prices above the soft energy bid cap often materialize because of supply scarcity in the markets,<sup>27</sup> making less economic and more limited resources critical to meet demand. Although the CAISO does not foresee reliability issues this summer due to a lack of capacity, the CAISO still has every incentive to send the correct price signals to the market to avoid the need for out-of-market actions to keep limited resources available for the net peak hours and meet their day-ahead schedules.

## II. Proposed Changes

### A. Revising the Cap on Default Energy Bids

The CAISO proposes to remove its current restriction that scheduling coordinators manually submit reference level adjustment requests to raise their

<sup>27</sup> Costs above the soft energy bid cap do not always occur during or even close to the CAISO's peak demand. For example, energy offers could rise above the soft energy bid cap during a Winter cold snap that results in results in extremely high fuel costs for gas-fired resources.

default energy bids above \$1,000/MWh when the default energy bids would, by their own calculation, rise above \$1,000/MWh.<sup>28</sup> Because each resource can bid up to the higher of its specific default energy bid or the soft energy bid cap, each resource will be able to bid above the soft energy bid cap in those intervals when its default energy bid is above the soft energy bid cap.<sup>29</sup> Resources could still submit reference level change requests to bid above their default energy bids if they believe their costs are greater, and can still receive after-market compensation if their requests are rejected before the market but justified after.<sup>30</sup> All energy bids, including default energy bids, will still be subject to the hard energy bid cap of \$2,000/MWh.<sup>31</sup>

Under the CAISO's proposal, Figure 2, above, becomes Figure 3, enabling hydroelectric resources to bid to the higher of their default energy bids or the soft energy bid cap:<sup>32</sup>

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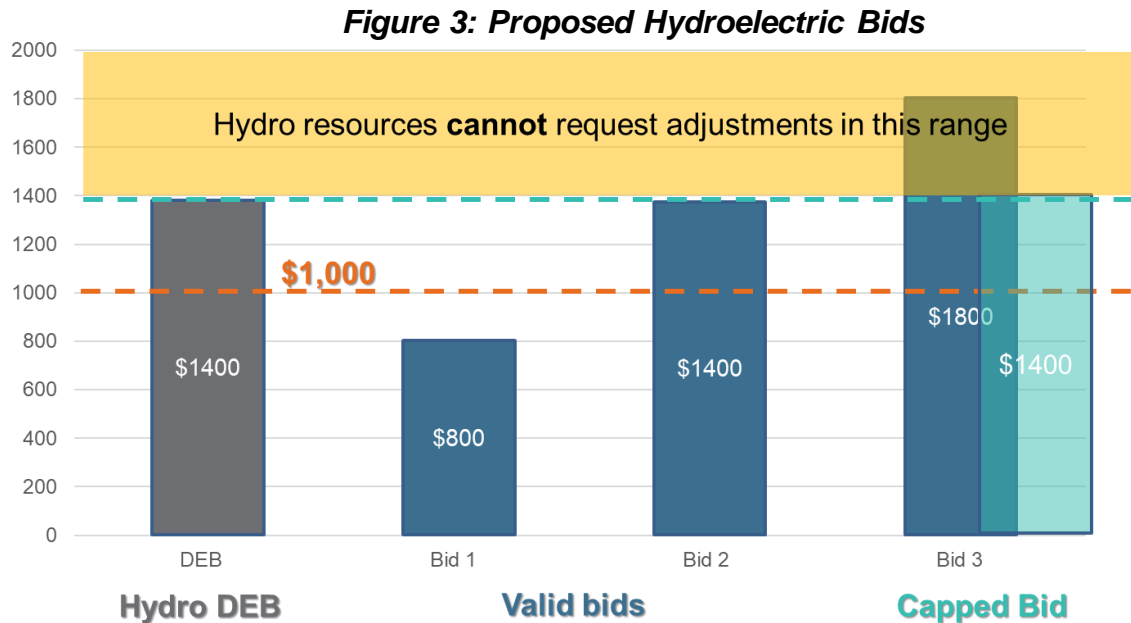
<sup>28</sup> Revised sections 30.7.12.2, 30.11.2.3, and 39.7.1 of the CAISO tariff.

<sup>29</sup> If mitigated for market power, a resource could still be mitigated down to the maximum of the default energy bid and the competitive price.

<sup>30</sup> Under current tariff eligibility and criteria.

<sup>31</sup> *Id.*

<sup>32</sup> Gas-fired resources will be subject to the same cost verification rules as today, but will have an easier administrative process: They automatically will be able to bid to the higher of their default energy bid or the soft energy bid cap, and would only be required to submit a reference level change request above their default energy bid if they wish to bid above their default energy bid (where today one would be required for all bids above \$1,000/MWh). This improvement will be more efficient for the CAISO as well, removing its need to approve those requests it knows are cost-justified before the opening of each market.



Experience has demonstrated that artificially capping default energy bids at \$1,000/MWh is unnecessary and can inhibit resources from submitting cost-justified bids, resulting in inferior price signals and inefficient dispatch. The CAISO and its Market Surveillance Committee both compiled data showing when the default energy bid cap restricted resources on constrained days.<sup>33</sup> The CAISO has included that data in Attachments C and E to this transmittal letter.

Essentially, today the CAISO requires resources to justify energy bid costs the CAISO already knows are justified based on the calculation of the default energy bid. The default energy bid is among the rare energy industry terms that means what it says: it is intended to represent a resource’s “default” energy bid based on the accepted inputs to that bid. Each default energy bid is bespoke to that specific resource. Any resource that believes it has unique cost components not captured by existing structures can request to negotiate a custom default energy bid with the CAISO. The Commission was correct to identify the default energy bid as a practical vehicle to cost-verify bids above \$1,000 under Order No. 831.<sup>34</sup> The CAISO believes that the artificial restriction to cap default energy bids at \$1,000/MWh is unnecessary and counterproductive to using the default energy bids for cost verification. The CAISO and its Market Surveillance Committee also do not believe that removing this restriction will affect any potential use of market power. Again, the CAISO is merely approving those

<sup>33</sup> See CAISO Draft Final Proposal at 16, included herewith as Attachment C; Market Surveillance Committee Opinion at 8-10, included herewith as Attachment E.

<sup>34</sup> Order No. 831 at P 143.

energy bids it already knows are cost-justified based on the default energy bids. Resources exercising market power will still be mitigated to a value pre-determined to be an accurate reflection of the resources cost. The CAISO respectfully requests that the Commission approve as just and reasonable the tariff revisions to remove the \$1,000/MWh cap on default energy bids.<sup>35</sup>

### **B. Adding a Storage-specific Cost Verification Mechanism in the CAISO's Real-Time Markets**

Although removing the \$1,000/MWh cap on default energy bids will better enable resources to bid above the soft energy bid cap when justified, it is unlikely to enable storage resources to do so. The “storage resource option” default energy bid includes intra-day opportunity costs, but in the day-ahead market the CAISO calculates those costs based on all resources’ bids into that market, and the real-time opportunity costs are based on day-ahead prices.<sup>36</sup> Because CAISO storage resources are almost universally modeled as four-hour resources, this opportunity cost is generally based on the fourth-highest priced hour.<sup>37</sup> Historically, the day-ahead prices in these intervals rarely rise above the soft energy bid cap even on days where actual real-time prices—and thus storage resources’ actual opportunity costs—are well above the soft energy bid cap. Storage resources’ day-ahead default energy bids cannot inform their energy bids because the default energy bids are unavailable until after the energy bids are submitted.<sup>38</sup> Although the default energy bid potentially could inform real-time bids, enhancements to the storage resource option default energy bid would take longer to develop, and the software enhancements could not be implemented for this summer.<sup>39</sup>

The CAISO proposes to create a custom mechanism to recognize when storage resources’ intra-day opportunity costs warrant real-time energy bids above the soft energy bid cap.<sup>40</sup> The CAISO proposes to allow storage

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<sup>35</sup> More precisely, the CAISO proposes to revise the cap on default energy bids to the hard energy bid cap of \$2,000/MWh.

<sup>36</sup> Section 39.7.1.8 of the CAISO tariff.

<sup>37</sup> The storage option default energy bid is customized to each resource based on its modeling election and technical parameters, including charge duration and round-trip efficiency.

<sup>38</sup> Revised section 30.7.12.2 thus includes the phrase, “Energy Bids for storage resources may exceed the Soft Energy Bid Cap pursuant to Section 30.7.12.6” to direct the reader to the tariff provision setting forth the applicable rules for storage resources.

<sup>39</sup> Removing the \$1,000/MWh cap will affect the other default energy bid options available for storage. The CAISO thus proposes to reference them expressly in proposed tariff section 30.7.12.6.

<sup>40</sup> Because storage is a technology always evolving, the CAISO tariff does not define energy storage resources. As such, proposed tariff section 30.7.12.6 refers to “energy storage

resources to bid to the higher of (a) the fourth-highest calculated hourly value of the maximum import bid price for that trading day; (b) the highest-priced cost-verified energy bid for the applicable trading hour;<sup>41</sup> and (c) the resource's default energy bid if it uses the variable cost option, LMP option, or the negotiated rate option.<sup>42</sup> The CAISO believes that, taken together, these values provide the best potential proxies to calculate storage resources' real-time opportunity costs. Effectively, they represent the level other resource classes may bid to. Attachments C and E to this transmittal letter both analyze data on constrained days and find meaningful correlation between real-time prices and these metrics. Figure 4, for example, shows these metrics in relation to real-time prices on September 6, 2022.<sup>43</sup>

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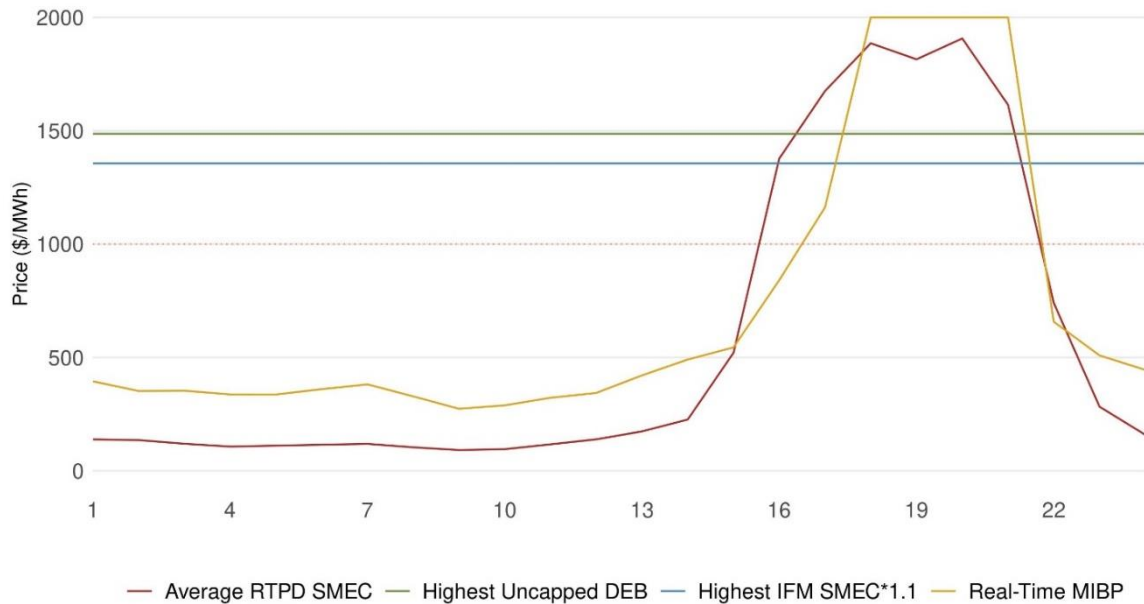
resources using the Non-Generator Resource Model.” Some other technologies use the Non-Generator Resource model—“Generic Non-Generator Resources” and Participating Loads—but these resources are not storage resources by the plain meaning of those words. As such, they would be ineligible to bid above the soft energy bid cap like storage. Hybrid Resources may use the Non-Generator Resource Model and have storage capabilities, but are expressly excluded because they manage their own state of charge, and their intra-day opportunity costs are different than storage resources'. The CAISO will consider Hybrid Resources' abilities to bid above the soft energy bid cap in the future. The CAISO notes that Hybrid Resources elect that designation specifically for the ability to self-optimize between their mixed-fuel components. They may elect to be or convert to Co-located Resources instead, availing the storage components to the energy storage bidding options described in this filing.

<sup>41</sup> This metric is an actual submitted, accepted energy bid; not simply a potential value like a default energy bid or a reasonableness threshold. The tariff also limits the eligible bids to those resources with cost verification under Order No. 831, expressly excluding Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources.

<sup>42</sup> Storage resources today may use these default energy bid options in addition to the storage option. Section 39.7.1 of the CAISO tariff. They also may change their preference at any time. Although less likely, it is possible the values for the three enumerated default energy bids could rise above the soft energy bid cap. The CAISO has not included the storage option default energy bid at this time for the reasons described above and because the CAISO cannot implement software at this time that would enable the storage option default energy bid to inform how high a storage resource can bid. In any case, if a storage resource bid is mitigated in the market power mitigation process, the bid would be mitigated down to the maximum of the default energy bid and the competitive price. The Commission has already approved this result as just and reasonable, and the CAISO does not have the capability to alter the software dictating how a storage resource bid would be mitigated at this time. Moreover, the CAISO believes this is a prudent, incremental step at this time to ensure the growing-fleet of storage resources cannot exercise market power at higher prices when the CAISO depends on it to meet its net peak demand on the most constrained days. The CAISO intends to consider mitigation in relation to bidding above the soft energy bid cap as it examines enhancements to the storage option default energy bid.

<sup>43</sup> The highest uncapped default energy bid value is assumed to be analogous to the highest cost-verified bid for the purposes of this example; however, a high-priced default energy bid alone would not serve as a cost-verified bid. Likewise, the cost-verified bid does not set a daily price for storage. Storage resources can bid to the highest cost-verified bid in that trading hour. This prevents sporadic high bids from setting a price for the whole day and misleading storage resources from their actual opportunity costs.

**Figure 4: September 6, 2022 Price Comparisons**



Although the maximum import bid price generally correlates best with real-time prices on constrained days, a cost-verified bid may set the real-time price, and thus also could represent storage resources' opportunity costs.

The CAISO proposes to use the fourth-highest hour of the maximum import bid price for the entire trading day to reflect that CAISO storage resources are almost universally four-hour resources, and that storage resources' opportunity costs should be based on when the resource would elect to begin discharging (foregoing lesser hours).<sup>44</sup> For similar reasons, the CAISO proposes to use the fourth-highest hour of the maximum import bid price for the whole trading day rather than matching hour to hour. As the Market Surveillance Committee explained:

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.

<sup>44</sup> Meaning that a completely charged storage resource would discharge in four hours if the CAISO's optimization dispatched it to discharge at maximum until depleted.

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.<sup>45</sup>

The CAISO notes that bilateral hub prices that support offers greater than \$1,000/MWh have occurred only a handful of days in recent years: six trade dates thus far in 2024, two trade dates in 2023, and seven trade dates each in 2021 and 2022. The CAISO does not expect its enhancements to significantly increase the number of days that would contain prices above \$1,000/MWh, but it may increase the number of hours in those days with prices above \$1,000/MWh.<sup>46</sup>

The CAISO proposes to enable storage resources to bid above the soft energy bid cap based on the proposed proxies in the real-time markets only.<sup>47</sup> Based on stakeholder feedback and the Market Surveillance Committee opinion, the CAISO believes this incremental step is prudent. The CAISO is concerned that expanding this proposal to day-ahead market bids would be premature and could lead to unintended results. It is the real-time markets where storage resources face the risk for premature depletion of state of charge. Although the CAISO believes that it is generally preferable to have rules aligned in the day-ahead and real-time markets, the CAISO has not had sufficient time to explore with its stakeholders the historical data and potential consequences in the day-ahead horizon for this proposal. The day-ahead market's 24-hour horizon will optimize the use of storage and result in day-ahead discharge schedules in the highest value hours.

