July 9, 2020

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER20-____-000

Tariff Amendment to Enable Updates to Default Commitment Cost and Default Energy Bids, Request for Timely Commission Order, and Request for Waiver of 120-Day Notice Requirement

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to enable suppliers to request adjustments to their CAISO-calculated commitment cost and energy price reference levels that more accurately reflect their costs.[1] These enhancements arise from the CAISO's Commitment Costs and Default Energy Bid Enhancements (CCDEBE) stakeholder initiative.[2]

Currently CAISO tariff rules do not permit suppliers to request updates to cost-based CAISO-calculated reference levels. This can produce cost-based reference levels that do not sufficiently compensate suppliers and prevent the CAISO from scheduling or dispatching resources. To address these issues, the CAISO proposes pre- and post-market procedures that allow suppliers to request changes to their reference levels to reflect increases in their fuel cost exposure. The pre- and post-market verification procedures will also verify supplier bids above $1,000 per megawatt-hour (MWh) in compliance with Commission Order

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[1] The CAISO submits this filing pursuant to section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d.

[2] The enhancements are in most (but not all) respects identical to those the CAISO proposed in the tariff amendment it submitted last year in Docket No. ER19-2727, which the Commission rejected without prejudice to refiling. *See Cal. Indep. Sys. Operator Corp.*, 170 FERC ¶ 61,015, at PP 39-42 (2020) (First CCDEBE Order).

Nos. 831 and 831-A.[3] The CAISO has proposed tariff changes in compliance with those orders in a separate compliance filing.[4]

The tariff amendment also addresses certain concerns expressed in the First CCDEBE Order regarding the use of multipliers in connection with reference level changes.[5] Specifically, the CAISO no longer proposes to include any multipliers when calculating reference levels in the context of an adjustment based on verifiable actual or expected costs.

Finally, this tariff amendment also includes certain refinements to provisions developed in the CCDEBE stakeholder initiative that were later developed in the CAISO's Local Market Power Mitigation Enhancements (LMPME) stakeholder initiative. Stakeholders generally supported these proposed tariff revisions in both stakeholder initiatives. For the reasons set forth below, the Commission should accept the CAISO's proposals and reject any alternative suggestions from stakeholders.[6]

The CAISO expects to implement the changes proposed in this tariff amendment between October 1, 2020 and January 31, 2021. The CAISO requests authority to provide at least fourteen days' notice of the actual effective date to the Commission and market participants.[7] To allow the CAISO to meet the earliest of these possible effective dates, the CAISO requests that the Commission issue an order by September 21, 2020 accepting this tariff amendment. The CAISO also respectfully requests that the Commission grant

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[3] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, FERC Stats. & Regs. ¶ 31,387 (2016) (Order No. 831), *order on reh'g and clarification*, Order No. 831-A, 161 FERC ¶ 61,156 (2017) (Order No. 831-A).

[4] *See* Docket No. ER19-2757. In the instant filing, the CAISO refers to the filing it submitted in that docket to comply with Order No. 831 as the "Order No. 831 Compliance Filing". The CAISO has informed the Commission of its intent to file further amendments to its tariff under Section 205 of the FPA related to setting of its penalty prices implicated by Order No. 831 as well as verification rules for import bids above $1,000/MWh to address issues raised by certain stakeholders. *See* Motion for Leave to Answer and Answer of the California Independent System Operator Corporation to Comments and Limited Protests, Docket No. ER19-2757-000, at 9-11 (Oct. 11, 2019).

[5] *See* First CCDEBE Order at PP 40-41.

[6] The CAISO submits this tariff amendment of a single proposal the elements of which are not severable from each other and are interrelated. The Commission should consider the just and reasonableness of the proposal as such.

[7] The CAISO has included an effective date of 12/31/9998 as part of the tariff records submitted with this filing. The CAISO will make a filing pursuant to Commission Filing Code 150 to provide notice of the actual effective date of these tariff records at least fourteen days prior to implementation.

waiver of its 120-day notice requirement, in case such waiver is needed to permit the actual effective date.

I. EXECUTIVE SUMMARY

During the past several years, the CAISO has conducted several stakeholder initiatives[8] to enhance its market rules regarding three-part bids for energy supply resources. Prior tariff amendments improved rules for (1) commitment cost bids, *i.e.*, costs to start up resources (start-up costs), costs to keep resources running at a minimum operating level (minimum load costs), and costs to transition a multi-stage generator between configurations (transition costs), and (2) cost-based bids for energy above minimum load.[9]

Since then, the CAISO determined through the extensive CCDEBE and LMPME stakeholder initiatives, and other communications with energy suppliers, that the existing cost-based reference levels (which consist of the cost-based default commitment cost bids and default energy bids) sometimes fail to reflect actual or expected costs. Generally, the CAISO's market design provides sufficient bidding flexibility for suppliers to submit economic bids reflecting their actual costs. However, the current rules unduly limit a supplier's ability to reflect its verifiable actual or expected costs when it is subject to cost-based reference levels. These limitations can discourage suppliers from participating in the CAISO market because they cannot recover their costs. Further, the CAISO market relies on suppliers submitting supply offers that reflect their actual or expected costs to produce an efficient market dispatch.

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8 *See Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282 (2009); *Cal. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,257 (2011); *Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,237 (2012); *Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,082 (2013); *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,284 (2014); *Cal. Indep. Sys. Operator Corp.*, 152 FERC ¶ 61,185 (2015); *Cal. Indep. Sys. Operator Corp.*, 157 FERC ¶ 61,138 (2016); *Cal. Indep. Sys. Operator Corp.*, 163 FERC ¶ 61,211 (2018); *Cal. Indep. Sys. Operator Corp.*, 168 FERC ¶ 61,213 (2019) (LMPME Order). The LMPME Order addressed three sets of proposed tariff revisions to implement the CAISO's LMPME initiative. It accepted two of the sets but rejected the third. The CAISO filed a request for rehearing of the LMPME Order with regard to the rejected tariff revisions. The request for rehearing is currently pending before the Commission.

9 The commitment cost market rule changes addressed the level of caps imposed on commitment cost bids (*i.e.*, the default commitment cost bids) and resources' ability to re-bid commitment costs in the CAISO's real-time market. These market rule changes addressed bids for energy above minimum load, incorporated opportunity costs into default energy bids, and created a default energy bid specific to hydroelectric resources. The CAISO uses default energy bids as part of the market's local market power mitigation process and for certain energy financial settlement provisions.

The CAISO uses CAISO-calculated cost-based reference levels in four circumstances.[10] First, suppliers can bid commitment costs (start-up and minimum load costs) up to a resource's default commitment cost bids, which are the cost-based commitment costs calculated by the CAISO based on prescribed procedures and formulas. Second, although the CAISO allows suppliers to bid up to $1,000/MWh for energy above minimum load, the market systems use a supplier's default energy bid to schedule or dispatch the resource when its energy bid is subject to market power mitigation. Third, the CAISO uses a supplier's default energy bid as part of various energy financial settlement provisions for residual energy and exceptional dispatches under certain scenarios. Fourth, the CAISO market systems calculate resources' cost-based commitment costs and energy costs (1) to produce generated bids, which are bids generated when resource adequacy resources fail to submit required bids, or (2) when the CAISO market systems must complete an incomplete submitted bid.

For natural gas-fired resources, which constitute a significant portion of the resources in the CAISO market, the CAISO-calculated commitment costs and default energy bids are based on published natural gas price indices used to reflect those resources' daily fuel costs. However, suppliers' actual natural gas costs may be greater than a price derived from these published indices. If suppliers can accurately reflect such costs, the market will ensure that resources are dispatched optimally and suppliers recover their costs.

The proposed revisions proposed will better allow reference levels to reflect actual costs and promote more optimal dispatch. The tariff amendment provides a means for suppliers to request adjustments to their resources' commitment costs and default energy bids levels before the CAISO market clearing process.

The CAISO proposes two pre-market options so it can evaluate suppliers' requests to change their reference levels before using the updated reference levels in the applicable CAISO market:

(1) An automated option whereby the CAISO can make incremental adjustments to reference levels by comparing the requested

[10] Under the CAISO tariff, commitment cost bid caps are calculated using either a defined "proxy cost" methodology or "registered cost" methodology. Commitment cost bid caps calculated using the proxy cost methodology are sometimes called "commitment cost reference levels". Default energy bids are sometimes called "energy reference levels". A resource's cost-based commitment cost bid caps and default energy bids are sometimes collectively called the resource's "reference levels".

reference level changes with CAISO-calculated reasonableness thresholds of a suppliers reference levels;[11] and

(2) A manual option whereby the CAISO evaluates information that reflects fuel cost increases submitted by suppliers along with the reference level change requests that would not be captured by the reasonableness thresholds.

The CAISO requests authority to audit automated reference level change requests to ensure suppliers submitted such requests based on a reasonable expectation that their fuel costs would be greater than the fuel costs included in their reference levels. Because the automated option is not intended to be a safe haven for requests within the reasonableness thresholds, the CAISO must audit and prevent misuse to protect the integrity of the automated procedure.

The CAISO also proposes procedures to allow suppliers to request the CAISO provide uplift payments for actual fuel costs suppliers are unable to recover through market payments, and that are not verified before the market clearing process. The CAISO also proposes to allow suppliers to request recovery of such costs through a Commission order directing the CAISO to provide uplift payments.

In the First CCDEBE Order, the Commission rejected similar enhancements based on its determination that the CAISO had not demonstrated that one element of its proposal (*i.e.,* the CAISO's proposal to apply a 125 percent multiplier to default commitment cost bids that are calculated pursuant to an approved reference level change request) was just and reasonable. However, the Commission provided guidance to the CAISO and expressly stated its decision was without prejudice to the CAISO to refile its proposal. In response to the Commission's guidance, the CAISO has modified its proposal to remove. The multipliers in the calculation of any reference levels calculated pursuant to verifiable actual or expected fuel costs under a reference level change request. The data collected by the CAISO and the Department of Market Monitoring (DMM) supports this change, and shows there is insufficient evidence to support applying multipliers to reference levels that are calculated in the context of reference level change requests based on verifiable actual or expected fuel costs. The CAISO's prior proposal, which the Commission rejected, included multipliers in the context of a reference level change request based on the CAISO's expectation that fuel prices could change throughout the day after the supplier submitted its initial reference level change request. However, subsequent CAISO research showed that prices do not vary sufficiently to warrant such multipliers.

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[11] The CAISO will calculate the reasonableness thresholds for each resource based on the resource's reference levels and additional margins to account for potential fuel variability.

The proposed tariff amendment is just and reasonable, because it provides a reliable and verifiable method for expeditiously updating cost-based reference levels before the CAISO markets clear, which will enable efficient and reliable market outcomes. The proposed cost verification procedures ensure suppliers have the ability to request increases to their cost-based reference levels for their verifiable actual or expected fuel cost increases. This will ensure they do not experience revenue deficiencies to cover their fuel costs when fulfilling CAISO commitments and dispatches, while ensuring the cost-based reference levels continue to be based on verifiable costs. To the extent actual fuel costs cannot be verified before clearing the market, the proposed amendment includes an objective after-the-fact process for verifying actual fuel costs to the extent their market revenues do not cover such costs. Further, the proposed amendment is just and reasonable, because it eliminates concerns with the inclusion of multipliers in the calculations of reference levels that are based on verifiable actual or expected fuel costs, and are not based on price indices that may not may not reflect such costs accurately. Finally, the proposed verification mechanisms will also serve as the foundational mechanism the CAISO requires to fulfill its obligation to comply with Order No. 831.

Finally, the CAISO proposes several clarifying tariff revisions, including changes to defined terms and cross references, necessitated by the market rule changes proposed herein. These also include revisions to clarify and reorganize the existing tariff provisions on the proxy cost methodology.

II. BACKGROUND

A. Overview of CAISO Market Structure

The CAISO administers day-ahead and real-time wholesale electricity markets.[12] Although the day-ahead market[13] only includes the CAISO balancing authority area, the real-time market[14] extends to other balancing authority areas

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12 Existing tariff appendix A, existing definition of "CAISO Markets". For the sake of clarity, this transmittal letter distinguishes between existing tariff provisions (*i.e.*, provisions in the current CAISO tariff), new tariff provisions (*i.e.*, new provisions that the CAISO proposes to add to the tariff in this filing), revised tariff provisions (*i.e.*, existing tariff provisions that the CAISO proposes to revise in this filing), and deleted tariff provisions (*i.e.*, existing tariff provisions that the CAISO proposes to delete in this filing).

13 The day-ahead market consists of the following processes performed in sequence: the market power mitigation process, the integrated forward market (IFM), and the residual unit commitment (RUC). Existing tariff section 31.

14 The real-time market (RTM) consists of the following processes: the hour-ahead scheduling process (HASP), the real-time unit commitment (RTUC), the short-term unit

participating in the Energy Imbalance Market (EIM),[15] which currently includes the CAISO and ten EIM entities.

The real-time market conducts a multi-interval optimization for each of the real-time market processes. Thus, each real-time market run produces results for multiple market intervals. The real-time unit commitment (RTUC) runs every 15 minutes, and looks ahead from four-to-seven 15-minute intervals, depending on the run. The STUC runs once an hour, and looks out four hours and 30 minutes. The STUC and the RTUC perform security-constrained economic dispatch and unit commitment to produce start-up and shutdown instructions, and advisory schedules and prices, most of which are not used for financial settlement. The second interval of each RTUC run produces financially binding energy, ancillary service, and flexible ramping product schedules and prices for the fifteen minute market model (FMM). The CAISO market financially settles the FMM based on differences from day-ahead schedules or, in the EIM, from base schedules. The CAISO uses one of the RTUC runs to initially schedule imports and exports, *i.e.*, the HASP.

The RTD conducts a security-constrained economic dispatch to produce binding energy dispatch instructions and prices, and flexible ramping product schedules, every 5 minutes. The RTD looks out from nine to thirteen 5-minute intervals, depending on the run. The first RTD interval is the binding market interval used for the final resource dispatch and financial settlement. The results for the RTD intervals beyond the binding run are advisory, and are not the basis for settlements or dispatch. The CAISO financially settles the RTD based on differences from FMM schedules.

The CAISO market design includes specific rules for submitting bids and self-schedules of energy and ancillary services in the CAISO market,[16] and allows market participants to submit separate bid components for commitment costs and market bids for energy above minimum load. Market participants can also engage in convergence bidding (sometimes called virtual bidding) to hedge their physical market positions that have exposure to differences between day-ahead and real-time prices.[17] The maximum energy bid price is $1,000/MWh.[18]

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commitment (STUC), the fifteen minute market (FMM), and the real-time dispatch (RTD). Existing tariff section 34.

[15] The EIM is generally addressed in existing tariff section 29, *et seq.*

[16] Existing tariff section 30, *et seq.*

[17] Existing tariff section 30.9.

[18] Existing tariff section 39.6.1.1. The tariff definition of an energy bid includes virtual bids. Tariff appendix A, existing definition of “Energy Bid”. In the Order No. 831 Compliance Filing, the CAISO indicated then that it intended to commence a stakeholder process to consider changes to cost-verify import bids that exceed $1,000/MWh, and the setting of penalty prices currently

The CAISO operates its markets using a market software system that utilizes various information. The information includes transmission constraints that the CAISO enforces consistent with good utility practice to ensure, to the extent possible, that the market model used in each CAISO market reflects all the factors that contribute to actual real-time flows on the CAISO controlled grid, and that the CAISO market results align with actual physical conditions on the grid.[19]

B. Bidding and Compensation of Generating Resource Commitment Costs

In making commitment decisions, the CAISO market separately considers the costs of bids for energy above minimum load, the costs of starting up resources (start-up costs), the costs of operating resources at their minimum operating levels (minimum load costs),[20] and, for resources that are modeled as multi-stage generating resources, the costs of transitioning from one resource configuration to another (transition costs).[21] All resources, except for certain use-limited resources that are modeled under the registered cost methodology described below, bid their start-up costs, minimum load costs, and transition costs pursuant to the proxy cost methodology.[22] Resources subject to the proxy cost methodology submit daily bids for their start-up costs, minimum load costs, and transition costs that are between zero and 125 percent of the calculated

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pegged to the bid cap, which are used to price energy when the power balance and transmission constraints are relaxed. *See* transmittal letter for Order No. 831 Compliance Filing at 20-21. More recently, the CAISO notified the Commission that although it had intended to implement Order No. 831 by the fall of 2020, it now expects to do so in the fall of 2021 to accommodate any changes it must make to its tariff, and systems based on the outcome of the pending stakeholder initiatives considering these two matters. *See* pages 4-5 of the motion for leave to answer and supplemental answer to comments, and limited protests the CAISO filed in Docket No. ER19-2757 on January 31, 2020.

[19] Existing tariff section 27.5.6.

[20] Existing tariff section 31.3; tariff appendix A, existing definitions of “Start-Up Cost” and “Minimum Load Costs”.

[21] The tariff refers to these latter resources as MSG resources. *See* tariff appendix A, existing definition of “Multi-Stage Generating Resources”. For an MSG resource, transition cost is the dollar cost per feasible transition from a given MSG configuration to a higher MSG configuration when the resource is already on. Tariff appendix A, existing definition of “Transition Cost”.

[22] Existing tariff section 30.4. Commitment costs calculated using the proxy cost methodology are sometimes called “commitment cost reference levels”.

proxy cost (the proxy cost bid cap, also referred to herein as the default commitment cost bid), which is largely driven by daily natural gas prices.[23]

The Commission approved the existing proxy cost-based default commitment cost bid structure, which includes applying a 125 percent multiplier (*i.e.*, the commitment cost multiplier) to the calculated proxy costs.[24] The CAISO based the existing proxy cost-based default commitment cost bid on its analyses of intra-day gas purchasing costs, which showed that some bidding headroom is appropriate to allow resources to recover costs associated with day-over-day and intra-day gas price volatility. The CAISO's proxy cost 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 proxy cost do not, and cannot, perfectly reflect the actual costs incurred by generators.

If resources under the proxy cost methodology do not recover the sum of their bid-in costs through the market, *i.e.*, commitment, energy, ancillary services, and RUC costs, the resources can recover them through a bid cost recovery uplift payment.[25] If such a supplier incurs, but cannot recover through the bid cost recovery process, any actual marginal fuel procurement costs that exceed the limit on start-up costs, transition costs, and minimum load bid costs, the supplier may seek to recover those costs through a Commission filing under FPA section 205[26]

In 2019, the CAISO implemented tariff changes regarding the treatment of use-limited resources and the CAISO's opportunity cost policies. These tariff changes included new rules to: (1) allow eligible use-limited resources to include opportunity cost adders in their commitment costs and default energy bid costs; (2) limit the registered cost methodology to use-limited resources with fewer than 12 months of locational marginal pricing data; and (3) clarify the definition of use-limited resources and make certain tariff clarifications.[27] Instead of using the proxy cost methodology, suppliers for use-limited resources that have fewer than

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23 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).

24 *See Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,284.

25 Existing tariff section 11.8, *et seq.*

26 Existing tariff section 30.11.

27 The Commission accepted the tariff revisions in relevant part in *California Independent System Operator Corporation*, 165 FERC ¶ 61,038 (2018).

12 months of locational marginal pricing data can elect the registered cost methodology to register fixed commitment cost values of their choosing in the master file.[28] The registered cost methodology is reserved for new use-limited resources because the CAISO is unable to calculate opportunity costs without 12 months of locational marginal prices (LMPs) at a resource's location.

Under tariff revisions accepted in the First CCDEBE Order,[29] the CAISO calculates natural gas prices for the day-ahead market, except for Mondays when a Monday-only gas price index is available and meets specified liquidity criteria, based on natural gas price index information published by the Intercontinental Exchange (ICE) one day prior to the applicable trading day between 8:00 a.m. and 9:00 a.m. Pacific Time[30] for next-day gas trading occurring on the morning of the day-ahead market execution. The CAISO also calculates natural gas prices for the real-time market, again subject to a Monday-only gas price index, based on natural gas price index information published by at least one of the following publications: Natural Gas Intelligence (NGI); SNL Energy/BTU's Daily Gas Wire (SNL); or Platt's Gas Daily (Platt's). The CAISO updates the gas price indices for the real-time market between 7:00 p.m. and 10:00 p.m. using the natural gas prices published one day prior to the applicable trading day.[31]

C. Default Energy Bids and Generated Bids

The market power mitigation process for the CAISO market uses default energy bids for energy above a resource's minimum load when local market

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[28] Existing tariff sections 30.4 and 30.4.1.2; tariff appendix A, existing definition of "Master File" (a file maintained by the CAISO that contains information regarding generating, loads, and other resources). The registered costs are subject to a cap set at 150 percent of the calculated projected proxy cost. Existing tariff section 39.6.1.6. The cap for registered costs is based on historical fuel price levels and fuel volatility demonstrating that the 150 percent registered cost cap will cover the monthly fuel price risk associated with purchasing natural gas on the spot market. The 150 percent registered cost cap accounts for opportunity costs, any risk in gas markets, and any non-fuel costs not included in the proxy cost calculation. Finally, the 150 percent registered cost cap is intended to be a market mitigation measure. *See Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,082, at PP 7, 21-24.

[29] *See* First CCDEBE Order at PP 49-50, 56.

[30] In this transmittal letter, all specified times are Pacific Time.

[31] Existing tariff sections 39.7.1.1.1.3(a)-(c). These tariff provisions went into effect on a permanent basis on January 28, 2020. *See* http://www.caiso.com/Documents/ManualProcess-UpdateGasPriceIndexWillResume-012820.html#search=January%2024%2C%202020%20market%20notice (CAISO market notice announcing the January 28 effective date). If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index as set forth in existing tariff section 39.7.1.1.1.3(c).

power mitigation is triggered in a market interval.[32] When a resource's bid is mitigated, the CAISO market systems substitute the greater of a resource's default energy bid or the "competitive LMP" for the resource's bid in the market clearing process and uses this mitigated bid price as part of determining the resource's bid cost recovery compensation.[33] Default energy bids also factor into the settlement of residual imbalance energy and exceptional dispatches in some circumstances.[34]

Each supplier can choose one of four options for calculating default energy bids for a resource: (1) the variable cost option; (2) the negotiated rate option; (3) the LMP option; or (4) the hydro default energy bid option.[35] For a natural gas-fired resource subject to the variable cost option, the default energy bid is based on incremental fuel costs, which are based on gas prices published in natural gas price indices. All default energy bids under the variable cost option include a 10 percent multiplier (*i.e.*, default energy bid multiplier) to the CAISO's calculated cost based on the gas price indices.[36] The CAISO calculates default energy bids for the day-ahead and real-time markets, respectively, using the gas commodity price formulas described above for commitment costs.[37]

The CAISO generates cost-based bids (*i.e.*, generated bids) using the same cost components and resource-specific information used in calculating the variable-cost default energy bid when a supplier does not submit a bid for a resource adequacy resource subject to a must-offer requirement or under the generally applicable scheduling and bidding rules set forth in the CAISO tariff and

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32 Existing tariff section 39.7.1, *et seq.* Default energy bids are sometimes called "energy reference levels". A resource's cost-based commitment costs and default energy bids are sometimes collectively called the resource's "reference levels".

33 Existing tariff section 11.8, *et seq.* The competitive LMP is the LMP at the resource's location minus the portion of the LMP's congestion component that is attributable to uncompetitive transmission constraints.

34 Existing tariff sections 11.5.5 and 11.5.6.

35 Existing tariff sections 39.7.1 – 39.7.1.3. Further, a supplier for a frequently mitigated unit has a fourth option for calculating default energy bids, the frequently mitigated unit option. Existing tariff section 39.7.1.4. In addition, a supplier for a hydroelectric resource with storage capability has a fifth option for calculating default energy bids, the hydro default energy bid option. Existing tariff section 39.7.1.7. *See also California Independent System Operator Corporation.*, 168 FERC ¶ 61,213 (2019). The CAISO may also establish temporary default energy bids. Existing tariff section 39.7.1.5.

36 The Commission authorized the CAISO to implement the 10 percent adder in *California Independent System Operator Corporation*, 116 FERC ¶ 61,274, at P 1045 (2006).

37 Existing tariff sections 39.7.1.1 – 39.7.1.1.1 and 39.7.1.1.1.3 – 39.7.1.1.1.4.

the business practice manual.[38] As with commitment costs and variable-cost default energy bids, the CAISO determines gas costs for generated bids of natural gas-fired resources using the gas pricing provisions described above.[39]

D. Stakeholder Processes Preceding this Tariff Amendment

The CAISO initiated the CCDEBE stakeholder process that led to this tariff amendment in November 2016.[40] The stakeholder process included the following opportunities for stakeholder input and participation:

- The CAISO issued five papers;[41]
- The CAISO held several stakeholder conference calls and working group meetings to discuss the issues raised in the CAISO papers and provided opportunities for stakeholders to submit comments on the papers;
- The CAISO developed draft tariff provisions; and
- The CAISO held additional conference calls and provided opportunities for stakeholders to submit written comments on the draft tariff provisions.[42]

The CAISO Governing Board (Board) voted unanimously to authorize this filing at its public meeting held on March 22, 2018.[43]

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38 Pursuant to the current tariff rules, generated bids do not include the 10 percent adder that the CAISO applies to default energy bids. *See* existing tariff section 39.7.3.4.

39 Existing tariff sections 30.7.3.4 and 40.6.8; tariff appendix A, existing definition of "Generated Bid".

40 Materials related to the CCDEBE stakeholder process are available at http://www.caiso.com/StakeholderProcesses/Commitment-costs-and-default-energy-bid-enhancements.

41 These papers included the Second Revised Draft Final Proposal provided in attachment C to this filing. As discussed further below, the CAISO subsequently determined that it should include in this filing some of the changes contemplated in the Second Revised Draft Final Proposal but not others.

42 A list of key dates in the stakeholder process is provided in attachment F to this filing.

43 Materials related to the Board's authorization are available at http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx. These materials included a memorandum to the Board from Keith Casey, Vice President, Market & Infrastructure Development (CCDEBE Board Memorandum), which is provided in attachment D to this filing. The EIM Governing Body also issued a memorandum supporting the proposed CCDEBE changes. *See* http://www.caiso.com/Documents/Decision_CCDEBEProposal-EIMGoverningBodyAdvisoryOpinion-Mar2018.pdf.

Stakeholders generally support the policies reflected in this tariff amendment; although, some stakeholders object to certain features. The CAISO addresses any objections in the relevant sections of this transmittal letter.

This filing also contains some tariff revisions arising from the separate LMPME stakeholder initiative to refine the gas prices used in reasonableness thresholds for the real-time market.[44] The CAISO specifically identifies the LMPME-related tariff revisions in the discussion below.

The CAISO initiated the LMPME stakeholder process that led to some of the changes proposes in this tariff amendment in October 2018. The stakeholder process included the following opportunities for stakeholder input and participation:

- The CAISO issued four papers;
- The CAISO held several stakeholder conference calls and working group meetings to discuss the issues raised in the CAISO papers and provided opportunities for stakeholders to submit comments on the papers;
- The CAISO developed draft tariff provisions; and
- The CAISO held additional conference calls and provided opportunities for stakeholders to submit written comments on the draft tariff provisions.
- The Board voted unanimously to authorize this filing at its public meeting held on March 27, 2019.[45]

Through the stakeholder process, the CAISO developed a comprehensive set of market rule changes in response to these stakeholder concerns. The revised market rules would enable the CAISO to update the gas price used in

[44] Materials related to the LMPME stakeholder process are available at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2018.aspx. The CAISO filed a separate tariff amendment to implement LMPME (other than the components of LMPME reflected in the instant filing) on July 2, 2019 in Docket No. ER19-2347-000 (LMPME Tariff Amendment). As noted above, the LMPME Order addressed the proposals in that tariff amendment.

[45] The CAISO provides, in attachment E to this filing, a memorandum to the Board from Keith Casey, Vice President, Market & Infrastructure Development regarding the proposed LMPME changes (LMPME Board Memorandum). The EIM Governing Body also issued a memorandum supporting the changes proposed in this tariff amendment. *See* http://www.caiso.com/Documents/Decision-LocalMarketPowerMitigationEnhancementsProposal-EIMGoverningBodyAdvisoryInput-Mar2019.pdf.

calculating commitment costs and default energy bids and give market participants more flexibility in bidding commitment costs above the current cost-based commitment cost bid caps. The revised market rules would also require market power mitigation, as necessary, while providing such flexibility. Specifically, the CAISO developed the following changes to its market rules:

1. Allow suppliers to request adjustments to their resource's commitment cost and energy reference levels based on their actual or expected costs.

2. Allow suppliers to seek after-the-fact cost recovery of actually incurred costs for which the CAISO did not approve a reference level adjustment request before the market ran.

3. Make permanent the interim Aliso Canyon tariff provision that allows the CAISO to calculate reference levels for the day-ahead market based on natural gas price index information reported by ICE based on next-day gas trading occurring on the morning of the day-ahead market.

4. Make permanent the interim Aliso Canyon tariff provision that requires the CAISO to publish two-day-ahead advisory market results to suppliers.

5. Replace the CAISO's existing static commitment cost cap with "market-based" commitment cost bids, and implement a commitment cost local market power test with commitment cost mitigation to the commitment cost reference level triggered by the test.

6. Allow for hourly minimum load costs in the day-ahead market.

7. Establish a negotiated option for determining commitment cost reference levels, similar to the existing negotiated rate option for determining default energy bids.

8. Recalibrate the CAISO market's constraint relaxation price parameters to be consistent with the increased $2,000/MWh energy bid cap required by Order No. 831.[46]

Because of implementation constraints, the CAISO separated the implementation of the complete set of rules changes into two phases. The tariff amendment addressed in the First CCDEBE Order and this tariff amendment

[46] CCDEBE Board Memorandum at 4-8.

implement the first phase (covering items 1-4 above). The CAISO plans to propose tariff amendments to implement the second phase (covering items 5-8) at a future time.

E. Initial CCDEBE Filing and First CCDEBE Order

On August 30, 2019, the CAISO filed a tariff amendment to allow suppliers to request adjustments to their CAISO-calculated commitment cost and energy reference levels to more accurately reflect these costs (First CCDEBE Tariff Amendment).[47] Those tariff enhancements included, *inter alia*, a proposal to apply a 125 percent multiplier to supplier-submitted proxy commitment costs and a 110 percent multiplier to supplier-submitted default energy bids that are calculated pursuant to reference level change requests.[48] The CAISO also proposed in the First CCDEBE Tariff Amendment to:

(1) Permanently implement modified versions of certain tariff revisions the Commission previously accepted on an interim basis to address the limited operability of Aliso Canyon. Specifically, the CAISO proposed to permanently implement tariff provisions to improve the accuracy of the gas commodity price indices it uses to calculate proxy costs, default energy bids, and generated bids used in the day-ahead market, by reflecting the most recent gas commodity information.[49] The CAISO also proposed to permanently implement tariff provisions to help suppliers make more informed gas procurement decisions by providing them with advisory information regarding their resources' potential commitment in the day-ahead market.[50]

(2) Allow using Monday-only volume-weighted average prices to more accurately reflect available trading data in commitment cost bid caps and default energy bids for the day-ahead and real-time markets for Monday operating days, *i.e.*, implement a Monday-only gas price index.[51]

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47 The CAISO filed the First CCDEBE Tariff Amendment on August 30, 2019 in Docket No. ER19-2727, and later submitted its other filings discussed below in the same docket.

48 *See* transmittal letter for First CCDEBE Tariff Amendment at 27.

49 *See id.* at 31-32, 53-55.

50 *See id.* at 54-55.

51 *See id.* at 35-40.

(3) Clarify that the bid-effectiveness thresholds in the tariff apply to the individual flowgates that make up a nomogram, not to the nomogram itself.[52]

Subsequently, the Commission issued a deficiency letter to the CAISO regarding the First CCDEBE Tariff Amendment, to which the CAISO filed a response (CCDEBE Deficiency Letter Response).[53] The CCDEBE Deficiency Letter Response included support for applying a 110 percent multiplier to both supplier-submitted proxy commitment costs and supplier-submitted default energy bid costs.[54]

In the First CCDEBE Order, the Commission accepted the three numbered proposals listed above, subject to a compliance filing to be submitted by the CAISO regarding the first-listed (*i.e.*, Aliso Canyon-related) proposal.[55]

The Commission also found the CAISO had not demonstrated the proposal to apply a 125 percent multiplier to supplier-submitted proxy commitment costs that are based on verifiable actual or expected costs was just and reasonable, and for that reason the Commission rejected the balance of the proposed tariff revisions to allow adjustments to CAISO-calculated commitment cost and energy reference levels.[56] The Commission stated that when it accepted the 125 percent multiplier for use as the proxy cost-based default commitment cost bid, it did so "to apply the 125 percent multiplier to proxy costs developed using an index, and this was meant to account for the potential divergence between the supplier's average costs using an index and the supplier's actual cost."[57] The Commission contrasted the context of its initial acceptance of the proxy cost bid cap with the "meaningfully different context"

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52 *See id.* at 56.

53 The CAISO filed the CCDEBE Deficiency Letter Response on November 22, 2019.

54 CCDEBE Deficiency Letter Response at 13-18. For example, the CAISO explained how "historical data does support using the [1]10 percent multiplier in both the commitment cost and default energy bid calculations." *Id.* at 14.

55 First CCDEBE Order at PP 49-50, 55-56, 58. The Commission accepted these three proposals to become effective on their actual implementation date, to be followed by a CAISO eTariff submittal to provide notification of the actual effective date. *Id.* at P 9 and Ordering Paragraphs (A)-(B). On February 4, 2020, the CAISO submitted a notification that the actual effective date was January 28, 2020. On February 20, 2020, the CAISO submitted the compliance filing regarding the Aliso Canyon-related proposal described above. The compliance filing is currently pending before the Commission.

56 *Id.* at PP 39-42. Except as discussed below, the Commission expressly made no findings regarding this element of the CCDEBE proposal, and did not address other issues raised in the comments with respect to this proposal. *Id.* at P 39 n.45.

57 *Id.* at P 40 (citing *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,284, at P 31).

presented by the First CCDEBE Tariff Amendment, in which the CAISO proposed to apply the 125 percent multiplier to verifiable supplier-submitted proxy commitment costs: "Specifically, whereas a multiplier applied to an index captures deviations from an average cost, and therefore may account for resource-specific cost deviations from the index, a multiplier applied to supplier-submitted costs would provide additional headroom on top of verifiable, above-average costs."[58] The Commission found the CAISO had not adequately justified using the 125 percent multiplier in the latter circumstance, *i.e.*, with the CCDEBE tariff enhancements in effect.[59]

The Commission stated its rejection of the remaining tariff revisions proposed in the First CCDEBE Tariff Amendment was without prejudice to the CAISO's refiling them with additional support.[60]

F. Stakeholder Process Following Issuance of the First CCDEBE Order

Following issuance of the First CCDEBE Order, the CAISO resumed the CCDEBE stakeholder process described above. The CAISO posted revised tariff language and held a stakeholder conference call on February 27, 2020, to discuss the changes it proposed to make to the CCDEBE tariff provisions in light of the Commission's guidance. In response to requests by certain stakeholders, the CAISO held another stakeholder call on March 19, 2020 to discuss its proposal and the data it had collected in support of the proposal. The CAISO also solicited written comments, which it received and posted on the CAISO's website.

After reviewing stakeholder comments and additional data, the CAISO modified its proposal further and held a stakeholder call on May 20, 2020, to discuss its proposed changes responding to stakeholder concerns.[61]

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58 First CCDEBE Order at PP 40-41.

59 *Id.* at P 41. Regarding the idea of applying a 110 percent multiplier to both supplier-submitted proxy commitment costs and supplier-submitted default energy bid costs, the Commission stated that "CAISO notes that it could provide support for a 110 percent multiplier to supplier submitted costs based on the potential variability in costs between when a supplier submits its estimated gas costs in its reference level change request and when it actually purchases gas." *Id.* *See also id.* at P 37 (describing the support the CAISO provided in the CCDEBE Deficiency Letter Response).

60 *Id.* at PP 9, 42.

61 Materials regarding these events in the CCDEBE stakeholder process are available on the same website page cited above, available at http://www.caiso.com/StakeholderProcesses/Commitment-costs-and-default-energy-bid-enhancements.

III. NEED FOR TARIFF AMENDMENT

A. Current Commitment Cost Bidding Rules Can Unnecessarily Restrict Resources' Ability to Reflect Their Actual Commitment Costs in the CAISO Market and to Recover Such Costs

Over the years, 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.[62]

The CAISO agrees with stakeholders that the current bidding rules can fail to a resource's actual commitment costs and constraints. After a robust stakeholder process, the CAISO concluded it is necessary to modify the existing rules to give market participants additional flexibility in submitting market-based commitment cost bids, while still ensuring conditions are sufficiently competitive and suppliers are unable to exercise market power.

The CAISO is the only ISO/RTO that does not allow market-based commitment costs bids subject to market power mitigation. The CAISO's survey of ISO/RTO bidding rules showed that all other ISO/RTOs support market-based bids for all components of the supply bid, including commitment costs, and apply mitigation to each component under various complex rules.[63]

These limitations can cause unfavorable market outcomes if they fail to capture a resource's actual or expected commitment costs. If the CAISO market is unable to capture a resource's costs accurately, the market may dispatch a resource that appears to be economic but actually has higher costs than are reflected in the market optimization. This can cause the inefficient scheduling or dispatch of resources and market prices to not reflect actual costs. It is inefficient

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[62] *See, e.g.*, CCDEBE Board Memorandum at attachment A, columns 2 and 3 (summarizing comments of stakeholders that support the CAISO's proposals to (1) introduce market-based commitment cost bids and (2) move from daily to hourly minimum load offers).

[63] PJM Interconnection, L.L.C. (PJM) uses a three-pivotal-supplier test to detect market power that is similar to the CAISO's local market power mitigation test discussed below. However, PJM only limits commitment costs if a resource fails the test. PJM Open Access Transmission Tariff (OATT), Attachment K – Appendix, at section 6.4. The New York Independent System Operator, Inc. (NYISO), Midcontinent Independent System Operator, Inc. (MISO), ISO New England Inc. (ISO-NE), and Southwest Power Pool, Inc. (SPP) each 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. ISO-NE Transmission, Markets and Services Tariff, Section III, Market Rule 1, at sections III.A.3-III.A.5; MISO Tariff, at sections 63-65; NYISO Market Administration and Control Area Services Tariff, at sections 23.1-23.3; SPP OATT, Attachment AF, at section 3.

for the market to use commitment costs for individual resources that are less than their actual costs because it may prevent the market from committing the resources that are the actually the most economic. This situation can erode suppliers' confidence in the CAISO market and can decrease participation.

Having accurate commitment costs is especially important because commitment costs are a significant factor in determining whether the market starts up a resource, and they constitute a significant portion of the costs of operating a resource. Flexibility in bidding commitment costs is also important to allow suppliers to reflect gas system operational constraints or to reflect inherent inaccuracies in the CAISO market's modeling of resource operational characteristics. In addition, actual costs may differ than those calculated by the administrative formulas the CAISO uses to calculate resources' costs.

B. Supplier Filings with the Commission to Recover Unrecovered Fuel Costs

The current limitations in the ability to reflect a resource's actual or expected fuel costs in its reference levels have resulted in several after-the-fact filings by suppliers to recover fuel-related costs not recovered through CAISO market revenues. Under the current tariff rules, suppliers may seek recovery of unrecovered fuel-related costs to cover their commitment costs.[64] Further, under tariff rules that were in effect on an interim basis until December 31, 2019,[65] suppliers could seek recovery of unrecovered incremental fuel costs associated with default energy bids and generated bids.[66] Three suppliers submitted such filings to the Commission.[67] These filings also reflect the need for better methods for suppliers to recover their costs through the CAISO markets, and support the need for the market rule changes proposed in this tariff amendment.

Although these after-market filings may be effective in providing cost recovery, they do not promote the important goal of optimizing resources' costs and efficiently scheduling and dispatching resources, which will maximize the

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[64] Existing tariff section 30.11.

[65] *See* 2018 Aliso Canyon Order at P 45.

[66] Before they expired on December 31, the interim provisions were contained in tariff section 30.12.

[67] One of the three filings resulted in the supplier receiving the unrecovered costs it sought to recover. *See NRG Power Marketing, LLC*, Commission Letter Order, Docket No. ER19-385-000 (June 3, 2019) (authorizing recovery of full requested amount of $285,224). The second filing resulted in Commission acceptance of an amended fuel cost recovery application and settlement agreement. *See EDF Trading North America, LLC*, 171 FERC ¶ 61,181 (2020). The third filing was ultimately withdrawn by the supplier following informal discussions it had with the CAISO and the DMM. See the filings submitted by GenOn Energy Management, LLC and NRG California South LP and other parties in Docket No. ER19-554-000.

benefits the CAISO market provides to society. Similarly, LMPs do not accurately reflect suppliers' marginal costs when the CAISO market does not use the suppliers' actual or expected costs. In addition, forcing suppliers to pursue an after-market process for compensation increases the risks and legal fees suppliers face in participating in the CAISO market. Also, it unnecessarily forces the supplier, the CAISO, other interested parties, and the Commission to address such issues in Commission proceedings.

C. Limitations in Current Reference Level Calculations

The calculated energy and commitment cost reference levels cannot always reflect a supplier's actual or expected costs, because the CAISO does not have exact information as to what each individual supplier's actual costs are. This issue is particularly acute for natural gas-fired resources, because the CAISO's calculations are based on published natural gas price indices that do not always reflect the actual price an individual supplier pays.[68]

Although the CAISO market rules provide flexibility for suppliers to submit economic bids for energy above minimum load within the current energy bid caps, there are three circumstances in which suppliers are exposed to cost-based energy and commitment cost bids that may not reflect their actual fuel costs. First, suppliers may only bid-in commitment costs up to the CAISO-calculated cost-based values, which are based on indices used to reflect the suppliers' daily fuel costs (*i.e.*, those default commitment cost bids determined under the proxy cost methodology). Second, although the CAISO market rules allow suppliers to bid up to $1,000/MWh for energy above minimum load, when a supplier is subject to mitigation, the CAISO market dispatches and compensates the supplier based on a mitigated bid price that uses the supplier's default energy bid as an input. Finally, there are some instances in which suppliers are required to submit a bid but fail to do so, and the CAISO market must generate a bid to use in the clearing process.[69]

The CAISO market relies on the cost-based default commitment cost bids and default energy bids that are largely based on formulaic approaches that include fuel costs. For gas-fired resources, the formulaic cost based default commitment cost bids and default energy bids are based on available price indices, which in most cases will not reflect the supplier's actual costs. The

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68 Other types of thermal resources generally have less volatile fuel prices, because they do not purchase their fuel each day, and it typically is stored on-site. The costs of hydroelectric resources and demand response resources are generally opportunity costs that either do not vary by day, or for which the daily variation is accounted for in their negotiated default energy bids or by hydro default energy bids. Storage resources do not have commitment costs, and their energy bids are not subject to market power mitigation.

69 *See supra* sections II.B-C of this transmittal letter.

CAISO tariff specifies that the CAISO uses a gas price that is based on gas price indices that are published by the evening before the day the CAISO runs the applicable day-ahead or real-time market. This results in a one-day lag in the gas prices used in the day-ahead and real-time markets. Because of gas price volatility, this creates the possibility that a supplier's cost-based bids would not capture its actual gas costs. In the First CCDEBE Order, the Commission approved the CAISO using an updated index in the day-ahead market available on the same calendar day it executes the day-ahead market for the next trading day.[70] Although there may still be a difference between the actual price the supplier pays and the index as discussed below, this process at least removed the lag time the day-ahead market previously faced.

