California Independent System Operator Corporation

January 23, 2025

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

Re: California Independent System Operator Corporation
Docket No. ER25-___-000

Tariff Amendment to Clarify Process for After-Market Fuel Cost Recovery

Dear Secretary Reese:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to clarify the process for scheduling coordinators to seek after-market fuel cost recovery under section 30.12 of the CAISO tariff.[1] These amendments will address perceived ambiguities in the existing tariff language and ensure the tariff aligns with the policies underlying section 30.12. Specifically, these clarifications will help ensure the after-market fuel cost recovery process does not create inefficient market outcomes or subsidize and incentivize speculative market participation. Additional clarity also will reduce the likelihood of extended administrative proceedings before the Commission to resolve after-market requests. The CAISO requests these tariff revisions take effect January 24, 2025, with an order issued by March 24, 2025. Immediate effectiveness of the clarified tariff language is necessary to ensure that, in the event of unexpected volatility in the fuel market, all future requests for after-market fuel cost recovery are assessed under the clarified tariff provisions, which more accurately reflect the important policies underlying the after-market request process.

[1] 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.

I. Background

A. Summary of Current Tariff Rules

1. Three-Part Bidding and Bid Cost Recovery

Generators submit a three-part bid to the CAISO market. The first two parts are bids for start-up costs and minimum load costs. These bids reflect the costs to the resource of starting up and maintaining its minimum load, respectively. These two costs are referred to collectively as commitment costs because these are the costs of being committed by the market. The third part of the bid is called the incremental energy bid, and covers the costs of providing energy above minimum load.

The CAISO's markets use all three bid components to ensure the least-cost dispatch considers the total submitted cost of a generating unit. The market clearing process uses a multi-interval optimization and inter-temporal constraints, but only the incremental energy bid cost is used in setting the LMP for a market interval. As a consequence, absent additional intervention, the resulting market clearing prices may be too low to cover a generator's commitment costs and a generator may face risk that they will not recover their commitment costs through market payments.

The CAISO addresses this risk by providing cost recovery based on a generator's submitted commitment cost bids through the bid cost recovery (BCR) mechanism. The BCR mechanism provides resources with uplift payments when revenues from the sale of energy and ancillary services do not cover the resource's start-up, minimum load, and energy bid costs during a day.[2] The CAISO recovers the costs of BCR payments made to resources by allocating those costs to scheduling coordinators representing load.

2. The Role of Reference Levels

The proxy commitment costs and default energy bids are referred to generally as reference levels. They are resource-specific and calculated daily by the CAISO. The proxy commitment costs place an upper limit on the resource's commitment cost bids to ensure protection against market power if uncompetitive situations arise. The default energy bid is used in the local market power mitigation process when an incremental energy bid is mitigated.[3]

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[2] See existing tariff section 11.8.6.

[3] Energy bids are also subject to a soft cap of $1,000/MWh and a hard cap of $2,000/MWh. Existing tariff Appendix A, "Soft Energy Bid Cap" & "Hard Energy Bid Cap."

For most resources, the CAISO calculates reference levels using a formula that reflects the resource's physical characteristics and daily natural gas index prices.[4] Those index prices are further adjusted to reflect additional costs in the specific fuel region in which the resource takes delivery of fuel. The CAISO's formula does not account for gas-related costs other than commodity and transportation costs, *e.g.*, costs associated with intra-day gas purchases, hedging costs, other risk premiums, and certain non-gas-related variable costs.

The standard resource-specific costs used to calculate reference levels do not, and cannot, perfectly reflect the actual costs incurred by generators. The reference levels include a multiplier that accounts for most potential variation between what is known to the CAISO when reference levels are calculated and resource-specific costs that ultimately materialize. Generators have opportunities to request cost adjustments when these multipliers are insufficient.

3. Addressing Gas Market Volatility—Before-Market Reference Level Changes and After-Market Uplift Payments

The CAISO has recognized that gas market volatility can create circumstances where the gas price index information it uses to calculate reference levels does not reflect a generator's actual gas procurement costs. The gas price index used in the market is a weighted average gas price derived from multiple gas trades at a certain point in time, but resources will be exposed to resource-specific gas prices. Should reference levels underestimate a resource's costs, BCR can also wind up limiting a resource's cost recovery below its actual costs. This outcome (*i.e.*, resources being unable to recover their costs through the market) is something BCR is designed to avoid.

To address this potential consequence of unrecovered market costs, the CAISO tariff permits generators to request both: (1) before-market reference level changes;[5] and (2) after-market fuel cost uplift payments to supplement BCR payments.[6]

Scheduling coordinators can make automated before-market reference level changes within reasonableness thresholds, subject to audit. Before-market requests that go beyond the reasonableness thresholds are permitted but are subject to manual review by the CAISO. Changing the reference level upfront

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[4] Existing tariff sections 30.4.1.1.1(b), 30.4.1.1.2(b), 30.4.1.1.5, 30.7.9(c), and 30.7.10. The calculated proxy cost includes various cost components listed in the tariff, *e.g.*, fuel input costs, auxiliary power costs, greenhouse gas cost adders, adders for major maintenance expenses, and operation and maintenance costs. Existing tariff sections 30.4.1.1.1(a) and 30.4.1.1.2(a).

[5] Before-market requests are covered in CAISO tariff section 30.11.

[6] After-market requests are covered in tariff section 30.12.

allows the resource to bid higher commitment costs that more accurately reflect a resource's true commitment costs. Those costs are then incorporated in the market clearing process. If the resource is then still subject to BCR, its recovery under that mechanism will be based on more accurate costs. This helps ensure appropriate and accurate cost recovery for the resources.

If the before-market reference level change request opportunity still leaves a resource with unrecovered fuel costs after BCR calculations, then the resource can request an after-market uplift payment for those costs that otherwise would go unrecovered. The CAISO tariff states the after-market uplift payment is for "amounts in a Reference Level Change Request that were not approved pursuant to Section 30.11."[7] Scheduling coordinators can submit an initial after-market request to the CAISO or the Commission. If the CAISO rejects the request or cannot validate the request, then the scheduling coordinator can submit a follow-on request to the Commission.

B. Prior Relevant CAISO Initiatives and Commission Proceedings

1. Aliso Canyon Gas Issues and Creation of After-Market Fuel Cost Recovery Requests

The CAISO granted scheduling coordinators the ability to seek an after-market uplift payment for unrecovered fuel costs through a 2016 tariff filing related to managing gas/electric coordination issues posed by the limited availability of the Aliso Canyon natural gas storage facility.[8] The main purpose of that filing was to "improve the CAISO's market dispatches so that they are more efficient and reflective of gas system constraints."[9] The CAISO recognized that even with these measures, gas price volatility could create conditions that would "require resources to incur gas-related costs that exceed the gas price values used in the CAISO markets."[10] Modeled on a similar provision in the ISO New England market, the CAISO proposed the after-market uplift option as a "safety valve" mechanism to ensure generators had a full opportunity to recover fuel procurement costs.

The initial tariff provisions provided "[i]f a Schedule Coordinator incurs but cannot recover through the Bid Cost Recovery process any actual marginal fuel procurement costs that exceed" the applicable bidding limits, then it "may seek to

[7] CAISO tariff section 30.12.1.

[8] *Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,224, PP 85-96 (2016); *Cal. Indep. Sys. Operator Corp.*, Transmittal Letter, at 36-38, FERC Docket No. ER16-1649 (May 9, 2016) (Aliso Canyon filing).

[9] Aliso Canyon filing at 38.

[10] *Id.*

recover those costs through a FERC filing made pursuant to Section 205 of the Federal Power Act."[11] The tariff also provided that if "FERC authorizes the Scheduling Coordinator to recover any costs pursuant to the Scheduling Coordinator's filing, the CAISO will pay the Scheduling Coordinator any amounts the Commission deems recoverable and will allocate such amounts pursuant to Section 11.14."[12]

2. Creation of Before-Market Reference Level Change Requests and After-Market Uplift Requests

Through the Commitment Costs and Default Energy Bid Enhancements stakeholder initiative, the CAISO enhanced the measures developed in the Aliso Canyon proceeding to better reflect current gas price conditions in the market optimization.[13] One measure was creating the option to request a before-market reference level change.

The CAISO noted that over time "stakeholders have expressed concerns that the current commitment cost bidding rules sometimes preclude suppliers from submitting commitment costs bids that reflect their costs including those driven by resource or gas system constraints."[14] The CAISO rules did not "permit suppliers to request updates to cost-based CAISO-calculated reference levels," which created "cost-based reference levels that do not sufficiently compensate suppliers and prevent the CAISO from scheduling or dispatching resources."[15] The CAISO also explained these "limitations can discourage suppliers from participating in the CAISO market because they cannot recover their costs."[16] The CAISO proposed to create the before-market reference level change process to address these concerns.

Through the stakeholder initiative the CAISO also updated the tariff provisions on after-market uplift requests. Most significantly, the CAISO added the option for scheduling coordinators to submit requests directly to the CAISO, rather than the Commission. The CAISO anticipated the process of a scheduling coordinator demonstrating that its actually-incurred fuel costs were incurred prudently would be straightforward. By allowing a scheduling coordinator to make this demonstration to the CAISO, the CAISO explained it "reduces the

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[11] Prior tariff section 30.11.

[12] *Id.*

[13] *Cal. Indep. Sys. Operator Corp.*, 172 FERC ¶ 61,263 (2020); *Cal. Indep. Sys. Operator Corp.*, Transmittal Letter, at 26-57, FERC Docket No. ER20-2360 (Jul. 9, 2020) (CCDEBE filing).

[14] CCDEBE filing at 18.

[15] *Id.* at 1.

[16] *Id.* at 3.

supplier's and the CAISO's legal and processing costs associated with suppliers seeking after-market cost recovery with the Commission."[17]

3. Winter Storm Uri and Implementing New Commitment Costs and Default Energy Bid Rules

The CAISO implemented the revised commitment costs and default energy bid provisions on February 15, 2021. After implementing the new tariff rules the CAISO received three requests for after-market recovery submitted to FERC related to Winter Storm Uri in February 2021.[18]

C. Need to Amend Tariff Section 30.12

In addressing the three after-market requests following Winter Storm Uri and more generally discussing tariff section 30.12 with stakeholders and internally, the CAISO understands there are several perceived ambiguities in how the text of that tariff section was meant to apply. These ambiguities have been taken to suggest the tariff demands outcomes that never were the CAISO's intent.[19] Removing these ambiguities is important for two reasons:

1. They create risk the Commission will apply section 30.12 in ways that undermine the policy goals behind the 2016 filing related to Aliso Canyon and the 2020 commitment costs and default energy bid revisions.

2. They create administrative burden for CAISO and market participants to potentially litigate these issues at the Commission.

D. Stakeholder Engagement

On December 5, 2024, the CAISO published a white paper for stakeholders that outlined the CAISO's reasons for clarifying section 30.12 and provided draft revisions to section 30.12.[20] The CAISO followed publication of this document with a stakeholder meeting on December 12, 2024, to discuss the proposed revisions and provide stakeholders a forum for discussion and

[17] *Id.* at 53-54.

[18] *San Diego Gas & Elec. Co.*, Docket No. ER21-2193-000; *Sempra Gas & Power Mktg., LLC*, Docket No. ER21-2192-000; *EDF Trading North America LLC*, Docket No. ER21-2579-000.

[19] One significant example is the Commission's order in response to EDF's petition, *EDF Trading North America LLC*, 186 FERC ¶ 61,174 (2024), and the CAISO's request for rehearing of that order. *EDF Trading North America LLC*, Request for Rehearing of the California Independent System Operator Corporation, FERC Docket No. ER21-2579-000 (Apr. 8, 2024).

[20] The stakeholder white paper is available at https://www.caiso.com/documents/white-paper-after-market-fuel-cost-recovery-tariff-clarification-dec-05-2024.pdf.

feedback.[21] No party opposed the CAISO's proposed course of action. One party requested clarification on how the tariff contemplates instances where fuel cost volatility occurs after day-ahead market bidding closes. The CAISO addresses that issue below.

II. Tariff Clarifications

The CAISO's tariff clarifications have four objectives:.

1. Ensure that in all cases, an after-market recovery request is only permitted if there has been a before-market reference level change request.

2. Clarify there is no difference between CAISO after-market review and FERC after-market review in terms of required information, substantive standard, or outcome if request granted.

3. Limit supplemental uplift to recovery of costs that could not have been recovered through BCR, rather than costs that could have been recovered but were not because of the scheduling coordinator's market participation choices.

4. Clarify supplemental payments are what results from adjusting inputs to the existing BCR mechanism and cannot include types of costs that are not recoverable through, or recognized in, BCR.

The after-market fuel cost recovery process exists to provide generators an expedited process for providing just and reasonable cost recovery in times of fuel market volatility. Achieving these four objectives is critical to ensuring this purpose is met without creating inefficient market outcomes that inappropriately raise costs to load and without subsidizing speculative market activity.

A. Objective #1 – Before-Market Reference Level Change Request is Necessary Prerequisite for After-Market Uplift Request

1. Perceived Ambiguity

The Commission's March 7, 2024, order in response to one of the after-market requests found the CAISO tariff as written only makes a before-market request a prerequisite for after-market requests made to the CAISO.[22] The

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[21] The presentation slides are available at https://www.caiso.com/documents/presentation-tariff-clarification-after-market-fuel-cost-recovery-dec-12-2024.pdf. A video recording of the presentation is available at https://youtu.be/jPP1KcgnvgA.

[22] *EDF Trading North America LLC*, 186 FERC ¶ 61,174, at P 59.

Commission concluded the general statement in section 30.12.1 that after-market uplift payment requests can only be for “amounts in a Reference Level Change Request that were not approved pursuant to Section 30.11” applied only to after-market requests made under section 30.12.4 (requests submitted to the CAISO) but not to after-market requests made under section 30.12.5 (requests submitted to the Commission). The basis of this conclusion is that tariff section 30.12.4 contains a general cross-reference to section 30.12.1, whereas section 30.12.5 does not. Based on the “meaningful-variation canon,” the March 7 order concluded the differences in language “lead to different results and alternate pathways for after-market fuel cost recovery.”[23]

2. Statement of CAISO View

The CAISO always intended for a before-market reference level change request to be a prerequisite for making an after-market uplift request to either the CAISO or the Commission.

3. Justification of CAISO View

The CAISO’s view about the relationship between before-market and after-market requests was reflected in multiple places through the commitment costs and default energy bid enhancements initiative and related activities. These statements taken together demonstrate the CAISO always intended a before-market request to be a prerequisite for all after-market requests.

In the memorandum CAISO management presented to the CAISO Board of Governors seeking authority to file the commitment costs and default energy bid enhancements initiative, the CAISO stated the “costs submitted for *ex post* cost recovery cannot be higher than what the supplier requested as part of its *ex ante* reference level adjustment request, which had to be based on actual documented fuel market prices.”[24] This statement does not distinguish between an after-market request submitted to the CAISO and one submitted to the Commission. It states that after-market requests, wherever they are directed, are capped by the values in the before-market request. The implication of this principle is that a before-market change request of zero dollars then limits the after-market request to zero dollars.

The CAISO’s tariff amendment filing proposing the amendments and the Commission’s order approving the amendments similarly discussed the after-market request as a single topic, without suggesting a request to the CAISO

[23] *Id.* at P 61 (citing *Entergy Servs., Inc. v. FERC*, 568 F.3d 978, 984 (D.C. Cir. 2009)).

[24] Memorandum from Keith Casey, Vice President, Market & Infrastructure Development, to the CAISO Board of Governors, Attachment B, Response to Comments of Department of Market Monitoring at 8 (Mar. 14, 2018) (provided as Attachment C).

would be subject to materially different requirements than a request to the Commission.[25] For example, citing tariff section 30.12.1, the CAISO's transmittal letter to the Commission stated the after-market "uplift payments must be for amounts in a reference level change request the CAISO did not approve in the before-market reference level change request process."[26] This statement only makes sense if a before-market request is a prerequisite to making an after-market request. An after-market request not preceded by a before-market request by definition could not be a request for payment of an amount included in a "reference level change request the CAISO did not approve." Further, nothing about these statements suggests the before-market request is only a prerequisite for after-market requests directed to the CAISO.

The BPM revisions the CAISO made as part of implementing the commitment cost and default energy bid enhancements further reflect the CAISO's intended relationship between before-market and after-market requests. Attachment O of the CAISO's Business Practice Manual for Market Instruments provides further explanation and detail on the process for requesting after-market uplift payments.[27] It contains several statements explaining the connection between before-market reference level change requests and after-market uplift payment requests. It explains the "after-market cost recovery process is intended to provide the opportunity for uplift payments to cover costs that, prior to the execution of the market, the SC requested to be included in their reference levels but could not be included due to . . . limitations built into the CAISO's reference level change request process."[28] It also states a scheduling coordinator "must have made an automated or manual Reference Level Change Request that was not approved" and that failing "to make a Reference Level Change Request disqualifies a SC from requesting after-market cost recovery."[29] Finally, it states the "after-market cost recovery process is meant to work in conjunction with the Reference Level Change Request process."[30]

There are several reasons it is just and reasonable and sound policy to require scheduling coordinators in all cases to make a before-market reference

[25] The Commission's order approving the CCDEBE tariff amendments also failed to distinguish between the two routes for recovery and noted the purposes of the after-market requests was to "provide resources further assurance that they will be able to recover prudently incurred costs that were not able to be included in their reference levels prior to the market run." *Cal. Indep. Sys. Operator Corp.*, 172 FERC ¶ 61,263, P 41 (2020).

[26] *Cal. Indep. Sys. Operator Corp.*, Transmittal Letter, at 54, FERC Docket No. ER23-2360-000 (Jul. 9, 2020).

[27] Notably, this language from the Market Instruments BPM has been in effect from the time sections 30.11 and 30.12 went into effect.

[28] CAISO Business Practice Manual for Market Instruments, Attachment O, at §O.3.

[29] *Id.* at §O.3.1.

[30] *Id*. at §O.3.

level change to be eligible for an after-market uplift request. This requirement advances market efficiency by creating a direct incentive for scheduling coordinators to try to ensure their true gas costs are considered in the market clearing process. Without this incentive, scheduling coordinators could request after-market recovery of costs on a generator the market never would have dispatched had the resource made a before-market reference level change request and bid up to its allowable caps. In this scenario, CAISO load would be forced to bear costs that never would have been incurred had the market had the opportunity to see these costs in advance to make an efficient optimization decision by not committing the expensive resource. Any alternative approach undermines least-cost dispatch principles and allows scheduling coordinators to shift inefficiently incurred costs to load serving entities.

The requirement to request a before-market reference level change also prevents one form of strategic bidding. This requirement helps prevent a generator from intentionally bidding low commitment costs to secure a market commitment, hoping to profit from prices above the generator's true costs. Under this strategy, if the higher prices occur, then the generator can profit through the high prices. If the higher prices do not occur, then the resource can still seek an uplift payment to make it whole through the BCR process. This creates an incentive for the generator to bid at low commitment costs, while facing limited downside risks. This would be a highly problematic market design the CAISO never intended.

On the stakeholder call, one participant asked if the CAISO considered how to accommodate a market participant that does not yet have complete fuel cost information when bidding for the day-ahead market closes at 10 AM on the day before the operating day. The CAISO explained that two elements of the existing rules address this concern.

First, reference levels are calculated with 10 percent and 25 percent headroom adders for default energy bids and commitment costs, respectively, to create flexibility and give scheduling coordinators the opportunity to capture the possibility that actual fuel costs will exceed prices at the time day-ahead market bidding closes.[31]

Second, before-market reference level change requests can be made based on expected costs, rather than actual costs. The CAISO specifically pointed to Attachment O of the CAISO's Business Practice Manual for Market Instruments, which provides specific examples of how generators can request and support requested cost adjustments based on expected costs. The supporting documentation can include proof of a good faith but unsuccessful attempt to procure fuel near the weighted average gas price index. Importantly,

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[31] Existing tariff Appendix A, "Commitment Cost Multiplier" & "Default Energy Bid Multiplier."

even if the CAISO does not approve the full amount requested, the generator is still eligible for after-market cost recovery for the remaining amount based on actual fuel costs.

Both the presence of the multipliers and the ability to seek before-market reference level changes based on expected costs provide generators with the flexibility to request adjustments in anticipation of higher costs, but simultaneously preclude purely speculative fuel procurement practices and bidding behavior. The CAISO acknowledges these two elements of the rules could be insufficient if the scheduling coordinator has no reasonable basis to expect in the day-ahead timeframe their actual fuel costs might exceed the costs used in calculating the reference levels. In such a case, however, the scheduling coordinator is not precluded from seeking cost recovery. It is merely precluded from seeking recovery under the streamlined cost recovery provisions created by section 30.12. The entity could seek recovery through other procedural avenues, such as sections 206 or 309 of the Federal Power Act.

B. Objective #2 – Same Standards Apply Regardless of Who Reviews the After-Market Uplift Request

1. Perceived Ambiguity

In concluding a before-market request was not a prerequisite to making an after-market request, the Commission described requests posed to the CAISO and to the Commission as "alternate pathways for after-market fuel cost recovery."[32] Framing them as alternate pathways raises a question as to whether after-market requests to the CAISO are evaluated under different standards or based on different information requirements than requests made to the Commission. Similarly, there is the potential for mistakenly inferring that the Commission's authority to grant recovery of costs under section 30.12 is broader than the CAISO's authority.

2. Statement of CAISO View

The CAISO never intended to create any difference between CAISO and Commission after-market review in terms of required information, substantive standard, or outcome if the request is granted.

3. Justification of CAISO View

The CAISO's tariff filing for the commitment cost and default energy bid enhancements initiative stated: "Whether the supplier seeks after-market cost

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[32] *EDF Trading North America LLC*, 186 FERC ¶ 61,174, P 61.

recovery from the CAISO or the Commission, the supplier must submit supporting documentation demonstrating the submitted costs represent actually incurred daily fuel or fuel-equivalent costs for a given trading day that exceed the fuel or fuel-equivalent costs the CAISO used to calculate the resource's reference levels."[33] This statement reflects the CAISO's view that the only difference between CAISO review and Commission review was which organization would conduct the review. All aspects of the review, including the required information, the substantive inquiry, and the consequences of granting the request were meant to be identical.

Enforcing parallel treatment is important because section 30.12 represents a unique cost recovery option that does not impose on a market participant the burden of filing under either section 205 or section 206 of the Federal Power Act. They merely must demonstrate what fuel costs they incurred for the trade date. Such a streamlined out-of-market cost recovery opportunity provides market participants a clear benefit. With that benefit, they should be held to the intended tariff rules and not be given an opportunity to strategically file with the Commission to receive this streamlined opportunity without also living with the intended tariff restrictions.

C. Objective #3 – After-Market Uplift Payments Limited to Costs that Could Not Be Recovered from the Market

1. Perceived Ambiguity

There is potential confusion that section 30.12 could be used to recover costs not recovered through the market even if the scheduling coordinator had the opportunity to recover the costs had it, for example, bid their commitment costs to the allowable limits or selected a more appropriate fuel region that more accurately reflected their fuel costs. The question is whether section 30.12 compensates for costs that: (a) were not recovered through the market; or (b) were not recoverable through the market. Option (a) focuses only on whether there were unrecovered costs. Option (b) involves some element of counterfactual inquiry.

Some aspects of section 30.12 could be read to suggest option (a). For example, section 30.12.1 refers to the additional uplift payment as relating to the Bid Costs "used in the Bid Cost Recovery mechanism." This reference could be understood as focusing solely on the actual costs used, which suggest the tariff would not contemplate a counterfactual inquiry about what the scheduling coordinator would have recovered had it participated differently. Also, section 30.12.3 states the required supporting documentation for a request must demonstrate the actually incurred costs exceed the "fuel costs or fuel-equivalent

[33] CCDEBE filing at 54.

costs the CAISO used to calculate the resource's Reference Levels for the applicable Trading Days." This provision does not additionally require the scheduling coordinator to demonstrate anything about their actual bidding. Not requiring such a demonstration could suggest the scheduling coordinator's actual market participation is not relevant.

2. Statement of CAISO View

The CAISO's view is section 30.12 only should permit after-market recovery of costs that could not have been recovered from the market through direct market revenues or BCR (*i.e.*, costs that were not recoverable from the market). The CAISO does not find it is appropriate to offer uplift for costs that could have been recovered had the scheduling coordinator taken full advantage of the opportunities the CAISO market presented to them to reflect their costs accurately to the maximum extent possible.

3. Justification of CAISO View

In the commitment costs and default energy bid enhancements policy process, the CAISO explained it was proposing "to make eligible for ex post review and after-the-fact cost recovery any reference level adjustment request that was limited because the amount exceeded the reasonableness threshold. "[34] This statement reflects the limited purpose after-market recovery was meant to play under the rules. Recovery was meant to be limited to cases where the scheduling coordinator had unrecovered costs solely because the before-market process did not provide a full opportunity to ensure reference levels reflected actual costs. Unrecovered costs incurred because of other factors were intended to stay unrecovered.

The Commission adopted this view in considering Sempra's application for recovery under the CAISO's prior after-market uplift tariff provisions. There, Sempra claimed it faced unrecovered fuel costs because it submitted market bids that it inadvertently calculated using out-of-date gas prices.[35] In rejecting the request, the Commission found "[i]nadvertent use of an inaccurate natural gas price, even if it results in unrecovered fuel costs, does not meet the requirements for fuel cost recovery."[36] The Commission additionally rejected Sempra's request

[34] Commitment Cost and Default Energy Bid Enhancements Second Revised Draft Final Proposal at 41 (Mar. 2, 2018) (CCDEBE Second Revised Draft Final Proposal) (provided as Attachment D).

[35] *Sempra Gas & Power Mktg., LLC*, 180 FERC ¶ 61,021, P 5 (2022).

[36] *Id.* at P 23.

because Sempra did not avail itself of opportunities to secure a higher allowable minimum load cost bid.[37]

The rationale for requiring scheduling coordinators to fully use the opportunities available to them is similar to the reasons for making a before-market reference level change a prerequisite. It would harm market efficiency if resources could receive an after-market uplift payment for costs that never would have been incurred had the resource used the opportunities available to it to ensure the market had information about the resource's true costs. The CAISO does not find it appropriate to indemnify a market participant for losses incurred because its intentional business decision turned out to have been suboptimal. Permitting after-market recovery of costs that a scheduling coordinator did not request through pre-market processes but that could have been validated pre-market provides scheduling coordinators a free option to submit low commitment cost bids to be dispatched hoping to profit from price spikes but also recover any costs incurred if such price spikes do not materialize.

D. Objective #4 – Section 30.12 Does Not Expand Scope of Costs Recoverable Under Bid Cost Recovery

1. Perceived Ambiguity

There is a mistaken belief among some parties that section 30.12 was meant to permit recovery of any gas-related costs not recovered under BCR as long as there are no imbalance penalties imposed by a gas pipeline operator.

Section 30.12.1 in part describes after-market uplift as covering "a resource's actual fuel costs or *fuel-equivalent* costs associated with Start-Up Bid Costs, Minimum Load Bid Costs, Transition Bid Costs, and Energy Bid Costs used in the Bid Cost Recovery mechanism." Referring to fuel-equivalent costs raises whether section 30.12 was meant to cover something besides the direct costs of procuring fuel. The phrase "associated with" creates further potential ambiguity as to whether this is meant to cover: (a) only what the start-up, minimum load, transition cost, and energy bid costs would be using the actual fuel costs; or (b) any actually incurred fuel-related costs having to do with bidding in the market. Section 30.12.1 then specifies "costs associated with gas company imbalance penalties" are not recoverable under section 30.12. One view of the current tariff language would be that the statement about imbalance penalties resolves the ambiguity by saying that all fuel-related costs, except imbalance penalties, are recoverable. For example, this conceivably would permit recovery of gas imbalance costs from gas the generator procured but ultimately did not burn.

[37] *Id.* at P 24.

2. Statement of CAISO View

After-market recovery under section 30.12 was only meant to provide scheduling coordinators an opportunity to demonstrate the direct cost of procuring the fuel needed to meet their market awards exceeded the costs used in calculating their reference levels. A successful demonstration will result in the CAISO recalculating BCR based on those demonstrated costs. When the CAISO processes that recalculation through its settlements system, the difference between the initial BCR payment and the new BCR payment represents the "additional uplift payment" under section 30.12. The CAISO had no intent to provide any other form of payment through section 30.12.

3. Justification of CAISO View

Permitting recovery of extraneous costs such as imbalance costs would be based on finding those costs were "actual fuel costs or fuel-equivalent costs" that are "associated with" bid costs. Even if such a finding were possible, those costs would need to be run through the BCR rules in section 11.8 of the CAISO tariff. It would never be a straight payment of the claimed costs. But those established rules have no way to account for these gas imbalance costs. To permit their recovery would require reimagining what costs are covered under BCR because they would not reflect the direct costs of starting up, remaining at minimum load, or providing energy above minimum load. Nothing in the record of the underlying commitment costs and default energy bid enhancements initiative, however, reflects the CAISO intended to rewrite BCR in this way.

To the contrary, during the policy process, the CAISO stated that the after-market payment "will be for actually incurred costs that exceed either a cap or mitigated price level, which may not include any adders above cost such as risk related adder, unrecovered through market revenues."[38] Permitting recovery of extraneous costs beyond those for the direct purchase of fuel would effectively permit an adder.

When the Commission considered the CAISO's first version of the after-market uplift provisions in the Aliso Canyon initiative, the Commission rejected a request that the CAISO be ordered to amend its tariff to permit recovery of imbalance costs. One party noted that where "a generator purchases same-day gas to meet a CAISO dispatch, and then the dispatch is rescinded or the gas company curtails service to the generator due to local pressure concerns, the generator may have to liquidate gas or sell it back to the pipeline at a steep discount." The Commission concluded these circumstances would not be "legitimate for inclusion in cost recovery filings with the Commission."[39]

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[38] CCDEBE Second Revised Draft Final Proposal at 41.

[39] *Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,224, PP 90 & 96.

Again, allowing costs beyond the direct cost of procuring fuel needed to meet CAISO dispatch would be bad policy because it would incentivize speculative market activity. Allowing recovery for imbalance costs provides generators a free option to purchase extra gas hoping to capitalize on high prices through incremental real-time market awards. If the resource bets correctly, then it keeps the market rents. If the unneeded gas must be sold back to the pipeline at a loss, CAISO load would absorb those costs through the incremental after-market payment. It would be unjust and unreasonable to expect CAISO load to subsidize such market participant speculation.

III. Proposed Tariff Amendments

A. Revisions to Section 30.12.1

The amendments in section 30.12.1 provide clarity that an after-market uplift request under section 30.12 can only be for costs presented to the CAISO as a before-market reference level change request, which request the CAISO did not approve.

Part (a) frames allowable after-market requests as covering “amounts in a Reference Level Change Request that were not approved pursuant to Section 30.11.” This phrasing is potentially ambiguous because it does not specify whether the amounts were not approved because they were never presented to the CAISO or because the CAISO reviewed the costs and actively decided not to approve the reference level change request. Per the amendment to part (a), this section would now state after-market requests can only be for “amounts in a Reference Level Change Request presented to the CAISO pursuant to Section 30.11 that the CAISO did not approve.” This amendment removes any doubt from the tariff that making a before-market reference level change request is a necessary prerequisite to making an after-market uplift request.

Section 30.12.1 also states that a scheduling coordinator cannot request uplift payments for gas company imbalance penalties. The CAISO proposes to amend this statement to also say that uplift requests for costs not specifically included in a before-market reference level change request cannot be included in an after-market request. This reinforces that the intent of permitting after-market requests is solely to address potential gaps in the before-market process. It is thus appropriate that the before-market request establishes the permissible ambit of an after-market request.

B. Revisions to Section 30.12.2

Section 30.12.2 imposes a 30-business-day deadline “after the applicable Trading Day” for a scheduling coordinator to notify the CAISO if it plans to seek an after-market uplift payment. Part (a) imposes that deadline on requests submitted to the CAISO and part (b) imposes that deadline on requests submitted to the Commission. However, part (b) does not differentiate between requests submitted in the first instance to the Commission and requests submitted to the Commission after having first been considered by the CAISO.

As applied to part (b), the reference to the applicable trading day might suggest the deadline only applies to cases where the scheduling coordinator makes its initial filing with the Commission. This is because where the Commission filing follows an unsuccessful request to the CAISO, there is not necessarily an "applicable Trading Day." However, in either instance (an initial filing with the Commission or a Commission filing following an unsuccessful CAISO request) it is important to impose a 30-business-day notice deadline so the CAISO has certainty about whether the relevant trading day remains subject to further dispute and discussion. The CAISO accordingly proposes to add an additional statement in section 30.12.2 clarifying that where the Commission request follows an unsuccessful CAISO request, the applicable trading day is the day the CAISO informed the scheduling coordinator the request was not successful.[40]

The existing tariff implies, but does not state directly, that failure to meet this deadline disqualifies a scheduling coordinator from receiving an after-market uplift payment. The CAISO proposes to amend section 30.12.2 to state this consequence explicitly.

C. Revisions to Section 30.12.3

Section 30.12.3 states what supporting documentation must accompany an after-market request and does not distinguish between requests made to the CAISO and requests made to the Commission. Because of the Commission's conclusion in its *EDF* order that section 30.12.5 represents an independent path to cost recovery, the current construction could be misunderstood as applying only to requests made to the CAISO under section 30.12.4. To avoid this potential confusion, the CAISO proposes to amend section 30.12.3 to be explicit that the supporting documentation for an after-market request is the same regardless of where the request is reviewed.

D. Revisions to Section 30.12.4

Section 30.12.4.1 describes some of the processes applicable to after-market uplift requests submitted to the CAISO. The CAISO proposes to add to

[40] Importantly, this 30-business-day deadline is only to provide the CAISO notice that a Commission filing is forthcoming. Section 30.12.5 establishes separate timing requirements for submitting the filing to the Commission.

section 30.12.4.1 a cross-reference to the supporting documentation requirements established in section 30.12.3. This cross-reference reinforces that the documentation requirements apply to requests made under section 30.12.4.

Section 30.12.4.3 currently describes how the CAISO settles amounts it deems recoverable. The CAISO proposes to delete this part of section 30.12.4 and provide a consolidated statement in new section 30.12.6 to describe how the CAISO settles granted requests regardless of whether the request is granted by the Commission or the CAISO.

Sections 30.12.4.4 and 30.12.4.5 state a scheduling coordinator may request Commission review of its request if the CAISO either cannot verify the request or determines the scheduling coordinator is ineligible for recovery, respectively. The CAISO proposes minor clarifying and conforming changes to these two sub-sections.

E. Revisions to Section 30.12.5

Section 30.12.5.1 describes the processes applicable to after-market uplift requests submitted to the Commission. The CAISO proposes multiple revisions to more clearly outline these processes and delineate the paths a request can take on its way to the Commission. Specifically, the existing tariff provides scheduling coordinators 90 business days "after either the applicable Trading Day or the date the CAISO informs the Scheduling Coordinator that it is not eligible to recover its fuel costs" to file with the Commission. However, current section 30.12.4.4 suggests if the CAISO cannot verify the costs, as opposed to determining the costs are ineligible, then the scheduling coordinator has only 30 business days to file with the Commission. The CAISO finds it is appropriate for the deadline for all three procedural paths to be in section 30.12.5.1 and that they be consistent. The proposed amendments to section 30.12.5.1 reflect this conclusion.

These amendments also reinforce and clarify there are three paths to recovery under section 30.12 but they fall under the same basic rules:

1. Initial request to CAISO and recovery granted.
2. Initial request to FERC and recovery granted.
3. Initial request to CAISO not granted but follow-on request to FERC is granted.

As with current section 30.12.2, the tariff implies, but does not state explicitly, that failure to meet this deadline makes the scheduling coordinator ineligible to receive an additional uplift payment. The CAISO proposes amendments to make this consequence explicit. Section 30.12.5.2 currently describes how the CAISO settles amounts the Commission deems recoverable.

As with section 30.12.4.3, the CAISO proposes to delete this material in favor of consolidating the settlement issues in new section 30.12.6.

F. New Section 30.12.6

The CAISO proposes a new section 30.12.6 to provide a unified and more direct statement of how the CAISO will settle the additional uplift payment if either the CAISO or Commission validate actual fuel costs.

If the costs are validated, then the CAISO "will resettle Bid Cost Recovery and Exceptional Dispatch for the resource using Bid Costs and Default Energy Bids, as applicable, that are revised to reflect the validated fuel costs or fuel-equivalent costs." This clarifies that if the CAISO or the Commission grants a request, then the consequence is the CAISO takes revised cost inputs and reruns BCR with those new inputs. The additional uplift payment is whatever increased payment the scheduling coordinator receives on the applicable recalculation settlement statement. A granted request guarantees no specific incremental uplift payment.

The CAISO also clarifies that even if the CAISO or the Commission validate that a specific cost was incurred, the scheduling coordinator will not receive incremental recovery to the extent that cost is not otherwise already part of the BCR mechanism.

Finally, CAISO proposes to limit the incremental uplift payment through BCR to the difference between the BCR payment using the validated costs and the BCR payment the scheduling coordinator would have initially received had it taken maximum advantage of the bidding opportunities it had available.

These amendments reinforce the purpose of section 30.12, which is to permit additional recovery in limited cases where existing limitations in processes surrounding reference level updates made it impossible for scheduling coordinators to recover costs they otherwise could have recovered.

G. Summary of Tariff Revisions

The table below summarizes the tariff revisions presented in this filing and categorizes which sections are revised to meet which of the four noted objectives. The table also identifies where revisions are proposed for general clarity and not necessarily to address potential discrepancies between the tariff and the intended policy.

Tariff Section	Description of Tariff Amendment	Objective Number
30.12	No revisions—High-level heading for after-market recovery requests	N/A
30.12.1	Clarifies after-market recovery is only for costs presented under section 30.11 that were not approved	No. 1
30.12.2	Additional clarity on consequence if scheduling coordinator does not meet deadline	General clarification
30.12.3	Clarifying that supporting documentation is same regardless of where after-market request is directed	No. 2
30.12.4	No revisions—Heading for after-market requests directed to CAISO	N/A
30.12.4.1	Adding cross-reference for further specificity	General clarification
30.12.4.2	No revisions	N/A
30.12.4.3	Deleting statement describing recoverable amounts for request directed to CAISO because methodology is same regardless of where request is directed	No. 2
30.12.4.4	Adding clarity on next steps if CAISO is unable to validate after-market request	General clarification
30.12.4.5	Adding clarity on next steps if CAISO deems scheduling coordinator ineligible for after-market recovery	General clarification
30.12.5	No revisions—Heading for after-market requests directed to FERC	N/A
30.12.5.1	States after-market requests directed to FERC are based on same documentation covered by CAISO requests; general clarifications on required timing of submitting request to FERC	No. 2; General clarification
30.12.5.2	Deleting statement describing recoverable amounts for request directed to FERC because methodology is same regardless of where request is directed	No. 2
30.12.6	Creates a single statement outlining the costs that are recoverable if an after-market request is granted; the CAISO makes a straight resettlement of BCR but also limits incremental payment based on assumption resource bid maximum allowable commitment costs in the market	No. 3; No. 4

Objective No. 1—Before-Market Reference Level Change Request is a Necessary Prerequisite for After-Market Uplift Requests
Objective No. 2—Same Standards Apply Regardless of Who Reviews the After-Market Uplift Request
Objective No. 3—After-Market Uplift Payments Limited to Costs that Could Not Be Recovered from the Market
Objective No. 4—Tariff Section 30.12 Does Not Expand the Scope of Costs Recoverable Under Bid Cost Recovery

IV. Effective Date

The CAISO respectfully requests an effective date of January 24, 2025 for these tariff revisions. Good cause exists for the Commission to grant a waiver of its notice requirement to permit the requested effective date.[41] Waiving the notice requirement will ensure that in the event of unexpected fuel market volatility, all future after-market fuel cost recovery requests are considered under the clarified tariff provisions that more directly reflect the important policy imperatives discussed above. The CAISO respectfully requests that the Commission issue an order accepting the tariff revisions by March 24, 2025.

V. Communications

Under Rule 203(b)(3),[42] the CAISO respectfully requests that all correspondence and other communications about this filing be served upon:

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VI. 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.

VII. Contents of this filing

Besides this transmittal letter, this filing includes these attachments:

Attachment A	Clean CAISO tariff sheets

[41] Specifically, under Section 35.11 of the Commission's regulations, 18 C.F.R. § 35.11, the CAISO respectfully requests waiver of the notice requirement in section 35.3(a)(1) of the Commission's regulations, 18 C.F.R. § 35.3(a)(1), to allow the tariff revisions to go into effect with less than 60 days' notice.

[42] 18 C.F.R. § 385.203(b)(3).

Attachment B	Redlined CAISO tariff sheets
Attachment C	Commitment Cost and Default Energy Bid Enhancements Board Memorandum
Attachment D	Commitment Cost and Default Energy Bid Enhancements Second Revised Draft Final Proposal

VIII. 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 by March 24, 2025, effective as of the date specified herein.

Respectfully submitted,

/s/ David S. Zlotlow

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Attachment A – Clean Tariff

Tariff Amendment to Clarify Process for After-Market Fuel Cost Recovery

California Independent System Operator Corporation

January 23, 2025

30.12 After-CAISO Market Process Cost Recovery

30.12.1 Applicability

Scheduling Coordinators may request an additional uplift payment to cover a resource's actual fuel costs or fuel-equivalent costs associated with Start-Up Bid Costs, Minimum Load Bid Costs, Transition Bid Costs, and Energy Bid Costs used in the Bid Cost Recovery mechanism, and that are for:

(a) amounts in a Reference Level Change Request presented to the CAISO pursuant to Section 30.11 that the CAISO did not approve; or

(b) amounts in a Reference Level Change Request for a Default Energy Bid or Default Minimum Load Bid that exceeds the Hard Energy Bid Cap or the Minimum Load Cost Hard Cap, respectively.