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<sup>45</sup> Market Surveillance Committee Opinion at 27-28, included as Attachment E.

<sup>46</sup> Taken together, the overall net cost impact would depend on factors such as the frequency and magnitude of hydroelectric and storage resources bidding above \$1,000/MWh, the impact on market clearing prices, and the potential efficiency gains from improved resource dispatch. Although there is potential for some increase in market costs during tight days (because resources could potentially set prices above \$1,000/MWh in hours prior to the peak times), this should be weighed against the potential benefits of more efficient dispatch, reduced out-of-market actions and associated make-whole costs, and improved resource availability during critical periods.

<sup>47</sup> It is possible that future enhancements may supplant this rule for storage resources; however, the CAISO believes its proposal is just and reasonable. Accordingly, the CAISO does not propose any sunset date on this rule for storage.

The Commission should approve these enhancements as just and reasonable and consistent with Order No. 831. They represent prudent, incremental steps to address real-time issues that may grow if unchecked. They also represent practical solutions that can be implemented this summer when the issues are most likely to arise. The CAISO's enhancements provide meaningful cost-verification and market power mitigation based on existing rules in use and already approved by the Commission. Although the CAISO conducted an expedited stakeholder process, it duly considered several alternative solutions, and concluded the enhancements proposed here were the optimal solutions.

### **III. Effective Date**

The CAISO requests an effective date of August 1, 2024, 62 days from today.

### **IV. Communications**

Under Rule 203(b)(3),<sup>48</sup> the CAISO respectfully requests that all correspondence and other communications about this filing be served upon:

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### **V. Service**

The CAISO has served copies of this filing on the CPUC, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

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<sup>48</sup> 18 C.F.R. § 385.203(b)(3).



**VI. Contents of this filing**

Besides this transmittal letter, this filing includes these attachments:

Attachment A	Clean CAISO tariff sheets
Attachment B	Redlined CAISO tariff sheets
Attachment C	Final Proposal
Attachment D	Board of Governors Memo
Attachment E	Market Surveillance Committee Opinion

**VII. Conclusion**

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission issue an order accepting the tariff revisions in this filing effective August 1, 2024.

Respectfully submitted,

**/s/ William H. Weaver**

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**Attachment A – Clean Tariff**

**Tariff Amendment – Price Formation Enhancements**

**California Independent System Operator Corporation**

**May 31, 2024**

### **30.7.12.2 Energy Bids that Exceed the Soft Energy Bid Cap**

In addition to all other Bid validation rules that apply to Energy Bids, if a Scheduling Coordinator submits an Energy Bid price that exceeds the Soft Energy Bid Cap, the CAISO will modify the Energy Bid price for purposes of clearing the relevant CAISO Market Process to the higher of the Soft Energy Bid Cap or the resource's Default Energy Bid, including when the Default Energy Bid is modified pursuant to a Reference Level Change Request pursuant to Section 30.11 or when the Default Energy Bid would rise above the Soft Energy Bid Cap based upon its general calculation. Energy Bids for storage resources may exceed the Soft Energy Bid Cap pursuant to Section 30.7.12.6.

\* \* \* \* \*

### **30.7.12.6 Energy Storage Bids**

For energy storage resources using the Non-Generator Resource model, the CAISO will allow Energy Bids that exceed the Soft Energy Bid Cap subject to the Bid price screens described here. This Section 30.7.12.6 does not apply to Hybrid Resources. Notwithstanding any other provision, the CAISO will reject Energy Bids that exceed the Hard Energy Bid Cap. In the Real-Time Market, the CAISO will accept Energy Bids from Scheduling Coordinators for storage resources using the Non-Generator Resource model up to the higher of (a) the fourth-highest calculated hourly value of the Maximum Import Bid Price for that Trading Day in the applicable CAISO Market Process; (b) the highest-priced Energy Bid from a resource subject to a Default Energy Bid that the CAISO has accepted for the applicable Trading Hour pursuant to Section 30.7.12.2, excluding without limitation Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources; and (c) the resource's Default Energy Bid if it uses the Variable Cost Option, LMP Option, or the Negotiated Rate Option. The CAISO will reduce Bids for storage resources that exceed (a), (b), and (c) to the maximum permissible value. In the Day-Ahead Market, the CAISO will accept Energy Bids from Scheduling Coordinators for storage resources using the Non-Generator Resource model up to the resource's Default Energy Bid if it uses the Variable Cost Option, LMP Option, or the Negotiated Rate Option.

\* \* \* \* \*

### **30.11.2.3 Energy Bids Above the Soft Energy Bid Cap**

Except for Energy Bids permitted under Section 30.7, a Scheduling Coordinator whose Default Energy Bid does not exceed the Soft Energy Bid Cap and that intends to submit an Energy Bid that exceeds the Soft Energy Bid Cap must submit a Reference Level Change Request. The CAISO will further verify Energy Bids in excess of the Soft Energy Bid Cap pursuant to the applicable rules in Section 30.7.

\* \* \* \* \*

## **39.7 Local Market Power Mitigation for Energy Bids**

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM and Sections 34.1.5 for the RTM.

### **39.7.1 Calculation of Default Energy Bids**

Default Energy Bids shall be calculated by the CAISO, for the on-peak hours and off-peak hours for both the DAM and RTMs, pursuant to one of the methodologies described in this Section. The Scheduling Coordinator for each Generating Unit owner or Participating Load must rank order the following options of calculating the Default Energy Bid starting with its preferred method. The Scheduling Coordinator must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost Option in the rank order, in which case the Scheduling Coordinator must have a negotiated rate established with the CAISO. If no rank order is specified for a Generating Unit or Participating Load, then the default rank order of (1) Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. For the first ninety (90) days after changes to resource status and MSG Configurations as specified in Section 27.8.3, including the first ninety (90) days after the effective date of Section 27.8.3, the Default Energy Bid option for the resource is limited to the Negotiated Rate Option or the Variable Cost Option. Default Energy Bids will not exceed the Hard Energy Bid Cap in any interval,

regardless of the result of their inputs or calculations. Scheduling Coordinators for storage resources participating as Non-Generator Resources also may rank the storage resource option among their options. If no rank is specified for a storage resource participating as a Non-Generator Resource, then the default rank will be (1) Variable Cost Option and (2) LMP Option. Scheduling Coordinators for storage resources participating as Non-Generator Resources must provide the data necessary for determining the storage resource option if that option is the first in rank order.

**Attachment B – Marked Tariff**  
**Tariff Amendment – Price Formation Enhancements**  
**California Independent System Operator Corporation**  
**May 31, 2024**

### **30.7.12.2 Energy Bids that Exceed the Soft Energy Bid Cap**

In addition to all other Bid validation rules that apply to Energy Bids, if a Scheduling Coordinator submits an Energy Bid price that exceeds the Soft Energy Bid Cap, the CAISO will modify the Energy Bid price for purposes of clearing the relevant CAISO Market Process to the higher of the Soft Energy Bid Cap or the resource's Default Energy Bid, including when the Default Energy Bid is modified pursuant to a Reference Level Change Request pursuant to Section 30.11 or when the Default Energy Bid would rise above the Soft Energy Bid Cap based upon its general calculation. Energy Bids for storage resources may exceed the Soft Energy Bid Cap pursuant to Section 30.7.12.6.

\* \* \* \* \*

### **30.7.12.6 Energy Storage Bids**

For energy storage resources using the Non-Generator Resource model, the CAISO will allow Energy Bids that exceed the Soft Energy Bid Cap subject to the Bid price screens described here. This Section 30.7.12.6 does not apply to Hybrid Resources. Notwithstanding any other provision, the CAISO will reject Energy Bids that exceed the Hard Energy Bid Cap. In the Real-Time Market, the CAISO will accept Energy Bids from Scheduling Coordinators for storage resources using the Non-Generator Resource model up to the higher of (a) the fourth-highest calculated hourly value of the Maximum Import Bid Price for that Trading Day in the applicable CAISO Market Process; (b) the highest-priced Energy Bid from a resource subject to a Default Energy Bid that the CAISO has accepted for the applicable Trading Hour pursuant to Section 30.7.12.2, excluding without limitation Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources; and (c) the resource's Default Energy Bid if it uses the Variable Cost Option, LMP Option, or the Negotiated Rate Option. The CAISO will reduce Bids for storage resources that exceed (a), (b), and (c) to the maximum permissible value. In the Day-Ahead Market, the CAISO will accept Energy Bids from Scheduling Coordinators for storage resources using the Non-Generator Resource model up to the resource's Default Energy Bid if it uses the Variable Cost Option, LMP Option, or the Negotiated Rate Option.

\* \* \* \* \*

### **30.11.2.3 Energy Bids Above the Soft Energy Bid Cap**

Except for Energy Bids permitted under Section 30.7, Aa Scheduling Coordinator whose Default Energy Bid does not exceed the Soft Energy Bid Cap and that intends to submit an Energy Bid that exceeds the Soft Energy Bid Cap must submit a Reference Level Change Request. The CAISO will further verify Energy Bids in excess of the Soft Energy Bid Cap pursuant to the applicable rules in Section 30.7.

\* \* \* \* \*

## **39.7 Local Market Power Mitigation for Energy Bids**

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM and Sections 34.1.5 for the RTM.

### **39.7.1 Calculation of Default Energy Bids**

Default Energy Bids shall be calculated by the CAISO, for the on-peak hours and off-peak hours for both the DAM and RTMs, pursuant to one of the methodologies described in this Section. The Scheduling Coordinator for each Generating Unit owner or Participating Load must rank order the following options of calculating the Default Energy Bid starting with its preferred method. The Scheduling Coordinator must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost Option in the rank order, in which case the Scheduling Coordinator must have a negotiated rate established with the CAISO. If no rank order is specified for a Generating Unit or Participating Load, then the default rank order of (1) Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. For the first ninety (90) days after changes to resource status and MSG Configurations as specified in Section 27.8.3, including the first ninety (90) days after the effective date of Section 27.8.3, the Default Energy Bid option for the resource is limited to the Negotiated Rate Option or the Variable Cost Option. ~~Default Energy Bids used for purposes other than for calculating~~



~~Reasonableness Thresholds will be subject to the Soft Energy Bid Cap, unless the CAISO has approved a Reference Level Change Request pursuant to Section 30.11 in support of an Energy Bid above the Soft Energy Bid Cap. Default Energy Bids will not exceed the Hard Energy Bid Cap in any interval, regardless of the result of their inputs or calculations.~~ Scheduling Coordinators for storage resources participating as Non-Generator Resources also may rank the storage resource option among their options. If no rank is specified for a storage resource participating as a Non-Generator Resource, then the default rank will be (1) Variable Cost Option and (2) LMP Option. Scheduling Coordinators for storage resources participating as Non-Generator Resources must provide the data necessary for determining the storage resource option if that option is the first in rank order.

**Attachment C – Final Proposal**  
**Tariff Amendment – Price Formation Enhancements**  
**California Independent System Operator Corporation**  
**May 31, 2024**



# **Rules for bidding above the soft offer cap**

## **Final Proposal**

**May 17, 2024**

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# Rules for bidding above the soft offer cap

## Final Proposal

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## 1. Executive Summary

Through the *Price Formation Enhancements (PFE) stakeholder working group*, market participants have requested the ISO consider and prioritize policy enhancements for summer 2024 that would allow resources with intra-day opportunity costs to reflect those costs in their energy bids. Market participants have posited that allowing these costs to be accurately reflected will ensure the market can effectively and efficiently manage the dispatch of these resources.

FERC Order 831 establishes that resource market bids are subject to a soft offer cap of \$1000/MW, primarily to address concerns about the exercise of market power. Bids can be submitted above \$1000/MWh but must be cost verified by the market operator or market monitor.

On stressed days with high prices that can exceed the soft offer cap, the soft offer bid cap can create challenges for energy-limited resources that do not have sufficient headroom to reflect their opportunity costs in their bids without hitting the cap, and cannot incorporate intra-day opportunity costs into their bids. Bids from these resources can appear lower cost and “economic” to dispatch early in the day resulting in the premature dispatch and exhaustion of these energy limited resources prior to the critical net load peak evening hours. For these reasons, market participants have stressed the importance of the ISO timely addressing intra-day opportunity costs in relation to the soft offer cap for energy limited resources such as battery storage, hydroelectric resources, and demand response resources.

Solutions to these issues depend on 1) the ISO’s ability to make timely technology enhancements for implementation for summer 2024, and 2) the policy and regulatory risks and associated tradeoffs discussed with stakeholders during the PFE working groups. Considering stakeholder recommendations and input — and the various regulatory, policy and technology feasibility risks — the ISO recommends the following:

1. Remove the \$1000/MWh cap on Default Energy Bids (DEBs). Removing the cap on DEBs will allow hydro resources to reflect costs within their DEB and to be compensated up to that value, even if it is above \$1000/MWh.
2. Modify the bid cap for energy storage resources to provide bidding flexibility using a proxy opportunity cost value. This will allow energy storage resources to submit bids that are higher than the current \$1000/MWh soft offer cap **in the real-time market**. It will also allow the resources to indicate to the market their intra-day opportunity costs that support their availability for discharge during more stressed grid conditions, when prices might exceed the current soft offer cap.

The ISO believes that this proposal represents a balanced, reasonable and equitable approach for addressing the near-term market needs by allowing market participants to better reflect opportunity costs in their energy offers within the existing regulatory framework. The ISO is actively evaluating the feasibility of implementing these changes in summer 2024.

## 2. Background

FERC Order No. 831 requires market operators to verify the costs of incremental energy offers above \$1,000/MWh (the “soft offer cap”) before using these bids in the market. Its intent is to manage and mitigate concerns about market power. To comply with this order, the ISO uses its “reference level change request” (RLCR) process to verify costs above the soft offer cap. A reference level change request enables suppliers to update their “Default Energy Bids” (DEBs), which serve as a cost-based reference price used for mitigating market power. If approved, this request updates their DEB and enables them to bid up to their adjusted DEB if it exceeds the soft offer cap.

The RLCR process allows suppliers to adjust for energy cost changes not captured by their DEB in the ISO's market processes. When initially designed, the RLCR process was tailored toward gas resources that faced discrepancies between their actual fuel costs and the costs that CAISO's market systems used to calculate their DEB. The RLCR process was designed to validate requested DEB adjustments, using a reference based on fuel costs, in response to changing fuel costs. However, it lacks similar functionality for processing changes to the opportunity costs associated with storage, hydro, and demand response resources.

Through the *Price Formation Enhancements (PFE)* stakeholder working groups, stakeholders identified two primary issues that CAISO should promptly evaluate and address to manage resource availability during high price conditions, which generally correlate with stressed grid conditions across the market footprint:

1. Resources with intra-day opportunity costs may be unable to bid in a way to preserve their limited energy for the highest priced hours.
2. These resources may not be able to bid a way to maintain their day-ahead market schedules when real-time prices exceed the soft offer cap.