This relief, however, is not currently available, for the real-time market. The gas price indices used by the real-time market are still based on next-day gas trading on the day before the real-time market.[71] As a result, the gas price indices frequently do not capture suppliers' actual marginal costs, which are typically the costs for same-day gas purchased on the day of the real-time market. For example, for the real-time market on Thursday, the CAISO market uses a gas price based on Wednesday's next-day gas trading, *i.e.*, gas purchased on Wednesday for delivery on Thursday. However, suppliers would presumably purchase same-day gas on Thursday for Thursday's real-time market. However, as discussed further in this transmittal letter, the procedure used for the day-ahead market is not appropriate for the real-time market, because the price indices during the same day may not be as liquid or available throughout the day.

Figure 1 below illustrates how the natural gas prices the CAISO uses in the real-time market, which are based on gas price indices published on the day before the real-time market, can underestimate resources' costs. Figure 1 is based on gas price indices published during July 2018 – July 2019 for the PG&E Citygate and SoCal Citygate natural gas hubs. It compares the gas price the CAISO uses in the real-time market (*i.e.*, based on next-day gas price indices published the day before the real-time market) with the gas price that suppliers actually had to pay to purchase gas on the operating day (*i.e.*, the price reported by indices published at the end of the operating day for same-day gas purchases). Figure 1 shows this information separately for Mondays and for weekdays following holidays.[72]

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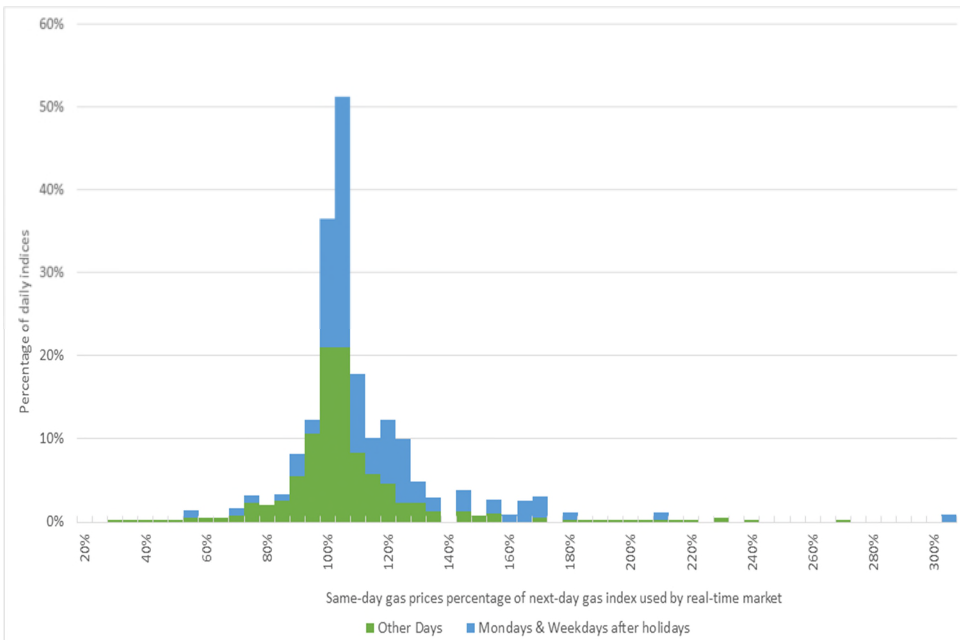
70 Existing tariff section 39.7.1.1.1.3(b). As discussed below, the Commission accepted this tariff provision on an interim basis in the Aliso Canyon proceedings and accepted it on a permanent basis in the First CCDEBE Order at P 56.

71 Existing tariff section 39.7.1.1.1.3(c).

72 A weekday following a holiday can, of course, also be a Monday. Prior to the CAISO implementing the Monday-only gas price index pursuant to the First CCDEBE Order, gas prices

Figure 1 shows that during July 2018 – July 2019, for days other than Mondays and weekdays following holidays, same-day gas prices were greater than the next-day gas index prices used by the real-time market 52 percent of the time (*i.e.*, the sum of all of the bars to the right of 100 percent) that those indices were published. For Mondays and for weekdays following holidays, same-day gas prices were greater than the next-day gas index prices used by the market 77 percent of the time those indices were published. Consequently, the gas price the CAISO used to calculate reference levels was less than suppliers' actual costs for a substantial portion of the time.[73]

Figure 1: PG&E Citygate and SoCal Citygate Natural Next-Day Gas Index Prices Compared with Real-Time Gas Prices



The CAISO's findings are confirmed by the DMM's recent studies. Over the past few years, the DMM has reported that the gas index prices the CAISO

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the CAISO market used for Mondays could be particularly inaccurate, because the CAISO used prices from indices posted on Friday, and prices could significantly change over the intervening days. A similar issue existed for weekdays following holidays.

[73] Due to the implementation of the Monday-only gas price index on January 28, 2020, the CAISO would expect an improvement in the index uses for Mondays. However, even with this improvement, there would still be greater differences between same-day gas prices on Mondays and the index used for Mondays, because the Monday-only index is produced two to three days ahead.

uses in calculating a supplier's reference levels for the real-time market are significantly lower than actual same-day gas transaction prices for purchases on the day of the real-time market. The DMM has also reported that these differences are greater for Mondays and weekdays after holidays. Based on its findings, the DMM has repeatedly recommended that the CAISO develop the ability to adjust gas prices used in the real-time market based on prices observed on ICE the morning of each operating day.[74] The DMM has also validated that the Aliso Canyon interim measure for updating gas prices for the day-ahead market, which is now in effect, has been effective in closing the gap in gas index prices that would have existed absent that interim measure.[75]

The CAISO also agrees with the DMM that the CAISO should modify the market rules to update the gas prices indices used for the real-time market. However, because the real-time gas price index may lack sufficient liquidity, the CAISO is proposing in this tariff amendment a different approach to ensure the CAISO employs a more up-to-date gas price in calculating real-time commitment costs and default energy bids.

An additional short-coming with using price indices is that the published natural gas index prices are average prices, which may be less than the price an individual supplier actually pays for gas for an individual resource. This issue applies to both the day-ahead and real-time market.

Figure 2 and Figure 3 below compare the price indices used by the day-ahead market to the individual next-day gas purchases on the day of the day-ahead market, and the price indices used in the real-time market to individual same-day gas purchases. Figure 2 compares these prices for the SoCal Citygate hub, and Figure 3 does so for the PG&E Citygate hub. As illustrated by these figures, the price of the actual trades may vary significantly.

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[74] *See Q1 Report on Market Issues and Performance* at 64 (June 28, 2019) (Q1 2019 Market Report), available at http://www.caiso.com/Documents/2019FirstQuarterReportOnMarketIssuesAndPerformance.pdf. The DMM made the same recommendation, for example, at page 98 of the *2018 Annual Report on Market Issues & Performance* (2018 Annual Market Report), available at http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf, and at page 245 of the *2016 Annual Report on Market Issues & Performance*, available at http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

[75] *See, e.g.*, Q1 2019 Market Report at 67-69. The DMM's analyses also show that a substantial portion of the commitment costs and default energy bids used in the CAISO market may not have been sufficient to recover the fuel costs that market participants actually incur in real-time. The DMM's analysis supports the need to modify the CAISO market rules so the CAISO can use more up-to-date measures of gas prices in its markets. The CAISO agreed with, and implemented, the DMM recommendation to make permanent the Aliso Canyon interim measure for updating gas prices for the day-ahead market.

Figure 2: Distribution of Price Deviations for SoCal Citygate Hub

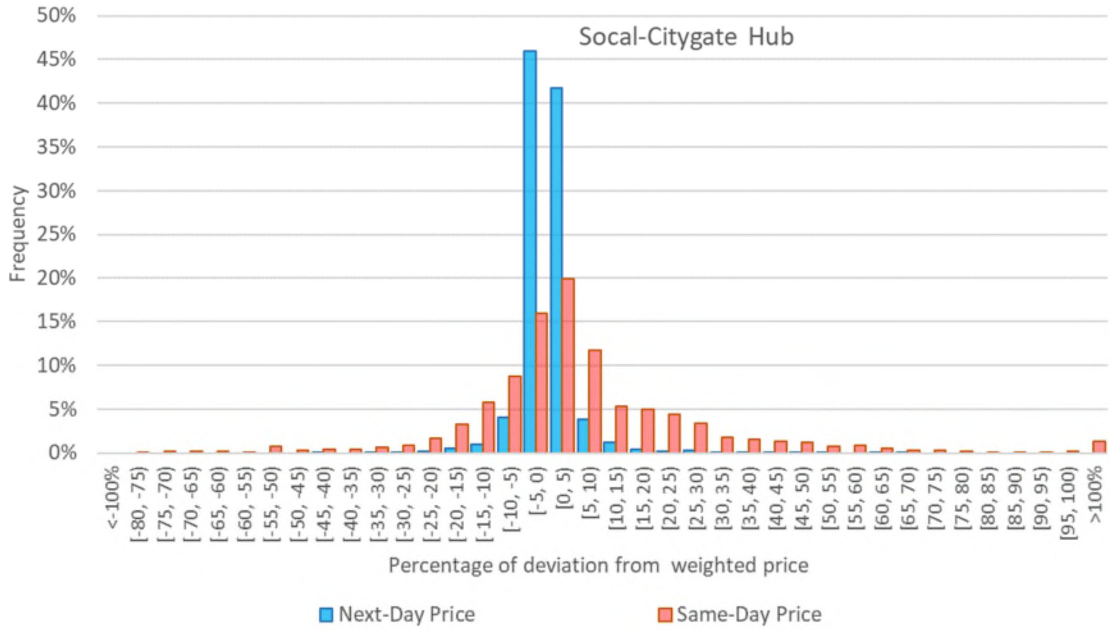
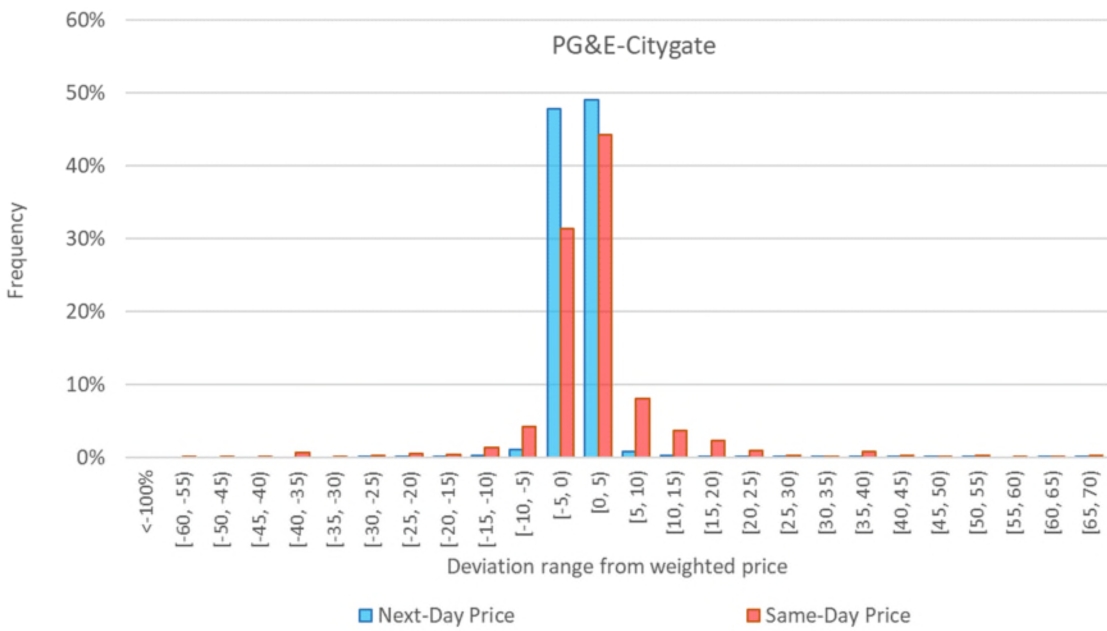


Figure 3: Distribution of Price Deviations for PG&E Citygate Hub



D. Order Nos. 831 and 831-A

Order Nos. 831 and 831-A directed Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to implement the requirements described therein as to (1) offer cap structure, (2) a verification process for cost-based offers for energy above minimum load, (3) resource neutrality, and (4) virtual transactions and external transactions.[76] Specifically, the Commission required ISOs/RTOs to verify that cost-based energy offers above $1,000/MWh reasonably reflect a supplier's actual or expected costs prior to being used to calculate LMPs.[77] The Commission found this was necessary, because market power issues are heightened when a supplier's short-run marginal costs exceed $1,000/MWh. The Commission recognized that RTO/ISOs would build on existing mitigation processes for calculating or updating cost-based incremental energy offers.[78]

The CAISO's separate Order No. 831 Compliance Filing details the tariff revisions it proposes to comply with Order Nos. 831 and 831-A.[79] As explained therein, the CAISO does not have pre-market verification procedures that it could leverage to comply with the Orders. Under the CAISO's existing market power mitigation processes, which include using default energy bids when suppliers are subject to mitigation, the CAISO does not have procedures that allow it to verify increases in a supplier's default energy bid that could also be used to verify cost-based energy offers (*i.e.*, energy reference levels) above $1,000/MWh. The mechanisms proposed in the instant tariff amendment provide a robust set of rules that will enable the CAISO to verify cost-based energy offers above $1,000/MWh.

IV. PROPOSED TARIFF REVISIONS

The CAISO refiles its CCDEBE proposal consistent with the guidance provided in the First CCDEBE Order. The tariff revisions proposed in this filing are the same as those proposed in the First CCDEBE Tariff Amendment, except with respect to use of multipliers in the calculation of reference levels when suppliers request reference level changes. Specifically, in response to the Commission's guidance in the First CCDEBE Order, the CAISO now proposes

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[76] The requirements are also contained in section 35.28(g)(11) of the Commission's regulations, 18 C.F.R. § 35.28(g)(11). *See Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, et al.*, Correcting Amendment, 165 FERC ¶ 61,136 (2018). The CAISO's separate Order No. 831 Compliance Filing provides a detailed discussion of the directives in Order Nos. 831 and 831-A.

[77] Order No. 831 at PP 139-40.

[78] *Id.* at P 131.

[79] At this time, the CAISO believes it will be prepared to implement the tariff revisions contained in the Order No. 831 Compliance Filing in the fall of 2021.

that the commitment cost multiplier and the default energy bid multiplier will not be applied to verifiable actual or expected costs that are the basis for a reference level change request. In addition, this tariff amendment includes changes and clarifications to the proposed tariff language that the CAISO suggested making in the First CCDEBE Answer, and in the CCDEBE Deficiency Letter Response with regards to the inclusion of gas company imbalance penalties in reference level change requests. Specifically, the CAISO clarifies that suppliers cannot recover such costs either in the pre- or post-market requests for fuel cost recovery.

The CAISO discusses the changes proposed in this second CCDEBE tariff amendment in more detail below.

A. Authority to Adjust Fuel or Fuel-Equivalent Price Used in Calculation of Default Commitment Cost Bids and Default Energy Bids

The CAISO proposes tariff revisions to allow suppliers to request adjustments to their default commitment cost bids and default energy bids. The proposed tariff revisions will provide a just and reasonable method for verifying a supplier's request to increase its reference levels when its actual or expected costs will be greater than CAISO-calculated costs, based on verifiable contemporaneously available information. These procedures will enable the CAISO to use fuel or fuel-equivalent[80] costs in calculating reference levels that reflect suppliers' verifiable actual or expected fuel or fuel-equivalent costs. This in turn will provide the CAISO with more efficient resource schedules and dispatches and will ensure suppliers are adequately compensated. The CAISO proposes administratively efficient and reliable procedures to enable the CAISO to screen and verify such requests, both automatically and on a manual basis, as feasible. To protect the integrity of the automated procedure, the CAISO will be authorized to audit requested adjustments and to impose sanctions for failure to comply with the adjustment rules.[81] If these measures do not result in fuel-cost recovery, the CAISO will allow suppliers to seek after-the-fact recovery of actual incurred costs not verified before the execution of a market run.

The tariff revisions are consistent with the guidance the Commission provided in the First CCDEBE Order. Because the CAISO proposes to allow reference level adjustments based on actual or expected verifiable costs, the CAISO does not propose to include the commitment cost or default energy bid multipliers when calculating the revised reference levels. As discussed further below, the CAISO has found that it lacks sufficient evidence that actual gas

[80] Fuel-equivalent costs consist of non-traditional resource costs such as for demand response resources.

[81] These rules specify that suppliers must base adjustment requests on actual or expected costs based on information the supplier has at the time it requests an adjustment.

transaction prices will vary from the actual or expected costs submitted in a reference level change request after it is approved.

For the reasons discussed below, the Commission should find the CAISO's proposed revisions are just and reasonable and establish rules that will (1) enable the CAISO to reasonably verify the legitimacy of costs prior to a market run, based on verifiable data, and (2) allow those costs to flow through the market with appropriate checks to avoid unjustly inflating market costs.

1. Adjustments to Default Commitment Cost Bids and Default Energy Bids Before Clearing the CAISO Markets

As discussed in more detail below, the tariff revisions specify two processes for the CAISO to adjust reference levels upon a supplier's request prior to the CAISO market process.[82] Suppliers for all types of resources (except non-resource-specific system resources, *i.e.*, imports not identified with a specific external resource)[83] can submit requests to change their resource's reference levels to reflect the resource's actual or expected fuel or fuel-equivalent costs.[84] Suppliers under the registered cost methodology may not request reference level change requests for default commitment cost bids,[85] because costs under this methodology are not based on variable fuel prices. Instead, costs are based on projected gas prices and are eligible for a 150 percent scalar. Further, suppliers may not submit reference level change requests to recover costs associated with gas company imbalance penalties.[86] As the CAISO explained in the CCDEBE Deficiency Letter Response, such reference level change requests are inappropriate, because the fuel price indices the CAISO uses seem to be capturing the bulk of the costs associated with gas imbalance charges.[87]

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[82] New tariff sections 30.4.3 and 30.11, *et seq.*; tariff appendix A, new definition of "Reference Levels".

[83] *See* new tariff sections 30.11.1.1 and 30.11.2.1. The CAISO does not calculate commitment costs or default energy bids for non-resource-specific system resources. Similarly, suppliers cannot submit reference level change requests for virtual bids (*see* new tariff section 30.11.1.1), because the CAISO does not calculate commitment costs or default energy bids for virtual bids.

[84] New tariff sections 30.11.2.1 and 30.11.2.2; tariff appendix A, new definition of "Reference Level Change Request". The CAISO does not propose to allow adjustments to default transition bids for MSG resources. Instead, the supplier should submit a reference level change request to adjust the default start-up bid for the MSG resource, and any verified amounts will also include transition costs.

[85] New tariff section 30.11.2.1.

[86] *Id.*

[87] CCDEBE Deficiency Letter Response at 8-10.

Suppliers must have specified types of documentation to support their reference level change requests.[88] Suppliers will be able to choose between two processes for proposing and evaluating adjustments: an automated process and a manual process.

A supplier can only submit reference level change requests based on its reasonable expectation that its daily actual fuel or fuel-equivalent costs will exceed the costs otherwise used by the CAISO market systems to calculate the resource's reference levels. Any changes must reflect reasonable and prudent procurement practices.[89] A supplier must calculate revised reference levels that it submits in a change request using the same methodology the CAISO systems use to calculate a resource's proxy cost-based default start-up bids, default minimum load bids, and variable cost-based default energy bids.[90] This ensures the CAISO can isolate the evaluation of reference level change requests to fuel or fuel-equivalent costs, because all the other costs should remain the same. This also ensures the CAISO can isolate the need for the reference level change to differences in fuel costs, which are typically the main costs that vary day-to-day, and may vary based on individual resource locations. As discussed further below, the supplier's calculation of revised commitment cost and energy reference levels, under both the automated process and the manual process, will not include either the commitment cost or default energy bid multiplier.

Once the CAISO has validated and accepted a reference level change request for the day-ahead market, the revised reference level (*i.e.*, the revised default commitment cost bid or revised default energy bid) will apply to all hours of the day. For the real-time market, the revised reference level will apply from the first real-time market trading hour for which it is practicable for the CAISO to apply the change. The revised reference level will remain until the last hour of the day for which the reference level change request was specified, unless a subsequent adjustment request is submitted and approved. The supplier may submit an application for after-market cost recovery for any costs it was unable to have verified through the reference level change request processes.[91]

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88 New tariff section 30.11.2.2.

89 *Id.*

90 New tariff section 30.11,3,2. The default start-up bids, default minimum load bids, and default transition bids (together referred to as the default commitment cost bids) are the new terms the CAISO proposes to use to describe the maximum bid cap for start-up, minimum load bids, and transition bids, respectively. For use-limited resources using the registered cost methodology, the CAISO will use the registered costs as registered in the master file as the default commitment cost bids. New tariff section 30.4.4.3.

91 New tariff section 30.11.5; tariff appendix A, new definitions of "Revised Default Commitment Cost Bids" and "Revised Default Energy Bid".

In the stakeholder process that preceded the First CCEBE Filing, some stakeholders argued that the CAISO should update the gas price used to calculate real-time market reference levels based on natural gas trades the CAISO observes on ICE, rather than implement automated reference level adjustments.[92] The CAISO does not believe updating the gas price would be consistent with the Commission's directives in the Aliso Canyon proceedings requiring the CAISO to use only gas price index information that meets specified Commission liquidity standards.[93] The CAISO concluded that this is not a robust process, because the gas trade information these stakeholders suggest using does not meet the liquidity standards. The CAISO has observed that in many instances the trades reported and reflected in the same day indices such as ICE tend to be scarce. This low liquidity means the indices would not reflect a supplier's actual gas costs. Rather than relying on the indices the CAISO proposed processes that enables the supplier to reflect its verifiable actual or expected costs.

Further, there is no need to adopt such an alternative approach. As discussed below, the CAISO proposes to update the reasonableness thresholds based on available information.[94] This enables the CAISO to actually review (either prior to updating the reference levels through the manual reference level change requests, or through its audits of the automated reference level change requests) whether the information submitted by the supplier supports a finding that it faced higher fuel costs. Implementing the proposed reasonableness thresholds effectively balances the goals of minimizing implementation cost and complexity, providing suppliers with bidding flexibility, and protecting against adverse market behavior.

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[92] *See* CCDEBE Board Memorandum at 9-10; CCDEBE Board Memorandum, attachment B at 6-7.

[93] *See* 2016 Aliso Canyon Order at P 12 n.14 ("We remind CAISO that in order to use an index reported by ICE, the index must conform to the Commission's *Policy Statement on Natural Gas and Electric Price Indices*"); *Cal. Indep. Sys. Operator Corp.*, 157 FERC ¶ 61,029, at P 10 (2016) ("We find that CAISO's use of the new natural gas price index, as described in the tariff provisions accepted in the [2016 Aliso Canyon] Order, conforms to the Policy Statement and the Commission's Price Index Order. Pursuant to the Policy Statement and the Price Index Order, in order to ensure a robust and transparent tariff, any index used in a tariff must meet specific guidelines.") (citation omitted).

[94] *See supra* section IV.A.1.b(2) of this transmittal letter.

a. Automated Reference Level Change Requests

(1) Submissions of Automated Reference Level Changes

Under the proposed automated process, a supplier can request an adjustment to its resource's reference levels, and the CAISO market systems will compare the proposed adjusted amount to a resource-specific "reasonableness threshold" the systems will calculate.[95] The market systems will calculate the reasonableness thresholds by recalculating default commitment cost bids and default energy bids using fuel prices increased by fixed percentages. The reasonableness thresholds will be different for each resource, even if resources face the same fuel price, because each resource has different operational characteristics. The reasonableness thresholds are distinct from the reference levels used by the CAISO markets, and are used only to evaluate a supplier's automated request to update its resource's reference levels.

If the cost submitted in a supplier's automated reference level change request is equal to or less than the reasonableness threshold (described below) for a resource, the CAISO will include the verified reference level as soon as practicable in the next applicable CAISO market run.[96] If, on the other hand, the cost submitted in an automated reference level change request exceeds the resource's reasonableness threshold, the CAISO will approve the reference level change request only to the level that equals the resource's reasonableness threshold, and will include the revised reference level in the next applicable market run as soon as practicable.[97] The supplier can request after-market recovery for any amounts not accepted through the automated reference level change request process.[98]

Although a supplier is not required to submit supporting documentation with its automated reference level change request, the supplier must have contemporaneously available documentation supporting its request on hand when it submits the request.[99] The supplier must retain that information because the CAISO may later audit the supplier, and the supplier may be required to

[95] New tariff sections 30.11.1 and 30.11.3.1; tariff appendix A, new definition of "Reasonableness Threshold".

[96] New tariff sections 30.11.3.4 and 30.11.5. The CAISO will not update the applicable reasonableness threshold when it accepts an automated reference level change request. New tariff section 30.11.5.

[97] New tariff sections 30.11.3.4 and 30.11.5.

[98] New tariff section 30.11.5.

[99] New tariff section 30.11.3.3.

produce such information in support of its request.[100] A supplier cannot submit a reference level change request for the purpose of inflating its default commitment cost bids or default energy bids above what these values would be if calculated based on its actual or expected fuel costs.[101] Because the CAISO must rely on the *ex post* audit process to verify the documentation supporting an automated reference level change request, this tariff provision clearly states the CAISO's expectations for suppliers submitting automated requests.

Automated reference level change requests will not be available for hydro default energy bids. Hydro default energy bids are calculated using an opportunity cost methodology based on both electricity prices and natural gas prices. Only the natural gas component of the hydro default energy bid is eligible for adjustment, and the CAISO will evaluate that through its proposed manual adjustment request process.[102]

To illustrate how an automated reference level change request will work, the CAISO provides the hypothetical request described in Example 1 and subsequent examples provided below for a change to a gas-fired resource's default commitment cost bids. The default commitment cost bids (which consist of the commitment costs calculated pursuant to the proxy-cost methodology multiplied by the commitment cost multiplier or the registered costs for a limited number of resources) are the maximum start-up, minimum load cost, or transition cost bids that a resource can submit.[103] The examples shown in this transmittal letter focus on the default minimum load bid and illustrate how the various

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[100] *Id.*

[101] New tariff section 30.11.3.1. The wording of this tariff provision is consistent with a clarification the CAISO provided in the CCDEBE Deficiency Letter Response (at 18-19). The CAISO has also modified the wording of the tariff provision to reflect the fact that it is no longer proposing to include the commitment cost multiplier or the default energy bid multiplier in the calculation of reference level change requests. The exclusion of those modifiers will reduce the risk of inflated reference level change requests.

[102] New tariff sections 30.11.3.1 and 30.11.6. The CAISO implemented hydro default energy bids pursuant to authorization granted in the LMPME Tariff Amendment. *See* LMPME Order at PP 36-38.

[103] *See* 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 CAISO is not proposing substantive changes to how it calculates these amounts. However, the CAISO proposes to refer to these amounts as the default commitment cost bids, which consist of default start-up bids, default minimum load bids, and default transition bids. *See* tariff appendix A, new definitions of "Default Commitment Cost Bids", "Default Start-Up Bids", "Default Minimum Load Bids", and "Default Transition Bids". These changes in terminology are necessary to convey the relationship between these types of bids and the revised default commitment cost bids that will now be possible with the adoption of the reference level change processes contained in this tariff amendment.

elements of the CAISO's proposal impact these amounts.[104] However, these same principles would apply to all the other types of reference levels, *i.e.*, default start-up cost bids, default transition cost bids, and default energy bids. In addition, the examples in this transmittal letter all focus on the same resource with minimum load (Pmin) of 10 MW, a heat rate of 8 MMBtu/MWh, and $100 in other hourly costs.

In Example 1, assume it has a gas cost of $2.50/MMBtu, the resource's default minimum load cost bid is calculated today, and will continue to be calculated as:

Example 1

Default MLC Bid = *Commitment Cost Multiplier** ([*FRP* * *Pmin* * *HR*] + *Other Costs*)

= 125% * ([$2.50/MMBtu * 10 MW * 8 MMBtu/MWh] + $100) = 125% * $300

= $375/hour

Where:

FRP = Fuel region price, which consists of gas commodity price such as the ICE index price, plus the fuel transportation cost;[105]

Pmin = The minimum load of the resource as registered in the CAISO's master file;

HR = Heat rate at minimum load;

Other Costs = As prescribed by provisions in existing tariff section 30.4.1.1.1(a)[106] these may include, if applicable: (i) operation and maintenance costs; (ii) a greenhouse gas adder; (iii) the rates for the market services charge and system operations charge multiplied by the Pmin of the resource; (iv) the bid segment fee; and (v) a resource-specific adder, if applicable, for major maintenance expenses;

[104] The gas-fired resource in the example is not a use-limited resource, and therefore it does not have any opportunity costs that need to be included in the calculation of minimum load costs.

[105] The rules for calculating natural gas prices are set forth in existing tariff section 39.7.1.1.1.3 and the business practice manual for market instruments. The CAISO does not propose substantive changes to these rules.

[106] These provisions are renumbered in this tariff amendment as tariff section 30.4.5.1(c).

Commitment Cost Multiplier = Pursuant to existing tariff section 30.7.10.1, the CAISO applies a 125 percent multiplier to the calculation of default commitment cost bids. This same multiplier will continue to apply to that calculation pursuant to new tariff section 30.4.4.1 and the new defined term "Commitment Cost Multiplier" contained in tariff appendix A.

The CAISO is not proposing any changes in how the default commitment costs (or default energy bids) are calculated, and suppliers will still be able to submit minimum load bid costs up to these amounts, *i.e.*, up to a resource's default minimum load cost bid. However, the CAISO proposes to adopt the rules discussed above that enable the supplier to update these amounts through an automated reference level change request. This is predicated on the supplier possessing, at the time it submits its request, contemporaneously available documentation that supports that the higher fuel costs the supplier expects or actually faces.

For Example 2, assume the same supplier described in Example 1 calculates its expected or actual fuel cost to be \$3.50/MMBtu, which is greater than the CAISO calculated fuel cost of \$2.50/MMBtu in its default minimum load cost bid. In this instance, the supplier would submit an automated reference level request with the requested fuel cost amount, calculated using the formula below:

Example 2

Request for revised minimum load cost bid through automated request

= ([*Actual or Expected Fuel cost * Pmin * HR]* + *Other Costs*)

= ([\$3.50/MMBtu * 10 MW * 8 MMBtu/MWh] + \$100)

= \$380/hour

Under Example 2, the supplier submits its requested revised minimum load cost bid calculated based on the same formula used to calculate the default minimum load cost bid in Example 1. However, there are two differences: (1) the supplier does not apply the Commitment Cost Multiplier, and (2) the supplier replaces the fuel region price with its actual or expected fuel cost. The CAISO will then validate this amount (*i.*e., \$380/hour, the requested reference level change) using the resource specific reasonableness threshold calculation, as described below.

(2) Reasonableness Thresholds

The CAISO market systems will evaluate automated reference level change requests by comparing the submitted reference level to a reasonableness threshold. Reasonableness thresholds are a screening mechanism that establishes a maximum default commitment cost bid or default energy bid amount for each resource that the CAISO will use to automatically approve automated reference level change requests process prior to the market clearing process. The CAISO market systems will calculate reasonableness thresholds on a resource-by-resource basis.[107]

The CAISO market systems will calculate reasonableness thresholds for natural gas-fired resources using the same methodology used to calculate resource's proxy cost-based default start-up bids, proxy cost-based default minimum load bids, and variable cost-based default energy bids.[108] The fuel price used in the calculation of reasonableness thresholds also is multiplied by a fixed percentage equal to 125 percent or 110 percent, depending on the day. These fixed percentages should not be confused with the commitment cost and default energy bid multipliers, and are referred to as fuel price scalars in this transmittal letter. The fuel price scalars are necessary because actual fuel prices may be greater than the prices the CAISO market systems use to calculate reference levels due to fuel price volatility, or because a supplier may purchase its fuel at a higher price than the reported weighted average index price.[109]

As shown in Figure 1 above, the same-day gas prices frequently exceeded the price indices used by the real-time market and that these differences were significantly greater for Mondays and for weekdays following holidays.[110]

For a non-natural gas-fired resource, the reasonableness threshold will equal the resource's proxy cost-based default start-up bid, proxy cost-based

[107] New tariff sections 30.11.1.1 and 30.11.3.4. The CAISO will not calculate reasonableness thresholds for evaluating reference level change requests for hydro default energy bids and virtual bids. Hydro default energy bids are based on a comprehensive formulaic approach that considers their opportunity costs, and are not driven by fuel price changes as are gas-fired resources. Virtual bids are not cost-based bids and therefore are not limited accordingly. New tariff section 30.11.1.1. The wording of this tariff provision tracks the clarification the CAISO proposed in the First CCDEBE Answer (at 19-20).

[108] It is important to note that in this calculation, the CAISO will establish the reasonableness threshold starting with the same formula it uses to calculate the proxy-based default commitment cost bids and default energy bids and will include the commitment cost multiplier and the default energy bid multiplier. This is necessary because the CAISO uses the reasonableness threshold to evaluate revisions to the reference level, which would not be submitted unless the expected or actual reference levels would exceed the previously established amounts.

[109] The CAISO only uses the fuel price scalars in the reasonableness threshold and does not use them to calculate the actual reference levels.

[110] This analysis is consistent with the results of the DMM's analysis as reported in its quarterly reports. *See, e.g.*, Q1 2019 Market Report at 64.

default minimum load bid, or variable cost-based default energy bid, with the fuel or fuel-equivalent cost component of the calculation being multiplied by 110 percent, as discussed above.[111]

The CAISO proposes that for days without a published daily gas price index (*i.e.*, Mondays, weekends and weekdays following holidays), the fuel price scalar will be 125 percent.[112] For other days, the fuel price scalar will be 110 percent.[113]

The CAISO determined a 110 percent fuel price scalar for days other than Mondays and for weekdays following holidays, because this is sufficient to capture a reasonable amount of the differences on these days between actual same-day natural gas trading prices and the next-day gas index prices the CAISO market uses for the real-time market. The 10 percent margin also reasonably accounts for differences between the gas price the CAISO systems use for the day-ahead market and actual same-day gas prices.

The day-ahead market that runs on Sundays for the Monday operating day normally uses the indices published on the preceding Friday. The real-time market on Mondays uses this same index price. The indices that are published on Fridays are based on next day gas trading for weekend delivery. ICE does not open for gas trading during on Saturday or Sunday. Suppliers typically purchase gas on Fridays as part of a package for delivery on Saturday, Sunday, and Monday. Consequently, this creates an average gas price for gas procurement costs across Saturday, Sunday, and Monday. Also, the weekend gas package generally requires purchasers to take delivery of the same volumes on each of the three days. On Fridays, suppliers can also purchase gas separately for Mondays when demand for gas is anticipated to be higher than reflected in the weekend gas package. When anticipated demand for Monday is higher than reflected in the weekend gas package, suppliers either purchase additional gas for Monday-only on Friday, or purchase a same-day gas product on Monday. Prices for gas for Monday-only are typically higher than the Saturday or weekend package prices because demand for gas for Monday is greater than over the weekend.

Also, the 125 percent fuel scalar accounts for instances when a supplier may wait until Monday to buy same-day gas to meet day-ahead CAISO' schedules. This fuel purchasing practice may be prudent because gas conditions can change over a three-day period (*e.g.*, Friday to Monday). By Sunday, when the day-ahead market for Monday runs, a supplier may anticipate

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111 New tariff section 30.11.1.2.2.

112 New tariff section 30.11.1.2.1.

113 *Id.*

that same-day gas prices will be higher than the Monday-only price was on Friday. These same day gas prices are also applicable to the CAISO's real-time market on Monday's.

Consequently, the CAISO proposes a higher fuel scalar of 125 percent for days without a published daily gas price index. The 125 percent fuel scalar used in reasonableness thresholds for Mondays and for weekdays following holidays, captures a reasonable amount of the differences between actual same-day natural gas trading prices and the next-day gas index prices used in the day-ahead and real-time markets. Although the Commission approved using a Monday-only gas price index, the CAISO would only use the Monday-only gas price index if it is seen to be sufficiently liquid.[114] The fuel price scalar provides suppliers a reasonable opportunity to recover their actual or expected costs when the applicable indices do not capture those costs.

For Example 3, the CAISO calculates the resource specific reasonableness threshold using a 110 percent fuel price scalar.[115] As discussed above, the reasonableness threshold is based on the same formula used to calculate the default commitment cost bids, with adjustments to the fuel price.

Example 3

Reasonableness threshold

= *Commitment Cost Multiplier* * ([{(Fuel Price Scalar * Commodity Price) + Transportation Cost} * Pmin * HR] + Other Costs)

= 125% * ([{(110% * $2.00/MMBtu) + $0.50/MMBtu} * 10 MW * 8 MMBtu/MWh] + $100)

= 125% * $316

= $395/hour

In Example 3, the resource's reasonableness threshold is $395/hour. When the supplier submits its request for a change to the default minimum load cost bid, the CAISO compares the supplier's revised minimum load cost bid to its the reasonableness threshold. The supplier's reference level change request shown in Example 2 is $380, which is lower than the $395 reasonableness threshold. Therefore, the resource's request for a revised default commitment cost bid would pass the screen. The revised default minimum load cost bid of $380 is used in subsequent market intervals.

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114 *See* First CCDEBE Order at PP 49-50, 56; existing tariff sections 39.7.1.1.1.3(a)-(c).

115 As noted above, this fuel scalar applies for days with a published daily gas price index.

Note that although the reasonableness thresholds contained the commitment cost multiplier, the revised default commitment cost bid is calculated without the commitment cost multiplier. Also, although the reasonableness threshold was calculated using the fuel price scalars, the fuel price scalar was not included in the calculation of the default commitment cost bid requested by the supplier. Therefore, a supplier would only be able to obtain a default minimum load bid that is as high as $395/hour, if the supplier had contemporaneously available documentation that demonstrates its expected or actual fuel costs to be at a level that supports its requested change.

During the stakeholder processes that preceded the First CCDEBE Order, the DMM questioned why the CAISO included the proposed 125 percent and 110 percent fuel price scalars intended to capture fuel price volatility in its calculation of the reasonableness thresholds, given the CAISO also proposed to permanently implement the interim day-ahead market procedure that allows the CAISO to update the gas commodity price indices used to calculate reference levels in the day-ahead market.[116] The CAISO proposes to still include the fuel price scalars because price indices do not always reflect actual or expected costs for an individual resource. As discussed above, the same-day prices frequently exceed the price indices. The reasonableness thresholds enable a supplier that reasonably expects its fuel or fuel-equivalent costs to be greater than a CAISO-calculated reference level to request an increase to a resource's reference levels.

Finally, the market is not harmed by a higher reasonableness threshold, because the reasonableness thresholds – including the fuel price scalar – are not a safe harbor that suppliers can use to inflate their bids irrespective of actual costs. The CAISO can audit whether a supplier that submits automated reference level change requests had contemporaneously available documentation supporting its request. If the CAISO finds the supplier had no such documentation, the CAISO will prohibit the supplier from making automated reference level change requests to protect the market from attempts to increase such costs unjustly. This will incentivize suppliers to submit automated reference level change requests only when they are warranted.

116 *See* CCDEBE Board Memorandum, attachment B at 5.

(3) Updates to Gas Prices Used to Calculate Reasonableness Thresholds and Reference Levels

The CAISO proposes several tariff changes to improve the accuracy of the gas prices it uses in calculating reasonableness thresholds and reference levels for the day-ahead and real-time markets. These tariff changes will allow the CAISO to update gas resource's reasonableness thresholds and hydro default energy bids based on changes in gas prices, and to adjust reasonableness thresholds to account for persistent conditions.

(a) CAISO Updates of Fuel Prices in Regions

Today, the CAISO's market systems calculate a gas price from at least two indices for the real-time market using prices from either NGI, SNL, or Platt's.[117] Each day, between 7:00 p.m. and 10:00 p.m., the market systems calculate a gas price for the next day's real-time market using natural gas prices published that day based on next-day gas trading. The CAISO market systems use these gas prices in a daily "fuel region" calculation, which is used to calculate each resource's reference levels. The CAISO then uses these reference levels in the next day's real-time market. Because these gas prices reflect next-day gas trading from the previous day, rather than same-day gas trading on the operating day, they may differ from a supplier's actual costs to procure gas to respond to real-time market dispatches.

The CAISO proposes two procedures to allow for updates to the fuel price it uses in calculating the reasonableness thresholds based on the CAISO's observations of changes in natural gas prices.[118]

First, if the CAISO observes that the same-day gas price is greater than the next-day gas price by at least 10 percent, the CAISO will update the reasonableness thresholds for all resources within a fuel region.[119] An adjustment based on at least a 10 percent increase is appropriate to account for actual gas costs that would not be accommodated under reasonableness thresholds using the existing gas price.

The CAISO will determine whether current same-day gas prices are at least 10 percent greater than the gas price previously used to calculate the

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[117] Existing tariff section 39.7.1.1.1.3(c).

[118] As described in the next section of this transmittal letter, the CAISO also proposes to update hydro default energy bids when it determines there is a need to increase fuel prices in particular regions.

[119] New tariff sections 30.11.1.3 (flush language) and 30.11.1.3(a)(i).

reasonableness thresholds through two processes. First, the CAISO will review same-day gas prices currently trading on ICE. Second, the CAISO will review same-day gas price information submitted through all relevant verified manual reference level change requests for all resources within the applicable fuel region(s).[120]

The CAISO will use the greater of the volume-weighted average price of same-day gas trades occurring on ICE or the volume-weighted average of all relevant verified manual reference level change requests. The CAISO proposes to use the greater of these two values to help ensure the value it uses accounts for prices of individual transactions that may not be accounted for in either the ICE trades or manual reference level change requests.

It is possible the CAISO will be unable to determine that same-day gas prices are in fact 10 percent greater than the gas price previously used to calculate the reasonableness thresholds because of aberrations in reported indices. This includes a degradation of the liquidity of the indices at particular locations, which would make the indices unreliable. If the CAISO is unable to make this determination, it will not update the reasonableness thresholds for affected resources.

If, on the other hand, based on its review of this information, the CAISO determines that same-day gas prices are at least 10 percent greater than the next-day gas prices otherwise used to calculate the reasonableness thresholds for resources in a fuel region, the CAISO will update the reasonableness thresholds for the resources in a fuel region. These recalculated reasonableness thresholds will be used in beginning with the next feasible real-time market bid submission window. All updates to reasonableness thresholds through this process will apply throughout the remainder of the day for the real-time market.[121]

Example 4 illustrates how the CAISO will calculate the updated reasonableness threshold for a supplier within a fuel region for which the CAISO received verified manual reference level adjustment requests.

Example 4

In this example, assume the CAISO has observed at least a 10 percent fuel price increase for a given fuel region based on three approved manual requests. The three approved manual requests had verified fuel prices of

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120 New tariff sections 30.11.1.3(a) – 30.11.1.3(a)(i).

121 New tariff section 30.11.1.3(b). This proposal was developed in the LMPME stakeholder initiative, for implementation with the CCDEBE enhancements. LMPME Board Memorandum at 6.

$2.90/MMBtu, $2.90/MMBtu, and $5/MMBtu. In addition, all three verified manual requests were for the same amount of volume of gas, which resulted in a volume-weighted average of $3.60/MMBtu. The volume-weighted average price of same-day gas trades occurring on ICE for the same region for that day is $4.00/MMBtu.