Scheduling Coordinators may not request additional uplift payments under this Section 30.12 to cover costs: (1) associated with gas company imbalance penalties; or (2) that were not specifically included in a Reference Level Change Request.

30.12.2 Notice

The Scheduling Coordinator must notify the CAISO within thirty (30) Business Days after the applicable Trading Day whether it will:

(a) request a CAISO evaluation of its costs, pursuant to Section 30.12.4; or

(b) submit a filing to FERC to recover its costs pursuant to Section 30.12.5.

For purposes of part (b), in cases where the scheduling coordinator did not first make a request under Section 30.12.4, the applicable Trading Day is the Trading Day for which additional uplift has been requested. In cases where the Scheduling Coordinator first makes a request to the CAISO under Section 30.12.4 but the CAISO informed the Scheduling Coordinator it is not eligible to recover its fuel costs through Section 30.12.4 or that the CAISO was unable to verify the costs, then the applicable Trading Day is the Trading Day on which the CAISO informed the Scheduling Coordinator of its ineligibility or the CAISO's inability to verify the costs, respectively.

A Scheduling Coordinator is not eligible to receive an additional uplift payment under this Section 30.12 if it fails to provide notice within this 30-Business Day period.

30.12.3 Supporting Documentation

For requests under Section 30.12.4 and Section 30.12.5, Scheduling Coordinators must submit supporting documentation to the CAISO or FERC, respectively, that demonstrates that submitted costs represent actually procured daily fuel costs or fuel-equivalent costs for a given Trading Day that exceed the fuel costs or fuel-equivalent costs the CAISO used to calculate the resource's Reference Levels. These fuel costs or fuel-equivalent costs must be reasonable and reflect prudent procurement practices. Permissible supporting documents include invoices for fuel purchased, or other appropriate documentation demonstrating fuel costs or fuel-equivalent costs actually incurred that exceed the fuel costs or fuel-equivalent costs the CAISO used to calculate the resource's Reference Levels for the applicable Trading Days.

30.12.4 CAISO After-Market Evaluation of Fuel Costs

30.12.4.1 Process

If the Scheduling Coordinator requests that the CAISO evaluate the costs specified in Section 30.12.1 based on the documentation specified in Section 30.12.3, then within sixty (60) Business Days after the Trading Day for which the Scheduling Coordinator provides notice to the CAISO per this Section 30.12.4, the CAISO will:

(a) provide the Scheduling Coordinator with a written explanation of any effect that events or circumstances in the CAISO Markets and fuel market conditions may have had on the resource's inability to recover the costs on the applicable Trading Day; and

(b) notify the Scheduling Coordinator whether the costs are eligible for evaluation pursuant to this Section 30.12.4.

30.12.4.2 CAISO Evaluation

In evaluating a request submitted by a Scheduling Coordinator, the CAISO will verify that the submitted costs represent actual incurred fuel costs or fuel-equivalent costs, and that these costs are reasonable and reflect prudent procurement practices.

30.12.4.3 [Not Used]

30.12.4.4 CAISO Inability to Verify Costs

If the CAISO is unable to verify within the sixty (60) Business Day period that the resource's incurred costs are eligible for recovery pursuant to this Section 30.12.4, then the Scheduling Coordinator may submit a filing to FERC under Section 30.12.5 to recover costs.

30.12.4.5 Ineligibility

If the CAISO determines the resource is ineligible to recover its fuel-related costs through this Section 30.12.4, then the Scheduling Coordinator may submit a filing to FERC under Section 30.12.5 to recover costs..

30.12.5 FERC Fuel Cost Recovery Filings

30.12.5.1 Process

A Scheduling Coordinator may request that FERC evaluate the costs specified in Section 30.12.1 based on the documentation specified in Section 30.12.3.

If the Scheduling Coordinator makes such request without having first made a request pursuant to Section 30.12.4, then the Scheduling Coordinator has ninety (90) Business Days after the applicable Trading Day to submit its filing for fuel cost recovery to FERC.

If the Scheduling Coordinator first makes a request to the CAISO under Section 30.12.4 but the CAISO informed the Scheduling Coordinator it is not eligible to recover its fuel costs through Section 30.12.4 or that the CAISO was unable to verify the costs, then the Scheduling Coordinator has ninety (90) Business Days after being informed of its ineligibility or the CAISO's inability to verify the costs, respectively, to submit its filing for fuel cost recovery to FERC.

A Scheduling Coordinator is not eligible to receive an additional uplift payment under this Section 30.12 if it fails to file with FERC within the applicable 90-Business-Day period.

30.12.5.2 [Not Used]

30.12.6 Allowable Recovery and Settlement

If the CAISO (per section 30.12.4) or FERC (per section 30.12.5) validate that the Scheduling Coordinator did not recover through the Bid Cost Recovery mechanism the actual incurred fuel costs or fuel-equivalent costs specified in Section 30.12.1, then the CAISO will resettle Bid Cost Recovery and Exceptional Dispatch for the resource using Bid Costs and Default Energy Bids, as applicable, that are revised to reflect the validated fuel costs or fuel-equivalent costs. The validated costs are not recoverable outside of Bid Cost Recovery and any validated costs that are not otherwise recognized in Bid Cost Recovery will not be part of an uplift payment under this Section 30.12. The CAISO effectuates the resettlement by issuing Recalculation Settlement Statement(s) within the normal Recalculation Settlement Statements timelines specified in Section 11.29 or by issuing an Unscheduled Directed Recalculation Settlement Statement if the normal timelines have elapsed.

Provided, however, the increase in Bid Cost Recovery payment for a Trading Day cannot exceed the difference between the Bid Cost Recovery payment for the resource based on the validated costs and the maximum Bid Cost Recovery payment the Scheduling Coordinator could have received using the fuel and fuel-equivalent costs in place for market bidding processes on the Trading Day.

Attachment B – Marked Tariff

Tariff Amendment to Clarify Process for After-Market Fuel Cost Recovery

California Independent System Operator Corporation

January 23, 2025

30.12 After-CAISO Market Process Cost Recovery

30.12.1 Applicability

Scheduling Coordinators may request an additional uplift payment to cover a resource's actual fuel costs or fuel-equivalent costs associated with Start-Up Bid Costs, Minimum Load Bid Costs, Transition Bid Costs, and Energy Bid Costs used in the Bid Cost Recovery mechanism, and that are for:

(a) amounts in a Reference Level Change Request presented to the CAISO ~~that were not approved~~ pursuant to Section 30.11 that the CAISO did not approve; or

(b) amounts in a Reference Level Change Request for a Default Energy Bid or Default Minimum Load Bid that exceeds the Hard Energy Bid Cap or the Minimum Load Cost Hard Cap, respectively.

Scheduling Coordinators may not request additional uplift payments under this ~~section~~ Section 30.12 to cover costs: (1) associated with gas company imbalance penalties; or (2) that were not specifically included in a Reference Level Change Request.~~.~~

30.12.2 Notice

The Scheduling Coordinator must notify the CAISO within thirty (30) Business Days after the applicable Trading Day whether it will:

(a) request a CAISO evaluation of its costs, pursuant to Section 30.12.4; or

(b) submit a filing to FERC to recover its costs pursuant to Section 30.12.5.

For purposes of part (b), in cases where the scheduling coordinator did not first make a request under Section 30.12.4, the applicable Trading Day is the Trading Day for which additional uplift has been requested. In cases where the Scheduling Coordinator first makes a request to the CAISO under Section 30.12.4 but the CAISO informed the Scheduling Coordinator it is not eligible to recover its fuel costs through Section 30.12.4 or that the CAISO was unable to verify the costs, then the applicable Trading Day is the Trading Day on which the CAISO informed the Scheduling Coordinator of its ineligibility or the CAISO's inability to verify the costs, respectively.

A Scheduling Coordinator is not eligible to receive an additional uplift payment under this Section 30.12 if it fails to provide notice within this 30-Business Day period.

30.12.3 Supporting Documentation

For requests under Section 30.12.4 and Section 30.12.5, Scheduling Coordinators must submit supporting documentation to the CAISO or FERC, respectively, that demonstrates that submitted costs represent actually procured daily fuel costs or fuel-equivalent costs for a given Trading Day that exceed the fuel costs or fuel-equivalent costs the CAISO used to calculate the resource's Reference Levels. These fuel costs or fuel-equivalent costs must be reasonable and reflect prudent procurement practices. Permissible supporting documents include invoices for fuel purchased, or other appropriate documentation demonstrating fuel costs or fuel-equivalent costs actually incurred that exceed the fuel costs or fuel-equivalent costs the CAISO used to calculate the resource's Reference Levels for the applicable Trading Days.

30.12.4 CAISO After-Market Evaluation of Fuel Costs

30.12.4.1 Process

If the Scheduling Coordinator requests that the CAISO evaluate the costs specified in Section 30.12.1 based on the documentation specified in Section 30.12.3, then within sixty (60) Business Days after the Trading Day for which the Scheduling Coordinator provides notice to the CAISO per this Section 30.12.4, the CAISO will:

(a) provide the Scheduling Coordinator with a written explanation of any effect that events or circumstances in the CAISO Markets and fuel market conditions may have had on the resource's inability to recover the costs on the applicable Trading Day; and

(b) notify the Scheduling Coordinator whether the costs are eligible for evaluation pursuant to this Section 30.12.4.

30.12.4.2 CAISO Evaluation

In evaluating a request submitted by a Scheduling Coordinator, the CAISO will verify that the submitted costs represent actual incurred fuel costs or fuel-equivalent costs, and that these costs are reasonable and reflect prudent procurement practices.

30.12.4.3 [Not Used] ~~Settlement of Recoverable Amounts~~

~~To the extent the CAISO's evaluation results in verification that the resource's actually incurred costs claimed by the Scheduling Coordinator were not recovered through the Bid Cost Recovery process, the~~

~~CAISO will resettle Bid Cost Recovery and Exceptional Dispatch using revised Bid Costs and revised Default Energy Bids, as applicable, for the resource and will issue Recalculation Settlement Statement(s) within the normal Recalculation Settlement Statements timelines specified in Section 11.29.~~

30.12.4.4 ~~Extensions~~CAISO Inability to Verify Costs

If the CAISO is unable to verify within the sixty (60) Business Day period that the resource's incurred costs are eligible for ~~evaluation~~ recovery pursuant to this Section 30.12.4, then the Scheduling Coordinator may submit a filing to FERC under Section 30.12.5 to recover costs.

~~CAISO will provide the Scheduling Coordinator with an extension of thirty (30) Business Days to submit a filing to FERC to recover costs.~~

30.12.4.5 Ineligibility

If the CAISO determines the resource is ineligible to recover its fuel-related costs through this Section 30.12.4, then the Scheduling Coordinator may submit a filing to FERC under Section 30.12.5 to recover costs.~~submit a filing for fuel cost recovery to FERC pursuant to Section 30.12.5~~.

30.12.5 FERC Fuel Cost Recovery Filings

30.12.5.1 Process

A Scheduling Coordinator may request that FERC evaluate the costs specified in Section 30.12.1 based on the documentation specified in Section 30.12.3.

If the Scheduling Coordinator makes such request without having first made a request pursuant to Section 30.12.4, then the Scheduling Coordinator has ninety (90) Business Days after the applicable Trading Day to submit its filing for fuel cost recovery to FERC.

If the Scheduling Coordinator first makes a request to the CAISO under Section 30.12.4 but the CAISO informed the Scheduling Coordinator it is not eligible to recover its fuel costs through Section 30.12.4 or that the CAISO was unable to verify the costs, then the Scheduling Coordinator has ninety (90) Business Days after being informed of its ineligibility or the CAISO's inability to verify the costs, respectively, to submit its filing for fuel cost recovery to FERC.

A Scheduling Coordinator is not eligible to receive an additional uplift payment under this Section 30.12 if it fails to file with FERC within the applicable 90-Business-Day period.

~~If the Scheduling Coordinator provides notice of its intent to submit a filing for fuel cost recovery to FERC,~~

~~or if the CAISO has determined that the Scheduling Coordinator is not eligible to recover fuel costs through Section 30.12.4, the Scheduling Coordinator will have ninety (90) Business Days after either the applicable Trading Day or the date the CAISO informs the Scheduling Coordinator that it is not eligible to recover its fuel costs through Section 30.12.4, whichever is applicable, to submit its filing for fuel cost recovery to FERC.~~

30.12.5.2 ~~Settlement of FERC-Approved Amounts~~[Not Used]

~~To the extent FERC issues an order finding the resource actually incurred costs claimed by the Scheduling Coordinator that were not recovered through the Bid Cost Recovery process, the CAISO will resettle Bid Cost Recovery using revised Bid Costs for the resource so that these costs can be recovered through the Recalculation Settlement Statement(s) within the normal timelines specified in Section 11.29.~~

30.12.6 Allowable Recovery and Settlement

If the CAISO (per section 30.12.4) or FERC (per section 30.12.5) validate that the Scheduling Coordinator did not recover through the Bid Cost Recovery mechanism the actual incurred fuel costs or fuel-equivalent costs specified in Section 30.12.1, then the CAISO will resettle Bid Cost Recovery and Exceptional Dispatch for the resource using Bid Costs and Default Energy Bids, as applicable, that are revised to reflect the validated fuel costs or fuel-equivalent costs. The validated costs are not recoverable outside of Bid Cost Recovery and any validated costs that are not otherwise recognized in Bid Cost Recovery will not be part of an uplift payment under this Section 30.12. The CAISO effectuates the resettlement by issuing Recalculation Settlement Statement(s) within the normal Recalculation Settlement Statements timelines specified in Section 11.29 or by issuing an Unscheduled Directed Recalculation Settlement Statement if the normal timelines have elapsed.

Provided, however, the increase in Bid Cost Recovery payment for a Trading Day cannot exceed the difference between the Bid Cost Recovery payment for the resource based on the validated costs and the maximum Bid Cost Recovery payment the Scheduling Coordinator could have received using the fuel and fuel-equivalent costs in place for market bidding processes on the Trading Day.

Attachment C – Commitment Cost and Default Energy Bid Enhancements

Board Memorandum

Tariff Amendment to Clarify Process for After-Market Fuel Cost Recovery

California Independent System Operator Corporation

January 23, 2025

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: March 14, 2018

Re: **Decision on commitment costs and default energy bid enhancements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes to modify the ISO's rules for submitting supply offers to allow suppliers to more accurately reflect their costs in the ISO market. The modifications will provide increased flexibility for suppliers to bid in their actual costs, along with safeguards to mitigate market power under uncompetitive conditions. Some of these rule changes are also needed to comply with Federal Energy Regulatory Commission (FERC) Order No. 831.

The ISO market design allows resources to submit separate bid components for their market bid for energy above minimum load, minimum load costs, start-up costs and, for multi-stage resources, their transitions from one configuration to another. Minimum load, start-up, and transition costs are collectively referred to as "commitment costs."

Under the current design, the ISO calculates daily "reference levels" for each natural gas generator that are based on published natural gas price indices. Commitment cost bids are capped at reference levels determined by 125 percent of the ISO-calculated costs. The ISO sets reference levels for energy above minimum load at 110 percent of its calculation of each resource's costs. These energy reference levels are referred to as "default energy bids."

Unlike energy bids, which the ISO market only limits to a resource's default energy bid if it detects local market power, commitment cost bids are always capped at the resource's reference level, even under competitive conditions. The California ISO is the only ISO in the United States to do this. Other ISOs only limit commitment cost bids to reference levels if market power is detected.

Suppliers have raised concerns that the current commitment cost bid cap does not always allow suppliers to reflect their actual or expected costs. The gas price indices used to calculate reference levels may not reflect the wide variety of generators throughout the ISO balancing area and the broader Energy Imbalance Market footprint, and may not reflect volatile or illiquid gas markets. This existing cap can undermine market efficiency and discourage participation in the market. Additionally, the existing daily minimum load bid construct prevents resources from reflecting minimum load costs that vary throughout the day.

Management proposes to enhance suppliers' ability to reflect commitment costs by replacing the static commitment cost bid cap with a dynamic commitment cost local market power mitigation test. The ISO will run the test in the market systems and will mitigate commitment cost bids prior to executing the applicable market run if a resource is needed to relieve a transmission overload. Management also proposes a "circuit-breaker" commitment cost bid cap to protect against test failures.

Management's proposal also includes enhancements that enable suppliers to request adjustments to both commitment cost and energy reference levels before the ISO market runs. Verified cost adjustments would then be used in the ISO market runs. In the event the costs could not be verified prior to the market run, Management proposes that the market participant be given the opportunity for an after-the-fact recovery of actual costs that could not be verified before the market ran. The proposal also changes minimum load bids from daily to hourly.

Management presented this proposal to the Energy Imbalance Market governing body on March 8, and the Governing Body voted to provide advisory input to the ISO Board of Governors supporting this proposal.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposal to implement the commitment costs and default energy bid enhancements described in the memorandum dated March 14, 2018; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the commitment costs and default energy bid enhancements described in the memorandum dated March 14, 2018, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Federal Energy Regulatory Commission guidance in any initial ruling on the proposed tariff amendment.***

DISCUSSION AND PROPOSAL

The following sections first provide related background information describing the ISO existing supply bidding related market rules and FERC's Order No. 831, and then describe Management's proposal to enhance suppliers' ability to reflect and recover costs in the ISO market.

Background

The ISO market design allows resources to submit separate bid components for their market bid for energy above minimum load, minimum load costs, start-up costs and, for multi-stage resources, their transitions from one configuration to another. Minimum load, start-up, and transition costs are collectively referred to as "commitment costs."

The ISO calculates daily reference levels for each natural gas generator that are based on published natural gas price indices.[1] The ISO sets commitment cost reference levels at 125 percent of its calculation of each resource's costs. The ISO sets reference levels for energy above minimum load at 110 percent of its calculation of each resource's costs. These energy reference levels are referred to as "default energy bids."

The ISO market uses the energy reference levels as part of its local market power mitigation measures for energy bids. The market replaces a resource's energy bid with its default energy bid if the resource fails a test that detects if the resource has market power in setting energy locational marginal prices. Otherwise, the market rules only limit energy bids to a $1,000/MWh "circuit-breaker" cap.

In contrast, commitment cost bids are always limited by a static bid cap set at the ISO's daily calculation of 125 percent of a resource's costs.[2] The California ISO is the only ISO or RTO in the United States to do this. Other ISOs and RTOs only limit commitment cost bids to reference levels if market power is detected. Specifically, PJM uses a three-pivotal supplier test to detect local market power, which is similar to the California ISO's energy local market power test, and only limits commitment costs if a resource fails the test. Alternatively, NYISO, MISO, SPP, and ISO-NE use a conduct and impact market power test for commitment costs, and only potentially limit commitment costs if a supplier's bids (i.e. its "conduct") are above a certain cost threshold.

A temporary tariff provision adopted to address the limited use of the Aliso Canyon storage facility provides for the ISO to calculate reference levels for the day-ahead market based on natural gas price index information published by the Intercontinental Exchanges (ICE) based on "next-day" gas trading occurring on the morning of the day-ahead market. The ISO

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[1] The ISO calculates reference levels for other supply resources based on costs suppliers submit to the ISO's master file.

[2] Use limited resources are currently allowed to use the "registered cost" option for commitment costs that fixes a resource's commitment cost up to 150% of projected costs for 30 days. Changes approved by the Board of Governors in March 2016 will limit the registered cost option to new use-limited resources that do not have one year of locational marginal price data to calculate an opportunity cost adder.

calculates reference levels for the real-time market based on gas price indices published the evening before the day of the real-time market, which are based on next-day gas trading.

These gas price indices used for the day-ahead market and real-time market may not reflect actual costs, particularly for the real-time market, because "same-day" gas prices can be significantly different than the next-day gas prices that occurred on the prior day. These gas price indices may also not reflect individual generators' costs throughout the ISO balancing area and the broader western energy imbalance market footprint that may be located away from the gas trading hubs on which the indices are based.

Resources are also limited in accurately reflecting commitment costs because minimum load bids are currently daily values in which suppliers can only submit a single hourly minimum load cost for the entire day. Although suppliers can update this cost for the remainder of the day in the real-time market, not allowing minimum load cost bids to vary by hour prevents either the day-ahead or real-time markets to consider costs that may vary hourly.

In summary, the ISO's existing commitment cost bidding rules based on a static commitment cost bid cap can inappropriately limit resources from reflecting their actual costs. It is especially important for suppliers to be able to reflect accurate commitment costs so that the ISO market efficiently commits the right set of resources. Similarly, the ISO's existing calculation of default energy bids may not accurately reflect individual resources' actual costs to produce energy.

Management's proposal also addresses compliance with FERC's Order No. 831. This order requires allowing energy supply bids that can set market prices of up to $2,000/MWh if the bid is based on verifiable actual costs. Bids for virtual supply or imports do not have to demonstrate actual costs. The order states that energy supply bids above $1,000/MWh that are subject to cost verification can only set market prices if the ISO can verify the costs prior to the market run. Otherwise, the resource is eligible for an uplift payment if the ISO verifies the costs after-the-fact.

Proposed changes

Management proposes to modify the ISO's rules for submitting supply offers to allow suppliers to accurately reflect and recover their costs in the ISO market. These rule changes include safeguards against market power and are described in the following sections.

Replace static commitment cost cap with "market-based" commitment cost bids and commitment cost local market power mitigation test

Management proposes to replace the static commitment cost bid cap set at each resource's reference level with rules that will allow suppliers to submit "market-based" commitment cost bids. The market would only mitigate these bids to a resource's commitment cost reference level if a test in the market detects the resource has commitment cost local market power. Otherwise, these "market-based" bids will only be limited by a circuit-breaker commitment cost bid cap. Management also proposes related rule changes to protect against inflated commitment costs when the market must keep a resource on because of inter-temporal constraints or other market conditions.

There are two situations under which the proposed commitment cost market power mitigation test will mitigate commitment costs. First, the test will mitigate commitment costs when a resource can relieve a non-competitive constraint that is "binding" in the market, for example, when flows on a transmission line are at the line's capacity.[3] Second, the test will mitigate commitment costs of any committed resource the market could have potentially committed to relieve the constraint. This second situation is necessary because the market may commit a resource based on its minimum load and then the constraint the market committed it to relieve becomes not binding. These are the resources that potentially have commitment cost market power because the market may have committed them to unload the constraint.

Management proposes to limit market-based commitment cost bids to a circuit-breaker bid cap to guard against potential situations not accounted for by the commitment cost local market power mitigation test and related rules. Management proposes to phase-in commitment cost bidding flexibility to ensure the commitment cost local market power mitigation test and related rules are functioning appropriately when first implemented. Management proposes to set the circuit breaker commitment cost bid cap for the first 18 months at 150 percent of each resource's commitment cost reference level. After this period, the cap will increase to 300 percent of each resource's commitment cost reference level. Management proposes 300 percent because it provides a reasonable range based on historical gas-price volatility to capture costs the vast majority of the time and because it is similar to the bid amounts subject to mitigation under other ISO's conduct and impact test commitment cost market power mitigation methodologies.

Similarly, management proposes to phase-in the level to which the market will mitigate commitment costs in the event a resource fails the commitment cost market power test. For the first 18 months, Management proposes to mitigate the commitment costs of resources that fail the commitment cost market power test to 125 percent of ISO-calculated costs, which is similar to the current static commitment cost bid cap. This is so that suppliers will not be subject to a more restricted ability to reflect costs than under the existing rules in the event the new commitment cost local market power mitigation test inaccurately detects market power when in fact it does not exist. After 18 months, the market will mitigate commitment costs of resources that fail the commitment cost market power mitigation test to 110 percent of ISO-calculated costs. This value is calculated similarly to a default energy bid, which is also 110 percent of ISO-calculated costs.

[3] It will also mitigate the commitment cost of any resource needed to meet a minimum online constraint. These constraints commit a minimum amount of capacity within a limited area and generally do not entail competitive conditions.

The phased-in approach provides protection against potential false positives and false negatives of the dynamic commitment cost market power mitigation. In the event the ISO determines the market power mitigation is not functioning as designed, we will correct the mitigation or file with FERC to extend the period of the interim bid caps.

Management proposes related rules to disallow changes to minimum load bids when the market must keep a resource or multi-stage generator configuration on or off because of an exceptional dispatch instruction. Similar to the existing energy settlement rules for exceptional dispatches, these rules would apply to exceptional dispatches needed to relieve constraints deemed uncompetitive ahead of time based on historical pivotal supplier test results. Similar rules will apply when the market cannot shut a resource down until it ramps it to its minimum load.

Allow market participants to request adjustments to their energy and commitment cost reference levels

As described earlier, in the operational timeframe, a resource's actual costs may differ from the ISO-calculated costs used to determine a resource's energy or commitment cost reference level. Management proposes to allow suppliers to request an adjustment to a resource's reference level if its documented costs exceed the costs the ISO used to calculate the reference level.

Management proposes to screen energy and commitment cost bids reference level adjustment requests using an automated "reasonableness threshold." The market will automatically accept reference level adjustment requests that fall within the reasonableness threshold. Otherwise, it will cap the adjustment at the reasonableness threshold. An exception will be for energy bid costs above $1,000/MWh as required by FERC Order No. 831, which mandates that the ISO verify incremental energy offers above the $1000/MWh cap are cost-based and accurately reflect their actual or expected short-run marginal cost prior to the market run. Consistent with this requirement, time permitting, the ISO will review manually the resource's costs that exceed the energy before the market runs, if the supplier submits the appropriate evidence in a timely manner. Management does not propose to extend this same manual verification opportunity to the commitment costs because it would be virtually impossible to verify these costs before the market run given that they are based on more complex factors other than the cost of fuel, which is the main driver for incremental energy costs and more easily verifiable. In any case, as discussed below, Management proposes that suppliers have the opportunity to demonstrate their costs incurred after the market run if they exceed the thresholds and could not be verified before the market run.

Management proposes that the reasonableness threshold be the result of a daily resource-specific calculation that adds a fixed percentage to the fuel cost component of a resource's reference level calculation. For natural-gas-fired resources, Management proposes to calculate the reasonableness threshold by scaling the gas price used in the reference level calculation by 125 percent on Mondays or days after holidays, which are subject to increased price volatility due to the lag between the trading and operational days, and by 110 percent on other days. Management proposes to scale the fuel or fuel-equivalent costs of other resources by 110 percent.

Management selected these scaling percentages to capture most of the difference between actual gas purchases and the published indexes. The reasonableness threshold calculation for Mondays and days after holidays scales gas price by a higher percentage because the practices for purchasing gas over the weekend and for Monday, and trading conditions involving holidays, frequently cause the actual gas purchase price to exceed the published index.

Management proposes that the ISO have the ability to modify the standard reasonableness threshold calculation of individual resources to reflect particular differences between these resources' costs and the costs used to calculate their reference levels. As described below, Management's proposal includes provisions for suppliers to seek after-the-fact cost recovery for actual costs incurred but for which the supplier submitted a reference level adjustment that was limited by the reasonableness threshold. The ISO would modify the standard reasonableness threshold calculation for an individual resource if repeated after-the-fact cost recovery requests showed the standard calculation did not reflect the resource's costs.

Management proposes to require that suppliers base reference level adjustment requests on actual price quotes. The ISO will have the authority to audit these requests even if they fall within the thresholds and there will be provisions to suspend the ability of a supplier to request reference level adjustments, and to potentially refer the supplier to FERC for submitting false information, if its requests cannot be backed up with actual price quotes.

Allow market participants to seek after-the-fact cost recovery for actual incurred costs for which the ISO approved a reference level adjustment request before the market ran

Management proposes to allow suppliers to request after-the-fact that the ISO review a reference level adjustment request that was limited by the reasonableness threshold and not incorporated into the market. Verified actual costs would be eligible for after-the-fact recovery through a bid cost recovery uplift payment. To comply with FERC Order No. 831, this will include energy costs above the $1000/MWh that were not manually verified before the market run and $2,000/MWh cap that were not included in the market.

The costs eligible for after-the-fact recovery will be limited to documented actual costs. The supplier would have to incur these costs contemporaneously with the market they were used for and the gas system balancing rules would have to not allow any delay in procurement. In addition, the supplier will have to attest it does not have balancing group arrangements that allow it to delay purchasing gas. If a supplier can delay purchasing gas, it could presumably purchase gas at prices more consistent with the reasonableness threshold.

Hourly minimum load costs

Management proposes to change minimum load bids from daily to hourly bids. As described earlier, resources currently are unable to accurately reflect commitment costs because suppliers can only submit a single hourly minimum load cost for the entire day. Allowing minimum load cost bids that vary by hour will allow the ISO market to consider costs that may vary by hour and better enable suppliers to recover these costs.

Management also proposes to allow resources that do not have a minimum load output level, i.e. minimum load value is set at zero MW, to nonetheless have an hourly commitment that the market will treat the same as a minimum load cost. An example of such a cost is the cost for a demand response resource to maintain readiness to respond to a real-time market dispatch instruction.

Other changes

Finally, management proposes the following additional changes:

- Establish a negotiated option for determining commitment cost reference levels, similar to the existing negotiated option for determining default energy bids.
- Make permanent the existing temporary tariff provision that provides for the ISO to calculate reference levels for the day-ahead market based on natural gas price index information published by the Intercontinental Exchanges (ICE) based on "next-day" gas trading occurring on the morning of the day-ahead market. This is an important provision as it improves the accuracy of resource reference levels used for the day-ahead market.
- Make permanent an existing tariff provision that provides for the ISO to publish two-day-ahead advisory market results to market participants. This will benefit market participants as it allows them to better estimate day-ahead market results so they can more accurately purchase gas before the day-ahead market runs.
- Recalibrate the ISO market's constraint relaxation price parameters to be consistent with the increased $2,000/MWh energy bid cap required by FERC Order No. 831. These price parameters are intended to be reflected in the market to reflect scarcity in the event the market has to relax a constraint to come to a feasible solution. They need to be proportional to the level of the energy bid cap to function appropriately.

POSITIONS OF THE PARTIES

Stakeholders are generally divided on the balance between increased bidding flexibility to allow suppliers to more accurately reflect costs versus protecting against market power and other adverse market behavior.

The ISO's Market Surveillance Committee, EIM participants, third-party generators, and the Environmental Defense Fund either strongly support management's proposal or support it as better than the existing rules but maintain it still does not offer enough bidding flexibility. These stakeholders strongly support management's proposal to allow "market-based" commitment cost cap bids that are only mitigated under local market power conditions, maintaining that ISO-calculated reference levels are often below resources' actual costs. These stakeholders believe it is important to expeditiously implement Management's proposal to correct this.

The Market Surveillance Committee concludes in its final opinion on Management's proposal as follows: "Overall, we support these elements of the CAISOs dynamic market power design and believe it will both enable the CAISO to provide more offer price flexibility to gas-fired resources within the CAISO during periods of gas price volatility and will also enable the CAISO to coordinate a more efficient market across the broader EIM region and better accommodate the diverse gas supply situations of utility generation across the west." The Environmental Defense Fund notes that Management's proposal is critical to ensure the full actual costs of gas-fired generation are reflected in the ISO market so that the ISO market does not overly rely on gas-fired generation, and thus increasing greenhouse gas emissions, by artificially suppressing its price.

EIM participants and third party generators generally maintain the commitment cost circuit breaker bid caps should be higher because they could restrict legitimate costs, especially during the initial 18-month phase-in period.

The ISO Department of Market Monitoring (DMM), as well as PG&E and SCE, appear to agree with Management's proposal in principle, but maintain it needs additional safeguards to protect against market power and other ways adverse market behavior could inflate costs. They maintain Management's proposal that allows suppliers to request adjustments to resource reference levels, and greater commitment cost bidding flexibility in general, may provide opportunity for adverse market behavior to inflate costs. DMM and PG&E also maintain the ISO should further test commitment cost local market power mitigation before implementing it. In response, Management changed its proposal by lowering the interim circuit breaker bid cap from 200 percent to 150 percent of a resource's reference level. This change allows additional protections during the first 18 months to ensure the new market power mitigation provisions are working as designed.

DMM and PG&E, as well as some other stakeholders, maintain the ISO should implement a DMM proposal to update the gas price used to calculate real-time market reference levels based on gas trades the ISO observes on ICE rather than implementing Management's proposed procedures for automated reference level adjustments.

Management believes its proposal strikes an appropriate balance between increased bidding flexibility to allow suppliers to more accurately reflect costs versus protecting against market power and other adverse market behavior. Management believes a core design principle should be that suppliers are much more able than the ISO to determine their costs. Management's proposal for commitment cost local market power mitigation is robust, and Management has examined the potential for other adverse market behavior to inflate costs under its proposal and has addressed all of the identified ways this could occur.

Management does not believe DMM's proposal to update real-time market reference levels based on gas trades observed on ICE would be consistent with FERC's recent guidance on the ISO's Aliso Canyon gas-electric coordination proposals. FERC has required the ISO to only use gas price index information that meets certain FERC standards. The gas trade information DMM proposes to use does not meet those standards. While management believes that gas trade information could be used, along with other information, as part of a manual reference level adjustment approval process, that process would be labor intensive. Management believes its proposal for an automated proposal strikes a balance between implementation cost and complexity, providing suppliers flexibility, and protecting against adverse market behavior.

A stakeholder comment matrix is included as Attachment A. The Department of Market Monitoring raised several concerns in their comments on the revised draft final proposal. Management has provided a detailed response to DMM's comments included as Attachment B. The Market Surveillance Committee provided a formal opinion on Management's proposals and is included as Attachment C.

CONCLUSION

Management requests Board approval of the proposal discussed above. The proposed changes will significantly improve suppliers' ability to accurately reflect cost expectations, provide an additional mechanism for cost recovery, and encourage increased participation from flexible resources in the ISO balancing area and the voluntary western energy imbalance market.

Attachment A

Stakeholder Process: Commitment Costs and Default Energy Bid Enhancements

Summary of Submitted Comments

Stakeholders submitted eight rounds of written comments to the ISO under the Commitment Costs and Default Energy Bid Enhancements stakeholder initiative on the following dates:

- Round One (comments on Issue Paper), 12/09/2016
- Round Two (comments following working group discussions March 30 and April 20, 2017), 05/03/2017
- Round Three (comments on Straw Proposal), 07/20/2017
- Round Four (comments on Revised Straw Proposal and planned revisions to Revised Straw Proposal), 08/15/2017
- Round Five (comments on Draft Final Proposal), 09/11/2017
- Round Six (comments on Joint Parties alternative proposal), 09/26/2017
- Round Seven (comments on planned revisions to Draft Final Proposal), 01/11/2018
- Round Eight (comments on Revised Draft Final Proposal), 02/27/2018

Stakeholder comments received from:
Arizona Public Service Co. (APS), Environmental Defense Fund (EDF), Idaho Power Corporation, NRG Energy, Inc. (NRG), NV Energy (NVE), OhmConnect, Pacific Gas & Electric (PG&E), PacifiCorp (PAC), Portland General Electric (PGE), Powerex, Puget Sound Energy, San Diego Gas & Electric (SDG&E), Seattle City Light (SCL), Six Cities, Southern California Edison (SCE), The Joint Parties, Western Power Trading Forum (WPTF), and Department of Market Monitoring (DMM).

Stakeholder comments are posted at:
Commitment Costs and Default Energy Bid Enhancements: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCosts_DefaultEnergyBidEnhancements.aspx.

Other stakeholder efforts include:

Commitment Costs and Default Energy Bid Enhancements:

- Conference call, 11/22/2016
- Working group discussion, 03/30/2017
- Working group discussion, 04/20/2017
- Meeting, 07/06/2017
- Working group discussion, 08/03/2017
- Conference call, 08/11/2017
- Conference call, 08/30/2017
- Conference call, 12/21/2017
- Conference call, 02/01/2018

Comments of following Market Participants	Introduce market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions	Move from daily to hourly minimum load offers	Allow energy and commitment cost reference levels adjustments in day-ahead or real-time subject to verification	Provide after-the-fact cost recovery of costs that failed automatic screen	Recalibrate penalty price parameters	Permanently use approximation of next day gas price in daily gas price index and publish two day-ahead advisory schedules
Arizona Public Service Co. (APS)	Strongly supports market-based commitment cost bids and dynamic market power mitigation	Strongly supports. This allows suppliers to accurately reflect costs that vary by hour	Strongly supports because Monday gas price differences will be reflected in bids	No comment	No comment	No comment
Environmental Defense Fund (EDF)	Strongly supports market-based commitment cost bids and dynamic market power mitigation	Supports. Allows bidding flexibility to reflect suppliers' costs	Supports. This is a vital bidding enhancement to advance the integration of renewables	Supports. Additional avenue for suppliers to recover actual costs	No comment	No comment

Comments of following Market Participants	Introduce market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions	Move from daily to hourly minimum load offers	Allow energy and commitment cost reference levels adjustments in day-ahead or real-time subject to verification	Provide after-the-fact cost recovery of costs that failed automatic screen	Recalibrate penalty price parameters	Permanently use approximation of next day gas price in daily gas price index and publish two day-ahead advisory schedules
NRG Energy, Inc. (NRG)	Strongly supports market-based commitment cost bids and dynamic market power mitigation Supports circuit breaker cap. However, proposal does not go far enough for bidding flexibility. Suppliers' costs can be more than 300% of a reference level	Strongly supports. This allows suppliers to accurately reflect costs that vary by hour	Supports. Bidding flexibility and process to revise reference level is important for accurately reflecting suppliers' costs	Strongly supports. Additional avenue for suppliers to recover actual costs	No comment	Strongly supports. Next day gas price information has a significant effect on gas prices
NV Energy (NVE)	Strongly supports market-based commitment cost offers and dynamic market power mitigation. Provides improvements for calculating EIM participant's actual costs. Supports phased-in commitment cost circuit breaker cap. Ensures resources are no worse off than today.	Supports. Provides more bidding flexibility	Strongly supports. The design better informs the ISO of generators' actual costs when prices are not correctly represented in a gas index.	Strongly supports this additional method to potentially recover costs	No comment	No comment
OhmConnect	Supports market-based commitment cost offers and dynamic market power mitigation. Provides valuable flexibility to proxy demand resources (PDRs) with significant behavioral response components to participate in the real-time market.	Supports. Demand response resources have limited flexibility and availability costs vary throughout the day	No comment	No comment	No comment	No comment

Comments of following Market Participants	Introduce market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions	Move from daily to hourly minimum load offers	Allow energy and commitment cost reference levels adjustments in day-ahead or real-time subject to verification	Provide after-the-fact cost recovery of costs that failed automatic screen	Recalibrate penalty price parameters	Permanently use approximation of next day gas price in daily gas price index and publish two day-ahead advisory schedules
Pacific Gas & Electric (PG&E)	Do not yet believe the benefits of market-based commitment costs and dynamic market power mitigation relative to the risks have been demonstrated. Performance testing should be done prior to go-live. Support concept of commitment cost circuit breaker cap, but believes may provide too much room for suppliers to inflate costs	Opposes because market participants might be able to exploit design to inflate bid costs	Supports principle of adjustments. Oppose the calculation of the reasonableness threshold because it seems to be double counting fuel cost expectations Note - PG&E had several questions regarding this topic that are implementation details not policy related	No comment	Supports and believes determination of penalty prices should be different.	Supports
Portland General Electric (PGE)	Supports market-based commitment cost bids and dynamic market power mitigation. Provides a good start for EIM participants' greater bidding flexibility Supports commitment cost circuit breaker caps but believes caps are too conservative	Supports as it allows hydro resources to reflect varying hourly costs	Supports ability for suppliers to accurately reflect costs that may differ from calculated costs	Supports for cost recovery	No comment	No comment

Comments of following Market Participants	Introduce market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions	Move from daily to hourly minimum load offers	Allow energy and commitment cost reference levels adjustments in day-ahead or real-time subject to verification	Provide after-the-fact cost recovery of costs that failed automatic screen	Recalibrate penalty price parameters	Permanently use approximation of next day gas price in daily gas price index and publish two day-ahead advisory schedules
Powerex	Strongly supports market-based commitment cost bids and dynamic power mitigation. Provides EIM participants with sufficient bidding flexibility to reflect their own estimates of cost, risks and business needs.	Supports. Important for energy-limited hydro resources external to the ISO footprint	Supports because it allows for incorporating the unique market considerations and system conditions experienced in the EIM area.	No comment	No comment	No comment
San Diego Gas & Electric (SDG&E)	Strongly supports market-based commitment cost bids and dynamic market power mitigation Supports commitment costs circuit breaker cap. 300% is too high and may allow for market participants to inflate costs	Supports ability to reflect varying hourly costs	Supports adjustments but would like additional safeguards to protect against inflated costs	Supports method for recovery of actual costs	No comment	No comment
Seattle City Light (SCL)	Supports market-based commitment cost bids and dynamic market power mitigation. It is necessary to address commitment cost market power issues that come from market-based bids	Supports bidding flexibility for hydro generators	Supports process for suppliers to update costs to better inform ISO dispatches	No comment	No comment	No comment

Comments of following Market Participants	Introduce market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions	Move from daily to hourly minimum load offers	Allow energy and commitment cost reference levels adjustments in day-ahead or real-time subject to verification	Provide after-the-fact cost recovery of costs that failed automatic screen	Recalibrate penalty price parameters	Permanently use approximation of next day gas price in daily gas price index and publish two day-ahead advisory schedules
Six Cities	Strongly supports market-based commitment cost bids and dynamic market power mitigation proposal. Provides greater bidding flexibility for suppliers' need to reflect business needs. Supports commitment cost circuit breaker caps. The review of mitigation performance needs to include a date before the automatic increases/decreases occur	Supports ability to reflect varying hourly costs	Supports allowing suppliers to adjust verified costs	Supports. Proposal is too conservative for recovery of gas resources and gas penalties	Supports but opposes methodology for prices for relaxing power balance constraints	Supports
Southern California Edison (SCE)	Supports market-based commitment cost bids and dynamic market power mitigation. However wants performance testing completed before implementing in market	Supports	No opinion	No opinion	No opinion	Supports
Western Power Trading Forum (WPTF)	Strongly supports market-based commitment cost offers and dynamic market power mitigation. Testing mitigation performance should include stakeholders. Strongly supports commitment cost circuit breaker caps. Phased-in approach ensures suppliers are no worse off today.	Supports the flexibility to reflect varying hourly costs	Supports ability to update costs	Supports method for cost recovery	No opinion	No opinion