Intra-day opportunity costs refer to the potential revenues foregone when the market dispatches a resource with limited energy (i.e., battery storage, hydro generation) during a lower-priced period of the day instead of waiting for a higher-priced period, generally coinciding with periods when supply is most limited. If resources’ DEBs do not accurately reflect these opportunity costs, these resources may be dispatched sub-optimally or otherwise not be available during higher-priced hours. This can cause inefficiencies and potential revenue losses. Additionally, if these energy limited resources have depleted their energy earlier in the day, they may be unable to meet their day-ahead market awarded schedules. Consequently, they would need to buy back their day-ahead schedules at high real-time prices to cover their positions. The inability to bid above the soft offer cap in the real-time market due to RLCR limitations exacerbates this issue. It prevents a resource from reflecting its opportunity costs and conserving its limited energy for the higher-priced hours that it had been scheduled for in the day-ahead market.



## 2.1. Default Energy Bids represent resource specific verified costs

FERC Order No. 831 requires that each resource's incremental energy offer is capped at the higher of \$1,000/MWh or that resource's verified cost-based incremental energy offer.<sup>1</sup> FERC contemplated that cost verification requirements could work in conjunction with market power procedures; however, FERC does not prescribe the manner in which costs are verified.<sup>2</sup> Each ISO/RTO was empowered to propose how it would verify costs above \$1,000/MWh in its compliance filing. FERC also requires verified cost-based incremental energy offers be capped at \$2,000/MWh.

The default energy bid (DEB) mirrors a resource's competitive marginal costs in the market in conditions when market participants might have market power. These values are intended to be resource specific, and calculated pre-market based on information available at that time. Today, all DEBs are capped at \$1,000/MWh when they are initially calculated. However, DEBs can be adjusted to above \$1,000/MWh and up to \$2,000/MWh through the reference level change request described below.

Absent perfect information, the DEB serves as a reasonable benchmark for a resource's specific short run marginal costs using predefined resource-specific operating parameters, and considering specific intra-day opportunity costs like nodal specific LMPs used in storage DEBs and bilateral prices used in hydro DEBs.<sup>3</sup> Most DEB calculations include a scalar<sup>4</sup> to account for some margin of error between the value defined by the DEB, calculated based on information known to the ISO, and a resource's actual costs.

For cost variability beyond what can be accounted for pre-market, market participants can use reference level change request process. The ISO's reference level change request (RLCR) process allows market participants to update the costs reflected through their DEB.<sup>5</sup> Two options are available: the manual and automated RLCR process. These options can be leveraged whenever a generator wishes to request that the ISO use a different fuel or fuel-equivalent cost in its reference level calculations, whether bidding above the soft offer cap or not.

Today, resources use the RLCR process to request DEB adjustments beyond the value of their DEB by providing the ISO with the necessary information to inform that adjustment. However, a resource's DEB might otherwise be calculated to be above \$1,000/MWh if not for the cap on the DEB. In this case, though the ISO already has sufficient information to verify the resource's costs, the current process requires the resource's scheduling coordinator to take action through the RLCR process to reflect those costs in the market.

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<sup>1</sup> Order No. 831 at P 1.

<sup>2</sup> If the cost verification standard cannot be accommodated through the cost-verification process, resources are eligible for make-whole payments.

<sup>3</sup> More on DEB options can be found in Appendix A.

<sup>4</sup> More on Scalars can be found in Appendix B.

<sup>5</sup> The RLCR process also enables updates to commitment cost bids, i.e. minimum load cost and startup cost bids.

The RLCR process does not yet accommodate requested changes in response to intra-day opportunity costs.

Energy storage and hydro resources are effectively not able to use the RLCR process today to adjust their DEBs in response to intra-day opportunity costs, because the ISO does not have rules to determine a reasonable cost expectation upon which to base an intra-day opportunity cost adjustment request. Without the ability to use the automated RLCR process, hydro and storage resources cannot request DEB adjustments *or* bid above the soft offer cap when opportunity costs materialize in real-time.

Through the stakeholder working group discussions, stakeholders have expressed support for enhancements to the RLCR process, but enhancements will be technology and policy resource intensive and beyond scope of what is feasible for a summer 2024 implementation. The ISO is committed to evaluating enhancements as part of a longer term evaluation of the design and these potential enhancements are highlighted in Section 6 of this paper.

For implementation for summer 2024, the ISO recommends proposals described in Section 4 of this paper.

## 3. Proposal Development Process

### 3.1. Stakeholder Recommendations for Policy Design

Stakeholders in the PFE working groups made recommendations and held discussions about changes to ISO rules for bidding above the soft offer cap, which primarily drove the development of this proposal.<sup>6</sup>

Stakeholders support finding a solution that can be in place for Summer 2024 to support energy limited resources', particularly battery storage and hydro generation, ability to hold their positions in the supply stack and maintain their DA schedules in real-time during higher priced periods that generally coincide with more challenging operating conditions.

Stakeholders understand that a summer 2024 timeline is highly constrained and may not support a holistic, durable, policy solution or novel technology development. Most stakeholders acknowledge an interim solution may not be optimal, but agree it would improve the status quo during the summer period where stressed operating conditions are likely. Meanwhile, some stakeholders advocate caution when revising policy and implementing new technology solutions on an expedited basis. Ultimately, stakeholders agree that resources with opportunity costs should be able to reflect those costs accurately in the market.

In addition to the short-term changes, stakeholders support a more robust initiative to serve the broader problem statement of improving resources' ability to adjust their costs in response to changing

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<sup>6</sup> PFE Rules for bidding above the soft offer cap Issue Paper P. 10 [IssuePaper-StakeholderRecommendations-PriceFormationEnhancements-Rules-BiddingAboveSoftOfferCap.pdf](https://www.aiso.com/IssuePaper-StakeholderRecommendations-PriceFormationEnhancements-Rules-BiddingAboveSoftOfferCap.pdf) (caiso.com)

market conditions. A future initiative would support developing a definition of, and calculation for, intra-day opportunity costs for use in DEBs and the real-time optimization.

### Objective: improve resource's ability to hold their positions in the supply stack during high priced periods

Stakeholder recommendations intend to provide resources with sufficient energy bidding flexibility to ensure the market appropriately values these resources and efficiently utilizes a resource's limited energy. Stakeholders recommended a range of values to serve as proxies for intra-day opportunity costs, summarized in Table 1.

The Maximum Import Bid Price (MIBP) is currently used by the ISO in other processes to estimate prevailing bilateral prices, and some stakeholders support it as an appropriate proxy for both storage and hydro opportunity costs. Some stakeholders expressed concerns regarding the liquidity of bilateral indices on which this proxy price is based, as well as the accuracy of the resultant proxy price once a methodology to decompose the 16-hour block into an hourly value is applied. Stakeholders also have expressed mixed opinions on the appropriateness of using a single, peak, or hourly MIBP value to represent an opportunity cost for energy limited resources.

In response to stakeholder concerns around the MIBP, the ISO proposed using prices calculated in its day-ahead market as the forecast for real-time opportunity costs. Stakeholders also submitted for consideration the hard bid cap of \$2,000/MWh as a reference price.

**Table 1: Proxy values under consideration**

Proxy Value	Purpose
Highest cost-verified bid, MIBP	This stakeholder proposal reflects the same logic used today to screen non-resource-specific RA import bids above \$1000/MWh
Highest value of the MIBP	Stakeholders propose this solution as an improvement over the MIBP hourly curve, as the real-time market does not optimize over the full horizon.
4 <sup>th</sup> highest Value of the MIBP	This solution considers that limited energy resources are able to derive an opportunity cost based on prevailing bilateral prices, but mimics the use of the 4 <sup>th</sup> highest hour in the storage DEB to represent the flexibility needed for a typical 4-hour battery storage resource.
\$2,000/MWh	This value represents the hard cap for resource bids to set LMPs under Order No. 831.
Highest DA Price	This value was proposed by the ISO for stakeholder consideration. The opportunity cost estimate would be based on a more liquid market result, but may not capture real time conditions or conditions outside of the CAISO BA.

Stakeholders put forth several interim measures that aim to enhance the bidding flexibility of energy-limited resources to represent their opportunity costs under tight system conditions. Below is a summary of these stakeholder recommendations for policy development. Stakeholders prefer a solution that would modify the DEB to ensure that market power mitigation would not reduce bids below a value that captures the agreed upon opportunity costs.

### *Summary of stakeholder recommendations for policy development*

- Approach 1** **Directly modify the cap applied to bids and default energy bids.** These proposals would allow certain resources to bid up to a specified cap whose value is a proxy for opportunity costs.
- Remove the \$1,000/MWh cap on default energy bids
  - Apply the same logic used today for non-resource specific RA imports
  - Allow resources to bid up to a static value—4<sup>th</sup> highest MIBP, highest MIBP, \$2,000/MWh
  - Make these bid cap modifications conditional, or limited to only hours of the day in which issues have been observed
- Approach 2** **Leverage existing tools to ensure resources can retain their day-ahead schedules in real-time.** These options provide a backstop for reliability. Importantly, these options would not require any immediate policy or implementation changes.
- End-of-Hour State of Charge constraint
  - Self-Schedule the day-ahead schedule in real-time
  - Base Schedule for WEIM entities
  - Exceptional dispatch
- Approach 3** **Enhance resources' ability to accurately identify and reflect costs through the reference level change request process.** These proposals are focused on modifications to DEB and/or the reference level change request process.
- Modify the reasonableness threshold to allow hydro and storage resources to request adjusted DEBs based on the highest (or 4<sup>th</sup> highest) MIBP value

### 3.2. Analysis: Proxies for intra-day opportunity costs on historical high priced days

None of the stakeholder recommended values, summarized in Table 1 above, are a perfect proxy for intra-day opportunity costs. Intra-day opportunity costs are the foregone profits of producing now rather than being able to produce later, so any proxy will necessarily be based on a forecast or assumption. The goal in identifying a sufficient energy offer cap is to find a proxy value that demonstrates a correlation with a resource's intra-day opportunity costs. For example, a proxy value for a four-hour duration battery storage resource would correlate with the four net peak load hours.

The options discussed in this paper intend to balance a reasonable representation of intra-day opportunity costs with the risk of overstating them. Over- or under-estimating costs can lead to undesirable outcomes.

The ISO performed analysis on historical high-priced days to investigate how the proposed offer cap proxies may have performed on a counterfactual basis when compared to real-time prices, specifically

the hourly average system marginal energy cost (SMEC) from the fifteen minute (RTPD) market. The purpose of comparing to the RTPD SMEC is to show how closely each proxy might have correlated to realized, historical real-time prices, however this does not provide a perfect comparison.

Figure 1, Figure 2, and Figure 3 below plot the hourly average RTPD SMEC against three different proxies: the highest uncapped DEB value, the highest IFM SMEC value multiplied by a scaling factor of 1.1, and the hourly real-time maximum import bid price (MIBP). For the purposes of this analysis, the highest uncapped DEB value is assumed to be analogous to the highest cost-verified bid, however a high-priced DEB alone would not serve as a cost-verified bid. The plots are shown for three reference days that experienced tight system conditions: September 6, 2022, August 16, 2023, and January 14, 2024.

For the two summer days in 2022 and 2023, the real-time MIBP tracks the general shape of realized RTPD SMEC but does not provide a perfect correlation under all conditions. For example, the hourly real-time MIBP understates RTPD SMEC during the evening ramp of September 6, 2022 and subsequently overstates RTPD SMEC during evening peak hours of August 16, 2023. Further divergence is observed on January 14, 2024, when the MIBP was driven high due to high bilateral prices in the Pacific Northwest while system-wide SMEC stayed lower.

Static parameters like the highest cost-verified bid (as proxied by the highest counterfactual DEB) or highest IFM SMEC multiplied by 1.1 will inherently eliminate intra-day fluctuations and may also over- or under-state prices depending on the time of day. For example, the two static parameters undershoot the RTPD SMEC in peak hours on September 6, 2022 but overshoot the RTPD SMEC for other hours of the day. Static parameters may not sufficiently capture intra-day price variations; in particular, IFM SMEC may not capture regional price variations well enough to serve as a proxy for opportunity costs outside the CAISO area.