As discussed above, pursuant to the proposed section 30.11.1.3, the CAISO proposes to update the fuel price for the region by the maximum of the ICE same-day volume-weighted average gas price index or the volume-weighted average of all relevant verified manual reference level change requests.

Revised fuel price = max ($4.00, $3.60)
= $4.00/MMBtu

The updated reasonableness threshold for the resource in the previous examples would be as follows:

Reasonableness Threshold for the default minimum load cost bid
= 125% * ([{110% * Updated Gas Price Index + Transportation Costs} * Pmin * HR] + Other Costs)
= 125% * ([{(110% * $4.00/MMBtu) + $0.50/MMBtu} * 10 MW * 8 MMBtu/MWh] + $100)
= $615/hour

By increasing the reasonableness thresholds in the fuel region, the CAISO can accept an automated reference level change request, if the supplier has actual or expected costs greater than its default bid. However, it is important to note that an updated reasonableness threshold does not result in an automatic increase in reference levels for resources in that region.

By increasing the reasonableness thresholds and only increasing the reference levels based on an accepted reference level change request, the CAISO can verify the supplier actually expects to face the higher costs for the day. Suppliers will remain subject to audits by the CAISO to verify they have contemporaneously available information demonstrating they reasonably expected their fuel costs to be greater than the fuel costs the CAISO market systems would otherwise use to calculate their reference levels.

A supplier will also still be eligible to request a manual reference level change request if it is concerned the CAISO's assessment of fuel prices will not result in a sufficient increase in its resource's reasonableness threshold. The process for suppliers to request a manual reference level change request is described below.

(b) Updates to a Resource's Hydro Default Energy Bid

If the CAISO updates the fuel price used in the reasonableness thresholds, the CAISO will automatically recalculate the gas floor component portion for all hydro default energy bids in the applicable fuel regions.[122] This component of the hydro default energy bid is intended to ensure that bid is at least as high as the cost of marginal gas generation. The CAISO developed this provision to update the gas floor component in the LMPME stakeholder initiative for inclusion in the instant tariff amendment.[123] This provision is necessary to account for changes in gas prices so the "gas floor" component of the hydro default energy bid accurately reflects current gas prices. It is appropriate to update the gas component if gas prices increase significantly relative to the price otherwise used by the market. The hydro default energy bid is the maximum of three components:[124] (1) the gas floor component, (2) the short-term component based on the opportunity cost of reserving output for sales in the day-ahead or month-ahead timeframe,[125] or (3) the long-term component for resources with more than a month of storage that can reserve output for sales in future months.[126]

As discussed in the LMPME Tariff Amendment,[127] the gas floor component of the hydro default energy bid is based on the heat rate for a typical gas turbine generator obtained from the Energy Information Administration. The CAISO calculates the gas component of the hydro default energy bid by multiplying the heat rate by the gas price for the fuel region where the hydroelectric resource is located, and then multiplying that total by 110 percent. The gas floor component is calculated similarly to how the CAISO calculates a resource's default energy bid under the variable cost option for natural gas-fired resources, which is based on a resource's fuel usage, (*i.e.*, heat rate) and prevailing gas costs.

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122 New tariff sections 30.11.1.3(a) and 30.11.1.3(a)(ii).

123 LMPME Board Memorandum at 6.

124 Existing tariff sections 39.7.1.7.1 – 39.7.1.7.1.3.

125 The short-term component represents the opportunity cost of sales at the local wholesale electric pricing hub. The calculation for the short-term component includes a 140 percent multiplier.

126 The long-term component represents the opportunity cost of sales at the default and additional electric pricing hubs over future months of the storage horizon. The long-term component is calculated as the maximum of the day-ahead, balance-of-month, and month–ahead future power price indices for the resource. The calculation for the long-term component includes a 110 percent multiplier.

127 Transmittal letter for LMPME Tariff Amendment at 41-42.

For example, if the CAISO detected a same-day gas price update for the fuel region of $4/MMBtu, and the heat rate for a typical gas turbine generator obtained from the Energy Information Administration is 11.176 MMBtu/MWh, the calculation would be as follows:

Gas floor component
= 110% * (updated gas price Index * HR)
= 110% * ($4.00/MMBtu * 11.176 MMBtu/MWh)
= $49.17

The hydro default energy bid includes a component that reflects the cost of generation from a typical gas-fired peaker unit in the region in which the resource using the hydro default energy bid is located. This gas floor component ensures the hydro default energy bid is sufficiently large so that hydroelectric resources with limited output are not completely depleted before other effective resources are dispatched. Therefore, if the CAISO observes an increase in gas prices for a particular fuel region, it is appropriate to adjust the gas floor component of the hydro default energy bid of all resources with a hydro default energy bid located in the fuel region to appropriately reflect hydroelectric resource's opportunity costs. The same criteria for updating a fuel region also apply to hydro default energy bids. The CAISO will update the hydro default energy bids for all resources in a fuel region for which the CAISO updates the natural gas price. This process is different from the reasonableness threshold adjustment process, which needs to be initiated by the supplier, because hydroelectric resource owners may not also be purchasers of gas and have gas price information.[128]

(4) CAISO Adjustments for Persistent Conditions

The CAISO proposes to adjust a resource's reasonableness thresholds if the CAISO observes the resource's actual fuel or fuel-equivalent costs are repeatedly systematically greater than the costs the CAISO uses in calculating the resource's reference levels each day.[129] This may be due to the specific circumstances of an individual resource, such as gas costs that are systematically greater than the weighted average gas prices observed on ICE. The CAISO will adjust the resource's reasonableness threshold based on the need for persistent payments to the resource through the after-market cost

[128] The CAISO understands that some resource owners may control both a hydroelectric resource and a natural gas-fired resource in the same gas region. To address this situation, the CAISO proposes to allow the supplier to request a manual reference level adjustment to its hydro default energy bid based on the gas-fired resource's increased real-time natural gas costs. *See* proposed tariff section 30.11.6. The CAISO discusses the proposed tariff revisions regarding such updates to hydro default energy bids in the manual reference level change request process below.

[129] New tariff section 30.11.1.4.

recovery process discussed below. These adjustments will be in the form of a set percentage multiplier to the calculated reasonableness threshold. This will allow the CAISO to tune the resource's reasonableness thresholds to reflect better the resource's actual costs.

These adjustments to the reasonableness thresholds will enable the CAISO to cost-verify a supplier's reference level change requests more readily through the automated adjustment request process prior to the close of the market. Suppliers will still be subject to all the same requirements for automated reference level change requests discussed above, including potential audits by the CAISO to verify that indeed the supplier reasonably anticipated higher fuel costs for the applicable market.

Example 5

For the purposes of example 5, a resource has conditions the CAISO has determined are systematic, and the resource is permitted to have an additional 3 percent of buffer added to its reasonableness threshold to account for the persistent conditions.

Reasonableness threshold for a resource with persistent conditions

= *Commitment Cost Multiplier* * ([{(Fuel Price Scalar * Commodity Price* Persistent Conditions Scalar) + Transportation Cost} * Pmin * HR] + Other Costs)

= 125% * ([{(113% * $2.00/MMBtu) + $0.50/MMBtu} * 10 MW * 8 MMBtu/MWh] + $100)
= 125% * $321
= $401.25/hour

During the stakeholder process preceding the First CCDEBE Order, the DMM questioned whether the CAISO needs authority to adjust the reasonableness threshold for a resource if its actual fuel or fuel-equivalent costs are systematically greater than the gas price indices or fuel-equivalent costs the CAISO uses in calculating the resource's corresponding reference level, given suppliers already can negotiate their default energy bids under the negotiated rate option.[130] Presumably, the DMM assumes the negotiated rate option would provide the necessary flexibility. Although the CAISO agrees that the negotiated rate option generally provides resources greater flexibility in defining their costs, the CAISO disagrees it should rely on this option to allow resources to reflect daily increases in fuel costs. It is more appropriate to enhance the proxy cost-based commitment costs and variable cost-based default energy bids to account

130 *See* CCDEBE Board Memorandum, attachment B at 7.

for higher fuel prices when justified by verifiable evidence of market conditions. Resources should not be forced to follow the more burdensome process of negotiating new reference levels.

The proxy cost methodology for commitment costs and the variable-cost default energy bid option provide uniform methods for accounting for such costs that meet the requirements for most natural gas-fired resources. Also, the CAISO's proposed approach is more efficient, timely, and adaptable to changing daily conditions than the default energy bid negotiation process. It would be more onerous for the CAISO and suppliers to pursue the negotiated rate option to allow for such increases, which requires additional resources. Moreover, the reasonableness thresholds will screen reference level change requests, and the supplier must base its request on documented actual or expected costs. Therefore, even if the CAISO increases the reasonableness thresholds with the multiplier, the supplier must still have verifiable actual or expected costs. The reasonableness thresholds are not intended to be a safe harbor that suppliers can bid up to irrespective of their actual costs, and the CAISO has proposed robust procedures to ensure the process is not abused. In contrast, 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 of whether it based the bid on documented costs.[131]

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[131] In addition, the DMM suggested that the CAISO should adopt new tariff provisions allowing EIM 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 reasonableness threshold. *See* CCDEBE Board Memorandum, attachment B at 5. Not only is the DMM's suggested alternative beyond the scope of the instant filing, it would require the CAISO to establish significant new manual processes. Also, requiring the CAISO to approve repeated manual adjustment requests for the resource would unnecessarily increase the CAISO's workload. The CAISO proposal is just and reasonable without such additional mechanism. There are no grounds to require the CAISO to adopt this new proposal, which constitutes a material change to the CAISO's proposal and, as such, is contrary to Commission precedent and the guidance provided by the D.C. Circuit's *NRG* decision. *See, e.g., Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,135, at P 44 & n.43 (2012). As the Commission explained in that order, pursuant to section 205 of the FPA, the Commission limits its evaluation of a utility's proposed tariff revisions to an inquiry into "whether the rates proposed by a utility are reasonable – and not to extend to determining whether a proposed rate schedule is more or less reasonable to alternative rate designs." *City of Bethany v. FERC*, 727 F.2d 131, 1136 (D.C. Cir. 1984). The proposed revisions "need not be the only reasonable methodology." *Oxy USA v. FERC*, 64 F.3d. 679, 692 (D.C. Cir. 1995). As a result, even if an intervenor develops an alternative proposal, the Commission must accept a section 205 filing if it is just and reasonable, regardless of the merits of the alternate proposal. *S. Cal. Edison Co., et al.*, 73 FERC ¶ 61,219, at 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protestors." (citing *City of Bethany*, 727 F.2d at 1136).

(5) Documentation Requirements, Right to Audit Automated Reference Level Change Requests, and Consequences of Failing to Product Requisite Documentation

Although a supplier is not required to submit any supporting information when it submits an automated reference level change request, the supplier must possess and retain information indicating the resource's actual or expected costs are the same as those submitted in the reference level change request.[132] The revised tariff defines this documentation as "contemporaneously available information" because it refers to documentation that must exist at the time a supplier submits a reference level change request, as opposed to documentation that the supplier later creates or produces to justify *ex post* a reference level change request.[133]

The contemporaneously available documentation may include either (1) quotes from natural gas suppliers, (2) gas purchase invoices, (3) evidence of a bid price that was part of an unsuccessful good-faith effort to purchase fuel, or (4) other appropriate documentation demonstrating fuel or fuel-equivalent costs.[134] Quotes from natural gas suppliers are representative of a supplier's expected costs. Basing reference levels on expected costs is consistent with Order Nos. 831 and 831-A.[135] Gas price invoices reflect a supplier's actual costs. Evidence of a bid price that was part of an unsuccessful good-faith effort to purchase fuel demonstrates that a supplier was trying to purchase gas, but was unable to do so because there was no counterparty able to supply the gas. This indicates that the prevailing price of gas is at least equal to the price at which the supplier attempted to buy gas. It is reasonable to allow for other appropriate documentation demonstrating fuel or fuel-equivalent costs to account for costs of non-traditional resources and circumstances that are not currently contemplated. The CAISO does not believe the documentation requirements should be overly prescriptive, because fuel and fuel-equivalent pricing information may come in different forms. However, the CAISO proposes the requirements described above to ensure the requests are reliable and actually reflect increased fuel or fuel-equivalent cost exposure.

The tariff revisions require the documents show the price of fuel is based on next-day procurement for the day-ahead market, and based on same-day or next-day procurement for the real-time market. This will ensure the current

132 New tariff section 30.11.3.3.

133 Tariff appendix A, new definition of "Documentation of Contemporaneously Available Information".

134 *Id.*

135 *See* Order No. 831 at P 139; Order No. 831-A at P 23.

prevailing cost of fuel is the driver for a reference level adjustment, not higher prices that suppliers incurred for a future operating day as part as a hedging strategy. For non-standard gas trading days, the documentation must show the price of fuel is for procurement no sooner than the most recent standard gas trading day.

The proposed revisions authorize the CAISO to audit automated reference level change requests, even if they fall within the reasonableness thresholds.[136] The automated reference level change request process will facilitate pre-market clearing verification of actual or expected costs that are greater than the reference levels the CAISO market would otherwise use. This will provide an administratively efficient pre-market verification procedure, while ensuring reference level changes are based on actual or expected fuel or fuel-equivalent costs that are greater than a resource's reference levels. The reasonableness thresholds are not intended as "safe harbors" that suppliers can bid up to irrespective of their actual costs. The CAISO must, therefore, be able to verify after the fact that the automated reference level change requests are appropriately based on the supplier's actual or expected costs. Absent such audit authority, suppliers may over time increase their costs used by the CAISO market systems and inflate their costs above their actual or expected costs. This could result in unjustified higher costs to the CAISO market through unsupported and unjustified higher energy and commitment costs.

In an audit, the CAISO will request the supplier provide the CAISO its cost calculations, including documentation of contemporaneously available information, at any time. An audit can begin immediately after the CAISO has executed the applicate market. Therefore, the supplier should have the required documentation in its possession at the time it actually submits the automated reference level change request. The CAISO may need to audit a supplier as soon as possible to avoid exposing the market to adverse outcomes caused by a supplier's false submissions. Similarly, the CAISO must be able to audit a supplier weeks or even months after the requested adjustment, because the CAISO may obtain additional information suggesting the supplier's actual or expected costs may not have been greater than a resource's reference levels.

Although the supplier must demonstrate that the documentation supporting its request existed at the time it submitted its request, the CAISO proposes a reasonable timeframe for the supplier to respond and produce the documentation in response to an audit request. Specifically, suppliers must

136 New tariff sections 30.11.3.3 and 30.11.3.5(a). The CAISO does not propose to have authority to audit manual reference level change requests because suppliers will be required to submit the documentation of contemporaneously available information when they submit the manual request, which the CAISO will review prior to clearing the market as practicable.

provide the requested information within five business days of the CAISO's request.[137] This provides the supplier with sufficient time to validate that the information is responsive and accurate. More time is unnecessary because suppliers will be on notice that they should retain supporting documentation when they submit reference level change requests, and such supporting documentation must exist at the time of the adjustment request, *i.e.*, the supplier should already have the documentation. Further, a lengthier response time would unnecessarily delay the CAISO's verification whether the reference level change request was indeed appropriate.

The CAISO will evaluate the submitted information and determine whether it supports the supplier's automated reference level change request within ten business days of receiving the supplier's cost calculations and supporting documentation.[138] The CAISO intends to respond quickly. However, the CAISO needs at least ten business days because the verification may require additional consultations and reviewing further corroborating evidence.

If the CAISO determines the documentation submitted by a supplier does not show the supplier had a reasonable expectation that a resource's fuel or fuel-equivalent costs would be higher than the fuel or fuel-equivalent costs the CAISO used to determine the resource's reference levels, the supplier will be prohibited from submitting automated reference level change requests for 60 days after the CAISO informs the supplier of its finding. Subsequent findings by the CAISO that the supplier did not submit documentation in support of its automated reference level change request will result in a 180-day prohibition from submitting automated reference level change requests.[139]

These consequences of failing to provide adequate documentation will help to ensure the rules for reference level change requests are not inappropriately exploited. The Commission accepted a similar stepped penalty scheme in the NYISO tariff regarding fuel information suppliers submit to determine reference levels.[140] The consequences are not unjust and unreasonable because the supplier may still request a manual reference level change request, and the supplier is still eligible to pursue after-market cost recovery. Further, these consequences are not based on any findings of adverse

137 New tariff section 30.11.3.5(a).

138 *Id.*

139 New tariff section 30.11.3.5(c).

140 NYISO Market Administration and Control Area Services Tariff, at sections 23.3.1.4.6.9 – 23.3.1.4.6.9.2. The Commission accepted the original version of the NYISO's stepped penalty scheme by letter order issued on December 21, 2010 in Docket No. ER10-2062-001, finding that the NYISO scheme complied with an earlier Commission directive in the proceeding to "provide specificity in the criteria to be used in penalty assessment and the application of mitigation". The NYISO has subsequently made incremental revisions to it.

market behavior, but are simply based on a finding that the supplier lacked sufficient documentation of information that led it to determine a need for a reference level change request. The CAISO may still refer suppliers to the Commission for any adverse market behavior it observes in the submission of automated or manual reference levels change requests.

If the CAISO determines the submitted information does not support the reference level change request, the supplier may appeal the CAISO's determination under the CAISO's existing alternative dispute resolution (ADR) procedures within five business days of the CAISO's response. If the supplier requests the CAISO ADR procedures, the supplier will not be permitted to submit automated reference level change requests until resolution of those ADR procedures. In addition, if the CAISO ADR procedures confirm the documentation of contemporaneously available information did not support the supplier's automated reference level change request, the supplier will be prohibited from submitting automated reference level change requests for the duration of the applicable time periods.[141]

b. Manual Reference Level Change Requests

The CAISO proposes that natural gas-fired resources can request a manual consultation from the CAISO to propose reference level changes to default start-up bids, default minimum load bids, and default energy bids. Non-gas-fired resources may submit manual reference level change requests only for default energy bids.[142] A supplier can request a manual reference level change when its actual or expected fuel or fuel-equivalent costs exceed the fuel or fuel-equivalent costs the CAISO used to calculate the resource's reference level by the higher of 10 percent or $0.50/MMBTU.[143] Presumably, if the resource's fuel or fuel-equivalent costs exceed those used by the CAISO by less than 10 percent, the supplier would have submitted an automated reference level request change. The additional $0.50/MMBTU criteria is intended to avoid the manual reference level change process for relatively small price changes. Suppliers should submit the automated request, if costs are within thresholds, because they can be processed more readily and efficiently. The CAISO expects to conduct manual requests only if costs exceed the automated thresholds. Therefore, these metrics indicate when reasonable grounds exist to submit

[141] New tariff section 30.11.3.5(b). If the ADR process results in a finding that the documentation did support the supplier's request, the CAISO will remove restrictions on the supplier's ability to submit requests for reference level changes.

[142] New tariff section 30.11.4.1(b). The CAISO considered making the manual process available for proposed changes to a non-natural gas-fired resource's default start-up bids and default minimum load bids, but identified significant challenges in implementing a manual process for these variables. The CAISO plans to consider that enhancement in the future.

[143] New tariff section 30.11.4.1.

manual reference level change requests and minimize the CAISO's administrative burden.

Like automated reference level adjustment requests, manual reference level change request calculations for default commitment cost bids and default energy bids will exclude the 125 percent commitment cost multiplier or the 110 percent default energy bid multipliers.

A supplier must submit a manual reference level change request by 8:00 a.m. on the business day the applicable CAISO market is executed.[144] Manual requests must be submitted by 8:00 a.m. to provide the CAISO with sufficient time to conduct its due diligence in reviewing the requests. Unlike the automated process for requesting reference level changes, a manual reference level change request must include documentation of contemporaneously available information supporting the supplier's actual or expected fuel or fuel-equivalent cost at the time of submission.[145] To verify requests manually, the CAISO must actually review information submitted by the supplier and validate that information against any other information it has available. This may take some time to ensure the supplier is not increasing its reference levels based on unreliable or inadequate information. The CAISO is unable to manually verify reference level change requests throughout the day. Therefore, it developed the automated process to ensure suppliers can readily increase their cost calculations within a reasonable range.

Prior to the day-ahead market, if practicable, or as soon as practicable for requests submitted for the real-time market, the CAISO will (1) validate the submitted information and any other available evidence of current costs that apply to the manual reference level change request, and (2) implement the reference level change, if it determines the information supports the request.[146] If the CAISO accepts the fuel cost submitted in the reference level change request, the CAISO will recalculate the reference level using the accepted actual or expected fuel costs (without applying the commitment cost multiplier or the default energy bid multiplier) and use the revised reference level in the CAISO market processes and for settlement. If the CAISO cannot validate the information, either because it does not have sufficient time to validate the submissions, or because the information submitted does not support the request, the CAISO will reject the manual reference level change request and make no changes to the resource's reference level.[147] However, as with automated

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[144] New tariff section 30.11.4.2.

[145] *Id.*

[146] New tariff section 30.11.4.3.

[147] *Id.*

reference level change requests, suppliers may request after-market reference level adjustments for any amounts the CAISO does not validate prior to execution of the applicable market run.

If the CAISO accepts a manual reference level change request, in addition to updating the supplier's reference levels, the CAISO will update the resource's reasonableness threshold.[148] This will ensure that if the supplier's costs increase further after its manual request, and the supplier has in its possession new contemporaneously available information (*i.e.*, not the same data used to support the manual request) that supports an increase in its actual or expected fuel costs, the supplier has the ability to request an automated reference level change request. This will allow the supplier to increase its reference levels in the event that the CAISO increases the fuel costs used to update the resource's reasonableness threshold on its own initiative as discussed above in this transmittal letter.

c. Submissions of Reference Level Change Requests Must not Include Commitment Cost Multipliers or Default Energy Bids Multipliers

All reference level change request calculations for default commitment cost bids and default energy bids processed through the automated and manual processes will exclude the 125 percent commitment cost multiplier or the 110 percent default energy bid multipliers. The 125 percent commitment cost and 110 percent default energy bid multipliers are included in the existing calculation of reference levels under the current tariff.[149] If a supplier chooses to submit a reference level change request, it is an indication that the supplier anticipates the weighted index price does not capture an anticipated or actual higher fuel cost. Consequently, the supplier must submit a proposed reference level using the same methodology used to calculate the reference level, except the calculation will reflect a higher actual or expected fuel cost. The rationale for excluding these multipliers from reference level change request calculations is the updated reference level includes actual or expected fuel costs. This is consistent with the Commission's guidance in the First CCDEBE Order, in the context of such requests, the supplier must submit its actual or expected fuel costs.

[148] New tariff sections 30.11.1.2.1 and 30.11.5.

[149] New tariff sections 30.11.3.1 – 30.11.3.2, and 30.11.4.3. As explained above, the 125 percent commitment cost multiplier is set forth in existing tariff sections 30.4.1.1.5, 30.7.9(c), and 30.7.10.1, and the 110 percent default energy bid multiplier is set forth in existing tariff section 39.7.1.1. In this tariff amendment, the CAISO proposes to add the new defined terms "Commitment Cost Multiplier" and "Default Energy Bid Multiplier" to tariff appendix A to specify these percentages, and to use those definitions in the body of the tariff (*see, e.g.*, new tariff sections 30.4.4.1 – 30.4.4.2 and revised tariff section 39.7.1.1).

As illustrated in Example 2 above, the supplier would not be permitted to include the commitment cost multiplier or the default energy bid multiplier in its request. Although the CAISO is unable to immediately validate whether the supplier's submission does not include multipliers, the CAISO will evaluate the supplier's submissions in an ex-post audit, as discussed below. If the CAISO determines through its audit process that the supplier's submission was based on the use of a multiplier, the supplier will fail the audit.

As in the First CCDEBE Tariff Amendment, the CAISO proposes to allow suppliers to request reference level changes for either expected or actual fuel or fuel-equivalent costs. This is consistent with the Commission's guidance in Order No. 831, which anticipates that updates to a resource's reference levels may be based on expected costs in addition to actual costs.[150] The CAISO understands "expected" fuel costs to refer to an estimate of a later actual fuel purchase cost based on an estimated cost that is based on the price of gas at the time the estimate is made.[151] Thus, a supplier's actual costs when the supplier actually purchases gas may be different from its expected costs at the time it submits a reference level change request.[152] For example, a supplier may need to purchase additional gas after it receives its day-ahead market schedules around 1:00 p.m. These costs may be different from the estimated costs included in the supplier's day-ahead market bids that were due at 10:00 a.m., and for which it requested a reference level change prior to 10:00 a.m.[153]

Since the CAISO submitted the First CCDEBE Tariff Amendment, the CAISO has examined more closely how next-day gas prices for gas purchased to meet day-ahead schedules might vary over the day from the time the supplier must submit a reference level change request to the time the supplier actually procures the fuel. As discussed below, the supplier must submit its reference level change request for the day-ahead market by 8:00 a.m. on the day the

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150 *See* Order No. 831 at P 139 (clarifying that each Independent System Operator or Regional Transmission Organization must "verify that any incremental energy offer above $1,000/MWh reasonably reflects the associated resource's actual or expected costs prior to using that offer to calculate LMPs"); Order No. 831-A at P 23 (amending regulatory text by "adding the words 'actual or expected' [to] . . . provide more certainty to market participants and more clearly state the Commission's intention that both actual and expected costs over $1,000/MWh may be submitted for verification").

151 The CAISO plans to clarify this in the business practice manual.

152 *See* Final Version of Opinion on System Market Power Mitigation issued by the CAISO's Market Surveillance Committee at 34-35 (Nov. 5, 2019), available at http://www.caiso.com/Documents/MSC-DraftOpiniononSystemMarketPowerMitigation-Nov5_2019.pdf.

153 The Commission has previously recognized the need for adders to account for such fuel cost uncertainties as part of the cost verification process. *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,155, at P 32 (2017).

applicable market is executed.[154] At that time, the supplier may have a quote in hand that states the expected fuel price it faces and may legitimately submit a reference level change request reflecting such fuel price.

The CAISO's proposed changes ensures the CAISO systems can capture different types of unexpected increases in fuel prices. Therefore, the CAISO analyzed price data for days when gas conditions were strained and prices were high. The CAISO understands that on most days gas conditions are more stable and do not fluctuate as extensively. However, suppliers do not receive CAISO's day-ahead schedules until later in the day, usually after 1:00 p.m., *i.e.*, the time the CAISO posts the day-ahead market results. Suppliers may procure some of their expected gas needs before that time. Nevertheless, suppliers may have to procure additional gas after they receive their final day-ahead schedules to ensure they have sufficient gas when they are required to operate their resources.

The CAISO's analysis found there are very few days in which prices based on the next-day index and reported trades actually increased significantly over the day above the next-day index. For example, one of these rare gas price fluctuations occurred on February 17, 2018. Reported prices hovered around $3.80/MMBtu, but later in the day the prices jumped to nearly $5/MMBtu. On this day, a supplier would have only been able to show actual or verifiable costs at the lower price, even though it may have faced higher prices later when it became aware of its day-ahead schedule after 1:00 p.m.

Other examples of rare gas price fluctuations occurred during the real-time market for same-day gas trading. On January 6, 2017, the CAISO observed broad same-day gas price fluctuations after 8:30 a.m. The current CAISO market structure does not allow suppliers to update their reference levels to reflect gas price variations. Consequently, suppliers may have been committed to operate their resources at a price that was much lower than the actual cost of fuel. The CAISO observed similar patterns on October 30, 2017 and August 3, 2018. The widest gas price fluctuation observed was 25 percent on August 3, 2018.[155]

Although the CAISO did find that there were days on which prices may vary throughout the day, the CAISO was only able to find a handful of days over a period of 3 years during which such conditions were possible. The rest of the time, prices did not fluctuate sufficiently throughout the day to justify the inclusion of any multipliers.

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[154] *See* new tariff section 30.11.4.2.

[155] *See* CAISO Presentation on CCDEBE Changes, May 20, 2020, at slides 13-14, available at http://www.caiso.com/InitiativeDocuments/Presentation-CommitmentCosts-DefaultEnergyBidEnhancements-May20-2020.pdf.

In the stakeholder process preceding this tariff amendment, the CAISO initially proposed to decrease the multiplier it would apply to a revised default minimum load cost bid from 125 to 110 percent to capture the price variation it observed in those few constrained days. However, after reviewing comments by the DMM,[156] the CAISO concluded the DMM's data supported excluding the commitment cost multiplier and default energy bid multiplier when the supplier requests an adjustment of its fuel costs based on verifiable actual or expected fuel costs. The CAISO concluded applying the multipliers to reference level change requests would create a risk that suppliers would be permitted to increase their reference levels above their actual or expected costs. Further, even without the multipliers in the reference level change requests, suppliers would still be able to recover actual fuel costs through the after-the-fact recovery process described below, if such costs exceed what the suppliers could recover through the CAISO market. The data provided above show such events are so infrequent that excluding the multipliers from reference level change requests will not degrade suppliers' ability to recover their costs or market efficiency. For these reasons, it is just and reasonable to exclude the multipliers from reference level change requests as proposed in this tariff amendment.

d. Authority to Seek Payment of Actual Incurred Costs after the CAISO Market Process

The CAISO proposes new procedures that would allow suppliers to request adjustments to their resource reference levels based on a resource's actual fuel or fuel-equivalent costs up to 60 business days after the applicable CAISO market.[157] Because these tariff revisions supersede existing tariff provisions allowing after-the-fact recovery of commitment-related fuel costs and marginal fuel-related costs, the CAISO proposes to delete the existing tariff provisions.[158] The proposed after-market recovery procedures are similar to the existing tariff provisions, but, as described below, they allow the supplier to request the CAISO to consider and approve recovery of costs instead of, or before, Commission review. The CAISO proposes a CAISO-based process because in the after-market process, suppliers must demonstrate they actually incurred the fuel costs. A supplier should be able to provide documentation supporting its actual costs and prudent procurement practices that the CAISO can evaluate, and determine, whether or not, the supplier is warranted the recovery. This reduces the supplier's and the CAISO's legal and processing

156 *See* http://www.caiso.com/InitiativeDocuments/DMMComments-CommitmentCosts-DefaultEnergyBidEnhancements-StakeholderBriefing-Mar19-2020.pdf.

157 New tariff section 30.12, *et seq.*

158 Deleted tariff sections 30.11 and 30.12, *et seq*.

costs associated with suppliers seeking after-market cost recovery with the Commission. Moreover, this process is consistent with the Commission's direction in Order No. 831 allowing suppliers to seek after-the-fact uplift payments for unverified incremental energy offers above $1,000/MWh.[159]

Under the proposed after-market cost recovery process, a supplier may request an additional uplift payment to cover a resource's actual fuel or fuel-equivalent costs reflected in a resource's start-up bid costs, minimum load bid costs, transition bid costs, and energy bid costs used in the bid cost recovery mechanism. The requested 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.[160] The supplier must follow a specified process for either (1) requesting the CAISO evaluate the costs or (2) submitting a filing to the Commission seeking cost recovery. The supplier's submission must satisfy specified documentation requirements.[161] The proposed timeline for submitting a filing to the Commission and the documentation requirements resemble the existing, Commission-approved tariff provisions allowing after-the-fact recovery of commitment-related fuel costs[162] and after-the-fact recovery of marginal fuel-related costs.[163]

Whether the supplier seeks after-market cost 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. Also, these costs must be reasonable and reflect prudent procurement practices. Supporting documents can include invoices for fuel purchased or other appropriate documentation demonstrating that fuel or fuel-equivalent costs actually incurred exceed the fuel or fuel-equivalent costs the CAISO used to develop the resource's reference levels.[164] Because the supplier has already incurred the costs, the after-market recovery should be based on documentation of actually

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159 Order No. 831 at P 146.

160 New tariff section 30.12.1. New tariff section 30.12.1 also specifies that suppliers may not request additional uplift payments under the section to cover costs associated with gas company imbalance penalties.

161 New tariff sections 30.12.2 – 30.12.5.

162 *See Cal. Indep. Sys. Operator Corp.*, 157 FERC ¶ 61,138, at P 21.

163 *See* 2018 Aliso Canyon Order at P 45; *compare* new tariff sections 30.12.2 – 30.12.5 *with* existing tariff section 30.11 and former tariff sections 30.12.2 – 30.12.3 (as in effect on an interim basis until December 31, 2019).

164 New tariff section 30.12.3.

incurred costs, not expected costs, which can be the basis for before-market reference level change requests.

If the supplier requests the CAISO evaluate the costs, the CAISO will verify the submitted costs (1) represent actually incurred fuel or fuel-equivalent costs, and (2) are reasonable and reflect prudent procurement practices.[165] Suppliers must submit supporting documentation (*e.g.*, invoices for fuel purchased or other 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. The CAISO will evaluate whether the costs were actually incurred using prudent procurement practices based on the information submitted by the supplier. The supplier can seek recovery from the Commission if the CAISO determines the resource is ineligible for after-market fuel cost recovery, or the supplier chooses to seek recovery from the Commission instead of the CAISO.[166]

If the CAISO or the Commission finds the supplier actually incurred the additional claimed costs that it did not recover through the bid cost recovery process, the CAISO will resettle the bid cost recovery for the resource for the relevant day-ahead and real-time markets using revised bid costs for the resource calculated using the actually incurred fuel or fuel-equivalent price. The CAISO will process these uplift payments through subsequent recalculation settlement statement(s) consistent with the CAISO's normal recalculation settlement statements timelines.[167] Calculating the uplift payment through the bid cost recovery process ensures the supplier will receive compensation for its actual costs only if it did not already recover those costs through CAISO market revenues. This is consistent with the existing tariff rules that a resource is only compensated for its bid costs if it does not recover such costs through CAISO market revenues.[168] Also, consistent with existing performance requirements in the CAISO's bid cost recovery rules, if the resource does not perform consistent with the resource's dispatches and commitments, it will not receive full compensation through the bid cost recovery processes.[169] Suppliers should not be allowed to avoid otherwise applicable rules through the after-market recovery

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165 New tariff section 30.12.4.2.

166 New tariff section 30.12.5.1.

167 New tariff sections 30.12.4.3 and 30.12.5.2.

168 Existing tariff section 11.8.

169 *See e.g.*, existing tariff sections 11.8.2 and 11.8.2.5 (both referencing the real-time performance metric set forth in existing tariff section 11.8.4.4).

process, which would cause the same performance problems the rules are intended to solve.[170]

During the stakeholder process preceding this tariff amendment, one stakeholder argued that the CAISO should reimburse resources for gas usage imbalance penalties after the fact.[171] The CAISO did not adopt this recommendation, because doing so would provide a disincentive for suppliers to follow gas pipeline instructions. The Commission too has taken this position. In the 2016 Aliso Canyon Order, the Commission accepted the CAISO's tariff revisions on after-market cost recovery, on which the comparable tariff revisions proposed herein are modeled. In that order, the Commission rejected a commenter's argument that a resource that incurs gas imbalance penalties pursuant to a CAISO dispatch instruction should be entitled to recover them after-the-fact:

> Likewise, we reject NRG's request to include OFO [operational flow order] penalty costs within the scope of fuel costs recoverable under these provisions. The Commission has previously found that "[a]llowing generators to recover costs and penalties associated with unauthorized natural gas consumption could jeopardize the reliability of natural gas pipeline and transmission systems and is therefore at odds with the reliability and costs benefits otherwise associated with allowing generators to recover actual fuel costs in reference levels." We find that the Commission's rationale in that proceeding applies with equal force here.[172]

For these reasons, the CAISO does not propose to provide after-the-fact cost reimbursement for gas penalties. Further, the stakeholder's request that the CAISO allow the recovery of gas usage penalties is inconsistent with the guidance provided in *NRG*. If a resource wants to recover gas usage penalty costs associated with a CAISO dispatch instruction after the CAISO has dispatched the resource, it can seek relief from the pipeline or local distribution company.

In addition, the DMM contended that the proposal for after-the-fact recovery of actual costs may allow a resource to recover costs arising from its

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170 *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at P 37 (2013) (finding that the CAISO's real-time performance metric is "reasonable because [it] will ensure that CAISO pays bid cost recovery only for the costs associated with energy dispatched by CAISO in the real-time market that a resource delivers").

171 *See* CCDEBE Board Memorandum, attachment A at 6, 7.

172 2016 Aliso Canyon Order at PP 90, 96 (quoting *N.Y. Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,111, at P 39 (2016)).

exercise of market power.[173] To the contrary, a supplier's after-the-fact cost recovery must be fully documented, must be based on actual fuel market prices, and cannot be cannot be greater than its original adjustment request. Thus, even a resource with market power will be unable to recover any actual costs that do not meet those requirements.

C. Revisions to Clarify and Reorganize the Proxy Cost Methodology Tariff Provisions

The CAISO proposes to reorganize its tariff provisions on the proxy cost methodology to reflect the revisions in this tariff amendment.[174] The proposed changes do not change the substance of the existing tariff provisions.

The CAISO also propose to introduce new terms to capture the default commitment cost bids it calculates for resources. The CAISO calculates default commitment cost bids under its existing tariff, but does not have defined terms for those bids. The CAISO proposes to define default commitment cost bids as consisting of default start-up bids, default minimum load bids, and default transition bids.[175] This will add greater clarity to the tariff. The CAISO will continue to calculate default commitment cost bids using the proxy cost methodology for all resources except for (1) non-resource-specific system resources and non-generating resources, and (2) use-limited resources that are subject to the registered cost methodology.[176] The CAISO also proposes to reorganize relevant provisions of the tariff to list how the default commitment cost bids (*i.e.,* default start-up bids, default minimum load bids, and default transition bids) are derived using the proxy or registered cost methodologies.[177]

In addition, the CAISO proposes to:

(1) Renumber the tariff sections on the proxy cost methodology;[178]

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173 *See* CCDEBE Board Memorandum, attachment B at 8.

174 Revised tariff section 30.4, *et seq.*

175 Tariff appendix A, new definitions of "Default Commitment Cost Bids", "Default Start-Up Bid", "Default Minimum Load Bid", and "Default Transition Bid". The CAISO has also made conforming revisions throughout the tariff to replace the existing terms "Start-Up Cost", "Minimum Load Cost", and "Transition Cost" with those new defined terms. New tariff section 30.4.4.4; revised tariff sections 4.12.1.1(ii), 27.7.1, 30.4.2, 30.4.7, 30.5.2.4, 39.6.1.6.1 – 39.6.1.6.2, and 39.7.1.1.2; tariff appendix A, revised definitions of "Generated Bid" and "Projected Proxy Cost".

176 Revised tariff section 30.4.1. As stated above, for use-limited resources that are subject to the registered cost methodology, the CAISO will use the costs registered in the master file as the default commitment cost bids.

177 Revised tariff section 30.4, *et seq.*

178 *Id.* (*passim*).

(2) Add tariff section headings for ease of reference;[179]

(3) Move existing provisions on the proxy cost methodology to other nearby locations in the tariff where the provisions are more relevant.[180]

(4) Clarify the meaning of existing tariff provisions regarding the proxy cost methodology;[181]

(5) Define the types of proxy costs (*i.e.*, proxy start-up costs, proxy minimum load costs, and proxy transition costs), and use those new definitions in the tariff;[182] and

(6) Add new tariff provisions describing the format and validation of transition bids that were missing and reflect the current methodology for determining those costs.[183]

These tariff revisions will enhance the existing tariff language regarding the proxy cost methodology, and will provide greater clarity on how these amounts are determined for purpose of later discussing how suppliers may request reference level changes.[184]

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[179] Headings for new tariff section 30.4.4.4 and revised tariff sections 30.4.2, 30.4.5.1(a)-(e), 30.4.5.2(a)-(e), 30.4.5.3.1 – 30.4.5.3.2, and 30.4.5.4.1 – 30.4.5.4.4.

[180] New tariff sections 30.4.4.5 (incorporating provisions from existing tariff section 30.4.1.1.2(a), 30.4.5.1(d) (incorporating provisions from existing tariff section 30.4.1.1.5), and 30.4.5.2(d) (same).

[181] New tariff section 30.4.4.4; revised tariff sections 30.4.5.1 – 30.4.5.1(c), 30.4.5.2 – 30.4.5.2(c), 30.4.5.3.1 – 30.4.5.4.4, 30.4.6.1.1, 30.5.1(c),30.5.2.4, 30.6.2.1.2, 30.7.3.1, 30.7.8, 30.7.9 – 30.7.10, 31.3.1.3, 31.3.1.4, 31.5.6, 34.7, and 34.11.

[182] New tariff section 30.4.5.1(d); revised tariff sections 29.30(b), 30.4.5.1(b)-(c), 30.4.5.2, 30.4.5.2(b)-(c), 30.4.5.3.2 – 30.4.5.4.3, 30.4.6.2.2, and 30.7.9(h); tariff appendix A, revised definition of “Proxy Cost”; tariff appendix A, new definitions of “Proxy Start-Up Cost”, “Proxy Minimum Load Cost”, and “Proxy Transition Cost”.

[183] New tariff section 30.7.11. The CAISO proposes to define a transition bid as the bid component that indicate the transition cost from one MSG configuration of an MSG resource to another MSG configuration. Tariff appendix A, new definition of “Transition Bid”.

[184] New tariff section 30.11.

C. Other Tariff Revisions

As explained above,[185] the CAISO generates cost-based bids (*i.e.*, generated bids) using the same cost components and resource-specific information used in the variable-cost default energy bid when a supplier does not submit a bid for a resource adequacy resource subject to a must-offer requirement, or pursuant to the CAISO's generally applicable scheduling and bidding rules. The CAISO determines gas costs for generated bids of natural gas-fired resources using the same gas pricing provisions it uses to determine gas costs for commitment costs and variable-cost default energy bids. To reflect these existing features of generating bids, the CAISO proposes to revise its tariff to define a generated bid as a post-market bid generated by the CAISO "using the applicable Default Energy Bid and Default Commitment Cost Bids."[186]

The CAISO also proposes revisions to correctly capitalize existing tariff-defined terms and use such existing defined terms more precisely,[187] clarify the meaning of certain tariff provisions,[188] and implement new and more precise definitions that in some cases supersede existing tariff terms.[189]

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185 *See supra* section II.B of this transmittal letter.

186 Tariff appendix A, revised definition of "Generated Bid".

187 Revised tariff sections 6.5.3.1.3, 8.4.1.2, 11.8.1.3(3), 11.8.2.1.1(c), 11.8.2.1.2(f), 11.8.2.3.2, 11.8.3.1.1(c), 11.8.4.1.1 – 11.8.4.1.1(g), 11.8.4.4.1 – 11.8.4.4.2, 27.7.1, 27.7.3, and 27.7.5; tariff appendix A, revised definition of "Start-Up Bid".

188 Revised tariff sections 6.5.6.1.2, 11.8, 11.8.2.1.1 – 11.8.2.1.2, 11.8.3.1.1, 11.8.3.1.1(e), 11.8.3.1.2, 11.8.4.1, 11.8.4.1.2, 11.8.4.3.2, 11.8.4.4.1 – 11.8.4.4.5, 11.17.2.1 – 11.17.2.2, 30.4.6.2.2(2)-(3), 30.4.7, 30.5.1, 30.7.3.1, 30.7.3.4, 30.7.9, 31.3.1.4, 31.5.6, 34.7(7) and -(12), 34.11, 39.6.1.6 – 39.6.1.6.2, and 39.7.1.1.1.2; tariff appendix A, revised definitions of "Minimum Load Bid", "Minimum Load Costs", "RTM AS Bid Cost", and "Start-Up Bid".