	Introduce market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions	Move from daily to hourly minimum load offers	Allow energy and commitment cost reference levels adjustments in day-ahead or real-time subject to verification	Provide after-the-fact cost recovery of costs that failed automatic screen	Recalibrate penalty price parameters	Permanently use approximation of next day gas price in daily gas price index and publish two day-ahead advisory schedules
Management Response	Management's proposal appropriately balances suppliers' need for bidding flexibility to reflect cost and protecting against the exercise of market power. The ISO also believes that suppliers are more able than the ISO to determine their costs. Additionally, the dynamic market power mitigation proposal is robust and has several conservative safeguards to protect against adverse market behavior. Commitment cost circuit breaker caps are also a safeguard against market power and are initially set conservatively during the phase-in periods. This allows the ISO to closely review the new mitigation design to ensure resources are not being over or under mitigated.	After numerous discussions with stakeholders, the ISO believes suppliers' costs vary hourly and such costs should be reflected accordingly. It is important that suppliers are bidding their actual costs to improve market efficiency. Management's proposal allows suppliers this flexibility while also protecting against intertemporal constraints or bidding behaviors through current bidding rules.	Management understands there is a need for updated gas prices related to Mondays. However, updating real-time reference levels based on gas trades observed on ICE is inconsistent with FERC's previous guidance regarding standards for gas-price indices. To capture real-time gas trading, the ISO would need to manually review suppliers' adjustment requests. This process would be labor intensive. Management believes its proposal balances implementation costs and complexity.	Management does not believe reimbursing gas penalties after the fact is appropriate because it provides a disincentive for suppliers to follow gas pipeline instructions. Additionally, FERC recently directed NYISO that it was inappropriate for suppliers to seek cost recovery for gas penalties for that the same reason.	PG&E believes the ISO should only raise penalty parameters when there are bids greater than $1000. Dynamically setting penalty prices would cause significant implementation challenges. Also, penalty prices are designed to reflect scarcity. The penalty prices are appropriately scaled to the bid caps. Management disagrees with Six Cities' proposed method of using an adder for penalty prices. Management believes the penalty prices are designed to reflect scarcity. The proposed penalties are appropriately scaled to the bid caps.	Not applicable

Attachment B

Department of Market Monitoring Comments: Commitment Costs and Default Energy Bid Enhancements

Revised Draft Final Proposal Section #	Department of Market Monitoring Comments Page #	Department of Market Monitoring Comment	ISO Management Response
5.2.1 Dynamic market power mitigation enhancements	Pages 17-18	"… The ISO's new commitment cost mitigation procedures do not mitigate the commitment costs of uncommitted resources appropriately. In many situations, this will result in the automated mitigation processes failing to mitigate economic withholding by a supplier who has a portfolio of resources with local market power (e.g. bidding lower cost units at a higher price, so that a unit with a higher commitment and/or energy cost unit must be dispatched). ...The ISO is only proposing to mitigate committed resources that are effective against a non-binding constraint. As a result, a supplier whose portfolio of resources has market power due to a particular constraint could economically withhold its lower cost resources in order to get the software to commit a higher cost resource. By bidding its lower cost resources at the 250 percent market based commitment cost cap and its highest cost resource at a slightly lower bid, the supplier could ensure that those low costs resources are not committed, and therefore not mitigated, while its most expensive resource gets committed with mitigated commitment cost bids at 125 percent of estimated costs. The supplier would have	Management proposes only to mitigate committed resources that are effective against non-binding transmission constraints. This is because non-binding constraints do not create local market power that would enable a resource to set energy prices. This is different from the situation with binding constraints where a non-committed resource could inflate local energy prices and for which management proposes to mitigate both committed and uncommitted resources. When non-binding constraints are involved, Management proposes, and the Market Surveillance Committee concurs, that since the ISO only pays committed resources for commitment costs, it is appropriate only to mitigate the commitment costs of resources actually committed. Although, DMM's hypothetical example that a supplier might try to inflate the commitment costs of one resource to get another resource committed to earn a slightly higher margin on its mitigated commitment costs could conceivably occur, Management believes an important benefit

		an incentive to execute this form of economic withholding in order to receive the 25 percent profit margin on the largest cost basis possible."	of its proposal is to avoid committing resources at costs below their actual costs. Thus, in this situation, the ISO believes it should provide a supplier the ability to submit bids based on its own cost estimates so that the ISO market does not commit its resource below cost.
5.2.1 Dynamic market power mitigation enhancements	Page 19	**STUC optimization example:** "...Therefore, If at T-75 a resource submits bids of $1,000/MWh for all energy above pmin up to its pmax for the upcoming hour and bids of -$150/MWh for its energy above pmin for the subsequent three hours considered by the upcoming STUC run, the -$150/MWh energy in future hours will make the resource appear inexpensive to keep committed. This will be true even if the supplier has submitted very high market-based minimum load cost bids all four hours. When the next set of real-time energy bids are due at T-75 before the second hour, the supplier can change its energy bids for that hour to $1,000/MWh while submitting energy bids of -$150/MWh for the subsequent three hours considered by the upcoming STUC run."	While this could conceivably occur, Management believes this would be blatant manipulative behavior with no legitimate purpose and the ISO or DMM would refer this to FERC.
5.2.1 Dynamic market power mitigation enhancements	Page 21	**Pmin re-rates:** "If the ISO uses a value other than the DEB for incorporating the costs of pmin rerates, this can create BCR gaming opportunities. This is particularly true for resources that have a minimum run time. Suppose it is economic to commit the resource with energy bids near cost, and a minimum load cost bid at 175% of reference levels. In the hours in which the resource is dispatched at pmin, it may be able to use a pmin rerate to increase its BCR. The resource may be able to rerate its pmin to a higher level, and force dispatch and cost recovery of the DEB costs scaled by 175% for the entire range of the rerate. At that time, the market software will not decommit	Scaling the DEB cost by the same percentage the resource's minimum load bid is greater than its minimum load reference level is appropriate. In DMM's example, the resource's minimum load cost would have been accepted by the market under competitive conditions. Consequently, the DEB cost used to adjust the resource's minimum load cost during the pmin rerate should be adjusted by the same percentage. In any case, the tariff prohibits suppliers from temporarily increasing a resource's minimum load ("Pmin rerate") for other than physical or

		the resource. No rule seems to exist in the revised proposal to prevent this form of BCR manipulation. Capping cost recovery at DEB for pmin rerates would mitigate this form of intertemporal market power"	environmental reasons. It would be a tariff violation for a supplier to temporarily increase a resource's minimum load to inflate bid cost recovery uplift payments and a clear basis for a referral at FERC.
5.2.3 Mitigate exceptional dispatches commitment costs	Page 20	DMM contends this proposal leaves significant gaps in the ISO's ability to mitigate market power exercised through operator-initiated commitments. Example of gap: "First, even if operators log an Exceptional Dispatch commitment as being for a competitive reason and operators have several generators to choose from when issuing an Exceptional Dispatch, DMM's experience is that they often have very limited ability to compare costs and select the least costly option..."	Management proposes to mitigate resource's commitment costs when exceptionally dispatched under the same categories of conditions for which the ISO mitigates resource's energy bids today under exceptional dispatches. FERC has in the past stated that the ISO can only mitigate exceptional dispatch payments when dispatched to relieve uncompetitive constraints in the market and that the ISO should only request for additional mitigation of exceptional dispatch if the ISO has gathered "evidence to demonstrate the potential to exercise market power for specific instances of Exceptional Dispatch." At this time, the ISO and DMM have not gathered evidence that supports expanding the current categories of mitigation.
5.3.2 Formulate energy cost reference levels	Page 23	"...The ISO clarifies that this statement applies to supply resources that are currently exempt from market power mitigation such as Participating Load, Reliability Demand Response Resources, Proxy Demand Resources, and Non-Generating Resources. The ISO has not defined the criteria that will be used to determine reference levels for these types of resources that are currently exempt from market power mitigation."	As under existing rules, the ISO market will not use reference levels for these resources as they are not subject to local market power mitigation. Although the Management clarifies, that FERC has recently granted the ISO authority to generic non-generating resources in some cases and does not propose to changes to this rule in this initiative.
5.4.1 Support verified ex ante reference level adjustments	Page 24	Supporting documentation for requests: "For example, the revised proposal does not specify that fuel price quotes must come from unaffiliated entities. Affiliated entities may have the incentive to provide a supplier with artificially high fuel price quotes that could allow a supplier to exercise market power through the volatility scalar. Quotes from affiliated entities should	Management plans to define this level of detail in implementation-level documentation.

		therefore not be considered appropriate supporting documentation. ."	
5.4.1 Support verified ex ante reference level adjustments	Page 24	"There may also be some ambiguity in how the ISO defines "actual current information" that must be used as supporting documentation. In the context of the list of appropriate supporting documentation that the ISO provides, DMM interprets "actual current information" to mean information that verifies that prevailing fuel (or fuel equivalent) market prices exceed the estimates used in ISO reference levels. DMM asks that the ISO further clarify that this interpretation is correct, and that suppliers cannot use historical information to support reference level adjustment requests (e.g. 'intra-day gas prices were 20 percent higher than the next-day index last Tuesday, so I expect intra-day gas prices to be 20 percent higher than the next-day index this Tuesday as well')."	Management confirms this is correct.
5.4.2 Support ex ante verification	Page 3	**Reasonableness threshold -** "These fuel volatility scalars will be static values incorporated in the ISO tariff. Because these new fuel volatility scalars are static, this will make bid caps used in mitigation too high most days (i.e. when the scalars exceed the actual variation in gas prices), while making bid caps too low on the few days each year when gas prices in the same day market jump significantly above next-day gas market prices. This very static approach is contrary to the key objective the ISO set for this initiative – i.e. to make bids used in real-time mitigation more reflective of actual marginal costs."	The allowance for fuel volatility in the reasonableness thresholds is not a ''safe harbor" that suppliers can bid up to irrespective of their actual costs. Management's proposed reasonableness thresholds are merely an additional safeguard the ISO will use for automatically screening reference level adjustment requests. The rules will specify that suppliers must only request reference adjustments based on documented costs. Management is proposing audit authority to be able to verify this and proposes specific sanctions for unjustified reference level adjustment requests.

5.4.2 Support ex ante verification	Page 7	"Unlike resources in the ISO's California footprint, some EIM participants may need to procure gas from hubs that are not as liquid and for which ICE gas market data may not be available. The ISO should establish a way for these participants to request a special adjustment to the reasonableness threshold on days when gas supplies are limited and only available at prices higher than the static 10 percent/25 percent reasonableness threshold proposed by the ISO."	What DMM is advocating would require significant new manual processes to be established by the ISO. Management proposes its automated reference level adjustment approach based on balancing suppliers' ability to adjust reference levels versus the additional staffing and associated costs that would accompany a manual review process that would be needed to fully accommodate any gas volatility. Such a manual review process may also be prone to errors.
5.4.2 Support ex ante verification	Page 11	"The ISO proposal appears to indicate the fuel volatility scalar will be applied to the day-ahead market, as well as the real time market. The ISO provides no justification for this, given that the ISO's proposal includes making the updating of gas prices used in the day-ahead market based on next day gas market data from ICE each morning permanent. As shown in Figure 3, this enhancement has made the gas price index used in the day-ahead market a highly correlated indicator of the price of gas in the next day market corresponding to each operating day. It is unclear why an additional fuel volatility adder would be routinely needed in the day-ahead market."	The fact that actual "next-day" gas prices are usually closer to the index the ISO uses for the day-ahead market than "same-day" gas prices are to the index the ISO uses for the real-time market doesn't obviate the need to for suppliers to at times adjust the reference levels the ISO uses for the day-ahead market. As described above, the allowance for fuel volatility in the reasonableness thresholds is not a ''safe harbor" that suppliers can bid up to irrespective of their actual costs.
5.4.2 Support ex ante verification	Page 13	"The ISO's revised proposal indicates that the default values for the reasonableness threshold (25 percent on Mondays, 10 percent other days) will be in the ISO tariff. However, the proposal also states that in order to deter market power and manipulative behavior "the California ISO will not provide these values to suppliers." The ISO should clarify these apparent inconsistencies."	The statement was correct for the reasonableness thresholds the ISO calculates for the day-ahead market as the ISO does not publish the day-ahead indices it uses. It does publish the gas price indices it uses for the real-time market. Consequently, a supplier could conceivably calculate its real-time market reasonableness threshold unless the ISO makes resource-specific adjustments to a resources reasonableness threshold. In any case, the rules will specify that suppliers must only request reference adjustments based on documented costs. Management is proposing audit authority to be

			able to verify this and proposes sanctions for unjustified reference level adjustment requests.
5.4.2 Support ex ante verification	Page 5	**Real-time gas price information :** "Since 2015, DMM has been recommending that the ISO utilize same day gas market information that is available each morning to update gas prices used in calculating bid caps and/or setting the new reasonableness thresholds used in mitigation. DMM's proposed procedure would essentially eliminate the occurrence of same day trades in excess of the 10 percent of gas prices that would be used for real-time market mitigation."	The ISO is not proposing to use same day gas information for the real-time market the following reasons: • The ISO recently made a change to use an index obtained from ICE obtained between 8-9 am for use in the day-ahead market. When FERC approved this change, FERC ordered that the index information the ISO uses has to conform to their "Policy Statement on Natural Gas Price Indices." This is the case for the index information the ISO uses for the day-ahead market, but not for the same-day trading information on ICE that DMM recommends the ISO use. • Even if FERC would allow the ISO to use the same-day trade information from ICE to calculate an ISO specific index, this would entail significant manual work. • ICE real-time trades are illiquid and may not be representative of a supplier's actual gas costs. The supplier is in a much better position to estimate its costs. Using the ICE real-time trade information could be useful as a data point if Management were proposing to review adjustment requests manually

			(Management is only proposing manual review for energy bids above $1,000 as required by FERC 831). Using the ICE real-time trade information as a data point in a manual process would not conflict with the FERC index policy because the ISO would not be automatically incorporating it into a bid cap. Management proposed an automated process for commitment cost bids and energy bids below $1,000 rather than manual review because manual review would be very labor intensive and the reasonableness thresholds Management proposes capture most instances.
5.4.2 Support ex ante verification	Page 6	**Feedback loop term –** "…DMM requests further clarification of this potentially important feature. For example, would the terms be set to capture the upper end of any costs incurred (e.g. with a relatively low probability) or would they be based on the expected value (e.g. mean or median) of the range of costs incurred in excess of the fuel cost used by the ISO?"	Management plans to define this level of detail in implementation-level documentation. The policy intent is to use resource-specific adjustments (i.e. "feed-back loop term") to resources' reasonableness thresholds so that their volatility iscaptured to the same extent the standard 110%/125% scalar captures other resource's cost volatility.
5.4.2 Support ex ante verification	Page 7	"DMM also questions the need for this new resource specific feedback loop, given the negotiated option of the ISO tariff. Currently, suppliers can already request a customized default energy bid under the negotiated option of the ISO tariff which reflects any additional costs they can demonstrate are routinely incurred. The revised proposal extends the negotiated option in the ISO tariff to include commitment cost reference levels. With this new negotiated option, "suppliers would be able to seek consideration of tailoring its reference level to reflect more complex cases than a generic reference level formula could." Thus, it seems any systematic cost differences identified in this resource specific feedback loop would be incorporated in the negotiated option for commitment cot and default energy bids."	Management believes resource-specific adjustments (i.e. "feed-back loop term") to resources' reasonableness thresholds is the more appropriate way to handle resources whose fuel costs are systematically different than the gas-price index the ISO uses. The ISO will use reasonableness thresholds to screen reference level adjustment requests, which the supplier must base on documented costs. Incorporating the systematic gas-price difference into a negotiated reference level would provide the supplier with a "safe-harbor' to bid up to the reference level, irrespective whether it based the bid on documented costs.

5.4.3 Support ex post cost recovery	Pages 24-25	"The ISO proposes that all ex post review of requested reference level adjustments be based on actual incurred costs. These reference level adjustments would apply to resources that have been determined to have market power. Allowing resources with market power to recover any incurred costs presents several behavioral issues that can lead to market inefficiency... ...The ISO proposes to only approve the recovery of these costs if the fuel had to be procured immediately due to constrained fuel supply conditions. DMM appreciates that this provision will help to mitigate the extent to which the ex post recovery of incurred costs can lead to inefficient fuel procurement and inappropriately inflated reference levels. However, the ISO's proposal still seems to allow market participants to recover any incurred cost under these conditions, regardless of whether or not the incurred costs deviated significantly from observed fuel market prices and conditions. Depending on the details of how the feedback loop is implemented, this proposal could therefore allow entities with market power to manipulate their future reference levels through intentionally high priced fuel procurement during days when gas companies require daily balancing."	A supplier's ability to document actual costs is unrelated to its market power. A supplier with market power should not be equated with being prone to rule manipulation or submission of false information. The policy states that costs have to represent reasonable procurement. The costs submitted for *ex post* cost recovery cannot be higher than what the supplier requested as part of its *ex ante* reference level adjustment request, which had to be based on actual documented fuel market prices.
5.4.3 Support ex post cost recovery	Page 25	"In the revised proposal, the ISO also proposes to not approve ex post recovery of fuel costs incurred before "the market that produced relevant award". DMM recommends that ISO reconsider this element of the ex post cost recovery policy."	Management clarifies that for day-ahead market, procurement after the D+2 advisory results would not be considered to be before the market that produced the relevant award and, as such would be eligible for ex post cost recovery.

5.4.3 Support ex post cost recovery	Page 26	"...DMM requests that the ISO provide more detail on how this process would work, including proposed timelines for a typical request and any standards that can be used to verify costs in real time. The standards to be followed for constructing a reference level adjustment are included in Appendix D of the revised proposal, but exactly how this would feed into a real time request is not clear. Is the ISO proposing that whoever has the authority to perform the manual consultation should be able to receive and review the documentation before the market runs in order to approve a new reference level? Details on this process will be very important to determine how well it can be used, how effective it is, and to what degree the process might be subject to inaccuracies, gaming or manipulation..."	Management plans to define this level of detail in implementation-level documentation. For the manual consultation for energy costs greater than $1,000/MWh, the ISO would require the same documentation it would look at if it audited any reference level adjustment request.
5.4.4 Re-calibrate penalty price parameters	Pages 8 & 9	"...However, the proposal indicates that it is acceptable – if not encouraged – for suppliers to increase the commitment cost reference levels and default energy bids to reflect scarcity of fuel supply and the full cost of potential gas imbalance penalties... DMM requests that ISO explain the logic of allowing gas risk adders reflecting potential gas penalties into reference bid adjustment requests, but not into negotiated bids or actual costs recovered. Under the ISO's revised proposal, it appears that bids will be allowed to automatically increase by about 10 percent (the default reasonableness threshold for most units on most days) whenever an OFO is in effect. Is the intent of this to allow reference levels to increase by about 10 percent when OFOs occur as a method to allow resources in gas constrained areas to increase their bids to move them up in the supply stack (i.e. similar to the Aliso gas price adders)? If so, a much better way to do this is to simply allow the ISO to dynamically increase the threshold to reflect actual same day gas market prices, as proposed by DMM. On days when gas conditions are constrained,	Yes, Management's intent is to allow reference levels to increase by about 10 percent when OFOs occur as a method to allow resources in gas constrained areas to increase their bids to move farther down in the supply stack (i.e. similar to the Aliso gas price adders). The higher bids will cause the market to dispatch resources away from constrained gas regions. The ISO would only make *ex ante* adjustments for this situation to the extent the request passed the automated reasonableness criteria.

		this approach would allow reasonableness thresholds higher than the static 10 percent/25 percent levels proposed by the ISO when needed and appropriate..."	
5.4.4 Re-calibrate penalty price parameters	Page 9	"...Is the intent of this to allow reference levels to increase by about 10 percent when OFOs occur as a method to allow resources in gas constrained areas to increase their bids to move them up in the supply stack (i.e. similar to the Aliso gas price adders)? If so, a much better way to do this is to simply allow the ISO to dynamically increase the threshold to reflect actual same day gas market prices, as proposed by DMM. On days when gas conditions are constrained, this approach would allow reasonableness thresholds higher than the static 10 percent/25 percent levels proposed by the ISO when needed and appropriate."	Management believes *ex ante* adjustments are appropriate to decrease the chance that the ISO market will dispatch a resource and cause it to violate an OFO. Management does not consider gas penalties in after-the-fact reimbursement because recent FERC orders (NYISO) forbids this as it would undermine the gas system penalties. Management does propose to consider the high gas purchase costs that accompany stressed gas system conditions in the *ex post* cost recovery process As described above, Management believes several factors prevent it from adjusting resource reference levels as DMM suggests based on same-day gas trading information on ICE.
Appendix	Pages 27-28	"Appendix C introduces changes to reference commitment cost calculation in equations for proxy cost calculation that are not included in the proposal itself. Although these changes may have been introduced inadvertently and were not discussed in the stakeholder process, DMM recommends clarifying these apparent changes before the proposal is presented to the Board for approval and before implementation work by ISO teams proceeds further. 1. Non-gas minimum load greenhouse gas cost calculation: The equation for greenhouse gas cost	Management plans to define this level of detailand correct any errors in the implementation-level documentation.

		calculation listed for non-gas resources in the text box on page 50 includes HEAT_AVG_COSTPoint1. Current practice for greenhouse gas cost calculation for non-gas resources in the ISO has relied on heat rate rather than HEAT_AVG_COST curves. DMM recommends relying on heat rates rather than HEAT_AVG_COST curves, as doing so allows non-greenhouse gas cost related components to be excluded from the calculation. 2. Inclusion of start opportunity cost in minimum load cost calculation: The table on page 51 of the draft final proposal lists both calculated opportunity cost for eligible start limitations and negotiated opportunity cost for eligible start limitations as inputs to minimum load cost calculations. The introduction of start-up opportunity costs rather than minimum load opportunity cost to the minimum load cost calculation appears to have been unintentional. 3. Start-up cost reference level calculation should include start-up fuel cost rather than being defined as a function of itself: In the second box on page 51, start-up costs are defined as a sum of terms including start-up costs. DMM recommends that start-up costs be defined as a sum of terms including start-up fuel costs rather than start-up costs. 4. GMC Adder calculation: The text box on page 51 of the Draft Final Proposal defines GMC as a function of the start-up time of point 2. This formula is inconsistent with the Market Instruments BPM and the CAISO tariff. Current BPM and tariff definitions state that the fastest Start-Up Time Period registered in the Master File will be used in this calculation, regardless of segment. DMM recommends that the ISO revise this equation, if this change to GMC calculation was introduced inadvertently.	

		Variable Indexing in Appendix E DMM believes that several mistakes have been made in the variable definitions and descriptions in Appendix E. In descriptions in Table 6 several references are made to resource r, while the corresponding variables being defined reference resource i. For example, the variable is defined as “Maximum operating level of resource r where Pmaxi is regulation Pmax if on regulation otherwise operational Pmax. Note – for MSG plants these are plant level maximums and derates.” DMM is not clear if this is a typo and the descriptions are meant to reference resource i or if, as is written in the proposal, the variables serve to relate two different sets of resources, i and r. The meanings of the defined variables changes significantly depending on the answer. In DMM’s experience, documents such as Revised Draft Final Proposals can be important reference materials for implementation teams that may not have been involved in designing the proposal. Therefore, it is important that all details like this are properly and clearly specified. DMM requests that the ISO review the tables and definitions in this appendix and correct any errors found."	

Opinion on
Commitment Costs and Default Energy Bid Enhancements (CCDEBE)

by

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1. Introduction and Summary of Recommendations

The collection of costs associated with starting a generation unit and positioning it to provide at least its minimum amount of electrical energy are known as commitment costs. There is a potential for the exercise of market power through inflated commitment cost offers. Inflated commitment cost offers have the potential to impact the market in two ways. First, they can serve to economically withhold capacity, driving up energy prices when transmission constraints bind and the high cost of committing a resource causes a resource to not be committed and in turn causing energy prices to be set by high cost incremental energy offers of another resource. Besides higher prices, the result can be unnecessarily high resource costs in meeting load because load would not be met by the least-cost set of resources. Second, inflated commitment cost offers can also raise consumer costs through high bid-cost recovery (BCR) or exceptional dispatch (ED) payments required to cover inflated as-bid costs that are incurred when a resource must be committed to relieve a transmission constraint.

The California ISO (CAISO) has addressed these possibilities by either of two ways. Either resources could be scheduled based on commitment costs calculated by the CAISO, rather than using offer prices submitted by the resource operator, or commitment costs are submitted by the market participant, with the allowed offers being subject to caps calculated by the CAISO based on the CAISO's cost estimates.

The CAISO's commitment cost mitigation approach relies upon an assumption that the CAISO can estimate the true costs of most or all resources with reasonable accuracy. In particular, such approaches rely upon the availability of accurate *ex ante* measures of the natural gas costs that would be incurred by generators in order to generate incremental power. As CAISO markets have expanded to regions in which not all gas-fired generation is located at liquid trading points for gas with published indexes and may in the future include more unconventional generation, the assumption about the visibility of marginal costs to the CAISO is becoming less reliable.

The current CAISO design for mitigation of commitment costs has contributed to market problems as the western gas market has become more volatile and as the need has grown for the CAISO to improve its utilization of use-limited resources to balance short-term variations in net load. This design has also become less workable because of the expansion of the CAISO real-time market to include the EIM region. This expansion has taken the CAISO market design into regions dominated by vertically integrated, regulated, utilities and with a wide diversity of supply situations for gas fired generation. The challenge is that the CAISO now needs to estimate commitment costs for an expanded set of gas-fired resources with a greater diversity of supply alternatives.

The CAISO has therefore proposed a comprehensive reform of its rules considering commitment cost offers and how the CAISO mitigates potential market power in those offers.[1] The Market Surveillance Committee (MSC) has been asked to prepare this Opinion on this proposed reform, which is called the Commitment Costs and Default Energy Bid Enhancements (CCDEBE). The MSC has participated extensively in the CCDEBE development process, including discussions addressing principles and detailed implementation issues that have taken place at several MSC public meetings over the past two years.[2] Moreover, this is not the first time that the MSC has considered the issues involved in designing a commitment cost bidding system that is both cost-reflective and safe from the exercise of market power. The MSC has written over 10 opinions since 2007 (summarized in Section 2) addressing those issues in response to the initial MRTU design as well as subsequent proposed changes.

In general, the CCDEBE proposal attempts to focus mitigation of commitment costs on a subset of units deemed to possess local market power using a dynamic test, and to allow more flexibility for market offers of these costs to other units. This philosophy closely mirrors that applied by CAISO in the mitigation of energy cost bids. For reasons discussed below, the implementation of this approach is more complicated with commitment costs than it is with energy bids. However, we agree that this is an important and necessary initiative to undertake. In brief, we agree that the volatility of gas prices and the need to encourage resources to make flexible offers into the market mean that it is desirable that the CAISO implement a more flexible system that allows resources to offer commitment costs that better reflect recent and anticipated costs particularly during periods of gas price volatility. Further, we agree, and have previously recommended, that dynamic market power tests be implemented that would give resources without market power more flexibility to bid their costs during periods while protecting consumers against the exercise of market power in those locations and at those times that there is a significant risk of that exercise. We believe the proposal will also enable the CAISO to coordinate a more efficient market across the broader EIM region and better accommodate the diverse gas supply situations of utility generation across the west.

Therefore, we recommend that the CAISO move forward with the development, testing and implementation of its design for dynamic mitigation of commitment costs as proposed. We also make the two additional recommendations for alternative implementations that may have some advantages, and should be considered if computational performance of the market software or the frequency of "false positives" becomes an issue. One is to combine market power tests on binding non-competitive constraints for energy and commitment cost offers; this would be more efficient computationally, and could reduce false positives. The second is to use after-the-fact

[1] California ISO, Commitment Cost and Default Energy Bid Enhancements, Revised Draft Final Proposal, January 31, 2018, www.caiso.com/Documents/RevisedDraftFinalProposal-CommitmentCosts-DefaultEnergyBidEnhancements.pdf

[2] Presentations and discussions on CCDEBE occurred in MSC meetings held June 17 and Nov. 18, 2016; and May 5, July 10, Sept. 8, and Dec. 1, 2017.

mitigation of commitment cost offers if a resource that is not committed in the market power run also does not impact binding noncompetitive constraints, but would significantly affect nonbinding critical constraints.

Additional conclusions include the following. Overall, we support the transition to commitment cost reference levels that can be based on negotiated values or supplier updated cost information, consistent with the changes that have been introduced in the overall market power mitigation design of other ISOs over the past 5-7 years. With the greater ability of suppliers to reflect their actual costs in reference prices, it is appropriate to reduce the general mitigation threshold for commitment costs from 125% to the same 110% used for other resources. Finally, we continue to support the efforts by the CAISO and its Department of Market Monitoring (DMM) to base offer price mitigation on updated gas price information when available and sufficiently reliable.

We note that this is a very complex proposal with many features that stakeholders have commented extensively on. We have not expressed views on every issue raised; we instead emphasize the MSC's long-standing support for the general ideas of dynamic mitigation tests for commitment cost offers, and address a subset of particular implementation issues for which our views may offer a distinctive perspective. We have focused on evaluating whether the CCDEBE proposal addresses the major problems with the current design. We do not discuss other possible designs, such as a conduct-and-impact paradigm that might have some advantages but would entail much larger changes relative to the current design. Such more radical reforms of the commitment cost bidding and mitigation system might be worth considering in the future should the CCDEBE reforms turn out to be less effective than intended in adding flexibility while protecting against the exercise of market power.

This Opinion is organized as follows. In the following section, we provide background on the proposal by reviewing past market issues that motivated previous revisions of the CAISO procedures for making and mitigating commitment cost offers, and recent developments that have led the ISO to revisit those procedures. We also summarize the recommendations of previous MSC opinions on commitment cost costs and mitigation; the principles underlying the CCDEBE proposal are broadly consistent with those recommendations. Then in Section 3, we summarize the CAISO's general goals in designing this initiative. In Sections 4-6, we discuss issues associated with three core elements of the CCDEBE proposal:

- market-based offers for commitment costs (Section 4),
- dynamic mitigation of commitment cost offers (Section 5), and
- revised definition procedures for reference prices (Section 6).

2. Background and Previous MSC Opinions

2.1. Past Market and Operational Problems

The cost of supplying electric power is characterized by non-convexities, such as prohibited zones of operation and the expense of starting up or operating at minimum load. As a result, a fundamental issue in designing power markets is that it may not be possible to calculate a price that clears the market. That is, there may be no price that results in supply equaling demand, while supporting the overall least-cost solution (i.e., resulting in the social least-cost schedule being the same as the profit-maximizing schedule for each resource, given the prices). This results in a fundamental difficulty, which is that clearing prices in the CAISO markets do not always fully cover the as-bid costs of all generators, even when they are selected as part of the least-cost market solution. To address this problem, in the CAISO's market design, as well as all other organized U.S. markets, generators can submit offers that include commitment costs and prohibited zones, and the market operator makes side-payments if clearing prices would not cover the as-bid costs of accepted supply offers, called bid cost recovery. This leads to several conceptual and practical challenges, such as how to allocate the resulting uplift as well as concerns that the market price may not adequately incent investment.

The concern addressed in this proposal is the potential for market power in commitment cost offers, in which resources would be able to increase their revenues by submitting commitment cost offers that materially exceed their costs. Such inflated offers might be able to increase net revenues by raising local marginal prices (LMPs), either for the resource making the offer or for other resources in a supplier's portfolio, or by increasing BCR payments to the resource. This increase in commitment cost offers can directly increase costs to consumers by raising their energy prices or allocated uplift, and also can inflate the resource cost of meeting load by shifting dispatch and commitments away from the least-cost schedule.

The risk of these cost shifts and distortions has been a central concern in the Market Redesign and Technology Upgrade (MRTU) from the very beginning of its design process after the 2000-01 crisis. There were several objectives in designing market rules that govern bidding of commitment costs. One is that bids must be able to fully reflect all the costs faced by resources so that suppliers can be assured that their costs will be covered; to do otherwise provides incentives to offer inflexibly ("self-schedule") or to not offer at all, which reduces the ability of the operator to reach a reliable and economic market solution and increases consumer costs. The second objective is to avoid exercise of market power to the detriment of market efficiency and consumers. Other objectives include transparency and simplicity of administration, avoiding slowing down the market clearing process, and minimizing the total amount of uplift so that market value and costs are reflected in market prices as much as possible.

A central tradeoff in applying market power mitigation to commitment cost bidding systems is between the risks of false negatives versus false positives. False negatives occur when bids should have been mitigated, but weren't, and the result is the exercise of market power and its attendant distortions. In contrast, false positives occur when bids were mitigated, but didn't need to be because the resource owner did not exercise market power. If the CAISO can confidently and accurately estimate the actual commitment costs of all resources, then market inefficiencies are unlikely to result from over-mitigation. This has heretofore been the philosophy of the CAISO's commitment cost bidding system. Its key feature has been that *all* commitment cost bids are subject to a bid cap determined by the ISO, without regard to the application of a market power test (which bore similarities to the design in PJM at the time the MRTU market power mitigation design was developed). The approach was simple, and provided strong assurance that the exercise of market power would be avoided.

Since the design and implementation of MRTU, the CAISO has revisited and adjusted its commitment cost bidding procedures multiple times. Table 1, below, summarizes in reverse chronologic order twelve MSC opinions that address fundamental issues and/or details of implementation of those procedures.

Table 1: Summary of MSC Opinions Addressing Commitment Costs (Left Column), Their Mitigation (Right Column), or Both

<table>
<tr><th>Commitment Cost Offers and Cost Calculations</th><th>Mitigation of Commitment Cost Offers</th></tr>
<tr><td colspan="2">Bidding Rules & Commitment Cost Bidding Enhancements (2016):[3] The purpose of the Commitment Cost Enhancements 3 and BRE initiatives was to improve the CAISO’s calculation of commitment costs so that commitment cost bids will better reflect actual resource costs, including opportunity costs, while still effectively mitigating the potential for the exercise of market power. The MSC strongly supported calculation and inclusion of opportunity costs. The proposal also provided a safety valve in case commitment cost bid caps do not fully cover incurred fuel costs, by giving resources a right to file at FERC for recovery of those costs, which the MSC supported if used rarely. The MSC repeated earlier recommendations that a dynamic local market power test be used to limit mitigation of commitment cost offers to units possessing such market power.</td></tr>
<tr><td>Reliability Services Phase 1 & Commitment Costs Enhancements Phase 2 (2015):[4] The MSC recommended that opportunity costs implemented in commitment cost calculations in the near future. In the interim, it supported restricting use-limited designations to resources with physical or regulatory constraints.</td><td>LMPM Implementation in EIM (2014):[5] The MSC supported modification of the LMPM framework to deal with market structures that are quite different than inside the CAISO balancing authority. Among other differences are the degree concentration and the lack of a must-offer obligation in these other markets.</td></tr>
<tr><td rowspan="2">Commitment Cost Enhancements (2014):[6] The volatile 2013-14 natural gas market exposed limitations in procedures for adapting the CAISO’s commitment cost estimates to changing conditions. Lags in updating costs resulted in underestimation of minimum run costs, and ensuing distortions in dispatch. The MSC agreed with the CAISO proposal to increase the cap on start-up and minimum load offers to 125% of the calculated cost, because it will reduce mitigation of offer prices of suppliers lacking market power. The MSC reiterated the urgency of including opportunity costs in cost estimates, which was not part of this proposal.</td><td>Appropriateness of the 3 Pivotal Supplier Test & Other Competitive Screens (2013):[7] In response to a FERC request, the MSC analyzed CAISO data, and concluded that there is no compelling justification for changing the three pivotal supplier screen in the LMPM competitive path assessment. Potential ways were identified for improving the definition of path competitiveness and the determination of DEBs in order to decrease the likelihood of false negatives and false positives.</td></tr>
<tr><td>Mitigation Measures for Bid Cost Recovery (2012):[8] The MSC supported a simple and transparent approach to monitoring persistent real-time deviations from dispatch instructions.</td></tr>
</table>

[3] J. Bushnell, S. Harvey and B. Hobbs, Opinion on Commitment Cost Bidding Improvements,” March 10, 2016, www.caiso.com/Documents/MSC_Opinion_CommitmentCostBiddingImprovements-Mar10_2016.pdf

[4] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, Opinion on Reliability Services Phase 1 and Commitment Costs Enhancements Phase 2, March 23, 2015, www.caiso.com/Documents/ Decision_ReliabilityServicesPhase1-MSC_Opinion-Mar2015.pdf

[5] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, "Opinion on LMPM Implementation in the Energy Imbalance Market," July 7, 2014, www.caiso.com/Documents/FinalOpinion-LocalMarketPowerMitigation-Implemenation-EnergyImbalanceMarket-July7_2014.pdf

[6] J. Bushnell, S. Harvey, B. Hobbs, and S. Oren, "Opinion on Commitment Cost Enhancements," Sept. 8, 2014, www.caiso.com/Documents/MSC_FinalOpinionCommittmentCostEnhancements-Sept2014.pdf

[7] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, Report on the Appropriateness of the Three Pivotal Supplier Test and Alternative Competitive Screens, June 27, 2013, www.caiso.com/Documents/Report-Appropriateness-ThreePivotalSupplierTest-AlternativeCompetitiveScreens.pdf

[8] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, “Opinion on Mitigation Measures for Bid Cost Recovery,” Dec. 5, 2012, www.caiso.com/Documents/ FinalOpinionBidCostRecoveryMitigationMeasures.pdf

<table>
<tr><th>TABLE 1, Continued
Commitment Cost Offers and Cost Calculations</th><th>Mitigation of Commitment Cost Offers</th></tr>
<tr><td colspan="2">BCR Mitigation Measures and Commitment Costs Refinement (2012):[9] The MSC supported its major features, including the modified day-ahead metered energy adjustment factor; the real-time performance metric; and the persistent uninstructed energy (PUIE) check, subject to careful monitoring and tuning. It also supported inclusion of several categories of costs, and ex post recovery of operational flow order-related costs</td></tr>
<tr><td colspan="2">Renewable Integration, Final Product Review (2011):[10] The MSC supported these proposals, which lowered of the bid floor in two stages, quantified additional categories of costs, and revised the bid cost recovery mechanism (BCR) to allow for separate calculation of BCR in the day-ahead and real-time markets. The MSC recommended that opportunity costs be considered, and careful review of the persistent uninstructed energy (PUIE) check.</td></tr>
<tr><td colspan="2">Changes to Bidding and Mitigation of Commitment Costs (2010):[11] This opinion expressed support for most of the elements of the ISO’s proposal to change start-up, minimum load, and transition costs for multistage generators (MSGs). The MSC supported the ISO’s recommendations not to consider opportunity cost bidding at that time, and to retain a 30 day minimum time period between changes in registered costs.</td></tr>
<tr><td rowspan="2">Changes to Bidding Start-Up and Minimum Load (2009):[12] The MSC supported removal of barriers to reflecting verifiable commitment costs in offers. These costs could include opportunity costs. The MSC recommended that the ISO proceed with more frequent bidding only if improved mitigation procedures were put in place.</td><td>LMPM & Dynamic Competitive Path Assessment (2011):[13] The MSC endorsed the proposal because it would allow the LMPM process to consider all demand and supply bid into the day-ahead market (including virtual bids); eliminate the potential for anomalous outcomes arising from the two-pass approach; and speed up the process, potentially allowing on-line (dynamic) competitive path analysis.</td></tr>
<tr><td>Start-Up & Minimum Load Bid Caps Under MRTU (2007):[14] The MSC concluded that, in the long run, the most suitable approach for mitigating SU/ML bids would be an extension of the MRTU LMPM mechanism to encompass all bids submitted by generators, not just energy bids.</td></tr>
</table>

[9] J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, “Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement,” May 7, 2012, www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf

[10] J. Bushnell, S. Harvey, B.F. Hobbs, “Final Opinion on Renewable Integration: Market Product Review, Phase 1,” Dec. 11, 2011, www.caiso.com/ Documents/MSC_Final_Opinion_RenewableIntegrationMarket-ProductReviewPhase1.pdf

[11] F. Wolak, J. Bushnell, B. Hobbs, "Opinion on Changes to Bidding and Mitigation of Commitment Costs", June 4, 2010, www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf

[12] F. Wolak, J. Bushnell, B. Hobbs, "Comments on Changes to Bidding Start-Up and Minimum Load," July 9, 2009, www.caiso.com/Documents/DraftOpiniononStart-UpandMinimumLoadBiddingRules.pdf

[13] J. Bushnell, S. Harvey, and B. Hobbs, “Opinion on Local Market Power Mitigation and Dynamic Competitive Path Assessment,” July 1, 2011, www.caiso.com/Documents/ 110713Decision_LocalMarketPowerMitigationEnhancements-MSC%20Opinion.pdf

[14] F. Wolak, J. Bushnell, B. Hobbs, "Opinion on Start-Up and Minimum Load Bid Caps Under MRTU," Aug. 2007, www.caiso.com/Documents/FinalOpiniononStart-upandMinimumLoadBidCapsUnderMRTU.pdf

Four of these principles, most of which have been discussed in several of the previous opinions as well as opinions concerning other aspects of the CAISO market design, include the following:

1. *ISO markets need to reward flexibility, preferably through spot market revenues.* This principle has been promoted by the MSC in its discussion of other market issues such as the energy bid floor, flexible ramp product, regulation pay-for-performance, and flexible resource adequacy requirements. The markets need to ensure that generators will have incentive to offer flexibly, which means that BCR and bid mitigation systems must allow recovery of all variable costs.