Figure 1. Price trend comparison on September 6, 2022

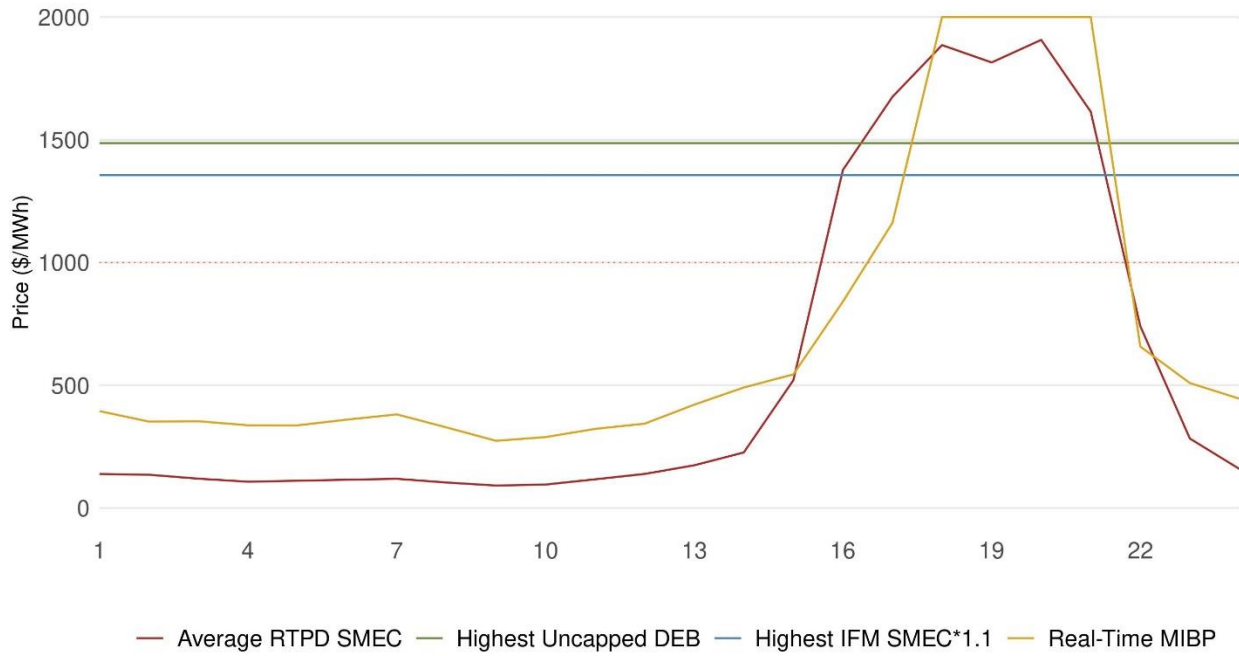


Figure 2. Price trend comparison on August 16, 2023

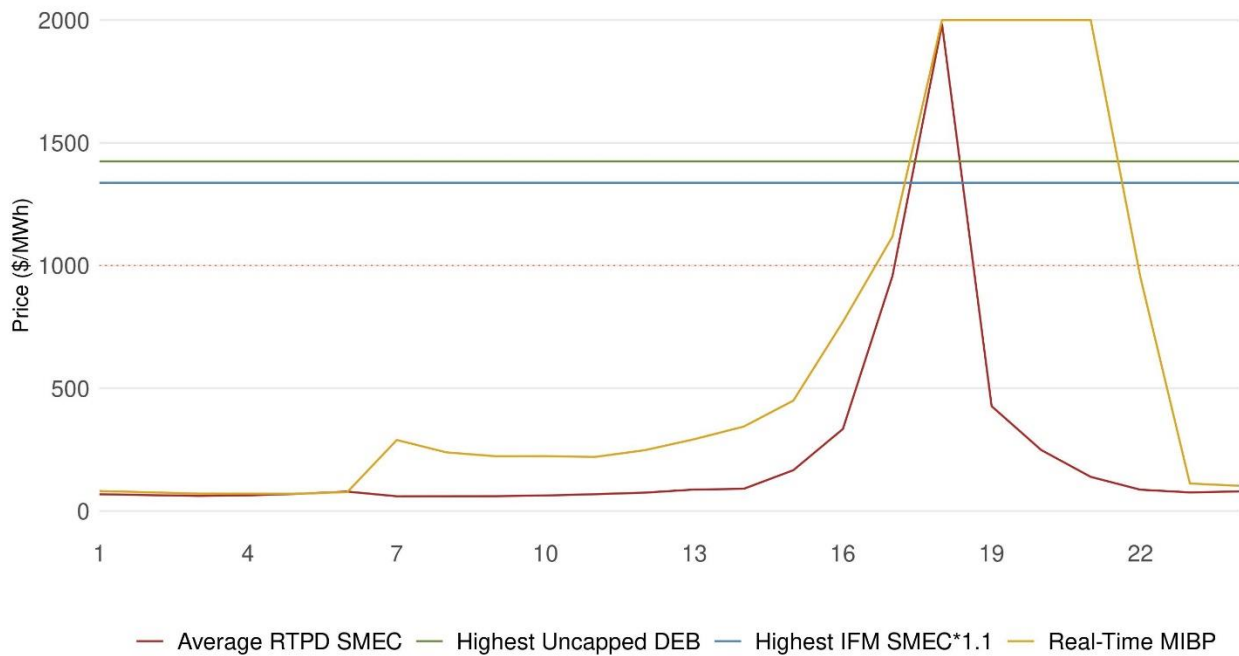
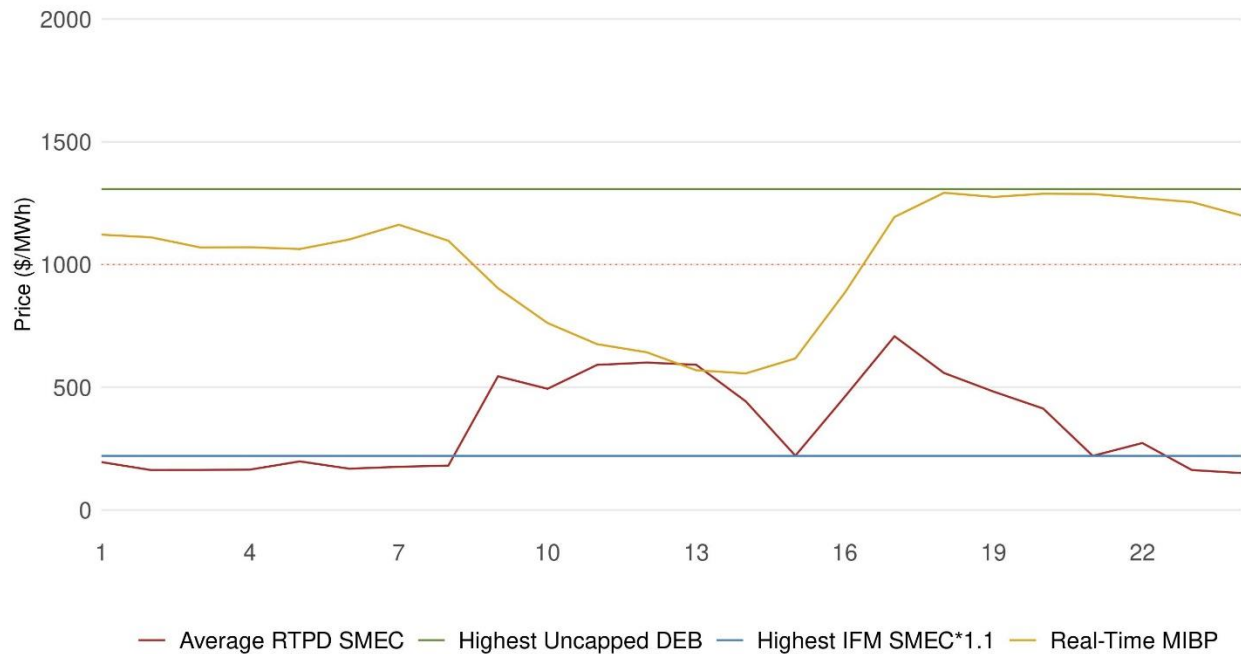


Figure 3. Price trend comparison on January 14, 2024



## 4. Proposed Policy Changes for summer 2024

Considering the stakeholder recommendations and input, the ISO has identified proposals that may be feasible for summer implementation, pending further refinement and stakeholder input. These proposals (1) remove the cap on DEBs for all resources and (2) modify the bid cap for energy storage resources **in the real-time market**.

The proposals in this section address the identified issues for hydro and battery storage resources separately. The ISO considers this to be an appropriate outcome given the differences between how energy storage and hydro resources define opportunity costs today.

The ISO proposes the following:

- **(Section 4.1) Revise the cap on all Default Energy Bids from \$1,000/MWh to \$2,000/MWh.** This proposal would “uncap the DEB” for all resources. In particular, this would allow hydro resources to bid up to a value that reflects the opportunity costs already defined in their DEBs, even when those costs exceed \$1,000/MWh.
- **(Section 4.2) Modify the bid cap for energy storage resources.** The additional modification of this proposal offers bidding flexibility to storage resources to maintain their relative position in the supply stack **in the real-time market**.

#### 4.1. Proposal: **Revise the cap on all Default Energy Bids from \$1,000/MWh to \$2,000/MWh**

This proposal would revise the cap on DEBs from \$1,000/MWh to \$2,000/MWh. This change would apply to all DEBs<sup>7</sup> in both the day-ahead and real-time markets. As the DEB was designed to represent a resource's verifiable cost-based offer, this proposal is consistent with FERC Order No. 831 rules that require verified cost-based incremental energy offers to be capped at \$2,000/MWh.

This proposal represents a process change, not a value change. Removing the \$1,000/MWh cap from DEB calculations does not change the basis for calculating marginal reference costs accepted as default energy bid as described in the ISO's tariff. This proposal would not change the resource-specific parameters defined by any resource's DEB calculation, but offers value to resources for whom the automated RLCR process is cumbersome or unusable for validating costs above \$1,000/MWh. The ISO has observed that DEB values today may, at times, rise above \$1,000/MWh if not for the existing cap, based on the analysis in this section.

Today, gas resources can verify costs above \$1,000/MWh through the RLCR process. This proposal does not give gas resources any additional headroom to make adjustments, but instead simplifies the adjustment process by removing the requirement to confirm existing cost information captured in the DEB. Gas resources would still rely on the RLCR process to make DEB adjustments in response to gas price volatility, in cases where the ISO-calculated DEB did not sufficiently capture that gas price volatility. Additional supporting information would still be required to support those types of DEB adjustment requests.

*This proposal represents the foundational step for all further enhancements. A durable change, this proposal will simplify and support future enhancements to the RLCR process as well as additional interim rules.*

In the near term, this change would have important impacts to bidding rules and market power mitigation.

#### **Bidding Rules when the uncapped DEB is above \$1,000/MWh: each resource's DEB becomes its bid cap**

The offer cap for each resource would be set by that resource's DEB, should the value of the DEB rise above \$1,000/MWh. In effect, a resource's energy offer above \$1,000/MWh would be considered cost-verified because it is assessed against the DEB value, which is accepted today as a reasonable measure of resource-specific, verifiable costs.

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<sup>7</sup> Through the PFE working group effort, stakeholders identified proxy demand response (PDR) for consideration within the scope of an interim approach. These resources do not currently have a DEB option, but are discussed in Section 6.2 of this paper. Other resources without DEBs, including hybrid resources, are out of scope for the interim.



This proposal to remove the cap from the DEB does not obviate the need for the RLCR process generally. In the event of fuel price spikes, gas-fired resources may still need to use the RLCR process to adjust their DEB if the ISO-calculated DEB does not capture the fuel price spike. A gas resource's DEB ("uncapped DEB") is calculated pre-market, but the SC can use the automated RLCR process to validate an adjusted DEB in excess of the uncapped DEB value in response to changing gas prices<sup>8</sup>.

This proposal would cap bids above \$1,000/MWh by the higher of \$1,000/MWh, the uncapped DEB, or the adjusted DEB. This logic ensures that future enhancements to the RLCR process recommended by stakeholders to allow storage and hydro resources to adjust their DEBs in response to intra-day opportunity costs will be consistent with existing rules.

When the uncapped DEB is above \$1,000/MWh, the uncapped DEB becomes the resource's specific bid cap. A resource's ability to bid up to its uncapped DEB would not be conditional on any other factors. The conditions must be met for other unspecified resources (e.g. RA imports, virtual bids) to bid above \$1,000/MWh—a cost-verified bid above \$1,000/MWh or a MIBP value above \$1,000/MWh—do not impact the bid cap for resources with an uncapped DEB.

➔ **The bidding rules in this proposal cannot be applied to resources using the storage DEB option in the timeframe prescribed by stakeholders.** Uncapping the DEB could still confer the benefits of improved outcomes post-mitigation to storage resources under certain conditions.<sup>9</sup> Storage resources (and all resources) also are still eligible for after-market cost recovery under the CAISO's tariff. To ensure the problem statement posed by stakeholders can be resolved, the proposal in Section 4.2 provides an incremental, interim solution narrowly targeted for battery storage resources.

### Market Power Mitigation when the DEB is above \$1,000/MWh

Revising the DEB calculation cap to \$2,000/MWh may improve outcomes for resources subject to local market power mitigation procedures. Stakeholders emphasized the importance of DEB modifications to prevent resources from being mitigated to a DEB that is capped at \$1,000/MWh. This proposal offers some relief to mitigated resources without substantially changing existing market power policy.

Stakeholders emphasized the need to modify DEBs to prevent mitigating resource bids to \$1,000/MWh or lower. Many stakeholders support re-evaluating DEB calculations to better capture opportunity costs. Stakeholders also support leveraging the RLCR process to facilitate DEB adjustments in response to intra-day opportunity costs. While most stakeholders agree with these approaches, many stakeholders are concerned about changing existing DEB calculations through an expedited policy process. This proposal offers some relief to mitigated resources, in so far as the uncapped DEB rises above \$1,000/MWh, without changing existing market power mitigation policy or procedure.

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<sup>8</sup> The Issue Paper for Rules for Bidding Above the Soft Offer Cap explains the automated RLCR process in more detail: [IssuePaper-StakeholderRecommendations-PriceFormationEnhancements-Rules-BiddingAboveSoftOfferCap.pdf \(caiso.com\)](https://www.aiso.com/IssuePaper-StakeholderRecommendations-PriceFormationEnhancements-Rules-BiddingAboveSoftOfferCap.pdf)

<sup>9</sup> See Appendix D for examples

### Uncapped storage DEB calculations may not be sufficient to allow bidding above the soft offer cap

This proposal is an important first step and makes an incremental improvement, but may not solve in its entirety the problem presented by stakeholders. Stakeholders support uncapping the DEB as an initial step but note that it may not achieve the objective for summer.

Of immediate concern, if implemented in isolation, this proposal may exacerbate the ability for battery storage resources to maintain state of charge should limited energy hydro resources be able to systemically position themselves higher in the offer stack. Stakeholders have expressed concern that the ISO calculated DEBs do not accurately reflect expected costs, and do not explicitly consider potential opportunity costs informed by other technology types or prevailing regional conditions illustrated by the counterfactual analysis in Figures 5 and 6 below, the existing calculation of the storage DEB might be calculated to be less than \$1,000/MWh and less than hydro DEBs even uncapped.

The opportunity cost defined by the storage DEB option is based on the 4<sup>th</sup> highest day-ahead LMP, which has not been observed to regularly be above \$1,000/MWh during conditions when prices rise above \$1,000/MWh in real-time. Figure 4 below shows a counterfactual calculation of hydro DEBs and storage DEBs, had the \$1,000/MWh cap in the existing calculation not been applied. The values of these counterfactual DEBs are represented in a box-whisker plot<sup>10</sup> where hydro DEBs are plotted in blue, storage DEBs are plotted in red, and a horizontal dashed line is shown at \$1,000/MWh for reference. The data is plotted for a broader set of high-priced days from 2022 to 2024.

High nodal LMPs on September 6, 2022 drove counterfactual storage DEBs to exceed the \$1,000/MWh threshold but only for a few, resource-specific outliers, primarily due to congestion, while counterfactual hydro DEBs all remained below \$1,000/MWh. However, on both August 16, 2023, and January 14, 2024, more counterfactual hydro DEBs were above the \$1,000/MWh threshold due to high bilateral market prices while fewer counterfactual storage DEBs were above the threshold.

An uncapped DEB alone may not be sufficient for storage resources to submit energy offers at or above \$1,000/MWh.

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<sup>10</sup> A box-whisker plot represents data where the box covers the interquartile range (25<sup>th</sup> to 75<sup>th</sup> percentile), the line in the middle of the box represents the median (50<sup>th</sup> percentile), and dots represent outliers.

Figure 4. Counterfactual uncapped default energy bid values, high-priced days in 2022