189 Revised tariff sections 11.8 – 11.8.1, 11.8.1.3 – 11.8.1.3(3)(b), 11.8.2.1, 11.8.2.1.1, 11.8.2.1.1(g), 11.8.2.1.2(f), 11.8.2.3.2, 11.8.3.1 – 11.8.3.1.2, 11.8.4.1 – 11.8.4.1.1(h), 11.8.4.1.1(g), 11.8.4.1.2, 11.8.4.3.2, 27.7.3, 27.7.5, 30.7.9(d), 30.7.9(f), 30.7.9(i), 31.3.1.4, 40.6.8(e), 40.6.8.1 – 40.6.8.1.3, and 40.6.8.1.5; tariff appendix A, revised definition of "Bid Costs," ; tariff appendix A, new definitions of "IFM Start-Up Cost", "Minimum Load Bid Cost", "Non-Resource-Specific System Resource", "RTM Energy Bid Cost", "RTM Pump Shut-Down Cost", "RTM Start-Up Cost", "RTM Transition Cost", "RUC Start-Up Cost", "RUC Transition Cost", "Start-Up Bid Cost", "Start-Up Cost Curve", "Transition Bid Cost", and "Transition Opportunity Cost"; tariff appendix A, deleted definition of "Subset of Hours Contract". In the cited tariff provisions, the new term "Non-Resource-Specific System Resource" replaces the existing term "non-Resource-Specific System Resource".

V. RESPONSE TO STAKEHOLDER REQUESTS FOR ADDITIONAL CHANGES

A. Responses to Concerns with the CAISO's Decision not to Change the Calculation of Proxy-Based Default Commitment Cost Bids

After reviewing the First CCDEBE Order, the CAISO considered reducing the commitment cost multiplier used in calculating default commitment cost bids today from 125 to 110 percent. The CAISO based this decision on its observations that the actual fuel price suppliers pay may exceed the price indices used to calculate the default commitment cost bids that are based on the weighted price indices. Based on its observations, which it discussed during the stakeholder process, the CAISO considered there was sufficient support to lower the multiplier.

The CAISO solicited comments on its proposal, and although some stakeholders supported reducing the commitment cost multipliers, numerous stakeholders objected to this proposed modification. In particular, stakeholders noted that this proposed change went beyond what was necessary to respond to the Commission's concerns and significantly modified the total package changes the CAISO Board of Governors approved. As part of the package of changes, the CAISO proposed to lower the commitment cost multiplier after it implements the dynamic market power mitigation of commitment costs. With this dynamic market power mitigation, commitment cost bids would only be limited to default commitment cost bids in the event the dynamic market power mitigation process detected market power. In contrast, under the current rules, which the CAISO does not propose to modify herein, suppliers are subject to the default commitment cost bids at all times.[190]

In response to stakeholder concerns, after considering the pricing data further and the phased-in approach for the CCDEBE initiative, the CAISO concluded that it is appropriate to leave the multipliers in place unless it approves a supplier's reference level adjustment request. In particular, because the data show there are still many instances in which actual fuel prices deviate from the weighted average price indices, reducing the multipliers at this time would likely force suppliers to have to submit more frequent reference level change requests. In addition, because the CAISO now proposes to exclude all multipliers in the context of reference level change requests, reducing the multipliers may force market participants to request after-the-fact cost recovery more frequently. That would reduce the efficiency gains obtained under the proposed tariff changes that will allow the CAISO to consider a supplier's costs in the market clearing

[190] The CAISO will consider such change when it submits a tariff amendment to implement the dynamic market power mitigation rules in the second phase of the CCDEBE initiative.

process. Finally, the CAISO agreed that lowering the commitment cost multiplier without the additional changes contemplated under the complete CCDEBE policy changes would require additional action from the Board of Governors given that it is not directly responsive to the Commission's directives in the First CCDEBE Order.

B. Consideration of Proposal to Include the Commitment Cost Multiplier and Default Energy Bid Multiplier in the Context of a Reference Level Change Request

Based on the First CCDEBE Order, the CAISO considered reducing the commitment cost and default energy bid multipliers in the calculation of reference levels subject to reference level change requests from 125 percent to 110 percent. The CAISO's initial proposal in the stakeholder process following the First CCDEBE Order was based on its observation that although there are variations in prices throughout the day, the prices did not vary sufficiently to warrant a 125 percent multiplier. Therefore, the CAISO proposed reducing the multiplier to 110 percent.

In response to the CAISO's proposal, the DMM commented that it did "not believe that a more detailed and complete analysis of same day gas price volatility after 8:30 am would support inclusion of a 110% multiplier," and that it was not consistent with the Commission's guidance in the First CCDEBE Order. The DMM concluded that because the analysis does not support including a 10 percent adder in suppliers' calculations of their actual or expected costs, the CAISO should justify the inclusion of multipliers in the context of reference level change requests based on other reasons.[191] As discussed above, after consideration, the CAISO decided not to allow inclusion of any multiplier (either 110 percent or 125 percent) in reference level change requests.

VI. EFFECTIVE DATE, REQUEST FOR TIMELY COMMISSION ORDER, AND REQUEST FOR WAIVER

The CAISO expects to implement the changes proposed in this tariff amendment between October 1, 2020 and January 31, 2021. The CAISO requests authority to provide at least fourteen days' notice of the actual effective date to the Commission and market participants.[192]

[191] *See* http://www.caiso.com/InitiativeDocuments/DMMComments-CommitmentCosts-DefaultEnergyBidEnhancements-StakeholderBriefing-Mar19-2020.pdf, at p. 2.

[192] The CAISO has included an effective date of 12/31/9998 as part of the tariff records submitted with this filing. The CAISO will make a filing pursuant to Commission Filing Code 150 to provide notice of the actual effective date of these tariff records at least fourteen days prior to implementation. For all the reasons set forth above, the Commission should accept the tariff revisions proposed in this filing without condition or modification. The CAISO again notes that a

To allow the CAISO to meet the earliest of these possible effective dates, the CAISO requests that the Commission issue an order by September 21, 2020 accepting this tariff amendment. The CAISO also respectfully requests that the Commission grant waiver of its 120-day notice requirement, in case such waiver is needed to permit the actual effective date.[193] Granting the requested waiver will give the CAISO sufficient time to implement the tariff changes and will not have an adverse impact on any entity. Therefore, good cause exists to grant the requested waiver.

VII. COMMUNICATIONS

Pursuant to Rule 203(b)(3) of the Commission's Rules of Practice and Procedure,[194] the CAISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon:

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VIII. SERVICE

The CAISO has served copies of this filing on the California Public Utilities Commission, 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.

Commission order on an FPA section 205 filing may propose targeted modifications to the utility's proposed revisions provided that the modifications do not result in a rate design that is entirely different from that contained in the original filing. *See NRG Power Marketing, LLC v. FERC*, 862 F.3d 108, 115 (D.C. Cir. 2017).

193 Specifically, pursuant to Section 35.11 of the Commission's regulations (18 C.F.R. § 35.11), the CAISO requests waiver of the 120-day notice requirement set forth in Section 35.3(a)(1) of the Commission's regulations (18 C.F.R. § 35.3(a)(1)).

194 18 C.F.R. § 385.203(b)(3).

IX. CONTENTS OF FILING

Besides this transmittal letter, this filing includes the following attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions in this tariff amendment
Attachment C	Second Revised Draft Final Proposal
Attachment D	CCDEBE Board Memorandum
Attachment E	LMPME Board Memorandum
Attachment F	List of key dates in the stakeholder processes for this tariff amendment

X. CONCLUSION

The CAISO respectfully requests that the Commission issue an order by September 30, 2020 accepting the tariff changes proposed in this filing effective no earlier than November 1, 2020 and no later than December 31, 2020.

Respectfully submitted,

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Attachment A – CleanTariff

Commitment Costs and Default Energy Bid Enhancements

California Independent System Operator Corporation

July 9, 2020

4.12.1 General Responsibilities

4.12.1.1 Operate Pursuant to Relevant Provisions of CAISO Tariff

Resource-Specific System Resource owners shall operate, or cause their facilities to be operated, in accordance with the relevant provisions of this CAISO Tariff, including but not limited to the following.

(i) A Resource-Specific System Resource shall only be eligible for Bid Cost Recovery if the Resource-Specific System Resource has complied with a Start-Up Instruction or Dispatch Instruction issued by the CAISO as specified in Section 11.8.

(ii) In order to be eligible for Bid Cost Recovery, a Resource-Specific System Resource owner shall ensure that its Scheduling Coordinator makes an election for Default Start-Up Bids and Default Minimum Load Bids pursuant to Sections 30.4 and 30.5.2.4.

(iii) A Resource-Specific System Resource owner shall ensure that any Ancillary Services Bids submitted by its Scheduling Coordinator are submitted in accordance with Section 30.5.2.6.

(iv) Owners of Dynamic Resource-Specific System Resources that are Resource Adequacy Resources shall comply with additional availability requirements to the extent required by Section 40.6.5.1.

(v) Each Resource-Specific System Resource owner shall immediately inform the CAISO, through its respective Scheduling Coordinator and using the CAISO's outage management system as described in Section 9, of any change or potential change in the current status of any Resource-Specific System Resource that may affect a submitted Bid. This will include, but not be limited to, any change in status of equipment that could affect the maximum output of a Resource-Specific System Resource, the Minimum Load of a Resource-Specific System Resource, or the ability of a Resource-Specific System Resource to provide Ancillary Services in accordance with its Bid.

(vi) In the event that a Resource-Specific System Resource owner cannot meet its Generation schedule as specified in the Day-Ahead Schedule, or comply with a Dispatch Instruction, whether due to a Resource-Specific System Resource trip or the loss of a piece of equipment causing a reduction in capacity or output, the Resource-Specific

System Resource owner shall notify the CAISO, through its Scheduling Coordinator, at once. If a Resource-Specific System Resource owner will not be able to meet a time commitment or requires the cancellation of a Resource-Specific System Resource Start-Up, it shall notify the CAISO, through its Scheduling Coordinator, at once.

* * * * *

6.5.3 Day-Ahead Market Communications

6.5.3.1 Communications with Scheduling Coordinators

6.5.3.1.1 Prior to 6:00 a.m., the CAISO will continuously screen Inter-SC Trades of Energy for the DAM submitted by Scheduling Coordinators and will provide feedback to the Scheduling Coordinators about the consistency and validity of these Inter-SC Trades based on information available to the CAISO.

6.5.3.1.2 Between 6:00 a.m. and the end of the Day-Ahead Inter-SC Trade Period, the CAISO performs the validation of Inter-SC Trades of Energy for the DAM and will notify the participants of the status of these Inter-SC Trades.

6.5.3.1.3 Between 5:00 a.m. and 10:00 a.m., the CAISO will provide feedback to Scheduling Coordinators about their validated ETC and TOR quantities, and calculated Default Energy Bids curves and in addition, the RMR Proxy Bids for Energy and the Minimum Load Bid and Start-Up Bid curves for Legacy RMR Units.

6.5.3.1.4 After the close of the DAM bidding at 10:00 a.m., the CAISO will send a message to the Scheduling Coordinators regarding the outcome of the Bid validation.

6.5.3.1.5 By 1:00 p.m., the CAISO will publish the result of the DAM and the resource will be flagged if it is being dispatched under its Legacy RMR Contract and will be deemed an RMR Dispatch Notice under the Legacy RMR Contract.

6.5.3.1.6 After the results of the DAM are published by 1:00 p.m., the CAISO performs the Inter-SC Trade of Energy post-market validation and communicates the results back to the applicable Scheduling Coordinator.

6.5.3.1.7 The results of the Day-Ahead Market will be published by 1:00 p.m. and will include:

(a) Unit Commitment status for resources committed in the IFM;

(b) Day-Ahead Schedules and prices;

(c) Day-Ahead AS Awards and prices;

(d) RUC Awards and RUC Capacity and resource-specific RUC Prices;

(e) RUC Start-Up Instructions;

(f) Start-Up Instructions resulting from the ELC Process;

(g) Post-market summary of Day-Ahead and Real-Time Energy Schedules, Ancillary Service Awards, RMR Dispatches, and Legacy RMR Units;

(h) Day-Ahead final resource Bid mitigation results; and

(i) Day-Ahead finally qualified Load following capacity.

6.5.3.1.8 All Expected Energy results will be published at one (1) day after the Trading Day and will include post-market Energy accounting results for Settlement calculations.

6.5.3.2 Public Market Information

6.5.3.2.1 Before 10:00 a.m. one (1) day before the Operating Day the CAISO will publish updated Outage information regarding the transmission system on OASIS. The updated Outage information will include planned and actual Outage events per Transmission Interface, including Outage description, Outage start time and end time, and rating of the curtailed line.

6.5.3.2.2 The results of the Day-Ahead Market will be published on OASIS by 1:00 p.m. and will include:

* * * * *

6.5.6.1.2 Start-Up and Minimum Load Costs

Within seven (7) days after the Trading Day, the CAISO will publish via OASIS total Start-Up Costs and Minimum Load Costs for CAISO committed resources.

* * * * *

8.4.1.2 Regulation Energy Management

The CAISO will make Regulation Energy Management available to Scheduling Coordinators for Non-Generator Resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation. A Scheduling Coordinator for a resource using Regulation Energy Management may submit a Regulation Bid for capacity (MW) of up to four (4) times the maximum Energy (MWh) the resource can generate or curtail for fifteen (15) minutes after issuance of a Dispatch Instruction. In the Real-Time Market, a Scheduling Coordinator for a resource using Regulation Energy Management will produce energy as needed to satisfy the sixty (60) minute continuous Energy requirement for Regulation Awards in the Day-Ahead Market.

Scheduling Coordinators may request to use Regulation Energy Management for these Non-Generator Resources by submitting a request to certify such a resource to provide Regulation using Regulation Energy Management. The owner or operator of a Resource using Regulation Energy Management must execute both a Participating Generator Agreement and/or Participating Load Agreement and may provide only Regulation in the CAISO Market. A resource using Regulation Energy Management may not provide Energy other than Energy associated with Regulation. Scheduling Coordinators for Resources using Regulation Energy Management may define a Ramp Rate for operating as Generation and a Ramp Rate for operating as Load, respectively. These resources shall comply with the requirements to provide Regulation as specified in this Section 8, Appendix K, and the CAISO's Operating Procedures, including the requirement to undergo a market simulation using Regulation Energy Management as part of the certification procedure.

Scheduling Coordinators for resources using Regulation Energy Management shall register these resources in the Master File. Scheduling Coordinators may only submit Bids for Regulation Up and Regulation Down and Mileage for these resources. Scheduling Coordinators may not submit Energy Bids, Energy Self-Schedules, Residual Unit Commitment Bids, or Ancillary Service Bids other than Regulation and Mileage for these resources. Scheduling Coordinators may not submit any type of commitment costs as part of their Regulation Up and Regulation Down Bids for resources using Regulation Energy Management, including Start-Up Bids, Minimum Load Bids, Pumping Cost or Pump Shut-Down Cost Bids, or Transition Bids. All other bidding rules for Regulation set forth in Section 30 shall apply to resources using Regulation Energy Management.

The CAISO will settle Dispatches from resources using Regulation Energy Management as energy. The portion of Demand of Non-Generator Resources using Regulation Energy Management that is dispatched as Regulation in any Settlement Interval shall not be considered Measured Demand for purposes of allocating payments and charges pursuant to Section 11 during that Settlement Interval.

The CAISO shall control the resource's operating set point through its Energy Management System with the objective of maintaining the resource's operating set point at its preferred operating point. In the Day-Ahead Market and FMM, the procurement of Regulation from resources using Regulation Energy Management will not be constrained by the resource's MWh limit to generate, curtail the consumption of, or consume Energy continuously. In the Real-Time Dispatch, the CAISO will base the Dispatches on the resource's capability to provide Regulation. When the resource has a physical MWh limit, the CAISO will observe the resource's MWh constraint during Real-Time Dispatch and will assess whether the CAISO can support the resource's self-provided Regulation capacity or Regulation award with Real-Time Market Dispatches. To the extent the CAISO determines in the Integrated Forward Market or FMM that the MWh constraint of resources using Regulation Energy Management limits the capability of the CAISO, through Real-time Dispatch, to support these resources' self-provided Regulation capacity or Regulation awards, the CAISO may disqualify resources using Regulation Energy Management on a pro rata basis across the System Region from providing Regulation, which shall result in the rescission of the disqualified portion of the resources' self-provided or awarded Regulation capacity payments.

*** * * * ***

11.8 Bid Cost Recovery

For purposes of determining the Unrecovered Bid Cost Uplift Payments for each Bid Cost Recovery Eligible Resource as determined in Section 11.8.5 and the allocation of Unrecovered Bid Cost Uplift Payments for each Settlement Interval, the CAISO shall sequentially calculate the Bid Costs, which can be positive (IFM Bid Cost Shortfall, RUC Bid Cost Shortfall, or RTM Bid Cost Shortfall) or negative (IFM Bid Cost Surplus, RUC Bid Cost Surplus, or RTM Bid Cost Surplus) in the IFM, RUC, and the Real-Time

Market, as the algebraic difference between the respective IFM Bid Cost, RUC Bid Cost, or RTM Bid Cost and the IFM Market Revenues, RUC Market Revenues, or RTM Market Revenues as further described below in this Section 11.8. The RTM Energy Bid Costs and RTM Market Revenues include the FMM Energy Bid Costs. In any Settlement Interval a resource is eligible for Bid Cost Recovery payments pursuant to the rules described in the subsections of Section 11.8 and Section 11.17. Bid Cost Recovery Eligible Resources for different MSS Operators are supply resources listed in the applicable MSS Agreement. All Bid Costs shall be based on Bids as mitigated pursuant to the requirements specified in Section 39.7. Virtual Awards are not eligible for Bid Cost Recovery. Virtual Awards are eligible for make-whole payments due to price corrections pursuant to Section 11.21.2. In order to be eligible for Bid Cost Recovery, Non-Dynamic Resource-Specific System Resources must provide to the CAISO SCADA data by telemetry to the CAISO's EMS in accordance with Section 4.12.3 demonstrating that they have performed in accordance with their CAISO commitments. Scheduling Coordinators for Non-Generator Resources are not eligible to recover Start-Up Bid Costs, Minimum Load Bid Costs, Pumping Costs, Pump Shut-Down Costs, or Transition Bid Costs but are eligible to recover Energy Bid Costs, RUC Availability Payments and Ancillary Service Bid Costs.

11.8.1 CAISO Determination of Self-Commitment Periods

For the purposes of identifying the periods during which a Bid Cost Recovery Eligible Resource is deemed self-committed and thus ineligible for Start-Up Bid Costs, Transition Bid Costs, Minimum Load Bid Costs, IFM Pump Shut-Down Costs and IFM Pumping Costs, the CAISO derives the Self-Commitment Periods as described below. The CAISO will determine the Self-Commitment Periods for Multi-Stage Generating Resources based on the applicable MSG Configuration. MSS resources designated for Load following are considered to be self-committed if they have been scheduled with non-zero Load following capacity, or are otherwise used to follow Load in the Real-Time. The IFM Self-Commitment Period and RUC Self-Commitment Period will be available as part of the Day-Ahead Market results provided to the applicable Scheduling Coordinator. The interim RTM Self-Commitment Periods as reflected in the RTM will be available as part of the RTM results for the relevant Trading Hour as provided to the applicable Scheduling Coordinator. The final RTM Self-Commitment Period is determined ex-post for Settlements purposes. ELS Resources committed through the ELC Process described in Section 31.7

are considered to have been committed in the IFM Commitment Period for the applicable Trading Day for the purposes of determining BCR settlement in this Section 11.8.

* * * * *

11.8.1.3 Multi-Stage Generating Resource Start-Up Bid Costs, Minimum Load Bid Costs, or Transition Bid Costs

For the settlement of the Multi-Stage Generating Resource Start-Up Bid Costs, Minimum Load Bid Costs, and Transition Bid Costs in the IFM, RUC, and RTM, the CAISO will determine the applicable Commitment Period and select the applicable Start-Up Bid Costs, Minimum Load Bid Costs, and Transition Bid Costs based on the following rules.

(1) In any given Settlement Interval, the CAISO will first apply the following rules to determine the applicable Start-Up Bid Costs and Transition Bid Costs for the Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period and/or RUC Commitment Period MSG Configuration(s) are different from the RTM CAISO Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Cost and Transition Bid Cost will be settled based on the RTM CAISO Commitment Period MSG Configuration Start-Up Bid Costs, and Transition Bid Costs, as described in Section 11.8.4.1.

(b) there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period in any MSG Configuration and there is also a RTM Self-Commitment Period in any MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Bid Costs and Transition Bid Costs, as described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this Section below.

(c) the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration is the same as the CAISO RTM Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Bid Costs and Transition Bid Costs described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (3) of this Section below.

(d) the IFM Self-Commitment Period and RUC Self-Commitment Period MSG Configuration(s) are the same as the CAISO RTM Commitment Period MSG Configuration, then the Multi-Stage Generating Resource's Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO RTM Commitment Period MSG Configuration Start-Up Bid Costs and Transition Bid Costs as described in Section 11.8.4.1.

(2) For the purpose of determining which MSG Configuration Minimum Load Bid Costs will apply in any given Commitment Interval, the CAISO will apply the following rules.

(a) If there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period, the CAISO will calculate the IFM Minimum Load Costs and/or RUC Minimum Load Costs, pursuant to Section 11.8.2.1 or 11.8.3.1, respectively, based on the MSG Configuration committed in the IFM or RUC.

(b) For purposes of determining the MSG Configuration Minimum Load Bid Costs included in the RTM Minimum Load Costs calculated pursuant to Section 11.8.4.1.2, the CAISO will use the difference between the amounts determined under (i) and (ii) below.

(i) The CAISO will calculate the RTM MSG Configuration Minimum Load Bid Costs as the RTM Minimum Load Costs attributed to the MSG Configuration committed in the RTM, whether that MSG Configuration is Self-Scheduled or CAISO-committed.

(ii) The CAISO will determine one of the two applicable amounts:

a. If there is a Real-Time Market Self-Schedule, the maximum of (A) the Minimum Load Bid Costs attributed to the MSG Configuration either self-Scheduled or CAISO-committed in the IFM or RUC; and (B) the Minimum Load Cost attributed to the MSG Configuration Self-Scheduled in the RTM.

b. If there is no Real-Time Market Self-Schedule, the Minimum Load Bid Costs attributed to the MSG Configuration either self-Scheduled or CAISO-committed in the IFM or RUC.

(3) In any given Settlement Interval, after the rules specified in part (1) and (2) above of this Section have been executed, the CAISO will apply the following rules to determine whether the IFM Start-Up Cost or RUC Start-Up Cost, IFM Minimum Load Cost or RUC Minimum Load Cost, and IFM Transition Cost or RUC Transition Cost apply for Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period MSG Configuration is different from the CAISO RUC Commitment Period MSG Configuration the Multi-Stage Generating Resource's Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost will be settled based on the CAISO RUC Commitment Period MSG Configuration Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost as described in Section 11.8.3.1.

(b) the CAISO IFM Commitment Period MSG Configuration is the same as the CAISO RUC Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost will be based on the CAISO IFM Commitment Period MSG Configuration Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost as described in Section 11.8.2.1.

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11.8.2.1 IFM Bid Cost Calculation

For each Settlement Interval, the CAISO shall calculate IFM Bid Cost for each Bid Cost Recovery Eligible Resource as the algebraic sum of the IFM Start-Up Cost, IFM Transition Cost, IFM Minimum Load Cost, IFM Pump Shut-Down Cost, IFM Energy Bid Cost, IFM Pumping Cost, and IFM AS Bid Cost. For Multi-Stage Generating Resources, in addition to the specific IFM Bid Cost rules described in Section 11.8.2.1, the CAISO will apply the rules described in Section 11.8.1.3 to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Cost, Transition Bid Cost, and Minimum Load Bid Cost in any given Settlement Interval. For Multi-Stage Generating Resources, the incremental IFM Start-Up Costs, IFM Minimum Load Costs, and IFM Transition Costs to provide Energy Scheduled in the Day-Ahead Schedule or awarded RUC or Ancillary Service capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the IFM rules specified in Section 31.3. For RMR Resources, the CAISO shall calculate the IFM Bid Cost as the algebraic sum of the IFM Start-Up Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, IFM Transition Cost adjusted to remove Opportunity Costs and Major Maintenance Adder Costs, IFM Minimum Load Costs adjusted to remove Opportunity Costs and Major Maintenance Adder Costs, IFM Energy Bid Cost adjusted to remove Opportunity Costs, and IFM AS Bid Cost.

11.8.2.1.1 IFM Start-Up Cost

The IFM Start-Up Cost for any IFM Commitment Period shall be equal to the Start-Up Bid Costs applicable to the IFM divided by the number of Settlement Intervals within the applicable IFM Commitment Period. For each Settlement Interval, only the IFM Start-Up Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the IFM Start-Up Costs for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration. The following rules shall apply sequentially to qualify the IFM Start-Up Cost in an IFM Commitment Period:

(a) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is an IFM Self-Commitment Period within or overlapping with that IFM Commitment Period.

(b) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-

Ahead Schedule in the Day-Ahead Market anywhere within the applicable IFM Commitment Period.

(c) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is no actual Start-Up at the start of the applicable IFM Commitment Period because the IFM Commitment Period is the continuation of an IFM Commitment Period, RUC Commitment Period, or RTM Commitment Period from the previous Trading Day.

(d) If an IFM Start-Up is terminated in the Real-Time within the applicable IFM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource was starting up, the IFM Start-Up Cost for that IFM Commitment Period shall be prorated by the ratio of the Start-Up Time before termination over the total IFM Start-Up Time.

(e) The IFM Start-Up Cost is qualified if an actual Start-Up occurs within the applicable IFM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Intervals that fall within the CAISO IFM Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether the resource's metered Energy is at or above the resource's Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3.

(f) The IFM Start-Up Cost will be qualified if an actual Start-Up occurs earlier than the start of the IFM Commitment Period if the advance Start-Up is a result of a Start-Up instruction issued in a RUC or Real-Time Market process subsequent to the IFM, or the advance Start-Up is uninstructed but is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the targeted IFM Start-Up.

(g) The Start-Up Bid Costs for a Bid Cost Recovery Eligible Resource that is a Short Start Unit committed by the CAISO in the IFM and that further receives a Start-Up Instruction from the CAISO in the Real-Time Market to start within the same CAISO IFM Commitment Period, will be qualified for the CAISO IFM Commitment Period instead of being qualified for the CAISO RTM Commitment Period; and Start-Up Bid Costs for subsequent Start-Ups will be further qualified as specified in Section 11.8.4.1.1(h).

11.8.2.1.2 IFM Minimum Load Cost

The IFM Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Bid Cost applicable to the Integrated Forward Market, divided by the number of Settlement Intervals in a Trading Hour subject to the rules described below.

(a) For each Settlement Interval, only the IFM Minimum Load Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery.

(b) The IFM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is in an IFM Self Commitment Period for the Bid Cost Recovery Eligible Resource; or (2) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule for the applicable Settlement Interval.

(c) If the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits an RMR Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the sum of IFM Minimum Load Costs, adjusted to remove Minimum Load Opportunity Costs and Minimum Load Major Maintenance Costs, are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(d) If a Multi-Stage Generating Resource is committed by the CAISO and receives a Day-Ahead Schedule and subsequently is committed by the CAISO to a lower MSG Configuration where its Minimum Load capacity as registered in the Master File in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration's Minimum Load as registered in the Master File, the resource's IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section

11.8.4.4. If the CAISO commits an RMR Multi-Stage Generating Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the sum of IFM Minimum Load Costs, adjusted to remove Minimum Load Opportunity Costs and Minimum Load Major Maintenance Costs, are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(e) If the conditions in Sections 11.8.2.1.2 (c) and (d) do not apply, then the IFM Minimum Load Cost for any Settlement Interval is zero if the Bid Cost Recovery Eligible Resource is determined to be Off during the applicable Settlement Interval. For the purposes of determining IFM Minimum Load Cost, a Bid Cost Recovery Eligible Resource is assumed to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its (i) Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and (ii) the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(f) For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. If application of section 11.8.1.3 dictates that the IFM is the Commitment Period, then the calculation of the IFM Minimum Load Costs will depend on whether the IFM committed MSG Configuration is determined to be On. If it is determined to be On, then, the IFM Minimum Load Costs will be based on the Minimum Load Bid Costs of the IFM committed MSG Configuration. For the purposes of determining IFM Minimum Load Cost for a Multi-Stage Generating Resource, a Bid Cost Recovery Eligible Resource is determined to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its IFM MSG Configuration Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(g) The IFM Minimum Load Costs calculation is subject to the Shut-Down State Variable and is disqualified as specified in Section 11.17.2.

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11.8.2.3.2 MSS Elected Net Settlement

For an MSS Operator that has elected net Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the Energy Bid Costs and revenues for IFM Bid Cost Recovery is settled at the MSS level. The IFM Bid Cost as described in Section 11.8.2.1 above and IFM Market Revenue as provided in Section 11.8.2.2 above, of each MSS will be, respectively, the total of the IFM Bid Costs and IFM Market Revenues over all BCR Eligible Resources within the MSS where each BCR Eligible Resource's IFM Market Revenues for its Energy shall be calculated as described in Section 11.2.3.2 at the relevant IFM MSS price. The IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for Energy and AS are first calculated separately for the MSS for each Trading Hour of the Trading Day with qualified Start-Up Bid Costs and qualified Minimum Load Bid Costs included in the IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for Energy calculation. The MSS's overall IFM Bid Cost Shortfall or IFM Bid Cost Surplus is then calculated as the algebraic sum of the IFM Bid Cost Shortfall or IFM Bid Cost Surplus for Energy and the IFM Bid Cost Shortfall or IFM Bid Cost Surplus for AS for each Trading Hour.

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11.8.3.1 RUC Bid Cost Calculation

For each Settlement Interval, the CAISO shall determine the RUC Bid Cost for a Bid Cost Recovery Eligible Resource as the algebraic sum of the RUC Start-Up Cost, RUC Transition Cost, RUC Minimum Load Cost, and RUC Availability Bid Cost. For Multi-Stage Generating Resources, in addition to the specific RUC Bid Cost rules described in Section 11.8.3.1, the rules described in Section 11.8.1.3 will be applied to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Costs, Transition Bid Costs, and Minimum Load Bid Costs. For Multi-Stage Generating Resources, the incremental RUC Start-Up Costs, RUC Minimum Load Costs, and RUC Transition Costs to provide RUC awarded capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the RUC optimization rules in specified in Section 31.5. For each Settlement Interval, the CAISO shall determine the RUC Bid Cost for an RMR Resource as the algebraic sum of the RUC Start-Up Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, and RUC Transition Cost adjusted to remove Opportunity Costs and Major Maintenance Costs.

11.8.3.1.1 RUC Start-Up Cost

The RUC Start-Up Cost for any Settlement Interval in a RUC Commitment Period shall consist of Start-Up Bid Cost of the Bid Cost Recovery Eligible Resource for the applicable RUC Commitment Period divided by the number of Settlement Intervals in the applicable RUC Commitment Period. For each Settlement Interval, only the RUC Start-Up Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RUC Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RUC.

The following rules shall be applied in sequence and shall qualify the RUC Start-Up Cost in a RUC Commitment Period:

(a) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is an IFM Commitment Period within that RUC Commitment Period.

(b) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or is flagged as an RMR Dispatch in the Day-Ahead Schedule anywhere within that RUC Commitment Period.

(c) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is no RUC Start-Up at the start of that RUC Commitment Period because the RUC Commitment Period is the continuation of an IFM Commitment Period, RUC Commitment Period, or RTM Commitment Period from the previous Trading Day.

(d) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Start-Up is delayed beyond the RUC Commitment Period in question or cancelled by the Real-Time Market prior to the Bid Cost Recovery Eligible Resource starting its start-up process.

(e) If a RUC Start-Up is terminated in the Real-Time within the applicable RUC Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost

Recovery Eligible Resource is starting up, the RUC Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the RUC Start-Up Time.

(f) The RUC Start-Up Cost for a RUC Commitment Period is qualified if an actual Start-Up occurs within that RUC Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates that the resource is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether its metered Energy is at or above the resource's Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3.

(g) The RUC Start-Up Cost shall be qualified if an actual Start-Up occurs. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period.

11.8.3.1.2 RUC Minimum Load Cost

The RUC Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Bid Cost of the Bid Cost Recovery Eligible Resource, divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RUC Minimum Load Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The RUC Minimum Load Cost for any Settlement Interval is zero if: (1) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in that Settlement Interval; (2) the Bid Cost Recovery Eligible Resource is not committed or Dispatched in the Real-time Market in the applicable Settlement Interval; or (3) the applicable Settlement Interval is included in an IFM Commitment Period. For the purposes of determining RUC Minimum Load Cost for a Bid Cost Recovery Eligible Resource, recovery of the RUC Minimum Load Cost is subject to the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of section 11.8.1.3. The RUC Minimum Load Cost calculation will be subject to the Shut-Down State Variable and disqualified as specified in Section 11.17.2.

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11.8.4.1 RTM Bid Cost Calculation

For each Settlement Interval, the CAISO shall calculate RTM Bid Cost for each Bid Cost Recovery Eligible Resource, as the algebraic sum of the RTM Start-Up Cost, RTM Minimum Load Cost, RTM Transition Cost, RTM Pump Shut-Down Cost, RTM Energy Bid Cost, RTM Pumping Cost and RTM AS Bid Cost. For each Settlement Interval, the CAISO shall calculate RTM Bid Cost for each RMR Resource as the algebraic sum of the RTM Start-Up Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, RTM Transition Costs adjusted to remove Opportunity Costs and Major Maintenance Costs, RTM Energy Bid Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, and RTM AS Bid Cost. For Multi-Stage Generating Resources, in addition to the specific RTM Bid Cost rules described in Section 11.8.4.1, the rules described in Section 11.8.1.3 will be applied to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Cost, Transition Bid Cost, and Minimum Load Bid Cost, in a given Settlement Interval. For Multi-Stage Generating Resources, the incremental RTM Start-Up Cost, RTM Minimum Load Cost, and RTM Transition Cost to provide RTM committed Energy or awarded Ancillary Services capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the RTM optimization rules in specified in Section 34.

11.8.4.1.1 RTM Start-Up Cost

For each Settlement Interval of the applicable RTM Commitment Period, the RTM Start-Up Cost shall consist of the Start-Up Bid Cost of the Bid Cost Recovery Eligible Resource applicable to the Real-Time Market divided by the number of Settlement Intervals in the applicable RTM Commitment Period. For each Settlement Interval, only the RTM Start-Up Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RTM Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in the RTM. The following rules shall be applied in sequence and shall qualify the RTM Start-Up Cost in an RTM Commitment Period:

(a) The RTM Start-Up Cost is zero if there is an RTM Self-Commitment Period within the RTM Commitment Period.

(b) The RTM Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource has been manually pre-dispatched under a Legacy RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule or Real-Time Market anywhere within that RTM Commitment Period.

(c) The RTM Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource is started within the Real-Time Market Commitment Period pursuant to an Exceptional Dispatch issued in accordance with Section 34.11.2 to: (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; or (3) perform PMax testing.

(d) The RTM Start-Up Cost is zero if there is no RTM Start-Up at the start of that RTM Commitment Period because the RTM Commitment Period is the continuation of an IFM Commitment Period or RUC Commitment Period from the previous Trading Day.

(e) If an RTM Start-Up is terminated in the Real-Time within the applicable RTM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the RTM Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the Real-Time Market Start-Up Time.

(f) The RTM Start-Up Cost shall be qualified if an actual Start-Up occurs within that RTM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Interval(s) indicates the unit is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Interval that falls within the CAISO RTM Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether its metered Energy is at or above the resource’s Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3. The CAISO will determine that the Multi-Stage Generating Resource is On based on the MSG Configuration that the CAISO has committed in the Real-Time Market.

(g) The RTM Start-Up Cost for an RTM Commitment Period shall be qualified if an actual Start-Up occurs earlier than the start of the RTM Market Start-Up, if the relevant Start-Up is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the RTM Start-Up, otherwise the Start-Up Bid Cost is zero for the RTM Commitment Period.

(h) For Short-Start Units, the first Start-Up Bid Costs within a CAISO IFM Commitment Period are qualified IFM Start-Up Costs as described above in Section 11.8.2.1.1(g). For subsequent Start-Ups of Short-Start Units after the CAISO Shuts Down a resource and then the CAISO issues a Start-Up Instruction pursuant to a CAISO RTM Commitment Period within the CAISO IFM Commitment Period, the Start-Up Bid Costs shall be qualified as RTM Start-Up Costs, provided that the resource actually Shut-Down and Started-Up based on CAISO Shut-Down and Start-Up Instructions.

11.8.4.1.2 RTM Minimum Load Cost

The RTM Minimum Load Cost is the Minimum Load Bid Cost of the Bid Cost Recovery Eligible Resource applicable for the Real-Time Market, divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RTM Minimum Load Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The RTM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is included in a RTM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; (2) the Bid Cost Recovery Eligible Resource has been manually dispatched under a Legacy RMR Contract or the resource has been flagged as an RMR Dispatch in the Day-Ahead Schedule or the Real-Time Market in that Settlement Interval; (3) for all resources that are not Multi-Stage Generating Resources, that Settlement Interval is included in an IFM Commitment Period or RUC Commitment Period; or (4) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.11.2 for the purpose of performing Ancillary Services testing, pre-commercial operation testing for Generating Units, or PMax testing. A resource’s RTM Minimum Load Costs for Bid Cost Recovery purposes are subject to the application of the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of Section

11.8.1.3. For all Bid Cost Recovery Eligible Resources that the CAISO Shuts Down, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its Day-Ahead Schedule that was also from a CAISO commitment, the RTM Minimum Load Costs will include negative Minimum Load Cost Bids for Energy between the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and zero (0) MWhs.

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11.8.4.3.2 MSS Elected Net Settlement

For MSS entities that have elected net Settlement regardless of other MSS optional elections (i.e., Load following or not, or RUC opt-in or out), unlike non-MSS resources, the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus is treated at the MSS level and not at the resource specific level, and is calculated as the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus of all BCR Eligible Resources within the MSS. In calculating the Energy RTM Market Revenue for all the resources within the MSS as provided in Section 11.8.4.2, the CAISO will use the FMM MSS Price or the RTD MSS Price, as applicable. The RUC Bid Cost Shortfall, RUC Bid Cost Surplus, RTM Bid Cost Shortfall, and RTM Bid Cost Surplus for Energy, RUC Availability and Ancillary Services are first calculated separately for the MSS for each Settlement Interval of the Trading Day, with qualified Start-Up Bid Costs, qualified Minimum Load Bid Costs, and qualified Multi-Stage Generator Transition Bid Costs included into the RUC Bid Cost Shortfalls, RUC Bid Cost Surpluses, RTM Bid Cost Shortfalls, and RTM Bid Cost Surpluses of Energy calculation. The MSS's overall RUC Bid Cost Shortfall or RUC Bid Cost Surplus, and RTM Bid Cost Shortfall or RTM Bid Cost Surplus is then calculated as the algebraic sum of the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus for Energy and the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus for Ancillary Services for each Settlement Interval.

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11.8.4.4.1 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric to RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs, and not the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric instead of Day-Ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and not the IFM Market Revenues.

11.8.4.4.2 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs are greater than or equal to zero (0) and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs and the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs are greater than or equal to zero (0) and the IFM Market Revenues are negative the CAISO will apply the Real-Time Performance Metric instead of the Day-ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and IFM Market Revenues.

11.8.4.4.3 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs are negative and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will not apply Real-Time Performance Metric to the RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs or the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the sum of IFM Energy Bid Costs and the IFM Minimum Load Costs is negative and the IFM Market Revenue is greater than or equal to zero (0), the CAISO will not apply the Real-Time Performance Metric to the IFM Minimum Load Costs, IFM Energy Bid Costs or the IFM Market Revenues.

11.8.4.4.4 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs, and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Market Revenues but not the RTM Energy Bid Costs or the RUC

Minimum Load Costs and RTM Minimum Load Costs. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric instead of the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues but not the IFM Minimum Load Costs and IFM Energy Bid Costs.

11.8.4.4.5 If for a given Settlement Interval the absolute value of the resource's Metered Energy, less Regulation Energy and less Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Real-Time Performance Metric to the calculation of the RTM Energy Bid Cost, RUC Minimum Load Cost and RTM Minimum Load Cost, or RTM Market Revenue.

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11.13.3 Daily Variable Cost Payment

For each Trading Day, the CAISO shall calculate IFM Bid Cost Recovery Amount described in Section 11.8.2 and RTM Bid Cost Recovery Amount described in Section 11.8.4 for each RMR Resource while adjusting to remove Major Maintenance Cost and Opportunity Cost adders, calculated pursuant to Section 30.4.6, including any if the limits used to calculate the Opportunity Cost are established pursuant to Article 6 of the RMR Contract. The RMR Resource shall receive any Unrecovered Bid Cost Uplift Payment(s) as described in Section 11.8.5. The Daily Variable Cost Uplift Settlement is the sum of the IFM Unrecovered Bid Cost Uplift Payment as described in Section 11.8.5.1 and the RUC and RTM Unrecovered Bid Cost Uplift Payment as described in Section 11.8.5.2.

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11.17.2 Shut-Down Adjustment

11.17.2.1 Disqualification Based on Advisory Schedules

From the Dispatch Interval in which the CAISO has determined that the Dispatch Operating Point minus the Shut-Down State Variable is less than or equal to the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and until the Shut-Down State Variable is reset, the IFM Minimum Load Costs, RUC Minimum Load Costs, or RTM Minimum Load Costs, as applicable, will be disqualified from the Bid Cost Recovery calculation.

11.17.2.2 Disqualification Based on ADS Shut-Down Instruction

In the event that the CAISO issues a binding Shut-Down Instruction through ADS, a resource will not be eligible for recovery of RTM Minimum Load Costs or RUC Minimum Load Costs from the point of the Shut-Down Instruction forward for the duration of the resource's registered Minimum Down Time. If a resource ignores the binding Shut-Down Instruction and it has a Day-Ahead Schedule, the resource is not eligible for IFM Minimum Load Cost recovery as specified in Section 11.8.2.1.2 for the minimum of: 1) the resource's Minimum Down Time; and 2) the IFM Commitment Period.

11.17.2.3 Bid Basis for Settlement Bid Cost Recovery

For any resource that receives a Shut-Down Instruction in the Real-Time Market, any Integrated Forward Market Energy Bid Cost Recovery or Real-Time Market Energy Bid Cost Recovery that may otherwise apply pursuant to the rules in Section 11.8 will be based on the relevant Energy Bid price, as mitigated, that was considered by the Real-Time Market in making the decision to shut down the resource for the length of time defined by the greater of (a) the resource's Minimum Down Time or (b) the period in which it is Off after the Shut-Down time, which is not to exceed the time until the end of the Trading Day.

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27.7.1 Election of Constrained Output Generator Status

A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status must make an election to have the resource treated as a COG before each calendar year by registering the resource's PMin in the Master File as equal to its PMax less 0.01 MW (PMin = PMax – 0.01 MW) within the timing requirements specified for Master File changes described in the applicable Business Practice Manual. Generating Units with COG status will be eligible to set LMPs in the IFM and RTM based on their Calculated Energy Bids.

As with all Generating Units that are not Use-Limited Resources, a Scheduling Coordinator on behalf of a

COG that is not a Use-Limited Resource must use the Proxy Cost methodology, as provided in Section 30.4, for determining its Default Start-Up Bids and Default Minimum Load Bids. A Scheduling Coordinator on behalf of a COG that is a Use-Limited Resource must elect to use either the Proxy Cost methodology or the Registered Cost methodology, as provided in Section 30.4, for determining its Default Start-Up Bids and Default Minimum Load Bids. A Calculated Energy Bid of a COG that is not a Use-Limited Resource will be calculated based on the Proxy Cost methodology. A Calculated Energy Bid of a COG that is a Use-Limited Resource will be calculated based on its election of the Proxy Cost methodology or the Registered Cost methodology. Whenever a Scheduling Coordinator for a COG submits an Energy Bid into the IFM or RTM, the CAISO will override that Bid and substitute the Calculated Energy Bid if the submitted Bid is different from the Calculated Energy Bid.