2. *There is a tradeoff between needs for cost recovery and to prevent market power.* The MSC has often discussed the frequency and consequences of false positives vs. false negatives. For this reason, the MSC has argued for dynamic market competitiveness tests that reflect up-to-date costs and market conditions that determine whether or not a particular resource has market power, and that give flexibility to resources lacking such market power to bid their costs as they see them. The CCDEBE proposal would implement such a test.

3. *Start-up and minimum-load (SU/ML) bid caps are needed, but tight caps should be imposed only where the market is insufficiently competitive to prevent exercise of market power.* For instance, in 2007 (Table 1, above), the MSC recommended that a variant of LMPM be used to identify market power in commitment cost bids, based on pivotal-type tests on supply to relieve congestion. Then, loose constraints on allowable bid levels and frequency of changes could be allowed where markets were likely to be competitive. On the other hand, tighter constraints on bids would then be imposed where exceptional dispatch, load pocket conditions, or other constraints limit contestability. The MSC recognized that dynamic tests are harder to define and implement for SU/ML bids due to lumpiness, and it suggested using results of transmission constraint generation in market software to identify paths of interest

4. *SU/ML bid caps should reflect all variable costs.* This means that when cost estimates are used to define mitigation thresholds and default bids, they should include all significant categories of costs, such as wear-and-tear, opportunity costs, fuel costs, operational flow orders (OFO). The MSC recognized that these can be very hard to estimate reliably. Examples of difficult-to-estimate costs include: the relevance of resource adequacy revenues to opportunity costs; intra-day gas prices, gas imbalance penalties; and expected OFO costs, gas prices for resources remote from liquid gas trading hubs, and the opportunity costs of start or emission limited resources. So, the MSC guardedly supported negotiated caps on bids, and after-the-fact review and recovery of costs that were unrecovered. Significant attention was paid to updating cost estimates as gas prices fluctuated, and the MSC proposed an approach based on daily gas indices for fuel cost-dominated components of costs, and slower changes for other cost components.

Based on these principles, the MSC has made a number of specific recommendations over the years for improving the commitment cost bidding and mitigation system, and has made note of emerging issues. Examples of recommendations and new issues include the following, as well as others in Table 1:

1. Adjustments to BCR calculation procedures in order to improve incentives to bid, and protect against market power. For instance, the separation of BCR for the day-ahead and real-time

markets; the calculation of opportunity costs of starts, energy, and operating hours based on multiweek or longer look-aheads; and design of "Performance Measure and Persistent Uninstructed Energy Check" procedures to discourage strategic behavior aimed at increasing BCR without greatly penalizing normal deviations.

2. In response to a charge from the Federal Energy Regulatory Commission to the MSC in FERC's MRTU Order, the MSC assessed and recommended retaining the three pivotal supplier test.

3. High gas price volatility will often mean that commitment cost estimates used in the CAISO market power mitigation system become rapidly outdated. This directly led to the Winter 2013-14 difficulties, where the commitment costs estimated by the CAISO were grossly understated relative to energy price bids submitted by market participants, since the latter could be updated to reflect more current market conditions. This in turn caused the market software to inefficiently operate many generators at their minimum output levels, inflating actual system costs, inflating gas demand for power generation on a winter day with high gas demand, thereby endangering both gas and electric system reliability.[15]

4. Generator use plans have become a highly inefficient way of managing opportunity costs of units that have limited numbers of starts or operating hours, or limited energy availability. Because such plans give the operator little flexibility to change their usage in response to changing conditions they are no longer suited to the CAISO's needs for balancing load and generation, given its current and prospective resource mix. A much better way is to quantify opportunity costs and allow their inclusion in SU/ML and energy offers. This is now being implemented by the CAISO.

5. Market power mitigation in the Energy Imbalance Market (EIM) is challenging because participation is voluntary, non-CAISO balancing authorities have high concentrations of suppliers, and gas-fired generation is often not located at liquid gas trading points with published indexes. The application of market power mitigation in the EIM is also more challenging because there is a greater diversity of gas supply situations, differing abilities to use storage, and a greater variety of supply constraints and options than in the CAISO footprint.

2.2. Emerging Problems

Questions concerning how to respond to gas price volatility, and how to mitigate market power in the EIM are examples of issues concerning mitigation of commitment costs that have become more urgent recently. An example of the challenges for the current mitigation design is provided by the Aliso Canyon situation, in which the limited operability of a gas storage facility in southern California has tightened gas imbalance requirements and has increased price volatility for Southern California gas-fired generation.

Another increasingly important issue is the use of gas price indices for mitigating market power for Monday bids. Mitigation of Monday offer prices is based on the Weekend/Monday gas in-

[15] See CAISO, Commitment Costs Enhancement, Revised Draft Final Proposal, Aug. 21, 2014, p. 3, www.caiso.com/Documents/RevisedDraftFinalProposalCommitmentCostEnhancements.pdf

dex, which can provide a poor measure of the cost of buying gas for Monday because gas demand is lower over the weekend. Moreover, neither the weekend index for trades on Friday nor an index based on prior week Monday-only ICE trades would reflect changes in gas market conditions over the weekend as can be the case with changing weather forecasts. The California ISO DMM has conducted an analysis that has shown that understated gas prices on the first work day of the week has become fairly frequent over the past few years.[16] Similar issues with the accuracy of gas price indices exist around holidays, when the transactions used to compute the index can occur several days prior to the flow date for the gas, creating the potential for a significant difference between the gas price index and the cost of buying gas on the holiday for delivery on the day following the holiday,

The final issue of increasing importance is the prospect of increased natural gas price volatility. The exit of coal generation and a resulting increased reliance on gas fired generation to meet load appears to be increasing gas price volatility.[17] This trend of coal generation being replaced with gas and intermittent resources could continue, which could lead to further increases in gas price volatility in both day-ahead and intra-day gas markets.

The increasing risks posed to market efficiency and reliability by these emerging issues indicate that the present commitment cost mitigation system, in which all offers are mitigated, needs to be replaced by a more flexible bidding system. Such a system would dynamically identify and mitigate market power and allow bids to quickly reflect changes in gas prices. The CAISO has responded by developing the CCDEBE proposal, whose goals we discuss next.

[16] Figure 3.11 in the CAISO DMM's 2016 "Annual Report on Market Issues and Performance" compares the same day trade prices to next day index over the period June –December 2016. It shows that the proportion of trades at prices in excess of 110% of the next day index was much higher on the first trade day of the week. The same pattern is portrayed in Figure 3.2 of DMM's 3Q 2017 "Report on Market Issues and Performance," which compares same day trade prices to an updated same day average.

[17] An apparent increase in gas price volatility can be seen in successive CAISO DMM reports. Figure 3.12 in the 2016 "Annual Report on Market Issues and Performance" compares the next-day trade price to the next day index from the prior day for the SoCal City gate over the period June –December 2016. It shows that there were no trades at more than 125% of the prior day's next day index. The similar Figure 3.2 for the third quarter of 2017 in DMM's Q3 "Report on Market Issues and Performance" shows a few trades at more than 125% of the prior next day price, and it appears to show many more at more than 110% of the prior next day price than had been the case in 2016. Figure 3.8 in DMM's recently released 4Q Report on Market Issues and Performance not only shows an apparent increase in trades at slightly more than 125% of the prior day's next day index, but shows a distribution of next day trade prices extending up to several hundred percent of the prior next day price.

3. CCDEBE Goals and Summary of Mitigation Procedures

3.1. Overall Market Design Goal

In summary, the CAISO seeks to develop a market design that will allow market-based bidding of commitment costs while applying market power mitigation to prevent the exercise of locational market power that can decrease market efficiency and raise consumer costs by either materially raising market prices above the competitive level or inflating BCR payments.

3.2. Practical Complications

The application of market power mitigation to commitment costs is more complicated than the mitigation of energy offers because it needs to consider the impact of inflated commitment costs on BCR and ED payments as well as on market clearing energy prices.

Another complication is the lumpiness of commitment decisions. Unlike the dispatch of energy, which can be done in small increments, the commitment of a unit adds discrete blocks of energy to the market to accommodate the minimum operating level of that unit. As a result, a resource could be committed to solve a constraint that would have bound had the resource not been committed, but is non-binding in the dispatch with the resource on-line. Such a resource could submit inflated offers that would entitle it to large BCR or ED payments if the only way to avoid overloading a particular transmission constraint was to commit that resource. Therefore, a constraint may have bestowed locational market power on a resource, even if it is non-binding after the market solution is resolved. [18]

A third complication is the expansion of CAISO dispatch to EIM, which has introduced many additional gas procurement situations that need to be addressed in determining reference prices for mitigation. The increased potential for calculating erroneous reference prices increases the importance of limiting application of mitigation to situations in which there is a potential for significant exercise of locational market power. Not only does the EIM expansion make the likelihood of a false positive finding of inflated costs higher, but the consequences of the ensuing mitigation for market efficiency are greater when gas prices are opaque. The negative impact of "over-mitigation" is limited if the CAISO has highly accurate information about the marginal costs of the plants it is mitigating. The stakes are greater when the cost data available to the CAISO may not accurately reflect supplier costs.

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[18] Such outcomes reflect the lumpiness of the unit commitment decision due to the minimum load block of the resource, whether or not commitment cost offers equal actual costs. As a trivial example, there may be several costly 25 MW units in a load pocket, each of which has a 18 MW minimum operating level (Pmin). If the load in the pocket is 80 MW and the transfer capability into that load pocket is 50 MW, then it is necessary to have at least 30 MW of local generation, which might be most cheaply achieved by committing two local units and operating them at their minimum levels. This implies 36 MW of local generation, so that 44 MW more needs to be imported; consequently, the 50 MW transfer limit is slack. The resulting LMP in the load pocket may be the system price, and those two units will require bid cost recovery.

However, market participants might deliberately structure offer prices to achieve such an outcome, perhaps in an attempt to evade triggering a pivotal supplier test on a constraint. That possibility motivates the first and second features of the proposed CCDEBE mitigation process (Sections 5.1 and 5.2, *infra*.).

3.3. CCDEBE Mitigation Procedure: Summary

As background, we provide here a brief synopsis of the CCDEBE mitigation procedure. Then in the next three sections (Sections 4-6), we summarize some issues associated with three core elements of the CCDEBE proposal (market-based commitment cost offers, commitment cost offer mitigation, and reference price modifications).

We start our synopsis by first noting that there are three basic steps for checking for market power and in defining market schedules and prices when the running the CAISO day-ahead and 15 minute real-time markets:

- Step 1: Using the unmitigated energy and commitment cost offers for all resources, execute the "Market Power Mitigation" (MPM) run, and determine which noncompetitive constraints are binding or, alternatively, sufficiently close to binding to be considered "critical constraints".

- Step 2: All resources, whether committed or not in the MPM run, are then subjected to various tests to determine whether they should be mitigated. In the case of commitment cost bids, the tests are summarized below, and result in each resource being placed in one of six categories; for three of those categories, the resource's start-up, transition, and minimum load bids are mitigated to the reference level. These categories include resources that affect congestion on noncompetitive binding constraints or that could provide significant relief to near-binding ("critical") constraints, as defined by the new CCDEBE tests, as well as resources that could potentially affect minimum on-line constraint congestion. On the other hand, if the resource is placed in one of the other three categories, then its commitment cost offers are not mitigated.

- Step 3: Market runs (scheduling and pricing) are executed using mitigated energy and commitment cost bids.

We now summarize the logic of the procedure for determining whether commitment cost offers are mitigated or not, which results in classifying each resource into one of six categories.[19] If the resource winds up in categories (1)(A) ("***MOC+***"), (2)(A) ("***Binding+***"), or (3)(A)(i)(a) ("***Non-binding/Committed/DispatchExcess+***"), then the commitment cost offers are mitigated. On the other hand, a resource that winds up in the other possible categories (3)(A)(i)(b), (3)(A)(ii), or (3)(B) is not mitigated.

Procedure:

(1) *Start:* Does the resource in question contribute to meeting any minimum on-line constraint (which is automatically deemed noncompetitive)?

(A) If yes, then <u>mitigate commitment cost offers</u> ("***MOC+***"). *Stop*.

(B) If no, then go to (2)

[19] This summary is based on our interpretation of information in the CCDEBE proposal (op. cit.) and other information provided by ISO staff. However, the responsibility for any errors is ours.

(2) Does the resource affect any noncompetitive constraint that is binding in the MPM run by the new CCDEBE pivotal supplier test? (In particular, does a resource have negative shift factor for any non-competitive binding constraint?)

(A) If yes, then mitigate commitment cost offers ("***Binding+***"). *Stop*.

(B) If no, then go to (3)

(3) Does the resource affect any critical noncompetitive nonbinding constraints by the new CCDEBE pivotal supplier test? (In particular, does a resource have negative shift factor for any non-competitive non-binding constraint?) (Given that the resource doesn't fall under categories (1) or (2), above, a "yes" here implies that energy prices aren't affected (*i.e.*, the local LMP equals system price, plus any adjustments for binding competitive constraints), but its bid cost recovery or exceptional dispatch payments might be.) Possible outcomes include:

(A) If yes, then check whether the resource committed in the MPM run? Possible outcomes:

(i) If committed, then check if the resource's dispatch in the MPM run is equal to or in excess of the unloaded capacity of the critical noncompetitive nonbinding constraint. Possible outcomes of this check:

(a) If yes, then mitigate commitment cost offers because its output is needed to satisfy that constraint ("***Nonbinding/Committed/DispatchExcess+***"). *Stop*.

(b) If no, then do not mitigate, since it is assumed that its dispatch is a result of it being competitive relative to system resources. *Stop*.

(ii) If not committed, then do not mitigate. (Note that it is possible that in the subsequent Step 3 market runs, the resource might be committed. [20] If it turns out that its scheduled dispatch is greater than the unloaded capacity of a critical nonbinding noncompetitive constraint, then a false negative has occurred; the resource should have been mitigated when it wasn't.) *Stop*.

(B) If the answer is no to (3) (the resource doesn't affect a critical noncompetitive nonbinding constraint by the CCDEBE test), then do not mitigate. *Stop*.

We now turn to a discussion of issues associated with the three core elements of the proposal.

[20] If the MPM and market dispatch are carried out in the same software run, such an outcome should be very rare with minor impacts, as the offer prices of other resources in the market run should be less than or equal to the offer prices in the MPM run. Such an outcome is possible as a result of solution differences due to MIP gap or changes in congestion when lower cost resources are committed due to mitigation in the market pass.

4. Market-Based Commitment Cost Design Issues

There are three core elements to the CCDEBE proposal, and we discuss several of their features in this and the following two sections. The first element is to allow market-based offers for commitment costs. We address issues concerning two features of this element in the following subsections. One is the proposed transition of the commitment cost bid cap from 200% to 300% if no problems emerge. The other is whether start-up cost offers should be allowed to vary within a day, consistent with the ISO's proposal for minimum load cost offers. In Section 5, we consider issues associated with the second core element, which is the proposed dynamic mitigation of commitment cost offers. Section 6 considers the third element, which is the revised definition procedures for reference prices. At the close of each section, we summarize our conclusions.

4.1. Transitional Cap on Commitment Cost Offers

The CAISO proposes to gradually shift to market-based bidding of commitment costs.[21] Even when not mitigated for local market power, commitment costs bids will be limited by a "damage control" cap. Market-based commitment cost bids will initially be capped at no more than 200% of the estimated reference level costs, with this cap rising to 300% after 18 months if there are no material unanticipated problems arising from the increased offer price flexibility.[22] The damage control cap on commitment costs could presumably be adjusted further in the future, but the proposal does not address this.

There are at least two rationales for the transitional cap on commitment cost offers. First, the 200% cap provides a limit on offer prices and market impacts in the event some element of the market power mitigation design that is implemented does not operate as intended. Second, the cap will limit offer prices and market impacts in the event that there are flaws in other elements of the CAISO market design that have been masked by the current bid constraints and which therefore will need to be modified to accommodate market-based commitment cost offers.

The DMM, on the other hand, recommends that the CAISO continue to cap all market participant commitment cost offers at 200% of the CAISO's estimated commitment costs until another stakeholder process is conducted to consider this issue.[23] The DMM's rationale for this recommendation is that

> *"(t)his would allow stakeholders to demonstrate and justify the parameters for a reasonable level after they have some experience with the design of these new market features. A new stakeholder process is also more likely to result in a thorough evaluation of the functioning of the mitigation design*."[24]

Some of the considerations that are relevant to whether or not the cap should be raised automatically if no problems occur include the following:

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[21] See CCDEBE Revised Draft Final Proposal, *op. cit.*, Section 5, p. 15.

[22] *Ibid.*, Section 5.1.1, pp. 17-18.

[23] See California ISO, Department of Market Monitoring, Comments on CC DEB Initiative December 21, 2017 Stakeholder Call, January 11, 2018, p. 4.

[24] *Ibid.*, p. 4.

1. While DMM and the CAISO support the pivotal supplier test, it may turn out to not be a very good method for testing the application of market power involving commitment costs. If so, this would require changes in the limits on offers submitted by resources that are able to relieve a potentially binding transmission constraint.

2. Even if the pivotal supplier test is found to have weaknesses that require changes in the test design together with retention of or lowering of the 200% cap on the commitment cost offers of resources able to relieve a potentially binding transmission constraint, this would not warrant retaining that cap for resources whose output does not relieve any binding or potentially binding transmission constraint.

3. Unlike mitigation designs in other ISOs, the 200% and 300% caps would apply to any level of commitment costs; that is, there is no lower bound on dollar per megawatt hour or dollar per start offers to which the cap or mitigation would apply.

The CAISO proposes that the default caps on commitment cost offers would rise from 200% to 300% of the cost estimated by the CAISO after 18 months unless the CAISO files with FERC to defer this increase. We support this design as it allows the CAISO to defer the change in caps if market issues are identified during the first 12 months that provide reason for delay. The alternative of requiring a new stakeholder process before implementing the second increase would delay the increase in the cap regardless of whether there are any performance issues warranting such a delay. This alternative would also require that the CAISO and stakeholders devote resources to an unnecessary stakeholder process during a period when the CAISO and stakeholders will likely have a number of other complex initiatives that will need to be discussed.

4.2. Within-Day Variation of Commitment Cost Offers

Another issue with the commitment cost caps proposed by the CAISO is that while the CAISO proposes to allow market-based minimum load costs to vary by hour, market-based start-up and transition costs offers would be daily values.[25] While some market participants have pointed out the desirability of being able to vary start-up and transition cost offers over the day in response to changes in fuel prices or other factors impacting these costs,[26] it is our understanding that the current CAISO market software lacks the ability to readily accommodate start-up cost offers that vary over the day within a single software run.

Earlier CAISO proposals outlined work-arounds that would enable the submission of hourly start-up and transition cost offers, but the CAISO DMM has pointed out potential unintended consequences that could arise with implementation of those workarounds.[27] It appears to us that these concerns have likely been addressed by design in the Revised Draft Final Proposal which provides for a single start-up cost value to be used in the day-ahead market and a single value to be in effect in real-time.[28]

[25] See CCDEBE Revised Draft Final Proposal, Section 5.1, pp. 16-22.

[26] See Comments of NV Energy, January 11, 2018.

[27] CAISO DMM, Comments on CC DEB Initiative December 21, 2017 Stakeholder Call, *op. cit.*, p. 4.

[28] See CCDEBE Revised Draft Final Proposal, p. 16.

While this may not be an ideal resolution, market participants will be able to resubmit updated start costs each hour, which would be sufficient to reflect changes in gas costs over the day.

4.3. Conclusion

As stated above, we support the CAISO's design for a gradual transition to market-based commitment cost offers.

5. Local Market Power Mitigation (LMPM) Commitment Cost Design Issues

The second core element of the CAISO design is the implementation of a local market power mitigation design that would be applied to test for the need to apply market power mitigation to commitment cost offers.[29] The CAISO market power mitigation design has several significant features that have been a source of discussion among market participants, DMM, and CAISO staff. We review four of these features and their current status below.

5.1. Identification of Transmission Constraints Potentially Causing Unit Commitments

The starting point in the application of the CAISO's design for mitigating locational market power is identification of the transmission constraints that could potentially facilitate the exercise of locational market power. The CAISO has for several years applied a process for identifying binding transmission constraints as part of its LMPM design for energy offers. However, as discussed above, the complication that will be introduced with the application of LMPM to commitment costs is the potential for transmission constraints to bind in the unit commitment process and cause a resource to be committed, yet the transmission constraint might not bind in the dispatch schedule that the market software reports.

Hence, a resource could have been committed in order to solve a constraint that became non-binding with the resource committed. It is necessary to identify such constraints because although they do not directly affect energy market prices in the final market solution (because they are not binding), such constraints could have caused a resource to be committed even if it submitted non-competitive commitment cost offers that would entitle the resource to large BCR or ED payments. Further, such commitments are likely to affect market prices, meaning that non-binding constraints can indirectly affect energy prices.

While such a constraint would not be a binding constraint in the *final* dispatch solution, the iterative nature of the market model solution process means that any transmission constraint that impacts the commitment would be identified in an *earlier* pass and would remain in the constraint set of the final iteration of the process.[30] In the Siemens software these are referred to as "critical

[29] *Ibid.*, Section 5.2, pp. 24-31.

[30] That is, in a given iteration, a generation schedule is yielded by the optimizer, which has only included the subset of constraints included in the critical constraint set. A load flow model is then run in which the flows implied by the schedule are then checked against all constraints, including those not explicitly enforced in the market optimizer. If any omitted constraints are violated or have a flow that is within a given threshold of the flow limit, they are added to the critical set in the market optimization model, and it is run again. This process of "constraint generation" is repeated several times until all violated constraints are included or an iteration limit is reached.

constraints." Importantly, once an iteration identifies a constraint, and it is included in the set of critical constraints, it remains in the critical constraint set in all subsequent dispatch passes. This software structure is not an accident, as it is necessary to avoid cycling in the software due to a constraint dropping in and out of the critical set from iteration to iteration.

The critical constraint set is also defined to include all constraints with flows on the monitored element or elements that are within a specified threshold of the limit. This structure in which constraints enter the critical set without an actual overload is designed to improve solution efficiency by including potentially binding constraints in the optimization at an earlier iteration than they would be if they were only included after they were violated.

Because a resource could not have been committed to solve a transmission constraint unless the transmission constraint was included in the critical constraint set, the CAISO can determine whether a resource might have been committed in order to solve a non-binding constraint on which it had market power by assessing whether the resource had negative shift factors on any non-binding transmission constraint in the critical set.[31] In other words, the test looks at units that provide counterflow to critical constraints, binding or not. The CAISO design will use this information to identify transmission constraints that could potentially have allowed the exercise of locational market power by resources potentially eligible for BCR payments. If a resource would not relieve any of the binding or non-binding constraints in the critical set, there is no need for the application of market power mitigation to its commitment cost bids.

The CAISO's approach based on the critical constraint set is conservative and avoids the uncertainties and potential mitigation gaps associated with other approaches the CAISO considered.

5.2. Application of the Pivotal Supplier Test to Commitment Costs

The CAISO will continue to apply pivotal supplier tests to binding transmission constraints. Separate tests are proposed to be applied for energy bids (the existing local market power mitigation system) and commitment cost bids (the new CCDEBE procedures). If the test is failed, the CAISO should mitigate the offers of resources relieving the constraint. A market design question is whether separate tests are necessary and useful.[32]

The new feature of the CAISO design considered here is its proposal to apply a pivotal supplier test to constraints that are included in the critical constraints but are not binding in the final dis-

[31] The reference bus used to define shift factors will have to be appropriately defined for this test to ensure that this test operates as intended.

[32] The CAISO proposes to apply separate and slightly different pivotal supplier tests for incremental energy and commitment cost offers to test for the presence of locational market power and trigger the possible application of mitigation. It is likely that the tests will both trigger mitigation when there is a potential for the exercise of locational market power, but there is no need to apply two versions of the pivotal supply test in order to trigger potential mitigation of resources whose output would relieve binding transmission constraints. If a supplier has locational market power on a binding transmission constraint, we recommend that all of its offer prices should be evaluated for mitigation.

The CAISO also proposes to implement a variety of minor improvements in the current 3 pivotal supplier test that we do not discuss in this opinion.

patch, as well as to binding constraints. The application of the pivotal supplier test to non-binding constraints included in the critical constraint set requires that the CAISO account for the unloaded capacity on the non-binding constraint. The reason for this is to avoid mitigating relatively small units for providing counterflow to a constraint with more unloaded capacity than the mitigated unit is providing counterflow for. This accounting will necessarily be a rough calculation in the CAISO mitigation design, which does not redispatch the system without the capacity being tested for pivotality and instead relies on *ad hoc* rules to calculate the flows and use of otherwise unloaded capacity on the non-binding constraint that result from dispatching up of identified resources.

The design needs to identify and test <u>all</u> resources able to relieve a non-binding critical constraint because the level of uplift payments is not necessarily related to the congestion component at locations impacted by non-binding constraints. Hence the CAISO design will not apply the competitive constraint congestion component decomposition that is utilized by the present mitigation system in applying mitigation to resources able to relieve congestion on binding constraints. Instead, the CAISO design will test for the potential ability to exercise locational market power by all resources able to relieve congestion on any constraint in the critical set.[33]

5.3. Application of Mitigation to BCR or Exceptional Dispatch Payments

The market power testing and mitigation procedure for commitment costs summarized in Section 3.3 involves entirely "before-the-fact" tests.[34] As described in the previous section, market

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[33] It is unclear how useful and accurate the application of the pivotal supplier test proposed by the CAISO will be when applied to non-binding constraints for the purpose of commitment cost mitigation. The proposed test would almost always indicate a potential for the exercise of market power because it would compare (1) the sum of fringe capacity and potentially pivotal supplier capacity that cannot be physically withheld that would be available for dispatch to (2) the market power mitigation run's dispatch of capacity providing counterflow on the constraint; it then compares the output of the individual resource relative to the unloaded transmission capacity to which BCR mitigation would be applied. The pivotal supplier test may introduce so many false positives that it does little to limit the inappropriate application of mitigation [Note – the design performs the resource test of DOP>=unloaded capacity to address the potential for false positives of the PST so that the output is compared relative to unloaded trans capacity. We thought that mitigated false negatives based on our earlier discussions.], while weaknesses in the pivotal supplier test could fail to indicate the need for mitigation in some circumstances. The CAISO may find after implementing this design that it would be preferable to simply assume that resources able to relieve a non-binding constraint should be tested for whether commitment could have caused the constraint to become non-binding regardless of the amount of capacity available to commit, without applying a pivotal supplier test.

[34] An "after-the-fact" mitigation is in principle possible for BCR payments which are calculated after the fact depending on overall "as-bid costs" and revenues, and if that mitigation does not impact market clearing energy or reserve prices, which would be the case if the constraint does not bind in the dispatch or if the resource being tested was committed based on its unmitigated offer prices. (This is Section 3.3's mitigation category (3)(A)(i)(a) "***Nonbinding/Committed/DispatchExcess+***".)

There are several potential advantages to using such after-the-fact mitigation. First, it could simplify and speed execution of the market scheduling and pricing software by delaying some operations until later. Second, it could lessen the risk of "false negatives". As mentioned in Section 3.3, there is a risk of power mitigation would need to be applied before-the-fact (prior to the final market scheduling and pricing runs) to commitment cost offers of resources whose output would relieve binding constraints and which would not be committed based on their uncommitted offer prices. Then if mitigation results in the resource being committed, any BCR that is required would be based on mitigated bids, as just described.

Therefore, as summarized in Section 3.3, the test for BCR mitigation would need to be applied to resources that: (1) were committed, (2) whose output relieved a transmission constraint, and (3) had commitment cost offers that exceeded the reference levels. The purpose in applying the test to these resources would be to assess whether there is a significant potential for the exercise of locational market power by these resources. The test would be to assess whether any of the critical constraints relieved by the resource being tested could have required the commitment of the resource. This would necessarily be the case for resources relieving binding constraints. In the case of constraints that did not bind in the dispatch, this conceptually requires testing of whether there is sufficient unloaded capacity on the constraint in the dispatch solution such that the transmission constraint would not have bound even if the resource being tested had not been committed. If this is the case, the constraint could not have required commitment of the resource. On the other hand, if the constraint would have bound had the resource not been committed, then mitigation would be applied to the energy and commitment costs used to calculate BCR and ED payments. Then BCR and ED payments will be determined based on those mitigated bids.

A practical complication in applying this test to non-binding constraints is that whether the constraint would have been binding had the resource not been committed depends not only on the shift factor of the resource being tested on the constraint, but also on the shift factors of the resources that would have been dispatched up or committed to replace the resource's output if it had not been committed. For such non-binding constraints, the CAISO proposes to apply a simple test of whether the total output of the resource being tested exceeds the unloaded capacity on

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a false negative if the market power mitigation run (Step 1 of the market model) does not commit a resource and it the test does not find it is needed to satisfy a nonbinding critical constraint, but then the actual market scheduling run (Step 3) commits the resource (category (3)(A)(ii) in Section 3.3). If that resource inflated its commitment cost bid, then it could receive more BCR than it should be entitled too. After-the-fact mitigation could detect and mitigate such instances. Third, if a resource is not committed but doesn't impact noncompetitive binding constraints, there will be no BCR payments to mitigate, and no adverse market impacts from the application of mitigation based on inaccurate reference prices. Market prices for energy would not be affected because of the fact that the resource faces competitive energy prices. Fourth, after-the-fact mitigation of BCR payments also allows the CAISO to make use of market data that was not available in the timeframe of the day-ahead market or real-time dispatch, such as additional gas price transaction data. Finally, it will likely also reduce the need to apply the tests as there is no need to apply the test to resources that are not entitled to BCR if it turns out that they recover their commitment costs in their energy market margins.

We have been informed by ISO staff that after-the-fact alternative was considered but not adopted due to settlement complications and some stakeholder desires for all mitigation to take place prior to the market run. However, we suggest that it be considered in the future if either execution times or such false negatives become an issue.

the transmission constraint being evaluated.[35] Any resource that is committed would fail this test in the case of a binding constraint, so the test is only meaningful in the case of critical constraints that do not bind in the dispatch. A more complex test would be to rerun the dispatch step without the resource's output and test if the constraint would have bound. However, this would increase solution times and latency. Therefore, we support the CAISO's application of a simple test, as long as its performance is monitored carefully after implementation.

5.4. Application to Load Serving Entities

Another difference relative to the present system of energy market price mitigation is that mitigation of BCR payments needs to be applied to offers by LSEs who can be net buyers of energy. This is because even if the LSE would be adversely impacted by increases in energy market prices, it could also benefit from the receipt of additional BCR payments.[36] The CAISO proposes to apply commitment cost mitigation to the commitment cost offers of all resources able to relieve a potentially binding constraint, regardless of whether the resource is owned by a load serving entity that is a net buyer in the energy market. We support this element of the CAISO's design.

The test for the exercise of market power by net energy buyers (i.e., LSEs) only needs to be applied, however, to the impact of commitment cost offers on BCR and exceptional dispatch payments, not their impact on energy market prices. This is the approach taken by the CAISO's proposed design.

5.5. Conclusion

Overall, we support these elements of the CAISOs dynamic market power design and believe it will both enable the CAISO to provide more offer price flexibility to gas-fired resources within the CAISO during periods of gas price volatility and will also enable the CAISO to coordinate a more efficient market across the broader EIM region and better accommodate the diverse gas supply situations of utility generation across the west.

We have made two general suggestions for alternative implementations that may have some advantages, and should be considered if computational performance of the market software or the frequency of "false positives" becomes an issue. One is to combine market power tests on binding non-competitive constraints for energy and commitment cost offers; this would be more efficient computationally, and could conceivably avoid false negatives in which the energy offer prices is mitigated but commitment cost offers are not. The second would be to apply mitigation to BCR payments in an after-the-fact process if a resource that is not committed in the market power run also does not impact binding noncompetitive constraints, but is committed in the market run and would significantly affect nonbinding critical constraints.

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[35] See CCDEBE Revised Draft Final Proposal, Section 5.2.1, Table 2, pp. 25-26 and Appendix E, Section 7.2, p. 71.

[36] *Ibid.*, p. 25.

6. Mitigation Threshold and Reference Price Issues

In this section, we address three sets of issues associated with the definition of reference prices and thresholds for mitigation, which represent the third core element of the CCDEBE proposal. These three issues include: the consistency of thresholds for incremental energy and commitment costs (as a multiple of estimated costs); adjustment by offerors of reference cost values if the 110% threshold is insufficient, and procedures for reimbursement of those costs; and use of gas prices indices in reference price calculations. We support the ISO's proposed approaches to these issues, although we note some specific potential issues that should be monitored during implementation.

6.1. Thresholds for Mitigation

The CAISO currently allows market participants to submit incremental energy offers up to 110% of the cost calculated by the CAISO without triggering mitigation. For commitment cost offers, however, the threshold is presently 125% of the cost calculated by the CAISO that is allowed without triggering mitigation. The CCDEBE initiative proposes as part of these changes to adopt a common 110% threshold for both incremental energy and commitment cost offers. The reduction in the mitigation threshold for commitment cost offers would not be implemented initially but will be phased in with other adjustments after the new design has been in operation for 18 months.[37]

Part of the reason for the reduction in the mitigation threshold for commitment costs is that the CAISO will modify the calculation of commitment costs to include costs currently not included in commitment costs. These include minimum load costs for run hours not associated with energy output and the inclusion of eligible opportunity costs.[38] In addition, the tighter threshold would only be applied to resources whose output relieved a critical constraint.

6.2. Reference Level Adjustments

In addition to modifying the current default threshold for commitment cost offers in excess of the calculated costs, the CAISO proposes several mechanisms that would allow offers that exceed the calculated costs by more than the 10% threshold when a resource's commitment cost bids would otherwise be subject to mitigation (Section 3.3), when such offers are necessary to reflect actual costs. These will be implemented by adjusting the reference price for a resource to include:

- extending the option for negotiated reference levels that is currently available for incremental energy offers to allow negotiated reference levels for commitment cost offers,[39] and

[37] *Ibid.*, pp. 33-34.

[38] *Ibid.*, pp. 34-35.

[39] *Ibid.*, pp. 35-36.

- supplier-submitted adjustments to reference levels based on cost changes not reflected in the CAISO's cost calculation.[40]

Supplier-submitted reference level adjustments that are within a specified volatility threshold of the CAISO's cost calculation will be reflected in the unit commitment, impacting market clearing prices, and will also be reflected in BCR and exceptional dispatch payment calculations.[41] These thresholds are *ad hoc* simple percentage thresholds based on the CAISO and CAISO Department of Market Monitoring's comparison of gas trade prices on electronic exchanges to various types of gas price indexes for the same location. It is possible that it will be found over time that the CAISO will need to establish wider thresholds for resources not located close to liquid gas trading locations, that the width of thresholds will need to be increased or could be reduced because of changes in gas market price volatility, and/or that the width of the threshold could be conditioned on pipeline or other conditions that the CAISO can observe. The CAISO proposal also provides for resource-specific feedback loops.[42] The volatility thresholds proposed by the CAISO are a reasonable starting point given the data on current gas market volatility relied upon by the CAISO.

Supplier-submitted reference level adjustments in excess of this threshold will be eligible for after-the-fact recovery of incorrectly mitigated actual costs.[43] This design is consistent with the practice of other ISOs that apply market power mitigation to market-based commitment costs.[44] These supplier-submitted adjustments are not simply an increase in the 10% default threshold. They must reflect actual costs and are subject to verification.[45] The DMM has stated a concern that suppliers that have been "determined to have market power" (as determined by a three pivotal supplier test) should not be "automatically" compensated for costs in excess of threshold.[46]

Our understanding of the CAISO's provisions for *ex post* recovery of as-bid costs that were not recovered in market prices as a result of incorrectly mitigated offer prices is that the market participant will request this *ex post* recovery and the CAISO will make a determination of whether it will be provided. If the CAISO does not provide the make whole payment, the market participant will be able to make a FERC filing seeking recovery.[47] This does not describe a process for "automatic recovery" of as-bid costs in excess of the various thresholds, but rather provides for appropriate recovery of as-bid costs in excess of a threshold. Moreover, we do not agree that suppliers that fail the 3 pivotal supplier test have been determined to have market power. The 3

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[40] *Ibid.*, pp. 33-43.

[41] *Ibid.*, p. 33.

[42] *Ibid,* p. 40

[43] *Ibid.*, pp. 42-43.

[44] See MISO Tariff, Module D, Section 67; NYISO Market Services Tariff, Attachment H Sections 23.3.3.3.1, 23.3.3.3.2, and 23.6.

[45] See CCDEBE Revised Draft Final Proposal, *op. cit.*, Section 5.4.1, pp. 37-38.

[46] See CAISO DMM, Comments on CC DEB Initiative December 21, 2017 Stakeholder Call, *op. cit.*, p. 2

[47] See CCDEBE Revised Draft Final Proposal, *op. cit.*, Section 5.4.3, pp. 42-43.

pivotal supplier test is by design a very conservative test of competition, reflecting the many approximations in its application that could result in false negatives. The impact of this conservatism, however, is that it can produce many false positives. Rather than reflecting a finding that a market participant possesses market power, a failure to pass the three pivotal supplier test reflects a possibility that the supplier would possess market power.[48] In our opinion, there is no basis for the apparent position of DMM that costs above the threshold should never be recovered by suppliers that have otherwise been determined to have market power, even if the offers are clearly consistent with market conditions and other arms-length transaction prices. It is doubtful that such a policy will be acceptable to regulators in other states when applied to their utilities.

Another feature of the proposed reference price determination process is that the volatility threshold for gas fired resources will initially be set at 110% of the reference gas price for weekends and weekdays other than Monday's or weekdays following holidays. The threshold for the Mondays or weekdays following holidays will initially be set at 125%. These supplier-submitted cost adjustments would be used as the reference levels and the 110% (or, until changed, 125%) default threshold would be applied to cap offer prices.

An important rationale for this more relaxed threshold for the start of the work week is as follows. In assessing the need for suppliers to be able to make use of the volatility adjustment, it is important to recognize that the most often-used approach to comparing trade prices to an index is a comparison of transactions on the ICE to the index being used for the comparison at the same location. This calculation does not reflect the difference between the cost of purchasing gas over the weekend (most of which is purchased off-ICE) to the Friday gas price index. This calculation also does not reflect the difference between the gas index at a particular trading hub and the cost of acquiring gas delivered to gas fired generation not located at or near a reported gas trading point.

6.3. Gas Prices and Reference Price Calculations

The CAISO also proposes to continue making use of the best available data to estimate the gas prices that would be the starting point for the application of energy and commitment cost mitigation in the day-ahead market.[49]

This updating of the gas price indexes used for mitigation in the day-ahead and real-time markets based on transaction prices on electronic exchanges has been consistently recommended by the CAISO Department of Market Monitoring.[50] This updating is an important component of an improved bidding and market power mitigation design. This updating, however, is not a substitute for the elements of the CCDEB design which will enable gas fired generators to submit their own

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[48] See J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, Report on the Appropriateness of the Three Pivotal Supplier Test and Alternative Competitive Screens, June 27, 2013, www.caiso.com/Documents/Report-Appropriateness-ThreePivotalSupplierTest-AlternativeCompetitiveScreens.pdf

[49] Ibid., Section 5.3.1, p. 22.

[50] See CAISO DMM, Comments on CC DEB Initiative December 21, 2017 Stakeholder Call, *op. cit.*, p. 1.

offer prices when they lack market power. There are no gas price data on electronic exchanges—updated or otherwise—for gas purchased for delivery at locations that are not trading points on the electronic exchanges or for transactions carried out on the phone on weekends when there is little trading activity on electronic exchanges.[51]

6.4. Conclusions

Overall, we support the transition to commitment cost reference levels that can be based on negotiated values or supplier updated cost information, consistent with the changes that have been introduced in the overall market power mitigation design of other ISOs over the past 5-7 years. With the greater ability of suppliers to reflect their actual costs in reference prices, it is appropriate to reduce the general mitigation threshold for commitment costs from 125% to the same 110-% used for other resources. Finally, we continue to support the efforts by the CAISO and DMM to base offer price mitigation on updated gas price information where this is available and sufficiently reliable.

[51] Monday-only transaction prices from the prior week will not reflect gas market conditions over the weekend when the weather forecast is changing.

Attachment D – Commitment Cost and Default Energy Bid Enhancements

Second Revised Draft Final Proposal

Tariff Amendment to Clarify Process for After-Market Fuel Cost Recovery

California Independent System Operator Corporation

January 23, 2025

California ISO

Commitment Cost and Default Energy Bid Enhancements

(CCDEBE)

Second Revised Draft Final Proposal

March 2, 2018

Table of Contents

1. Executive Summary

The purpose of this initiative is to evaluate the California Independent System Operator Corporation's (California ISO) market rules relating to suppliers' bidding flexibility. Over the past decade, the California ISO has implemented several incremental changes to its market rules to increase suppliers' bidding flexibility. Even with these improvements, stakeholders maintain that the incremental changes have not resulted in the bidding flexibility they need to submit prices that reflect their cost expectations and other business needs. This second revised draft final proposal provides a comprehensive proposal to address these issues.

The California ISO proposes to support market-based commitment cost bids subject to caps and mitigation under uncompetitive supply conditions. Market-based commitment cost bids will be mitigated dynamically in the day-ahead and real-time market if any constraint that could trigger a commitment to resolve it is uncompetitive. Commitment and energy costs that are subject to mitigation are mitigated to a reference level, which estimates the commitment cost or energy cost of the resource. The California ISO proposes that suppliers will have the opportunity to negotiate commitment cost reference levels, similar to current provisions to negotiate reference levels for energy bids, if the California ISO reference level calculations do not accurately reflect their unique circumstances.

