Opinion on
Energy Storage Enhancements Proposal

by

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I. Introduction

The Market Surveillance Committee has been asked to comment on the Energy Storage Enhancements (ESE) proposal,[1] which concerns the market rules for short duration (typically 4 hour or less) battery-based energy storage facilities. The Committee has held public meetings addressing this initiative on May 21, Aug. 27, and Oct. 1, 2021; and Feb. 11, Sept. 19, and Sept. 26, 2022. We also previously addressed the market power mitigation issues that are addressed in this initiative in our Opinion on the Energy Storage and Distributed Energy Resources Initiative Phase 4 (ESDER 4), adopted on Sept. 8, 2021,[2] as well as in four public MSC meetings on ESDER4 in 2019 and 2020 that preceded adoption of that Opinion.

In the next section, we summarize the components of the ISO's proposal. In Section III, we offer observations and recommendations regarding each of those components. Our conclusions are summarized in Section IV.

II. Proposal Summary

The ESE proposal has four major components that address the following general issues:

1. *State-of-charge management for storage that provides regulation.* The goal is to ensure that energy storage resources that are scheduled to provide regulation-up and regulation-down (reg-up and -down) can maintain a state-of-charge sufficient to provide those services for a required minimum period of time. There are two underlying issues. The first is that the CAISO regulation market design does not have a mechanism that automatical-

[1] "Energy Storage Enhancements," Final Proposal, Market & Infrastructure Policy, California ISO, Oct. 27, 2022, www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorageEnhancements.pdf.

[2] J. Bushnell, S.M. Harvey, and B.F. Hobbs, "Opinion of Energy Storage and Distributed Energy Resources Phase 4," Final Opinion of the Market Surveillance Committee of the California ISO, Sept. 8, 2021, www.caiso.com/Documents/MSC-OpiniononEnergyStorageandDistributedResourcesPhase4-Sep8_2020.pdf.

ly enables a storage resource to maintain the state-of-charge required to cover its day-ahead market schedule; in contrast, thermal power generators can maintain their capability to provide regulation by simply being returned to their previous operating point in the next dispatch interval. The second is that the CAISO regulation market design does not incent the regulation provider to submit bids and offers that maintain a state-of-charge sufficient to support the resource's day-ahead market regulation schedules. The ESE proposal includes two elements intended to compensate for these limitations of the current design.

- In the first element, adjustments are proposed to the state-of-charge balance equations in the market software to account for anticipated discharge and charge of energy associated with deployment in real-time of reg-up and -down, respectively. These adjustments will be applied in both the integrated forward market (IFM) and in the real-time predispatch and dispatch (RTPD and RTD) markets. However, the adjustments will primarily impact scheduling in the IFM with its 24 hour look-ahead.

- In the second element, suppliers of reg-up and -down would be required to submit energy charging bids and discharging offers, respectively, to accompany accepted regulation and other ancillary service offers. This constraint will only be enforced in real-time.

  Although storage resources would not be required to submit energy offers for charging and discharging in the day-ahead market, the day-ahead market optimization would constrain the megawatt amount of the regulation schedules awarded in the day-ahead market so that the energy schedules required to accompany these schedules in real-time would be feasible in real-time in combination with day-ahead market regulation and reserve schedules.

2. *Exceptional dispatch (ED) of storage resources.* There are two elements of this proposal that address two distinct but related subissues.

   - The first subissue is the need for additional operator tools to manage storage resource state-of-charge which was highlighted by the problems with storage resource state-of-charge over the September 2022 heatwave. To address this subissue, the proposal will expand the range of ED tools for storage resources available to operators by allowing them to directly specify minimum states-of-charge for storage, as well as the present ED capability to specify energy charge or discharge rates.

   - A second subissue is the need to ensure that storage resources that are exceptionally dispatched to hold charge are compensated for losses incurred as a result of following exceptional dispatch instructions. The proposal will address this subissue by providing compensation for resources that are exceptionally dispatched to maintain a minimum state-of-charge[3]. The CAISO proposes to compensate exceptionally dispatched

[3] These payments are analogous to the bid cost recovery (BCR) payments made to other types of resources. However, these payments differ from BCR payments in that they are based on opportunity costs rather than a "make whole" payment calculated by comparing "as-bid" costs incurred over the day with revenues.

storage resources for foregone revenue opportunities by calculating two counterfactual schedules (with and without ED, respectively) and providing payments to compensate for any calculated decreases in energy revenue arising from imposition of the ED. This assurance of payments will both incent storage resources to comply with ED instructions and avoid the need to for storage resources to recover expected ED losses in their RA contracts.

3. *Co-located storage and variable renewable supply resources.*

   - This issue concerns the ability of storage that is co-located storage with variable renewable resources to maximize their federal tax subsidies by restricting or precluding grid charging of the storage, even at times that the ISO would otherwise want to do so for economic or reliability reasons. The issue also concerns enabling some storage resource operators to comply with provisions of contracts they have entered into that restrict or preclude grid charging.