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27.7.3 Constrained Output Generators in the IFM

In the IFM, resources electing COG status are modeled as though they are not constrained and can operate flexibly between zero (0) and their PMax. A COG is eligible to set IFM LMPs based on its Calculated Energy Bid in any Settlement Period in which a portion of its output is needed as a flexible resource to serve Demand. A COG is not eligible for recovery of Minimum Load Costs or BCR in the IFM due to the conversion of its Minimum Load Cost to an Energy Bid and its treatment by the IFM as a flexible resource. A COG is eligible for Start-Up Bid Cost recovery based on its Commitment Period as determined in the IFM, RUC, STUC or RTUC.

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27.7.5 Constrained Output Generators in the Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.3 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Bid Cost compensation.

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29.30 Bid and Self-Schedule Submission for CAISO Markets.

(a) **In General.** The provisions of Section 30 that are applicable to the Real-Time Market, as supplemented by Section 29.30, shall apply to EIM Market Participants.

(b) **Start-Up and Minimum Load.** For the determination of Proxy Start-Up Costs and Proxy Minimum Load Costs, the CAISO will utilize the Market Services Charge and System Operations Charge reflected in the EIM Administrative Charge.

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30.4 Default Start-Up Bids, Default Minimum Load Bids, and Default Transition Bids

30.4.1 Generally

The CAISO will calculate Default Commitment Cost Bids using the Proxy Cost methodology for all resources, except for:

(a) Non-Resource-Specific Resources and Non-Generating Resources; or

(b) a resource that is qualified by the CAISO as a Use-Limited Resource and the resource has fewer than twelve (12) consecutive months of fifteen-minute LMPs for Energy at the resource's PNode or Aggregated PNode, in which case the resource's Default Commitment Cost Bids will be determined as Registered Costs under the Registered Cost methodology pursuant to Section 30.4.7.

30.4.2 Transition of Use-Limited Resources to Proxy Costs

Scheduling Coordinators on behalf of Use-Limited Resources with fewer than 12 months of data can elect to use the Registered Cost methodology and remain on that methodology for a two-month period once 12 months of pricing data is collected, while the Scheduling Coordinator and the CAISO are going through the process of determining what Opportunity Costs, if any, apply to the Use-Limited Resource. Once this process concludes, all such Use-Limited Resources must be subject to the Proxy Cost methodology. For Use-Limited Resources eligible for the Registered Cost methodology, Scheduling Coordinators may elect on a thirty (30) day basis to use either the Proxy Cost methodology or the Registered Cost methodology for calculating their Default Start-Up Bids and Default Minimum Load Bids to be used for those resources in the CAISO Markets Processes, as well as for Default Transition Bids in the case of Multi-Stage Generating Resources. The elections are independent as to Default Start-Up Bids and Default Minimum Load Bids; that is, a Scheduling Coordinator for such a Use-Limited Resource may elect to use either the Proxy Cost methodology or the Registered Cost methodology for Default Start-Up Bids and may make a different election for Default Minimum Load Bids. However, in the case of Multi-Stage Generating Resources, the Scheduling Coordinator must make the same election (Proxy Cost methodology or Registered Cost methodology) for Default Transition Bids as it makes for Default Start-Up Bids. If a Scheduling Coordinator has not made an election, the CAISO will assume the Proxy Cost methodology as the default.

30.4.3 Scheduling Coordinator Reference Level Change Requests

The CAISO will verify Reference Level Change Requests for changes to Default Start-Up Bids and Default Minimum Load Bids as described in Section 30.11.

30.4.4 Default Commitment Cost Bids

30.4.4.1 Using Proxy Cost Methodology

For resources under the Proxy Cost methodology, the CAISO will calculate a resource's Default Commitment Cost Bids as the applicable Proxy Cost multiplied by the Commitment Cost Multiplier.

30.4.4.2 Use-Limited Resources

For Use-Limited Resources using the Proxy Cost methodology, the CAISO will calculate a resource's Default Commitment Cost Bids as the applicable Proxy Cost multiplied by Commitment Cost Multiplier plus the Start-Up Opportunity Cost, Transition Opportunity Cost, or Minimum Load Opportunity Cost as applicable.

30.4.4.3 Registered Costs

For Use-Limited Resources using the Registered Cost methodology, the CAISO will use the Registered Costs as registered in the Master File as the Default Commitment Cost Bids.

30.4.4.4 Insufficient Information

In the event that the Scheduling Coordinator for a resource (other than a Multi-Stage Generating Resource or a Multi-Stage Generating Resource in its lowest configuration in which it can be started) does not provide sufficient data for the CAISO to determine the resource's Default Commitment Cost Bids or one or more components of the resource's Default Commitment Cost Bids, the CAISO will assume that the resource's Default Commitment Cost Bids, or the indeterminable component(s) of the resource's Default Commitment Cost Bids, are zero. In the event that the Scheduling Coordinator for a Multi-Stage Generating Resource does not provide such data for an MSG Configuration beyond its lowest configuration in which it can be started, Section 30.4.5.3 applies.

30.4.4.5 Resources with Greenhouse Gas Compliance Obligations

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with the information submitted to the California Air Resources Board.

30.4.4.6 [Not Used]

30.4.5 Proxy Cost Methodology

The CAISO will calculate Proxy Costs as described in this Section 30.4.5.

30.4.5.1 Natural Gas-Fired Resources

For each natural gas-fired resource, the CAISO will calculate a resource's Proxy Costs based on the resource's actual unit-specific performance parameters and applicable gas prices as described below.

(a) **Fuel Input.** The CAISO will calculate Proxy Costs using formulaic natural gas cost values adjusted for fuel-cost variation, based on the natural gas price calculated pursuant to Section 39.7.1.1.1.3, and consistent with the requirements specified below.

(b) **Proxy Start-Up Cost.** Proxy Start-Up Costs will also include:

(i) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price;

(ii) a greenhouse gas cost adder for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price; and

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource as registered in the Master File, multiplied by 0.5.(c) **Proxy Cost Minimum Load Costs.** Proxy Cost Minimum Load Costs will also include:

(i) operation and maintenance costs as provided in Section 39.7.1.1.2;

(ii) a greenhouse gas cost adder for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each run-hour as the product of the resource's fuel requirement at Minimum Load as registered in the Master File, the greenhouse gas emissions rate authorized by the California Air

Resources Board, and the applicable Greenhouse Gas Allowance Price;

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource as registered in the Master File;

(iv) the Bid Segment Fee; and

(v) a resource-specific adder, if applicable, for major maintenance expenses ($ per operating hour) determined pursuant to Section 30.4.5.4.

(d) **Proxy Transition Costs.** For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Proxy Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG Configuration based on the difference between the Proxy Start-Up Costs for the higher MSG Configuration, and the Proxy Start-Up Costs for the lower MSG Configuration, as those costs are determined in accordance with the Proxy Start-Up Cost calculation methodology set forth in Section 30.4.5. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Proxy Transition Cost shall be zero.

(e) **Major Maintenance Adders.** Proxy Costs will include any major maintenance adders determined pursuant to Section 30.4.5.4.

30.4.5.2 Non-Natural Gas-Fired Resources

For each non-natural gas-fired resource, the CAISO shall calculate the Proxy Start-Up Cost and Proxy Minimum Load Cost values under the Proxy Cost methodology as specified below.

(a) **Fuel Input.** The Scheduling Coordinator for the resource will provide the fuel or fuel-equivalent input costs, which the CAISO will maintain in the Master File, pursuant to Section 39.7.1.1.1.2.

(b) **Proxy Start-Up Costs.** Proxy Start-Up Costs will also include, if applicable:

(i) greenhouse gas allowance costs for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator;

(ii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource as registered in the Master File, multiplied by 0.5.

(c) **Proxy Minimum Load Costs.** Proxy Minimum Load Costs will also include, if applicable:

(i) operation and maintenance costs as provided in Section 39.7.1.1.2;

(ii) greenhouse gas allowance costs for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator;

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource as registered in the Master File;

(iv) the Bid Segment Fee.

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(d) **Proxy Transition Costs.** For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Proxy Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG Configuration based on the difference between the Proxy Start-Up Costs for the higher MSG Configuration, and the Proxy Start-Up Costs for the lower MSG Configuration, as those costs are determined in accordance with the Proxy Start-Up Cost calculation methodology set forth in Section 30.4.5. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Proxy Transition Cost shall be zero.

(e) **Major Maintenance Adders.** Proxy Costs will include any major maintenance adders determined pursuant to Section 30.4.5.4.

30.4.5.3 Multi-Stage Generating Resources

30.4.5.3.1 Application of Proxy Costs

For Multi-Stage Generating Resources under the Proxy Cost methodology, the CAISO will apply the Proxy Cost methodology to all the MSG Configurations. The Proxy Costs for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration, including for each MSG Configuration that cannot be directly started.

30.4.5.3.2 Insufficient Information

Notwithstanding the rules set forth in Sections 30.4.5.1 and 30.4.5.2, to the extent that a Scheduling Coordinator for a Multi-Stage Generating Resource, other than in its lowest configuration in which the Multi-Stage Generating Resource can be started, does not provide sufficient data for the CAISO to determine a component of the Proxy Start-Up Costs or Proxy Minimum Load Costs for a particular MSG Configuration, the CAISO will, if feasible, use the value for that component associated with the next-lowest MSG Configuration.

30.4.5.4 Adders for Major Maintenance Expenses

30.4.5.4.1 Generally

Scheduling Coordinators may propose adders for major maintenance expenses as a component of Proxy Start-Up Costs, Proxy Minimum Load Costs, or both. Such proposed adders must be based solely on resource-specific information derived from actual maintenance costs, when available, or estimated maintenance costs provided by the Scheduling Coordinators to the CAISO and the Independent Entity.

30.4.5.4.2 CAISO Process

Scheduling Coordinators may submit updated resource-specific major maintenance information for purposes of seeking a change to any major maintenance adder, no sooner than thirty (30) days after a major maintenance adder has been determined. The CAISO or Independent Entity will evaluate the information provided by Scheduling Coordinators, and may require Scheduling Coordinators to provide additional information, to enable the CAISO or Independent Entity to determine reasonable adders for major maintenance expenses or to conduct audits of major maintenance expenses. Within fifteen (15) days of receipt of the information or any requested additional information, the CAISO or Independent Entity will notify the Scheduling Coordinator in writing whether it has sufficient and accurate information to determine reasonable major maintenance adders to be included in the Proxy Start-Up Cost or Proxy Minimum Load Cost calculations, or both. Within ten (10) days after providing written notification to the Scheduling Coordinator that the information is sufficient and accurate, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses to be included in the Proxy Start-Up Costs or Proxy Minimum Load Costs, or both, and will so inform the Scheduling Coordinator in writing.

In the event of a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, within ten (10) days of such agreement, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses and will provide the adder to the Scheduling Coordinator in writing. If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree upon the sufficiency or accuracy of the information during the 60-day negotiation period, the Scheduling Coordinator has the right to petition FERC to resolve the dispute as to the sufficiency or accuracy of its information.

In the event of a dispute regarding the CAISO's or Independent Entity's determination of adders for major maintenance expenses, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, the agreed-upon values will be effective as of the first Business Day following the resolution date.

30.4.5.4.3 FERC Process

If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree on the major maintenance values for either the Proxy Start-Up Costs or Proxy Minimum Load Costs following the 60-day negotiation period, the Scheduling Coordinator has the right to file proposed values and supporting information for major maintenance adders for the Proxy Start-Up Costs or Proxy Minimum Load Costs with FERC pursuant to Section 205 of the Federal Power Act.

30.4.5.4.4 Interim Adders Pending Dispute Resolution

In the event of a dispute regarding the reasonableness of the adder for major maintenance expenses determined by the CAISO or Independent Entity, but not a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity will determine a reasonable interim adder for major maintenance expenses until the adder for major maintenance expenses is determined by agreement between the CAISO or Independent Entity and the Scheduling Coordinator or by FERC. Any subsequent agreement or FERC order determining the adder for major maintenance expenses will be reflected in an adjustment to the interim adder for major maintenance expenses in the next applicable Settlement Statement.

30.4.6 Use-Limited Resources

30.4.6.1 Registration and Validation Process

A Scheduling Coordinator seeking to obtain Use-Limited Resource status for resource(s) will follow the registration and validation process set forth in this CAISO Tariff and the Business Practice Manual. The registration and validation process requires each Scheduling Coordinator to demonstrate on an annual basis that the resource has one or more limits that meet the Use-Limited Resource criteria as set forth in Section 30.4.6.1.1 and the Business Practice Manual, and allows each Scheduling Coordinator to seek to recover Opportunity Costs for Use-Limited Resources by making the demonstration set forth in Section 30.4.6.1.2.

30.4.6.1.1 Use-Limited Resource Criteria

In order for a resource to be considered a Use-Limited Resource, a Scheduling Coordinator must provide sufficient documentation demonstrating that the resource has one or more limits that meet all three of the following criteria:

(1) The resource has one or more limitations affecting its number of starts, its number of run-hours, or its Energy output due to (a) design considerations, (b) environmental restrictions, or (c) qualifying contractual limitations;

(2) The CAISO Market Process used to dispatch the resource cannot recognize the resource's limitation(s); and

(3) The resource's ability to select hours of operation is not dependent on an energy source

outside of the resource's control being available during such hours but the resource's usage needs to be rationed.

Design considerations that satisfy the requirements of this Section are those resulting from physical equipment limitations. A non-exhaustive list of such physical equipment limitations includes restrictions documented in original equipment manufacturer recommendations or bulletins, or limiting equipment such as storage capability for hydroelectric generating resources. Other design considerations that satisfy the requirements of this Section are those resulting from performance criteria for Demand Response Resources established pursuant to programs or contracts approved by Local Regulatory Authorities. Environmental restrictions that satisfy the requirements of this Section are those imposed by regulatory bodies, legislation, or courts. A non-exhaustive list of such environmental restrictions includes limits on emissions, water use restrictions, run-hour limitations in operating permits or other environmental limits that directly or indirectly limit starts, run hours, or MWh limits, but excludes restrictions with soft caps that allow the resource to increase production above the soft caps through the purchase of additional compliance instruments. Qualifying contractual limitations that satisfy the requirements of this Section are those contained in long-term contracts that: (i) were reviewed and approved by a Local Regulatory Authority on or before January 1, 2015, or were pending approval by a Local Regulatory Authority on or before January 1, 2015 and were later approved; and (ii) were evaluated by the Local Regulatory Authority for the overall cost-benefit of those contracts taking into consideration the overall benefits and burdens, including the limitations on such resources' numbers of starts, numbers of run-hours, or Energy output. Contracts limits that provide for higher payments when start-up, run-hour, or Energy output thresholds are exceeded are not qualifying contractual limitations. Effective April 1, 2022, no contractual limitations will constitute qualifying contractual limitations that satisfy the requirements of this Section. Pursuant to a process set forth in the Business Practice Manual, the CAISO will review the limits and the supporting documentation provided by the Scheduling Coordinator as well as any translation of indirect limits to determine whether the Scheduling Coordinator has made the required showing under this Section. Any dispute regarding the CAISO's determination will be subject to the generally applicable CAISO ADR Procedures set forth in Section 13, which apply except where a CAISO Tariff provision expressly provides for a different means of resolving disputes.

The following types of resources are not eligible to register as Use-Limited Resources: Reliability Demand Response Resources, Regulatory Must-Take Generation, where 100% of the capacity is regulatory must-take, Combined Heat and Power Resources where 100% of the capacity is dedicated to a host industrial process, and Variable Energy Resources.

30.4.6.1.2 Establishing Opportunity Cost Adders

A Scheduling Coordinator for a Use-Limited Resource that elects the Proxy Cost methodology may seek to establish Opportunity Cost adders for any limitation(s) that meet all three (3) of the following criteria:

(1) Satisfy the requirements of Section 30.4.6.1.1;

(2) Apply for period(s) longer than the time horizon considered in the applicable Day-Ahead Market process; and

(3) Can be reflected in a monthly, annual, and/or rolling twelve (12) month period.

The CAISO will review the documentation provided by the Scheduling Coordinator and determine whether the CAISO can calculate an Opportunity Cost pursuant to the methodology set forth in Section 30.4.6.2 using the Opportunity Cost calculator, or whether the Opportunity Cost for the limitation must instead be established pursuant to the negotiation process set forth in Section 30.4.6.3. Resources with limits that can be modelled using the Opportunity Cost calculator, are not eligible for a negotiated Opportunity Cost. Any Opportunity Cost formula rate resulting from either through the calculated or negotiated process, will remain in place unless and until the formula rate is modified or terminated by the CAISO. Opportunity Costs determined pursuant to a formula rate will remain in place until updated pursuant to Section 30.4.6.2.1 or Section 30.4.6.3 to reflect any changes in input values to the formula rate. Any Opportunity Cost bid adder will not be available until the first day of the month following the effective date of this tariff section.

A Scheduling Coordinator may submit documentation, either to establish a new limitation or to modify an existing limitation, in which case the Scheduling Coordinator can request reconsideration that may result in a new formula rate. In addition, Scheduling Coordinators must demonstrate on an annual basis that the resource has one or more limits that meet the Use-Limited Resource criteria as required pursuant to Section 30.4.6.1. In accordance with Section 39.7.1.3.2.2, the CAISO will make informational filings with FERC of any new, modified, or terminated Opportunity Cost formula rate developed pursuant to Section

30.4.6.2 or negotiated pursuant to Section 30.4.6.3.

A Use-Limited Resource to the extent it has a limitation that satisfies the requirements of Section 30.4.6.1 but applies for a period less than or equal to the time horizon considered in the Day-Ahead Market, is not eligible for an Opportunity Cost for any limitation.

30.4.6.2 Calculation of Opportunity Cost Adders

30.4.6.2.1 Calculation Schedule

The CAISO will calculate, and will update the most recent calculations of, Start-Up Opportunity Costs for each validated limitation on a Use-Limited Resource's number of starts, Minimum Load Opportunity Costs for each validated limitation on a Use-Limited Resource's number of run-hours, and Variable Energy Opportunity Costs for each validated limitation on a Use-Limited Resource's Energy output for which the Scheduling Coordinator has made the required showing under Section 30.4.6.1.2. Such calculations or updated calculations will actually be used to set the adder for each validated limitation that can be reflected in a monthly or a rolling twelve (12) month period and will be advisory for each validated limitation that can be reflected in an annual period. The CAISO plans to perform the calculations and updated calculations once a month. It is possible that circumstances may prevent the CAISO from performing the calculations on a monthly basis, in which case the CAISO will prioritize the workload based on Opportunity Costs most likely to need updating. The CAISO will provide the results of the calculations or updated calculations for a Use-Limited Resource to its Scheduling Coordinator.

In the event that the CAISO is unable to perform such calculations or updated calculations for all Use-Limited Resources, the CAISO will give priority to performing such calculations or updated calculations for those Use-Limited Resources that are currently on pace to reach their maximum allowed numbers of starts, maximum allowed numbers of run-hours, or maximum allowed Energy output more quickly than the most recent calculations of Opportunity Costs indicated. To the extent that the CAISO is unable to perform such calculations or updated calculations for a Use-Limited Resource, the CAISO will utilize the most recently calculated or updated Opportunity Costs that have been set or are advisory for the Use-Limited Resource.

30.4.6.2.2 Methodology for Opportunity Cost Calculator

For the Opportunity Cost calculator developed by the CAISO, each calculation of Opportunity Costs will equal the estimated profits foregone if the Use-Limited Resource had one fewer unit of starts, run-hours, or Energy output, whichever is applicable, in the future time period of the validated limitation. With regard to each validated limitation of the Use-Limited Resource, the calculation will take into account a margin set forth in the Business Practice Manual. The calculation will also take into account the effect of any validated limitation on a Use-Limited Resource's number of starts, number of run-hours, or Energy output in the monthly and annual and/or rolling twelve month periods. For MSG Transitions, the Opportunity Cost for each transition will be derivative of the number of Start-Ups required for the MSG Resource to achieve a specific MSG Configuration.

The CAISO will calculate the estimated profits for each validated limitation over the future time period of the limitation based on the following estimated inputs: (a) the forecasted hourly average of fifteen-minute LMPs for Energy at the Use-Limited Resource's PNode or Aggregated PNode multiplied by (b) the optimal hourly dispatch of the Use-Limited Resource, minus (c) the estimated monthly Proxy Start-Up Cost of the Use-Limited Resource, minus (d) the estimated monthly Proxy Minimum Load Cost of the Use-Limited Resource, minus (e) the estimated monthly variable Energy cost of the Use-Limited Resource multiplied by the difference between (f) the optimal hourly commitment and dispatch of the Use-Limited Resource and (g) the PMin of the Use-Limited Resource, minus (h) the estimated monthly Transition Cost of the Use-Limited Resource.

The CAISO will calculate input (a) listed above by executing the following steps in the order shown below:

(1) For each future hour, calculate an hourly implied heat rate at each applicable PNode or Aggregated PNode for a Use-Limited Resource based on the hourly average of the fifteen-minute Real-Time LMPs (reflecting the gas price index used in the Real-Time Market calculated pursuant to Section 39.7.1.1.1.3) from the same hour of the previous year, the Greenhouse Gas Allowance Price, calculated pursuant to Section 39.7.1.1.1.4, from the same day of the previous year, and the gas price index of the applicable fuel region from the same day of the previous year.

(2) For each future month, calculate a monthly future implied heat rate based on the applicable wholesale future power price of the applicable electric pricing hub as published by Intercontinental Exchange, the most recent Greenhouse Gas Allowance Price

calculated pursuant to Section 39.7.1.1.1.4, and the natural gas future commodity price of the applicable fuel region. The CAISO determines the natural gas futures commodity price by fuel region averaging available prices from the following vendors: Intercontinental Exchange, Natural Gas Intelligence, and SNL Energy/BTU's Daily Gas Wire.

(3) For each future month, calculate a monthly historical implied heat rate based on the wholesale historic power price of the applicable electric pricing hub as published by Intercontinental Exchange for the same month of the previous year, the average Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4 for the same month of the previous year, and the average natural gas commodity price, reflecting the gas price index used in the Real-Time Market calculated pursuant to Section 39.7.1.1.1.3, of the applicable fuel region for the same month of the previous year.

(4) For each future month, calculate a monthly power price conversion factor as the ratio of the future implied heat rate calculated under (2) above and the historical implied heat rate calculated under (3) above.

(5) For each future hour, scale the hourly implied heat rate calculated under (1) above by the power price conversion factor calculated under (4) above.

(6) For each future hour, calculate the LMPs by applying the gas price index of the future month and the most recent Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4 to the scaled implied heat rates calculated under (5) above.

For a Use-Limited Resource that has twelve (12) or fewer months of LMP data at its PNode or Aggregated PNode, the CAISO will calculate input (a) listed above using LMP data from a comparable PNode or Aggregated PNode.

Additional detail regarding the calculation of Opportunity Costs is provided in Appendix N to the Business Practice Manual for Market Instruments. Any dispute regarding the calculation of Opportunity Costs will be subject to the CAISO ADR Procedures set forth in Section 13.

30.4.6.3 Negotiation of Opportunity Costs

If, after receipt of the documentation required pursuant to Section 30.4.6.1.2, the CAISO determines that it cannot rely on the Opportunity Cost calculator to calculate Opportunity Costs for an eligible limitation pursuant to Section 30.4.6.2, the CAISO will establish the Opportunity Costs for the limitation pursuant to this Section. Upon making this determination, the CAISO will notify the Scheduling Coordinator for the resource and request that the Scheduling Coordinator provide the CAISO with a proposed methodology for determining Start-Up Opportunity Costs, Minimum Load Opportunity Costs, and/or Variable Energy Opportunity Costs for the limitation along with documentation supporting the methodology, and a proposed schedule for the CAISO to update such Opportunity Cost(s) under the methodology. The CAISO will either approve the submitted Opportunity Cost methodology or enter into good-faith negotiations with the Scheduling Coordinator to establish an agreed-upon Opportunity Cost methodology and the schedule for updating the Opportunity Costs under the methodology.

If the CAISO and the Scheduling Coordinator enter into good-faith negotiations, the negotiation period will be a minimum of sixty (60) days following the provision of all required documentation by the Scheduling Coordinator. Following the 60-day period, the parties can agree to continue good-faith negotiations or the Scheduling Coordinator can exercise its right to file with FERC as described below. In the event that the CAISO and the Scheduling Coordinator are unable to agree upon negotiated Opportunity Costs before the negotiation period terminates, the CAISO may propose reasonable interim Opportunity Cost value(s) that will apply to the Use-Limited Resource until the CAISO and the Scheduling Coordinator agree upon negotiated Opportunity Costs. The Scheduling Coordinator may accept or reject the proposed interim Opportunity Cost value(s). If the Scheduling Coordinator rejects the proposed interim Opportunity Cost value(s), the Use-Limited Resource will not receive Opportunity Costs unless and until the CAISO and the Scheduling Coordinator agree upon negotiated Opportunity Costs, or such costs are established by an order issued by FERC. In the event that the negotiation period terminates without the CAISO and the Scheduling Coordinator reaching agreement upon negotiated Opportunity Costs, and the Scheduling Coordinator declines to continue negotiations, the Scheduling Coordinator may file proposed Opportunity Costs and supporting documentation with FERC pursuant to Section 205 of the Federal Power Act.

Any updates to the negotiated Opportunity Costs adders established pursuant to this Section will consist solely of updates to the Opportunity Cost values themselves, and shall not affect the methodology for establishing those values. Any change in methodology would require the Scheduling Coordinator to initiate a new request pursuant to Section 30.4.6.1.2.

30.4.7 Registered Cost Methodology

Under the Registered Cost methodology, the Scheduling Coordinator for a Use-Limited Resource that is eligible for Opportunity Costs and either (i) does not have at least twelve (12) consecutive months of fifteen-minute LMPs for Energy at the Use-Limited Resource's PNode or Aggregated PNode; or (ii) has at least twelve (12) consecutive months of such LMPs but has not yet reached the start of the second month after the end of the twelfth consecutive month of having such LMPs, may register values of its choosing for Default Start-Up Bids and/or Default Minimum Load Bids in the Master File subject to the maximum limit specified in Section 39.6.1.6. A Scheduling Coordinator for a Multi-Stage Generating Resource that is a Use-Limited Resource registering Default Start-Up Bids must also register Default Transition Bids for each feasible MSG Transition, subject to the maximum limit specified in Section 39.6.1.7. For a Use-Limited Resource to be eligible for the Registered Cost methodology there must be sufficient information in the Master File to calculate the value pursuant to the Proxy Cost methodology, which will be used to validate the specific value registered using the Registered Cost methodology. Any such values will be fixed for a minimum of thirty (30) days in the Master File unless:

(a) the resource's costs for any such value, as calculated pursuant to the Proxy Cost methodology, exceed the value registered using the Registered Cost methodology, in which case the Scheduling Coordinator may elect to switch to the Proxy Cost methodology for the balance of any thirty (30)-day period, except as set forth in Section 30.4.7 (b); or

(b) any cost registered in the Master File exceeds the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7 after this minimum thirty (30)-day period, in which case the value will be lowered to the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7.

If a Multi-Stage Generating Resource elects to use the Registered Cost methodology, that election will apply to all the MSG Configurations for that resource. The cap for the Registered Cost values for each

MSG Configuration will be based on the Proxy Cost values calculated for each MSG Configuration, including for each MSG Configuration that cannot be directly started, which are also subject to the maximum limits specified in Sections 39.6.1.6 and 39.6.1.7.

30.5 Bidding Rules

30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the DAM for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the RTM for the following Trading Day shall be submitted starting from the time of publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. The CAISO will not accept any Energy or Ancillary Services Bids for the following Trading Day between 10:00 a.m. on the day preceding the Trading Day and the publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the RTM may be revised.

(c) A Scheduling Coordinator may submit in the Real-Time Market new daily Start-Up Bids, Minimum Load Bids, and Transition Bids for resources and MSG Configurations for which the Scheduling Coordinator previously submitted such Bids in the Day-Ahead Market, except for: (1) Trading Hours in which a resource or MSG Configuration has received a

Day-Ahead Schedule or has received a Start-Up Instruction in RUC; and (2) Trading Hours that span the Minimum Run Time of the resource or MSG Configuration after the CAISO has committed the resource or the Scheduling Coordinator has self-committed the resource in the RTM.

(d) Scheduling Coordinators may revise ETC Self-Schedules for Supply in the RTM to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Participating TO in accordance with Section 16.

(e) Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the Real-Time Market separate and apart from the awarded Ancillary Services capacity.

(f) Scheduling Coordinators may submit Energy Bids, AS Bids, and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day.

(g) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price.

(h) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30.

(i) In order to retain the priorities specified in Section 31.4 and 34.12 for scheduled amounts in the Day-Ahead Schedule associated with ETC and TOR Self-Schedules or Self-Schedules associated with Regulatory Must-Take Generation, a Scheduling Coordinator must submit to the Real-Time Market ETC or TOR Self-Schedules, or Self-Schedules associated with Regulatory Must-Take Generation, at or below the Day-Ahead Schedule quantities associated with the scheduled ETC, TOR, or Regulatory Must-Take Generation Self-Schedules. If the Scheduling Coordinator fails to submit such Real-Time Market ETC, TOR, or Regulatory Must-Take Generation Self-Schedules, the defined scheduling priorities of the ETC, TOR, or Regulatory Must-Take Generation Day-Ahead Schedule quantities may be subject to adjustment in the HASP and the Real-Time Market as further provided in Sections 31.4 and 34.12 in order to meet operating conditions.

(j) For Multi-Stage Generating Resources that receive a Day-Ahead Schedule, are awarded a RUC Schedule, or receive an Ancillary Services Award the Scheduling Coordinator must submit an Energy Bid in the Real-Time Market for the same Trading Hour(s). If the Scheduling Coordinator submits an Economic Bid for such Trading Hour(s), the Economic Bid must be for either: the same MSG Configuration scheduled or awarded in the Integrated Forward Market, or the MSG Configuration committed in RUC. If the Scheduling Coordinator submits a Self-Schedule in the Real-Time Market for such Trading Hour(s), then the Energy Self-Schedule may be submitted in any registered MSG Configuration, including the MSG Configuration awarded in the Day-Ahead Market, that can support the awarded Ancillary Services (as further required by Section 8).

(k) Scheduling Coordinators for Multi-Stage Generating Resources may submit into the Real-Time Market bids from up to six (6) MSG Configurations in addition to the MSG Configuration scheduled or awarded in the Integrated Forward Market and Residual Unit Commitment, provided that the MSG Transitions between the MSG Configurations bid into the Real-Time Market are feasible and the transition from the previous Trading Hour are also feasible.

(l) For the Trading Hours that Multi-Stage Generating Resources do not have a CAISO Schedule or award from a prior CAISO Market run, the Scheduling Coordinator can submit up to six (6) MSG Configurations into the RTM.

(m) A Scheduling Coordinator cannot submit a Bid to the CAISO Markets for a MSG Configuration into which the Multi-Stage Generating Resource cannot transition due to lack of Bids for the specific Multi-Stage Generating Resource in other MSG Configurations that are required for the requisite MSG Transition.

(n) In order for Multi-Stage Generating Resource to meet any Resource Adequacy must-offer obligations, the responsible Scheduling Coordinator must submit either an Economic Bid or Self-Schedule for at least one MSG Configuration into the Day-Ahead Market and Real-Time Market that is capable of fulfilling that Resource Adequacy obligation, as feasible. The Economic Bid shall cover the entire capacity range between the maximum bid-in Energy MW and the higher of Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin as registered in the Master File.

(o) For any given Trading Hour, a Scheduling Coordinator may submit Self-Schedules and/or Submissions to Self-Provide Ancillary Services in only one MSG Configuration for each Generating Unit.

(p) In any given Trading Hour in which a Scheduling Coordinator has submitted a Self-Schedule for a Multi-Stage Generating Resource, the Scheduling Coordinator may also submit Bids for other MSG Configurations provided that they concurrently submit Bids that enable the applicable CAISO Market to transition the Multi-Stage Generating Resource to other MSG Configurations.

(q) If in any given Trading Hour the Multi-Stage Generating Resource was awarded Regulation or Operating Reserves in the IFM, any Self-Schedules or Submissions to Self-Provide Ancillary Services the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(r) If a Multi-Stage Generating Resource has received a binding RUC Start-Up Instruction as provided in Section 31, any Self-Schedule or Submission to Self-Provide Ancillary Services in the RTM must be in the same MSG Configuration committed in RUC.

(s) If in any given Trading Hour the Multi-Stage Generating Resource is scheduled for Energy in the IFM, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Energy is scheduled in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(t) For a Multi-Stage Generating Resource, the Bid(s) submitted for the resource's configuration(s) shall collectively cover the entire capacity range between the maximum bid-in Energy MW and the higher of the Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin as registered in the Master File. This rule shall apply separately to the Day-Ahead Market and the Real-Time Market.

(u) A Scheduling Coordinator may submit a Self-Schedule Hourly Block for the RTM as an import to or an export from the CAISO Balancing Authority Area and may also submit Self-Scheduled Hourly Blocks for Ancillary Services imports. Such a Bid shall be for the same MWh quantity for each of the four (4) fifteen (15)-minute intervals that make up the applicable Trading Hour.

(v) A Scheduling Coordinator may submit a Variable Energy Resource Self-Schedule for the RTM can be submitted from a Variable Energy Resource. A Scheduling Coordinator can use either the CAISO forecast for Expected Energy in the RTM or can provide its own forecast for Expected Energy pursuant to the requirements specified in Section 4.8.2. The Scheduling Coordinator must indicate in the Master File whether it is using its own forecast or the CAISO forecast for its resource in support of the Variable Energy Self-Schedule. The Scheduling Coordinator is not required to include the same MWh quantity for each of the four (4) fifteen (15)-minute intervals that make up the applicable Trading Hour for the Variable Energy Resource Self-Schedule include. If an external Variable Energy Resource that is not using a forecast of its output provided by the CAISO submits a Variable Energy Resource Self-Schedule and the Expected Energy is not delivered in the FMM, the Scheduling Coordinator for the Variable Energy Resource will be subject to the Under/Over Delivery Charge as described in Section 11.31. Scheduling Coordinators for Dynamically Scheduled Variable Energy Resources that provide the CAISO with a two (2)-hour rolling forecast with five (5)-minute granularity can submit Variable Energy Resource Self-Schedules.

(w) Scheduling Coordinators can submit Economic Hourly Block Bids to be considered in the HASP and to be accepted as binding Schedules with the same MWh award for each of the four (4) FMM intervals. Scheduling Coordinator can also submit Economic Hourly

Block Bids for Ancillary Services. As specified in Section 11, a cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery.

(x) Scheduling Coordinators can submit Economic Hourly Block Bids with Intra-Hour Option. If accepted in the HASP, such a Bid creates a binding schedule with same MWh awards for each of the four (4) FMM intervals. After that, the RTM can optimize such schedules for economic reasons once through an FMM during the Trading Hour. As specified in Section 11, a cleared Economic Hourly Block Bid with Intra-Hour Option is not eligible for Bid Cost Recovery.

(y) A Scheduling Coordinator submitting Bids to the RTM is not required to submit a Self-Schedule Hourly Block, a Variable Energy Resource Self-Schedule, an Economic Hourly Block Bid, or an Economic Hourly Block Bid with Intra-Hour Option, and may instead choose to participate in the RTM through Economic Bids or Self-Schedules.

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30.5.2.4 Supply Bids for System Resources

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Resource-Specific System Resources shall also contain Start-Up Bids and Minimum Load Bids. Resource-Specific System Resources are subject to the Proxy Cost methodology or the Registered Cost methodology for Default Start-Up Bids and Default Minimum Load Bids as provided in Section 30.4, and Transaction ID as created by the CAISO. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in RTM on an equivalent basis as Generating Units. The quantity (in MWh) of Energy categorized as Interruptible

Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted.

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30.6.2.1.2 Real-Time Dispatch Options

For purposes of bidding and scheduling in the Real-Time Market, each Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource shall select either the Marginal Real-Time Dispatch Option or the Discrete Real-Time Dispatch Option prior to the start of the initial Reliability Demand Response Services Term applicable to the Reliability Demand Response Resource. The selection for each Reliability Demand Response Resource shall remain in effect until such time as the Scheduling Coordinator for the Reliability Demand Response Resource chooses to change its selection from the Marginal Real-Time Dispatch Option to the Discrete Real-Time Dispatch Option or vice versa, in which case the change in selection shall go into effect at the start of the next Reliability Demand Response Services Term applicable to the Reliability Demand Response Resource. A Reliability Demand Response Resource that is subject to either the Marginal Real-Time Dispatch Option or the Discrete Real-Time Dispatch Option shall have a Default Minimum Load Bid of zero (0) dollars registered in the Master File.

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30.7.3 Day-Ahead Market Validation

30.7.3.1 Validation Prior to Market Close and Master File Update

The CAISO conducts Bid validation in three steps:

Step 1: The CAISO will validate all Bids after submission of the Bid for content validation which determines that the Bid adheres to the structural rules required of all Bids as further described in the

Business Practices Manuals. If the Bid fails any of the content level rules the CAISO shall assign it a rejected status and the Scheduling Coordinator must correct and resubmit the Bid.

Step 2: After the Bids are successfully validated for content, but prior to the Market Close of the DAM, the Bids will continue through the second level of validation rules to verify that the Bid adheres to the applicable CAISO Market rules and if applicable, limits based on Master File data. If the Bid fails any level two validation rules, the CAISO shall assign the Bid as invalid and the Scheduling Coordinator must either correct or resubmit the Bid.

Step 3: If the Bid successfully passes validation in Step 2, it will continue through the third level of validation where the Bid will be analyzed based on its contents to identify any missing Bid components that must be present for the Bid to be valid consistent with the market rules contained in Article III of this CAISO Tariff and as reflected in the Business Practice Manuals. At this stage the Bid will either be automatically modified for correctness and assigned a status of conditionally modified or modified, or if it can be accepted as is, the Bid will be assigned a status of conditionally valid, or valid. A Bid will be automatically modified and assigned a status of modified or conditionally modified Bid, whenever the CAISO inserts or modifies a Bid component. The CAISO will insert or modify a Bid component whenever (1) a Self-Schedule quantity is less than the lowest quantity specified as an Economic Bid for either an Energy Bid or Demand Bid, in which case the CAISO extends the Self-Schedule to cover the gap; (2) for non-Resource Adequacy Resources, the CAISO will extend the Energy Bid Curve or, if the Scheduling Coordinator did not submit an Energy Bid Curve, use the Generated Bid to cover any capacity in a RUC Bid component, if necessary; and (3) for a Resource Adequacy Resource that is not a Use-Limited Resource, the CAISO will extend the Energy Bid Curve or, if the Scheduling Coordinator did not submit an Energy Bid Curve, use the Generated Bid to cover any capacity in a RUC Bid component and, if necessary, up to the full registered Resource Adequacy Capacity. The CAISO will generate a Proxy Bid or extend an Energy Bid or Self-Schedule to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule. To the extent that an Energy Bid to the HASP/RTM is not accompanied by an Ancillary Services Bid, the CAISO will insert a Spinning Reserve and Non-Spinning Reserve Ancillary Services Bid at $ 0/MW for any certified Operating Reserve capacity. The CAISO will also generate a Self-Schedule Bid for any Generating Unit that has a Day-Ahead Schedule but has not submitted Bids in HASP/RTM, up to the quantity in the Day-Ahead Schedule. Throughout the Bid evaluation process, the Scheduling Coordinator shall have the ability to view the Bid and may choose to cancel the Bid, modify and re-submit the Bid, or leave the modified, conditionally modified or valid, conditionally valid Bid as is to be processed in the designated CAISO Market. The CAISO will not insert or extend any Bid for a Resource Adequacy Resource that is a Use-Limited Resource.

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30.7.3.4 Validation after Market Close

To the extent that a Scheduling Coordinator fails to enter a Bid for a resource that is required to submit a Bid in the full range of available capacity consistent with the bidding provisions of Section 30 or the Resource Adequacy provisions of Section 40, the CAISO will create a Bid for the Scheduling Coordinator, which is referred to as the Generated Bid. This does not apply to Load-following MSSs. The Generated Bid will be created only after the Market Close for the DAM and will be based on data registered in the Master File, and, if applicable, published natural gas pricing data and published pricing data for greenhouse gas allowances. The Generated Bid components will be calculated as set forth in Sections 30 and 40.6.8. The Scheduling Coordinator may view Generated Bids, but may not modify such Bids, unless the CAISO has approved a Reference Level Change Request for the resource's Default Energy Bid. The CAISO will provide notice to the Scheduling Coordinator of the use of a Generated Bid prior to Market Clearing of the IFM. In addition, validation of export priority pursuant to Sections 31.4 and 34.12.1 and Wheeling Through transactions pursuant to Section 30.5.4 occur after the Market Close for the DAM.

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30.7.8 Format and Validation of Start-Up and Shut-Down Times

For a Generating Unit or a Resource-Specific System Resource, the submitted Start-Up Time expressed in minutes (min) as a function of down time expressed in minutes (min) must be a staircase function with up to three (3) segments defined by a set of one (1) to four (4) down time and Start-Up Time pairs. The Start-Up Time is the time required to start the resource if it is offline longer than the corresponding down time. The CAISO shall model Start-Up Times for Multi-Stage Generating Resource at the MSG Configuration level and Transition Times are validated based on the Transition Matrix submitted as provided in Section 27.8. The last segment will represent the time to start the unit from a cold start and will extend to infinity. The submitted Start-Up Time function shall be validated as follows:

(a) The first down time must be zero (0) minutes.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the maximum Start-Up Time function, as registered in the Master File for the relevant resource.

(c) The Start-Up Time for each segment must not exceed the Start-Up Time of the corresponding segment of the maximum Start-Up Time function, as registered in the Master File for the relevant resource.

(d) The Start-Up Time function must be strictly monotonically increasing, i.e., the Start-Up Time must increase as down time increases.

For Participating Load and for a Proxy Demand Resource or Reliability Demand Response Resource, a single Shut-Down time in minutes is the time required for the resource to Shut-Down after receiving a Dispatch Instruction. For Multi-Stage Generating Resources, the Scheduling Coordinator must provide Start-Up Bids for each MSG Configuration into which the resource can be started.

30.7.9 Format and Validation of Start-Up Bids and Shut-Down Costs

For a Generating Unit or a Resource-Specific System Resource, the submitted Start-Up Bid expressed in dollars ($) as a function of down time expressed in minutes must be a staircase function with up to three (3) segments defined by a set of one (1) to four (4) down time and Start-Up Bid pairs. The Start-Up Bid is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment of the Start-Up Bid will represent the cost to start the resource from cold Start-Up and will extend to infinity. The CAISO will validate the submitted Start-Up Bid as follows:

(a) The first down time must be zero (0) minutes.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the Start-Up Time information, as registered in the Master File.

(c) The Start-Up Cost for each segment must be non-negative.

(d) The Start-Up Cost Curve must be strictly monotonically increasing non-negative staircase curves (*i.e.,* the Start-Up Cost must increase as down time increases), up to three (3) segments, which represent a function of Start-Up Cost versus down time.