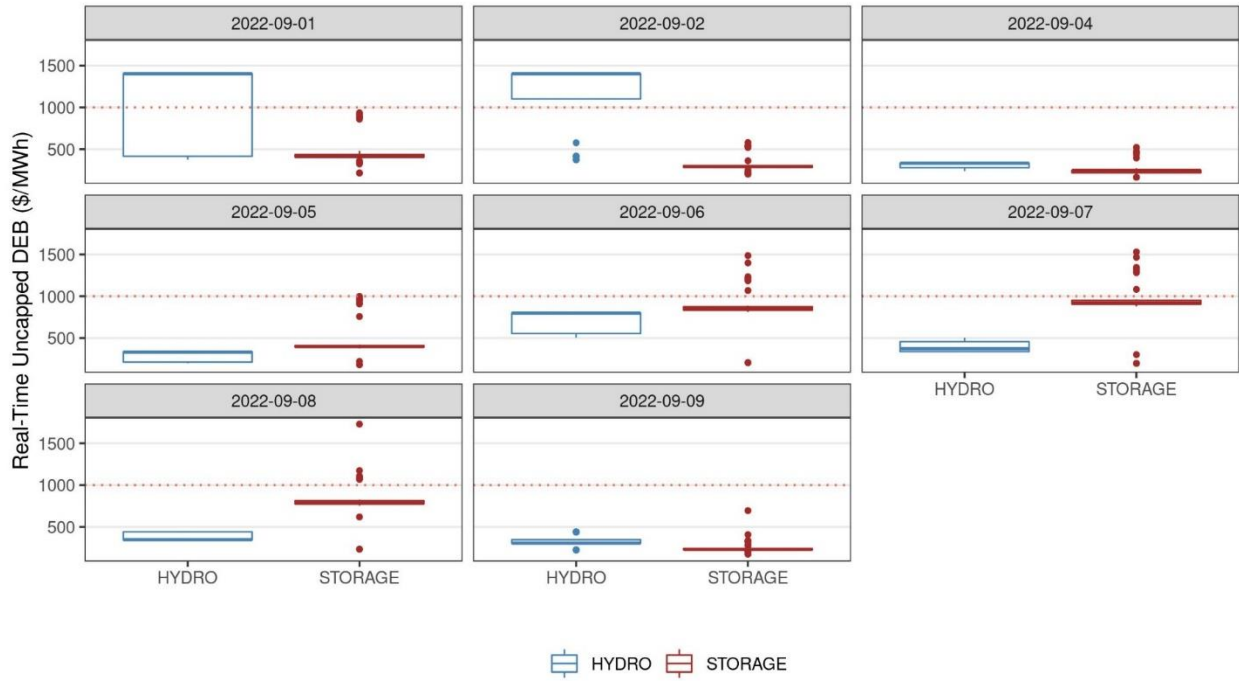
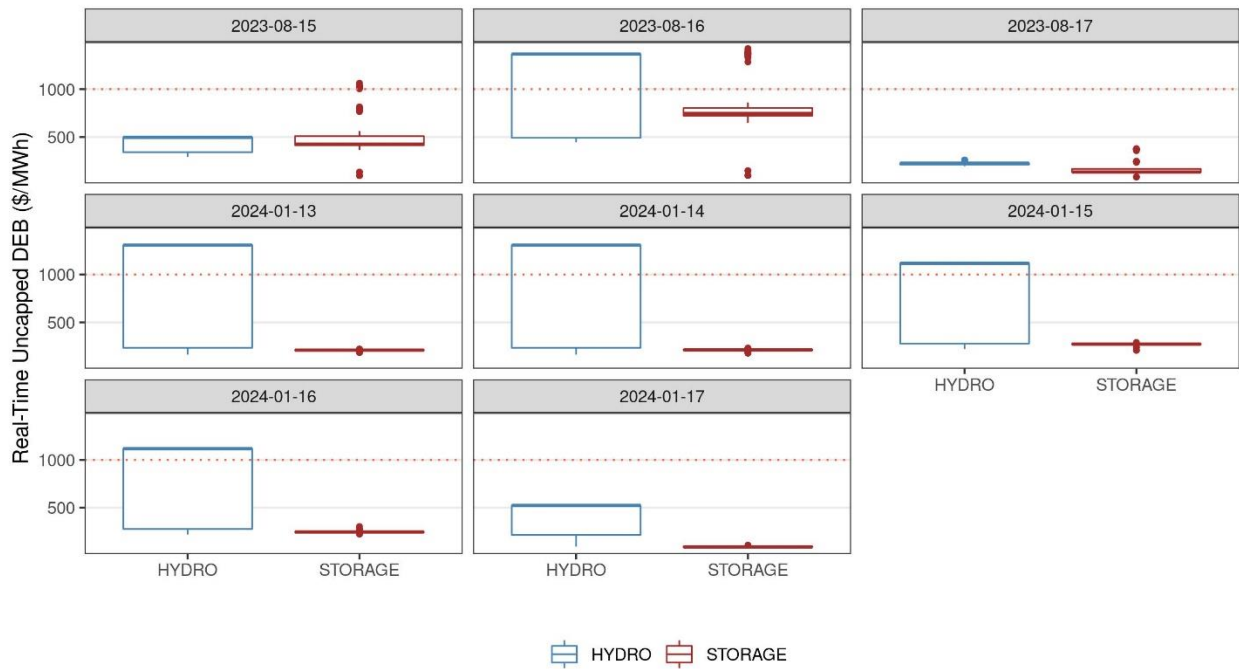


Figure 5. Counterfactual uncapped default energy bid values, high-priced days in 2023 and 2024



## 4.2. Proposal: **Modify the bid cap for energy storage resources using a proxy cost based on bilateral indices**

The technology implementation required to use the storage DEB option as a resource's bid cap is not feasible for implementation by stakeholders' desired implementation date. Some storage resources use different DEB options, e.g. a negotiated DEB (NDEB) option, for which implementation may be feasible for summer 2024. Regardless of implementation timelines, storage DEBs are not expected to be calculated at a sufficiently high value under the previous proposal alone to address stakeholder concerns. This proposal is incremental to the previous proposal, and extends equally to all storage resources<sup>11</sup>.

This proposal provides storage resources with additional bidding flexibility in the **real-time market** to reflect intra-day opportunity costs not fully captured by existing storage DEBs. It allows storage resources to benefit from the uncapped DEB value if market power mitigation occurs. This proposal is intended to ensure, to the extent practicable, that storage resources can *at least* reflect the value currently represented by their DEB.

Today, storage resource bids are capped at \$1000/MWh, without consideration of the DEB, going into the day-ahead market (DAM). Most stakeholders have not considered problem statements specific to the DAM because the market run can fully account for opportunity costs by optimizing over the time horizon of the full trade-day. Some stakeholders want solutions to address DA and RT to minimize differences, but did not identify modifications to the DAM as a high priority. **This element of the proposal will only apply in the real-time market.**<sup>12</sup> The ISO recognizes the immediate problem statement stakeholders asked for resolution on applies to the real-time market, which is where the risk arises for premature depletion of state of charge. While the ISO continues to believe that it is generally preferable to have rules aligned in the day-ahead and real-time markets, given the significant feedback and the existing ability of the day-ahead market to optimize storage over the twenty-four hour horizon, the ISO proposes to make this change only for the real-time market at this time. Future stakeholder conversations can provide additional time to consider any changes for the day-ahead market.

Today, storage resources can only bid above \$1,000/MWh in real-time if they receive a successfully adjusted DEB through the RLCR process, a function not available to storage resources today. Stakeholder proposals that would allow storage resources to successfully adjust their DEBs are not feasible for summer.

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<sup>11</sup> These resources will be identified by technology type instead of DEB type.

<sup>12</sup> This change is reflected in the memorandum provided to the ISO Board of Governors and Western Energy Imbalance Market Governing Body.

This proposal would apply to all battery storage resources, CAISO and WEIM, in ~~both day-ahead and the~~ real-time market.

### Bidding Rules above \$1,000/MWh for storage resources

The ISO proposes to allow storage resources to bid up to the maximum value of two additional proxies ~~in the real-time market~~: the fourth-highest hourly MIBP value and the highest cost-verified bid<sup>13</sup>.

For battery storage resource's whose DEBs cannot be used to inform the bid cap by stakeholders' targeted implementation date, the ISO proposes to allow these storage resources to bid up to the maximum of the MIBP's fourth-highest calculated hourly value and the highest cost-verified bid when either of those values rise above \$1,000/MWh.

For battery storage resource's whose DEBs can be used to inform the bid cap by stakeholders' targeted implementation date, the ISO proposes to allow these storage resources to bid up to the maximum of the resource's DEB, MIBP's fourth-highest calculated hourly value, and the highest cost-verified bid when any of those values rise above \$1,000/MWh. If none of those values rise above \$1,000/MWh, these resources' bids would be capped at \$1,000/MWh.

The ISO's proposal to utilize the fourth-highest hourly MIBP value would enable storage resources to manage their SOC ~~in the real-time market~~ through economic participation. Functionally, this proposal ensures four hours of SOC, which correlates to the typical sizing of the existing battery fleet, is available for use across net-peak hours, aligns with the day ahead schedules, and accurately values the storage resources' opportunity costs.

### MIBP: Stakeholder feedback, and supporting analysis

Stakeholder approaches using the MIBP as a proxy for storage opportunity costs received the most stakeholder support as an interim solution. However, stakeholder proposals vary in terms of how to apply the hourly MIBP values. Some stakeholders urge the ISO to carefully consider the risks and benefits of each approach to provide sufficient time for stakeholder input and analysis.

The ISO performed analysis to compare historical real-time storage locational marginal prices (LMPs) from the fifteen minute market (RTPD) to both the hourly MIBP and fourth-highest MIBP on three days of interest, September 6, 2022, August 16, 2023, and January 14, 2024. A snapshot of peak hours, hours ending 14 through 22, are shown. The purpose of this analysis is to compare the MIBP to realized real-time prices to evaluate how an MIBP-derived bid cap may have performed during tight system days. Note that while the effective storage bid cap was \$1,000/MWh for the days below, the energy component or SMEC was still able to rise above \$1,000/MWh, and nodal components like congestion also contributed to high LMPs during some hours. RTPD LMPs for all storage resources are shown using

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<sup>13</sup> With the exception of the DA Storage DEB option, most DEB calculations are known prior to the applicable market and with sufficient time to allow SCs to make adjustments to bids or request an adjusted DEB through the RLCR process. However, the values informing the battery storage bid cap may not be known at the time that SCs submit bids for the relevant trade-day or hour. For example, resources can submit 'cost-verified bids' up until 75 minutes prior to the relevant RTM. Battery storage resource SCs would not have visibility into how this information affects the bid cap prior to submitting bids.

a box-whisker plot, while the hourly and fourth-highest MIBP values are plotted in green and blue respectively.

On September 6, 2022, the hourly MIBP values track the interquartile range of storage RTPD LMPs fairly closely, with the exception of some outliers that are driven higher or lower based on other non-energy LMP components. The fourth highest MIBP maxes out at the \$2,000/MWh cap, so a bid cap based on the fourth-highest MIBP would have been set at a static \$2,000/MWh value for the entire day. Conversely, on August 16, 2023, the hourly MIBP tracks higher than the interquartile range of storage LMPs during the evening hours whereas the fourth-highest MIBP also maxes out at \$2,000/MWh. On January 14, 2024, the MIBP is far higher than RTPD storage LMPs, primarily driven by price separation between the high bilateral prices in the Pacific Northwest that set the MIBP and the relatively lower resource-specific LMPs.

Figure 6. Comparison of real-time storage LMPs and MIBP values, September 6, 2022

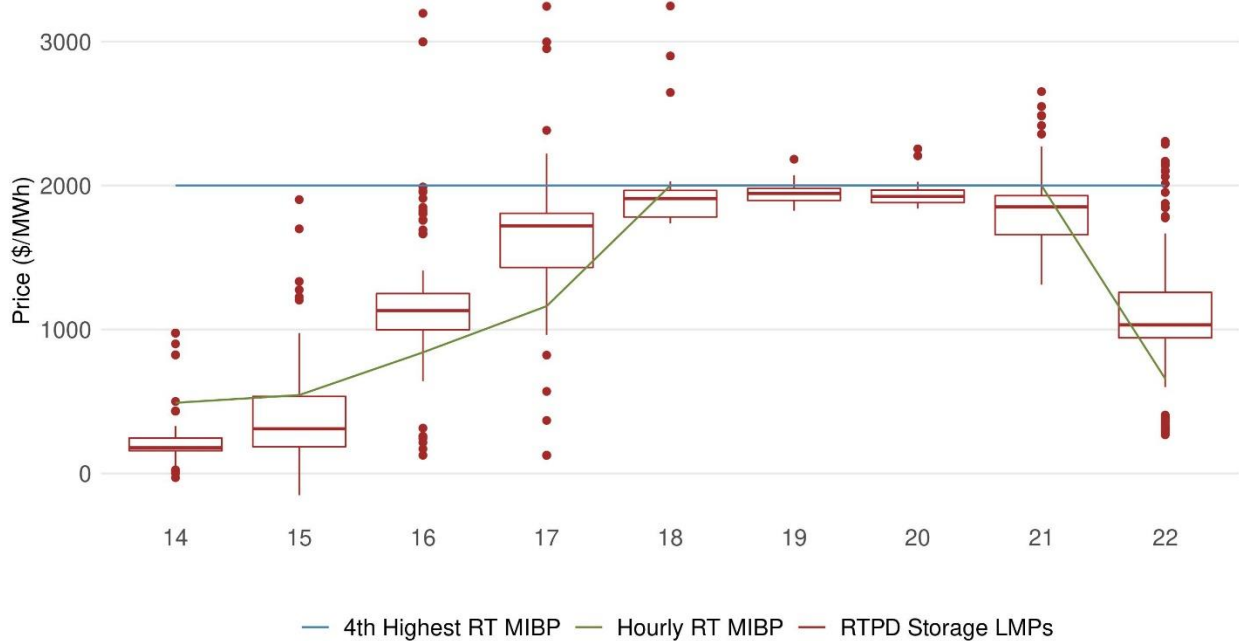


Figure 7. Comparison of real-time storage LMPs and MIBP values, August 16, 2023

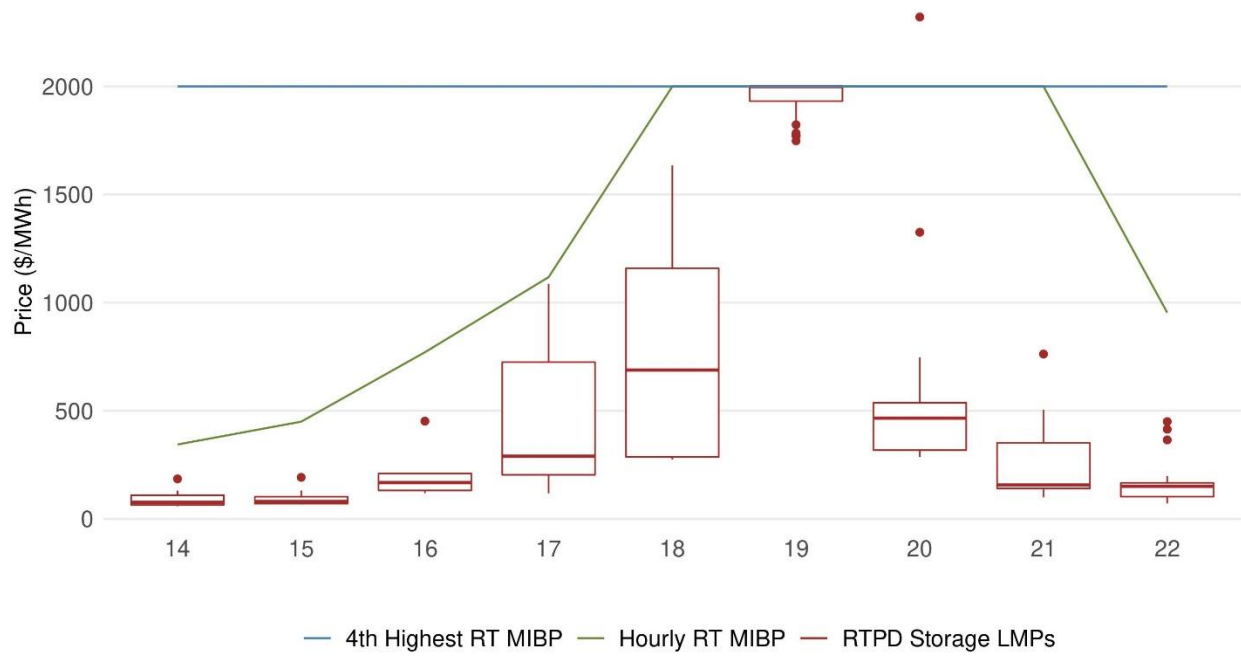
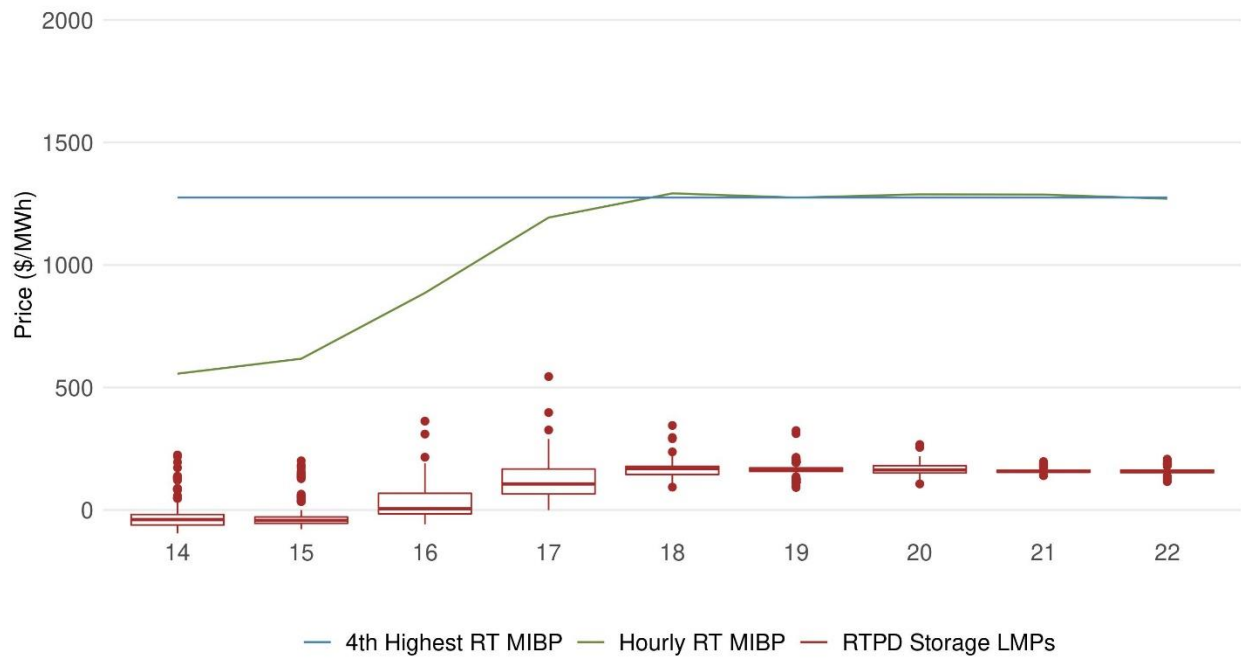


Figure 8. Comparison of real-time storage LMPs and MIBP values, January 14, 2024



### Market Power Mitigation when the storage DEB is above \$1,000/MWh

Market power mitigation may partially reduce the intended benefits of providing this additional bidding flexibility to storage resources if the bid cap does not consider the storage resource's DEB. Market power mitigation may also partially reduce the intended benefits of uncapping the DEB if the bid cap does not consider the storage resource's DEB.