   - The ESE proposal includes a provision that would allow co-located resources to restrict the rate of charging of storage in a scheduling interval to be no more than the scheduled amount of power by the co-located renewable supply. If resource owners elect to use this restriction, this provides assurance the resource will not sacrifice investment tax credits they may qualify for, given provisions of the tax code that can result in partial or full disqualification if batteries are charged from the grid rather than the co-located renewable resource.

4. *Market Power Mitigation in the Day-Ahead Market.*

   - One focus of our ESDER4 Opinion's discussion of opportunity costs in the day-ahead market—along with the desirability of reflecting them in default energy bids (DEBs)—was on opportunity costs that arise if day-ahead market schedules preclude the resource from taking advantage of the option value of responding to real-time price volatility.[4] This does not appear to be the issue addressed by the CAISO ESE proposal. Instead, the ESE proposal's concern is that the market power mitigation design now implemented in the day-ahead market only mitigates offers in the hour in which locational market power mitigation is triggered. This design can result in anomalous outcomes if the hours in which congestion triggers local market power mitigation are not the highest priced hours in the day-ahead market. In particular, the application of local market power mitigation only to offers in the hour in which the resource fails the pivotal supplier test can result in the day-ahead market software applying different spreads in scheduling resources over the hours of the day, with the possible result that the mitigated resource is scheduled in hours with lower prices than other hours.

   - The ESE proposal would address this issue by modifying ESDER4's market power provisions for the CAISO integrated forward market (IFM), in particular the defini-

[4] Bushnell et al., op. cit.

tion of DEB for storage discharge offers. ESDER4 specified that the storage DEB include only variable operations & maintenance costs, without provision for opportunity costs,[5] under the assumptions that (i) opportunity costs arise only from sales opportunities within the same day, and that (ii) the day-ahead market optimization automatically and correctly accounts for those.

- Hence, because storage facilities often submit non-zero price bids/offers to charge/discharge across the 24 hours of the day-ahead market, mitigation of discharge offers in some hours but not in others could result in inefficient storage schedules. The CAISO proposes to address this by defining the DEB of day-ahead discharge offers in given hour t to be equal to the maximum of two quantities multiplied by 110%: (i) the cost for the resource to buy energy (if positive) plus the variable cost of operations & maintenance (O&M) and (ii) an estimate of opportunity cost equal to the fourth highest price across all hours in the IFM's market power mitigation run.

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III. Analysis and Recommendations

We make the following observations and recommendations concerning these four components of the ESE proposal.

1. *State-of-charge management for storage that provides regulation.*

   - A core issue with the current regulation design is that the consequence of failing to deliver day-ahead procured regulation in real-time is simply "no pay," rather than requiring that the resource buy back its day-ahead market schedule at the real-time price for regulation. The proposal's changes are just addressing one manifestation of the underlying problem. If the ISO does not address this core problem, we may see a variety of other types of inefficient behavior. If regulation providers faced efficient pricing for their failure to perform, they would be incented to manage their resources so as to maintain the required state-of-charge; or would increase price offers for regulation to reflect the risks of imbalances; or would not provide regulation in the first place.

     Therefore, we recommend that consideration be given to penalizing regulation non-performance based on the costs that the ISO would incur to replace that regulation, or the software's constraint relaxation penalty for regulation, whichever applies in a particular market situation. A number of other US system operators have designs in which deviations from day-ahead market regulation schedules are settled at a real-time regulation price.[6] While the core reason for these designs is to enable regulation

[5] L. Carr, G. Murtaugh, J. Powers, and B. Sparks, "Energy Storage and Distributed Energy Resources Phase 4," Draft Final Proposal, May 20, 2020, www.caiso.com/InitiativeDocuments/DraftFinalProposalEnergyStorage-DistributedEnergyResourcesPhase4.pdf.

[6] NYISO Market Services Tariff, Section 15.3.5.2. Regulation demand curves are also used by some ISOs, which can set a scarcity-based price in real-time that can be the basis for real-time charges for regulation not showing up (NYISO Market Services Tariff, Section 15.3.7; MISO Tariff, Schedule 28).

capacity to be released into the dispatch to balance price spikes in the dispatch at a penalty price, those designs also have the effect that resources that are unable to meet their day-ahead market regulation schedule have to buy it back at the real-time price, which will reflect the regulation penalty price if other regulating resources are not available.

- The first of the two elements of this part of the ESE proposal recommends adjustments to the state-of-charge balance equations in the market software to account for expected discharge and charge of energy associated with deployment of reg-up and -down. Compared to the present situation (in which state-of-charge changes are not modelled at all), the adjustments are reasonable first-order approximations based on average values that should lessen the likelihood that real-time states-of-charge will reach levels that will make it infeasible to actually deploy the procured regulation.