(e) If the Proxy Cost methodology pursuant to Section 30.4.5 applies to the resource, the Scheduling Coordinator for that resource may submit a daily Start-Up Bid for which the included Start-Up Costs must be non-negative and may be less than or equal to the resource's Default Start-Up Bid.

(f) For a resource that is eligible and has elected to use the Registered Cost methodology pursuant to Section 30.4.7, if a Start-Up Cost value is submitted in a Start-Up Bid, the CAISO will override that submitted Start-Up Cost with the Registered Cost reflected in the Master File.

(g) If no Start-Up Cost is submitted in a Bid, the CAISO will insert the Proxy Start-Up Cost plus the applicable Start-Up Opportunity Cost, or the Master File Registered Cost based on the methodology elected pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Start-Up Cost is submitted in a Bid, the CAISO will insert the revised Reference Level Start-Up Cost.

(h) The Start-Up Bid for a Reliability Demand Response Resource shall be zero (0).

(i) For Participating Loads and Proxy Demand Resources, a single Shut-Down Cost in dollars ($) is the cost incurred to Shut-Down the resource after receiving a Dispatch Instruction. The submitted Shut-Down Cost must be non-negative.

(j) For Multi-Stage Generating Resources, for any MSG Configuration for which a Bid is submitted, the Scheduling Coordinator must provide the Start-Up Bid for each MSG Configuration into which the resource can be started.

30.7.10 Format and Validation of Minimum Load Bids

30.7.10.1 In General

Scheduling Coordinators may submit a Minimum Load Bid for a Generating Unit or a Resource-Specific System Resource, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource, expressed in dollars per hour ($/hr) representing the cost incurred for operating the unit at Minimum Load as registered in the Master File or as modified pursuant to Section 30.7.10.2. The CAISO will validate the Minimum Load Bids as follows:

(a) The submitted Minimum Load Cost must be non-negative. If the Proxy Cost methodology pursuant to Section 30.4.5 applies to the resource, the Scheduling Coordinator for that resource may submit a daily Bid for the Minimum Load Bid that must be non-negative and may be less than or equal to the Default Minimum Load Bid.

(b) For a resource that is eligible and has elected to use the Registered Cost methodology pursuant to Section 30.4.7, any submitted Minimum Load Cost must be equal to the Minimum Load Cost as registered in the Master File.

(c) If no Minimum Load Cost is submitted in a Bid, the CAISO will insert the Proxy Minimum Load Cost plus the applicable Minimum Load Opportunity Cost, or the Master File Registered Cost based on the methodology elected pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Minimum Load Cost is submitted in a Bid, the CAISO will insert the applicable Revised Default Commitment Cost Bid.

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30.7.10.3 [Not Used]

30.7.11 Format and Validation of Transition Bids

The Scheduling Coordinators may submit Transition Bids for a Multi-Stage Generating Resource that must meet the following requirements:

(a) The Transition Bids are non-negative.

(b) For resources under the Proxy Cost methodology, Transition Bids must be less than or equal to the Default Transition Bids calculated under the Proxy Cost methodology.

(c) For resources under the Registered Cost methodology, Transition Bids must equal the Default Transition Bids as registered in the Master File.

(d) If no Transition Cost is submitted in a Transition Bid, the CAISO will insert the Proxy Transition Cost plus the applicable Transition Opportunity Cost, or as registered in the Master File, based on the elected methodology pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Transition Cost is submitted in a Bid, the CAISO will insert the difference between the applicable Revised Default Commitment Cost Bid (*i.e.*, revised Default Start-Up Bid) for the higher MSG Configuration minus the applicable Start-Up Opportunity Cost for the higher MSG configuration and the revised applicable Revised Default Commitment Cost Bid (*i.e.*, revised Default Start-Up Cost Bid) for the lower MSG Configuration minus the applicable Start-Up Opportunity Cost for the lower MSG configuration, plus the applicable transition Opportunity Cost. If the result of this calculation is negative for any transition between two MSG Configurations, then the Transition Cost shall be zero.

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30.11 Adjustments to Reference Levels Prior to CAISO Market Processes

The CAISO will adjust Reference Levels prior to executing the applicable CAISO Market Processes as described in this Section 30.11. **30.11.1 Reasonableness Thresholds**

The CAISO will calculate the Reasonableness Thresholds for the purpose of evaluating increases to Reference Levels pursuant to this Section 30.11.1.

30.11.1.1 General Applicability

The CAISO will calculate the Reasonableness Thresholds for all resources except for Non-Resource-Specific System Resources. The CAISO will calculate Reasonableness Thresholds for evaluating Reference Level Change Requests for Bids from resources, other than Hydro Default Energy Bids and

Virtual Bids.

30.11.1.2 Calculations

30.11.1.2.1 Natural Gas-Fired Resources

For natural gas-fired resources, the CAISO will calculate the Reasonableness Threshold to equal the Proxy Cost-based Default Start-Up Bid, the Proxy Cost-based Default Minimum Load Bid, or the Variable Cost-based Default Energy Bid calculated for the specific resource, where the natural gas commodity price component determined pursuant to Section 39.7.1.1.1.3 is multiplied by: (i) one hundred twenty-five percent (125%) for days without a published daily gas price index consistent with the rules in Section 39.7.1.1.1.3, unless the CAISO has updated the natural gas commodity price used to calculate the Reasonableness Threshold pursuant to Section 30.11.1.3, in which case the CAISO will use one hundred ten percent (110%); or (ii) one hundred ten percent (110%) for all other days. Provided, however, that the CAISO will set the Reasonableness Threshold for a specific resource to its Reference Level when it accepts a manual Reference Level Change Request as provided in Section 30.11.5.

30.11.1.2.2 Non-Natural Gas-Fired Resources

For non-natural gas-fired resources, the CAISO will calculate the Reasonableness Threshold to equal the Proxy Cost-based Default Start-Up Bid, the Proxy Cost-based Default Minimum Load Bid, or the Variable Cost-based Default Energy Bid, with the fuel or fuel-equivalent cost component of that calculation registered in the Master File being multiplied by one hundred ten percent (110%).

30.11.1.3 CAISO Updates for the Real-Time Market

After the deadline for the submissions of manual Reference Level Change Requests specified in Section 30.11.4.2, the CAISO will review the same-day gas price information on trades occurring on the Intercontinental Exchange and will review the same-day gas price information submitted in the manual Reference Level Change Requests applicable for each commodity gas region, to determine whether the same-day gas prices are ten percent (10%) greater than the gas price index the CAISO previously used to calculate the Reasonableness Thresholds.

(a) If the CAISO determines that the representative same-day gas prices are ten percent (10%) greater than the gas price index the CAISO previously used to calculate the Reasonableness Thresholds, the CAISO will:

(i) use the higher of the volume-weighted average price of same-day gas trades occurring on the Intercontinental Exchange and the volume-weighted average of all relevant verified manual Reference Level Change Requests to update the Reasonableness Thresholds for all resources within the applicable fuel region(s); and

(ii) automatically recalculate all Hydro Default Energy Bids in the applicable fuel regions.

(b) The CAISO will implement the changes to the Reasonableness Thresholds in the next available Real-Time Market interval as soon as practicable. Any updates the CAISO makes to Reasonableness Thresholds through this process will apply to the Real-Time Market throughout the remainder of the Trading Day.

30.11.1.4 CAISO Adjustments for Persistent Conditions

The CAISO may adjust the Reasonableness Thresholds for a specific resource in the event of a resource's actual fuel or fuel-equivalent costs, observed by the CAISO in the after-CAISO Market Processes review pursuant to Section 30.12, are systematically greater than the gas price indices or fuel-equivalent costs used by the CAISO in calculating the resource's corresponding Reference Levels.

30.11.2 Reference Level Change Requests

30.11.2.1 Applicability

A Scheduling Coordinator may submit a Reference Level Change Request for Default Start-Up Bids, Default Minimum Load Bids, and Default Energy Bids, as applicable. Scheduling Coordinators may not submit Reference Level Change Requests for Bids by Non-Resource-Specific System Resources. Resources under the Registered Cost methodology are not eligible for Reference Level Change Requests for Default Minimum Load Bids or Default Start-Up Bids. Scheduling Coordinators may not submit Reference Level Change Requests to recover costs associated with gas company imbalance penalties.

30.11.2.2 Requirements

All Reference Level Change Requests must be based on the Scheduling Coordinator's reasonable expectation that its daily actual fuel costs or fuel-equivalent costs for a given Trading Day will exceed the costs used by the CAISO to calculate the resource's Reference Levels, and must reflect reasonable and prudent procurement practices. All Reference Level Change Requests must be calculated using actual or expected fuel costs or fuel-equivalent costs supported by Documentation of Contemporaneously Available Information.

30.11.3 Automated Reference Level Change Requests

30.11.3.1 Applicability

Scheduling Coordinators may submit automated Reference Level Change Requests. The CAISO will evaluate automated Reference Level Change Requests prior to the time the applicable CAISO Market Process is executed based on the Reasonableness Thresholds the CAISO calculates for each resource as specified in Section 30.11.1. The Scheduling Coordinator shall not submit a Reference Level Change Request for the purpose of inflating its Default Energy Bids or Default Commitment Cost Bids beyond what these values would be if calculated based on its actual or expected costs, without applying the Default Energy Bid Multiplier or Commitment Cost Multiplier. Scheduling Coordinators shall not submit an automated Reference Level Change Request that is supported by the same Documentation of Contemporaneously Available Information submitted with a manual Reference Level Change Request that the CAISO previously denied. The CAISO shall not accept automated Reference Level Change Requests for Hydro Default Energy Bids.

30.11.3.2 Requirements

Scheduling Coordinators must calculate the Reference Levels amounts included in their Reference Level Change Requests using the same methodology used to calculate the Proxy Cost-based Default Start-Up Bid, (without applying the Commitment Cost Multiplier), the Proxy Cost-based Default Minimum Load Bid (without applying the Commitment Cost Multiplier), and the Variable Cost-based Default Energy Bid (without applying the Default Energy Bid Multiplier).

30.11.3.3 Contemporaneously Available Supporting Documentation

Although the Scheduling Coordinator does not submit Documentation of Contemporaneously Available Information when it submits an automated Reference Level Change Request, the Scheduling Coordinator must retain the Documentation of Contemporaneously Available Information. The CAISO may request the Scheduling Coordinator to provide the CAISO with Documentation of Contemporaneously Available

Information pursuant to Section 30.11.3.4.

30.11.3.4 Evaluation of Automated Reference Level Change Requests

If the Reference Level change submitted by the Scheduling Coordinator for a resource in the automated Reference Level Change Request is equal to or less than the applicable Reasonableness Threshold for the resource, the CAISO will approve the Revised Default Commitment Cost Bid and Revised Default Energy Bid. If the Reference Level change submitted by the Scheduling Coordinator for a resource in the automated Reference Level Change Request process exceeds the applicable Reasonableness Threshold for the resource, the CAISO will approve the revised Reference Level to equal the resource's Reasonableness Threshold.

30.11.3.5 CAISO Audit of Automated Reference Level Change Requests

(a) **Audit Process**. The CAISO may audit a Scheduling Coordinator that submits an automated Reference Level Change Request at any time and may request the Scheduling Coordinator to provide the CAISO with its cost calculations and Documentation of Contemporaneously Available Information. In response to a CAISO audit request for information related to the audit, the Scheduling Coordinator must respond with the requested information within five (5) Business Days of the CAISO's request. The CAISO will evaluate the submitted information and determine whether it supports the Scheduling Coordinator's automated Reference Level Change Request within ten (10) Business Days of receipt of the Scheduling Coordinator's cost calculations and Documentation of Contemporaneously Available Information.

(b) In the event the CAISO determines the submitted information does not support the Reference Level Change Request, the Scheduling Coordinator may request CAISO ADR Procedures as specified in Section 13 of the CAISO Tariff within five (5) Business Days of the CAISO's response. If the Scheduling Coordinator requests CAISO ADR Procedures, the Scheduling Coordinator will not be permitted to submit automated Reference Level Change Requests for the affected resource as specified in Section 30.11.3.4(c) while the CAISO ADR Procedures are pending. If the CAISO ADR Procedures confirm that the Documentation of Contemporaneously Available Information did not support the Scheduling Coordinator's automated Reference Level Change Request, the Scheduling Coordinator will be prohibited from submitting automated Reference Level Change Requests until the time period specified in Section 30.11.3.4(c) has elapsed.

(c) **Consequence for Failure to Comply with CAISO Requirements**. If the CAISO determines that the Documentation of Contemporaneously Available Information submitted by the Scheduling Coordinator does not support a conclusion that the Scheduling Coordinator's actual or expected fuel costs, or fuel-equivalent costs, for a resource as calculated in Section 30.11.2.2 were higher than those the CAISO used to determine the resource's Reference Levels:

(1) The CAISO shall prohibit the Scheduling Coordinator from making any automated Reference Level Change Requests for the affected resource for sixty (60) days from the time the CAISO informs the Scheduling Coordinator that it did not submit Documentation of Contemporaneously Available Information that supports the Scheduling Coordinator's automated Reference Level Change Request.

(2) Any subsequent determination that the Scheduling Coordinator did not submit Documentation of Contemporaneously Available Information that supports its automated Reference Level Change Request will result in the CAISO prohibiting the Scheduling Coordinator from making any automated Reference Level Change Requests for the affected resource for one hundred eighty (180) days from the time the CAISO informs the Scheduling Coordinator of the subsequent failure to submit Documentation of Contemporaneously Available Information that supports its automated Reference Level Change Request.

30.11.4 Manual Reference Level Change Requests

30.11.4.1 Applicability

Scheduling Coordinators may request a manual Reference Level Change Request when the Scheduling Coordinator's actual or expected fuel costs or fuel-equivalent costs exceed the fuel or fuel-equivalent costs the CAISO used to calculate a resource's Reference Level by the greater of ten percent (10%) or $0.50/MMBTU, as applicable. The Scheduling Coordinator may submit a manual Reference Level Change Request for:(a) Default Energy Bids, Default Start-Up Bids, and Default Minimum Load Bids for natural gas-fired resources; and

(b) Default Energy Bids for non-natural gas-fired resources.

30.11.4.2 Requirements

Scheduling Coordinators must submit any manual Reference Level Change Requests by 8:00 a.m. of the Business Day on which the applicable CAISO Market is executed. Scheduling Coordinators must submit in their manual Reference Level Change Requests their actual or expected fuel costs that they request the CAISO to validate and to be used to calculate their resource's Reference Levels. For gas-fired resources, the Scheduling Coordinator must submit the gas fuel cost only and not include the gas transportation cost. Upon submission of a manual Reference Level Change Request, the Scheduling Coordinator must submit Documentation of Contemporaneously Available Information that shows that its resource's actual or expected fuel costs or fuel-equivalent costs exceed the fuel or fuel-equivalent costs used to calculate the resource's Reference Level.

30.11.4.3 Evaluation of Manual Reference Level Change Requests

The CAISO will evaluate requested fuel costs submitted in the manual Reference Level Change Requests based on information submitted by the Scheduling Coordinator and any other available evidence of current costs that applies to the Reference Level Change Request: (1) as practicable prior to the execution of the applicable Day-Ahead Market; and (2) as soon as practicable after submission of the manual Reference Level Change Request for the Real-Time Market. This evaluation will consist of whether the submitted information supports a change in the Reference Level. If the fuel cost submitted in the manual Reference Level Change Request is accepted, the CAISO will recalculate the Reference Level using the accepted actual or expected fuel costs (without applying the Commitment Cost Multiplier or the Default Energy Bid Multiplier). The CAISO will apply the Revised Default Commitment Cost Bid and Revised Default Energy Bid for use in the CAISO Market Processes and for Settlement purposes as specified in Section 30.11.5. If the CAISO does not accept the submitted actual or expected fuel costs, the CAISO will make no changes to the Reference Level.

30.11.5 Application of Revised Reference Level

For the Day-Ahead Market, the Revised Default Commitment Cost Bids and Revised Default Energy Bid will apply to the applicable Trading Day of the Day-Ahead Market. For the Real-Time Market, the Revised Default Commitment Cost Bids and Revised Default Energy Bid will apply from the Real-Time Market Trading Hour for which it is practicable for the CAISO to apply the change until the last Trading Hour of the Trading Day for which the Reference Level Change Request was specified. The CAISO will not update the applicable Reasonableness Threshold when it accepts an automated Reference Level Change Request. The CAISO will update a resource's applicable Reasonableness Threshold to equal the resource's Reference Level when it accepts a manual Reference Level Change Request. The Scheduling Coordinator may submit an application for after-CAISO Market Process adjustments pursuant to Section 30.12 for any costs not verified through the automated Reference Level Change Request process or that were rejected through the manual Reference Level Change Request process.

30.11.6 Hydro Default Energy Bids

In the event a Scheduling Coordinator that controls both a hydro resource and a natural gas-fired resource in the same gas fuel region submits a manual Reference Level Change Request for both the hydro resource's Hydro Default Energy Bid and the natural gas-fired resource's Reference Level, and the CAISO accepts the manual Reference Level Change Request for the natural gas-fired resource, the CAISO may also update the natural gas price used in the calculation of a hydro resource's Hydro Default Energy Bid when the CAISO adjusts the gas price used in the Reasonableness Thresholds for the entire gas fuel region in which the hydro resource is located pursuant to Section 30.11.1.

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 amounts in a Reference Level Change Request that were not approved pursuant to Section 30.11. Scheduling Coordinators may not request additional uplift payments under this section to cover costs associated with gas company imbalance penalties.

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.

30.12.3 Supporting Documentation

Scheduling Coordinators must submit supporting documentation 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, 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 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 using revised Bid Costs 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

If the CAISO is unable to verify within the sixty (60) Business Day period that the resource's incurred costs are eligible for evaluation pursuant to this Section 30.12.4, the 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, the Scheduling Coordinator may 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

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

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.

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31.3.1 Market Clearing and Price Determination

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31.3.1.3 Reduction of Self-Scheduled LAP Demand

In the IFM, to the extent the market software cannot resolve a non-competitive Transmission Constraint utilizing Effective Economic Bids such that self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-Priced Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-Priced Quantity to be adjusted, will be:

(a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Resource or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR Resource or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM process.

(b) Relax the constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

31.3.1.4 Eligibility to Set the Day-Ahead LMP

All Generating Units, Participating Loads, non-Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, System Resources, System Units, or Constrained Output Generators subject to the provisions in Section 27.7, with Bids, including Generated Bids, that are unconstrained due to Ramp Rates, MSG Transitions, Forbidden Operating Regions, or other temporal constraints are eligible to set the LMP, provided that (a) the Schedule for the Generating Unit or Resource-Specific System

Resource is between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid; or (b) the Schedule for the Participating Load, non-Participating Load, Proxy Demand Resources, Reliability Demand Response Resources, Non-Resource-Specific System Resource, or System Unit is between zero (0) MW and the highest MW value in its Economic Bid or Generated Bid. If (a) a resource's Schedule is constrained by its Minimum Operating Limit or the highest MW value in its Economic Bid or Generated Bid; (b) the CAISO enforces a resource-specific constraint on the resource due to an RMR Dispatch of a Legacy RMR Unit or Exceptional Dispatch; (c) the resource is constrained by a boundary of a Forbidden Operating Region or is Ramping through a Forbidden Operating Region; or (d) the resource's full Ramping capability is constraining its inter-hour change in Schedule, the resource cannot be marginal and thus is not eligible to set the LMP. Resources identified as MSS Load following resources are not eligible to set the LMP. A Constrained Output Generator will be eligible to set the hourly LMP if any portion of its Energy is necessary to serve Demand.

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31.5.6 Eligibility for RUC Compensation

All RUC Capacity is eligible for the RUC Availability Payment except for: (i) RMR Capacity from RMR Resources; (ii) Resource Adequacy Capacity; and (iii) RUC Capacity that corresponds to the resource's Minimum Load, which is compensated through the Bid Cost Recovery as described in Section 11.8. Resources not committed in the IFM that are committed in RUC, including Condition 1 Legacy RMR Units that were not designated for RMR Dispatches and Resource Adequacy Resources, are also eligible for RUC Cost Compensation, which includes Start-Up, Transition Costs, and Minimum Load Cost compensation, and Bid Cost Recovery, subject to the resource actually following its Dispatch Instructions as verified by the CAISO pursuant to procedures set forth in the Business Practice Manuals.

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34.7 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four (4) seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements and Uncertainty Requirements over the applicable forward-looking time period of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast of CAISO Demand or forecast of EIM Demand, adjusted as necessary by the CAISO or EIM operator to reflect scheduled changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTDD and RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Submissions to Self-Provide an Ancillary Service;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire forward-looking time period, the Dispatch for the target Dispatch Interval will be affected by: (a) Dispatch Instructions in prior intervals; (b) actual output of the

resource; (c) forecasted conditions in subsequent intervals within the forward-looking time period of the optimization; and (d) operational constraints of the resource, such that a resource may be dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval, considering the applicable MSG Configuration;

(7) Through Start-Up Instructions the CAISO may instruct resources to Start-Up or Shut-Down, or may reduce Load for Participating Loads, Reliability Demand Response Resources, and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted Bids, Start-Up Bids and Minimum Load Bids, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only start up resources that can start within the applicable time periods of the various CAISO Markets Processes that comprise the RTM;

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy; (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM; (c) the Generating Unit is not providing Regulation or Spinning Reserve; and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves;

(10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Target remains within

the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

(11) For Multi-Stage Generating Resources the CAISO will issue Dispatch Instructions by Resource ID and Configuration ID;

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition Bids, and Minimum Load Bids, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Run Time and Minimum Down Time defined for each MSG configuration and Minimum Run Time and Minimum Down Time at the Generating Unit.

(13) The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency.

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34.11 Exceptional Dispatch

The CAISO may issue Exceptional Dispatches for the circumstances described in this Section 34.11, which may require the issuance of forced Shut-Downs, forced Start-Ups, or forced MSG Transitions and shall be consistent with Good Utility Practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the CAISO Operator into the Day-Ahead or RTM optimization software so that they will be accounted for and included in the communication of Day-Ahead Schedules and Dispatch Instructions to Scheduling Coordinators. Exceptional Dispatches are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch. When considering the issuance of an Exceptional Dispatch to RA Capacity, the CAISO shall consider the effectiveness of the resource from which the capacity is being provided, along with Start-Up Bids, Transition Bids, and Minimum Load Bids, as adjusted pursuant to Section 30.7.10.2, if applicable, when issuing Exceptional Dispatches to commit a resource to operate at Minimum Load. When the CAISO issues Exceptional Dispatches for Energy to RA Capacity, the CAISO shall also consider Energy Bids, if available and as appropriate. Additionally, where the Exceptional Dispatch results in a CPM designation, the CAISO shall make CPM designations of Eligible Capacity for an Exceptional Dispatch by applying the criteria and procedures specified in Section 43A.4.

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39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for capacity of non-Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 will be limited to one hundred fifty percent (150%) of the Projected Proxy Cost. The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for capacity of Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 will be limited to one hundred fifty percent (150%) of the Projected Proxy Cost for each MSG Configuration of the resources. The Projected Proxy Cost for natural gas-fired resources will include a gas price component, a major maintenance expense component, if available, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6. The Projected Proxy Cost for non-natural gas-fired resources will be based on costs provided to the CAISO pursuant to Section 30.4.5.2, a major maintenance expense component, if available, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6.

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas-fired resources, the CAISO will calculate a gas price to be used in establishing Default Start-Up Bids and Default Minimum Load Bids after the twenty-first (21st) day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators for natural gas-fired Use-Limited Resources electing to use the Registered Cost methodology set forth in Section 30.4.7 until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery points, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the Default Start-Up Bids and Default Minimum Load Bids for Use-Limited Resources electing to use the Registered Cost methodology set forth in Section 30.4.7. The most geographically appropriate prices will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set forth in the Business Practice Manual will be added to the baseline gas price for each Use-Limited Resource that elects to use the Registered Cost methodology set forth in Section 30.4.7 to create a final gas price for calculating the Default Start-Up Bids and Default Minimum Load Bids for each such resource.

For non-natural gas-fired resources, the Projected Proxy Costs for Default Start-Up Bids and Default Minimum Load Bids will be calculated using the information as registered in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

39.6.1.6.2 Projected Greenhouse Gas Allowance Price

For resources that are registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a projected Greenhouse Gas Allowance Price component to be used in establishing maximum Default Start-Up Bids and Default Minimum Load Bids after the twenty-first (21st) day of each month and will post it on the CAISO Website by the end of that month. The projected Greenhouse Gas Allowance Price component will be applicable for Scheduling Coordinators on behalf of eligible Use-Limited Resources electing to use the Registered Cost methodology until a new projected Greenhouse Gas Allowance Price component is calculated and posted on the CAISO Website. The projected Greenhouse Gas Allowance Price component will be calculated by averaging the applicable daily Greenhouse Gas Allowance Prices calculated over the first twenty (20) days of the month using the methodology set forth in Section 39.7.1.1.1.4.

39.6.1.6.3 Major Maintenance Expense Component

The major maintenance expense component is determined based on the process set forth in Section 30.4.5.4.

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39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a volumetric Grid Management Charge adder plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, by multiplying the sum by the Default Energy Bid Multiplier, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel or fuel-equivalent cost plus a volumetric Grid Management Charge plus a greenhouse gas cost adder if applicable, multiplying the sum by the Default Energy Bid Multiplier, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any.

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39.7.1.1.1.2 Non-Natural Gas-Fired Resources

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel or fuel equivalent costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty percent (80%) of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. The CAISO will include, if applicable: (i) greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource; (ii) variable operation and maintenance cost; and (iii) a volumetric Grid Management Charge adder that consists of: (a) the Market Services Charge; (b) the System Operations Charge; and (c) the Bid Segment Fee divided by the MW in the Bid segment. Cost curves shall be stored, updated, and validated in the Master File.

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39.7.1.1.2 Variable Operation and Maintenance Cost Under the Variable Cost Option

The default value for the variable operation and maintenance cost portion will vary by fuel source or technology as follows: (1) solar $0.00/MWh; (2) nuclear $1.00/MWh; (3) coal $2.00/MWh; (4) wind $2.00/MWh; (5) hydro $2.50/MWh; (6) natural gas-fired combined cycle and steam units $2.80/MWh; (7) geothermal $3.00 WMh; (8) landfill gas $4.00/MWh; (9) combustion turbines and reciprocating engines $4.80/MWh; and (10) biomass $5.00/MWh. Resource-specific values may be negotiated with the CAISO or the Independent Entity charged with calculating the Default Energy Bid. Default operation and maintenance values as well as any negotiated values will also be used to calculate Default Minimum Load Bids pursuant to Section 30.4.

39.7.1.1.3 Variable Energy Opportunity Costs Under the Variable Cost Option

The CAISO will determine eligibility for Variable Energy Opportunity Costs for Use-Limited Resources pursuant to Section 30.4.6.

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39.7.1.3.1 Submission Process

Scheduling Coordinators that elect the Negotiated Rate Option for the Default Energy Bid shall submit a proposed Default Energy Bid along with supporting information and documentation as described in a BPM. Within ten (10) Business Days of receipt, the CAISO or an Independent Entity selected by the CAISO will provide a written response. If the CAISO or Independent Entity accepts the proposed Default Energy Bid, it will generally become effective within eleven (11) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO or Independent Entity selected by the CAISO does not accept the proposed Default Energy Bid, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates sixty (60) days following the date of submission of a proposed Default Energy Bid by a Scheduling Coordinator. If at any time during this period, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator agree upon the Default Energy Bid, it will generally become effective within eleven (11) Business Days of the date of agreement and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the sixty (60)-day period the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator fail to agree on the Default Energy Bid to be used under the Negotiated Rate Option, the Scheduling Coordinator has the right to file a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the sixty (60)-day period following the submission of a proposed negotiated Default Energy Bid by a Scheduling Coordinator, and pending FERC's acceptance in cases where the CAISO or Independent Entity selected by the CAISO fail to agree on the Default Energy Bid for use under the Negotiated Rate Option and the Scheduling Coordinator filed a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to Section 39.7. If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of these options, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5.

Any negotiated Default Energy Bid for a resource that includes an opportunity cost component as of April 1, 2019, will remain in effect, subject to the CAISO's renegotiation rights pursuant to Section 39.7.1.3.2.1, unless the Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.6.1.2. If a Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.6.1.2, the Scheduling Coordinator must either elect the Variable Cost Default Energy Bid or the CAISO will renegotiate the negotiated Default Energy Bid to, at a minimum, utilize the Variable Energy Opportunity Cost as a component of the negotiated Default Energy Bid in place of any previously negotiated Opportunity Cost value.

39.7.1.3.2 Negotiated Values and Informational Filings

39.7.1.3.2.1 Renegotiation of Values

The CAISO may require the renegotiation of any components including adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.5.1, 30.4.5.2, and 30.4.5.4, any Opportunity Costs negotiated pursuant to Section 30.4.6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operation and maintenance adders negotiated pursuant to Section 39.7.1.1.2, that have become outdated, are possibly erroneous, or for which the Scheduling Coordinator has changed. In the renegotiation process, the CAISO may review and propose modifications to such values, and may require the Scheduling Coordinator to provide updated information to support continuation of such values.

39.7.1.3.2.2 Informational Filings with FERC

The CAISO shall make an informational filing with FERC of any adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.5.1, 30.4.5.2, and 30.4.5.4, any Opportunity Costs calculated pursuant to Section 30.4.6.2 or negotiated pursuant to Section 30.4.6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy or operations and maintenance values were established.

* * * * *

40.6.8 Use of Generated Bids

(a) **Day-Ahead Market.** Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market.

(b) **Real-Time Market.** Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market.

(c) **Partial Bids for RA Capacity.** If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage.

(d) **Exemptions.** Notwithstanding any of the provisions of Section 40.6.8, for the following resource types providing Resource Adequacy Capacity, the CAISO only inserts a Bid in the Day-Ahead Market or Real-Time Market where the generally applicable bidding rules in Section 30 call for bid insertion: Use-Limited Resource, Non-Generator Resource, Variable Energy Resource, Hydroelectric Generating Unit (including Run-of River resources), Proxy Demand Resource, Reliability Demand Response Resource, Participating Load, including Pumping Load, Combined Heat and Power Resource, Conditionally Available Resource, Non-Dispatchable Resource, and resources providing Regulatory Must-Take Generation.

(e) **NRS-RA Resources.** The CAISO will submit a Generated Bid in the Day-Ahead Market for a Non-Resource-Specific System Resource in each RAAIM assessment hour, to the extent that the resource provides Resource Adequacy Capacity subject to the requirements of Section 40.6.1 and does not submit an outage request or Bid for the entire amount of that Resource Adequacy Capacity. Aside from where the generally applicable bidding rules in Section 30 call for Bid insertion, the CAISO will not submit a Generated Bid in the Real-Time Market for a Non-Resource-Specific System Resource that fails to meet its bidding obligations under Section 40.6.2. A Bid inserted for the Real-Time Market pursuant to the generally applicable bidding rules in Section 30 may not necessarily cover the full Real-Time Market obligation under Section 40.6.2 and the resource may thus remain exposed to Non-Availability Charges.

40.6.8.1 Generated Bids for NRS-RA Resources

Generated Bids to be submitted by the CAISO pursuant to Section 40.6.8 for Non-Resource-Specific System Resources that provide Resource Adequacy Capacity shall be calculated in accordance with this Section 40.6.8.1.

40.6.8.1.1 Calculation Options for Generated Bids

The Scheduling Coordinator for each Non-Resource-Specific System Resource that provides Resource Adequacy Capacity shall select the price taker option, LMP-based option, or negotiated price option as the methodology for calculating the Generated Bids to be submitted by the CAISO under Section 40.6.8

for both the DAM and RTMs. If no selection is made, the CAISO will apply the price taker option to calculate the Generated Bids. For the first ninety (90) days after a resource becomes a Non-Resource-Specific System Resource, the calculation of Generated Bids for Resource Adequacy capacity is limited to the price taker option or negotiated price option.

40.6.8.1.2 Price Taker Option

The price taker option is a Generated Bid of $0/MWh plus the CAISO's estimate of the applicable Grid Management Charge per MWh based on the gross amount of MWh scheduled in the DAM and RTM.

40.6.8.1.3 LMP-Based Option

The LMP-based option calculates the Generated Bid as the weighted average of the lowest quartile of LMPs, at the Intertie point designated for the Non-Resource-Specific System Resource's Resource Adequacy Capacity in the Supply Plan, during periods in which the resource was dispatched in the preceding ninety (90) days for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Generated Bid curve. Each Bid segment created under the LMP-based option for Generated Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP-based Generated Bid. The feasibility test is designed to avoid excessive volatility of the Generated Bid under the LMP-based option that could result when calculated based on a relatively small number of prices. If the Scheduling Coordinator for the Non-Resource-Specific System Resource elects the LMP-based method, it must additionally select either the price taker method or the negotiated-rate method as the alternative calculation method for the Generated Bids in the event that the feasibility test fails for the LMP-based method.

* * * * *

40.6.8.1.5 Partial Bids

If a Scheduling Coordinator for a Non-Resource-Specific System Resource that provides Resource Adequacy Capacity submits a Bid for a MW quantity less than the Resource Adequacy Capacity identified in the resource's Supply Plan, the CAISO will insert a Generated Bid only for the remaining Resource Adequacy Capacity by extending the last segment of the resource's bid curve to the full quantity (MWh) of the Resource Adequacy obligation.

40.6.8.1.6 [Not Used]

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Appendix A

Master Definitions Supplement

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- Bid Costs

The costs for resources manifested in the Bid components submitted, which include the Start-Up Bid Cost, Minimum Load Bid Cost, Energy Bid Cost, Transition Bid Cost, Pump Shut-Down Cost, Pumping Cost, Ancillary Services Bid Cost, and RUC Availability Payment.

* * * * *

- Commitment Cost Multiplier

The percentage amount by which the Proxy Costs are multiplied in calculating the Default Commitment Cost Bids, which is equal to one hundred twenty five percent (125%).

* * * * *

- Conditionally Available Resource

A resource that has demonstrated to the CAISO's reasonable satisfaction that it has one or more regulatory or operational limits that are not eligible use limits pursuant to Section 30.4.6.1.1 and that faces frequent and recurring periods of unavailability because of those limitations. A resource can be both a Conditionally Available Resource and a Use-Limited Resource if it has eligible use limits and also meets the definition of a Conditionally Available Resource.

* * * * *

- Default Commitment Cost Bids

Default Commitment Cost Bids are Default Start-Up Bids, Default Minimum Load Bids, and Default Transition Bids.

* * * * *

- Default Energy Bid

The cost-based Energy Bid Curve calculated by the CAISO pursuant to Section 39, and used, among other things, in Local Market Power Mitigation.

* * * * *

- Default Energy Bid Multiplier

The percentage amount by which the variable costs used to calculate the Default Energy Bid under Variable Cost Option are multiplied, which is equal to one hundred ten percent (110%).

- Default Minimum Load Bid

The CAISO's calculation of a resource's Minimum Load Cost pursuant to Section 30.4.

* * * * *

- Default Start-Up Bid

The CAISO's calculation of a resource's Start-Up Cost Curve pursuant to Section 30.4.

* * * * *

- Default Transition Bid

A resource's Transition Costs calculated by the CAISO pursuant to Section 30.4.

* * * * *

- Documentation of Contemporaneously Available Information

Documents that exist when a Reference Level Change Request is submitted that show the price of fuel or fuel-equivalent is based on next-day procurement for the Day-Ahead Market, and is based on same-day or next-day procurement for the Real-Time Market, except for non-standard gas trading days, in which case the documents must show the price of procurement for fuel or fuel-equivalent no sooner than the most recent standard gas trading day. Such documentation may include: quotes from natural gas suppliers; gas purchase invoices; evidence of a bid price that was part of an unsuccessful good faith effort to purchase fuel or fuel-equivalent; or other appropriate documentation demonstrating fuel costs or fuel-equivalent costs.

* * * * *

- Energy Bid Cost

An amount equal to the integral of the Energy Bid for resources operating above PMin.

* * * * *

- Generated Bid

A post-market Clean Bid generated by the CAISO, using the applicable Default Energy Bid and Default Commitment Cost Bids, in accordance with the provisions of Section 40 or other applicable provisions of the CAISO Tariff when a Bid is not submitted by a Scheduling Coordinator and is required for a Resource Adequacy requirement, an Ancillary Services Award, a RUC Award, a Day-Ahead Schedule, or as required by Section 30.7.3.5.

* * * * *

- IFM AS Bid Cost

The Bid Cost for Ancillary Service capacity a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.6.

* * * * *

- IFM Energy Bid Cost

The Energy Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.5.

* * * * *

- IFM Minimum Load Cost

The Minimum Load Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.2.

* * * * *

- IFM Pump Shut-Down Cost

The Pump Shut-Down Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.3.

* * * * *

- IFM Pumping Cost

The Pumping Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.4.

* * * * *

- IFM Start-Up Cost

The Start-Up Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.1.

* * * * *

- IFM Transition Cost

The Transition Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.7.

* * * * *

- Minimum Load Bid

The Bid component that indicates the Minimum Load Cost for the Generating Unit, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource specified by a non-negative number in dollars per hour ($/hr), which applies for the entire Trading Day for which it is submitted. Minimum Load Bids are subject to modification pursuant to the rules specified in Sections 30.7.10 and 30.11.

- Minimum Load Bid Cost

The Minimum Load Costs submitted in a Minimum Load Bid as modified pursuant to Sections 30.7.10 and 30.11 used for purposes of clearing the applicable CAISO Market Process and for Bid Cost Recovery.

- Minimum Load Costs

The costs a Generating Unit, Resource-Specific System Resource, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource incurs operating at Minimum Load, which in the case of

Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource must be non-negative and may be adjusted pursuant to Section 30.7.10.2, if applicable.

* * * * *

- Minimum Load Opportunity Costs

An adder consisting of the estimated profits foregone by a Use-Limited Resource with a limitation on its number of run-hours that satisfies the definition of a Use-Limited Resource and applies for a time period that satisfies the requirements of Section 30.4.6.1, if the Use-Limited Resource had one less run-hour in the time period.

* * * * *

- Non-Resource-Specific System Resource

A System Resource that is not a Resource-Specific System Resource.

* * * * *

- Projected Proxy Cost

A calculation of a resource's Default Start-Up Bids and Default Minimum Load Bids for a prospective period used to determine the maximum Registered Cost for the resource, as set forth in Section 39.6.1.6 for a thirty (30)-day period pursuant to Section 30.4.

* * * * *

- Proxy Cost

The Proxy Start-Up Costs, Proxy Transition Costs, or Proxy Minimum Load Costs of a generating resource for which the operating cost is calculated as an approximation of the actual operating cost pursuant to Section 30.4.5.

* * * * *

- Proxy Minimum Load Cost

A resource's Minimum Load Costs, calculated pursuant to the methodology specified in Section 30.4.5.

- Proxy Start-Up Cost

A resource's Start-Up Costs, calculated pursuant to the methodology specified in Section 30.4.5.

- Proxy Transition Cost

A resource's Transition Costs, calculated pursuant to the methodology specified in Section 30.4.5.

*** * * * ***

- Reasonableness Threshold

The cost-based criteria the CAISO uses to evaluate Reference Level Change Requests through an automated process, which represents a reasonable cost-based Energy Bid, Start-Up Bid, and Minimum Load Bid, calibrated to a resource's costs as described in Section 30.11.

*** * * * ***

- Reference Levels

A Default Start-Up Bid, Default Minimum Load Bid, and Default Energy Bid.

- Reference Level Change Request

A change requested by a Scheduling Coordinator to a resource's Reference Levels pursuant to Section 30.11.

*** * * * ***

- Registered Cost

The cost basis of a generating resource for which the operating cost is determined from registered values pursuant to Section 30.4.7.

* * * * *

- Revised Default Commitment Cost Bids

Default Commitment Cost Bids produced as part of an accepted automated or manual Reference Level Change Request, which are calculated without including the Commitment Cost Multiplier.

- Revised Default Energy Bid

The Default Energy Bid produced as part of an accepted automated or manual Reference Level Change Request, which are calculated without including the Default Energy Bid Multiplier.

*** * * * ***

- RTM AS Bid Cost

The Bid Cost for Ancillary Service capacity a Scheduling Coordinator may be eligible to recover pursuant to Section 11.8.4.1.6.

*** * * * ***

- RTM Energy Bid Cost

The Energy Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.5.

* * * * *

- RTM Minimum Load Cost

The Minimum Load Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.2.

* * * * *

- RTM Pump Shut-Down Cost

The Pump Shut-Down Cost a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.3.

- RTM Pumping Cost

The Pumping Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.4.

* * * * *

- RTM Start-Up Cost

The Start-Up Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.1.

* * * * *

- RTM Transition Cost

The Transition Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.7.

*** * * * ***

- RUC Minimum Load Cost

The Minimum Load Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.3.1.2.

*** * * * ***

- RUC Start-Up Cost

The Start-Up Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.3.1.1.

- RUC Transition Cost

The Transition Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.3.1.4.

*** * * * ***

- Start-Up Bid

The Bid component that indicates the Start-Up Time and Start-Up Cost curves for the Generating Unit, which applies for the entire Trading Day for which it is submitted. Start-Up Bids are subject to modification pursuant to the rules set forth in Sections 30.7.8 and 30.11.

- Start-Up Bid Cost

The Start-Up Costs submitted in a Start-Up Bid as modified pursuant to Sections 30.7.8 and 30.11, and used for purposes of the determination of Bid Cost Recovery.

*** * * * ***

- Start-Up Cost Curve

The format of the Start-Up Bid or the Default Start-Up Bids that must be strictly monotonically increasing non-negative staircase curves, of up to three (3) segments, which represent a function of Start-Up Cost versus down time.

*** * * * ***

- Start-Up Opportunity Costs

An adder consisting of the estimated profits foregone by a Use-Limited Resource with a limitation on its number of starts that satisfies the definition of a Use-Limited Resource and applies for a time period that satisfies the requirements of Section 30.4.6.1, if the Use-Limited Resource had one less start in the time period.

* * * * *

- [Not Used]

*** * * * ***

- Transition Bid

The Bid component that indicates the Transition Cost to transition a Multi-Stage Generating Resource from one MSG Configuration to another. Transition Bids are subject to modification pursuant to the rules specified in Section 30.7.11.

- Transition Bid Cost

The Transition Cost submitted in a Transition Bid as modified pursuant to Sections 30.7.8 and 30.11, and used for purposes of Bid Cost Recovery.

*** * * * ***

- Transition Opportunity Cost

Costs derived from the number of Start-Ups required for the Multi-Stage Generating Resource to achieve a specific MSG Configuration.

*** * * * ***

- Use-Limited Resource

A resource demonstrated to be a Use-Limited Resource pursuant to Section 30.4.6.1.1.

* * * * *

- Variable Energy Opportunity Costs

An adder consisting of the estimated profits foregone by a Use-Limited Resource with a limitation on its Energy output that satisfies the definition of a Use-Limited Resource and applies for a time period that satisfies the requirements of Section 30.4.6.1, if the Use-Limited Resource had one less megawatt-hour of Energy output in the time period.

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APPENDIX G

Pro Forma Reliability Must-Run Contract

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ARTICLE 6

OBLIGATIONS TO PARTICIPATE IN CAISO MARKETS

6.1 Must-Offer Obligation

(a) All Units are subject to all applicable CAISO Tariff provisions based on resource type and all applicable Resource Adequacy CAISO Tariff provisions, including the must-offer obligation to submit Energy, Ancillary Services, and Residual Unit Commitment bids for all RMR Contract Capacity in all hours as applicable. Consistent with Section 40 of the CAISO Tariff, Units subject to this Agreement will be subject to Resource Adequacy bid generation provisions unless otherwise exempted pursuant to CAISO Tariff Section 40.