This proposal is a necessary incremental step to unlock the benefit of uncapping the storage DEB for post-mitigation market outcomes. Even if a storage DEB uncapped is calculated to be above \$1,000/MWh, that DEB value will not be used in MPM if the resource cannot submit a bid above \$1,000/MWh. Storage resources will only have potential mitigation to a DEB calculated above \$1,000/MWh during the conditions identified in Section 4.2 that result in an increase in the storage resources separately determined offer cap.

Some stakeholders do not consider a bid above \$1,000/MWh and above the DEB to be "cost-verified", while others acknowledge the logic of the proxies represented in this proposal and the necessity of these considerations in the near-term. This proposal is intended to provide additional bidding flexibility in the near-term without superseding DEB calculations determined and approved by stakeholder processes.

## 4.3. Monitoring and Evaluation

The automated RLCR process allows the ISO to audit any submitted requests and requires scheduling coordinators to retain documentation that justifies their request. The penalty for audit failure may include a temporary suspension from using the automated RLCR process. While the ISO would already have the relevant supporting information for bids above \$1,000/MWh that are capped by the DEB, some stakeholders expressed concerns with divorcing the ability to bid above \$1,000/MWh from similarly standardizing controls.

The ISO proposes to monitor the use of the new bidding flexibility enabled through this proposal and consider associated market results in any evaluation of future market reforms.

## 5. Long term enhancements for future consideration

### 5.1. RLCR process

Stakeholders support enhancements to the RLCR process that would enable non-gas resources to verify and reflect changes to their resource specific opportunity costs in the market. Some stakeholder recommendations include:

- facilitating DEB adjustments in response to intra-day opportunity costs that vary hourly, and beyond the value calculated by the DEB
- informing real-time opportunity costs using a forward looking real-time market time horizon



## 5.2. Proxy Demand Response (PDR)

The ISO understands PDR opportunity costs to be different than the temporal opportunity costs due to energy limitations. The opportunity costs for PDR might include, for example, the forgone usage of energy for residential or commercial activity. The ISO lacks visibility into the underlying assets, and therefore has a limited ability to verify PDR specific costs. Engagement with the PDR community, significant policy discussion and stakeholder consideration is warranted to properly define the costs associated with those resources.

## 6. Stakeholder Engagement

Stakeholder input is critical for developing market design policy. The schedule proposed below allows opportunity to for stakeholder involvement and feedback.

### 6.1. Schedule

Table 2 lists the proposed schedule for the stakeholder process.

*Table 2: Schedule for Stakeholder Process*

<b>Item</b>	<b>Date</b>
<b>Draft Final Proposal</b>	May 1, 2024
Stakeholder call	May 2, 2024
Stakeholder comments due	May 8, 2024
<b>Market Surveillance Committee Opinion</b>	May 13, 2024
MSC Opinion Call	May 15, 2024
Joint EIM Governing Body and CAISO Board of Governors	<i>May 21-23, 2024</i>
Target Implementation	<i>Summer 2024</i>

The CAISO proposes to present its proposal to the EIM Governing Body and CAISO Board of Governors on May 21-23, 2024. The CAISO is committed to providing ample opportunity for stakeholder input into its market design, policy development, and implementation activities. Stakeholders should submit written comments to [InitiativeComments@caiso.com](mailto:InitiativeComments@caiso.com).

## 6.2. Governing Body Classification

This initiative proposes changes to allow certain resources to bid above the soft offer cap of \$1,000 MWh. As explained below, CAISO staff believes that the WEIM Governing Body has joint authority with the Board of Governors over the proposed change.

The role of the WEIM Governing Body with respect to policy initiatives changed on March 20, 2024, when the Board of Governors adopted revisions to the corporate bylaws and the Charter for WEIM and EDAM Governance to implement the Governance Review Committee's EDAM governance proposal. Under the new rules, the Board and the WEIM Governing Body have joint authority over any

proposal to change or establish a tariff rule applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in WEIM/EDAM... The scope of this joint authority excludes, without limitation, any other proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid.

Charter for WEIM and EDAM Governance § 2.2.1. The proposed tariff changes to implement the initiative would apply to the entire market footprint, and thus be "applicable to WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within WEIM/EDAM Entity balancing authority areas, in their capacity as participants in WEIM/EDAM." They would not be applicable "only to the CAISO balancing authority area or to the CAISO-controlled grid." Accordingly, the proposed changes fall within the scope of joint authority.

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

## 6.3. Next Steps

The CAISO will discuss the Draft Final Proposal during the stakeholder meeting on May 2, 2024. The CAISO requests stakeholders submit written comments on this proposal by May 8, 2024.

# 7. Appendices

## 7.1. Appendix A: The storage and hydro DEB calculations

Stakeholders and the ISO developed technology-specific DEB options for storage and hydro resources to better reflect their unique opportunity costs.

See BPM for Market Instruments Attachment D for more detail on DEB calculations.

### The Storage DEB Calculation

This option reflects the costs of storage resources with a limited storage duration and variable operating costs. This option is available to applicable, participating storage resources. Because the costs defined in this DEB calculation use data from the day-ahead market, this option is not available to WEIM storage resources outside of the CAISO BAA.

This storage DEB option was developed through recent stakeholder policy initiatives: Energy Storage and Distributed Energy Resources Phase 4<sup>14</sup>, and Energy Storage Enhancements<sup>15</sup>.

The Storage DEB has three main cost components:

1. Energy costs
2. Variable storage operations costs
3. Price-based opportunity costs

$$\text{Storage DEB} = \text{Max} \{ [\text{Max} (E_{n\delta/\eta}, 0) + \rho], \text{PB\_OC}_\gamma \} * \text{DEB Multiplier}$$

Where:

$E_n$	Energy Cost	Estimates the average cost of energy needed to charge the storage resource, using LMP prices from the relevant PNode
$\eta$	Round-Trip Efficiency	A resource-specific static value
$\delta$	Energy Charging Duration	Based on a resource's registered max/min continuous energy limit and Pmin, adjusted for round trip efficiency
$\gamma$	Energy Discharge Duration	Based on a resource's registered max/min continuous energy limit and Pmin, adjusted for round trip efficiency
$\rho$	Variable Storage Operations Cost	A resource-specific registered value representing costs associated with variable operation of the resource, including cycling and cell degradation costs
PB_OC	Price-based Opportunity Cost	Estimates the market opportunity cost corresponding to the $n$ th highest LMP, where $n$ corresponds to the discharge duration of the resource (e.g. 4 <sup>th</sup> highest hour for a 4 hour discharge duration)
DEB Multiplier	110% Multiplier (1.1)	Multiplier to cover any potential variability between the storage DEB calculation and

<sup>14</sup> [FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4-DefaultEnergyBid.pdf \(caiso.com\)](#)

<sup>15</sup> [FinalProposal-EnergyStorageEnhancements.pdf \(caiso.com\)](#)

		resource’s actual marginal costs; consistent with other DEB calculations
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**The Hydro DEB Calculation**

The Hydro DEB option reflects opportunity costs a hydroelectric generator faces due to their limited water supply. This option is available to hydroelectric resources in both CAISO and WEIM that have storage and can demonstrate limited water storage capability.

The hydro DEB option was developed through the Local Market Power Mitigation Enhancements stakeholder initiative to offer more flexibility for hydro resources. Stakeholders noted that the existing opportunity cost adders calculated monthly could account for the intertemporal energy sales at a unit’s specific location, but did not capture the opportunity for intertemporal sales outside of the CAISO’s real-time energy market, or reflect short-term (daily) limitations<sup>16</sup>.

The cost components are linked to resource-specific parameters including the resource’s maximum storage horizon, electric pricing hub based on the resource’s location, other electric pricing hubs to which the resource has firm transmission rights.

$\text{Hydro DEB} = \text{MAX}[\text{Gas floor, Short-term component, Long-term component}]$
----------------------------------------------------------------------------------------------

Where:

Gas floor	<p>The gas floor represents the opportunity cost for the hydroelectric generator to sell electricity generated from a similarly-situated gas resource instead of the hydro resource.</p> <p>This is formulated similarly to the variable cost DEB calculation for gas generators and uses a standard peaker heat rate.</p>	$1.1 * [11,068 \text{ MMBtu/MWh} * \text{Fuel region gas price}]$
Short-term component	<p>The short term component represents the opportunity cost of sales at the local wholesale electric pricing hub.</p>	$1.4 * \text{MAX}[\text{Day Ahead}_L, \text{Balance-of-Month}_L, \text{Month Ahead}_{L,+1}]$

<sup>16</sup> Local Market Power Mitigation Enhancements, Draft Final Proposal P 31 [DraftFinalProposal-LocalMarketPowerMitigationEnhancements2018.pdf \(caiso.com\)](#)

	The Day Ahead component is the DA power price index at the local default electric pricing hub. Balance of month and future monthly index prices are also included. This is the same bilateral price index used to calculate the MIBP.	
Long-term component	The long-term component represents the opportunity cost of sales at the default <u>and</u> additional electric pricing hubs over future months of the storage horizon using future monthly index prices.	$1.1 * \text{MAX}[\text{Day Ahead}_L, \text{Balance-of-Month}_L, \text{Month Ahead}_{L+1}]$

## 7.2. Appendix B: Scalars

Scalars incorporated within DEB calculations can account for a margin of error between the information available to the ISO when the DEB is calculated and the actual incremental costs facing generators. The DEB is a single value calculated each day but updated information may become available that can inform the DEB. The reasonableness threshold, which can also have a scalar, can account for intra-day variation and facilitate hourly adjustments through the automated RLCR process.

Scalars incorporated into DEB calculations represent a margin of error between what is known by the ISO and what is reasonably expected to materialize. For a scalar to be an effective proxy, it should be resource specific, or based on observations or known variations between the actual and expected marginal costs to which it is being applied.

**Hydro DEB option:** Hydro uses a 140% scalar for the short-term component of the DEB. The analysis to inform the scalar calculated the default energy bid for each day without a scalar and compared it to real-time FMM prices in the resource’s balancing area over a year<sup>17</sup>. It was observed that a resource would be dispatched any time EIM prices are greater than the DEB. The scalar equivocates the cost where the storage resource would be expected to be dispatched less than the potential daily energy availability 95% of the intervals assessed.

Previous policy discussions have considered the scalar on the DEB a safe harbor, while adjustments through the RLCR process require documentation to support actual costs. A larger scalar would account for a greater range of potential outcomes, but could also inflate costs unnecessarily if more precise information is available. Reasonableness thresholds based on a resource’s specific parameters should

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<sup>17</sup> Local Market Power Mitigation Enhancements October – December 2018: [Presentation-LocalMarketPowerMitigationEnhancements-WorkingGroup-Oct10\\_2018.pdf \(caiso.com\)](#), [Presentation-LocalMarketPowerMitigationEnhancements-Nov28\\_2018-UpdatedVersion.pdf \(caiso.com\)](#)

allow resources to reflect costs no less than the value of their DEB, and request adjustments beyond that value hourly in real-time given supporting documentation.

### 7.3. Appendix C: Conditions to raise the energy bid cap

Today, one of two conditions must be met to raise the energy bid cap above the soft offer cap:

1. The market accepts a bid above \$1,000/MWh from a resource-specific resource, or
2. The allowable MIBP goes above \$1,000/MWh

Today, the tariff requires resource-specific resources to successfully cost-verify and receive an adjusted DEB through the reference level change request (RLCR) process in order for the market to accept a bid above \$1,000/MWh. From a systems perspective, any bid above \$1,000/MWh from a resource specific resource would fulfill the condition to change the energy bid cap. However, the market only clears resource-specific resource bids above \$1,000/MWh that have been successfully verified through the RLCR process because that is the only way for resource-specific resources to reflect a bid above \$1,000/MWh in the market today.

When the bid cap goes up, a set of penalty price parameters are doubled so that priorities are preserved.

If the bid cap is raised in any hour of the day-ahead market, the penalty prices will be scaled up for all trading hours of the day-ahead market and real-time market for the same trading day.

If the bid cap is not raised in any hour of the day-ahead market, but the conditions apply to raise the bid cap in hours of the real-time market, the real-time market will use the scaled up penalty price for all intervals of overlapping real-time market horizons.

### 7.4. Appendix D: Examples of battery storage bidding rules and MPM outcomes

The proposal to revise the DEB cap to \$2,000/MWh may impact the outcome of MPM without otherwise changing existing market power policy. For battery storage resources, the impact depends on the degree of bidding flexibility provided by the proposal in Section 4.2.

The following examples are for illustrative purposes only.

In each example scenario illustrated in Table 3 below, two representative resources have the same calculated DEB value, submit the same bid, and are subject to the same bid cap. If the resource's bid is capped, **the revised bid is shown in bold**. If the resource's bid is subject to MPM, **the mitigated bid is shown in bold**.<sup>18</sup> A resource's bid could be both capped and subject to MPM.

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<sup>18</sup> The CAISO proposes no changes to existing MPM logic; for simplicity, these examples assume that if mitigated, resources are mitigated to the lower of their DEB value and submitted bid.

The difference between the two resources being compared is the implementation timeline for each resource's DEB option:

- Resource A's bids are capped by the battery storage bid cap without consideration of the DEB because Resource A uses a DEB option that can not be used to inform the bid cap pre-market consistently across both markets (e.g. storage DEB)
- Resource B's bids are capped by the higher of the LESR bid cap and its DEB (it uses a DEB option that can be used to inform a pre-market bid cap, e.g. negotiated DEB).

### Takeaways

If the DEB is not included in the bid cap logic, there is a risk that the battery storage bid cap may be too restrictive and could prevent a resource from reflecting the calculated DEB value in its bid. The two scenarios in which the outcome for Resource A and B differ, highlighted in blue in the table below, are Scenarios B and E where the DEB is higher than the highest value in the battery storage bid cap. However, the counterfactual analysis of storage DEB values suggests that this risk is low. The incremental proposal in Section 4.2 is expected to provide sufficient bidding flexibility to allow resources to reflect at least the value of their uncapped DEB.