    - However, because there is considerable uncertainty around the expected changes in state-of-charge associated with regulation, these adjustments cannot completely guarantee the operational feasibility of day-ahead market regulation schedules in real-time. While the proposed adjustments to the day-ahead state-of-charge calculation will be roughly accurate on average, the impact of providing regulation on storage resource state-of-charge will likely differ from these averages from day to day and hour to hour. For example, regulation deployment may have very different patterns during periods of system stress than on typical days. Regulation usage patterns will likely also vary from day to day with factors impacting the predictability of net load in RTD.

    - It is desirable to have more extensive data on the regulation scheduling patterns that typically result in depleted state-of-charge, such as whether these resources are typically providing only regulation up or regulation down, rather than providing offsetting amounts of regulation up and down.[7] However, the CAISO showed in the heat wave report that storage resources in aggregate were providing large amounts of regulation up over the net load peak and little or no regulation down.[8] This offering and scheduling pattern will inevitably have the result that the resources providing regulation up will deplete their state-of-charge, essentially selling energy while also being paid for regulation until they deplete their state-of-charge to the point they can no longer provide regulation.

[7]The data that the ISO has made available includes the following. The ISO has provided an example in www.caiso.com/InitiativeDocuments/Presentation-EnergyStorageEnhancements-July7-2022.pdf, while data on storage resource bids/ancillary service awards and potential drivers for inability to provide ancillary services is provided in www.caiso.com/InitiativeDocuments/Presentation-EnergyStorageEnhancements-Sep12-2022.pdf.

[8]California ISO, Summer Market Performance report, Sept 2022, Nov 2, 2022, Figures 82 and 83 p. 91; G. Bautista Alderete, California ISO, "September Heatwave Analysis, Summer Readiness," November 17, 2022 p. 27, http://www.caiso.com/Documents/Presentation-SummerMarketPerformanceReportforSep2022-Nov17-2022.pdf.

- The CAISO has noted that it has observed a pattern of storage resources ceasing to respond to regulation instructions, apparently because they have depleted their state-of-charge.[9]

- An alternative approach to using average values for deployment-related changes in state-of-charge would be to use more conservative parameters in calculating state-of-charge in the day-ahead market. This would have a similar impact in restricting the amount of regulation storage resources could provide but would be complex to implement as parameters that are conservative for maintaining state-of-charge would not be conservative for maintaining the ability to charge.

- We also note that underestimating changes in state-of-charge and thereby running out of reg-up or -down during the operating day may impose more costs on the system than over-estimating and scheduling more regulation on other resources; these asymmetric costs could imply that the expected change in state-of-charge would not strike an optimal balance between the two types of errors. Thus, more conservative values (overestimates) as described in the previous bullet may therefore be justified to provide a safety margin. However, justification of particular values should be based on collection and analysis of additional data; therefore, at this time, we view the ESE proposal to use average values as a reasonable first step, and adjustments can be considered later based on experience.

- Because actual state-of-charge changes due to regulation deployment can deviate significantly from the average values that ESE proposes to use, we also support the second element of the ISO's "belt-and-suspenders" approach, which is to also require minimum levels of charging bids/discharge energy offers in real-time to accompany reg-up and -down that has been procured day-ahead. This requirement is needed to ensure that state-of-charge levels can be maintained that ensure feasibility of deploying procured regulation.

  - The ISO has proposed that those minimum energy bids/offers be equivalent to half of the reg-up and -down procured, while the Department of Market Monitoring (DMM) has suggested that those bids/offers be at least the full amount of reg procured.[10] A larger required quantity of energy bids/offers will restrict regulation supply and thereby increase procurement costs, but would also provide a greater level of assurance that procured regulation will be feasible to deploy. We have not seen empirical evidence that one level or the other represents the best

[9] CAISO, Storage Workshop: "Storage Resources Providing Ancillary Service," September 12, 2022, pp. 5, 20-23, Appendix pp. 37-49, http://www.caiso.com/InitiativeDocuments/Presentation-EnergyStorageEnhancements-Sep12-2022.pdf; A. Miremadi and G. Murtaugh, California ISO, "Energy Storage Enhancements Second Revised Straw Proposal," Presentation, July 7, 2022, www.caiso.com/InitiativeDocuments/Presentation-EnergyStorageEnhancements-July7-2022.pdf, pp. 7-8.

[10] CAISO Department of Market Monitoring, "Comments on Energy Storage Enhancements Draft Final Proposal," Sept. 9, 2022, www.caiso.com/Documents/DMM-Comments-Energy-Storage-Enhancements-Draft-Final-Proposal-Sep-9-2022.pdf, p. 2.

balance of procurement costs and risk of infeasible deployment. Therefore we support the initial lower requirements proposed by the ISO as being less of a change from present practice, but recommend that the ISO be prepared to adjust those requirements should experience support a need for such adjustments.