(b) All Units must seek to establish a major maintenance adder pursuant to CAISO Tariff Section 30.4.5.4.

(c) If the Unit has an eligible use limit Owner must establish an Opportunity Cost, if applicable under CAISO Tariff Section 30.4.6. In addition, Owner must provide on Schedule L, on an annual basis, the number of remaining start-ups, run hours and MWhs for each Unit prior to the need for Capital Items to perform major maintenance. If the resource can safely provide the reliability service that is needed for the Contract Year in issue, CAISO may direct Owner to include these limits in the Opportunity Cost calculation process established under CAISO Tariff Section 30.4.6.

(d) Owner has the obligation to submit marginal cost-based bids that include 100 percent of Commitment Costs using the Proxy Cost Methodology set forth in CAISO Tariff Section 30.4.5, including any major maintenance adder and Opportunity Cost using limits established under Section 6.1(c) and calculated pursuant to CAISO Tariff Section 30.4.5. Marginal cost-based Commitment Cost and Energy Bids must be based on the same cost-based components used in CAISO's generated Proxy Costs and Variable Cost Default Energy Bids set forth in the CAISO Tariff and applicable CAISO BPM, plus 100 percent of any approved adders. Cost-based Ancillary Services and Residual Unit Commitment bids must equal $0/MW. Units may not exercise any bidding flexibility with respect to Commitment Cost or Energy bidding with the exception of fuel costs, where the fuel cost component can be higher than the price reflected in the CAISO Gas Price Index if the actual fuel costs exceed the Gas Price Index. The Owner shall procure all required fuel for operation of the Unit using prudent and good utility practice.

(e) For Units exempt from bid insertion, CAISO will monitor compliance with the bidding obligation.

(f) If the Unit has eligible use-limits under the CAISO Tariff or this Agreement, CAISO may order Owner to submit an appropriate outage card pursuant to the applicable CAISO BPM if CAISO determines that participation in CAISO Markets would impair CAISO's ability to dispatch the Unit to meet reliability needs at other times during the Contract Year.

* * * * *

APPENDIX II

Market-Based Rate Authority Suspension

4. Minimum Load, Start-Up, and Transition Costs

4.1. The Scheduling Coordinator responsible for submitting the resource's Minimum Load and Start-Up Costs for the resources of Market Participants subject to this Appendix will not be entitled to select the Registered Cost option available under Section 30.4.7 and can only select the Proxy Cost option as specified in Section 30.4.5 of the CAISO Tariff for their Minimum Load and Start-Up Costs.

4.2. If the resource is registered with the CAISO as a Multi-Stage Generating Unit resource, the Scheduling Coordinator may only register a Transition Cost of $0 per MW hour.

4.3. If the resource lacks a Start-Up or Minimum Load Cost in any market intervals, the CAISO will insert the Start-Up or Minimum Load Costs calculated based on the Proxy Cost option.

Attachment B – Marked Tariff

Commitment Costs and Default Energy Bid Enhancements

California Independent System Operator Corporation

July 9, 2020

4.12.1 General Responsibilities

4.12.1.1 Operate Pursuant to Relevant Provisions of CAISO Tariff

Resource-Specific System Resource owners shall operate, or cause their facilities to be operated, in accordance with the relevant provisions of this CAISO Tariff, including but not limited to the following.

(i) A Resource-Specific System Resource shall only be eligible for Bid Cost Recovery if the Resource-Specific System Resource has complied with a Start-Up Instruction or Dispatch Instruction issued by the CAISO as specified in Section 11.8.

(ii) In order to be eligible for Bid Cost Recovery ~~pursuant to Sections 30.4 and 30.5.2.4~~, a Resource-Specific System Resource owner shall ensure that its Scheduling Coordinator makes an election for Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids pursuant to Sections 30.4 and 30.5.2.4.

(iii) A Resource-Specific System Resource owner shall ensure that any Ancillary Services Bids submitted by its Scheduling Coordinator are submitted in accordance with Section 30.5.2.6.

(iv) Owners of Dynamic Resource-Specific System Resources that are Resource Adequacy Resources shall comply with additional availability requirements to the extent required by Section 40.6.5.1.

(v) Each Resource-Specific System Resource owner shall immediately inform the CAISO, through its respective Scheduling Coordinator and using the CAISO's outage management system as described in Section 9, of any change or potential change in the current status of any Resource-Specific System Resource that may affect a submitted Bid. This will include, but not be limited to, any change in status of equipment that could affect the maximum output of a Resource-Specific System Resource, the Minimum Load of a Resource-Specific System Resource, or the ability of a Resource-Specific System Resource to provide Ancillary Services in accordance with its Bid.

(vi) In the event that a Resource-Specific System Resource owner cannot meet its Generation schedule as specified in the Day-Ahead Schedule, or comply with a Dispatch Instruction, whether due to a Resource-Specific System Resource trip or the loss of a piece of equipment causing a reduction in capacity or output, the Resource-Specific System Resource owner shall notify the CAISO, through its Scheduling Coordinator, at once. If a Resource-Specific System Resource owner will not be able to meet a time commitment or requires the cancellation of a Resource-Specific System Resource Start-Up, it shall notify the CAISO, through its Scheduling Coordinator, at once.

*** * * * ***

6.5.3 Day-Ahead Market Communications

6.5.3.1 Communications with Scheduling Coordinators

6.5.3.1.1 Prior to 6:00 a.m., the CAISO will continuously screen Inter-SC Trades of Energy for the DAM submitted by Scheduling Coordinators and will provide feedback to the Scheduling Coordinators about the consistency and validity of these Inter-SC Trades based on information available to the CAISO.

6.5.3.1.2 Between 6:00 a.m. and the end of the Day-Ahead Inter-SC Trade Period, the CAISO performs the validation of Inter-SC Trades of Energy for the DAM and will notify the participants of the status of these Inter-SC Trades.

6.5.3.1.3 Between 5:00 a.m. and 10:00 a.m., the CAISO will provide feedback to Scheduling Coordinators about their validated ETC and TOR quantities, and calculated Default Energy Bids curves and in addition, the RMR Proxy Bids for Energy and the Minimum Load Bid and Start-Up ~~Cost~~ Bid curves for Legacy RMR Units.

6.5.3.1.4 After the close of the DAM bidding at 10:00 a.m., the CAISO will send a message to the Scheduling Coordinators regarding the outcome of the Bid validation.

6.5.3.1.5 By 1:00 p.m., the CAISO will publish the result of the DAM and the resource will be flagged if it is being dispatched under its Legacy RMR Contract and will be deemed an RMR Dispatch Notice under the Legacy RMR Contract.

6.5.3.1.6 After the results of the DAM are published by 1:00 p.m., the CAISO performs the Inter-SC Trade of Energy post-market validation and communicates the results back to the applicable Scheduling

Coordinator.

6.5.3.1.7 The results of the Day-Ahead Market will be published by 1:00 p.m. and will include:

(a) Unit Commitment status for resources committed in the IFM;

(b) Day-Ahead Schedules and prices;

(c) Day-Ahead AS Awards and prices;

(d) RUC Awards and RUC Capacity and resource-specific RUC Prices;

(e) RUC Start-Up Instructions;

(f) Start-Up Instructions resulting from the ELC Process;

(g) Post-market summary of Day-Ahead and Real-Time Energy Schedules, Ancillary Service Awards, RMR Dispatches, and Legacy RMR Units;

(h) Day-Ahead final resource Bid mitigation results; and

(i) Day-Ahead finally qualified Load following capacity.

6.5.3.1.8 All Expected Energy results will be published at one (1) day after the Trading Day and will include post-market Energy accounting results for Settlement calculations.

6.5.3.2 Public Market Information

6.5.3.2.1 Before 10:00 a.m. one (1) day before the Operating Day the CAISO will publish updated Outage information regarding the transmission system on OASIS. The updated Outage information will include planned and actual Outage events per Transmission Interface, including Outage description, Outage start time and end time, and rating of the curtailed line.

6.5.3.2.2 The results of the Day-Ahead Market will be published on OASIS by 1:00 p.m. and will include:

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6.5.6.1.2 Start-Up and Minimum Load Costs

Within seven (7) days after the Trading Day, the CAISO will publish via OASIS ~~all~~total Start-Up Costs and Minimum Load Costs for CAISO committed resources.

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8.4.1.2 Regulation Energy Management

The CAISO will make Regulation Energy Management available to Scheduling Coordinators for Non-Generator Resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation. A Scheduling Coordinator for a resource using Regulation Energy Management may submit a Regulation Bid for capacity (MW) of up to four (4) times the maximum Energy (MWh) the resource can generate or curtail for fifteen (15) minutes after issuance of a Dispatch Instruction. In the Real-Time Market, a Scheduling Coordinator for a resource using Regulation Energy Management will produce energy as needed to satisfy the sixty (60) minute continuous Energy requirement for Regulation Awards in the Day-Ahead Market.

Scheduling Coordinators may request to use Regulation Energy Management for these Non-Generator Resources by submitting a request to certify such a resource to provide Regulation using Regulation Energy Management. The owner or operator of a Resource using Regulation Energy Management must execute both a Participating Generator Agreement and/or Participating Load Agreement and may provide only Regulation in the CAISO Market. A resource using Regulation Energy Management may not provide Energy other than Energy associated with Regulation. Scheduling Coordinators for Resources using Regulation Energy Management may define a Ramp Rate for operating as Generation and a Ramp Rate for operating as Load, respectively. These resources shall comply with the requirements to provide Regulation as specified in this Section 8, Appendix K, and the CAISO's Operating Procedures, including the requirement to undergo a market simulation using Regulation Energy Management as part of the certification procedure.

Scheduling Coordinators for resources using Regulation Energy Management shall register these resources in the Master File. Scheduling Coordinators may only submit Bids for Regulation Up and Regulation Down and Mileage for these resources. Scheduling Coordinators may not submit Energy Bids, Energy Self-Schedules, Residual Unit Commitment Bids, or Ancillary Service Bids other than Regulation and Mileage for these resources. Scheduling Coordinators may not submit any type of commitment costs as part of their Regulation Up and Regulation Down Bids for resources using Regulation Energy Management, including Start-Up Bids~~Cost~~, Minimum Load ~~Cost~~Bids, Pumping Cost or

Pump Shut-Down Cost Bids, or Transition Bids~~Cost~~. All other bidding rules for Regulation set forth in Section 30 shall apply to resources using Regulation Energy Management.

The CAISO will settle Dispatches from resources using Regulation Energy Management as energy. The portion of Demand of Non-Generator Resources using Regulation Energy Management that is dispatched as Regulation in any Settlement Interval shall not be considered Measured Demand for purposes of allocating payments and charges pursuant to Section 11 during that Settlement Interval.

The CAISO shall control the resource's operating set point through its Energy Management System with the objective of maintaining the resource's operating set point at its preferred operating point. In the Day-Ahead Market and FMM, the procurement of Regulation from resources using Regulation Energy Management will not be constrained by the resource's MWh limit to generate, curtail the consumption of, or consume Energy continuously. In the Real-Time Dispatch, the CAISO will base the Dispatches on the resource's capability to provide Regulation. When the resource has a physical MWh limit, the CAISO will observe the resource's MWh constraint during Real-Time Dispatch and will assess whether the CAISO can support the resource's self-provided Regulation capacity or Regulation award with Real-Time Market Dispatches. To the extent the CAISO determines in the Integrated Forward Market or FMM that the MWh constraint of resources using Regulation Energy Management limits the capability of the CAISO, through Real-time Dispatch, to support these resources' self-provided Regulation capacity or Regulation awards, the CAISO may disqualify resources using Regulation Energy Management on a pro rata basis across the System Region from providing Regulation, which shall result in the rescission of the disqualified portion of the resources' self-provided or awarded Regulation capacity payments.

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11.8 Bid Cost Recovery

For purposes of determining the Unrecovered Bid Cost Uplift Payments for each Bid Cost Recovery Eligible Resource as determined in Section 11.8.5 and the allocation of Unrecovered Bid Cost Uplift Payments for each Settlement Interval, the CAISO shall sequentially calculate the Bid Costs, which can be positive (IFM Bid Cost Shortfall, RUC Bid Cost Shortfall, or RTM Bid Cost Shortfall) or negative (IFM

Bid Cost Surplus, RUC Bid Cost Surplus, or RTM Bid Cost Surplus) in the IFM, RUC, and the Real-Time Market, as the algebraic difference between the respective IFM Bid Cost, RUC Bid Cost, or RTM Bid Cost and the IFM Market Revenues, RUC Market Revenues, or RTM Market Revenues as further described below in this Section 11.8. The RTM Energy Bid Costs and RTM Market Revenues include the FMM Energy Bid Costs. In any Settlement Interval a resource is eligible for Bid Cost Recovery payments pursuant to the rules described in the subsections of Section 11.8 and Section 11.17. Bid Cost Recovery Eligible Resources for different MSS Operators are supply resources listed in the applicable MSS Agreement. All Bid Costs shall be based on Bids as mitigated pursuant to the requirements specified in Section 39.7. Virtual Awards are not eligible for Bid Cost Recovery. Virtual Awards are eligible for make-whole payments due to price corrections pursuant to Section 11.21.2. In order to be eligible for Bid Cost Recovery, Non-Dynamic Resource-Specific System Resources must provide to the CAISO SCADA data by telemetry to the CAISO's EMS in accordance with Section 4.12.3 demonstrating that they have performed in accordance with their CAISO commitments. Scheduling Coordinators for Non-Generator Resources are not eligible to recover Start-Up Bid Costs, Minimum Load Bid Costs, Pumping Costs, Pump Shut-Down Costs, or Transition Bid Costs but are eligible to recover Energy Bid Costs, RUC Availability Payments and Ancillary Service Bid Costs.

11.8.1 CAISO Determination ~~O~~of Self-Commitment Periods

For the purposes of identifying the periods during which a Bid Cost Recovery Eligible Resource is deemed self-committed and thus ineligible for Start-Up Bid Costs, Transition Bid Costs, Minimum Load Bid Costs, IFM Pump Shut-Down Costs and IFM Pumping Costs, the CAISO derives the Self-Commitment Periods as described below. The CAISO will determine the Self-Commitment Periods for Multi-Stage Generating Resources based on the applicable MSG Configuration. MSS resources designated for Load following are considered to be self-committed if they have been scheduled with non-zero Load following capacity, or are otherwise used to follow Load in the Real-Time. The IFM Self-Commitment Period and RUC Self-Commitment Period~~s~~ will be available as part of the Day-Ahead Market results provided to the applicable Scheduling Coordinator. The interim RTM Self-Commitment Periods as reflected in the RTM will be available as part of the RTM results for the relevant Trading Hour as provided to the applicable Scheduling Coordinator. The final RTM Self-Commitment Period is determined ex-post for Settlements purposes. ELS Resources committed through the ELC Process described in Section 31.7 are considered to have been committed in the IFM Commitment Period for the applicable Trading Day for the purposes of determining BCR settlement in this ~~s~~Section 11.8.

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11.8.1.3 Multi-Stage Generating Resource Start-Up Bid Costs, Minimum Load Bid Costs, or Transition Bid Costs

For the settlement of the Multi-Stage Generating Resource Start-Up Bid Costs, Minimum Load Bid Costs, and Transition Bid Costs in the IFM, RUC, and RTM, the CAISO will determine the applicable Commitment Period and select the applicable Start-Up Bid Costs, Minimum Load Bid Costs, and Transition Bid Costs based on the following rules.

(1) In any given Settlement Interval, the CAISO will first apply the following rules to determine the applicable Start-Up Bid Costs and Transition Bid Costs for the Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period and/or RUC Commitment Period MSG Configuration(s) are different from the RTM CAISO Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Cost and Transition Bid Cost will be settled based on the RTM CAISO Commitment Period MSG Configuration Start-Up Bid Costs, and Transition Bid Costs, as described in Section 11.8.4.1.

(b) there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period in any MSG Configuration and there is also a RTM Self-Commitment Period in any MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Bid Costs and Transition Bid Costs, as described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this

Section below.

(c) the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration is the same as the CAISO RTM Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Bid Costs and Transition Bid Costs described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (3) of this Section below.

(d) the IFM Self-Commitment Period and RUC Self-Commitment Period MSG Configuration(s) are the same as the CAISO RTM Commitment Period MSG Configuration, then the Multi-Stage Generating Resource's Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO RTM Commitment Period MSG Configuration Start-Up Bid Costs and Transition Bid Costs as described in Section 11.8.4.1.

(2) For the purpose of determining which MSG Configuration Minimum Load Bid Costs will apply in any given Commitment Interval, the CAISO will apply the following rules.

(a) If there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period, the CAISO will calculate the IFM Minimum Load Costs and/or RUC Minimum Load Costs, pursuant to Section 11.8.2.1 or 11.8.3.1, respectively, based on the MSG Configuration committed in the IFM or RUC.

(b) For purposes of determining the MSG Configuration Minimum Load Bid Costs included in the RTM Minimum Load Costs calculated pursuant to Section 11.8.4.1.2, the CAISO will use the difference between the amounts determined under (i) and (ii) below.

(i) The CAISO will calculate the RTM MSG Configuration Minimum Load Bid Costs as the RTM Minimum Load Costs attributed to the MSG Configuration committed in the RTM, whether that MSG Configuration is Self-Scheduled or CAISO-committed.

(ii) The CAISO will determine one of the two applicable amounts:

a. If there is a Real-Time Market Self-Schedule, the maximum of (A) the Minimum Load Bid Costs attributed to the MSG Configuration either self-Scheduled or CAISO-committed in the IFM or RUC; and (B) the Minimum Load Cost attributed to the MSG Configuration Self-Scheduled in the RTM.

b. If there is no Real-Time Market Self-Schedule, the Minimum Load Bid Costs attributed to the MSG Configuration either self-Scheduled or CAISO-committed in the IFM or RUC.

(3) In any given Settlement Interval, after the rules specified in part (1) and (2) above of this Section have been executed, the CAISO will apply the following rules to determine whether the IFM Start-Up Cost or RUC Start-Up Cost, IFM Minimum Load Cost or RUC Minimum Load Cost, and IFM Transition Cost or RUC Transition Cost apply for Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period MSG Configuration is different from the CAISO RUC Commitment Period MSG Configuration the Multi-Stage Generating Resource's Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost will be settled based on the CAISO RUC Commitment Period MSG Configuration Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost as described in Section 11.8.3.1.

(b) the CAISO IFM Commitment Period MSG Configuration is the same as the CAISO RUC Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost will be based on the CAISO IFM Commitment Period MSG Configuration Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost as described in Section 11.8.2.1.

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11.8.2.1 IFM Bid Cost Calculation

For each Settlement Interval, the CAISO shall calculate IFM Bid Cost for each Bid Cost Recovery Eligible Resource as the algebraic sum of the IFM Start-Up Cost, IFM Transition Cost, IFM Minimum Load Cost, IFM Pump Shut-Down Cost, IFM Energy Bid Cost, IFM Pumping Cost, and IFM AS Bid Cost. For Multi-Stage Generating Resources, in addition to the specific IFM Bid Cost rules described in Section 11.8.2.1, the CAISO will apply the rules described in Section 11.8.1.3 to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Cost, Transition Bid Cost, and Minimum Load Bid Cost in any given Settlement Interval. For Multi-Stage Generating Resources, the incremental IFM Start-Up Costs, IFM Minimum Load Costs, and IFM Transition Costs to provide Energy Scheduled in the Day-Ahead Schedule or awarded RUC or Ancillary Service capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the IFM rules specified in Section 31.3. For RMR Resources, the CAISO shall calculate the IFM Bid Cost as the algebraic sum of the IFM Start-Up Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, IFM Transition Cost adjusted to remove Opportunity Costs and Major Maintenance Adder Costs, IFM Minimum Load Costs adjusted to remove Opportunity Costs and Major Maintenance Adder Costs, IFM Energy Bid Cost adjusted to remove Opportunity Costs, and IFM AS Bid Cost.

11.8.2.1.1 IFM Start-Up Cost

The IFM Start-Up Cost for any IFM Commitment Period shall be equal to the Start-Up Bid Costs ~~submitted by the Scheduling Coordinator~~ applicable to ~~the CAISO for~~ the IFM divided by the number of Settlement Intervals within the applicable IFM Commitment Period. For each Settlement Interval, only the IFM Start-Up Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the IFM Start-Up Costs for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration. The following rules shall apply sequentially to qualify the IFM Start-Up Cost in an IFM Commitment Period:

(a) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is an IFM Self-Commitment Period within or overlapping with that IFM Commitment Period.

(b) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if the Bid Cost

Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in the Day-Ahead Market anywhere within the applicable IFM Commitment Period.

(c) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is no actual Start-Up at the start of the applicable IFM Commitment Period because the IFM Commitment Period is the continuation of an IFM Commitment Period, RUC Commitment Period, or RTM Commitment Period from the previous Trading Day.

(d) If an IFM Start-Up is terminated in the Real-Time within the applicable IFM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource was starting up, the IFM Start-Up Cost for that IFM Commitment Period shall be prorated by the ratio of the Start-Up Time before termination over the total IFM Start-Up Time.

(e) The IFM Start-Up Cost is qualified if an actual Start-Up occurs within the applicable IFM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Intervals that fall within the CAISO IFM Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether the resource's metered Energy is at or above the resource's Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3.

(f) The IFM Start-Up Cost will be qualified if an actual Start-Up occurs earlier than the start of the IFM Commitment Period if the advance Start-Up is a result of a Start-Up instruction issued in a RUC or Real-Time Market process subsequent to the IFM, or the advance Start-Up is uninstructed but is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the targeted IFM Start-Up.

(g) The Start-Up Bid Costs for a Bid Cost Recovery Eligible Resource that is a Short Start Unit committed by the CAISO in the IFM and that further receives a Start-Up Instruction from the CAISO in the Real-Time Market to start within the same CAISO IFM Commitment Period, will be qualified for the CAISO IFM Commitment Period instead of being qualified for the CAISO RTM Commitment Period; and Start-Up Bid Costs for subsequent Start-Ups will be further qualified as specified in Section 11.8.4.1.1(h).

11.8.2.1.2 IFM Minimum Load Cost

The IFM Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Bid Cost ~~submitted to the CAISO in the IFM, and as modified pursuant to Section 30.7.10.2, if~~ applicable to the Integrated Forward Market, divided by the number of Settlement Intervals in a Trading Hour subject to the rules described below.

(a) For each Settlement Interval, only the IFM Minimum Load Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery.

(b) The IFM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is in an IFM Self Commitment Period for the Bid Cost Recovery Eligible Resource; or (2) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule for the applicable Settlement Interval.

(c) If the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits an RMR Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the sum of IFM Minimum Load Costs, adjusted to remove Minimum Load Opportunity Costs and Minimum Load Major Maintenance Costs, are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(d) If a Multi-Stage Generating Resource is committed by the CAISO and receives a Day-Ahead Schedule and subsequently is committed by the CAISO to a lower MSG Configuration where its Minimum Load capacity as registered in the Master File in the

Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration's Minimum Load as registered in the Master File, the resource's IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits an RMR Multi-Stage Generating Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the sum of IFM Minimum Load Costs, adjusted to remove Minimum Load Opportunity Costs and Minimum Load Major Maintenance Costs, are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(e) If the conditions in Sections 11.8.2.1.2 (c) and (d) do not apply, then the IFM Minimum Load Cost for any Settlement Interval is zero if the Bid Cost Recovery Eligible Resource is determined to be Off during the applicable Settlement Interval. For the purposes of determining IFM Minimum Load Cost, a Bid Cost Recovery Eligible Resource is assumed to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its (i) Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and (ii) the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(f) For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. If application of section 11.8.1.3 dictates that the IFM is the ~~c~~Commitment ~~p~~Period, then the calculation of the IFM Minimum Load Costs will depend on whether the IFM ~~CAISO C~~committed MSG Configuration is determined to be On. If it is determined to be On, then, the IFM Minimum Load Costs will be based on the Minimum Load Bid Costs of the IFM committed MSG Configuration. For the purposes of determining IFM Minimum Load Cost for a Multi-Stage Generating Resource, a Bid Cost Recovery Eligible Resource is determined to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its IFM MSG Configuration Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and the Tolerance Band, and the Metered Energy is greater than zero (0)

MWh. Otherwise, such resource is determined to be Off.

(g) The IFM Minimum Load Costs calculation is subject to the Shut-Down State Variable and is disqualified as specified in Section 11.17.2.

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11.8.2.3.2 MSS Elected Net Settlement

For an MSS Operator that has elected net Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the Energy ~~b~~Bid ~~c~~Costs and revenues for IFM Bid Cost Recovery is settled at the MSS level. The IFM Bid Cost as described in Section 11.8.2.1 above and IFM Market Revenue as provided in Section 11.8.2.2 above, of each MSS will be, respectively, the total of the IFM Bid Costs and IFM Market Revenues over all BCR Eligible Resources within the MSS where each BCR Eligible Resource's IFM Market Revenues for its Energy shall be calculated as described in Section 11.2.3.2 at the relevant IFM MSS price. The IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for Energy and AS are first calculated separately for the MSS for each Trading Hour of the Trading Day with qualified Start-Up Bid Costs and qualified Minimum Load Bid Costs included in the IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for Energy calculation. The MSS's overall IFM Bid Cost Shortfall or IFM Bid Cost Surplus is then calculated as the algebraic sum of the IFM Bid Cost Shortfall or IFM Bid Cost Surplus for Energy and the IFM Bid Cost Shortfall or IFM Bid Cost Surplus for AS for each Trading Hour.

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11.8.3.1 RUC Bid Cost Calculation

For each Settlement Interval, the CAISO shall determine the RUC Bid Cost for a Bid Cost Recovery Eligible Resource as the algebraic sum of the RUC Start-Up Cost, RUC Transition Cost, RUC Minimum Load Cost, and RUC Availability Bid Cost. For Multi-Stage Generating Resources, in addition to the specific RUC Bid Cost rules described in Section 11.8.3.1, the rules described in Section 11.8.1.3 will be applied to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Costs, Transition Bid Costs, and Minimum Load Bid Costs~~, as modified pursuant to Section 30.7.10.2, if applicable, in any given Settlement Interval~~. For Multi-Stage Generating Resources, the incremental RUC Start-Up Costs, RUC Minimum Load Costs, and RUC Transition Costs to provide RUC awarded capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the RUC optimization rules in specified in Section 31.5. For each Settlement Interval, the CAISO shall determine the RUC Bid Cost for an RMR Resource as the algebraic sum of the RUC Start-Up Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, and RUC Transition Cost adjusted to remove Opportunity Costs and Major Maintenance Costs.

11.8.3.1.1 RUC Start-Up Cost

The RUC Start-Up Cost for any Settlement Interval in a RUC Commitment Period shall consist of Start-Up Bid Cost of the Bid Cost Recovery Eligible Resource ~~submitted to the CAISO~~ for the applicable RUC Commitment Period divided by the number of Settlement Intervals in the applicable RUC Commitment Period. For each Settlement Interval, only the RUC Start-Up Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RUC Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RUC.

The following rules shall be applied in sequence and shall qualify the RUC Start-Up Cost in a RUC Commitment Period:

(a) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is an IFM Commitment Period within that RUC Commitment Period.

(b) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or is flagged as an RMR Dispatch in the Day-Ahead Schedule anywhere within that RUC Commitment Period.

(c) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is no RUC Start-Up at the start of that RUC Commitment Period because the RUC Commitment Period is the continuation of an IFM Commitment Period, RUC Commitment Period, or RTM Commitment Period from the previous Trading Day.

(d) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Start-Up is delayed beyond the RUC Commitment Period in question or cancelled by the Real-Time Market prior to the Bid Cost Recovery Eligible Resource starting its start-up process.

(e) If a RUC Start-Up is terminated in the Real-Time within the applicable RUC Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the~~,~~ RUC Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the RUC Start-Up Time.

(f) The RUC Start-Up Cost for a RUC Commitment Period is qualified if an actual Start-Up occurs within that RUC Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates that the resource is Off before the time the resource is instructed to be On as specified in its Start~~-~~-Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether its metered Energy is at or above the resource's Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3.

(g) The RUC Start-Up Cost shall be qualified if an actual Start-Up occurs. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period.

11.8.3.1.2 RUC Minimum Load Cost

The RUC Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Bid Cost of the Bid Cost Recovery Eligible Resource, ~~as adjusted pursuant to Section 30.7.10.2, if applicable,~~ divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RUC Minimum Load Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The RUC Minimum Load Cost for any Settlement Interval is zero if: (1) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract or the resource is flagged as an

RMR Dispatch in the Day-Ahead Schedule in that Settlement Interval; (2) the Bid Cost Recovery Eligible Resource is not committed or Dispatched in the Real-time Market in the applicable Settlement Interval; or (3) the applicable Settlement Interval is included in an IFM Commitment Period. For the purposes of determining RUC Minimum Load Cost for a Bid Cost Recovery Eligible Resource, recovery of the RUC Minimum Load Cost~~s~~ is subject to the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of section 11.8.1.3. The RUC Minimum Load Cost calculation will be subject to the Shut-Down State Variable and disqualified as specified in Section 11.17.2.

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11.8.4.1 RTM Bid Cost Calculation

For each Settlement Interval, the CAISO shall calculate RTM Bid Cost for each Bid Cost Recovery Eligible Resource, as the algebraic sum of the RTM Start-Up Cost, RTM Minimum Load Cost, RTM Transition Cost, RTM Pump Shut-Down Cost, RTM Energy Bid Cost, RTM Pumping Cost and RTM AS Bid Cost. For each Settlement Interval, the CAISO shall calculate RTM Bid Cost for each RMR Resource as the algebraic sum of the RTM Start-Up Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, RTM Transition Costs adjusted to remove Opportunity Costs and Major Maintenance Costs, RTM Energy Bid Cost adjusted to remove Opportunity Costs and Major Maintenance Costs, and RTM AS Bid Cost. For Multi-Stage Generating Resources, in addition to the specific RTM Bid Cost rules described in Section 11.8.4.1, the rules described in Section 11.8.1.3 will be applied to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Cost, Transition Bid Cost, and Minimum Load Bid Cost, ~~as modified pursuant to Section 30.7.10.2, if applicable,~~ in a given Settlement Interval. For Multi-Stage Generating Resources, the incremental RTM Start-Up Cost, RTM Minimum Load Cost, ~~as modified pursuant to Section 30.7.10.2, if applicable,~~ and RTM Transition Cost to provide RTM committed Energy or awarded Ancillary Services capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the RTM optimization rules in specified in Section 34.

11.8.4.1.1 RTM Start-Up Cost

For each Settlement Interval of the applicable ~~Real-Time Market~~ RTM Commitment Period, the ~~Real-Time Market~~ RTM Start-Up Cost shall consist of the Start-Up Bid Cost of the Bid Cost Recovery Eligible Resource ~~submitted to the CAISO for~~ applicable to the Real-Time Market divided by the number of Settlement Intervals in the applicable RTM~~Real-Time Market~~ Commitment Period. For each Settlement Interval, only the ~~Real-Time Market~~RTM Start-Up Cost in a CAISO ~~Real-Time Market~~RTM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RTM Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in the RTM. The following rules shall be applied in sequence and shall qualify the ~~Real-Time Market~~RTM Start-Up Cost in an ~~Real-Time Market~~ RTM Commitment Period:

(a) The ~~Real-Time Market~~RTM Start-Up Cost is zero if there is an ~~Real-Time Market~~RTM Self-Commitment Period within the ~~Real-Time Market~~RTM Commitment Period.

(b) The ~~Real-Time Market~~RTM Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource has been manually pre-dispatched under a Legacy RMR Contract or the resource is flagged as an ~~Legacy~~ RMR Dispatch in the Day-Ahead Schedule or Real-Time Market anywhere within that ~~Real-Time Market~~ RTM Commitment Period.

(c) The ~~Real-Time Market~~ RTM Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource is started within the Real-Time Market Commitment Period pursuant to an Exceptional Dispatch issued in accordance with Section 34.11.2 to: (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; or (3) perform PMax testing.

(d) The ~~Real-Time Market~~RTM Start-Up Cost is zero if there is no ~~Real-Time Market~~ RTM Start-Up at the start of that ~~Real-Time Market~~ RTM Commitment Period because the ~~Real-Time Market~~ RTM Commitment Period is the continuation of an IFM Commitment Period or RUC Commitment Period from the previous Trading Day.

(e) If an ~~Real-Time Market~~RTM Start-Up is terminated in the Real-Time within the applicable ~~Real-Time Market~~RTM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the ~~Real-~~

~~Time Market~~ RTM Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the Real-Time Market Start-Up Time.

(f) The ~~Real-Time Market~~RTM Start-Up Cost shall be qualified if an actual Start-Up occurs within that ~~Real-Time Market~~RTM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Interval(s) indicates the unit is Off before the time the resource is instructed to be On as specified in its Start~~-~~-Up Instruction and is On in the Settlement Interval that falls within the CAISO ~~Real-Time Market~~RTM Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether its metered Energy is at or above the resource's Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3. The CAISO will determine that the Multi-Stage Generating Resource is On based on the MSG Configuration that the CAISO has committed in the Real-Time Market.

(g) The ~~Real-Time Market~~RTM Start-Up Cost for an ~~Real-Time Market~~ RTM Commitment Period shall be qualified if an actual Start-Up occurs earlier than the start of the ~~Real-Time~~ RTM Market Start-Up, if the relevant Start-Up is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the ~~Real-Time Market~~RTM Start-Up, otherwise the Start-Up Bid Cost is zero for the ~~Real-Time Market~~ RTM Commitment Period.

(h) For Short-Start Units, the first Start-Up Bid Costs within a CAISO IFM Commitment Period are qualified IFM Start-Up Costs as described above in Section 11.8.2.1.1(g). For subsequent Start-Ups of Short-Start Units after the CAISO Shuts Down a resource and then the CAISO issues a Start-Up Instruction pursuant to a CAISO RTM Commitment Period within the CAISO IFM Commitment Period, the Start-Up Bid Costs shall be qualified as ~~Real-Time~~ RTM Start-Up ~~c~~Costs, provided that the resource actually Shut-Down and Started-Up based on CAISO Shut-Down and Start-Up Instructions.

11.8.4.1.2 RTM Minimum Load Cost

The RTM Minimum Load Cost is the Minimum Load Bid Cost of the Bid Cost Recovery Eligible Resource ~~submitted to the CAISO~~applicable for the Real-Time Market, ~~as adjusted pursuant to Section 30.7.10.2, if~~

~~applicable,~~ divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RTM Minimum Load Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The RTM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is included in a RTM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; (2) the Bid Cost Recovery Eligible Resource has been manually dispatched under a Legacy RMR Contract or the resource has been flagged as an ~~Legacy~~ RMR Dispatch in the Day-Ahead Schedule or the Real-Time Market in that Settlement Interval; (3) for all resources that are not Multi-Stage Generating Resources, that Settlement Interval is included in an IFM Commitment Period or RUC Commitment Period; or (4) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.11.2 for the purpose of performing Ancillary Services testing, pre-commercial operation testing for Generating Units, or PMax testing. A resource's RTM Minimum Load Costs for Bid Cost Recovery purposes are subject to the application of the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of Section 11.8.1.3. For all Bid Cost Recovery Eligible Resources that the CAISO Shuts Down, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its Day-Ahead Schedule that was also from a CAISO commitment, the RTM Minimum Load Costs will include negative Minimum Load Cost Bids for Energy between the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and zero (0) MWhs.

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11.8.4.3.2 MSS Elected Net Settlement

For MSS entities that have elected net Settlement regardless of other MSS optional elections (i.e., Load following or not, or RUC opt-in or out), unlike non-MSS resources, the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus is treated at the MSS level and not at the resource specific level, and is calculated as the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus of all BCR Eligible Resources within the MSS. In calculating the Energy RTM Market Revenue for all the resources within the MSS as provided in Section

11.8.4.2, the CAISO will use the FM~~-~~M MSS Price or the RTD MSS Price, as applicable. The RUC Bid Cost Shortfall, RUC Bid Cost Surplus, ~~and~~ RTM Bid Cost Shortfall, and RTM Bid Cost Surplus for Energy, RUC Availability and Ancillary Services are first calculated separately for the MSS for each Settlement Interval of the Trading Day, with qualified Start-Up Bid Costs, qualified Minimum Load Bid Costs, and qualified Multi-Stage Generator ~~t~~Transition Bid ~~c~~Costs included into the RUC Bid Cost Shortfalls, RUC Bid Cost Surpluses, ~~and~~ RTM Bid Cost Shortfalls, and RTM Bid Cost Surpluses of Energy calculation. The MSS's overall RUC Bid Cost Shortfall or RUC Bid Cost Surplus, and RTM Bid Cost Shortfall or RTM Bid Cost Surplus is then calculated as the algebraic sum of the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus for Energy and the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus for Ancillary Services for each Settlement Interval.

* * * * *

11.8.4.4.1 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric to RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs, and not the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric instead of Day-Ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and not the IFM Market Revenues.

11.8.4.4.2 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs are greater than or equal to zero (0) and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs and the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs are greater than or equal to zero (0) and the IFM Market Revenues are negative the CAISO will apply the Real-Time

Performance Metric instead of the Day-ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and IFM Market Revenues.

11.8.4.4.3 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs are negative and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will not apply Real-Time Performance Metric to the RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs or the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the sum of IFM Energy Bid Costs and the IFM Minimum Load Costs is negative and the IFM Market Revenue is greater than or equal to zero (0), the CAISO will not apply the Real-Time Performance Metric to the IFM Minimum Load Costs, IFM Energy Bid Costs or the IFM Market Revenues.

11.8.4.4.4 If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs, and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Market Revenues but not the RTM Energy Bid Costs or the RUC Minimum Load Costs and RTM Minimum Load Costs. In addition, for the cases described in Sections 11.8.2.1.2 (c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric instead of the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues but not the IFM Minimum Load Costs and IFM Energy Bid Costs.

11.8.4.4.5 If for a given Settlement Interval the absolute value of the resource's Metered Energy, less Regulation Energy and less Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Real-Time Performance Metric to the calculation of the RTM Energy Bid Cost, RUC Minimum Load Cost and RTM Minimum Load Cost, or RTM Market Revenue.

* * * * *

11.13.3 Daily Variable Cost Payment

For each Trading Day, the CAISO shall calculate IFM Bid Cost Recovery Amount described in Section 11.8.2 and RTM Bid Cost Recovery Amount described in Section 11.8.4 for each RMR Resource while adjusting to remove Major Maintenance Cost and Opportunity Cost adders, calculated pursuant to Section 30.4.~~1.1.~~6, including any if the limits used to calculate the Opportunity Cost are established pursuant to Article 6 of the RMR Contract. The RMR Resource shall receive any Unrecovered Bid Cost Uplift Payment(s) as described in Section 11.8.5. The Daily Variable Cost Uplift Settlement is the sum of the IFM Unrecovered Bid Cost Uplift Payment as described in Section 11.8.5.1 and the RUC and RTM Unrecovered Bid Cost Uplift Payment as described in Section 11.8.5.2.

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11.17.2 Shut-Down Adjustment

11.17.2.1 Disqualification Based on Advisory Schedules

From the Dispatch Interval in which the CAISO has determined that the Dispatch Operating Point minus the Shut-Down State Variable is less than or equal to the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and until the Shut-Down State Variable is reset, the IFM Minimum Load Costs, RUC Minimum Load Costs, or RTM Minimum Load Costs, as applicable, will be disqualified from the Bid Cost Recovery calculation.

11.17.2.2 Disqualification Based on ADS Shut-Down Instruction

In the event that the CAISO issues a binding Shut-Down Instruction through ADS, a resource will not be eligible for recovery of RTM Minimum Load Costs or RUC Minimum Load Costs from the point of the Shut-Down Instruction forward for the duration of the resource's registered Minimum Down Time. If a resource ignores the binding Shut-Down Instruction and it has a Day-Ahead Schedule, the resource is not eligible for IFM Minimum Load Cost recovery as specified in Section 11.8.2.1.2 for the minimum of: 1) the resource's Minimum Down Time; and 2) the IFM Commitment Period.

11.17.2.3 Bid Basis for Settlement Bid Cost Recovery

For any resource that receives a Shut-Down Instruction in the Real-Time Market, any Integrated Forward

M~~arket Energy~~ Bid Cost Recovery or Real-Time Market Energy Bid Cost ~~r~~Recovery that may otherwise apply pursuant to the rules in Section 11.8 will be based on the relevant Energy Bid price, as mitigated, that was considered by the Real-Time Market in making the decision to shut down the resource for the length of time defined by the greater of (a) the resource's Minimum Down Time or (b) the period in which it is Off after the Shut-Down time, which is not to exceed the time until the end of the Trading Day.

* * * * *

27.7.1 Election ~~O~~of Constrained Output Generator Status

A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status must make an election to have the resource treated as a COG before each calendar year by registering the resource's PMin in the Master File as equal to its PMax less 0.01 MW (PMin = PMax – 0.01 MW) within the timing requirements specified for Master File changes described in the applicable Business Practice Manual. Generating Units with COG status will be eligible to set LMPs in the IFM and RTM based on their Calculated Energy Bids.

As with all Generating Units that are not Use-Limited Resources, a Scheduling Coordinator on behalf of a COG that is not a Use-Limited Resource must use the Proxy Cost methodology, as provided in Section 30.4, for determining its Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids. A Scheduling Coordinator on behalf of a COG that is a Use-Limited Resource must elect to use either the Proxy Cost methodology or the Registered Cost methodology, as provided in Section 30.4, for determining its Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids. A Calculated Energy Bid of a COG that is not a Use-Limited Resource will be calculated based on the Proxy Cost methodology. A Calculated Energy Bid of a COG that is a Use-Limited Resource will be calculated based on its election of the Proxy Cost methodology or the Registered Cost methodology. Whenever a Scheduling Coordinator for a COG submits an Energy Bid into the IFM or RTM, the CAISO will override that Bid and substitute the Calculated Energy Bid if the submitted Bid is different from the Calculated Energy Bid.

* * * * *

27.7.3 Constrained Output Generators in the IFM

In the IFM, resources electing COG status are modeled as though they are not constrained and can operate flexibly between zero (0) and their PMax. A COG is eligible to set IFM LMPs based on its Calculated Energy Bid in any Settlement Period in which a portion of its output is needed as a flexible resource to serve Demand. A COG is not eligible for recovery of Minimum Load Costs or BCR in the IFM due to the conversion of its Minimum Load Cost to an Energy Bid and its treatment by the IFM as a flexible resource. A COG is eligible for Start-Up Bid Cost recovery based on its Commitment Period as determined in the IFM, RUC, STUC or RTUC.

* * * * *

27.7.5 Constrained Output Generators in the Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.3 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Bid Cost compensation.

* * * * *

29.30 Bid and Self-Schedule Submission for CAISO Markets.

(a) **In General.** The provisions of Section 30 that are applicable to the Real-Time Market, as supplemented by Section 29.30, shall apply to EIM Market Participants.

(b) **Start-Up and Minimum Load.** For the ~~Proxy Cost~~ determination of Proxy Start-Up Costs and Proxy Minimum Load Costs, the CAISO will utilize the Market Services Charge and System Operations Charge reflected in the EIM Administrative Charge.