In Scenario G, the resource submits a bid less than the bid cap and DEB. If MPM is triggered, neither resource A nor B's bid is mitigated. Resource bids will not be revised up to the DEB if they cannot bid up to the value of the DEB, or choose not to bid up to the value of the DEB.

Even if a resource is able to bid above the value of the DEB and above \$1,000, there is still a risk that the resource's bid will be mitigated down to the value of the DEB.

**Table 3: Battery storage bidding rules and MPM outcomes**

Scenario	Both resources			Resource A, DEB is not considered in the bid cap		Resource B, DEB informs the bid cap	
	DEB (\$/MWh)	Bid (\$/MWh)	Battery Storage Bid Cap (\$/MWh)	If Capped (\$/MWh)	If Mitigated (\$/MWh)	If Capped (\$/MWh)	If Mitigated (\$/MWh)
A	900	2,000	900	<b>1,000</b>	<b>900</b>	<b>1,000</b>	<b>900</b>
B	1,400	2,000	900	<b>1,000</b>	1,000	<b>1,400</b>	1,400
C	900	2,000	1,400	<b>1,400</b>	<b>900</b>	<b>1,400</b>	<b>900</b>
D	1,400	2,000	1,400	1,400	1,400	1,400	1,400
E	2,000	2,000	1,400	<b>1,400</b>	1,400	2,000	2,000
F	1,400	2,000	2,000	2,000	<b>1,400</b>	2,000	<b>1,400</b>
G	2,000	1,100	2,000	1,100	1,100	1,100	1,100

### Contents of Table 1 by column

- DEB: values in this column represent the calculated, uncapped DEB consistent with the proposal in Section 4.1
- Bid: The values in this column represent the bid submitted by the resource prior to the bid being validated and submitted into the market for the MPM pass and the market clearing process.

- Battery Storage Bid cap: The value in this column is the highest value of the cap on battery storage resources, described in Section 4.2, that considers the fourth-highest value of the MIBP and the highest cost-verified bid. This column does not consider the DEB value.
- Resources:
  - Resource A: the bid cap is set by the battery storage bid cap
  - Resource B: the bid cap is set by the higher of the battery storage bid cap and the DEB.
- “If capped”: Bids are capped by the higher of the Battery Storage bid cap and the DEB if applicable. Bolded values are capped values used in the market. Un-bolded values would not be capped going into the market.
- “If mitigated”: bolded values are mitigated values. Un-bolded values would not have been impacted by MPM. These examples assume mitigated resources are mitigated down to the DEB, and do not consider the competitive LMP.



**Attachment D – Board of Governors Memo**  
**Tariff Amendment – Price Formation Enhancements**  
**California Independent System Operator Corporation**  
**May 31, 2024**



# Memorandum

**To:** ISO Board of Governors and Western Energy Imbalance Market Governing Body  
**From:** Anna McKenna, Vice President Market Design and Analysis  
**Date:** May 21, 2024  
**Re:** **Decision on rules for bidding above the soft offer cap**

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*This memorandum requires ISO Board of Governors and WEIM Governing Body action.*

## EXECUTIVE SUMMARY

Management proposes to modify the market rules for resources bidding above the \$1,000/MWh energy offer cap, also known as the "soft offer cap." Management launched this expedited stakeholder initiative in response to stakeholder concerns that the current rules may impede the ability of storage and hydro resources to reflect their opportunity costs in their energy offers when those costs exceed the \$1,000/MWh soft offer cap. Approval of this proposal will enable more optimal use of these resources during tight system conditions and will incentivize resources to offer economically in the market.

An expedited but thorough stakeholder process produced a solution feasible for implementation during summer 2024 that will enable these resources to reflect their costs more accurately in their energy offers in order to preserve battery state of charge or limited water in hydro reservoirs for the highest-priced periods. The proposed changes are intended to improve market and operational efficiency and avoid the need for manual actions putting stress on ISO operations. Management believes the proposal meets the objectives of delivering a meaningful improvement and being deliverable in the near-term.

Many stakeholders support the objective of finding a solution that aligns with existing market design objectives. Some stakeholders raise concern with the expedited pace of policy development or question the appropriateness of the interim methodology for representing opportunity costs. Many stakeholders agree that the proposal is incremental to existing policy and accept it as necessarily limited due to desired timing. Management believes the final proposal is a reasonable and balanced approach for addressing near-term market and operational needs and aligns with the scale of storage of energy limited hydro

resources in the system. Notably, in response to continued feedback, Management has elected to modify the proposal since the Draft Final Proposal was published, to better tailor the changes to the problem at hand, acknowledging the quick pace of policy development and the desire to avoid unintended consequences.

Management recommends the ISO Board of Governors and WEIM Governing Body approve the proposed changes to the market rules for resources bidding above the soft offer cap as described in this memorandum. These changes will enhance market efficiency and reliability by allowing storage and hydro resources to better manage their limited energy during tight grid conditions. Any further enhancements needed to better address the identified issues will be considered through the ongoing more comprehensive Price Formation Enhancements stakeholder initiative.

***Moved, that the ISO Board of Governors and WEIM Governing Body approve the change to the rules for bidding above the soft offer cap as described in the memorandum dated May 16, 2024; and***

***Moved, that the ISO Board of Governors and WEIM Governing Body authorize Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the change proposed in this memorandum, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.***

## **DISCUSSION AND ANALYSIS**

Federal Energy Regulatory Commission (“FERC”) Order No. 831, issued in 2016 and implemented by the ISO in 2021, requires the ISO to verify the cost of incremental energy offers above \$1,000/MWh (the “soft offer cap”) before allowing such bids in the market. FERC expressly intended for cost verification to work in conjunction with existing market power procedures. The ISO calculates default energy bids to mirror resources’ costs in the market in conditions when market participants might have market power. The ISO also uses the default energy bid to represent verified energy offers above \$1,000/MWh. Today, all default energy bid calculations are capped at \$1,000/MWh, *i.e.*, the soft offer cap. If suppliers need to bid above \$1,000/MWh, to ensure consistency with FERC Order No. 831, which requires only cost verified bids can go above the soft-offer cap, they must request an adjustment of their default energy bid, called a “reference level change request.”

The reference level change request (RLCR) process was designed to allow resources to request that different costs be used in ISO market processes. Today, gas resources can leverage two options – the manual and automated RLCR processes. The automated RLCR process gives gas resources the opportunity to adjust their default energy bid hourly in response to intra-day gas price volatility. However, storage and

hydro resources are unable to successfully adjust their default energy bids through the automated RLCR process, whether above the soft offer cap or not. The ISO and stakeholders have identified two immediate issues as a consequence:

1. Resources with intra-day opportunity costs may not be able to bid high enough to preserve their limited energy for the highest price hours.
2. These resources may not be able to maintain their day-ahead market schedules when real-time prices exceed the soft offer cap.

Consequently, when the bid cap increases for other resources, such as import and export bids or when a fuel region price increases for a large number of gas fired resources, storage and hydro resources' bids will inevitably be lower than those of other resources that are able to bid above \$1,000/MWh. This will result in such resources being dispatched by the market because they appear more economic. This could result in the depletion of the state of charge or the hydro needed to discharge energy later in the day.

The objective of this proposal is to enable storage and hydro resources with intra-day opportunity costs to reflect these costs more accurately in energy offers, when the bid cap exceeds \$1,000/MWh for other resources, and to ensure that these resources are able to preserve their limited energy for hours when it would be most valued.

Management proposes two sets of changes to address these issues that can be implemented in summer 2024.

First, Management proposes to remove the \$1,000/MWh cap on default energy bids for all resources, in both the day-ahead and real-time markets. This change would allow default energy bids to be calculated above \$1,000/MWh if the underlying cost calculations support such values, not to exceed the hard cap of \$2,000/MWh. It would allow resources to bid up to their true marginal costs, as reflected in their default energy bid, even if it is above \$1,000/MWh, without needing to go through the RLCR.<sup>1</sup> Lifting the cap on default energy bids is particularly relevant for resources using the standard hydro default energy bid. Our analysis shows that hydro default energy bids could have exceeded \$1,000/MWh on historical high-priced days. The \$1,000/MWh cap suppresses their ability to reflect their true opportunity costs in those periods. Note that while this change applies to all resource types, including thermal resources, this is a change in process rather than a change in rules. That is, this change will streamline the process of submitting offers over \$1,000/MWh for thermal resources, but it does not change the conditions under which resources would have a valid reason to offer over \$1,000/MWh.

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<sup>1</sup> The storage default energy bid is not available for use as a bid cap in the day-ahead market. Storage resources can bid in the day-ahead market above \$1,000/MWh up to a default energy bid if they use other default energy bid formulations, such as the Variable Cost Option, LMP Option, or the Negotiated Rate Option. The storage default energy bid calculation would have only ever yielded a value over \$1,000/MWh very infrequently and for only a few resources; this was the main driving factor for including the second part of the policy change in today's proposal.

Second, Management proposes to modify the bid cap for energy storage resources in the real-time market to provide additional bidding flexibility using a proxy opportunity cost value. Even if the default energy bid is uncapped, the opportunity cost used to calculate storage default energy bids may not be a sufficient proxy for real-time opportunity costs on high priced days. That is because the storage default energy bid is based on the fourth highest hourly day-ahead price. Bidding up to the fourth highest hourly day-ahead price means that four hour storage resources will generally be dispatched in real-time for the four hours of highest value, assuming that real-time prices are roughly equivalent to day-ahead prices. However, that assumption often does not hold true on high priced days. This proposal would allow storage resources to reflect real-time opportunity costs not fully captured by the default energy bid.

Note that it is a modification from the Draft Final Proposal to apply this only in the real-time market and not also in the day-ahead market. After further stakeholder feedback and consideration of the Market Surveillance Committee opinion, Management agrees that it is prudent at this stage to focus this rule change on the real-time market, which is where the risk arises for premature depletion of state of charge. While Management continues to believe that it is generally preferable to have rules aligned in the day-ahead and real-time markets, Management acknowledges the quick pace of policy development and the possibility for unintended consequences to arise. Moreover, the day-ahead market's 24 hour horizon will optimize the use of storage and result in day-ahead discharge schedules in the highest value hours, regardless of whether storage is able to bid over \$1,000/MWh.

In the real-time market, this proposal would allow storage resources to bid up to the higher of the 4<sup>th</sup>-highest hourly maximum import bid price value and the highest cost-verified bid, when either value rises above \$1,000/MWh. The maximum import bid price is a tool already used in the ISO markets to identify when import/export bids must be free to exceed \$1,000/MWh because bilateral markets outside the ISO are trading at prices above \$1,000/MWh. This reflects the opportunity cost for import/export bids and ensures the ISO balancing area can compete for external resources when needed.

This change will allow storage resources to submit real-time bids above the \$1,000/MWh soft offer cap when the bid cap is increased for other resources, enabling them to indicate to the market their intra-day opportunity costs. This change supports their availability for discharge during more stressed grid conditions when prices might exceed the current soft offer cap and avoids the ISO having to intervene manually to maintain their state of charge when the storage resources are needed during the net-peak. Note that this change is directed solely at storage resources because it is not needed for hydro resources – the hydro default energy bid already reflects the bilateral index prices that underpin the maximum import bid price.

Bilateral hub prices that support offers greater than \$1,000/MWh, either through the hydro default energy bid or through the maximum import bid price, have occurred only a handful of days per year in recent years (six trade dates thus far in 2024, two trade dates in 2023, and seven trade dates each in 2021 and 2022). Today's proposal is not expected to significantly increase the number of days that would contain prices above

\$1,000/MWh, but it may increase the number of hours in those days with prices above \$1,000/MWh. The overall net cost impact would depend on factors such as the frequency and magnitude of hydro and storage resources bidding above \$1,000/MWh, the impact on market clearing prices, and the potential efficiency gains from improved resource dispatch. While there is potential for some increase in market costs during tight days (because resources could potentially set prices above \$1,000/MWh in hours prior to the peak times), this should be weighed against the potential benefits of more efficient dispatch, reduced out-of-market actions and associated make-whole costs, and improved resource availability during critical periods.

Management believes this two-part proposal represents a balanced approach for allowing hydro and storage resources to better reflect opportunity costs in their energy offers within the existing regulatory framework. The removal of the DEB cap is a foundational change that will facilitate streamlined processes during future events where the bid cap rises above \$1,000/MWh for other resources that are able to cost verify their increased cost. Management recognizes that improvements to the storage DEB calculation may reduce the need for the storage bid cap change in today's proposal. Management commits to monitoring this element of the policy change, and will evaluate the continued need for it at the time of any future changes to the storage DEB calculation or other relevant policy changes.

## **POSITIONS OF THE PARTIES**

Though the stakeholder process preceding and supporting these proposed changes was expedited because of the urgency raised by stakeholders, the process was thorough. This expedited initiative was launched in response to concerns raised by stakeholders in the Price Formation Enhancements working groups about the inability of storage and hydro resources to reflect their opportunity costs in their energy bids when those costs exceed the \$1,000/MWh soft offer cap.

Through a series of five working group meetings and five opportunities for written comments, stakeholders were able to participate in discussions that explained the issues, considered alternative proposals, developed potential solutions, and refined the final proposal. Stakeholders broadly agree that the existing market rules can lead to premature dispatch of storage and hydro resources during tight system conditions, as these resources may be unable to sufficiently reflect their opportunity costs in their offers and preserve state of charge or limited water for the periods of highest prices or greatest system need.

Many stakeholders support pursuing a solution for summer 2024, though some prefer delaying implementation to allow more time to assess risks and avoid unintended consequences. Other key points of divergence are whether the solution should apply in both the day-ahead and real-time markets and the methodology for representing opportunity costs. Also, a few stakeholders suggested that certain demand response resources should also be in scope for this effort, but ultimately there was not sufficient information about the nature of such opportunity costs to merit inclusion at this time.

Some stakeholders object to or have concerns with using the maximum import bid price for this purpose, while others including the Department of Market Monitoring, worry that the methodology may increase the potential for storage and hydro resources to exercise market power.

Management has assessed the feasibility of various design options and is proposing policy that balances the need for an improved near-term solution with implementation, policy, and other constraints. While it may not fully satisfy every stakeholder position, the final proposal reflects many of the key principles and objectives emphasized by stakeholders. Stakeholders will continue to consider potential further enhancements through the ongoing Price Formation Enhancements initiative. During the stakeholder process preceding the changes proposed in this memorandum, stakeholders identified and discussed long-term improvements to the RLCR process, enhancements to default energy bid calculations, and exploring opportunity costs for demand response resources. These proposed changes go beyond those proposed for summer 2024 and will need to be developed further through greater stakeholder engagement. A matrix summarizing stakeholder positions and Management's responses is attached to this memorandum (Attachment 1).

Some stakeholders have raised concern about how the maximum import bid price is currently calculated. Management is committed to address this item, independently of its use in this proposal because, as noted above, the maximum import bid price is already used in the ISO markets to reflect the opportunity cost of import resources. Based on the outcome of that stakeholder engagement, Management will propose any further enhancements to the maximum import bid prices as necessary.

The Department of Market Monitoring raised concern that the proposal could increase unwarranted bid cost recovery payments to storage resources on days when the \$2,000/MWh hard cap is in effect. Because the concerns about unwarranted bid cost recovery payments to storage exist regardless of the changes proposed in this memorandum, Management is initiating a stakeholder process to consider enhancements to bid cost recovery as it applies to storage resources.

The Market Surveillance Committee considered the proposal at its April 24, 2024 general session meeting. The MSC's final opinion is attached for reference (Attachment 2).