- We note that the day-ahead market state-of-charge constraint proposed by the CAISO will not necessarily result in day-ahead market schedules that are consistent with the real-time energy offer requirement proposed by the CAISO. This is the case for two reasons. First, the day-ahead market state-of-charge requirement offsets the expected state-of-charge impact from providing both reg-up and -down while the real-time proposal does not. Second, the day-ahead state-of-charge constraint does not constrain the regulation up and down schedules in any individual hour, it only constrains schedules over the day.

- As explained above in our description of the CAISO proposal, we understand, based on the discussion during the Market Surveillance Committee meeting on November 21, 2022, that the CAISO proposes to avoid the potential for day-ahead market schedules that are inconsistent with the real-time energy offer requirement by imposing additional restrictions on the schedules awarded in the day-ahead market with the intent that the day-ahead market schedules will not be inconsistent with the real-time energy market requirements.

- There are a number of elements of the design that are not based on empirical analysis and may have impacts different from those envisioned by the CAISO. One such element is the real-time energy offer requirement being specified in a manner that does not account for storage resources that have offsetting regulation up and down schedules. It seems to us that the same empirical data that supports the parameters used to evaluate offsetting state-of-charge impacts from regulation up and down schedules in the day-ahead market indicates that a smaller energy offer requirement will be needed for resources that have offsetting regulation up and down schedules than for resources that are essentially selling energy by offering regulation up with little or no regulation down. Another element of the design that the CAISO should study after implementation is the impact of enforcing the regulation charging in RTD based on a one hour look-ahead. There were indications during the September heatwave that a one hour look-ahead can trigger charging at inopportune times. For example, state-of-charge constraints apparently bound during hour ending 18 on Sept. 6 resulting in net storage output falling to zero during the hour.[11]

[11] California ISO, "Summer Market Performance Report, Sept 2022," Nov 2, 2022, Fig. 146 (p.151); Fig. 150 (p. 154). G. Bautista Alderete, California ISO, "Summer 2022 Heatwave Discussion," Market Surveillance Committee Meeting, November 21, 2022, Slide 26, www.caiso.com/Documents/SummerHeatwave-Presentation-Nov21_2022.pdf.

2. *Exceptional dispatch (ED) of storage resources.*

- The first element of this part of the ESE proposal is to expand the range of ED tools for storage to allow operators to directly specify minimum states-of-charge for storage. We believe that making this tool available is likely to improve system reliability because operators will potentially have greater assurance that needed states-of-charge will be available for critical evening peaks.

  - However, we also note that the need for this additional exceptional dispatch tool in part reflects the incomplete ability of operators to ensure operation of storage to maximize reliability. The recently retired CAISO minimum charge requirement[12] seems to have provided some of the capability desired,[13] but is no longer available to operators. Even when that tool was available to operators, it was imperfect, as evidenced by the inability of storage resources to discharge at their capacity at the net load peak on September 6, 2022 and the increasing use of exceptional dispatch over the September 2022 heat wave.[14] While this expanded reliance on exceptional dispatch is necessary in the short-run, this need reflects significant flaws in the current storage bid cap, market power mitigation, and shortage pricing designs that need to be addressed. Moreover, these failures need be addressed soon given the expanding role of storage resources in the CAISO resource mix.

- We support the second element of this part of the ESE proposed, which would compensate storage for ED by calculating foregone revenues through a two-counterfactual approach, and we agree that this design change would improve incentives for complying with ED instructions. We also agree with the ISO's approach to construct the two counterfactuals (i) based on optimizing the resource's schedule based on realized real-time LMPs and the storage resource's bids and offers in intervals including and subsequent to the ED, and (ii) basing changes in revenues considering gross revenues rather than revenues net of bids/offers.

  - We observe that an underlying premise for the CAISO design is that the overall charges and discharges in each of the two counterfactuals will be such that the resource's final state-of-charge at end of the day will be the same in the two cases. However, it is also possible that there will be more energy left in storage in the

[12] The minimum state-of-charge requirement was implemented as a part of the Market Enhancements for Summer 2021 Readiness Initiative (https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness). When implemented, it was specifically requested for only a 2 year period, which expired earlier this year. That minimum state-of-charge requirement only applied on days when there were day-ahead RUC infeasibilities, which has only ever happened during the summer months (June-Sept).

[13] The constraint bound at times on September, 5,6 7 and 8 (California ISO, "Summer Market Performance Report, Sept 2022," op. cit., p. 154, Fig. 150).