To ensure the California ISO calculated reference levels can accurately reflect gas-fired units cost expectations, the California ISO proposes to make permanent the use of the next day gas commodity price from Intercontinental Exchanged published the morning of the day-ahead process in the day-ahead markets. Finally, the ISO proposes to allow suppliers to request adjustments from their reference levels in day-ahead or real-time if a fundamental driver has changes such that it drives their cost expectations away from the reference level used on a routine basis. These adjustments will be subject to verification requirements that ensure the adjustments are reasonable reflections of suppliers cost expectations.

The business rules the California ISO will use to implement the changes described in this second revised draft final proposal are available on the California ISO website.

2. Summary of changes

The purpose of this section is to summarize the major changes to the proposal.

The following describes the changes that are in this second revised draft final proposal:

- Market-based commitment cost circuit breaker cap

The following describes the significant changes that appeared in the January 31, 2018 revised draft final proposal from the August 2017 draft final proposal. It also includes the planned changes to the draft final proposal discussed in December 2017 including related stakeholder comments. The major changes were:

- Change to include phased approach for setting levels of market-based caps and headroom scalars
- Change to apply mitigation separately to energy and commitment cost bids
- Change to mitigate commitment costs if effective to any non-competitive non-binding constraint if resource could bid commitment costs to inflate uplift
- Change to settle resources in full ramp at bid for interval where ramp begins
- Change to mitigate exceptional dispatches to all four reasons in tariff today
- Change to include a manual verification prior to market
- Change to approach for calculating fuel volatility scalar in reasonableness threshold

- Change to ex post verification and cost recovery based on actual costs unrecovered through market
- Change to add audit authority to ensure reference level adjustments are cost-based bids

Change to include phased approach for setting levels of market-based caps and headroom scalars

Several stakeholders requested the California ISO perform testing of the new commitment cost mitigation design prior to go-live. Additionally, they requested the results be shared with stakeholders and if needed, that the California ISO hold a quick stakeholder initiative to correct any issues. The California will test the new mitigation functionality during the implementation phase as it does with all market changes. In addition, the California ISO proposes a phased in approach to setting the levels for the market-based bid circuit break caps and head room scalars.

Based in part on these stakeholder comments, the California ISO revises its proposal regarding market-based commitment cost circuit breaker caps and the headroom scalar used in the reference level calculations. The California ISO now proposes that initially the circuit breaker caps will be set at 150% and headroom scalar to 125%. After 18 months, the California ISO will automatically increase the circuit breaker cap to 300% and decrease the headroom scalar to 110%. The California ISO will review the performance of its enhanced dynamic market power mitigation of commitment cost using the first 12 months of available data. If design issues are identified, the California ISO would file with FERC to delay the automatic increase and decrease of the cap and headroom scalar respectively to allow for California ISO to address any issues with stakeholders. Any delay or change would apply to both increasing the circuit breaker cap from 150% to 300% and decreasing the headroom scalar from 125% to 110%.

The phased approach will allow a period to assure commitment cost market power mitigation is functioning correctly – balancing false positives and false negatives.

Change to apply mitigation separately to energy and commitment cost bids

The California ISO has revised its proposal to apply mitigation to energy and commitment cost components separately. Mitigation will be based on whether the resource test for energy (non-competitive congestion component) fails and whether the resource tests (non-competitive commitment mitigation criteria) fails.

Change to mitigate commitment costs if effective to any non-competitive non-binding constraint if resource could bid commitment costs to inflate uplift

The California ISO has revised a number of elements of its dynamic commitment cost market power mitigation proposal. The most significant of these is to now mitigate resources effective to any non-competitive critical constraints during periods where commitment cost bids could be bid to inflate uplift.

Change to include a manual verification prior to market

The California ISO proposes to perform ex ante verification through evaluating the reference level adjustment requests through an automated screen. This automatic screen would compare the requested adjusted values against a reasonableness threshold. After further considering FERC Order No. 831, the California ISO revised its proposal to allow for suppliers to seek an ex ante manual consultation for energy costs exceeding $1,000/MWh. The manual consultation is not being proposed for energy below $1,000/MWh, minimum load, or start-up costs due to the administrative burden this would incur. Suppliers may request ex post review for any reference level adjustment that were limited because their cost-based bid exceeded the reasonableness threshold.

Change to approach for calculating fuel volatility scalar in reasonableness threshold

DMM expressed concerns with the statistical approach proposed for the volatility scalar included in the reasonableness threshold calculation. In response, the California ISO proposes to modify its previous proposal to calculate the reasonableness threshold using a seasonal statistical measure to define in the tariff the exact level of the fuel volatility scalar included in its reasonableness threshold. The reasonableness threshold establishes a level up to which the California ISO would automatically verify an adjustment since this level is a being a reasonable reflection of a suppliers' cost expectations. The revised proposal calculates a reasonableness threshold by including a fuel price volatility scalar in the reference level formulations. The California proposes the volatility scalar will vary depending on the day of the week. For gas-fired resource, the volatility scalar will be 125% on Monday and days without a published index and 110% on all other days.

Change to ex post verification and cost recovery based on actual costs unrecovered through market

Based on the guidance FERC has issued in FERC Order No. 831, the California ISO proposes to modify its proposal for ex post verification and cost-recovery rules to state that eligibility will be based on actual incurred energy or commitment costs that exceed either a cap or mitigated price level, rather than expected costs, unrecovered through market revenues.

Change to add audit authority to ensure reference level adjustments are cost-based bids

To protect against the risk that suppliers submit market-based bids that include prices above cost expectations in the reference level adjustments, a violation of the guidelines, California ISO revised its proposal to have the authority to audit a supplier's adjustment requests and validate whether the requests are based on cost expectations or not (i.e. cost-based bids). If the California ISO finds that supplier did not bid based upon cost expectations, the California ISO will deem the supplier ineligible to submit reference level adjustments for a period of time and potentially refer the behavior to Federal Energy Regulatory Commission (FERC).

3. Stakeholder comments

The purpose of this section is to summarize comments received on the draft final proposal relevant to the proposals included in the revised draft final proposal. Stakeholders submitted comments on the draft final proposal and on planned changes to the draft final proposal discussed at a December 21, 2017 stakeholder call. The comments address:

- Market-based bid caps and headroom scalars
- Dynamic market power mitigation
- Mitigating minimum online constraints
- Hourly market-based bids
- Ex ante adjustments to reference levels subject to verification

Market-based offer caps and headroom scalars

Most stakeholders support the revised approach to phase the levels of the market-based cap and headroom scalars approach as a reasonable framework that will allow the opportunity to assess the effectiveness of dynamic market power mitigation of commitment cost while not overly limiting bidding flexibility in the interim. Some market participants contend that 300% is needed and appropriate to allow them to reflect their own cost expectations and business needs but they also recognize the need for a phased in approach to assure dynamic commitment cost mitigation accurately detects market power. Others comment that 200% is a more appropriate level and that 300% is excessively high. For this reason, the California ISO proposes the phased in approach.

Among those that believe that 300% is too high, DMM also opposes the automatic increase in the bid cap and believes stakeholders must prove a need for a bid cap increase before it is increased. DMM also maintains the 125% headroom scalar double counts (i.e. the reasonableness threshold already includes 110% or 125% on top of fuel costs) and any scalar should be significantly lower than 125%. The ISO will file to delay the automatic changes if it identifies concerns with the effectiveness of the local market power mitigation of commitment cost.

Market participants believe the reduction to the headroom scaler should not occur until the circuit-breaker bid cap is increased because until there is confidence that the mitigation does not result in excessive false positives, if the California ISO were to mitigate at similar levels to what it currently performs (100% mitigation) then suppliers whose costs do exceed what the reference levels with 110% headroom scaler allows them to recover will not be made worse off than they are today. The headroom scalar should not be decreased until the cap is increased to 300% allowing for the inclusion of risk margins to account for this risk during market runs where there is sufficient competition. The potential for receiving profits under competitive conditions mitigates the concern that potentially undercompensating during uncompetitive conditions leads to overall undercompensating suppliers costs since there is opportunity for profits the remainder of the time. This is similar to the dynamics suppliers face on the cost recovery for their energy bids in the existing market design. DMM believes the increase in the bid cap should not be linked to the increase in the headroom scaler. The California ISO believes specifying the automatic changes in the tariff is a reasonable compromise to effectively phase-in the bidding and mitigation changes.

Dynamic market power mitigation

NRG asked that the California ISO's principle that resources at the system level are competitive be codified in the tariff. The California ISO believes this is an opinion based on NRG's assessment of current conditions. The California ISO does not currently mitigate for system market power and therefore its tariff lacks any language enabling it to do so. Whether resources remain competitive at the system level can change over time with changes in system conditions and characteristics. However, at this time, the California ISO does not propose under this initiative to add the dynamic market power mitigation test for system competitiveness. The CAISO does test BAA level constraints for the Energy Imbalance Market, and does not plan on changing this in this initiative.

A number of stakeholders oppose both net buyers and net sellers of energy being included in the residual supply index calculation for commitment cost market power mitigation. Stakeholders are concerned that including net buyers will subject too many resources to mitigation and, alternatively, the California ISO should change its bid cost recovery allocation rules to address the potential to bid high commitment costs to inflate bid cost recovery. The CAISO believes net buyers should be included in the residual supply index because they would have the incentive to inflate commitment costs. The California ISO does not believe this can be addressed through bid cost recovery allocation rule changes. The California ISO determined through its *Bid Cost Recovery Enhancements* initiative that bid cost recovery cost allocation changes were not feasible.

Mitigating minimum online constraints

A number of stakeholders were confused why a proposal to mitigate minimum online constraints (MOCs) was included in *CCDEBE* when the *Contingency Modeling Enhancements (CME)* initiative was eliminated all MOCs. The California ISO clarified that the *Contingency Modeling Enhancements (CME)* design would eliminate most minimum online constraints (MOC). However, the California ISO might need to continue to enforce minimum online constraints for issues such as managing reactive power or voltage requirements. As such, the California ISO needed to include mitigation measures for minimum online constraints in its proposal. By definition, minimum online constraints are deemed "uncompetitive" because they are enforced for local issues and would likely include very few resources under the constraint.

Ex ante adjustments to reference levels subject to verification

Some stakeholders commented that by the California ISO publishing resource specific reasonableness thresholds to each market participant, that it would aid them in understanding how much headroom is available for adjustments. Other stakeholders commented that in order to protect against artificial price formation California ISO cannot make such information public.

California ISO clarifies that the reasonableness thresholds are not a safe harbor. The California ISO policy does not support using the reasonableness threshold to submit cost-based bids that are intended to exercise market power by including artificial price formation. The California ISO proposes suppliers will be required to submit bids based on cost expectations using contemporaneous information available to the supplier such as actual gas price quotes. Submitting requests to adjust any component by strategically bidding near the reasonableness threshold to inflate market revenues or uplift would be inconsistent with the market rules. The California ISO will not provide these values to suppliers.

4. Identified Issues

The following subsections describe the issues this proposal addresses.

4.1. Market-based commitment cost and hourly minimum load bids

The California ISO understands that stakeholders are concerned that the current bidding rules preclude suppliers from bidding market-based bids for their commitment costs and from bidding minimum load costs that vary by hour. They have expressed that this inflexibility limits their suppliers' to reflect accurately their cost estimates and other business needs.

Some stakeholders also maintain the current market implementation limits their ability to select hours in which to participate. However, the California ISO believes the current market largely allows this and stakeholders may have this perception because of the way the market inserts bids to accommodate resource intertemporal constraints and terminal conditions or for other circumstances for which an energy bid is needed for the market. Stakeholders expressed concern that the current rules are overly limiting because:

- Suppliers are required to submit cost-based bids for their commitment cost components subject to validation even under competitive conditions
- While suppliers can update the daily minimum load bids in real-time the single value is considered for each hour across the entire market optimization, if they are not awarded in day-ahead, this does not address need to have different values for minimum load in each hour so that the market optimization can evaluate the costs for operating it at least at its minimum operating level based on the costs for the given hour.

The California ISO is currently the only organized electricity market that does not support market-based commitment costs bids subject to mitigation. Only mitigating commitment cost bids when a resource has market power increases the ability for suppliers to reflect their cost expectations and business needs.

The findings of the California ISO's survey of organized markets bidding rules showed that all other organized markets support market-based bids for all components of the supply bid and apply mitigation to each component under various, complex rules. Most other markets support hourly variation across the minimum load energy costs (ISO-NE, MISO, PJM, and SPP). Requiring cost-based bids for commitment cost components for every run, not allowing hourly variation for minimum load costs, and forcing bids for every hour across the day results in an overly restrictive bid structure design.

Regardless of whether the bids could adversely affect the market, the current design precludes suppliers from submitting commitment cost bids based on prices that reflect their cost expectations and other business needs if these exceed the cost-based cap at 125% of fuel cost proxy. Currently, the California ISO treats commitment costs as uncompetitive in every run. California ISO currently applies a cost cap for every run at 125% of its reference levels. California ISO existing design limits cost-based bids to 125% because it has shown empirically that this level is a reasonable range of costs. Under most scenarios, the 25 percent appears to provide a sufficient margin of error for most resources to allow the suppliers' cost expectations to be reflected in their commitment cost bids.

However, this headroom may be insufficient to bid prices that reflect a market participant's own cost expectations or other business needs including risk margins, subsidies, contracts, or factors such as preferred use. This disregards that under competitive conditions, suppliers should be able to bid prices that reflect their own cost expectations or other business needs. As discussed in the Background section, this is appropriate because the competitive market forces exist to provide incentives that limit adverse market impacts from market power.

Stakeholders raised concerns during the *Commitment Cost and Default Energy Bid Enhancements* stakeholder process that non-resource adequacy resources may not want to participate during all hours of the day and should be able to select hours for their bidding. The California ISO clarifies that its current bidding policies do not, in themselves, require non-resource adequacy resources to bid power for every operating day or to submit bids for all hours of the day. California ISO will continue to support this policy.

Minimum load bids need to have ability to vary by hour

Stakeholder raised three examples for business needs to bid minimum load costs that vary across hour. First, multi-stage generators (MSGs) need flexibility to reflect minimum load costs that vary by hour because a higher configuration's minimum output levels may increase or decrease relative to the output level of the lower configuration. Since the lower configuration's output can be a function of ambient temperature, the maximum output of the lower configuration is at a higher output level during cooler periods, causing the minimum operating level of the higher configuration to increase. The variation of the minimum output level of higher configurations can vary significantly in desert climates with large temperature variations. This was addressed in *Bidding Rules Enhancements* but needs to be enhanced to allow the market-based bids which reflect preferred use of resource to bid at levels below the default energy bid used in the revised minimum load cost formula. Second, resources with physical minimum load rerates request flexibility to reflect their business needs in the default energy bid integration[1]. Third, that fuel costs can be expected to differ in various hours based on whether fuel was for the first gas day, second gas day, or hours after 5PM when pipeline flow orders may be issued.

4.2. Market power mitigation enhancements

In this proposal, the California ISO is addressing the need for enhancements to its existing local market power mitigation test. California ISO's current commitment cost market power mitigation methodology, which in effect applies bid price mitigation based on estimated costs in every run, without regard to the

[1] Described in detail in *Bidding Rules Enhancements* draft final proposal on minimum load costs, available at: http://www.caiso.com/Documents/DraftFinalProposal_BiddingRulesEnhancements_MinimumLoadCosts.pdf.

potential for the exercise of locational market power, may result in over-mitigation of units since it assumes uncompetitive market conditions in every run (cost-based cap). To address the concern that supplier bids should not be based on estimated costs when the market is competitive, the California ISO needs to design a market power mitigation test that includes ability of suppliers to withhold their capacity, including minimum load.

In its original nodal market design, the California ISO adopted the approach to treat biddable commitment costs as cost-based bids and subject to a validation of a percentage of its commitment cost reference levels. In the related board memo, the California ISO committed to evaluating whether a dynamic mitigation test would be feasible to implement stating:

> *"These proposed provisions have been specifically designed to be implemented without any changes in the MRTU market software. Over the longer term, the CAISO will assess other options for mitigation of start-up and minimum load bids which may be integrated into the MRTU software and allow for more targeted mitigation only when units are constrained on due to uncompetitive transmission constraints… more dynamic approach employed by PJM could not be implemented under the CAISO's current MRTU design since software modifications could not be made to incorporate mitigation of bid-based start-up and minimum load cost bids directly into the MRTU LMPM procedures."* [2]

Once implementation feasibility was no longer a primary barrier to implementing mitigation on the entire supply bid, the California ISO evaluated the merits of extending its mitigation paradigm and identified several issues that need to be addressed in implementing such a change. Its mitigation paradigm applies a local market power mitigation test that includes a dynamic competitive path assessment (DCPA)[3] to identify uncompetitive conditions on binding transmission paths and a resource test to identify whether a resource has a locational advantage to exercise market power to uncompetitive constraints.

The major issues that create challenges when applying local market power mitigation to committed units are:

- **DCPA does not test critical constraints that are non-binding in the market run, so applying the current DCPA design without modification could potentially allow resources to exercise market power.** This is because a resource may be committed to resolve congestion on the system when local constraints are enforced in the unit commitment run, called critical constraints. The commitment of a unit can add more capacity than needed to relieve the constraint due to the lumpiness of minimum load requirements. It is therefore possible for the commitment of a

[2] Decision on Bid Caps for Start-up and Minimum Load Bids under MRTU, September 7, 2007, Page 1 and 4, http://www.caiso.com/Documents/070906DecisiononBidCaps_Start-upandMinimumLoadBidsunderMRTU-Memo.pdf.

[3] Dynamic competitive path assessment performs a three pivotal supplier test (PST) and determines if there is sufficient residual supply of counterflow to meet the demand for counterflow on a given constraint, measured by a residual supply index (RSI).

resource to be triggered by a constraint, but the constraint no longer binds once the unit is committed. Testing non-binding as well as binding constraints will require developing an approach to treating the unloaded capacity on the constraint under a pivotal supplier test.

- **DCPA does not directly account for an offline resource's potential ability to withhold counterflow**: The current design does not directly account for all potential withheld capacity due to a simplified approach. The revised draft final proposal for the *Dynamic Competitive Path Assessment* initiative stated, "We note that this measure of potential withheld capacity does not directly account for a resource fully withholding by shutting down. We recognize that this potential exists but note that some of the withheld capacity will be accounted for in the proposed measure and the market will detect after a few intervals that the resource is now off-line and that absence of capacity will be reflected in the measure. In addition, the Department of Market Monitoring monitors for physical withholding."[4] A competitive path assessment would need to be enhanced to directly account for ability to withhold capacity to the extent possible.

- **The resource test used to assess the impact of a resource's bid on market prices does not account for the potential for inflated commitment cost bids to inflate uplift, only the ability to inflate energy prices. Hence, using the resource test to apply commitment cost mitigation could potentially allow resources to exercise market power by inflating uplift payments.** Hence, the determination of locational advantage based on the combined impact of non-competitive constraint's shadow prices and the resource's shift factors will not indicate an ability to inflate uplift. A resource test for locational advantage to submit inflated commitment costs bids in order to inflate uplift payments will need to not rely on shadow prices to identify the potential for the exercise of locational market power.

- **The resource test, which accounts for a net effect of a resource's output on binding transmission constraints across the system, while appropriate for energy mitigation, is not appropriate for commitment cost mitigation:** The market may commit a resource to resolve any enforced constraint while a corresponding contribution of prevailing flow elsewhere may not alter that commitment decisions or provide a disincentive to inflate bids. A resource test for locational advantage to withhold to inflate uplift will need to assess effectiveness to any non-competitive constraint.

The DMM stated during the Bidding Rules Enhancements initiative that the California ISO market faces several challenges when developing commitment costs mitigation methodology even beyond the specifics of the local market power mitigation test. DMM recommends that any future methodology would:

- Need to consider transmission and contingency constraints, exceptional dispatches, operator action to override market software, and outage re-rates among others to be effective

[4] Dynamic Competitive Path Assessment Revised Draft Final Proposal, Page 11, Footnote 4, July 5, 2011, http://www.caiso.com/Documents/RevisedDraftFinalProposal-DynamicCompetitivePathAssessment.pdf.

- Need to effectively identify opportunities for market power and appropriately applying mitigation.

In the revised draft final proposal, the California ISO addresses these concerns.

4.3. Supplier submitted reference level adjustments

The California ISO current method of calculating reference levels may not always reasonably reflect impact of externalities or suppliers' cost expectations. This inaccuracy is important relative to commitment cost reference levels as it may force an uneconomic resource to be committed. It also impacts any EIM participant that is required to submit bids to the California ISO at reference levels, at default energy bids (See Issue Paper Sections 4.4 and 4.5).

On the subject of clarifying the role of fuel replacement costs in establishing delivered gas price estimates, the California ISO notes that the marginal cost of fuel is the market price at which supplier would expect to replace the inventory – as that is a widely accepted principle – but there has been debate instead on "when" that replacement would or should occur. Establishing the marginal cost of fuel to an electric generator based on replacement cost of the next unit purchased is accepted widely because economics are rooted in the need to evaluate whether to burn the fuel to produce energy, maintain it in inventory, or sell fuel. A profit maximizing electricity supplier would evaluate and weigh each of those possibilities.

The California ISO understands the Department of Market Monitor to believe the replacement costs would be incurred at a time in the future when fuel prices are the lowest so as to maximize profits. However, the California ISO understands from other stakeholders they view the timing of that replacement as being tied to specific times of year or based on the prevailing market price at the time the decision is made.

The existing reference level design does not reflect cost expectations when significant price volatility occurs between the next day and non-standard gas products especially under constrained gas conditions. Related to constrained gas conditions, many stakeholders believe they need the ability to reflect costs in their bids better when those costs include risks such as non-compliance with gas pipeline instructions through no fault of the resource caused by California ISO dispatch instructions.

While the California ISO identified needs to address its bidding flexibility design for resource commitment costs and energy bids, the California ISO did not initially intend to address the unlikely risk that a suppliers' cost-based energy bid would exceed $1,000/MWh because it has not observed price volatility approaching those price levels in the West. However in November 2016, Federal Energy Regulatory Commission (Commission) released a Final Rule (FERC Order No. 831) requiring the California ISO to enhance its functionality to address bidding flexibility for cost-based energy bids above $1,000. To comply with FERC Order No. 831, the California ISO must allow suppliers' verified[5] cost-based energy bids greater than $1,000/MWh and up to $2,000/MWh to be eligible to contribute to setting bid merit order used in dispatch and pricing and be eligible to set locational marginal prices. FERC Order No. 831 also requires the California ISO to support an ex post verification process where any submitted

[5] Per Order 831, the standard for verification will be an ex ante verification on whether the cost-based energy offer is a reasonable reflection of cost expectations.

bids either above $2,000/MWh or any bid greater than $1,000/MWh and up to $2,000/MWh that is unverified ex ante, are eligible for an after-the-fact review and eligible for uplift payments if verifiable based on the after-the-fact review. The California ISO expanded the scope of this initiative to address FERC Order No. 831 compliance for cost-based energy bids above $1,000/MWh and proposes to leverage the ex-ante and ex post verification processes needed for FERC Order No. 831 compliance to address existing limitations in its calculation of commitment cost and energy bid reference levels.

4.4. Reference level calculations

California ISO believes its bidding rules can be enhanced to better allow suppliers to bid prices that reflect their own cost expectations or other business needs. By increasing the accuracy of its reference level calculations, the California ISO can better:

- Support integration of renewable resources through improving its valuation of resources under uncompetitive conditions in a manner that will incentivize flexible resources participation during tight fuel supply;
- Account for costs of flexible resources (gas and non-gas) to reduce risk of insufficient cost recovery, and
- Encourage participation of non-resource adequacy and Energy Imbalance Market resources.

The California ISO has evaluated under this initiative whether using only one value for prevailing gas market prices results in reference levels that effectively value the suppliers' cost expectations. Using one gas market price to value power production that encompasses hours across two gas flow days increases the likelihood that estimates will not perfectly align with a suppliers' estimates of its costs given the fuel costs across one electric day will be influenced by both days. One day, the later day (i.e. second gas day, gas day 2, GD2), will have more of an impact on actual costs as it represents gas commodity prices for ~75 percent of the hours. If on the other hand, the California ISO uses the earlier day (i.e. first gas day, gas day 1, GD1) then this price information would only apply to the valuation of gas flows during hours ending 1-7 comprising only about 25% of the operating day.

To illustrate how the gas market nomination cycles and gas commodity price publication times affect the California ISO's market operations, Figure 1visualizes the interplay between the gas trade day and electric trade day. Gray bars, titled "Electric Day-Ahead (TD-1)" and "Electric Trade Day (TD)", show the electric days. Further in the diagram, one vertical strip of gray shows the day-ahead market window from 10AM-1PM Pacific.

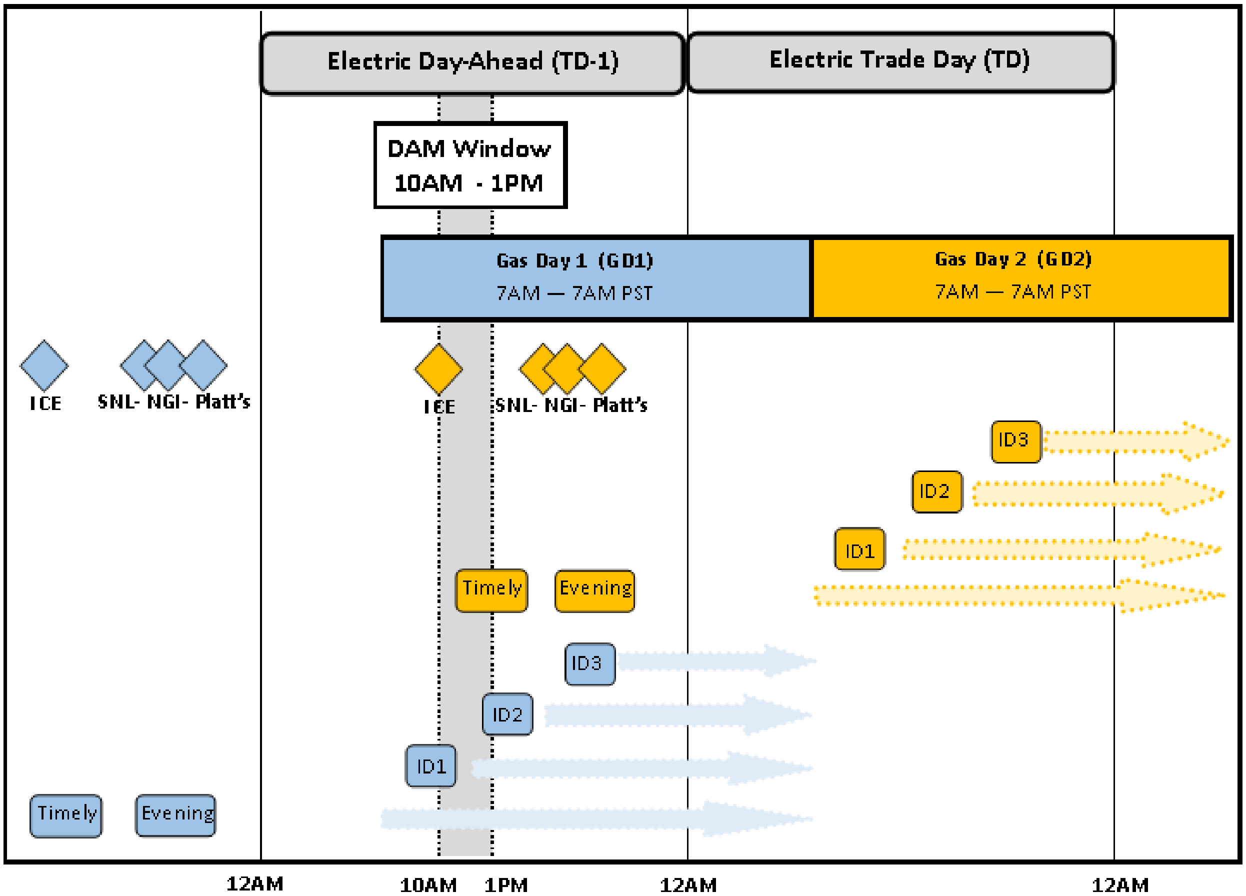

Figure 1: Gas and Electric Day Timelines effective April 1, 2016 (Order 809)

The colored items in this diagram show the gas trade day and publication timing for the first gas day that began flows TD-1 at 7AM Pacific (Gas Day 1 ,GD1) in blue and second gas day that begins flowing on TD at 7AM Pacific (Gas Day 2, GD2) in orange. The colored blocks represent each nomination cycle during the gas day from its deadline to final notification with arrows associated with each cycle showing the effective flow hours. The publication times associated with GD1's GPI are shown in Figure 1as blue diamonds and the flows hours under that contract is shown by the blue box entitled "Gas Day 1". The publication times associated with GD2's GPI are shown in Figure 1as orange diamonds and the flows hours for that product type is shown by the orange arrows under the orange box entitled "Gas Day 2". Table 1 shows the nomination cycles deadlines and when the gas flows based on a schedule in each cycle.

Nomination Cycle	Nomination Deadline (PT)	Notification of Nominate (PT)	Nomination Effective (PT)	Bumping of interruptible transportation
Timely	11:00 a.m.	3:00 p.m.	7:00 a.m. Next Day	N/A
Evening	4:00 p.m.	7:00 p.m.	7:00 a.m. Next Day	Yes

Intra-day 1	8:00 a.m.	11:00 a.m.	12:00 p.m. effective	Yes
Intra-day 2	12:30 p.m.	3:30 p.m.	4:00 p.m. effective	Yes
Intra-day 3	5:00 p.m.	8:00 p.m.	8:00 p.m. effective	No

Table 1: Gas nomination deadlines effective April 1, 2016 (PT)

As seen in Figure 1, the day-ahead market publication is released after all but one nomination cycle deadline for GD1 and after the timely cycle deadline for GD2, which increases the risk of a mismatch of nominated gas flow and actual gas demand triggering deviations from daily balancing requirement. If resources wait for ISO day-ahead schedules to procure gas and request nominations for gas flows in the early hours of its operating day, hours ending 1 through 7 associated with last hours of GD1 nominations, then the suppliers would procure gas during the last and most illiquid procurement and nomination cycle, intraday 3. The day-ahead market also does not inform timely gas procurement or pipeline nominations for its operating day hours ending 8 through 24 since the first cycle of gas nomination for GD2 concludes at 11AM PST TD-1.

The two different gas days will often have similar fundamental drivers so on a routine basis prices day-over-day in a month will be generally correlated. However, if fundamentals such as outages on the gas system differ between days the fundamental drivers might be significantly different so as to drive a weaker correlation between prices.

The reference level approach with a fuel cost estimate driven by next day gas commodity prices has generally worked well because California has historically experienced limited volatility and generators basis risk is moderate since California generators are geographically approximate to major trading hubs with published indices. However, with the expansion of the real-time footprint because of the EIM, more generators are farther away from liquid trading hubs and experience greater levels of basis risk than generators internal to the California balancing authority area.

Stakeholders have expressed to the California ISO that "working well" means they might still incur large losses on a particular day as result of market features. While the ability to submit ex ante reference levels subject to ex ante and ex post verification processes largely mitigates the insufficient cost recovery risks when the GD2 index is significantly different than the GD1 index, the automated screen using the reasonableness threshold that controls for outliers will ensure that requests that would result in significantly higher adjustments would be subject to a more rigorous ex post review. This means that even if the adjustment is within a reasonable threshold of the prevailing price trading on the morning of the California ISO day-ahead market, if the adjustment exceeds the reasonableness threshold it could be limited in the market and sent to cost recovery. While mitigating cost recovery risks, California ISO believes not allowing bids to reflect prevailing prices as observed on ICE in its day-ahead market would be a step backward away from market efficiency and accurate price formation.

5. Proposal

The California ISO proposes to allow market-based bids for each component of the supply bid subject to mitigation and allow greater flexibility to negotiate or adjust each component to support greater market efficiency. The proposal discussed in this section will address the limited flexibility of the California ISO bidding rules and reference level paradigm. California ISO notes the proposal will apply to all supply resources in the California ISO balancing authority area or Energy Imbalance Markets balancing authority areas. Supply resources include resources eligible to submit market-based or cost-based bids under the California ISO Tariff, which will include Generating Units, Participating Load, Reliability Demand Response Resources, Proxy Demand Resources, or Non-Generating Resources. If there are any differences in how the rules apply to the respective areas, the California ISO will call these out specifically in each section.

The ISO will describe the pieces of its proposal as follow:

- Market-based commitment costs and hourly minimum load
- Market power mitigation enhancements
- Reference levels
- Supplier submitted reference level adjustments

5.1. Market-based commitment costs and hourly minimum load

The purpose of this section is to describe the California ISO proposal to allow greater bidding flexibility by allowing Scheduling Coordinators of supply resources[6] (suppliers) to bid market-based commitment cost offers and to bid minimum load costs that vary by hour. Based on existing policy, bidding flexibility allows resources without a must-offer obligation to select hours in which they will submit their supply offers in day-ahead and real-time.

Under this proposal, the California ISO will allow suppliers to submit hourly bids for minimum load and daily values for start-up costs or transitions costs. The hourly minimum load bids are for the trade hour and may be resubmitted in real-time market pursuant to Section 30.5.1(b). The daily start-up and transition bids are for the entire trade day or as resubmitted in real-time market as pursuant to Section 30.5.1(b). Section 30.5.1(b) includes the provisions that allow real-time re-bidding where suppliers can resubmit their daily commitment costs in real-time for hours for which they do not have an integrated forward market award or residual unit commitment award associated with a binding residual unit commitment start up instruction (Section 30.5.1(b)).

Pursuant to current policy resulting from the Bidding Rules Enhancements initiative, suppliers can update their commitment costs in real-time for hours for which they do not have an integrated forward market award or residual unit commitment award associated with a binding residual unit commitment start up instruction. For any hours where a resource without a must-offer obligation does not submit a supply bid for any component, the California ISO will respect this bid strategy and will not insert bids into the market for that hour except to respect bid validation rules for must run resources, as is the current policy.

Today the California ISO does not permit Scheduling Coordinators to submit hourly amounts for any of the commitment cost bids. Although the software allows different hourly values for minimum load, start-up or transition costs in real-time today, the amounts bid are required to be a daily value. Going forward, the second revised draft final proposal policy will leverage the flexibility the software provides and allow

[6] Supply resources refers to resources eligible to submit market-based or cost-based bids under the California ISO Tariff, which will include Generating Units, Participating Load, Reliability Demand Response Resources, Proxy Demand Resources, or Non-Generating Resources.

Scheduling Coordinators to bid hourly amounts for minimum load. The second revised draft final proposal policy does not change the requirement to bid daily values for start-up or transition costs.

The California ISO will describe its proposal for hourly minimum load bids as follows:

- Support market-based commitment cost bids subject to caps
- Support market-based treatment under minimum load rerates
- Support hourly minimum load bids
- Settle commitment cost bid when no bid is present

5.1.1. Support market-based commitment cost bids subject to caps

Based on the California ISO understanding of virtually full consensus that it should support market-based commitment cost bids subject to caps as long as a sufficiently robust market power mitigation is applied, the California ISO proposes to pursue this enhancement. From a policy and market design perspective, the California ISO originally committed to this design change in 2007 contingent on it being feasible to implement commitment cost market power mitigation[7].

With an introduction of market-based commitment cost bids, the California ISO proposes it will apply "circuit breaker" hard caps on the commitment cost components of the market-based supply bids as well. Recall the fifth of the California ISO adopted principles under competitive conditions stated,

> *Market-based bids should be subject to "circuit breaker" caps to ensure that potential uncertainty impacting the mitigation test would not result in a significant false negative resulting in potential adverse market impacts.*

Today, the California ISO enforces a hard cap on its market-based energy bids at $1,000/MWh consistent with this principle. Similarly, the California ISO proposes hard caps on market-based commitment cost bids. These hard caps serve as backstop mitigation accounting for imperfect information in mitigation methods. California ISO proposes to establish a conservative cap initially and then as needed increase over time similar to the manner it phased in higher energy bid caps over several years.

Some stakeholders stated in their comments that the cap at the 300% of commitment cost reference levels the California ISO initially proposed was too high and others stated that it was too low. In response, California ISO proposes to establish the new market initially based commitment cost component caps at 150% of the commitment cost reference levels for start-up, transition, and minimum load bid components for the first 18 months. California ISO proposes to increase the percentage from 150% to 300% automatically after the first 18 months the bidding changes go into effect. After the data for the first 12 months is available, the California ISO proposes to analyze the mitigation performance. If the California ISO identifies that the market yields false negatives mitigation, would file to delay the automatic increase to allow for California ISO to address issues. This change would be in coordination with changing the headroom scalar from 125% to 110%.

[7] Decision on Bid Caps for Start-up and Minimum Load Bids under MRTU, September 7, 2007, http://www.caiso.com/Documents/070906DecisiononBidCaps_Start-upandMinimumLoadBidsunderMRTU-Memo.pdf.

The market-based cap will be a percentage multiplier of the resource-specific reference level[8]. If a resource submits an ex ante reference level adjustment and is successfully verified through the automated process, the market-based offer cap will be percentage multiplier of the adjusted reference level. The cap will initially multiply the reference level by 150% where the reference level is calculated as shown in Equation 3, Equation 4, and Equation 5. For example, if the minimum load reference level is calculated using the formula in Equation 3: Proxy Minimum Load Costs at $1,000/hour then the market-based bid cap for minimum load will be at $2,000/hour.

5.1.2. Support market-based treatment under minimum load rerates

This second revised draft final proposal includes a revised proposal for treatment of bids during hours for which a resource has a minimum load re-rate. The California ISO will not be able to support market-based bids to be submitted for the portion of the minimum load energy that is the rerated portion – i.e. the additional energy moved under the registered minimum load operating levels. However, the CAISO proposes to meet the spirit of its prior proposal by calculating a market-based bid ratio that will be applied to the default energy bid curve that is integrated into the minimum load.

Equation 1 shows the formulation for this enhancement to the DEB integration design implemented in the market as a result of the minimum load rerate rules developed under the *Bidding Rules Enhancements* initiative.

$$MLC' = MLC + \int_{P_{min}}^{P_{min'}} (\delta DEB(p)dp)$$

$Where$

$$I\ commitment\ costs\ are\ mitigated \rightarrow \delta = \min(1, \frac{MLC}{ML\ Ref})$$

$$If\ commitment\ costs\ are\ not - mitigated \rightarrow \delta = \frac{MLC}{ML\ Ref}$$

MLC'	Minimum load bid with the re-rated minimum load level's default energy bid integration
MLC	Minimum load bid (used in market after bid validation) subject to caps
ML Ref	Minimum load cost reference level
$DEB(p)$	Default energy bid cost associated with the cost of re-rating a resource or MSG configuration's minimum load

[8] Note - California ISO proposal includes revisions to its calculations for its commitment cost reference levels in Section 5.3 and Appendix C: Proposed reference level calculations.

dp	Change in energy

Equation 1: Minimum Load under Minimum Load Rerate

With this enhancement, the California ISO can ensure that, as long as not mitigated, the integrated portion of the default energy bid curve can better reflect the supplier's energy bid. Under uncompetitive conditions, the California ISO can allow the integrated curve to reflect lower values than the energy reference level if the market-based minimum load bids are submitted at levels lower than the minimum load reference level. California ISO proposes this so that if minimum load bids are submitted at say $0/hour to maintain units operation then when the default energy bid is integrated it will be integrated at $0 as well. This allows the market to reflect the preferred use of the resource up to the energy reference level.

5.1.3. Support hourly minimum load bids

Given the clarification that the current policy is to allow the flexibility for resources without a must-offer obligation to select hours to participate[9], the California ISO proposes to address the limitations issues identified for the need to vary minimum load costs hourly by supporting hourly minimum load bids.

While there was discussion of two minimum load bidding options during the stakeholder working groups, based on stakeholder input the California ISO understands there is broad support for resolution and either a "no load" or hourly treatment would resolve the issues. Given the much more limited implementation challenges involved with hourly treatment, the ISO proposes to adopt that option.

The minimum load bid will be an hourly component for which suppliers can submit different hourly prices. Minimum load costs will continue to represent the combined costs associated with power production as well as short-term fixed costs for a run hour. (e.g., major maintenance adders). Run hour costs refer to cost items associated with operating for an hour not related to energy production whereas the fuel cost or fuel cost equivalent are for the energy production in MWh.

California ISO clarifies that its existing rules allow for real-time market re-bidding of all commitment cost bids based on the re-bidding rules existing policy approved in November 2016 by FERC. . Under these rules, a supplier will be able to rebid minimum load, start-up, or transition costs in the real-time market for any hours without an integrated forward market or a residual unit commitment (RUC) schedule associated with a binding start-up instruction, the supplier may resubmit and update these daily bids in the real-time. Once a resource receives a binding real-time market start-up instruction, the resource will not be able to re-bid their commitment cost bids until it has fulfilled its minimum run time. California ISO clarifies that in combination with these existing rules a supplier may resubmit its commitment cost bids to higher values to reflect upward volatility or resubmit lower values to reflect

[9] Some suppliers maintain the current market implementation limits their ability to select hours in which to participate. However, the California ISO has examined this issue and does not require offers for hours not bid by the supplier unless the resource is a must run resource (e.g. ancillary service awards or self-schedules) or for units dispatched to respect a minimum up time or bid in the final interval. The only scenario the California ISO has identified that may be the basis of stakeholders concerns relates to seams issues where if there is a bid in the final interval then the market assumes there will be bids available in following runs, otherwise the market will shut the resource down. This applies to the last hour of day-ahead and the last interval of any short-term unit commitment run.

downward price volatility. The intent is to allow suppliers to bid prices that reflect their cost expectations and business needs.

In its comments on the California ISO straw proposal, WPTF recommended the California ISO provide an explicit statement on how stakeholders and the California ISO should understand this proposal related to resource adequacy resources. Resource adequacy resources in the content applies to any resource with an obligation to make capacity available to the California ISO under California ISO tariff. As stated at the July 6, 2017 stakeholder meeting discussing the straw proposal, the proposal for non-resource adequacy and energy imbalance market resources to select hours for submitting bids will not change resource adequacy resources' tariff must-offer obligations.