## **CONCLUSION**

Management recommends the Board of Governors and WEIM Governing Body approve the proposed modifications to the market rules for resources bidding above the \$1,000/MWh soft offer cap. These changes are critical for improving market and operational efficiency and reducing out-of-market actions during tight system conditions by allowing storage and hydro resources to reflect their opportunity costs more accurately in their bids.

Implementing these enhancements for summer 2024 is crucial for addressing pressing stakeholder concerns and ensuring these resources are optimally dispatched to preserve limited energy for the highest-priced periods. The proposed approach balances the need for timely improvements with implementation feasibility and stakeholder input.

Approving this proposal is an important step in evolving the ISO's market design to better integrate energy-limited resources and meet the needs of the transforming grid. The ISO remains committed to ongoing collaboration with stakeholders on further enhancements.



**Attachment E – Market Surveillance Committee Opinion**  
**Tariff Amendment – Price Formation Enhancements**  
**California Independent System Operator Corporation**  
**May 31, 2024**

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

by

James Bushnell, Member  
Scott M. Harvey, Member  
Benjamin F. Hobbs, Chair

Members of the Market Surveillance Committee of the California ISO<sup>1</sup>

Final, May 15, 2024

## 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.aiso.com/Documents/MSO-OpiniononEnergyStorageandDistributedResourcesPhase4-Sep8\\_2020.pdf](http://www.aiso.com/Documents/MSO-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.aiso.com/Documents/MSO-OpiniononFERC831ImportBiddingandMarketParameters-Sep9\\_2020.pdf](http://www.aiso.com/Documents/MSO-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.



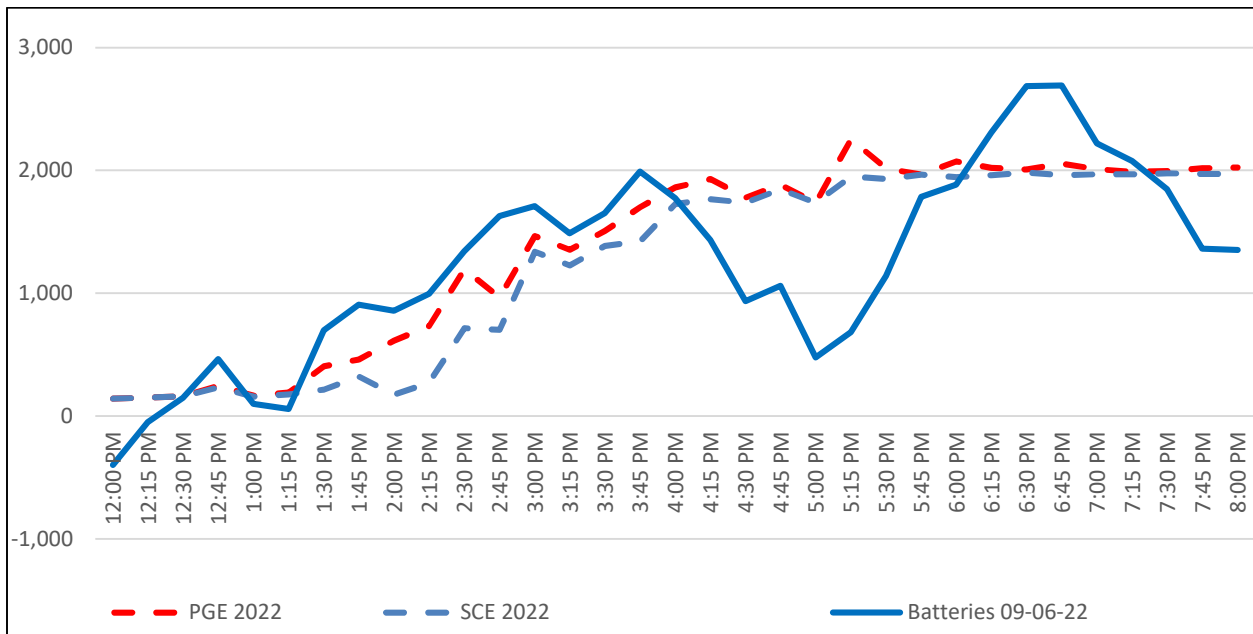
with the result that the energy-limited resources have too little state of charge to cover their day-ahead market schedules over the net load peak; and 2) energy-limited resources that have been dispatched in hours leading up to the net load peak or that are otherwise very tightly energy-limited in their 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.

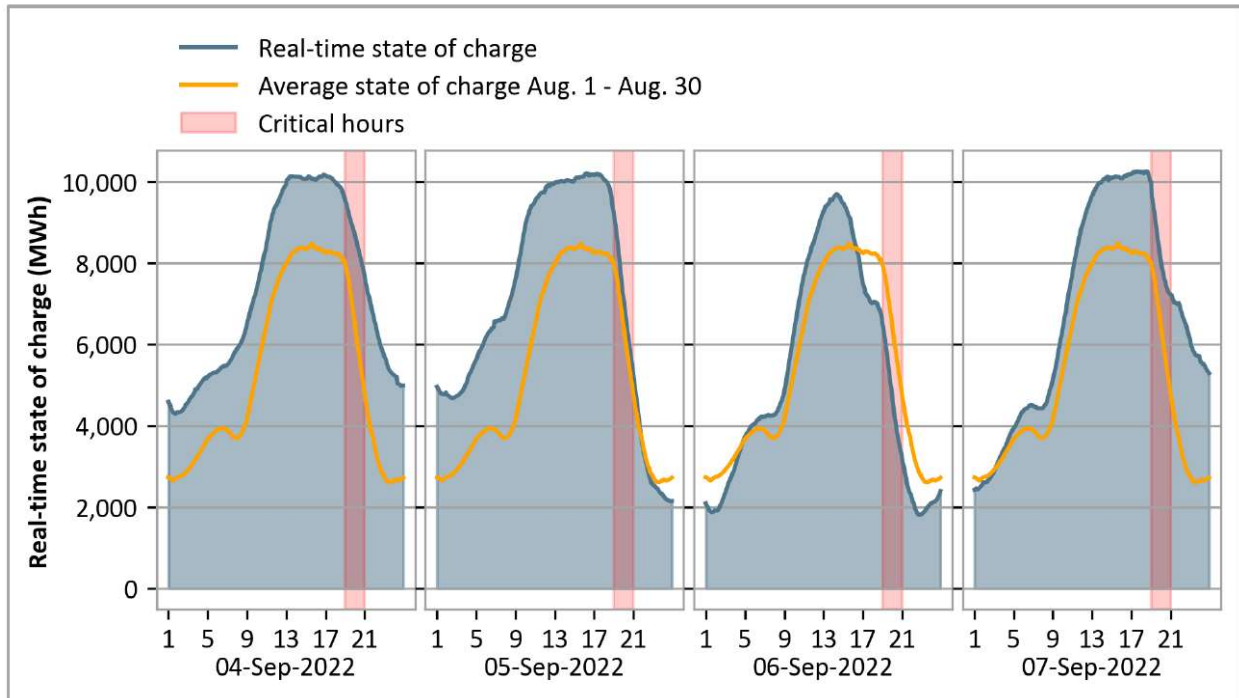
The summer report for September also indicates that the ancillary service state of charge constraint bound for some resources, forcing them to charge, although there is no discussion of the megawatts of battery capacity that were in this position approaching and during the net load peak hours.<sup>11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

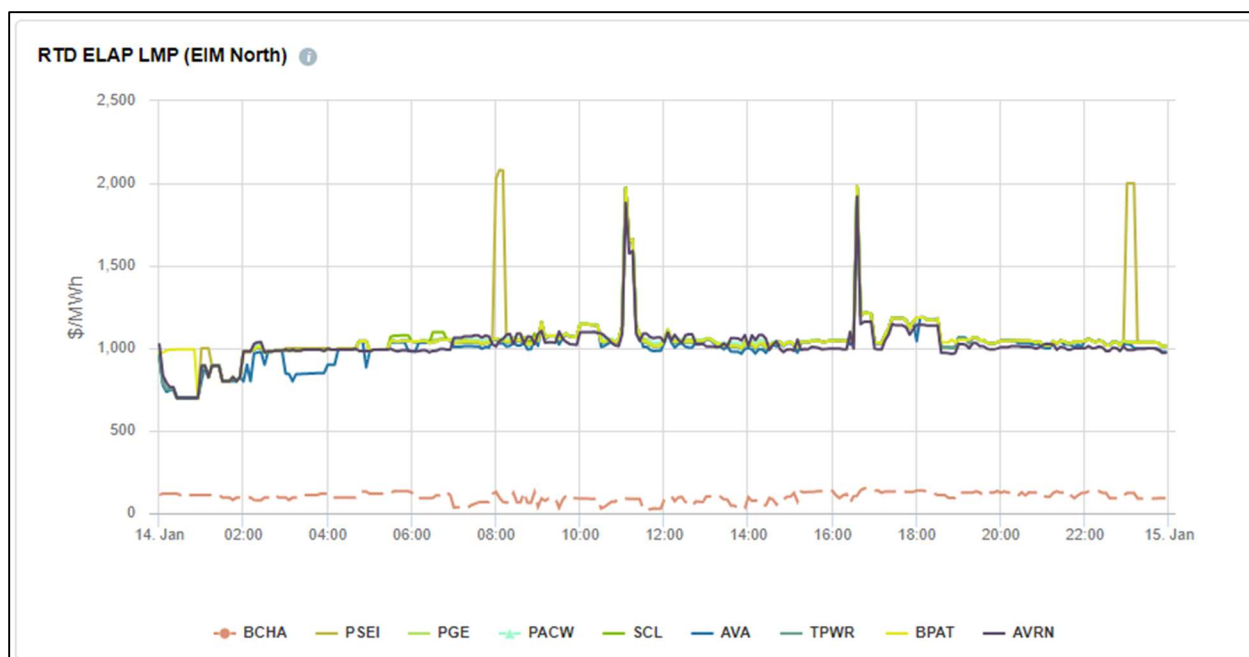
3 shows the EIM North RTD prices over the day on January 14, 2024. There was only a short period of low prices. Prices were at the soft cap all day after about 3 a.m., so we cannot discern from this data when the most stressed hours actually were and what opportunity costs would have been appropriate 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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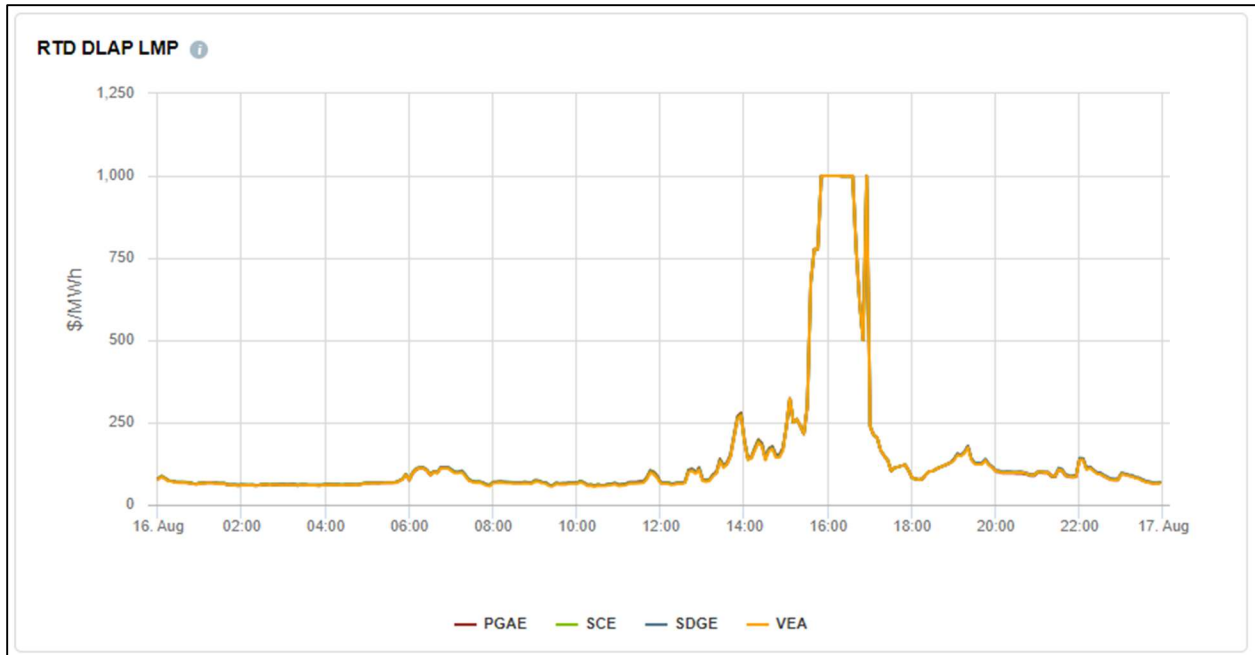
<sup>30</sup> See *ibid.*, Figure 63, p. 67.

<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.

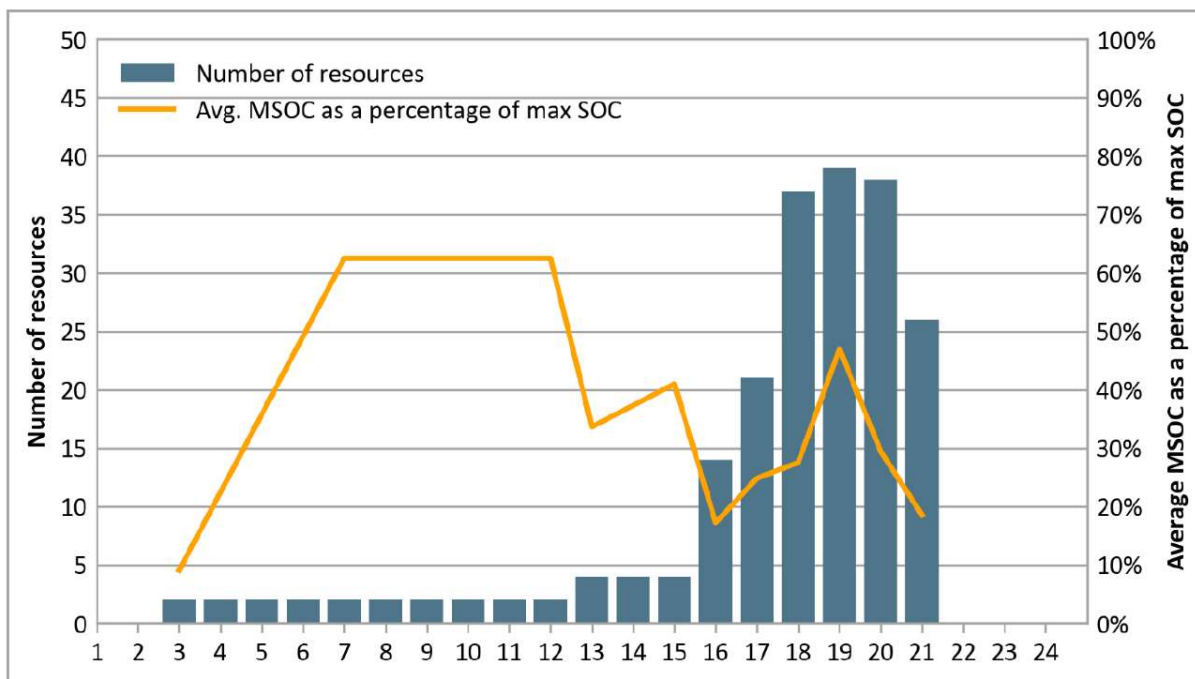
Above, we have discussed in the context of August 16, 2023 the potential for inflated BCR costs when CAISO operators withhold too much output with exceptional dispatch and drive real-time prices to the bid cap. When stakeholders consider the merits of relying on exceptional dispatch rather than offer 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.