[14] California ISO, "Summer Market Performance Report, Sept 2022," op. cit., Fig. 145 (p. 149) and Fig. 148 (p. 152); CAISO Department of Market Monitoring, "Issues and Performance during Summer 2022 Heatwave," November 8, 2022, www.caiso.com/Documents/Regional-Issues-Forum-Presentation-Market-Conditions-Issues-Performance-During-Summer-2022-Heat-Wave-2022-11-08.pdf, Slides 20 and 21.

exceptional dispatch counterfactual, which we understand will have zero value in the bid cost recovery calculation. This is significant because storage operators have a variety of mechanisms to control the dispatch of energy subsequent to receiving exceptional dispatch instructions, including their offer prices and end-of-hour state-of-charge requirements. As described, the proposed design appears to, in effect, provide a dollar reduction in foregone revenue recovery for every dollar of gross revenues received for the energy not dispatched due to the exceptional dispatch.

- The calculation of opportunity costs does not consider changes in variable O&M costs, which is valid if those costs per MWh are constant and the aggregate amount of charge and discharge are the same between the two counterfactuals. But this may not be true in the future if, for instance, the market design is modified in the future to have nonlinear O&M costs. If experience shows that consideration of O&M costs significantly changes the resulting estimates of opportunity costs, and if netting out O&M costs is feasible in the opportunity cost calculations, we recommend that the ISO elaborate the procedure to deduct changes in O&M costs from the revenue changes.

3. *Co-located storage and variable renewable supply resources.*

- We are disappointed that the investment tax credit provisions of the tax code—which have motivated much recent co-located/hybrid storage/variable renewable developments — have the potential to hobble the ISO's ability to use that storage to maximize system reliability.[15] Several analyses have pointed out that restrictions on recharging such storage from the grid lowers availability of stored energy during system peaks and thus potentially hurts system reliability.[16] We also understand that some co-located facilities have hardware or software that automatically prevents charging from the grid and cannot readily be overruled by ED instructions, or in the worst case cannot be overruled because of restrictions built into the resource operating software.

- We hope that the reduced reliability value of resources that cannot be grid charged when it is economic, or/and or needed to maintain reliability will be reflected in their value as RA (resource adequacy). We also recommend that if a significant proportion of storage in the CAISO and WEIM markets would be affected by this provision, then

[15] Under the 2022 Inflation Reduction Act, it appears that investment tax credits will be replaced with production tax credits, which would mean that this issue would not be a concern with facilities built in the future under the new tax provisions.

[16] Mills, A. D., & Rodriguez, P. (2020). A simple and fast algorithm for estimating the capacity credit of solar and storage. *Energy*, 210, 118587; and Schleifer, A. H., Murphy, C. A., Cole, W. J., & Denholm, P. L. (2021). The evolving energy and capacity values of utility-scale PV-plus-battery hybrid system architectures. *Advances in Applied Energy*, 2, 100015. Other ISOs discount the RA value of hybrid storage (Table 4, Ericson, S., et al. (2022). *Influence of Hybridization on the Capacity Value of PV and Battery Resources* (No. NREL/TP-5R00-75864), National Renewable Energy Lab).

consideration be given to providing incentives for grid charging when financially viable. By "financially viable", we mean that the net market revenue from selling energy storage services exceeds the foregone investment tax credit, consistent with DMM's proposal.[17] We believe that this would provide additional flexibility that could be crucial during times of high system stress. We suggest that the ISO or CPUC undertake a study to assess how hybrid storage subject to charging restrictions has contributed in practice to system reliability relative to stand-alone storage.

4. *Market Power Mitigation in the Day-Ahead Market.*

- Given the absence of publicly available data on the frequency and magnitude of mitigation of storage market power in the day-ahead market, we cannot assess whether the inefficiencies resulting from the present cure (the ESDER4 framework, which excludes opportunity costs from DEBS in the IFM) is worse than the disease of local market power. With this lack of data as well as the limitations we describe later in this Opinion, we also cannot assess whether the revised DEBs in the ESE proposal will result in local market power mitigation whose benefits to consumers will outweigh the schedule inefficiencies that might still result from mitigation.

  Given the large size of energy storage facilities (we understand that there are 13 in the ISO system that are 100 MW or more in size), the potential for local market power may exist in some small market areas, particularly in real-time because of their flexibility compared to other facilities. On the other hand, if most large facilities are in gen pockets, and so do not provide counterflow to congested transmission, they are not subject to mitigation (even though gen pocket market power has the potential to harm consumers[18]). It is unclear to us whether the present approach of mitigating discharge offers on an interval-by-interval basis will be effective, ineffective, or even counterproductive.

  We do not recommend delaying the present initiative. But in light of the rapid growth in that resource, we do recommend that the basic approach and specific implementation of local market power mitigation for storage be fundamentally reconsidered in the near future. This reconsideration should take into account the market structure of batteries, who owns them, what type of commercial arrangements they operate under, where they are located, and the ways in which charge bids and storage offers can be used to raise prices both in load pockets and gen pockets. Critically, the fundamental question of whether mitigation of storage batteries is worthwhile should be addressed.