Hourly bids will be locked to levels evaluated under existing re-bidding rules

Although several stakeholders indicated concern and the importance of ensuring bidding rules are effective to mitigate behavioral concerns with this enhanced flexibility, after further consideration the California ISO has determined its current real-time market re-bidding rules do not need to be modified. Current re-bidding rules allow suppliers to resubmit their commitment cost bids in real-time only if they did not receive an integrated forward market award or binding residual unit commitment start-up instruction for that hour. In addition, once committed by the real-time market, the ISO has automated bidding rules to ensure the commitment cost bids are locked at the last bid price level used by the market to initiate the commitment and maintained through the resource's inter-temporal constraint (e.g. minimum run time, minimum on time).

Figures 2, 3, and 4 illustrate the current re-bidding rules on the minimum load component under the proposed hourly treatment. In Figure 2, the green triangles represent the hourly minimum load bids initially submitted and evaluated in the short-term unit commitment process for the 4 ½ hour optimization window from 2:30 to 7:00 AM. As shown, the last minimum load bid evaluated by the commitment process was around $1,500 for hour ending 7 but at increased levels in hours ending 8 through hour ending 10 that would be evaluated in later STUC runs. This resource must be able to both meet its start-up time and fulfill its minimum run time by the end of the unit commitment horizon unless a bid is present in the final interval of the optimization window. If there is a bid in the final interval, the optimization will assume the next run will include bids in future intervals.

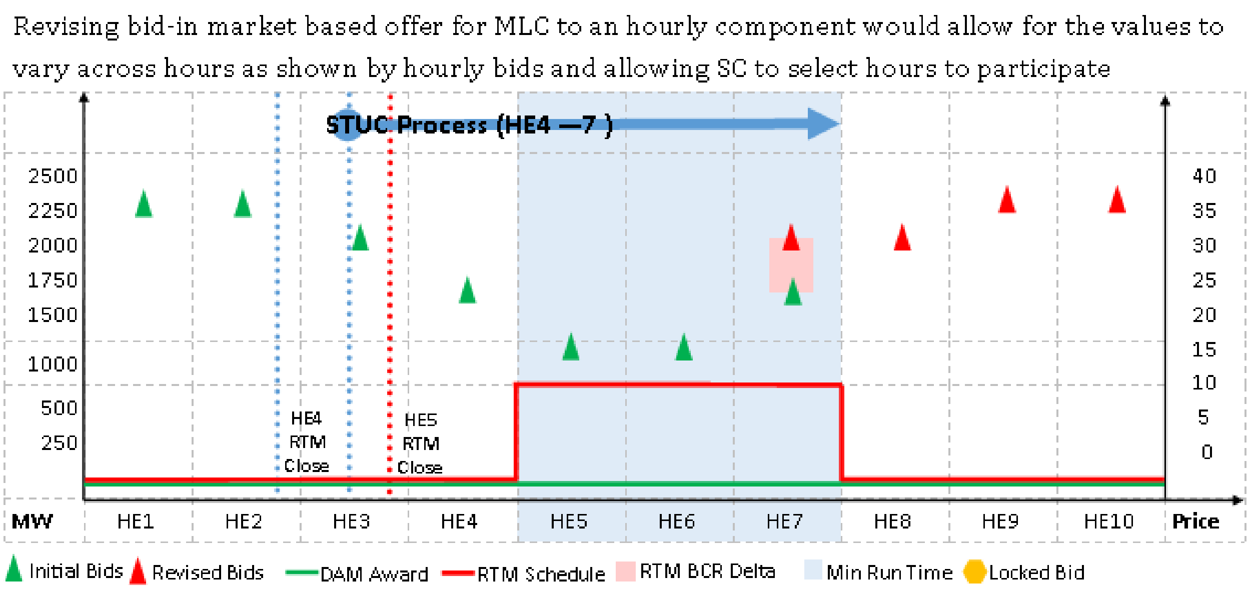

Figure 2: Illustration of proposed change for hourly minimum load

In Figure 3, once the hour ending 5 binding real-time market start-up instruction is issued then the ISO would automatically apply the re-bidding rules and lock the re-bidding window. In the current STUC run, if the supplier re-submitted a bid for hour ending 7 at $2,000/hour, the market would reject the bid since the bidding window is locked. This means California ISO will not accept any new bid submissions for commitment cost components and will ignore any values submitted to the California ISO until the resource completes the minimum run time.

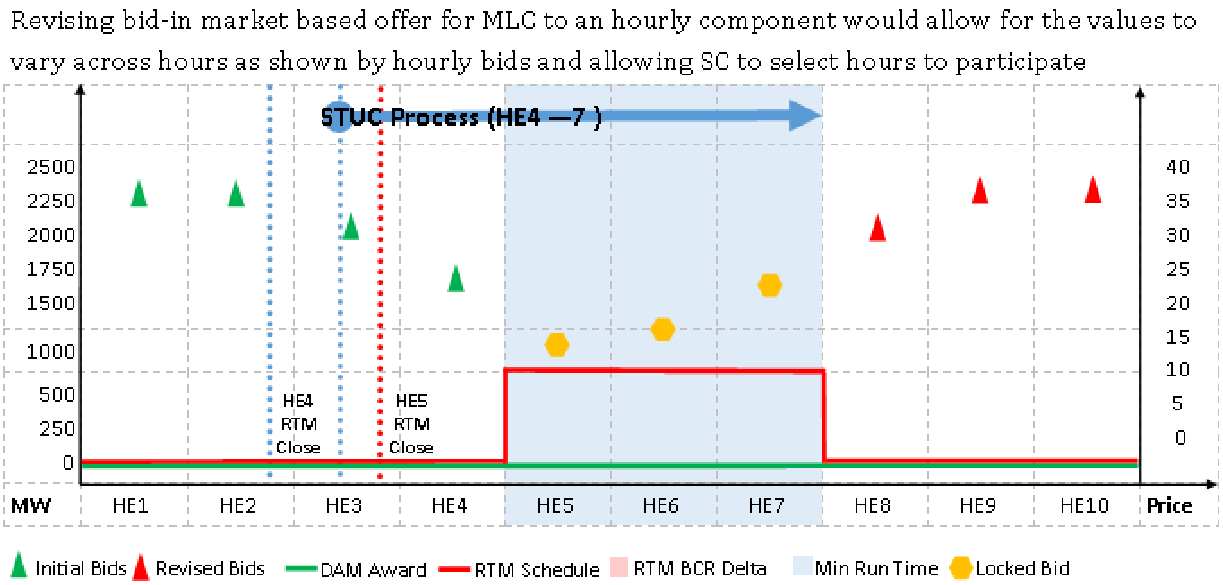

Figure 3: Illustration of rebidding rules on proposed change, no changes inside intertemporal constraints

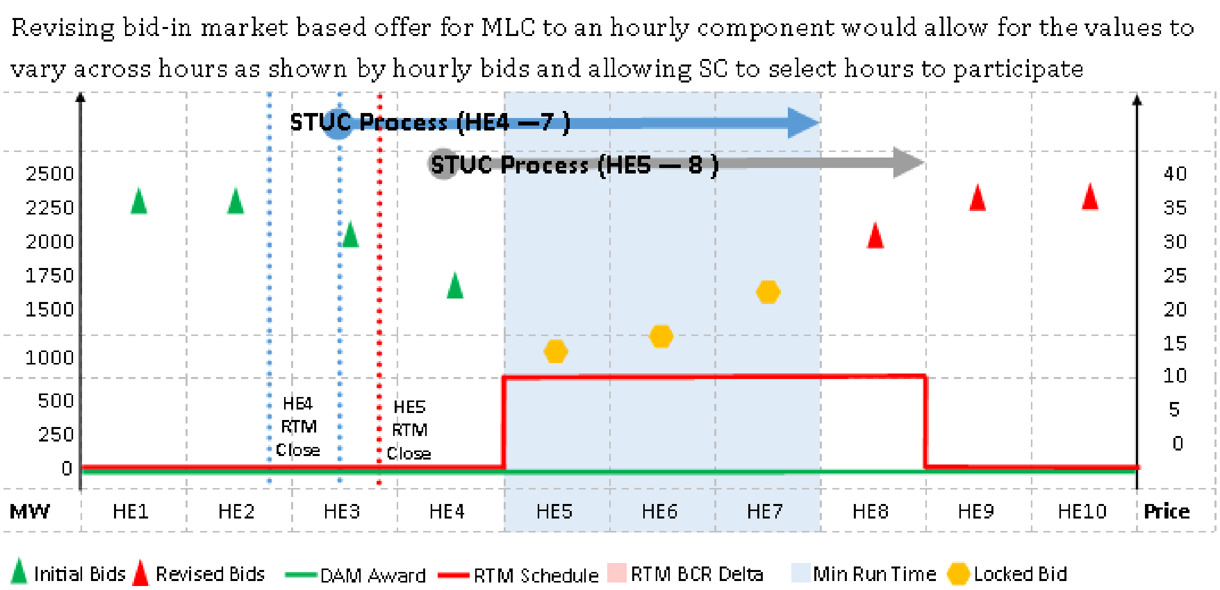

Figure 4shows the next STUC run for hours ending 5 through 8. In this run the market accepts the revised minimum load bid at the higher level of $2,000/hour for hour ending 8. If unmitigated, the market will use this value in the assessment of the unit's economics. This is appropriate because the unit commitment and economic dispatch runs can consider this value in its consideration of the optimal solution.

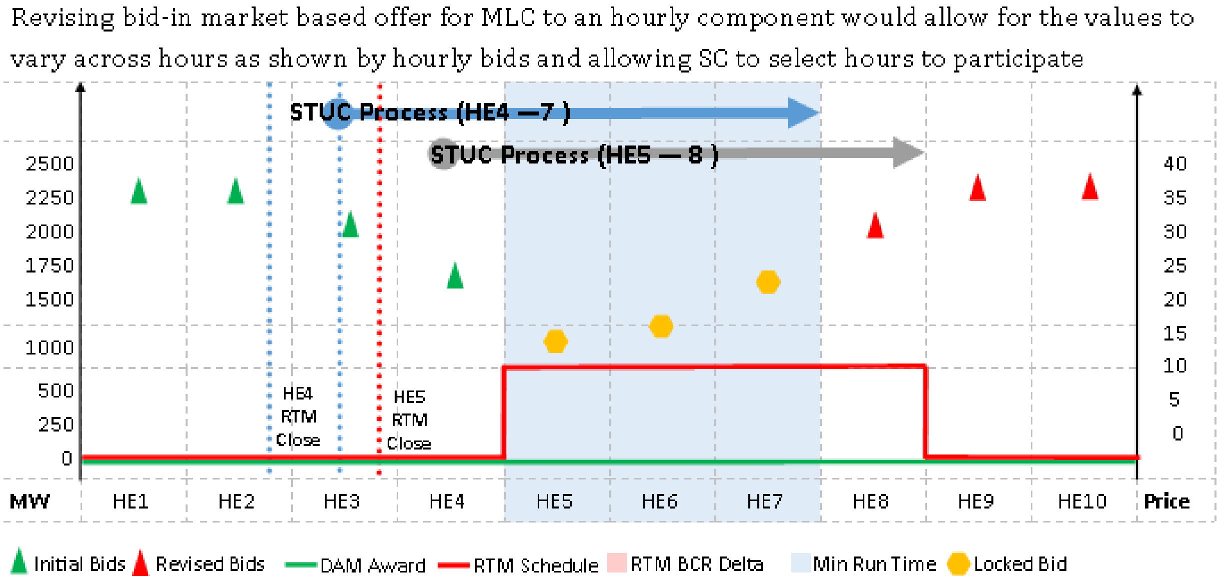

Figure 4: Illustration of rebidding rules on proposed change, changes outside of intertemporal constraints

The re-bidding rules protected against potential gaming concerns while allowing resources not under inter-temporal constraints to reflect their value to increase market efficiency. The higher bid for hour ending 7 was ignored by the market but the higher bid for hour ending 8 was considered because the market can now alter the resource's commitment status if no longer economic at that bid level.

5.1.4. Settle commitment cost bid when no bid is present

To implement effectively the California ISO supporting hourly supply bids, the ISO needs to propose a change to its settlement treatment of commitment cost bids when there is no bid available to the market but a resource must continue operating because of an inter-temporal constraint such as minimum run time.

California ISO market design respects physical constraints. California ISO needs to adopt a "no bid" process for instances without a bid to both respect physical constraints and settle resources appropriately. Figure 5shows the scenario of concern. This resource submitted hourly bids for hours ending 1 through hour ending 7. The commitment process evaluating commitments from 2:30AM to 7AM validates to ensure that sufficient bids are available to meet the inter-temporal constraint within the optimization window. However, as stated in the prior section, if there is a bid in the final interval the market will assume following runs will have bids in future intervals. In this example, the market sends a dispatch instruction to minimum load for hour ending 7 and then will not be able to issue a shutdown instruction until hour ending 10. If the resource was dispatched in hour ending 7 into its dispatchable curve, the market would send the resource to its minimum load beginning in hour ending 8 and maintain its dispatch until the end of hour ending 9 because there are no bids present but the market must respect the resource's minimum run time. The commitment cost no bid rule will be to settle an interval without commitment cost bids where the resource receives a dispatch instruction at its commitment cost reference levels.

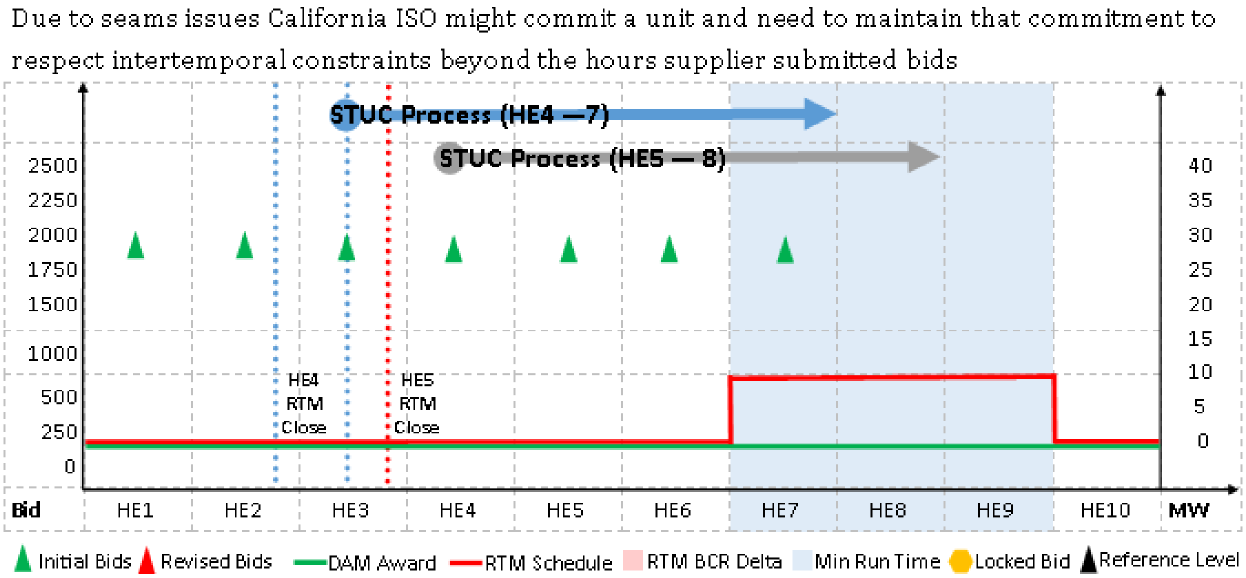

Figure 5: Illustration of need to dispatch even if no bid

In light of NV Energy's request to clarify how the default energy bid integration when a minimum load re-rate occurs impacts the California ISO proposal, the California ISO clarifies that for the purpose of this "no bid" process the methodology described in Section 4.1.2, "Support market-based treatment under minimum load rerates", will be followed and adopt the delta treatment for mitigated bids. This is for purposes of bid-cost recovery settlement.

5.2. Market power mitigation enhancements

The purpose of this section is to describe the California ISO proposal for dynamic local market power mitigation enhancements. California ISO proposes to allow market-based bids for each component of the supply resources'[10] bid subject to mitigation so that suppliers have greater flexibility to submit bids that support their cost expectations and business needs. The proposal will apply consistently to internal constraints in the California ISO and Energy Imbalance Market Balancing Authority Areas and to the BAA level net transfer constraints.

The California ISO will describe its proposal as follows:

- Dynamic market power mitigation enhancements
- Mitigate resources within a minimum online constraint
- Mitigate exceptional dispatches commitment costs
- Settle exceptional dispatches at commitment cost bids considered in initial instruction for the instruction period
- Settle resources in full ramp at the bid used in the interval

[10] Supply resources refers to resources eligible to submit market-based or cost-based bids under the California ISO Tariff, which will include Generating Units, Participating Load, Reliability Demand Response Resources, Proxy Demand Resources, or Non-Generating Resources.

5.2.1. Dynamic market power mitigation enhancements

California ISO recognizes and strongly agrees with stakeholders that an effective market power mitigation test is necessary to allow the introduction of market-based commitment costs. California ISO proposes to perform market power mitigation in all unit commitment processes with enhancements to the dynamic competitive path assessment and its resource test for locational advantage.

The California ISO will enhance its market power mitigation design to test critical constraints in its dynamic competitive path assessment. The California ISO also proposes that the new residual supply index calculation would be applied to critical constraints. Today, the dynamic competitive path assessment deems binding transmission constraints either competitive or uncompetitive based on a residual supply index. The residual supply index based on the current DCPA design will flag energy mitigation based on the value of the RSI_l.

The California ISO proposes to expand its competitiveness testing to all critical transmission and corrective capacity constraints. Specifically:

- Enhance existing calculation to account for potential for pivotal suppliers to shutdown
- Incorporate ability to reduce demand for counterflow by the unloaded capacity on a constraint
- Mitigate commitments costs for resources effective to any non-competitive critical constraints

Recall the California ISO current dynamic mitigation test performs a dynamic competitive path assessment (DCPA) using a three pivotal supplier test on binding constraints and then performs the resource test using the non-competitive congestion component at the resource's location. The resource test is used to flag the resources' locational advantage to exercise market power based on the combination of the portion of its marginal congestion component that comes from the combination of all non-competitive constraint (non-competitive congestion component mitigation criterion).

Table 2 presents the proposed characteristics for the enhanced dynamic market power mitigation test. Detailed explanations for the proposal for the enhancements to the dynamic market power mitigation methodology is provided in Appendix E: Details on local market power mitigation.

Mitigation Design Feature	**Day-ahead**		**Real-time**	
	Energy	**Commitments**	**Energy**	**Commitments**
Market power mitigation processes	Perform dynamic market power mitigation in all unit commitment processes (energy and commitment cost mitigation applied) and add a market power mitigation process in its short-term unit commitment run. Additional modification to allow consideration of minimum load energy in the assessment of competitive path designation if a resource can start up within the optimization time horizon of the unit commitment process time horizon[11].			

[11] Explicitly the inclusion of minimum load energy from off-line resources for each unit commitment process would consider a resource "startable" in each run as: day-ahead would consider all resources that are not extremely long start resources, RTUC#1 with a 105 minute time horizon would consider any resources with start-up times less than 105 minutes, RTUC#2 which includes

Mitigation Design Feature	Day-ahead		Real-time	
	Energy	**Commitments**	**Energy**	**Commitments**
Type of constraint tested	Binding transmission and corrective capacity constraints	Critical transmission and corrective capacity constraints	Binding transmission and corrective capacity constraints	Critical transmission and corrective capacity constraints
Identifying potentially pivotal suppliers	Exempt net buyers	Net buyers or sellers could be considered as potentially pivotal supplier	Exempt net buyers	Net buyers or sellers could be considered as potentially pivotal supplier
RSI calculation – considers commitment or de-commitments	Y[12]	Y	Y	Y
RSI calculation – basis for maximum capacity that could be withheld from pivotal suppliers	Maximum effective available capacity	Maximum effective available capacity	Maximum effective available capacity[13] (ramp constrained)	Maximum effective available capacity[14] (ramp constrained)
Mitigation Criteria	Non-competitive congestion component	Non-competitive commitment mitigation criterion for binding and non-binding constraints	Non-competitive congestion component	Non-competitive commitment mitigation criterion for binding and non-binding constraints
Exempt from mitigation	No changes to current policy that exempts demand response, participating load, non-generator resources and virtual supply from mitigation.			

STUC would consider any resources with start-up time less than 270 minutes, RTUC#3 with a 75 minute time horizon would consider any resources with start-up time less than 75 minutes, and finally RTUC#4 with a 60 minute time horizon would consider any resources with start-up time less than 60 minutes. If the optimization horizons change the resources eligible for start up would change to reflect the revised horizon.

[12] RSI calculation for energy mitigation does not allow de-commitments in the real-time market power mitigation processes today driving the need to apply an enhancement to the energy test as well.

[13] RSI calculation for energy mitigation assesses maximum ramp range within unloaded capacity in the real-time market power mitigation processes relative to prior interval in the mitigation run.

[14] RSI calculation for energy mitigation assesses maximum ramp range within unloaded capacity in the real-time market power mitigation processes relative to prior interval in the mitigation run.

Mitigation Design Feature	Day-ahead		Real-time	
	Energy	Commitments	Energy	Commitments
Apply mitigation	Existing	Minimum load – hour failed and other hours where resource is subject to intertemporal constraints Start-up or Transition – horizon if any hour fails	Existing	Minimum load – interval failed and other interval where resource is subject to intertemporal constraints. Start-up or Transition – horizon if any interval fails

Table 2: Proposed characteristics of market power mitigation enhancements

Propose to address issues that a resource test allowing for a net effect across the system and that does not capture ability to inflate uplift but only inflate energy prices while appropriate for energy mitigation is not appropriate for commitment cost mitigation.

California ISO must enhance its dynamic market power mitigation to add additional mitigation criterion used to flag resources that need to be mitigated based on their potential ability to exercise market power through their commitment cost bids rather than their energy bids. California ISO will apply mitigation to its energy and commitment cost components separately based on whether the resource test for energy (non-competitive congestion component) fails and whether the resource tests (non-competitive commitment mitigation criteria) fails.

If the non-competitive commitment mitigation criterion for binding constraints or the non-competitive mitigation criterion for non-binding constraints fail then only the market-based commitment cost bids are mitigated. The market-based commitment cost bids are mitigated to the commitment cost reference levels.

The mitigation will apply consistently to internal constraints in the California ISO and Energy Imbalance Market Balancing Authority Areas and to the BAA level net transfer constraints where these constraints will either be binding or non-binding based on the flow.

Propose to calculate two residual supply indices: test binding for energy mitigation (existing) and test all critical constraints for commitment cost mitigation.

Local market power mitigation enhancements will test all critical constraints. Binding constraints are constraints where power flows are at a 100% versus critical transmission constraints, which are all constraints enforced in the unit commitment run. Currently the critical constraint limit is set at 85% or greater of the line limit in the prevailing flow direction.

California ISO does not propose to change the constraints that it tests for identifying uncompetitive constraints that trigger energy mitigation if resource has a locational advantage to exercise market power. Today, the California ISO tests binding constraints. Binding constraints are constraints where power flows are at a 100% versus critical transmission constraints that are constraints where power flows are at a level close to the line limit of the constraint in the prevailing flow direction[15].

The California ISO believes that to feasibly implement a second residual supply index that could capture the effect of "lumpy" minimum load energy levels on relieving constraints that a wider selection of constraints need to be evaluated than binding constraints. California ISO proposes to perform a second residual supply index calculation on all critical constraints.

Currently the configurable parameter defining critical constraints is set at 85% or greater of the line limit in the network application power flow analysis. Any constraint with a power flow in any pass of the network application is greater than 85% will be enforced in the final unit commitment run. The final set of critical constraints that will be tested for insufficient supply will be the union of all constraints critical in any pass of the power flow analysis for a given unit commitment run. This is the set of constraints that could result in a commitment in the unit commitment run.

To address the concern that for non-binding constraints there is unloaded capacity from the lumpy effect of the commitments resolving the constraint with excess capacity, the California ISO proposes to remove this excess demand of counterflow from the denominator of the residual supply index. For example, if a line has a thermal limit of 1,000 MW and there is 2,000 MW of prevailing flow on this constraint, the market will dispatch resources to provide counterflow to bring the line within its limit. If there is no discontinuity in the market, no minimum online constraints or forbidden operating zones that drive "lumpy" decisions then the market would dispatch 1,000 MW of counterflow. However, there is discontinuity in the market from these physical constraints, if the market dispatches 1,020 MW of counterflow due to a minimum online constraint then and the "excess" counterflow of 20 MW would fully resolve the constraint. California ISO believes to include this excess in the demand for counterflow calculation would be over accounting for this demand and will remove the excess so that the demand for counterflow for this constraint would be assessed at its 1000 MW – demand without discontinuity.

The California ISO will apply constraints tests consistently to internal constraints in the California ISO and Energy Imbalance Market Balancing Authority Areas and to the BAA level net transfer constraints where these constraints will either be binding or non-binding based on the flow. For net transfer constraints, the California ISO proposes to only apply the commitment cost mitigation test if there is import congestion into the EIM BAA (net power balance constraints with positive shadow prices) consistent with its testing for energy mitigation today.

Propose to continue exempting net buyers from potentially pivotal suppliers in energy mitigation but to allow both net buyers and net sellers to be potentially pivotal suppliers in commitment cost mitigation.

Currently, the DCPA identifies potentially pivotal suppliers versus fringe competitive suppliers based on total withheld capacity (WC) by supplier on a portfolio basis. DCPA assigns resources to suppliers based on the Scheduling Coordinator ID adjusted for registered tolling agreements, suppliers portfolios are identified in equations with subscript B. All resources made available to the day-ahead or real-time market that can be started to respond to a dispatch in a period tested will be evaluated whether committed

[15] Note the flow level defining critical constraints is a configurable parameter that is tuned to ensure the number of constraints included in that set does not adversely impact market performance since it requires treating these constraints differently than other non-binding constraints such as calculated and saves shift factors for these constraints.

in all constraints run or not. For energy mitigation, the California ISO excludes net buyers of energy from being potentially pivotal suppliers.

California ISO maintains its policy that for energy mitigation, net buyers of energy do not have an incentive to withhold capacity to inflate locational marginal prices. There is no incentive for a net buyer to inflate energy costs because it would be exposed to higher costs for its load than it receives for its generation if it inflated energy costs through high supply bids.

On the other hand, the California ISO allocation of bid cost recovery is done in a manner that would allow either net buyers or net sellers to have the incentive to withhold their capacity to inflate uplift. Net buyers of energy incur allocations of bid cost recovery based on their ratio share of system load. If they were exempt from commitment cost mitigation, there could be an incentive for net buyers to inflate their commitment costs bids because they would recover all of their commitment costs but only be allocated a share of the resulting bid cost recovery. California ISO proposes to not make a distinction between net buyers and net sellers.

Propose to account for potentially withheld capacity directly by including minimum load energy when appropriate.

The California ISO proposes to include in the dynamic competitive path assessment an evaluation of whether a resource is capable of shutting down in the interval tested. If the resource is capable of bidding in a manner to withhold their entire capacity (energy and commitment cost mitigation), then this is supply of counterflow that a potentially pivotal supplier could bid strategically to withhold and result in inflated energy prices or uplift payments. This proposed change will impact the assessment of withheld capacity and supply of counter flow. This will allow the market to accurately account for a resource's potential ability to withhold counterflow addressing an existing limitation in the market power mitigation design.

The minimum load energy (as re-rated or as revised through outage management system) would be accounted for in the withheld capacity and would be excluded from the supply of counterflow from potentially pivotal supplier that would be withheld if the resource has fulfilled its minimum run time (also called minimum up time) and is not a must run resource with either self-schedules or ancillary service awards.

The details will be included in business rules and business practice manuals. These implementation details may be refined in the future if it is determined that refinements are needed to better effectuate the policy described above.

5.2.2. Mitigate resources within a minimum online constraint

California ISO proposes to mitigate all resources within minimum online constraints. Once the *Contingency Modeling Enhancements* (CME) policy is implemented, the corrective capacity constraints will largely replace minimum online constraints for managing thermal constraints. However, the California ISO may still need to enforce minimum online constraints for issues such as managing reactive power or voltage requirements. Therefore, if the ISO enforces such constraints, it will mitigate those constraints in the LMPM process. As it does today. California ISO clarifies it considers minimum online constraints for reactive power or voltage requirements by definition "uncompetitive" because they are enforced for local issues and would likely include very few resources under the constraint.

5.2.3. Mitigate exceptional dispatches commitment costs

The California ISO proposes to enhance the default competitive path assessment for purposes of mitigating commitment cost bids associated with exceptional dispatches by using the new unit commitment residual supply index results for all critical constraints.

As explained in the *Exceptional dispatch Mitigation in Real-time* initiative approved by FERC in 2013,

> "*While this feature [dynamic market power mitigation] will greatly improve the accuracy of local market power mitigation within the market dispatch, it does introduce a gap in identifying and mitigating for Exceptional Dispatch that have local market power. This proposal addresses that gap through a separate set of path designations that are based on the dynamic designations and will be used in applying mitigation to Exceptional Dispatch. The proposal also extends the methodology to providing a set of default path designations that will be used as "back-up" in the event that the dynamic competitive path assessment within the market software fails to produce a valid set of path designations."16*

California ISO maintains the existing policy to ensure the default competitive path assessment effectively mitigates market power concerns related to exceptional dispatches. Today, the California ISO mitigates the energy bid on exceptional dispatches under Section 39.10 of the Tariff:

> *"The CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive Transmission Constraints; (2) ramping resources with Ancillary Services Awards or RUC Capacity to a dispatch level that ensures their availability in Real-Time; (3) ramping resources to their Minimum Dispatchable Level in Real-Time; and (4) addressing unit-specific environmental constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch"."*

The California ISO proposes to apply the same four conditions on the mitigation of the commitment cost bids. The California ISO proposes that the default competitive path assessment be enhanced to support two sets of default path designations: (1) for purposes of mitigating incremental energy portion of the exceptional dispatch (default energy designations) and (2) for purposes of mitigation of commitment costs associated with an exceptional dispatch (default commitment designations).

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[16] *Exceptional Dispatch Mitigation in Real-time* draft final proposal, available at: http://www.caiso.com/Documents/DraftFinalProposal-ExceptionalDispatchMitigationRealTime.pdf.

The first static list is the one maintained today, which determines path designations for purposes of applying mitigation to energy bid of the exceptional dispatch based on whether the dispatch is effective to a constraint deemed non-competitive on the binding list. The historical assessment determines which constraints should be deemed competitive for mitigating energy costs based on whether two thresholds are met otherwise it is deemed non-competitive. The two thresholds are:

- Congestion Threshold: Congested in 10 hours or more in the RTUC run where the dynamic competitive path assessment is calculated, and
- Competitive Threshold: Deemed competitive 75 percent or more of the instances where the constraint was binding and tested.

The California ISO proposes to add a second static list for commitment cost mitigation that leverages the existing exceptional dispatch mitigation process. The historical assessment will determine which constraints should be deemed competitive for mitigating commitment costs based on whether two thresholds are met otherwise it is deemed non-competitive. The two thresholds are:

- Congestion Threshold: Critical flow in 10 hours or more in the RTUC run where the dynamic competitive path assessment is calculated, and
- Competitive Threshold: Deemed competitive 75 percent or more of the instances where the constraint was critical and tested.

The current static list used to mitigate the energy bids of exceptional dispatches is based on 60 days of historical data and has proven to be an effective sample size. The California ISO has not identified concerns with using 60 days of historical data and proposes given its experience and satisfaction with this approach to use the same date range and update frequency for mitigating the commitment cost bids of exceptional dispatches. The California ISO is not proposing any changes to the size of the historical dataset and frequency of maintaining these static lists. The current tariff codifies these requirements so that the data for the test statistics will reflect the most recent 60 days of trade dates available at the time of testing to focus application on more seasonal conditions and that this set of designations will be updated not less frequently than every seven days to reflect changes in system and market conditions.

The California ISO believes with these proposed enhancements to the default competitive path assessment and the application of mitigation in the other three instances described in Section 39.10 that there should be sufficient market power mitigation protections proposed to support increasing flexibility to support market-based commitment cost bids.

5.2.4. Settle exceptional dispatches at commitment cost bids considered in initial instruction for the instruction period

Several stakeholders requested the California ISO clarify how the real-time market re-bidding rules interact with exceptional dispatches[17]. As described above, the re-bidding rules established that suppliers without integrated forward market awards or binding residual unit commitment start-up instructions may re-bid their commitment costs until receiving a binding real-time market instruction. For the purpose of

[17] Note this proposal applies to energy imbalance market manual dispatches. At the time the EIM entity determines a manual dispatch is needed the commitment cost bids in the market at that time will be the values used for California ISO settlement.

treating resources who receive an exceptional dispatch similarly, California ISO proposes that the settlement of exceptional dispatches would be set at the commitment cost bid considered by the California ISO when it issued the exceptional dispatch. The California ISO will settle these exceptional dispatches using commitment cost bids considered when the initial decision was made and not settle the resource based on revised bids submitted through the instruction period. If exceptionally dispatched when there are no commitment costs or energy bids, the California ISO proposes that the bid cost used in the exceptional dispatch payment will follow the "no bid" process.

5.2.5. Settle resources in full ramp at the bid used in the interval

California ISO analyzed its bidding and settlement rules that exist to mitigate inter-temporal market power concerns and identified a need to settle resources dispatched down or up at full ramp to settle at bid at the start of the ramp period. California ISO proposes to settle these resources at the bid used in the interval at the start of the ramp down period.

While it introduced real-time re-bidding rules in 2016 that largely mitigated inter-temporal market power concerns it has identified that its treatment of resources bids when in full ramp need to be addressed. When resources are in full ramp, the market has already issued the shut down or full ramp instruction and changes to the commitment cost bids after the interval where the ramp down or up begins cannot influence the market solution. Therefore, any changes after the full ramp period begins are not appropriate to include in the settlements. Currently, the California ISO has similar rules for residual imbalance energy and proposes to extend the protection to commitment cost bids.

5.3. Reference levels

The purpose of this section is to describe the California ISO proposal to improve its administratively calculated reference levels and to maintain select measures from the *Aliso Canyon Gas-Electric Coordination Phase 1* initiative. California ISO proposes to enhance its calculated reference levels to represent better an estimate of suppliers' cost expectations through improving the commodity price used in the gas price index and ensuring the generic formulas produce robust cost estimates. The California ISO also proposes to make permanent the California ISO practice of sending scheduling coordinators the D+2 residual unit commitment advisory schedules report to assist in planning gas procurement. Finally, the California ISO proposes to continue to use the next day gas commodity price index published the morning of the day-ahead market in its day-ahead market.

The California ISO will describe its proposal as follows:

- Improve commodity price in gas price index
- Formulate energy cost reference levels
- Formulate commitment cost reference levels

5.3.1. Improve commodity price in gas price index

California ISO proposes to make permanent the *Aliso Canyon Gas-Electric Coordination* temporary measure that allows the California ISO to update manually the commodity price used in day-ahead market to calculate the day-ahead gas price index based on an approximation of the next day gas price index available off webICE between 8:30 and 9:00 Pacific Time. This next day gas index would be used for calculating the day-ahead gas price index – a key input into the day-ahead reference level calculations.

Accordingly, the California ISO proposes to make permanent the practice of calculating the day-ahead gas price index (GPI) input to the day-ahead reference level formulations using the approximation of the next day gas commodity price available the morning of its day-ahead market, called the GD2 index (shown in ***Equation 2: Gas Price Index for Delivered Gas Price Estimate***). This proposal is broadly supported by the stakeholder community given the benefits it has brought to the market through making the reference levels more relevant and accurate. The GD2 next day index is the Intercontinental Exchange commodity price index published for gas traded the morning of the day-ahead market for delivery the following day beginning at 7AM Pacific (exceptions around weekends and holidays). This printed index price is a volume weighted average price of trades done during ICE's next day window.

Under *Aliso Canyon Phase 1,* the California ISO has implemented the use of an approximation of the next day gas commodity price index for gas procured the morning on the day prior to its electric operating day for gas day beginning at 7AM Pacific during the operating day. The California ISO pulls an approximation of the ICE next day gas commodity price index made available to it via webICE platform. Additionally, the California ISO stopped performing its previous "manual gas price spike procedure" since an approximation of the next day gas commodity price index would now be routinely used in the day-ahead market.

In the event the California ISO process for pulling the approximation of the commodity price from webICE fails the morning of the day-ahead market, California ISO proposes that it will be appropriate for its systems to fall back to the average of the published indices for the prior day's next day gas commodity price index published the morning of the day prior to its day-ahead market for gas flows beginning the morning of its day-ahead market. This is a current practice under temporary authority.

5.3.2. Formulate energy cost reference levels

The California ISO proposes that the formulation for the energy reference levels will be calculated consistently for all market purposes including generating or inserting bids. For its energy cost reference levels, suppliers will continue to be able to elect either the estimated proxy cost option (variable), LMP, or negotiated option (with variations of these options available for resource adequacy import resources). Currently, generated energy bids are all based on a similar approach as the estimated proxy cost option and a resource's reference level selection is only used to select the energy cost reference level used in market power mitigation (with an exception for resource adequacy import resources). The California ISO proposes to modify this approach by generating energy bids based for all resources on the reference level option selected by the supplier.

5.3.3. Formulate commitment cost reference levels

The California ISO proposes to support two options for the commitment cost reference levels - negotiated and estimated proxy cost options.

5.3.3.1. Support estimated proxy cost option

California ISO proposes to support an estimated proxy cost option that largely leverages the existing proxy cost estimate used for validating the cost-based commitment cost bids under current bidding rules. The California ISO proposes enhancements to the existing formulations to ensure the estimates represent a reasonable reflection of cost expectations based on information available to the California ISO.

California ISO proposes to support commitment cost reference levels that:

- Include headroom scalar to account for incidental costs above fuel cost proxy:

  Under the proposed policy, the commitment cost reference levels (i.e. proxy costs) will include a headroom scalar, similar to the existing approach for energy cost reference levels (i.e. default energy bids). The headroom scalar is intended to account for incidental costs not captured in the California ISO estimate. Note that these incidental costs are not intended to account for fuel price volatility (fuel price volatility under the approach described in this proposal will be accounted for by suppliers requesting reference level adjustments).

  Currently, the California ISO includes a 110% headroom scalar in its energy cost reference level and believes including it in its commitment cost reference levels allows for the same inclusion of incidental costs. These headroom scalars also act as a conservative margin of error in the estimates. Ideally, the headroom scalars used to calculate the reference level should be at the same level in each bid component since it serves the same intent in each calculation.

  Currently the California ISO has a cost-based cap on commitment cost bids of 125% of commitment cost reference levels that is intended to account for both incidental costs not included in the estimate and fuel price volatility. Since fuel price volatility under the approach described in this proposal will be accounted for by suppliers requesting reference level adjustments, a 110% commitment cost headroom scaler, the same as for energy cost reference levels, will be more appropriate.

  The California ISO proposes to initially set the headroom scalar in the commitment cost reference levels at 125%, the same as the current bid cap, as a temporary phase-in measure to allow time to evaluate the effectiveness of the new dynamic commitment cost mitigation. Relevant to the headroom scaler, this will allow time to ensure the dynamic commitment cost market power mitigation is not mitigating when market power in fact does not exist which if immediately mitigating to reference levels that only include a 110% headroom scalar would make resources worse off than the current approach. The California ISO proposes to automatically decrease the scalar from 125% to 110% in 18 months after the effective date. The California ISO will launch a stakeholder process to analyze the mitigation performance after 12 months of data are available. If design issues are identified leading to high commitment cost mitigation test false positives or false negatives, California ISO would file to delay the automatic decrease, and the automatic increase in the commitment cost circuit breaker bid cap, to allow for California ISO and its stakeholders to evaluate and address identified issues.

- Include minimum load costs for run hours unassociated with energy provision:

  California ISO proposes that minimum load cost bids of all supply resources[18] should have the ability to include costs unassociated with energy output at minimum load. In the stakeholder process, stakeholders expressed concerns regarding the existing approach which restricts run hour costs and finds that there may be scenarios where resources may have costs unassociated with

[18] Supply resources refers to resources eligible to submit market-based or cost-based bids under the California ISO Tariff, which will include Generating Units, Participating Load, Reliability Demand Response Resources, Proxy Demand Resources, or Non-Generating Resources.

energy provision that they incur on an hourly basis for each hour that the resource is available. For example, even though demand resources may have a zero MW minimum load output level, they may incur hourly costs to commit the resource and have it ready to respond to a real-time market energy dispatch.

California ISO proposes that resources that elect the estimated proxy cost option may register run hour costs unassociated with energy output that are incurred on an hourly basis. California ISO proposes to have audit authority for these values to ensure these are based on cost expectations based on defined criteria.

- Include opportunity costs for eligible limitations as adder above headroom scalar:

  The California ISO proposes to include opportunity costs as developed in the *Commitment Cost Enhancements Phase 3 (CCE3)* policy initiative as an adder above the headroom scaler for both commitment cost and energy cost reference levels.

  The California ISO proposes to calculate the estimated proxy cost option for energy cost reference levels (DEBs) consistent with its policy for calculating reference levels that include opportunity costs as developed in *Commitment Cost Enhancements Phase 3 (CCE3)*. With CCE3 implementation, energy reference levels (DEB) will include an opportunity cost adder either calculated or negotiated on top of the values scaled using the headroom scalar. Equations Equation 3, Equation 4, and Equation 5 show the methodology for the inclusion of the opportunity cost adder on top of the headroom scalar.