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[17] CAISO DMM, " Comments on Energy Storage Enhancements Draft Final Proposal," op. cit., p . 6.

[18] The potential for generators to restrict output and decongest lines exporting from gen pockets, resulting in local LMPs popping up to the level of system prices, has been noted by academics (S. Oren, "Economic Inefficiency of Passive Transmission Rights in Congested Electricity Systems with Competitive Generation," *The Energy Journal*, 18(1), 1997, 63-83, https://oren.ieor.berkeley.edu/pubs/oren97.pdf). Such market power deprives the ISO of congestion revenues and ultimately increases costs to consumers who pay for the grid. But such market power has not been deemed deserving of mitigation by market monitors, perhaps in part because it is harder to detect.

Whether that type of strategic behavior is potentially profitable for storage in CAISO markets has not been ascertained, so we point this out just to indicate that there is a possibility (not yet confirmed) that storage in gen pockets would find similar behavior profitable. .

- We are doubtful that mitigation's benefits exceed the costs of inefficient schedules for smaller storage facilities. Although we do not have data on the frequency of mitigation for small versus larger storage facilities, it seems possible that the present 5 MW safe harbor threshold to exempt a storage facility from mitigation is much lower than it needs to be. If small facilities are often mitigated, thereby risking the scheduling inefficiencies that are of concern in this proposal, consideration should be given to raising the threshold.

- In our opinion, the economically most efficient way to reflect opportunity costs arising from operations in the day-ahead market is for charge bids/discharge offers to exclude IFM-related opportunity cost components.[19] This is because, as we explain in our ESDER4 Opinion,[20] the IFM software's inclusion of state-of-charge balances and limits on power and stored energy will automatically account for those opportunity costs in a rigorous manner. However, other opportunity costs that are not accounted for by the IFM, for example associated with the option value arising from relatively high real-time price volatility or the value of stored energy that is kept until the next day, can be justifiably included in day ahead bids/offers for stored energy.

- The ISO's present day-ahead DEB for storage, resulting from the ESDER4 initiative, is consistent with the opinion we express in the previous bullet, but the ESE proposal would modify the day-ahead DEB for discharge offers to reflect possible opportunity costs for discharge during the fourth highest price hour of the day. The rationale for this opportunity cost is different, however from the concern discussed above and in ESDER4. Rather than being intended to enable resources to withhold some state-of-charge from the day-ahead market in order to realize its option value in real time, the design is apparently intended to correct a flaw in the market power mitigation design. Hence, the concern as explained in the final proposal and in DMM's comments,[21] is that storage is likely to provide a set of 24 hour bids/offers that is intended by the resource's schedule coordinator to result in a profit-maximizing charge/discharge schedule, but if offers are mitigated to a DEB that is lower than the submitted offers in some but not all hours, then the result might be inefficient discharges.

    - For instance, if midafternoon offers (when prices are moderate) are mitigated, but offers during higher priced evening hours are not mitigated, the inadvertent result could be that the resource will not be scheduled to discharge in the day-ahead market in the highest priced hours. We understand that this outcome is not hypothetical but has been identified in day-ahead market solutions.

[19] By IFM-related opportunity costs, we mean opportunity costs arising from changes in energy or ancillary service sales at any time during the day that are made possible/necessary if more energy is charged/discharged in a given interval.

[20] Bushnell et al., op. cit.

[21] CAISO DMM, " Comments on Energy Storage Enhancements Draft Final Proposal", op. cit., pp. 7-8.

- For example, suppose that a resource submits a bid price to buy of $40 and an offer price to sell of $90, yielding a spread of $50. If the offer price is mitigated to $70 in some hours, that would be a spread of $30. That would have the consequence that the day-ahead market software would find it $20 cheaper to dispatch energy in the mitigated hour than in the non-mitigated hour. If the price was, say, $15 higher in the non-mitigated hours than in the mitigated hours, the energy would be scheduled to be discharged in the mitigated hour despite the lower energy price at that time.

- We agree with the general point that the entire 24-hour profile of bids/offers will impact how storage is dispatched, and that mitigating just a subset of those hours can result in large inefficiencies, and even deterioration of reliability. But we believe that the present proposal is incomplete for several reasons, among which are the following:

  - The problem of shifting schedules in inefficient directions by mitigating only some hours' offers is only partially solved by allowing offer DEBs to include IFM-related opportunity costs; the problem can still occur. The proposed design will avoid the distortion in day-ahead market schedules to the extent it eliminates mitigation by raising the DEB to the level of the storage resource offer, but if mitigation is triggered, the offer will still be lower in the mitigated hours than in unmitigated hours.

  - The present proposal, like the ESDER4-based mitigation system now in place, is also incomplete because they both do not consider how charge bids affect market power. It is the *spread* of the discharge offers relative to charge bids that, to a great extent, determines if and when storage is utilized, not the discharge offers by themselves. Thus, mitigating only offers presents, in our opinion, an inadequate obstacle to the exercise of market power, as energy discharges can be shifted in time or withheld entirely by the resource manipulating its charge bids, which are not presently subject to mitigation.[22] As noted in the ESDER4 proposal, mitigating spreads would require overhaul of the mechanics of the local market power mitigation procedures.

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[22] Consider a system in which there are four hours in the late afternoon with $160/MWh energy prices, and the other 24 hours have $30/MWh prices. Disregarding the complication of round-trip energy losses, if a storage resource offers $X/MWh to discharge, and makes a charge bid of $X-$129/MWh for all 24 hours, it will be efficiently charged and discharged, no matter what X is. But if the charge bid is $X-$131/MWh, it will not be scheduled. It is the spread that determines whether the resource can be economically withheld or not, not the discharge offer by itself.

Therefore, in this case a schedule coordinator who wants to withhold a storage resource from the market can do so by making a discharge offer at the ISO's DEB (here $160*1.1 = $176), and then making a charge bid that is more than $130 less than that offer—say $0/MWh. The offers and bids run no risk of being mitigated (assuming that the battery has correctly guessed what prices the market power mitigation run will yield), yet the coordinator can withhold that resource's capacity to the potential benefit of other resources that it operates.

It should be noted that with the complication of round-trip energy losses, then the threshold spread for charging and discharging storage would depend on the value of $X.

- The ESE DEB proposal is also incomplete because it disregards the potential for twice daily cycling of batteries. Although this may not be very important now, if growing solar penetration results in morning peak prices that start to drive storage operations towards two charge-discharge cycles per day, the proposal would be ineffective in addressing market power exercised during the cycle with lower peak prices.[23]

- Thus, we believe that since storage causes operations in different hours to be inextricably interdependent, it is desirable to carefully consider the entire 24 hour profile of bids/offers and how mitigation decisions affect operations. We note that it is standard practice across US ISOs in mitigating minimum load costs in the day-ahead market to mitigate them across ***all*** hours of the day-ahead market if market power mitigation is triggered in ***any*** of the hours of the resources minimum run time.[24] Hence, an approach to this problem that would be consistent with other elements of the CAISO day-ahead mitigation design would be to mitigate bids and offers over the entire operating day if mitigation was triggered in any hour.

    - For example, bids and offers could be mitigated to include only variable (registered) O&M costs if (i) the inclusion of opportunity costs results in a bid/offer spread (adjusted to account for roundtrip energy losses) for any pair of hours that exceeds the spread between the day's lowest and highest prices in IFM market power run,[25] and (ii) if the resource is found to possess local market power in any market interval. If this approach is not acceptable because it is viewed as overly restrictive of bid/offer strategies, then we propose that high discharge offers occurring in any hour be decreased to a cap (i.e., subject to a so-called "hair cut"), where the cap is determined such that the bid/offer spread (adjusted appropriately for losses) is no more than the maximum spread of relevant LMPs in the market power mitigation run.[26] Neither of these would address market power that could occur if two-cycle operation becomes common and if one price peak is appreciably less than the other; we conjecture that only by omitting IFM-related opportunity costs from IFM bids/offers would there be assurance that market power would likely mitigated and efficient operations will occur.

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[23] Consider a modified version of the previous footnote's case in which there is also a morning peak of any duration with prices of $100/MWh. Mitigating discharge offers to $176/MWh (as in the case described in the previous footnote) will mean that the storage unit will not be used to meet the morning peak, unless charge bids are large enough to make the spread less than ($100-$30); i.e., unless the charge bids exceed $106 = $176- ($100-$30). Thus, it will be easy to withhold battery capacity from discharging in the secondary peak by having a low charge bid (e.g., $0/MWh).

[24] NYISO and ISO-NE mitigate minimum generation offers over the longer of the minimum run time or the period in which mitigation is triggered (NYISO Market Services Tariff, Attachment H 23.4.2.2.5.2; ISO New England Market Rule 1, Section IIIA5.7).

[25] E.g., comparing the fourth lowest and the fourth highest hourly prices from the market power run of the IFM.

[26] Adjusted considering the duration of energy storage, as noted in Footnote 22.

- If the present day-ahead DEB, which mitigates opportunity cost portions of bids/offers to zero, is retained, it would eventually need to be modified to account for opportunity costs associated with real-time option values and degradation costs due to deep cycling. We recognize that there are not widely agreed-upon approaches to model these considerations, and that it is not practical to capture them in DEBs within the timetable of this initiative.