  The California ISO proposes to calculate its commitment cost reference levels so that they include the opportunity cost for eligible energy output, run hour, or start limitations on top of the reference levels including the headroom scalar. Consistent with CCE3 policy, the California ISO proposes that the minimum load reference level will include calculated or negotiated opportunity costs for eligible energy output limitations if the resource has a positive minimum load or eligible run hour limitations; start-up reference level will include calculated or negotiated opportunity costs for eligible start limitations; and transition cost reference levels will include calculated or negotiated eligible opportunity costs on the 'To' configuration.

With the combination of the enhancement of improving its day-ahead gas price index and these enhancements to improve its estimated proxy cost option for commitment costs, the California ISO believes it can provide robust estimates of expected costs to use on a routine basis for majority of resources.

The details will be included in business rules and business practice manuals. These implementation details may be refined in the future if it is determined that refinements are needed to better effectuate the policy described above.

5.3.3.2. Extend negotiated option

For resources with unique costs that may require more complex formulations, the California ISO proposes to extend its existing negotiated reference level option to commitment cost reference levels. The current provisions for negotiated default energy bids are found in the California ISO Tariff Section 39.7.1.3.1. The California ISO plans to extend the existing process to commitment costs.

This extension of the negotiated option will allow the California ISO to develop tailored reference levels across the entire supply bid that the California ISO can calculate on a routine basis to capture a resource's unique costs. The California ISO already provides this flexibility to suppliers for energy bid reference levels through the negotiated option for energy cost reference levels. The California ISO supports the negotiated rate option for purpose of reflecting systematic differences in cost formulations where suppliers have unique circumstances not captured by generic reference levels. The California ISO will not support negotiations on transition cost reference levels as the existing approach for the estimated proxy cost option for transition costs will already include the negotiated start-up cost values and the definition of transitions will continue to be the difference between start-ups of two different configurations of a multi-stage generator.

This design change will provide consistent levels of flexibility for relevant cost inclusion calculated on a routine basis for the entire supply bid. California ISO believes expanding its reference level design to also support negotiated commitment cost reference levels, as it currently supports for energy reference levels, is an appropriate approach to better reflect individual resources unique cost formulations for the entire bid.

Suppliers would be able to seek consideration of tailoring its reference level to reflect more complex cases than a generic reference level formula could. The ISO proposes the following general principles to administer the negotiations across the supply bid subject to sufficient justification:

- Support complex formulations of delivered fuel price especially for fuel-switching resources and resources that have opportunity to procure fuel from multiple locations or to transport fuel supplies across multiple pipelines
- Support complex formulations of delivered fuel price that do not assume the next day gas index is the appropriate price benchmark for the resource (i.e. fuel replacement costs).
- Include additional cost components not included in the generic reference level formula
- Exclude risk margin(s) for risks of undermining gas pipeline instructions or for cash-out risk
- Exclude price information outside of non-published indices since on a routine basis only benchmarks based on published indices that are appropriately monitored is appropriate

As part of this initiative's stakeholder process, the Department of Market Monitoring sought clarification on the process and to identify what cost components would be eligible for negotiation. The California ISO clarifies that at a minimum, the negotiation would include the cost components included in the California ISO's existing proxy commitment cost estimates. If a supplier believes additional components to its calculations are appropriate, the supplier would have to justify including these additional components as part of the negotiation. The California ISO proposes that all components of supply bid reference levels (i.e. start-up, minimum load, and energy costs) must be calculated under the negotiated option if a supplier seeks to negotiate any component. This is because generally these negotiations focus on the fuel or fuel equivalent cost input and the negotiated approach should be consistent across the bid (the start-up, minimum load, or energy reference levels).

Adding the negotiated option alone does not fully accommodate the appropriate level of bidding flexibility since significant changes in price volatility in real-time is largely observed in broker markets or between counterparties trading off the Intercontinental Exchange's electronic trading platform. Further, on an exceptional basis when conditions warrant, the ISO finds it appropriate for suppliers' valuation of fuel price to change to reflect fuel availability. Under these conditions the California ISO would prefer the supplier be able to request an adjustment to its reference levels or reflect the risk in their bids so the ISO dispatch can consider the scarcity in finding the optimal solution. The appropriate tool for reflecting the fuel insufficiency condition is through leveraging the California ISOs proposed ex ante reference level adjustments.

5.4. Supplier submitted reference level adjustments

California ISO proposes to allow market-based bids for each component of the supply resources'[19] bid subject to mitigation and allow suppliers greater flexibility to negotiate or adjust reference levels for each supply bid component. The purpose of this section is to describe the California ISO proposal to allow greater flexibility to negotiate or adjust each component of supply bid reference levels.

The ISO will describe its proposal for supplier submitted reference level adjustment as follows:

- Support verified, ex ante reference level adjustments
- Support ex ante verification
- Support ex post cost recovery
- Re-calibrate penalty price parameters

5.4.1. Support verified, ex ante reference level adjustments

California ISO proposes to allow suppliers to submit ex ante adjustments to its reference levels for start-up cost, minimum load cost, or energy costs[20]. Reference level adjustments are necessary to address the need to update reference levels based on changes in fundamental drivers that arise on an exceptional basis and that do not routinely impact a resource's cost expectations. The supplier can request an adjustment to deviate from the estimates, which are only designed to serve under largely stable conditions[21]. The feature would be used when conditions arise that drive the suppliers' cost expectations away from the administratively calculated cost estimates – negotiated or estimated.

The California ISO proposes to require these submissions to be based on cost expectations given contemporaneous information available to the supplier. It will not be consistent with these guidelines to submit requests to adjust any component by strategically bidding near the reasonableness threshold to inflate market revenues or uplift. California ISO will reserve the right to verify these guidelines were followed in submitting ex ante adjustments to mitigate risk that a supplier may misuse the tool to adjust reference level to values that include costs outside of a cost-based bid through the ex-ante (using automated screen), ex post, and potentially perform an audit on frequently submitted and approved

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[19] Supply resources refers to resources eligible to submit market-based or cost-based bids under the California ISO Tariff, which will include Generating Units, Participating Load, Reliability Demand Response Resources, Proxy Demand Resources, or Non-Generating Resources.

[20] California ISO will not support adjustment requests to the transition component. Instead, a supplier should submit the request to adjust the start-up costs of the multi-stage generators configurations. The verified amounts will be used in the estimated proxy cost option for transition costs.

[21] This proposal for adjustments to energy cost reference levels is the vehicle for submitting cost-based energy offers above $1,000 subject to verification requirements required under FERC Order 831

adjustments. In the event the California ISO identifies a supplier may be strategically bidding in this manner it will consider a referral to FERC.

Suppliers must be able to support sufficient justification for need to request a reference level adjustment as reference level adjustments must be based on reasonable cost expectations based on actual current information. Supporting documentation will be required to support there is justification for adjusting suppliers' reference levels. Suppliers will not be required to submit this documentation for every adjustment request but it must be available upon the California ISO request. The supporting documentation should indicate a fundamental driver is driving cost expectations to depart from California ISO estimates. The supporting documentation should be contemporaneous information used to:

- Support need for departure from California ISO cost estimates,
- Support which component of costs are impacted by the changes in fundamental drivers or operational needs, and
- Support monetary amount included in adjustment.

California ISO proposes the following list as a non-comprehensive list of appropriate supporting documentation:

- Market price information Supply bids reflecting fuel price volatility will be supported in day-ahead or real-time for cost-based bids that exceed the reference level calculated by the California ISO. Supporting documentation may include index publisher information (consummated low-mid-high), electronic platform information (bid-ask spreads), or off-ICE quotes. Suppliers must have documentation consisting of at least three quotes. The California ISO will assume reasonable pricing excludes the highest quote unless the supplier documents conditions that reasonably required it to procure the highest quote. Suppliers may document less than three price quotes if they document conditions that made it unable to obtain three quotes. California ISO adopts a principle that suppliers should pursue a good faith effort to obtain these quotes.
- Pipeline documentation: Real-time supply bids reflecting risk margin or scarcity value needed to support reliability on upstream fuel systems only eligible for adjustments in hours after 4PM Pacific under scenarios where gas pipeline instruction has been released or gas system capacity levels are insufficient to deliver fuel supply to avoid violating a gas pipeline instructions. If based on notice of fuel transport flow orders, California ISO proposes a reasonable monetary adjustment would be to adjust the delivered gas price estimate from the next day index used in the cost estimate up by adding the non-compliance charge associated with the specific level of flow order associated with hours between TD HE17 and TD HE24. Under fuel market or transport availability conditions[22] documentation may include current line pack levels or other pipeline capacity reports, notice of fuel transport flow orders (e.g. OFO, EFO), or fuel scarcity conditions (e.g. "can't find counterparty").

[22] While fuel market or transport availability conditions may impact market prices triggering need for the "fuel market price conditions" request categories, this second category is for instances when the market price – on and off ICE – does not reflect the fuel constraint. Documentation required for any cost-based components priced based on fundamentals outside of market price information.

- If supplier is basing delivered gas price off of procurement locations other than standard procurement location or based on additional costs likely to be incurred due to deliverability or capacity limitation on the fuel system, California ISO will support inclusion of other procurement locations or additional fees for items such as backhauling fees. This support is contingent on supporting the constraint by submitting current line pack levels or other pipeline capacity reports.
- Fuel-switching resources to revise reference level to reflect the higher cost fuel if the resource needs to switch to that prime mover to continue to provide power and effectively allow for improved ability for California ISO to support reliability
- Fundamental drivers affecting non-gas units "fuel" or "prime mover" equivalent that will require documentation supporting exogenous factor is impacting ability to produce energy changing non-gas fuel equivalent costs from those registered in Master File. Supporting documentation will be required.

The California ISO proposes to require subjecting adjustments on either commitment cost or energy cost reference levels to verification requirements[23] prior to the market run (ex-ante verification) and if unable to verify in time will verify afterward whether costs were incurred above the adjusted reference level (ex post verification)[24]. California ISO also proposes that the adjustments on commitment cost reference levels should not be subject to any backstop or "circuit breaker" caps while the adjustments on energy cost reference levels will be subject to a $2,000/MWh cap for purpose of setting locational marginal prices.

California ISO notes that FERC Order No. 831 limits the ability of verified cost-based bids – verified reference level adjustments – to set locational marginal prices but requires the ability for uplift settlements if supplier can verify actual costs even at levels above $2,000/MWh. California ISO proposes that the adjustments to energy cost reference levels will be accepted at any price level, subject to screening against a reasonableness threshold, similar to for the rules for commitment costs, but with nuances to their treatment as to whether they can set locational marginal prices or only be eligible for ex post cost recovery.

While the California ISO proposes to allow reference level adjustments on the entire value, these will be required to be based on variations of the fuel cost or fuel cost equivalent components. The California ISO arrived at this decision after reflecting on comments from WPTF that the CAISO should not pursue market enhancements only applicable to gas-fired units given increasingly diverse resources in the market. The California ISO believes allowing adjustments on the reference level instead of changes to the fuel input will provide flexibility in a technology agnostic manner.

The California ISO proposes that the guidelines should not provide specific conditions that would warrant suppliers' requesting adjustments but allow for some flexibility to expand these guidelines as the California ISO gains experience or as the fleet changes in the future. The ISO proposes that the overarching principle for these guidelines be that suppliers should be able to utilize this tool to reflect

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[23] Verification requirements proposed were developed to also comply with Order 831.

[24] Suppliers will be eligible for after-the-fact uplift resettlement for energy costs incurred above the $2,000/MWh if the actual costs can be verified.

changes in their expected fuel or fuel equivalent costs to reflect changes in fundamental drivers that impact the fuel equivalent costs of non-gas fired resources.

California ISO has developed an initial process flow diagram to support stakeholders and the California ISO in evaluating the feasibility of the proposed verification requirements[25]. This process includes collaboration between California ISO and the DMM. Additional details are available in Appendix D: Proposed guidelines for ex ante adjustment requests and verification processes. The details will be included in business rules and business practice manuals. These implementation details may be refined in the future if it is determined that refinements are needed to better effectuate the policy described above.

5.4.2. Support ex ante verification

The CAISO proposes to perform ex ante verification through evaluating the reference level adjustment requests through an automated screen comparing the adjusted value against a reasonableness threshold. The reasonableness threshold establishes a level up to which the CAISO will automatically verify a reference level adjustment as a reasonable reflection of a suppliers' cost expectations. California ISO will establish reasonableness thresholds as follows:

- For gas resources: Calculate reference levels with scaled gas price indices and resource-specific feedback loop inputs[26]. The scaled gas price indices are calculated by applying a volatility scalar to the next day commodity price. The volatility scalars will vary depending on the day. For Monday and days without a published index when the market would fall back on the prior day's published index (e.g. weekdays after holidays), the volatility scalar will be 125%. For all other days the volatility scalar will be 110%.
- For non-gas resources: Calculate reference levels with scaled fuel equivalent costs and resource-specific feedback loop inputs. The scaled fuel equivalent costs are calculated by applying a volatility scalar to Master File registered fuel equivalent cost values. The volatility scalar will be 110%.

The resource specific feedback loop inputs will be based on systematic positive differences between a resource's actual fuel or fuel-equivalent costs exceeding the gas price indices or fuel equivalent costs used by the CAISO.

For commitment costs, if the adjustments fall below the reasonableness threshold then the California ISO will accept the reference level adjustment automatically. If the adjustment request is higher than the reasonableness threshold then the California ISO will limit the adjusted reference level to the reasonableness threshold and send the original adjustment request to the ex post verification process. For energy costs, if the energy adjustment falls below the reasonableness threshold, the California ISO will accept the reference level adjustment automatically. If the adjustment is higher than the lower of the reasonableness threshold or cost-based cap at $2,000/MWh then the California ISO will adjust the

[25] The process flow diagram is available at: http://www.caiso.com/Documents/ProcessFlow-CommitmentCosts_DefaultEnergyBidEnhancements.pdf.

[26] Resource-specific feedback loop term is a percent multiplier on the reference level that would allow tuning based on observed actual costs verified through the ex post review process.

reference level adjustment to the lower of the reasonableness threshold or the cost-based bid cap and send the original adjustment request to the ex post verification process.

California ISO proposes to introduce a manual verification process for requests above $1,000/MWh. CAISO will allow suppliers to pursue a manual consultation for reference level adjustments for energy costs above $1000/MWh. The consultation should follow the requirements for developing a reference level adjustment and sufficient supporting justification. If verifiable prior to the market close then the verified value will be the adjusted reference level value.

If a market-based bid is submitted at levels lower than the cost-based bid, the California ISO will use the market-based bid. This is an existing practice to use the lower of the bid or the reference level. For bids above $1,000/MWh, the California ISO will support bids above $1,000/MWh but they must be backed with either an administratively calculated reference level above $1,000/MWh or the submission of a reference level adjustment request. The California ISO will limit energy bids to the lower of the $2,000/MWh cap or the higher of the $1,000/MWh cap or the reference level as calculated or adjusted. Any adjustment requests capped at levels lower than the request will be eligible for ex post review.

<u>Verify demand response resources under FERC Order No. 831</u>

California ISO proposes that demand response resource should have the same flexibility to submit reference level adjustments as a generating resource. The ex-ante and ex post verifications for demand response resources will ensure customer opportunity costs[27] form the basis of both ex ante and ex post verification. In the Order on Rehearing and Clarification regarding FERC Order No. 831, FERC clarified that opportunity costs are actual costs.

For validating the reference level adjustment requests, demand response resources will be subject to the same validation rules as generating resources. For energy adjustment request, the requests will be verified up to the lower of the reasonableness threshold or the $2,000/MWh cost-based bid cap.

<u>Reliability Demand Response Resources (RDRR) under FERC Order No. 831</u>

Some stakeholders sought a specific statement from the California ISO on the interaction of this proposal to allow cost-based bids above the market-based offer cap set at $1,000/MWh to a California Public Utility Commission settlement on reliability demand response resources (RDRR) that set bid price of RDRR at 95%-100% of the bid cap. The bid cap referenced is the current $1,000/MWh bid cap that is the circuit breaker bid cap on market-based bids. Like all resources, if the cost expectations were to exceed the $1,000/MWh cap for either day-ahead or real-time, RDRR would be able to utilize the ex-ante reference level adjustment tool.

In day-ahead, RDRR are eligible to submit economic bids consistent with market rules. Therefore if a RDRR submits a request to adjust its reference level in the day-ahead market, the market will accept this as long as it meets the validation rules that limit energy bids to the lower of the $2,000/MWh cap or the higher of the $1,000/MWh cap or the reference level as calculated or adjusted.

In real-time, RDRR are not eligible to bid economically. RDRR resources will not be selected for normal dispatch unless one or more of the following conditions occur:

[27] Customer opportunity costs is associated with foregoing whatever end use the energy would have been used for.

- For system emergencies, including
- Transmission emergencies; and
- Mitigating imminent or threatened operating reserve deficiencies
- For resolving local transmission and distribution system emergencies.

CAISO operator may choose to activate a software flag which will allow these resources to be dispatched. Likewise, after the condition has ended and conditions have stabilized, the operator will reset the flag which will prevent the resources from being dispatched, other than to their day-ahead awarded value. The California ISO will activate these bids in the software based on either the marginal real-time dispatch option (Section 30.6.2.1.2.1) or the discrete real-time dispatch option (Section 30.6.2.1.2.2). For both options, the California ISO proposes to revise the bid price requirements for RDRR to require either a single-segment bid or a multi-segment bid in real-time that must be at least 95% of the market-based cap at $1,000/MWh and can be no greater than the lower of the $2,000/MWh cap or the higher of the $1,000/MWh cap or the reference level as calculated or adjusted.

<u>Verify non-resource specific intertie transactions and virtual resources under FERC Order No. 831</u>

California ISO proposes to exempt non-resource specific intertie transactions and virtual resources from the verification requirements. FERC Order No. 831 does not require verification to be performed on reference level adjustment requests. Non-resource specific intertie transactions and virtual resources will be able to utilize the reference level adjustment tool where energy adjustment requests will be limited to the $2,000/MWh cost-based cap.

<u>Suppliers without market-based rate authority</u>

For resources without market-based rate authority, the California ISO will allow these resources to request reference level adjustments since these are cost-based bids. California ISO will subject these requests to the ex-ante verification against the reasonableness threshold. In addition to limiting an adjustment request if it exceeds the reasonableness threshold, the California ISO will automate a market-based cap for suppliers without market-based rate authority to the adjusted reference levels. In this way, the supplier can submit a cost-based bid and market-based bids at the same level and fulfill its requirement to only submit cost-based bids under the California ISO’s cost-based bid design.

5.4.3. Support ex post cost recovery

California ISO proposes to make eligible for ex post review and after-the-fact cost recovery any reference level adjustment request that was limited because the amount exceeded the reasonableness threshold. The proposal will leverage the existing process for the after-the-fact cost recovery filings. After-the-fact recovery will be for actually incurred costs that exceed either a cap or mitigated price level, which may not include any adders above cost such as risk related adder, unrecovered through market revenues.

The supplier must notify the California ISO within thirty (30) business days after the operating day on which the resource incurred the unrecovered costs (actual costs), whether it seeks a California ISO ex post review of its actual costs or if it will proceed directly to a FERC filing. If the supplier does not seek a California ISO ex post review it must submit the filing to FERC within ninety (90) business days after that trading day otherwise the supplier will be subject to ex post review at California ISO prior to having a filing deadline.

Within sixty (60) Business Days after the trading day for which the supplier provides notice to the California ISO per this Section, the California ISO will provide the Scheduling Coordinator with a written explanation of any effect that events or circumstances in the California ISO markets and fuel market conditions may have had on the resource's inability to recover the costs on the Trading Day. If the supplier also elected a California ISO ex post review, the California ISO will also notify the supplier if it is eligible for an ex post review based on whether it had a reference level adjustment that was limited by the reasonableness threshold. If the California ISO is unable to verify a limited reference level adjustment it will extend the requirement for filing at FERC until 30 days after the ex post review is complete.

California ISO proposes that each ex post review the supplier submits to the California ISO must include all the information required to be submitted at FERC plus additional information to assist the California ISO review. The documents will include:

(1) Data supporting the supplier's claim to the unrecovered costs it seeks, including invoices for the unrecovered costs;

(2) A description of the resource's participation in any gas pooling arrangements;

(3) An explanation of why recovery of the costs is justified; and

(4) Notification of gas pipeline instructions, if applicable.

The California ISO will first review the submission to determine if the request required immediate fuel procurement due to constrained conditions. The California ISO will verify that the submitted invoice(s) are dated after the market that produced relevant award where gas balancing rules did not allow delay in procurement. Further, the California ISO will require an attestation that no pooling arrangement or balancing rules would allow other than immediate procurement. California ISO will verify whether gas rules would have allowed additional time for procurement, if immediate procurement is required then the California ISO would verify the costs otherwise it would not verify.

California ISO will not support cost recovery for non-compliance charges incurred in response to a market dispatch because it has no method of identifying authorized or unauthorized gas. California ISO maintains its policy that suppliers need to seek recovery from the gas company for these charges where the gas company may choose to waive the charges.

California ISO will not be supporting ex post review of non-gas resources at this time. Until specific circumstances and experience can be gained on how to verify actual costs for such resources, the California ISO will limit the verification to the ex-ante review. Non-gas resources that have opportunity costs are limited to calculated or negotiated opportunity cost adders developed under *Commitment Cost Enhancements Phase 3.*

Given the proposal that the California ISO support an ex post verification of actual costs, the California ISO believes it prudent to retain the option for stakeholders to seek after-the-fact cost recovery at Federal Energy Regulatory Commission in the event that the California ISO cannot verify the request for uplift re-settlement based on actually incurred costs.

California ISO proposes to make permanent the 205 filing right at FERC for actual energy costs exceeding the energy adjustment cap or the mitigated price at its energy cost reference level that were unrecovered through market revenues. This policy was initially proposed and stakeholdered under *Aliso*

Canyon Phase 1. The revised draft final proposal in *Aliso Canyon Phase 1* proposed "cost recovery filing opportunity for incurred marginal procurement costs associated with providing incremental energy."

While this is currently effective in the California ISO tariff, the provision is temporary. California ISO proposes to make permanent this opportunity to complement the already permanent tariff language for a cost recovery filing opportunity for incurred commitment costs above commitment cost caps unrecovered through market revenues. California ISO notes that the filing right at FERC will not be limited to instances where the reference level adjustment request was limited but consistent with the current temporary tariff language.

5.4.4. Re-calibrate penalty price parameters

California ISO will support reference level adjustments up to $2,000/MWh in every market run therefore it proposes to re-calibrate its penalty price parameters to be appropriate for the increased $2,000/MWh cap. Table 3below shows each market run, the parameter or sequence that is currently codified in the Tariff, current value, and finally the proposed revised values. The California ISO has reviewed the priority sequence and is not proposing any changes to the sequence. After reviewing the values for the internal and intertie transmission constraint scheduling parameter, the California ISO will propose to amend its tariff to reflect the proposed revised values.

Market Run	Parameter or Sequence	Current Value	Revised Value
IFM	Internal and Intertie Transmission Constraint scheduling parameter	$5,000/MWh	**$10,000/MWh**
RUC	Internal and Intertie Transmission Constraint scheduling parameter	$1,250/MWh	**$2,500/MWh**
RTM	Internal and Intertie Transmission Constraint scheduling parameter	$1,500/MWh	**$3,000/MWh**
IFM	Priority sequence for reduction of self-scheduled LAP demand	No policy change required to priority sequence.	
IFM	Adjustment sequence to non-priced quantities	No policy change required to priority sequence.	
RTM	Adjustment sequence to non-priced quantities	No policy change required to priority sequence.	

Table 3: Proposed penalty parameter changes

California ISO proposes to retain the relative priority of the internal and intertie transmission constraint penalty prices at 500% of cap in integrated forward market (IFM), 125% of cap in residual unit commitment (RUC) process, and 150% of cap in the real-time market (RTM). This proposal adopts the assumption that the relative difference between the current values for the internal and intertie transmission constraint scheduling parameter relative to the current $1,000/MWh offer cap is the appropriate relationship between these parameters and the cap.

6. Energy Imbalance Market classification

The California ISO proposes that this initiative should involve the EIM Governing Body's advisory role to the Board of Governors.

Some stakeholders, PGE and NVE believe it appropriate for the Energy Imbalance Market Governing Body to have an approval role for this initiative since it could have a unique effect on Energy Imbalance Market (EIM) participants. The California ISO disagrees. The California ISO continues believe this initiative involves an advisory role for the EIM Governing Body as the initiative is proposing changes to generally applicable real-time market rules.

This initiative affects the day-ahead and real-time market rules where the real-time market rules will affect the Energy Imbalance Market entities. These rule changes to ensure consistency and support of an efficient market will need to be applied across the California ISO market, including the EIM, so that the least cost solution produced is assessing costs based on similar principles. Accordingly, the California ISO does not anticipate carving EIM specific scope items out from the overarching design making any proposed changes "generally applicable".

Arizona Public Service Co. asked for clarity on which aspects of this proposal impact the Energy Imbalance Market Entities in their comments on the revised straw proposal. California ISO would like to clarify that this initiative will affect EIM entities as the proposed changes all apply to the real-time market.

Appendix A: Stakeholder Engagement Plan

Commitment Costs and Default Energy Bid Enhancements (CCDEBE) will be going to the March 2018 EIM Governing Body and California ISO Board of Governors meeting. Current schedule for this initiative is shown in Table 4.

Milestone	Date
Issue paper posted	November 18, 2016
Stakeholder call	November 22, 2016
Stakeholder written comments due	December 9, 2016
Straw Proposal Posted	June 30, 2017
Stakeholder meeting	July 6, 2017
Stakeholder written comments due	July 20, 2017
Revised straw proposal	August 1, 2017
Stakeholder technical workshop	August 3, 2017
Stakeholder written comments due	August 15, 2017
Draft final proposal posted	August 23, 2017
Stakeholder call	August 30, 2017
Stakeholder written comments due	September 11, 2017
Revised draft final proposal posted	January 30, 2018
Stakeholder call	February 1, 2018
Stakeholder comments due	February 20, 2018
Second revised draft final proposal posted	March 2, 2018
Stakeholder comments opportunity at Market Surveillance Committee meeting	March 5, 2018
EIM governing body meeting	March 8, 2018
Board of Governors meeting	March 21-22, 2018

Table 4: Initiative Schedule

Appendix B: Proposed revisions to cost and bid definitions

California ISO proposes to ensure its market rules and reference level calculations accurately capture cost expectations of gas and non-gas resources. California ISO systems will need to be able to support minimum load costs even for resources without minimum load energy that incur run hour costs. Consequently, the California ISO proposes to revise its supply bid component definitions to be more technology agnostic. Further, the California ISO will define the market-based and cost-based bid components providing clarity for bidding.

Proposals to revise its definitions for to be more technology agnostic

The text in the following revisions is intended to convey the intent of the revised definitions. The actual text may be modified in the tariff development process.

<u>Proposed revisions to revise "Energy":</u>

"The electrical energy *provided*, flowing or supplied by *resources*, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc."

<u>Proposed revisions to revise "Minimum Load":</u>

"For a *resource*, the minimum sustained operating level at which it can operate at a continuous sustained level, as defined in the Master File, or if applicable, as modified pursuant to Section 9.3.3. For a Participating Load, the operating level at reduced consumption pursuant to a Dispatch Instruction. For a *Reliability Demand Response Resource, Proxy Demand Resource or Non-Generating Resource*, the smallest discrete load reduction possible for *Reliability Demand Response Resource, Proxy Demand Resource or Non-Generating Resource*."

<u>Proposed revisions to "Start-up":</u>

"A Commitment Status transition from Off to On *from being shut down or in a state not capable of providing energy into a mode it can provide energy."*

Proposals to revise its definitions of commitment costs (supports cost-based bids)

<u>Proposed revisions to "minimum load costs":</u>

"The costs a Generating Unit, Participating Load, Reliability Demand Response Resource, Proxy Demand Resource, *or Non-Generating Resource* incurs operating at minimum load or for *run hour costs unrelated to energy provision possible even for resources with 0 MWh minimum load*, which in the case of Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource may not be negative. Minimum Load Costs may be adjusted pursuant to Section 30.7.10.2, if applicable."

<u>Proposed revisions to "start-up costs":</u>

"The cost incurred by a particular Generating Unit, *Participating Load, Reliability Demand Response Resource*, *Proxy Demand Resource, or Non-Generating Resource* during Start-Up from *the time of beginning to bring a resource into a state capable of providing energy*, the time of receipt of a CAISO Dispatch Instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the *resource* reaches its Minimum Load."

Proposals to revise its definitions of cost-based bids and add cost-based energy bids

Proposed revisions to add a "cost-based energy bid curve":

"The bid component that indicates the *expected costs associated with providing energy* and related quantity at which a resource bids energy in a monotonically increasing (decreasing for participating load) staircase function, consisting of no more than 10 segments defined by 11 pairs of MW operating points and $/MWh, which may be different for each Trading Hour of the applicable Bid time period. If the resource has forbidden operating regions, each forbidden operating region must be reflected as a single, separate energy bid curve segment."

Proposed revisions to the "cost-based minimum load bid":

"The bid component that indicates the *expected* Minimum Load Cost for the Generating Unit, Participating Load, Reliability Demand Response Resource, Proxy Demand Resource, *or Non-Generating Resource* specified by a non-negative number in dollars per hour, which applies *for the hour for* which it is submitted."

Proposed revisions to the "cost-based start-up bid":

"The bid component that indicates the Start-Up Time and *expected* Start-Up Cost curves for the Generating Unit, which applies for a given market horizon. Start-Up Cost curves are strictly monotonically increasing non-negative staircase curves, up to three segments, which represent a function of Start-Up Cost versus down time. *Start-Up Cost curves may be updated pursuant to Section 30.5.1*."

Proposals to revise its definitions of market-based bids and adding market-based commitment bids

Proposed revisions to the "market-based energy bid curve":

"The bid component that indicates the *prices associated with providing energy* and related quantity at which a resource bids energy in a monotonically increasing (decreasing for participating load) staircase function, consisting of no more than 10 segments defined by 11 pairs of MW operating points and $/MWh, which may be different for each Trading Hour of the applicable Bid time period. If the resource has forbidden operating regions, each forbidden operating region must be reflected as a single, separate energy bid curve segment."

Proposed revisions to the "market-based minimum load bid":

"The bid component that indicates the *prices of* Minimum Load Cost for the Generating Unit, Participating Load, Reliability Demand Response Resource, Proxy Demand Resource, *or Non-Generating Resource* specified by a non-negative number in dollars per hour, which applies *for the hour for* which it is submitted."

Proposed revisions to the "market-based start-up bid":

"The bid component that indicates the Start-Up Time and *prices of* Start-Up Cost curves for the Generating Unit, which applies for the entire Trading Day or as resubmitted in real-time market as pursuant to Section 30.5.1(b). Start-Up Cost curves are strictly monotonically increasing non-negative staircase curves, up to three segments, which represent a function of Start-Up Cost versus down time. *Start-Up Cost curves may be updated pursuant to Section 30.5.1*."

Proposed revisions to the "market-based transition bid":

"The bid component that indicates the transition matrix, transition time, and *prices of* Transition Cost for a Multi-Stage Generating Resource for the entire Trading Day or as resubmitted in real-time market as pursuant to Section 30.5.1(b), where prices are for the dollar cost per feasible transition from a given MSG Configuration to a higher MSG Configuration when the resource is already On. Transition Cost bids must be non-negative."

Appendix C: Proposed reference level calculations

This section provides proposed formulations for the improved gas price indices and each reference level.

The gas price index is the delivered gas price estimate based on next day gas commodity price indices, transportation rates, cap-and-trade credits, etc. California ISO calculates day-ahead and real-time GPIs.

Gas Price Index

$$GPI_{DA} = Commodity\ Price_{DA,DAFallBack} + Transportation\ Rate + \text{Shrinkage Allowance}_{DA} + Cap\ \&\ Trade\ Credit + Miscellaneous$$

$$GPI_{RT} = Commodity\ Price_{RT} + Transportation\ Rate + \text{Shrinkage Allowance}_{RT} + Cap\ \&\ Trade\ Credit + Miscellaneous$$

Where:

$Commodity\ Price_{DA} = ICE_{GD2,8-9AM}$ (ICE calculated midpoint made available prior to official index publication)

$Commodity\ Price_{DAFallBack} = average(SNL_{GD1}, Platts_{GD1}, ICE_{GD1}, NGI_{GD1})$

$Commodity\ Price_{RT} = average(SNL_{GD2}, Platts_{GD2}, ICE_{GD2}, NGI_{GD2})$[28]

$$\text{Shrinkage Allowance}_{DA,RT} = Commodity\ Price_{GD2} * \frac{Fuel\ Reimbursement\ Rate}{1 - Fuel\ Reimbursement\ Rate}$$

Transportation Rate is the approved gas pipeline shipping company rates on the company's electric supplier rate for that region.

Cap & Trade Credit (neg. value) is the approved CARB-jurisdictional gas pipeline shipping company rates on the company's electric supplier rate for that region that are only eligible to resources on the CARB covered entities list or to those who opt-in to the CARB list.

Miscellaneous costs will be defined specific to the fuel region.

***Equation 2: Gas Price Index for Delivered Gas Price Estimate*[29]**

Minimum load costs are costs incurred per hour to maintain the resource at the minimum operating point as specified by the minimum load value in the Master File. These costs do not require having a minimum operating point above zero since it could include short-term fixed costs incurred for a run hour or variable costs for power production at minimum load.

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28 SCE1, SCE2, SDG1, SDG2 fuel regions have calculated commodity price in RT that include a scalar on the average of the published indices (175% for purpose of calculating maximum allowable commitment costs 125% for purpose of calculating default energy bids) under temporary *Aliso Canyon* provisions.

29 Formula will be effective when *Bidding Rules Enhancements* is implemented to add the shrinkage allowance, cap-and-trade credits, and miscellaneous costs.

Minimum Load Cost

$$
= \begin{cases}
\text{(Minimum Load Fuel Cost + VOM + GMC Adder)*}Scalar, \\
GHG_{Flag} =' N' and\ MMA = 0\ and\ OC = 0 \\
\text{(Minimum Load Fuel Cost + VOM + GMC Adder + GHG Cost)*Scalar}, \\
GHG_{Flag} =' Y' and\ MMA = 0\ and\ OC = 0 \\
\text{(Minimum Load Fuel Cost + VOM + GMC Adder + GHG Cost + } MMA\text{)*Scalar}, \\
GHG_{Flag} =' Y' and\ MMA \neq 0\ and\ OC = 0 \\
\text{(Minimum Load Fuel Cost + VOM + GMC Adder + GHG Cost + } MMA\text{)*Scalar+OC Adder}, \\
GHG_{Flag} =' Y' and\ MMA \neq 0\ and\ OC \neq 0
\end{cases}
$$

Where:

If gas resource, then:

Minimum Load Fuel Cost =

$$MIN\_LOAD\_COST + (Unit\ Conversion * HEAT_{HEAT_{RATE}\,Point1} * MIN_{GEN} * GPI_{DA,DAFallBack,RT})$$

else if non-gas, then:

Minimum Load Fuel Cost

$$= (Unit\ Conversion * HEAT\_AVG\_COST_{POINT1} * MIN\_GEN + MIN\_LOAD\_COST)$$

$$VOM = VOM_{Default,Negotiated} * MIN\_GEN$$

GMC Adder = $MIN\_GEN * GMC$

GHG Cost = $Unit\ Conversion * HEAT\_AVG\_COST_{POINT1} * MIN\_GEN *$ GHG_EMISSION_RATE $*$ *GHG Allowance Rate*

Unit conversion = 0.001

MMA = ISO determined major maintenance adder saved in Master File as ADDER_AMT

Scalar=1.25

OC Adder = ISO determined opportunity cost adder for resources with eligible run hour limitations calculated or negotiated

Inputs:

Master File Registered Values: $HEAT\_HEAT\_RATE_{Point1}$, $HEAT\_AVG\_COST_{POINT1}$[30], MIN_LOAD_COST[31], MIN_GEN, GHG_EMISSION_RATE, GHG_COMPLIANCE_OBLIG (i.e. GHG_{Flag}).

California ISO Calculated Inputs: $GPI_{DA,RT}$, EPI, GHG Allowance Rate, calculated opportunity cost for eligible start limitations.

[30] First segment in the average heat rate field in Master File where segment 1 must be the Pmin (i.e. minimum load).

[31] California ISO will revise the definition of this field to make clear that for proxy cost units the registered values should only be the run hour costs expected outside of energy production costs up to Pmin.

California ISO Defined or Negotiated Values: GMC (BPM), VOM (BPM values or negotiated value), ADDER_AMT, negotiated opportunity cost for eligible start limitations.

Equation 3: Proxy Minimum Load Costs

Start-up (or shutdown) cost is a cost incurred per start-up event that is the cost of bringing the resource into a mode by which it can operate hourly and to a given dispatch level. The cost does not vary with the number of hours the resource is kept online.

Start-up Cost Reference Level Calculation

$$= \begin{cases} (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}) * Scalar, \\ GHG_{Flag} =' N' and\ MMA = 0 \\ (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}) * Scalar, \\ GHG_{Flag} =' Y' and\ MMA = 0 \\ (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA) * Scalar, \\ GHG_{Flag} =' Y' and\ MMA \neq 0 \\ (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA) * Scalar + OC\ Adder \\ GHG_{Flag} =' Y' and\ MMA \neq 0\ and\ OC \neq 0 \end{cases}$$

Where:

If gas resource, then:

Start-up Fuel Cost = $STRT\_STARTUP\_FUEL * GPI_{DA,RT}$

else if non-gas, then:

Start-up Fuel Cost = $STRT\_STARTUP\_COST$

Start-up Energy Cost = $STRT\_STARTUP\_AUX * EPI$

$$GMC\ Adder = \frac{1}{2}(MIN\_GEN * GMC * \frac{STRT\_STARTUP\_TIME_{Point2}}{60})$$

GHG Cost = $STRT\_STARTUP\_FUEL$ * GHG_EMISSION_RATE * GHG Allowance Rate

MMA = ISO determined major maintenance adder saved in Master File as STRT_STARTUP_MMA

Scalar=1.25

OC Adder = ISO determined opportunity cost adder for resources with eligible start limitations calculated or negotiated

Inputs:

Master File Registered Values: STRT_STARTUP_FUEL, STRT_STARTUP_COST, STRT_STARTUP_AUX, $STRT\_STARTUP\_TIME_{Point2}$, MIN_GEN, GHG_EMISSION_RATE, GHG_COMPLIANCE_OBLIG (i.e. GHG_{Flag}).

California ISO Calculated Inputs: $GPI_{DA,RT}$, EPI, GHG Allowance Rate, calculated opportunity cost for eligible start limitations.

<u>California ISO Defined or Negotiated Values:</u> GMC (BPM), STRT_STARTUP_MMA, negotiated opportunity cost for eligible start limitations.

Equation 4: Proxy Start-Up Costs

Transition cost is a cost incurred per event of the resource that is the cost of moving from one state of operation ("From Configuration") to another state of operation ("To Configuration"). The cost does not vary with the hours the resource is called on or at what dispatch level. California ISO views these costs as similar to starting up a higher configuration and is the difference in start-up costs between the two configurations. See Tariff section 30.4.1.1.5.

Transition Cost

$$= \begin{cases} (Proxy\ Start\ Up\ Costs_{ToConfig} - Proxy\ Start\ Up\ Costs_{FromConfig}), OC = 0 \\ (Proxy\ Start\ Up\ Costs_{ToConfig} - Proxy\ Start\ Up\ Costs_{FromConfig}) + OC\ Adder, \\ \qquad OC \neq 0 \end{cases}$$

Where:

$Proxy\ Start\ Up\ Costs_{ToConfig}$
$= Calculated\ proxy\ start\ up\ costs\ of\ the\ \text{“}To\ Configuration\text{”}\ resource\ is\ transitioning\ to$

$Proxy\ Start\ Up\ Costs_{FromConfig}$
$= Calculated\ proxy\ start\ up\ costs\ of\ the\ \text{“}From\ Configuration\text{”}\ resource\ is\ transitioning\ fro$

Scalar=1.25

OC Adder = ISO determined opportunity cost adder for resources with eligible start limitations calculated or negotiated on the "To Configuration"

Inputs:

<u>California ISO Calculated Inputs:</u> start up proxy costs and opportunity cost for eligible start limitations.

<u>California ISO Defined or Negotiated Values:</u> Negotiated opportunity cost for eligible start limitations.

Equation 5: Proxy Transition Costs

Appendix D: Proposed guidelines for ex ante adjustment requests and verification processes

This appendix provides the details for the proposed guidelines for the California ISO proposal to support supplier submitted ex ante reference level adjustments subject to verification.

D.1 Proposed reference level adjustment calculations

The following formulations should be used for adjustments to the start-up, minimum load, and energy components. A supplier must use the existing reference level calculation and will be allowed to submit a request for reference level adjustment based on their reasonable expectations of fuel (or fuel-equivalent) related costs. Suppliers will be expected to calculate the reference level adjustment requests using the formulas under the estimated proxy cost option. The Supplier will be able to revise the values of fuel (or fuel-equivalent) related costs using these formulas.

California ISO will expect the supplier to submit the total reference level value including the variable operations and maintenance cost, grid management charge adder, greenhouse gas compliance costs (if appropriate), frequently mitigated adders (if appropriate), negotiated major maintenance adders (if appropriate), and opportunity cost adders (if appropriate) but that those values will be static and consistent with California ISO existing calculations. Further, the resource characteristics that feed into these equations will be required to be consistent with Master File registered values or as revised through outage management system. For example, the supplier may request a reference level adjustment, based on fuel cost or fuel cost equivalent component variations from the costs the California ISO uses in its calculations by including their expectation of fuel or fuel equivalent cost in a recalculated cost-based bid that the supplier will submit and if verified then used as an adjusted reference level.