IV. Conclusions

Concerning the four major components of the Energy Storage Enhancements proposal that we address, we highlight our following recommendations:

1. *State-of-charge management for storage that provides regulation.*

   - An important issue with the current design for procuring regulation services is that the consequence of failing to deliver day-ahead procured regulation in real-time is simply "no pay," rather than requiring that the resource buy back its day-ahead market schedule at the real-time price for regulation. The proposal's changes are just addressing one manifestation of the underlying problem. Therefore, we recommend that consideration be given to penalizing regulation non-performance based on the costs that the ISO would incur to replace that regulation, or the software's constraint relaxation penalty for regulation, whichever applies in a particular market situation.

   - The ESE proposal's recommendation of adjustments the state-of-charge balance equations in the market software to account for expected discharge and charge of energy associated with deployment of reg-up and -down are reasonable initial approximations that should lessen the likelihood that real-time states-of-charge will reach levels that will make it infeasible to actually deploy the procured regulation. But there will always be considerable uncertainty around the expected changes in state-of-charge associated with regulation.

   - Because actual state-of-charge changes due to regulation deployment can deviate significantly from the average values that the ISO proposes to use in the state-of-charge adjustments, we also support the requirement of minimum levels of charging bids/discharge energy offers in real-time to accompany reg-up and -down that has been procured day-ahead. This requirement is needed to ensure that state-of-charge levels can be maintained that ensure feasibility of deploying procured regulation.

   - Several elements of the proposal are not based on empirical analysis and may have impacts different from those envisioned by the CAISO. More extensive data is needed on regulation scheduling patterns that typically result in depleted state-of-charge, and their correlations with system conditions; these data could be used to refine the elements of the design.

2. *Exceptional dispatch (ED) of storage resources.*

   - The first element of this part of the ESE proposal is to expand the range of ED tools for storage to allow operators to directly specify minimum states-of-charge for storage. We believe that making this tool available is likely to improve system reliability because operators will potentially have greater assurance that needed states-of-charge will be available for critical evening peaks.

   - We also support the second element of this part of the ESE proposal, which would compensate storage for ED by calculating foregone revenues through a two-counterfactual approach. We think that result would be improved incentives for complying with ED instructions. Because this is a departure from the ISO's general approach to bid cost recovery, we recommend that the performance of this approach be closely monitored for effectiveness and possible strategic behavior.

3. *Co-located storage and variable renewable supply resources.*

   - We are disappointed that investment tax credit provisions of the present tax code that apply to some hybrid/co-located storage-renewable facilities have the potential to hobble the ISO's ability to use that storage to maximize system reliability. It is important to recognize and quantify the reduced reliability value of storage resources that cannot be grid charged at times when it is either economic, or/and or needed to maintain reliability, and to reflect the conclusions in California's resource adequacy mechanism. If the reduction is significant, consideration should be given to providing economic incentives for such facilities to grid charge rather than imposing a hard constraint to prevent such charging.

4. *Market Power Mitigation in the Day-Ahead Market.*

   - The ESE's proposal to add an opportunity cost component to default energy bids in the day-ahead market addresses an obvious potential for inefficient storage management under the present system of mitigating discharge offers on an hour-by-hour basis. In our opinion, however, the overall system of DEBs in the day-ahead market is likely to be ineffective in addressing market power that could be exercised by storage. This is because that system does not address bids to charge and the resulting bid-offer spread, which can still be readily manipulated to economically withdraw storage from the market at times the system needs storage for economic and reliability reasons.

   - Given the absence of publicly available data on the frequency and magnitude of mitigation of storage market power in the day-ahead market, and the general lack of understanding of how storage can affect the efficiency and payments in the ISO markets, we cannot assess whether the revised DEBs in the ESE proposal will result in local market power mitigation whose benefits to consumers will outweigh the schedule inefficiencies that might still result from mitigation.

- We doubt that mitigation's benefits exceed the costs of inefficient schedules for smaller storage facilities. Although we do not have data on the frequency of mitigation for small versus larger storage facilities, it seems possible that the present 5 MW safe harbor threshold is lower than necessary.

- As we noted in our previous ESDER4 Opinion, the economically most efficient way to reflect opportunity costs arising from operations in the day-ahead market is for charge bids/discharge offers to simply exclude IFM-related opportunity cost components, and to let the day-ahead software automatically calculate those costs by considering states-of-charge, prices, and operating limits over the 24 hour horizon, with appropriate recognition of the value of stored energy in the last period. But if (i) that recommendation is not acceptable to the ISO; (ii) market power for storage is a potential concern; and (iii) the ISO wants to effectively mitigate the market power, then we believe that it is essential to carefully consider the entire 24 hour profile of bids/offers and how mitigation decisions affect operations. There is not time to design such a feature in the present ESE proposal, but it should be revisited in the near future.