Equation 6 The individual components that a supplier is allowed to adjust the values within the formula are limited to:

- Gas Price Index for gas resources
- Average cost curve for non-gas resources[32]
- GHG allowance rate for resources where GHG flag in Master File is "On"

Default Energy Bid Cost

$$= \begin{cases} \text{(Segment's Fuel Cost + VOM + GMC Adder)} * Scalar, \\ GHG_{Flag} =' N' and\ DEBA = 0\ and\ OC = 0 \\ \text{(Segment's Fuel Cost + VOM + GMC Adder + GHG Cost)} * Scalar, \\ GHG_{Flag} =' Y' and\ DEBA = 0\ and\ OC = 0 \\ \text{(Segment's Fuel Cost + VOM + GMC Adder + GHG Cost)} * Scalar + DEBA\ , \\ GHG_{Flag} =' Y' and\ DEBA\ \neq 0\ and\ OC = 0 \\ \text{(Segment's Fuel Cost + VOM + GMC Adder + GHG Cost)} * Scalar + DEBA + OC\ Adder, \\ GHG_{Flag} =' Y' and\ DEBA\ \neq 0\ and\ OC \neq 0 \end{cases}$$

Where:

[32] Suppliers register average cost curves in Master File that are later converted to incremental cost curves. There is additional logic to the formulation of the incremental cost curve in tariff (analogous to that for incremental heat rates).

If gas resource, then:

$$Segment's\ Fuel\ Cost = Unit\ Conversion * Incremental\ Heat\ Rate * GPI_{DA,DAFallBack,RT},$$

where

$$Incremental\ Heat\ Rate = (HEAT\_RATE_{i+1} * MW_{i+1} - HEAT\_RATE_i * MW_i)/(MW_{i+1} - MW)_i$$ [33]

else if non-gas, then:

$$Segment's\ Fuel\ Cost = Incremental\ Cost\ Curve,\ where$$

$$Incremental\ Cost\ Curve = (AvgCost_{i+1} * MW_{i+1} - AvgCost_i * MW_i)/(MW_{i+1} - MW)_i$$ [34]

VOM=variable operating and maintenance adder (VOM)

$$GHG\ Cost = Unit\ Conversion * Incremental\ Heat\ Rate^{35} * Emissions\ Rate * GHG\ Allowance\ Rate$$

Unit conversion = 0.001

$$DEBA = ISO\ determined\ default\ energy\ bid\ adder$$

$$Scalar = 1.1$$

OC Adder = ISO determined opportunity cost adder for resources with eligible output limitations calculated or negotiated

Equation 6: Default Energy Bid Variable Cost Calculation

below shows the proposed formulation for the estimated proxy cost option for minimum load reference levels. The individual components that an SC is allowed to adjust the values within the formula are limited to:

- Gas Price Index for gas resources
- Average cost segment 1 for non-gas resources
- Minimum load cost registered for proxy cost units expected run hour costs not associated with any energy production up to minimum load
- GHG allowance rate for resources where GHG flag in Master File is “On”

[33] Suppliers register average heat rates in Master File that are later converted to incremental heat rate. There is additional logic to the formulation of the incremental heat rate in tariff.

[34] Suppliers register average cost curves in Master File that are later converted to incremental cost curves. There is additional logic to the formulation of the incremental cost curve in tariff (analogous to that for incremental heat rates).

[35] Incremental heat rate reflects formula above and additional tariff language descriptions for incremental heat rate as described in footnote 33.

Minimum Load Cost

$$= \begin{cases} \text{(Minimum Load Fuel Cost + VOM + GMC Adder)*}Scalar\ , \\ GHG_{Flag} =' N' and\ MMA = 0\ and\ OC = 0 \\ \text{(Minimum Load Fuel Cost + VOM + GMC Adder + GHG Cost)*Scalar ,} \\ GHG_{Flag} =' Y' and\ MMA = 0\ and\ OC = 0 \\ \text{(Minimum Load Fuel Cost + VOM + GMC Adder + GHG Cost + }MMA\text{)*Scalar,} \\ GHG_{Flag} =' Y' and\ MMA\ \neq 0\ and\ OC = 0 \\ \text{(Minimum Load Fuel Cost + VOM + GMC Adder + GHG Cost + }MMA\text{)*Scalar+OC Adder,} \\ GHG_{Flag} =' Y' and\ MMA\ \neq 0\ and\ OC \neq 0 \end{cases}$$

Where:

If gas resource, then:

Minimum Load Fuel Cost =

$MIN\_LOAD\_COST + (Unit\ Conversion * \ HEAT_{HEAT_{RATE}\,Point1} * MIN_{GEN} * GPI_{DA,DAFallBack,RT})$

else if non-gas, then:

Minimum Load Fuel Cost
$= (Unit\ Conversion * HEAT\_AVG\_COST_{POINT1} * MIN\_GEN + MIN\_LOAD\_COST)$

$VOM = VOM_{Default,Negotiated} * MIN\_GEN$

GMC Adder = MIN_GEN * GMC

GHG Cost = $Unit\ Conversion * HEAT\_AVG\_COST_{POINT1} * MIN\_GEN *$ GHG_EMISSION_RATE
$*$ *GHG Allowance Rate*

Unit conversion = 0.001

MMA = ISO determined major maintenance adder saved in Master File as ADDER_AMT

Scalar=1.25

OC Adder = ISO determined opportunity cost adder for resources with eligible run hour limitations calculated or negotiated

Inputs:

<u>Master File Registered Values:</u> $HEAT\_HEAT\_RATE_{Point1}$, $HEAT\_AVG\_COST_{POINT1}$[36], MIN_LOAD_COST[37], MIN_GEN, GHG_EMISSION_RATE, GHG_COMPLIANCE_OBLIG (i.e. GHG_{Flag}).

<u>California ISO Calculated Inputs:</u> $GPI_{DA,RT}$, EPI, GHG Allowance Rate, calculated opportunity cost for eligible start limitations.

[36] First segment in the average heat rate field in Master File where segment 1 must be the Pmin (i.e. minimum load).

[37] California ISO will revise the definition of this field to make clear that for proxy cost units the registered values should only be the run hour costs expected outside of energy production costs up to Pmin.

California ISO Defined or Negotiated Values: GMC (BPM), VOM (BPM values or negotiated value), ADDER_AMT, negotiated opportunity cost for eligible start limitations.

Equation 7: Proxy Minimum Load Costs

Equation 8 below shows the proposed formulation for the estimated proxy cost option for start-up reference levels. The individual components that a supplier is allowed to adjust the values within the formula are limited to:

- Gas Price Index for gas resources
- Start-up fuel cost for non-gas resources
- Electricity price index
- GHG allowance rate for resources where GHG flag in Master File is "On"

Start-up Cost Reference Level Calculation

$$= \begin{cases} (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}) * Scalar, \\ GHG_{Flag} =' N' and\ MMA = 0 \\ (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}) * Scalar, \\ GHG_{Flag} =' Y' and\ MMA = 0 \\ (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA) * Scalar, \\ GHG_{Flag} =' Y' and\ MMA\ \neq 0 \\ (\text{Start-up Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA) * Scalar + OC\ Adder \\ GHG_{Flag} =' Y' and\ MMA\ \neq 0\ and\ OC\ \neq 0 \end{cases}$$

Where:

If gas resource, then:

Start-up Fuel Cost = $STRT\_STARTUP\_FUEL * GPI_{DA,RT}$

else if non-gas, then:

Start-up Fuel Cost = $STRT\_STARTUP\_COST$

Start-up Energy Cost = $STRT\_STARTUP\_AUX * EPI$

$$GMC\ Adder = \frac{1}{2}(MIN\_GEN * GMC * \frac{STRT\_STARTUP\_TIME_{Point2}}{60})$$

GHG Cost = $STRT\_STARTUP\_FUEL$ ∗ GHG_EMISSION_RATE ∗ GHG Allowance Rate

MMA = ISO determined major maintenance adder saved in Master File as STRT_STARTUP_MMA

Scalar=1.25

OC Adder = ISO determined opportunity cost adder for resources with eligible start limitations calculated or negotiated

Inputs:

Master File Registered Values: STRT_STARTUP_FUEL, STRT_STARTUP_COST, STRT_STARTUP_AUX, $STRT\_STARTUP\_TIME_{Point2}$, MIN_GEN, GHG_EMISSION_RATE, GHG_COMPLIANCE_OBLIG (i.e. GHG_{Flag}).

California ISO Calculated Inputs: $GPI_{DA,RT}$, EPI, GHG Allowance Rate, calculated opportunity cost for eligible start limitations.

California ISO Defined or Negotiated Values: GMC (BPM), STRT_STARTUP_MMA, negotiated opportunity cost for eligible start limitations.

Equation 8: Proxy Start-Up Costs

D.2 Proposed ex ante verification

California ISO will evaluate the reference level adjustment request through an automated screen comparing the adjusted value against a reasonableness threshold. California ISO proposes the reasonableness threshold should be a threshold calculated to represent a reasonable cost-based bid that can be calibrated to a specific resources' costs.

For gas-fired resources, the reasonableness threshold will be a calculation using the reference level calculations with a scaled next day gas commodity price in the gas price index. The California ISO proposes to scale the gas price indices as shown in Equation 9. Then the California ISO will calculate the energy, minimum load and start-up reasonableness thresholds using the reference level formulas with the scaled gas price index in place of the standard gas price index (formulas used shown in Equation 6, Equation 7, and Equation 8).

Scaled Gas Price Index

$$\begin{aligned} GPI_{DA} = {} & Commodity\ Price_{DA,DAFallBack} * Fuel\ Volatility\ Scalar \\ & + Transportation\ Rate + \text{Shrinkage Allowance}_{DA} + Cap \,\&\, Trade\ Credit \\ & + Miscellaneous \end{aligned}$$

$$\begin{aligned} GPI_{RT} = {} & Commodity\ Price_{RT} * Fuel\ Volatility\ Scalar + Transportation\ Rate \\ & + \text{Shrinkage Allowance}_{RT} + Cap \,\&\, Trade\ Credit + Miscellaneous \end{aligned}$$

Where:

$$Fuel\ Volatility\ Scalar = \begin{cases} 125\%, operating\ day\ is\ Monday\ or\ after\ Holiday^{38} \\ 110\%, operating\ day\ is\ non-Monday\ or\ index\ is\ available \end{cases}$$

$Commodity\ Price_{DA} = ICE_{GD2,8-9AM}$ (ICE calculated midpoint made available prior to official index publication)

$$Commodity\ Price_{DAFallBack} = average(SNL_{GD1}, Platts_{GD1}, ICE_{GD1}, NGI_{GD1})$$

$$Commodity\ Price_{RT} = average(SNL_{GD2}, Platts_{GD2}, ICE_{GD2}, NGI_{GD2})$$

[38] Proposal will utilize 125% for any day that the fallback is needed to account for increased need to reflect volatility.

$$\text{Shrinkage Allowance}_{DA,RT} = Commodity\ Price_{GD2} * \frac{Fuel\ Reimbursement\ Rate}{1\ - Fuel\ Reimbursement\ Rate}$$

Transportation Rate is the approved gas pipeline shipping company rates on the company's electric supplier rate for that region.

Cap & Trade Credit (neg. value) is the approved CARB-jurisdictional gas pipeline shipping company rates on the company's electric supplier rate for that region that are only eligible to resources on the CARB covered entities list or to those who opt-in to the CARB list.

Miscellaneous costs will be defined specific to the fuel region.

Equation 9: Scaled Gas Price Index in Reasonableness Threshold

For non-gas fired resources the reasonableness thresholds will be calculated for energy, minimum load, and start-up reference levels by applying a 110% fuel equivalent volatility scalar to the fuel equivalent cost component. Then the California ISO will calculate the energy, minimum load and start-up reasonableness thresholds using the reference level formulas with the scaled fuel equivalent costs in place of the registered fuel equivalent costs (formulas used shown in Equation 6, Equation 7, and Equation 8).

$$\boldsymbol{Minimum\ Load\ Fuel\ Cost} = 110\% * (Unit\ Conversion * HEAT\_AVG\_COST_{POINT1} * MIN\_GEN + MIN\_LOAD\_COST)$$

Equation 10: Scaled Minimum Load Fuel Equivalent Cost in Reasonableness Threshold

$$\textbf{Start-up Fuel Cost} = 110\% * STRT\_STARTUP\_COST$$

Equation 11: Scaled Start-up Fuel Equivalent Cost in Reasonableness Threshold

If the adjustment request falls below the reasonableness threshold, the California ISO will accept the reference level adjustment automatically. If the adjustment is higher than lower of the reasonableness threshold or cost-based cap if applicable[39], the California ISO will adjust the reference level adjustment to the reasonableness threshold – capping the adjustment at a reasonable rate and sending the original adjustment request to the ex post verification process.

D.3 Proposed ex post verification and auditing

For both commitment cost and energy reference level adjustments, California ISO proposes to perform ex post verification of actual incurred costs.

- Unverifiable reference level adjustments based on reasonableness thresholds, and
- Verified or unverifiable energy reference level adjustments greater than $2,000/MWh.

[39]California ISO proposing to only apply cost-based cap to the adjustments to energy cost reference levels. For the purpose of evaluating adjustments to commitment cost reference levels, these requests will only be evaluated against the reasonableness threshold.

If successfully verified, California ISO proposes to re-calculate the supplier's uplift settlement with the verified cost-based adjustment to the reference level(s) and if market revenues are insufficient to cover their costs (i.e., revenue shortfall) will be eligible for uplift.

If the California ISO identifies in its ex post verification process that supplier submitted reference level adjustments did not follow the established principles then the California ISO proposes to render the supplier ineligible to submit reference level adjustments until a defined amount of time has elapsed. This authority is essential as an additional measure to protect against artificial price impacts. California ISO proposes a stepped penalty approach[40].

The California ISO also proposes to add audit authority to allow it to audit automatically approved adjustments if it identifies that a supplier has frequently submitted and been frequently approved for these requests. This is necessary to ensure the adjustment requests were submitted with cost-based bids consistent with the rules.

The California ISO may render suppliers ineligible either through the ex post verification or through a failed audit. The first instance the California ISO determines the supplier failed to follow the guidelines, the California ISO will render the supplier ineligible for reference level adjustments for 60 days. The 60 day period shall start two business days after the date that the ISO provides written notice of its determination that the supplier did not follow the guidelines. The second time California ISO determines the same supplier failed to follow the guidelines, the California ISO will render the supplier ineligible for 180 days.

If failure to follow the rules appears to become a pattern of strategic bidding behavior or false or misleading information, the California ISO or its Department of Market Monitoring may refer behavior to the Federal Energy Regulatory Commission for a more detailed review of compliance with market behavior rules 35.41(b).

[40] Proposed penalty for failure to follow rules modeled after NYISO approach described in New York Independent System Operator Tariff Market Administration and Control Area Services Sections 23.3.1.4.6.8 - 23.3.1.4.6.8.2.

Appendix E: Details on local market power mitigation

Purpose of this appendix is to provide the details on the proposed changes to commitment cost bidding rules and mitigation design under *Commitment Cost and Default Energy Bid Enhancements.*

CAISO proposes to allow market-based bids for each component of the supply bid subject to mitigation where minimum load cost component is treated hourly and start-up and transition costs remain event-based costs at daily values. Proposed enhancements to dynamic market power mitigation will test binding constraints for energy mitigation and test all critical constraints for commitment cost mitigation.

The proposal will apply consistently to internal constraints in the California ISO and Energy Imbalance Market Balancing Authority Areas and to the BAA level net transfer constraints where these constraints will either be binding or non-binding based on the flow. For commitment cost mitigation, the will apply the calculations for binding constraints to the BAA level net transfer constraints that have a positive shadow price (import congestion). The BAA level net transfer constraints are performed using a power balance constraint which requires generation to equal demand, due to the equality constraint this constraint will always be binding. For mitigating commitment costs, the CAISO will apply the non-competitive commitment mitigation criterion for binding constraints to any non-competitive net power balance constraints.

CAISO proposes to apply real-time market commitment cost re-bidding rules as approved by Federal Energy Regulatory Commission on November 21, 2016 (ER16-2445).

E.1 Data inputs and subscript notations in the LMPM and DCPA

The following table, Table 5 and Table 6, contains the subscripts used in the equations for the mitigation process. These subscripts are based on those used in the Business Practice Manual sections on mitigation.

Subscript	Subscript Name	Subscript Description
j	SC	The SCID(s) adjusted for tolling agreements (establishes affiliate level for test)
d	Trading Day	Trading Day
i	Resource ID	Resource ID or node index
I	Set of resource IDs	All resource IDs
k	Binding constraint	Binding constraint from the all constraints run where power flows are 100% of line limit in direction of the reference bus
K	Set of binding constraints	All binding constraints

Subscript	Subscript Name	Subscript Description
l	critical constraint	All binding constraints and non-binding constraints identified as likely needing commitments to resolve the constraint, potentially critical constraint plus pre-determined constraints based on engineering or economic assessments
L	Set of critical constraints	All critical constraints
t	Interval	Interval within the optimization time horizon
T	Optimization time horizon	Set of all intervals that fall within the optimization time horizon

Table 5: Subscript notation

Variable	Market Run	Formulation	Description
$\boldsymbol{ENGYMIN_i}$	INPUT	$\max[(MINCAP_i + RD_i), self - scheduled\ energy]$	Minimum operating level for resource i that it can be dispatched to on energy bids respecting regulation down awards during test interval (i.e. lower operating limit plus regulation down award).
$\boldsymbol{MINCAP_i}$	INPUT	$\max(Pmin_i + Pmin\ Rerate_i, \min ED)$	Minimum operating level of resource r where $Pmin_i$ is regulation Pmin if on regulation otherwise operational Pmin.
$\boldsymbol{ENGYMAX_i}$	INPUT	$min((MAXCAP_i - OR_i - RU_i), (MAXECON_i - OR_i))$	Maximum operating level for resource i that it can be dispatched to on energy bids given outages and derates and respecting operating reserves and regulation up during test interval (i.e. upper operating limit minus operating reserves or regulation up awards).

Variable	Market Run	Formulation	Description
$\boldsymbol{MAXCAP_i}$	INPUT	$\min(Pmax_i - Derate_i, \max ED)$	Maximum operating level of resource r where Pmax$_i$ is regulation Pmax if on regulation otherwise operational Pmax. Note – for MSG plants these are plant level maximums and derates.
$\boldsymbol{MAXECON_i}$	INPUT	$\min\begin{pmatrix} Pmax_i - Derate_i, \\ \max ED, \\ \max econ\ bid\ MW \end{pmatrix}$	Maximum operating level of resource r where Pmax$_i$ is regulation Pmax if on regulation otherwise operational Pmax
$\boldsymbol{DERATE_i}$	INPUT	INPUT	Reduction in potential output from maximum operating level ($MAXCAP_i$) from unit outages or derates during test interval
$\boldsymbol{OR_i}$	INPUT	INPUT	Operating reserve awards for resource i in test interval. For HASP, ORi is (HASP qualified self-scheduled spinning including transferred DA spin capacity)+(HASP qualified self-scheduled non-spinning including transferred DA non-spinning capacity). For RTUC, ORi is awarded spinning capacity + awarded non-spinning capacity.
$\boldsymbol{RD_i}$	INPUT	INPUT	Regulation down award for resource i in the test interval. For real-time, HASP qualified self-scheduled regulation down including transferred DA regulation down capacity.
$\boldsymbol{RU_i}$	INPUT	INPUT	Regulation up award for resource i in the test interval. For real-time, HASP qualified self-scheduled regulation up including transferred DA regulation up capacity.

Variable	Market Run	Formulation	Description
$\boldsymbol{RR_i}$	INPUT	INPUT	Effective ramp rate at DOP_t in case of dynamic ramp rate.
$\boldsymbol{CC_i}$	INPUT	INPUT	Corrective capacity awards.
$\boldsymbol{DOP_i}$	INPUT	INPUT	Dispatch operating point for physical or virtual supply resource i for the Market Power Mitigation all constraints run results for the test interval[41].
$\boldsymbol{DOP_{i,t-1}}$	INPUT	INPUT	Dispatch operating point for physical or virtual supply resources I from the Market Power Mitigation all constraint run results for the interval prior to the test interval.
$\boldsymbol{SF_{l,i}}$	INPUT	INPUT	Shift factor from resource location r to constraint l where constraint set L includes all critical constraints. Note that for MSG Plants the SF is given per plant aggregate connectivity node.
$\boldsymbol{SF_{k,i}}$	INPUT	INPUT	Shift factor from resource location r to constraint k where constraint set K includes all binding constraints (subset of critical constraints set). Note that for MSG Plants the SF is given per plant aggregate connectivity node.
$\boldsymbol{SF_{ckc,i}}$	INPUT	INPUT	Shift factor from resource location r to constraint ckc where constraint set CKC includes all binding corrective capacity constraints. Note that for MSG Plants the SF is given per plant aggregate connectivity node.

[41] Technically referred to as Dispatch Operating Target (DOT); DOP(P) is the expected dispatch trajectory through the DOTs.

Variable	Market Run	Formulation	Description
$\boldsymbol{SF_{clc,i}}$	INPUT	INPUT	Shift factor from resource location r to constraint clc where constraint set CLC includes all critical corrective capacity constraints. Note that for MSG Plants the SF is given per plant aggregate connectivity node.

Table 6: Revised data inputs for commitment cost mitigation

E.2 Potentially pivotal or fringe competitive supplier

Identification of the top three potentially pivotal suppliers in the day-ahead market will be based on the available effective supply that can be withheld by each supplier. In the day-ahead this is the total effective counterflow supply. In real-time, it will be the ramp-constrained capacity including the minimum load energy a supplier could withhold.

The revised real-time withheld capacity calculations applied in both the energy test and the commitment cost test will have conditional logic so that the market removes the floor used to limit ramp capable movement to the minimum operating level. In real-time, the lowest output level for a resource i will account for the ability to de-commit or shutdown the resource by including conditional logic whereby if ramp capable, through its minimum run time, and not must run resource then the minimum load energy will be reflected.

E.2.1 Binding constraint calculations – WC

For each binding transmission constraint l and critical corrective capacity constraint ckc, suppliers are ranked on withheld capacity (WC) from highest to lowest and the top three suppliers are identified as within the set of potentially pivotal suppliers for that constraint and the remainder are identified as fringe competitive suppliers. For determining the array of potentially pivotal suppliers and fringe competitive suppliers for binding transmission or corrective capacity constraints, CAISO will continue to default net buyers to fringe competitive suppliers.

This withheld capacity (WC) from supplier B to critical constraint l is the sum across B's resources, which is expressed as follows where it is calculated for resources I in potentially pivotal supplier portfolio J with $SF_{k,i} < 0 \; or \; SF_{ckc,i} < 0$:

IFM Formulation:

$$WC_{k,j}^{CCM} = \sum_{i=1}^{n} (SF_{k,r} * ENGYMAX_i + SVCF_{k,j,i})$$

$$WC_{ckc,j}^{CCM} = \sum_{i=1}^{n}(SF_{ckc,r} * ENGYMAX_i + SVCF_{ckc,j,i})$$

RTUC formulation:

$$WC_{k,j}^{CCM} = \sum_{i=1}^{n}\Big[SF_{k,i} * \Big(\min\big(DOP_{i,t-1} + RR_i * 1, ENGYMAX_i\big) - \delta \max\big(DOP_{i,t-1} - RR_i * 15, ENGYMIN_i\big)\Big)\Big]$$

$$WC_{ckc,j}^{CCM} = \sum_{i=1}^{n}\Big[SF_{ckc,i} * \Big(\min\big(DOP_{i,t-1} + RR_i * 15, ENGYMAX_i\big) - \delta min\big[\max\big(DOP_{i,t-1} - RR_i * 15, ENGYMIN_i\big) + RR_i * 20, ENGYMAX_i\big)\big]\Big)\Big]$$

$$Where\ \delta = \{0,1\}$$

$$DOP_{i,IC} - RR_i * 15 * N \leq ENGYMIN_i \rightarrow \delta = 0$$

$$DOP_{i,IC} - RR_i * 15 * N > ENGYMIN_i \rightarrow \delta = 1$$

Where $DOP_{i,IC}$ is the binding dispatch point from the market that establishes the initial condition for the RTUC optimization and N is the number of interval in the time horizon (e.g. the 3rd interval is 3).

Note - Delta is locked to 1 for:

- Must-run resources (i.e. resources with self-schedules or AS awards),
- Resources that have not fulfilled their minimum run time (also called minimum up time)

Today in HASP, for a unit that is offline in the previous interval and has a startup time of 60 minutes or less, then WC = Pmin. For RTUC, the startup time to be used is reduced to 15 minutes or less. Under policy this will be generalized to allow resources with feasible start-ups in that unit commitment to be included in WC or supply of counterflow of fringe competitive suppliers.

Withheld Capacity (WC) shall not consider pump storage resources; demand side of PDR, RDRR, Dispatched Pump resources, and NGR; and any external resources are excluded (consistent logic to existing MPM).

E.2.2 Critical constraint calculations – WC

For each critical transmission constraint l and critical corrective capacity constraint clc (includes binding and non-binding), suppliers are ranked on withheld capacity (WC) from highest to lowest and the top three suppliers are identified as within the set of potentially pivotal suppliers for that constraint and the remainder are identified as fringe competitive suppliers. For determining the array of potentially pivotal suppliers and fringe competitive suppliers on all critical transmission or corrective capacity constraints, CAISO will not default net buyers to fringe competitive suppliers.

This withheld capacity (WC) from supplier B to critical constraint l is the sum across B's resources, which is expressed as follows where it is calculated for resources I in potentially pivotal supplier portfolio J with $SF_{l,i} < 0 \; or \; SF_{clc,i} < 0$:

IFM Formulation:

$$WC_{l,j}^{CCM} = \sum_{i=1}^{n} (SF_{l,r} * ENGYMAX_i + SVCF_{l,j,i})$$

$$WC_{clc,j}^{CCM} = \sum_{i=1}^{n} (SF_{clc,r} * ENGYMAX_i + SVCF_{clc,j,i})$$

RTUC formulation:

$$WC_{l,j}^{CCM} = \sum_{i=1}^{n} \Big[SF_{l,i} * \Big(\min\big(DOP_{i,IC} + RR_i * 15 * N, ENGYMAX_i\big) - \delta \max\big(DOP_{i,IC} - RR_i * 15 * N, ENGYMIN_i\big)\Big)\Big]$$

$$WC_{clc,j}^{CCM} = \sum_{i=1}^{n} \Big[SF_{clc,i} * \Big(\min\big(DOP_{i,IC} + RR_i * 15 * N, ENGYMAX_i\big) - \delta min\big[\max\big(DOP_{i,IC} - RR_i * 15 * N, ENGYMIN_i\big) + RR_i * 20, ENGYMAX_i)\big]\Big)\Big]$$

$Where \; \delta = \{0,1\}$

$DOP_{i,IC} - RR_i * 15 * N \leq ENGYMIN_i \rightarrow \delta = 0$

$DOP_{i,IC} - RR_i * 15 * N > ENGYMIN_i \rightarrow \delta = 1$

Where $DOP_{i,IC}$ is the binding dispatch point from the market that establishes the initial condition for the RTUC optimization and N is the number of interval in the time horizon (e.g. the 3rd interval is 3).

Note - Delta is locked to 1 for:

- Must-run resources (i.e. resources with self-schedules or AS awards),
- Resources that have not fulfilled their minimum run time (also called minimum up time)

Today in HASP, for a unit that is offline in the previous interval and has a startup time of 60 minutes or less, then WC = Pmin. For RTUC, the startup time to be used is reduced to 15 minutes or less. Under policy this will be generalized to allow resources with feasible start ups in that unit commitment to be included in WC or supply of counterflow of fringe competitive suppliers.

Withheld Capacity (WC) shall not consider pump storage resources; demand side of PDR, RDRR, Dispatched Pump resources, and NGR; and any external resources are excluded (consistent logic to existing MPM).

E.3 Counterflow supply from potentially pivotal suppliers

Effective supply of counterflow to a binding or non-binding constraint in the critical constraint set from a physical resource i belonging to a ***potentially pivotal supplier*** is the lowest output this supplier can achieve given the dispatch operating point in prior interval (energy mitigation) or initial condition (commitment cost mitigation), resource ramp rates in MW/min, and minimum output limits. In the day-ahead, this is the total effective supply without ramp constraints versus real-time which is ramp-constrained supply including minimum load energy.

The revised real-time supply of counterflow from potentially pivotal suppliers calculations applied in both the energy test and the commitment cost test will have conditional logic so that the market removes the floor used to limit ramp capable movement to the minimum operating level. In real-time, the lowest output level for a resource i will account for the ability to de-commit or shutdown the resource by including conditional logic whereby if ramp capable, through its minimum run time, and not must run resource then the minimum load energy will be reflected.

E.3.1 Binding constraint calculations – SCFPPS

The effective counterflow supply from potentially pivotal suppliers on constraint k (SCF_k^{PPSCCM}) or constraint ckc (SCF_{ckc}^{PPSCCM}) are expressed in the equations and input definitions described below and are calculated for resources I in potentially pivotal supplier portfolio J with $SF_{k,i} < 0 \; or \; SF_{ckc,i} < 0$:

$$SCF_k^{PPSCCM} = \sum_{j=1}^{n}\sum_{i=1}^{n} SPCF_{k,j,i}^{PPSCCM}$$

$$SCF_{ckc}^{PPSCCM} = \sum_{j=1}^{n}\sum_{i=1}^{n} SPCF_{ckc,j,i}^{PPSCCM}$$

IFM formulation:

$SPCF_{k,j,i}^{PPSCCM}$=0

$SPCF_{ckc,j,i}^{PPSCCM}$=0

RTUC formulation:

$$SPCF_{k,j,i}^{PPSCCM} = SF_{k,i} * \delta \max(DOP_{i,t-1} - RR_i * 15, ENGYMIN_i)$$

$$SPCF_{ckc,j,i}^{PPSCCM} = SF_{ckc,i} * \delta min\left[\max\left(DOP_{i,t-1} - RR_i * 15, ENGYMIN_i\right) + RR_i * 20, ENGYMAX_i)\right]$$

$$Where\ \delta = \{0,1\}$$

$$DOP_{i,IC} - RR_i * 15 * N \le ENGYMIN_i \rightarrow \delta = 0$$

$$DOP_{i,IC} - RR_i * 15 * N > ENGYMIN_i \rightarrow \delta = 1$$

Note - Delta is locked to 1 for:

- Must-run resources (i.e. resources with self-schedules or AS awards),
- Resources that have not fulfilled their minimum run time (also called minimum up time)

E.3.2 Critical constraint calculations – SCFPPS

The effective counterflow supply from potentially pivotal suppliers on constraint l (SCF_l^{PPSCCM}) or constraint clc (SCF_{ckc}^{PPSCCM}) are expressed in the equations and input definitions described below and are calculated for resources I in potentially pivotal supplier portfolio J with $SF_{l,i} < 0 \; or \; SF_{clc,i} < 0$:

$$SCF_l^{PPSCCM} = \sum_{j=1}^{n}\sum_{i=1}^{n} SPCF_{l,j,i}^{PPSCCM}$$

$$SCF_{clc}^{PPSCCM} = \sum_{j=1}^{n}\sum_{i=1}^{n} SPCF_{clc,j,i}^{PPSCCM}$$

IFM formulation:

$SPCF_{l,j,i}^{PPSCCM}$=0

$SPCF_{clc,j,i}^{PPSCCM}$=0

RTUC formulation:

$$SPCF_{l,j,i}^{PPSCCM} = SF_{l,i} * \delta \max(DOP_{i,IC} - RR_i * 15 * N, ENGYMIN_i)$$

$$SPCF_{clc,j,i}^{PPSCCM} = SF_{ckc,i} * \delta min\left[\max\left(DOP_{i,IC} - RR_i * 15 * N, ENGYMIN_i\right) + RR_i * 20, ENGYMAX_i)\right]$$

$Where \; \delta = \{0,1\}$

$DOP_{i,IC} - RR_i * 15 * N \leq ENGYMIN_i \rightarrow \delta = 0$

$DOP_{i,IC} - RR_i * 15 * N > ENGYMIN_i \rightarrow \delta = 1$

Note - Delta is locked to 1 for:

- Must-run resources (i.e. resources with self-schedules or AS awards),
- Resources that have not fulfilled their minimum run time (also called minimum up time)

E.4 Counterflow supply from fringe competitive suppliers

Effective supply of physical counterflow (SPCF) to binding or non-binding constraints in the critical constraint set from a physical resource i belonging to ***fringe competitive supplier*** (FCS) is the highest possible output from the fringe competitive suppliers. Fringe competitive suppliers do not withhold any capacity. In the day-ahead, this is the total effective supply without ramp constraints versus real-time which is ramp-constrained supply.

E.4.1 Binding constraint calculations – SCFFCS

No changes are being proposed to the test on binding constraints for supply of counterflow from fringe competitive supplier.

E.4.2 Critical constraint calculations – SCFFCS

The effective counterflow supply from fringe competitive suppliers on constraint l (SCF_l^{FCSCCM}) or constraint clc (SCF_{clc}^{FCSCCM}) are expressed in the equations and input definitions described below and are calculated for resources I in potentially pivotal supplier portfolio J with $SF_{l,i} < 0 \; or \; SF_{clc,i} < 0$:

$$SCF_l^{FCSCCM} = \sum_{j=1}^{n}\sum_{i=1}^{n} SPCF_{l,j,i}^{FCSCCM} + \sum_{j=1}^{n}\sum_{i=1}^{n} SVCF_{l,j,i}$$

$$SCF_{clc}^{FCSCCM} = \sum_{j=1}^{n}\sum_{i=1}^{n} SPCF_{ckc,j,i}^{FCSCCM} + \sum_{j=1}^{n}\sum_{i=1}^{n} SVCF_{clc,j,i}$$

IFM formulation:

$SPCF_{l,j,i}^{FCSCCM}=SF_{l,i} * ENGYMAX_i$

$SVCF_{l,j,i} = SF_{l,i} * DOP_i$

$SPCF_{clc,j,i}^{FCSCCM}=SF_{clc,i} * ENGYMAX_i$

$SVCF_{clc,j,i} = SF_{clc,i} * DOP_i$

RTUC formulation:

$SPCF_{l,j,i}^{FCSCCM} = SF_{l,i} * \min(DOP_{i,t-1} + RR_i * 15, ENGYMAX_i)$

$SPCF_{clc,j,i}^{FCSCCM} = SF_{clc,i} * \min(DOP_{i,t-1} + RR_i * 35, ENGYMAX_i)$[42]

$SVCF_{l,j,i} = 0$ (virtual bids liquidated prior to real-time)

$SVCF_{clc,j,i} = 0$ (virtual bids liquidated prior to real-time)

E.5 Demand for counterflow

The demand for counterflow to binding or critical constraint in the critical constraint set is the sum of all dispatched energy that will flow in the counterflow direction. Dispatched energy from both physical and virtual supply resources included as eligible resources. The set of resources summed will not include virtual supply in real-time since virtuals are liquated prior to the real-time market runs.

D.5.1 Binding constraint calculations – DCF

No changes are being proposed to the demand for counterflow.

[42] Note this corrective capacity constraint formulation for the SCF[FCS] is not a policy proposal under CCE3 but is included to aid comprehension.

D.5.2 Critical constraint calculations – DCF

The demand for counterflow to constraint l (DCF_l^{CCM}) or constraint clc (DCF_{ckc}^{CCM}) is expressed as follows and calculated for physical resources and virtual supply resources I with $SF_{l,i} < 0\ or\ SF_{clc,i} < 0$ and constraints l contained within the critical constraint list:

$$DCF_l^{CCM} = \sum_{i=1}^{n} SF_{l,i} * DOP_i$$

$$DCF_{clc}^{CCM} = \sum_{i=1}^{n} SF_{clc,i} * (DOP_i + CC_i)$$

The supply from pump storage and NGR resources shall be included in the counter flow calculation. The demand side of pump storage and NGR resources shall be excluded from the flow calculation. The NGR, demand side of PDR, RDRR, Dispatched Pump resources, and NGR shall be excluded from the flow calculation. The external resources will be excluded from the flow calculation.

E.6 Residual supply index

Residual supply index is the test metric for whether a constraint l contained within the critical transmission constraint list L or critical corrective capacity constraint list CKC is considered competitive or uncompetitive.

The test metric for this residual supply index for critical constraints is expressed as:

$$RSI_k^{CCM} = \frac{SCF_k^{PPSCCM} + SCF_k^{FCSCCM}}{DCF_k^{CCM} - (Limit_k - Flow_k)}$$

$$RSI_{ckc}^{CCM} = \frac{SCF_{ckc}^{PPSCCM} + SCF_{ckc}^{FCSCCM}}{DCF_{ckc}^{CCM} - (Limit_{ckc} - Flow_{ckc})}$$

$$RSI_l^{CCM} = \frac{SCF_l^{PPSCCM} + SCF_l^{FCSCCM}}{DCF_l^{CCM} - (Limit_l - Flow_l)}$$

$$RSI_{clc}^{CCM} = \frac{SCF_{clc}^{PPSCCM} + SCF_{clc}^{FCSCCM}}{DCF_{clc}^{CCM} - (Limit_{clc} - Flow_{clc})}$$

If $RSI_{k,ckc,l,clc}^{CCM} \geq 1$ then the constraint is deemed competitive else $RSI_{k,ckc,l,clc}^{CCM} < 1$ and deemed uncompetitive.

E.7 LMPM mitigation criteria

E.7.1 Binding constraint calculations – mitigation criterion

First, the CAISO will test for a resources' locational advantage to withhold to impact energy and mitigate the energy bid if the resource fails. For each interval within the optimization horizon, system will assess if the mitigation criterion is met. The mitigation criterion for mitigating energy bid is a positive non-competitive congestion component at the resource's LMP (LMP decomposition).

Given the mitigation reference bus, the analysis finds the binding constraints in AC run, and decomposes the locational marginal price (LMP) for every pricing node location I to identify what portion of the marginal congestion component (MCC, LMP_i^{NC}) comes from congestion costs associated with non-competitive constraints. Every unit with $LMP_i^{NC} > 0$ will be flagged for mitigation - a zero tolerance criterion.

LMP decomposition breaks out the contribution to marginal congestion component from the non-competitive constraints[43]:

$$LMP_i = LMP_i^{EC} + LMP_i^{LC} + LMP_i^{CC} + LMP_i^{NC}$$

Where:

LMP_i^{EC}= the energy component of LMP_i

LMP_i^{LC}= the loss component of LMP_i

LMP_i^{CC}= the congestion component of LMP_i due to the competitive constraints where $RSI_k \geq 1$ or $RSI_{ckc} \geq 1$

LMP_i^{NC}= the congestion component of LMP_i the non-competitive constraints where $RSI_k < 1$ or $RSI_{ckc} < 1$

E.7.2 Critical constraint calculations – mitigation criterion

The CAISO will calculate additional criteria for mitigating only the commitment cost components if the resource has locational advantage to inflate uplift due to non-competitive critical transmission or critical corrective capacity constraints. The non-competitive commitment mitigation criterion (DOP_i^{NC}) would be determined as follows for resources with negative shift factors to the constraint:

- For binding constraints mitigate if $SF_{l,i} < 0 \; or \; SF_{clc,i} < 0 \;\; and \; l \; or \; ckc \; has \; an \; RSI_k < 1$ or $RSI_{ckc} < 1$.
- For non-binding constraints mitigate if $DOP_i \geq (Limit_l - Flow_l)$ or $DOP_i \geq (Limit_{clc} - Flow_{clc})$ for where l or clc $has \; an \; RSI_k < 1$ or $RSI_{ckc} < 1$.

The non-competitive commitment mitigation criterion for binding constraints is the shift factor of any non-exempt resource. If a non-exempt resource has a negative shift factor to any non-competitive constraint it would fail the resource test. This is also a zero tolerance criterion.

The non-competitive commitment mitigation criterion for non-binding constraints is whether the resource has a dispatch that is greater than or equal to the unloaded capacity. If a non-exempt resource with a negative shift factor to each non-competitive constraint has a dispatch that provides counterflow that is greater than the unloaded capacity. This does not account for the exact sensitivity of the resource's injection to the non-competitive constraint. This is performed for each non-competitive, critical constraint.

[43] The ISO has a shift factor effectiveness threshold of 0.02, which means that any shift factor with absolute values less than 0.02 will not be considered in the decomposition.

ED.8 Mitigated values

As result of dynamic mitigation, minimum load bids will be mitigated at higher of the market revenues for minimum load energy (product of the LMP and the lower operating limit) and the lower of the minimum load cost bid or the minimum load reference level). Where start-up or transition cost bids will be mitigated at lower of the commitment cost bid of the commitment cost reference level. Mitigated reference levels regardless of which commitment cost component can be one either an estimated or negotiated reference level option or adjusted through the reference level adjustment request tool.

Demand response, participating load, non-generator resources and virtual supply are included in power balance constraint but are exempt from mitigation. Mitigation will not be applied to these types of resources (tariff requirement).

ED.9 Applying mitigation to commitment costs

LMPM applies mitigation to the commitment cost components as follows if the resource failed any of the mitigation criteria: non-competitive congestion component, non-competitive commitment on binding constraints, or non-competitive commitment on non-binding constraints.

Bid mitigation will be applied based on current bid mitigation rules if the non-competitive congestion component fails. Bid mitigation will be applied differently to the minimum load and the start-up/transition cost components if either the non-competitive commitment criterions fail. For minimum load bids, the California ISO will evaluate each interval within an impact window defined as the range of intervals tested (i+MUT). For start-up or transition bids, the California ISO will evaluate each interval within the optimization horizon (T).

LMPM applies mitigation to minimum load bids by:

- Day-ahead market: bids mitigated for the hour the resource failed
- Real-time market: bids mitigated for the range of intervals tested (impact window) if the criteria are met in any interval within the impact window

LMPM applies mitigation to start-up and transition cost bids by:

- Day-ahead market: bids mitigated for the set of intervals of the optimization window T if the criteria are met in any interval within the horizon T
- Real-time market: bids mitigated for the set of intervals of the optimization window T if the criteria are met in any interval within the horizon T