* * * * *

30.4 Default Start-Up Bids, Default Minimum Load Bids, and Default Transition Bids ~~Proxy Cost and Registered Cost Methodologies~~

30.4.1 Generally

The CAISO will calculate Default Commitment Cost Bids using the Proxy Cost methodology for all resources, except for:

(a) Non-Resource-Specific Resources and Non-Generating Resources; or

(b) a resource that is qualified by the CAISO as a Use-Limited Resource and ~~Scheduling Coordinators for Generating Units and Resource-Specific System Resources must use the Proxy Cost methodology for their Start-Up Costs and Minimum Load Costs, as well as for Transition Costs in the case of Multi-Stage Generating Resources unless~~ the resource has fewer than twelve (12) consecutive months of fifteen-minute LMPs for Energy at the resource's PNode or Aggregated PNode, in which case ~~and meets~~ the resource's ~~definition~~ Default Commitment Cost Bids will be determined as Registered Costs under the Registered Cost methodology pursuant to Section 30.4.7. ~~of a Use-Limited Resource.~~

30.4.2 Transition of Use-Limited Resources to Proxy Costs

Scheduling Coordinators on behalf of Use-Limited Resources with fewer than 12 months of data can elect to use the Registered Cost methodology and remain on that methodology for a two-month period once 12 months of pricing data is collected, while the Scheduling Coordinator and the CAISO are going through the process of determining what Opportunity Costs, if any, apply to the Use-Limited Resource. Once this process concludes, all such Use-Limited Resources must be subject to the Proxy Cost methodology. For Use-Limited Resources eligible for the Registered Cost methodology, Scheduling Coordinators may elect on a thirty (30) day basis to use either the Proxy Cost methodology or the Registered Cost methodology for ~~specifying~~ calculating their Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids to be used for those resources in the CAISO Markets Processes, as well as for Default Transition ~~Cost~~Bids in the case of Multi-Stage Generating Resources. The elections are independent as to Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids; that is, a Scheduling Coordinator for such a Use-Limited Resource may elect to use either the Proxy Cost methodology or the Registered Cost methodology for Default Start-Up ~~Cost~~Bids and may make a different election for Default Minimum Load ~~Cost~~Bids. However, in the case of Multi-Stage Generating Resources, the Scheduling Coordinator must make the same election (Proxy Cost methodology or Registered Cost methodology) for Default Transition ~~Cost~~Bids as it makes for Default Start-Up ~~Cost~~Bids. If a Scheduling Coordinator has not made an election, the CAISO will assume the Proxy Cost methodology as the default.

30.4.3 Scheduling Coordinator Reference Level Change Requests

The CAISO will verify Reference Level Change Requests for changes to Default Start-Up Bids and Default Minimum Load Bids as described in Section 30.11.

30.4.4 Default Commitment Cost Bids

30.4.4.1 Using Proxy Cost Methodology

For resources under the Proxy Cost methodology, the CAISO will calculate a resource's Default Commitment Cost Bids as the applicable Proxy Cost multiplied by the Commitment Cost Multiplier.

30.4.4.2 Use-Limited Resources

For Use-Limited Resources using the Proxy Cost methodology, the CAISO will calculate a resource's Default Commitment Cost Bids as the applicable Proxy Cost multiplied by Commitment Cost Multiplier plus the Start-Up Opportunity Cost, Transition Opportunity Cost, or Minimum Load Opportunity Cost as applicable.

30.4.4.3 Registered Costs

For Use-Limited Resources using the Registered Cost methodology, the CAISO will use the Registered Costs as registered in the Master File as the Default Commitment Cost Bids.

30.4.4.4 Insufficient Information

In the event that the Scheduling Coordinator for a resource (other than~~-~~ a Multi-Stage Generating Resource or a Multi-Stage Generating Resource in its lowest configuration in which it can be started) does not provide sufficient data for the CAISO to determine the resource's Default Commitment Cost Bids or one or more components of the resource's Default Commitment Cost Bids, the CAISO will assume that the resource's Default Commitment Cost Bids, or the indeterminable component(s) of the resource's Default Commitment Cost Bids, are zero. In the event that the Scheduling Coordinator for a Multi-Stage Generating Resource does not provide such data for an MSG Configuration beyond its lowest configuration in which it can be started, Section 30.4.5.3 applies.

30.4.4.5 Resources with Greenhouse Gas Compliance Obligations

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with the information submitted to the California Air Resources Board.

30.4.4.6~~1~~ [Not Used]~~Start-Up and Minimum Load Costs~~

30.4.5~~1.1~~ Proxy Cost Methodology

The CAISO will calculate Proxy Costs as described in this Section 30.4.5.

30.4.~~1.1~~5.1 Natural Gas-Fired Resources

For each natural gas-fired resource, the ~~Proxy Cost methodology uses formulas for Start-Up Costs and Minimum Load~~ CAISO will calculate a resource's Proxy Costs based on the resource's actual unit-specific performance parameters~~. The Start-Up Cost and Minimum Load Cost values utilized for each such resource in the CAISO Markets Processes will be either (a), if the Scheduling Coordinator does not submit a Start-Up or Minimum Load Cost Bid, or (b)~~ and applicable gas prices as described below.~~:~~

(a) **Fuel Input.** The CAISO will calculate Proxy Costs using ~~F~~formulaic natural gas cost values adjusted for fuel-cost variation, based on ~~a daily basis using~~ the natural gas price calculated pursuant to Section 39.7.1.1.1.3, and consistent with the requirements specified below.

(b) **Proxy Start-Up Cost.** Proxy Start-Up Costs will also include:

(i) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price;

(ii) a greenhouse gas cost adder for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price; and

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource as registered in the Master File, multiplied by 0.5.~~; (iv) a resource-specific adder, if applicable, for major maintenance expenses ($ per Start-Up) determined by the CAISO or Independent Entity selected by the CAISO to determine such major maintenance expenses; and (v) for a Use-Limited Resource, Start-Up Opportunity Costs determined pursuant to Section 30.4.1.1.6, if any.~~

(c) **Proxy Cost Minimum Load Costs.** Proxy Cost Minimum Load Costs will also include:

(i) operation and maintenance costs as provided in Section 39.7.1.1.2;

(ii) a greenhouse gas cost adder for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources

Board as having a greenhouse gas compliance obligation, which is calculated for each run-hour as the product of the resource's fuel requirement at Minimum Load as registered in the Master File, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price;

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource as registered in the Master File;

(iv) the Bid Segment Fee; and

(v) a resource-specific adder, if applicable, for major maintenance expenses ($ per operating hour) determined pursuant to Section 30.4.5.4~~1.1.4; and (vi) for a Use-Limited Resource, Minimum Load Opportunity Costs determined pursuant to Section 30.4.1.1.6, if any~~.

(d) **Proxy Transition Costs.** For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Proxy Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG Configuration based on the difference between the Proxy Start-Up Costs for the higher MSG Configuration, and the Proxy Start-Up Costs for the lower MSG Configuration, as those costs are determined in accordance with the Proxy Start-Up Cost calculation methodology set forth in Section 30.4.5. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Proxy Transition Cost shall be zero.

(e) **Major Maintenance Adders.** Proxy Costs will include any major maintenance adders determined pursuant to Section 30.4.5.4.

~~(b) Start-Up or Minimum Load Cost Bids specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10, subject to the provisions applicable to Multi-Stage Generating Resources set forth in Section 30.4.1.1.3.~~

~~In the event that the Scheduling Coordinator for a resource other than a Multi-Stage Generating Resource or for a Multi-Stage Generating Resource in its lowest startable configuration does not provide sufficient~~

~~data for the CAISO to determine the resource's Start-Up or Minimum Load Costs or one or more components of the resource's Start-Up or Minimum Load Costs, the CAISO will assume that the resource's Start-Up Costs or Minimum Load Costs, or the indeterminable component(s) of the resource's Start-Up Costs or Minimum Load Costs, are zero. In the event that the Scheduling Coordinator for a Multi-Stage Generating Resource does not provide such data for an MSG Configuration beyond its lowest startable configuration, Section 30.4.1.1.3 applies.~~

30.4.~~1.1~~5.2 Non-Natural Gas-Fired Resources

For each non-natural gas-fired resource, the CAISO shall calculate the Proxy Start-Up Cost and Proxy Minimum Load Cost values under the Proxy Cost methodology ~~shall be based on either (a) if the Scheduling Coordinator does not submit a Start-Up or Minimum Load Cost Bid, or (b)~~as specified below.~~:~~

(a) **Fuel Input.** The Scheduling Coordinator for the resource will provide the fuel or fuel-equivalent input costs, which the CAISO will maintain in the Master File, pursuant to Section 39.7.1.1.1.2.

(b) **Proxy Start-Up Costs.** ~~For~~ Proxy Start-Up Costs~~, the CAISO~~ will also include, if applicable:

(i) greenhouse gas allowance costs for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator;

(ii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource as registered in the Master File, multiplied by 0.5.~~;~~

~~(iii) a resource-specific adder, if applicable, for major maintenance expenses ($ per Start-Up) determined by the CAISO or Independent Entity selected by the CAISO to determine such major maintenance expenses; and (iv) for a Use-Limited Resource, Start-Up Opportunity Costs determined pursuant to Section~~

~~30.4.1.1.6, if any.~~

(c) **Proxy Minimum Load Costs.** ~~For~~ Proxy Minimum Load Costs ~~the CAISO~~ will also include, if applicable:

(i) operation and maintenance costs as provided in Section 39.7.1.1.2;

(ii) greenhouse gas allowance costs for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator;

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource as registered in the Master File;

(iv) the Bid Segment Fee.~~;~~

~~(v) a resource-specific adder, if applicable, for major maintenance expenses ($ per operating hour) determined by the CAISO or an Independent Entity selected by the CAISO; and (vi) for a Use-Limited Resource, Minimum Load Opportunity Costs determined pursuant to Section 30.4.1.1.6, if any~~.

(d) **Proxy Transition Costs.** For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Proxy Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG Configuration based on the difference between the Proxy Start-Up Costs for the higher MSG Configuration, and the Proxy Start-Up Costs for the lower MSG Configuration, as those costs are determined in accordance with the Proxy Start-Up Cost calculation methodology set forth in Section 30.4.5. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Proxy Transition Cost shall be zero.

(e) **Major Maintenance Adders.** Proxy Costs will include any major maintenance adders determined pursuant to Section 30.4.5.4.

~~For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the~~

~~Scheduling Coordinator must be consistent with information submitted to the California Air Resources Board. Adders for major maintenance expenses will be determined pursuant to Section 30.4.1.1.4, if any.~~

~~(b) Bids specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10, subject to the provisions applicable to Multi-Stage Generating Resources set forth in Section 30.4.1.1.3.~~

~~In the event that the Scheduling Coordinator for a resource other than a Multi-Stage Generating Resource or for a Multi-Stage Generating Resource in its lowest startable configuration does not provide sufficient data for the CAISO to determine the resource's Start-Up or Minimum Load Costs or one or more components of the resource Start-Up or Minimum Load Costs, the CAISO will assume that resource's Start-Up or Minimum Load Costs, or the indeterminable component(s) of the resource's Start-Up Costs or Minimum Load Costs, are zero. In the event that the Scheduling Coordinator for a Multi-Stage Generating Resource does not provide such data for an MSG Configuration beyond its lowest startable configuration, Section 30.4.1.1.3 applies.~~

30.4.~~1.1~~5.3 Multi-Stage Generating Resources

30.4.5.3.1 Application of Proxy Costs

For Multi-Stage Generating Resources under ~~T~~the Proxy Cost methodology, the CAISO ~~for calculating Start-Up Costs and Minimum Load Costs~~ will apply the Proxy Cost methodology to all the MSG Configurations. ~~for a Multi-Stage Generating Resource that is not a Use-Limited Resource and for a Multi-Stage Generating Resource that is a Use-Limited Resource and elects to use the Proxy Cost methodology.~~ The Proxy Costs ~~(Start-Up Cost, Transition Cost, and Minimum Load Cost)~~ for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration, including for each MSG Configuration that cannot be directly started.

30.4.5.3.2 Insufficient Information

Notwithstanding the rules set forth in Sections 30.4.5.1~~.1.1(b)~~ and 30.4.5.2~~1.1.2(b)~~, to the extent that a Scheduling Coordinator for a Multi-Stage Generating Resource, other than in its lowest ~~startable~~ configuration in which the Multi-Stage Generating Resource can be started, does not provide sufficient data for the CAISO to determine a component of the Proxy Start-Up Costs or Proxy Minimum Load Costs for a particular MSG Configuration, the CAISO will, if feasible, use the value for that component associated with the next-lowest MSG Configuration.

30.4.~~1.1~~5.4 Adders for Major Maintenance Expenses

30.4.5.4.1 Generally

Scheduling Coordinators may propose adders for major maintenance expenses as a component of Proxy Start-Up Costs, Proxy Minimum Load Costs, or both. Such proposed adders must be based solely on resource-specific information derived from actual maintenance costs, when available, or estimated maintenance costs provided by the Scheduling Coordinators to the CAISO and the Independent Entity.

30.4.5.4.2 CAISO Process

Scheduling Coordinators may submit updated resource-specific major maintenance information for purposes of seeking a change to any major maintenance adder, no sooner than thirty (30) days after a major maintenance adder has been determined. The CAISO or Independent Entity will evaluate the information provided by Scheduling Coordinators, and may require Scheduling Coordinators to provide additional information, to enable the CAISO or Independent Entity to determine reasonable adders for major maintenance expenses or to conduct audits of major maintenance expenses. Within fifteen (15) days of receipt of the information or any requested additional information, the CAISO or Independent Entity will notify the Scheduling Coordinator in writing whether it has sufficient and accurate information to determine reasonable major maintenance adders to be included in the Proxy Start-Up Cost or Proxy Minimum Load Cost calculations, or both. Within ten (10) days after providing written notification to the Scheduling Coordinator that the information is sufficient and accurate, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses to be included in the Proxy Start-Up Costs or Proxy Minimum Load Costs, or both, and will so inform the Scheduling Coordinator in writing. In the event of a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, within ten (10) days of such agreement, the CAISO or Independent Entity will determine the reasonable adder for major maintenance expenses and will provide the adder to the

Scheduling Coordinator in writing. If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree upon the sufficiency or accuracy of the information during the 60-day negotiation period, the Scheduling Coordinator has the right to petition FERC to resolve the dispute as to the sufficiency or accuracy of its information.

In the event of a dispute regarding the CAISO's or Independent Entity's determination of adders for major maintenance expenses, the CAISO or Independent Entity and the Scheduling Coordinator will enter a period of good faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO or Independent Entity and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, the agreed-upon values will be effective as of the first Business Day following the resolution date.

30.4.5.4.3 FERC Process

If the CAISO or Independent Entity and the Scheduling Coordinator fail to agree on the major maintenance values for either the Proxy Start-Up Costs or Proxy Minimum Load Costs following the 60-day negotiation period, the Scheduling Coordinator has the right to file proposed values and supporting information for major maintenance adders for the Proxy Start-Up Costs or Proxy Minimum Load Costs with FERC pursuant to Section 205 of the Federal Power Act.

30.4.5.4.4 Interim Adders Pending Dispute Resolution

In the event of a dispute regarding the reasonableness of the adder for major maintenance expenses determined by the CAISO or Independent Entity, but not a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO or Independent Entity will determine a reasonable interim adder for major maintenance expenses until the adder for major maintenance expenses is determined by agreement between the CAISO or Independent Entity and the Scheduling Coordinator or by FERC. Any subsequent agreement or FERC order determining the adder for major maintenance expenses will be reflected in an adjustment to the interim adder for major maintenance expenses in the next applicable Settlement Statement.

~~**30.4.1.1.5 Proxy Transition Cost**~~

~~For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG~~

~~Configuration based on the difference between the Start-Up Costs for the higher MSG Configuration, minus the Start-Up Costs for the lower MSG Configuration, as determined in accordance with the Start-Up Cost calculation methodology set forth in Section 30.4.1.1. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Transition Cost shall be zero. The Transition Costs calculated by the CAISO will be utilized in the CAISO Markets Processes unless the Scheduling Coordinator submits Transition Costs for the Multi-Stage Generating Resource in the form of daily Bids that are not negative and are less than or equal to the sum of (i) one hundred twenty-five (125) percent of the Transition Costs other than the portion of the Transition Costs that consist of Start-Up Opportunity Costs determined by the CAISO, if any; and (ii) one hundred (100) percent of the portion of the Transition Costs that consist of Start-Up Opportunity Costs determined by the CAISO, in which case the Transition Costs submitted in the form of daily Bids will be utilized in the CAISO Markets Processes.~~

30.4.~~1.1.~~6 Use-Limited Resources

30.4.~~1.1.~~6.1 Registration and Validation Process

A Scheduling Coordinator seeking to obtain Use-Limited Resource status for resource(s) will follow the registration and validation process set forth in this CAISO Tariff and the Business Practice Manual. The registration and validation process requires each Scheduling Coordinator to demonstrate on an annual basis that the resource has one or more limits that meet the Use-Limited Resource criteria as set forth in Section 30.4.~~1.1.~~6.1.1 and the Business Practice Manual, and allows each Scheduling Coordinator to seek to recover Opportunity Costs for Use-Limited Resources by making the demonstration set forth in Section 30.4.~~1.1.~~6.1.2.

30.4.~~1.1.~~6.1.1 Use-Limited Resource Criteria

In order for a resource to be considered a Use-Limited Resource, a Scheduling Coordinator must provide sufficient documentation demonstrating that the resource has one or more limits that meet all three of the following criteria:

(1) The resource has one or more limitations affecting its number of starts, its number of run-hours, or its Energy output due to (a) design considerations, (b) environmental restrictions, or (c) qualifying contractual limitations;

(2) The CAISO Market Process used to dispatch the resource cannot recognize the

resource's limitation(s); and

(3) The resource's ability to select hours of operation is not dependent on an energy source outside of the resource's control being available during such hours but the resource's usage needs to be rationed.

Design considerations that satisfy the requirements of this Section are those resulting from physical equipment limitations. A non-exhaustive list of such physical equipment limitations includes restrictions documented in original equipment manufacturer recommendations or bulletins, or limiting equipment such as storage capability for hydroelectric generating resources. Other design considerations that satisfy the requirements of this Section are those resulting from performance criteria for Demand Response Resources established pursuant to programs or contracts approved by Local Regulatory Authorities. Environmental restrictions that satisfy the requirements of this Section are those imposed by regulatory bodies, legislation, or courts. A non-exhaustive list of such environmental restrictions includes limits on emissions, water use restrictions, run-hour limitations in operating permits or other environmental limits that directly or indirectly limit starts, run hours, or MWh limits, but excludes restrictions with soft caps that allow the resource to increase production above the soft caps through the purchase of additional compliance instruments. Qualifying contractual limitations that satisfy the requirements of this Section are those contained in long-term contracts that: (i) were reviewed and approved by a Local Regulatory Authority on or before January 1, 2015, or were pending approval by a Local Regulatory Authority on or before January 1, 2015 and were later approved; and (ii) were evaluated by the Local Regulatory Authority for the overall cost-benefit of those contracts taking into consideration the overall benefits and burdens, including the limitations on such resources' numbers of starts, numbers of run-hours, or Energy output. Contracts limits that provide for higher payments when start-up, run-hour, or Energy output thresholds are exceeded are not qualifying contractual limitations. Effective April 1, 2022, no contractual limitations will constitute qualifying contractual limitations that satisfy the requirements of this Section. Pursuant to a process set forth in the Business Practice Manual, the CAISO will review the limits and the supporting documentation provided by the Scheduling Coordinator as well as any translation of indirect limits to determine whether the Scheduling Coordinator has made the required showing under this Section. Any dispute regarding the CAISO's determination will be subject to the generally applicable

CAISO ADR Procedures set forth in Section 13, which apply except where a CAISO Tariff provision expressly provides for a different means of resolving disputes.

The following types of resources are not eligible to register as Use-Limited Resources: Reliability Demand Response Resources, Regulatory Must-Take Generation, where 100% of the capacity is regulatory must-take, Combined Heat and Power Resources where 100% of the capacity is dedicated to a host industrial process, and Variable Energy Resources.

30.4.~~1.1.~~6.1.2 Establishing Opportunity Cost Adders

A Scheduling Coordinator for a Use-Limited Resource that elects the Proxy Cost methodology may seek to establish Opportunity Cost adders for any limitation(s) that meet all three (3) of the following criteria:

(1) Satisfy the requirements of Section 30.4.~~1.1.~~6.1.1;

(2) Apply for period(s) longer than the time horizon considered in the applicable Day-Ahead Market process; and

(3) Can be reflected in a monthly, annual, and/or rolling twelve (12) month period.

The CAISO will review the documentation provided by the Scheduling Coordinator and determine whether the CAISO can calculate an Opportunity Cost pursuant to the methodology set forth in Section 30.4~~.1.1~~.6.2 using the Opportunity Cost calculator, or whether the Opportunity Cost for the limitation must instead be established pursuant to the negotiation process set forth in Section 30.4.~~1.1.~~6.3. Resources with limits that can be modelled using the Opportunity Cost calculator, are not eligible for a negotiated Opportunity Cost. Any Opportunity Cost formula rate resulting from either through the calculated or negotiated process, will remain in place unless and until the formula rate is modified or terminated by the CAISO. Opportunity Costs determined pursuant to a formula rate will remain in place until updated pursuant to Section 30.4.~~1.1.~~6.2.1 or Section 30.4.~~1.1.~~6.3 to reflect any changes in input values to the formula rate. Any Opportunity Cost bid adder will not be available until the first day of the month following the effective date of this tariff section.

A Scheduling Coordinator may submit documentation, either to establish a new limitation or to modify an existing limitation, in which case the Scheduling Coordinator can request reconsideration that may result in a new formula rate. In addition, Scheduling Coordinators must demonstrate on an annual basis that the resource has one or more limits that meet the Use-Limited Resource criteria as required pursuant to

Section 30.4.~~1.1.~~6.1. In accordance with Section 39.7.1.3.2.2, the CAISO will make informational filings with FERC of any new, modified, or terminated Opportunity Cost formula rate developed pursuant to Section 30.4.~~1.1.~~6.2 or negotiated pursuant to Section 30.4.~~1.1.~~6.3.

A Use-Limited Resource to the extent it has a limitation that satisfies the requirements of Section 30.4.~~1.1.~~6.1 but applies for a period less than or equal to the time horizon considered in the Day-Ahead Market, is not eligible for an Opportunity Cost for any limitation.

30.4.~~1.1.~~6.2 Calculation of Opportunity Cost Adders

30.4.~~1.1.~~6.2.1 Calculation Schedule

The CAISO will calculate, and will update the most recent calculations of, Start-Up Opportunity Costs for each validated limitation on a Use-Limited Resource's number of starts, Minimum Load Opportunity Costs for each validated limitation on a Use-Limited Resource's number of run-hours, and Variable Energy Opportunity Costs for each validated limitation on a Use-Limited Resource's Energy output for which the Scheduling Coordinator has made the required showing under Section 30.4.~~1.1.~~6.1.2. Such calculations or updated calculations will actually be used to set the adder for each validated limitation that can be reflected in a monthly or a rolling twelve (12) month period and will be advisory for each validated limitation that can be reflected in an annual period. The CAISO plans to perform the calculations and updated calculations once a month. It is possible that circumstances may prevent the CAISO from performing the calculations on a monthly basis, in which case the CAISO will prioritize the workload based on Opportunity Costs most likely to need updating. The CAISO will provide the results of the calculations or updated calculations for a Use-Limited Resource to its Scheduling Coordinator.

In the event that the CAISO is unable to perform such calculations or updated calculations for all Use-Limited Resources, the CAISO will give priority to performing such calculations or updated calculations for those Use-Limited Resources that are currently on pace to reach their maximum allowed numbers of starts, maximum allowed numbers of run-hours, or maximum allowed Energy output more quickly than the most recent calculations of Opportunity Costs indicated. To the extent that the CAISO is unable to perform such calculations or updated calculations for a Use-Limited Resource, the CAISO will utilize the most recently calculated or updated Opportunity Costs that have been set or are advisory for the Use-Limited Resource.

30.4.~~1.1.~~6.2.2 Methodology for Opportunity Cost Calculator

For the Opportunity Cost calculator developed by the CAISO, each calculation of Opportunity Costs will equal the estimated profits foregone if the Use-Limited Resource had one fewer unit of starts, run-hours, or Energy output, whichever is applicable, in the future time period of the validated limitation. With regard to each validated limitation of the Use-Limited Resource, the calculation will take into account a margin set forth in the Business Practice Manual. The calculation will also take into account the effect of any validated limitation on a Use-Limited Resource's number of starts, number of run-hours, or Energy output in the monthly and annual and/or rolling twelve month periods. For MSG Transitions, the Opportunity Cost for each transition will be derivative of the number of Start-Ups required for the MSG Resource to achieve a specific MSG Configuration.

The CAISO will calculate the estimated profits for each validated limitation over the future time period of the limitation based on the following estimated inputs: (a) the forecasted hourly average of fifteen-minute LMPs for Energy at the Use-Limited Resource's PNode or Aggregated PNode multiplied by (b) the optimal hourly dispatch of the Use-Limited Resource, minus (c) the estimated monthly Proxy Start-Up Cost of the Use-Limited Resource, minus (d) the estimated monthly Proxy Minimum Load Cost of the Use-Limited Resource, minus (e) the estimated monthly variable Energy cost of the Use-Limited Resource multiplied by the difference between (f) the optimal hourly commitment and dispatch of the Use-Limited Resource and (g) the PMin of the Use-Limited Resource, minus (h) the estimated monthly Transition Cost of the Use-Limited Resource.

The CAISO will calculate input (a) listed above by executing the following steps in the order shown below:

(1) For each future hour, calculate an hourly implied heat rate at each applicable PNode or Aggregated PNode for a Use-Limited Resource based on the hourly average of the fifteen-minute Real-Time LMPs (reflecting the gas price index used in the Real-Time Market calculated pursuant to Section 39.7.1.1.1.3) from the same hour of the previous year, the Greenhouse Gas Allowance Price, calculated pursuant to Section 39.7.1.1.1.4, from the same day of the previous year, and the gas price index of the applicable fuel region from the same day of the previous year.

(2) For each future month, calculate a monthly future implied heat rate based on the

applicable wholesale future power price of the applicable ~~power trading~~ electric pricing hub as published by Intercontinental Exchange, the most recent Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4, and the natural gas future commodity price of the applicable fuel region. The CAISO determines the natural gas futures commodity price by fuel region averaging available prices from the following vendors: Intercontinental Exchange, Natural Gas Intelligence, and SNL Energy/BTU's Daily Gas Wire.

(3) For each future month, calculate a monthly historical implied heat rate based on the wholesale historic power price of the applicable ~~power trading~~ electric pricing hub as published by Intercontinental Exchange for the same month of the previous year, the average Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4 for the same month of the previous year, and the average natural gas commodity price, reflecting the gas price index used in the Real-Time Market calculated pursuant to Section 39.7.1.1.1.3, of the applicable fuel region for the same month of the previous year.

(4) For each future month, calculate a monthly power price conversion factor as the ratio of the future implied heat rate calculated under (2) above and the historical implied heat rate calculated under (3) above.

(5) For each future hour, scale the hourly implied heat rate calculated under (1) above by the power price conversion factor calculated under (4) above.

(6) For each future hour, calculate the LMPs by applying the gas price index of the future month and the most recent Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4 to the scaled implied heat rates calculated under (5) above.

For a Use-Limited Resource that has twelve (12) or fewer months of LMP data at its PNode or Aggregated PNode, the CAISO will calculate input (a) listed above using LMP data from a comparable PNode or Aggregated PNode.

Additional detail regarding the calculation of Opportunity Costs is provided in Appendix N to the Business Practice Manual for Market Instruments. Any dispute regarding the calculation of Opportunity Costs will be subject to the CAISO ADR Procedures set forth in Section 13.

30.4.~~1.1.~~6.3 Negotiation of Opportunity Costs

If, after receipt of the documentation required pursuant to Section 30.4.~~1.1.~~6.1.2, the CAISO determines that it cannot rely on the Opportunity Cost calculator to calculate Opportunity Costs for an eligible limitation pursuant to Section 30.4.~~1.1.~~6.2, the CAISO will establish the Opportunity Costs for the limitation pursuant to this Section. Upon making this determination, the CAISO will notify the Scheduling Coordinator for the resource and request that the Scheduling Coordinator provide the CAISO with a proposed methodology for determining Start-Up Opportunity Costs, Minimum Load Opportunity Costs, and/or Variable Energy Opportunity Costs for the limitation along with documentation supporting the methodology, and a proposed schedule for the CAISO to update such Opportunity Cost(s) under the methodology. The CAISO will either approve the submitted Opportunity Cost methodology or enter into good-faith negotiations with the Scheduling Coordinator to establish an agreed-upon Opportunity Cost methodology and the schedule for updating the Opportunity Costs under the methodology.

If the CAISO and the Scheduling Coordinator enter into good-faith negotiations, the negotiation period will be a minimum of sixty (60) days following the provision of all required documentation by the Scheduling Coordinator. Following the 60-day period, the parties can agree to continue good-faith negotiations or the Scheduling Coordinator can exercise its right to file with FERC as described below. In the event that the CAISO and the Scheduling Coordinator are unable to agree upon negotiated Opportunity Costs before the negotiation period terminates, the CAISO may propose reasonable interim Opportunity Cost value(s) that will apply to the Use-Limited Resource until the CAISO and the Scheduling Coordinator agree upon negotiated Opportunity Costs. The Scheduling Coordinator may accept or reject the proposed interim Opportunity Cost value(s). If the Scheduling Coordinator rejects the proposed interim Opportunity Cost value(s), the Use-Limited Resource will not receive Opportunity Costs unless and until the CAISO and the Scheduling Coordinator agree upon negotiated Opportunity Costs, or such costs are established by an order issued by FERC. In the event that the negotiation period terminates without the CAISO and the Scheduling Coordinator reaching agreement upon negotiated Opportunity Costs, and the Scheduling Coordinator declines to continue negotiations, the Scheduling Coordinator may file proposed Opportunity Costs and supporting documentation with FERC pursuant to Section 205 of the Federal Power Act.

Any updates to the negotiated Opportunity Costs adders established pursuant to this Section will consist solely of updates to the Opportunity Cost values themselves, and shall not affect the methodology for establishing those values. Any change in methodology would require the Scheduling Coordinator to initiate a new request pursuant to Section 30.4.~~1.1.~~6.1.2.

30.4.7~~1.2~~ Registered Cost Methodology

Under the Registered Cost methodology, the Scheduling Coordinator for a Use-Limited Resource that is eligible for Opportunity Costs and either (i) does not have at least twelve (12) consecutive months of fifteen-minute LMPs for Energy at the Use-Limited Resource's PNode or Aggregated PNode; or (ii) has at least twelve (12) consecutive months of such LMPs but has not yet reached the start of the second month after the end of the twelfth consecutive month of having such LMPs, may register values of its choosing for Default Start-Up ~~Cost~~Bids and/or Default Minimum Load ~~Cost~~Bids in the Master File subject to the maximum limit specified in Section 39.6.1.6. A Scheduling Coordinator for a Multi-Stage Generating Resource that is a Use-Limited Resource registering ~~a~~ Default Start-Up ~~Cost~~ Bids must also register Default Transition ~~Cost~~Bids for each feasible MSG Transition, subject to the maximum limit specified in Section 39.6.1.7. For a Use-Limited Resource to be eligible for the Registered Cost methodology there must be sufficient information in the Master File to calculate the value pursuant to the Proxy Cost methodology, which will be used to validate the specific value registered using the Registered Cost methodology. Any such values will be fixed for a minimum of thirty (30) days in the Master File unless:

(a) the resource's costs for any such value, as calculated pursuant to the Proxy Cost methodology, exceed the value registered using the Registered Cost methodology, in which case the Scheduling Coordinator may elect to switch to the Proxy Cost methodology for the balance of any thirty (30)-day period, except as set forth in Section 30.4.7~~1.2~~ (b); or

(b) any cost registered in the Master File exceeds the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7 after this minimum thirty (30)-day period, in which case the value will be lowered to the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7.

If a Multi-Stage Generating Resource elects to use the Registered Cost methodology, that election will apply to all the MSG Configurations for that resource. The cap for the Registered Cost values for each MSG Configuration will be based on the Proxy Cost values calculated for each MSG Configuration, including for each MSG Configuration that cannot be directly started, which are also subject to the maximum limits specified in Sections 39.6.1.6 and 39.6.1.7.

30.5 Bidding Rules

30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the DAM for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the RTM for the following Trading Day shall be submitted starting from the time of publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. The CAISO will not accept any Energy or Ancillary Services Bids for the following Trading Day between 10:00 a.m. on the day preceding the Trading Day and the publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the RTM may be revised.

(c) A Scheduling Coordinator may submit in the Real-Time Market new daily ~~Bids for~~ Start-Up ~~Cost~~Bids, Minimum Load ~~Cost~~Bids, and Transition ~~Cost~~Bids for resources and MSG Configurations for which the Scheduling Coordinator previously submitted such Bids in the Day-Ahead Market, except for: (1) Trading Hours in which a resource or MSG Configuration has received a Day-Ahead Schedule or has received a Start-Up Instruction in RUC; and (2) Trading Hours that span the Minimum Run Time of the resource or MSG Configuration after the CAISO has committed the resource or the Scheduling Coordinator has self-committed the resource in the RTM.

(d) Scheduling Coordinators may revise ETC Self-Schedules for Supply in the RTM to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Participating TO in accordance with Section 16.

(e) Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the Real-Time Market separate and apart from the awarded Ancillary Services capacity.~~;~~

(f~~c~~) Scheduling Coordinators may submit Energy Bids, AS Bids, and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day.~~;~~

(g~~d~~) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price.~~;~~

(h~~e~~) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30.~~; and~~

(i~~f~~) In order to retain the priorities specified in Section 31.4 and 34.12 for scheduled amounts in the Day-Ahead Schedule associated with ETC and TOR Self-Schedules or Self-Schedules associated with Regulatory Must-Take Generation, a Scheduling Coordinator must submit to the Real-Time Market ETC or TOR Self-Schedules, or Self-Schedules associated with Regulatory Must-Take Generation, at or below the Day-Ahead Schedule quantities associated with the scheduled ETC, TOR, or Regulatory Must-Take Generation Self-Schedules. If the Scheduling Coordinator fails to submit such Real-Time

Market ETC, TOR, or Regulatory Must-Take Generation Self-Schedules, the defined scheduling priorities of the ETC, TOR, or Regulatory Must-Take Generation Day-Ahead Schedule quantities may be subject to adjustment in the HASP and the Real-Time Market as further provided in Sections 31.4 and 34.12 in order to meet operating conditions.

(j~~g~~) For Multi-Stage Generating Resources that receive a Day-Ahead Schedule, are awarded a RUC Schedule, or receive an Ancillary Services Award the Scheduling Coordinator must submit an Energy Bid in the Real-Time Market for the same Trading Hour(s). If the Scheduling Coordinator submits an Economic Bid for such Trading Hour(s), the Economic Bid must be for either: the same MSG Configuration scheduled or awarded in the Integrated Forward Market, or the MSG Configuration committed in RUC. If the Scheduling Coordinator submits a Self-Schedule in the Real-Time Market for such Trading Hour(s), then the Energy Self-Schedule may be submitted in any registered MSG Configuration, including the MSG Configuration awarded in the Day-Ahead Market, that can support the awarded Ancillary Services (as further required by Section 8).

(k) Scheduling Coordinators for Multi-Stage Generating Resources may submit into the Real-Time Market bids from up to six (6) MSG Configurations in addition to the MSG Configuration scheduled or awarded in the Integrated Forward Market and Residual Unit Commitment, provided that the MSG Transitions between the MSG Configurations bid into the Real-Time Market are feasible and the transition from the previous Trading Hour are also feasible.

(l~~h~~) For the Trading Hours that Multi-Stage Generating Resources do not have a CAISO Schedule or award from a prior CAISO Market run, the Scheduling Coordinator can submit up to six (6) MSG Configurations into the RTM.

(m~~i~~) A Scheduling Coordinator cannot submit a Bid to the CAISO Markets for a MSG Configuration into which the Multi-Stage Generating Resource cannot transition due to lack of Bids for the specific Multi-Stage Generating Resource in other MSG Configurations that are required for the requisite MSG Transition.

(n~~j~~) In order for Multi-Stage Generating Resource to meet any Resource Adequacy must-offer obligations, the responsible Scheduling Coordinator must submit either an Economic Bid or Self-Schedule for at least one MSG Configuration into the Day-Ahead Market and Real-Time Market that is capable of fulfilling that Resource Adequacy obligation, as feasible. The Economic Bid shall cover the entire capacity range between the maximum bid-in Energy MW and the higher of Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin as registered in the Master File.

(o~~k~~) For any given Trading Hour, a Scheduling Coordinator may submit Self-Schedules and/or Submissions to Self-Provide Ancillary Services in only one MSG Configuration for each Generating Unit.

(~~l~~p) In any given Trading Hour in which a Scheduling Coordinator has submitted a Self-Schedule for a Multi-Stage Generating Resource, the Scheduling Coordinator may also submit Bids for other MSG Configurations provided that they concurrently submit Bids that enable the applicable CAISO Market to transition the Multi-Stage Generating Resource to other MSG Configurations.

(q~~m~~) If in any given Trading Hour the Multi-Stage Generating Resource was awarded Regulation or Operating Reserves in the IFM, any Self-Schedules or Submissions to Self-Provide Ancillary Services the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(r~~n~~) If a Multi-Stage Generating Resource has received a binding RUC Start-Up Instruction as provided in Section 31, any Self-Schedule or Submission to Self-Provide Ancillary Services in the RTM must be in the same MSG Configuration committed in RUC.

(s~~o~~) If in any given Trading Hour the Multi-Stage Generating Resource is scheduled for Energy in the IFM, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Energy is scheduled in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(<u>t</u>~~p~~) For a Multi-Stage Generating Resource, the Bid(s) submitted for the resource's configuration(s) shall collectively cover the entire capacity range between the maximum bid-in Energy MW and the higher of the Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin as registered in the Master File. This rule shall apply separately to the Day-Ahead Market and the Real-Time Market.

(<u>u</u>~~q~~) A Scheduling Coordinator may submit a Self-Schedule Hourly Block for the RTM as an import to or an export from the CAISO Balancing Authority Area and may also submit Self-Scheduled Hourly Blocks for Ancillary Services imports. Such a Bid shall be for the same MWh quantity for each of the four <u>(4)</u> fifteen (15)-minute intervals that make up the applicable Trading Hour.

(<u>v</u>~~r~~) A Scheduling Coordinator may submit a Variable Energy Resource Self-Schedule for the RTM can be submitted from a Variable Energy Resource. A Scheduling Coordinator can use either the CAISO forecast for Expected Energy in the RTM or can provide its own forecast for Expected Energy pursuant to the requirements specified in Section 4.8.2. The Scheduling Coordinator must indicate in the Master File whether it is using its own forecast or the CAISO forecast for its resource in support of the Variable Energy Self-Schedule. The Scheduling Coordinator is not required to include the same MWh quantity for each of the four <u>(4)</u> fifteen (15)-minute intervals that make up the applicable Trading Hour for the Variable Energy Resource Self-Schedule include. If an external Variable Energy Resource that is not using a forecast of its output provided by the CAISO submits a Variable Energy Resource Self-Schedule and the Expected Energy is not delivered in the FMM, the Scheduling Coordinator for the Variable Energy Resource will be subject to the Under/Over Delivery Charge as described in Section 11.31. Scheduling Coordinators for Dynamically Scheduled Variable Energy Resources that provide the CAISO with a two <u>(2)</u>-hour rolling forecast with five <u>(5)</u>-minute granularity can submit Variable Energy Resource Self-Schedules.

(<u>w</u>~~s~~) Scheduling Coordinators can submit Economic Hourly Block Bids to be considered in the HASP and to be accepted as binding Schedules with the same MWh award for each of the four (4) FMM intervals. Scheduling Coordinator can also submit Economic Hourly Block Bids for Ancillary Services. As specified in Section 11, a cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery.

(x~~t~~) Scheduling Coordinators can submit Economic Hourly Block Bids with Intra-Hour Option. If accepted in the HASP, such a Bid creates a binding schedule with same MWh awards for each of the four (4) FMM intervals. After that, the RTM can optimize such schedules for economic reasons once through an FMM during the Trading Hour. As specified in Section 11, a cleared Economic Hourly Block Bid with Intra-Hour Option is not eligible for Bid Cost Recovery.

(y~~u~~) A Scheduling Coordinator submitting Bids to the RTM is not required to submit a Self-Schedule Hourly Block, a Variable Energy Resource Self-Schedule, an Economic Hourly Block Bid, or an Economic Hourly Block Bid with Intra-Hour Option, and may instead choose to participate in the RTM through Economic Bids or Self-Schedules.

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30.5.2.4 Supply Bids for System Resources

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Resource-Specific System Resources shall also contain~~:~~ ~~the relevant Ramp Rate;~~ Start-Up ~~Cost~~Bids~~;~~ and Minimum Load ~~Cost~~Bids. Resource-Specific System Resources are subject to the Proxy Cost methodology or the Registered Cost methodology for Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids as provided in Section 30.4, and Transaction ID as created by the CAISO. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in RTM on an equivalent basis as Generating Units. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted.

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30.6.2.1.2 Real-Time Dispatch Options

For purposes of bidding and scheduling in the Real-Time Market, each Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource shall select either the Marginal Real-Time Dispatch Option or the Discrete Real-Time Dispatch Option prior to the start of the initial Reliability Demand Response Services Term applicable to the Reliability Demand Response Resource. The selection for each Reliability Demand Response Resource shall remain in effect until such time as the Scheduling Coordinator for the Reliability Demand Response Resource chooses to change its selection from the Marginal Real-Time Dispatch Option to the Discrete Real-Time Dispatch Option or vice versa, in which case the change in selection shall go into effect at the start of the next Reliability Demand Response Services Term applicable to the Reliability Demand Response Resource. A Reliability Demand Response Resource that is subject to either the Marginal Real-Time Dispatch Option or the Discrete Real-Time Dispatch Option shall have a Default Minimum Load ~~Costs~~ Bid of zero (0) dollars registered in the Master File.

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30.7.3 Day-Ahead Market Validation

30.7.3.1 Validation Prior to Market Close and Master File Update

The CAISO conducts Bid validation in three steps:

Step 1: The CAISO will validate all Bids after submission of the Bid for content validation which determines that the Bid adheres to the structural rules required of all Bids as further described in the Business Practices Manuals. If the Bid fails any of the content level rules the CAISO shall assign it a rejected status and the Scheduling Coordinator must correct and resubmit the Bid.

Step 2: After the Bids are successfully validated for content, but prior to the Market Close of the DAM, the Bids will continue through the second level of validation rules to verify that the Bid adheres to the applicable CAISO Market rules and if applicable, limits based on Master File data. If the Bid fails any level two validation rules, the CAISO shall assign the Bid as invalid and the Scheduling Coordinator must either correct or resubmit the Bid.

Step 3: If the Bid successfully passes validation in Step 2, it will continue through the third level of validation where the Bid will be analyzed based on its contents to identify any missing Bid components that must be present for the Bid to be valid consistent with the market rules contained in Article III of this CAISO Tariff and as reflected in the Business Practice Manuals. At this stage the Bid will either be automatically modified for correctness and assigned a status of conditionally modified or modified, or if it can be accepted as is, the Bid will be assigned a status of conditionally valid, or valid. A Bid will be automatically modified and assigned a status of modified or conditionally modified Bid, whenever the CAISO inserts or modifies a Bid component. The CAISO will insert or modify a Bid component whenever (1) a Self-Schedule quantity is less than the lowest quantity specified as an Economic Bid for either an Energy Bid or Demand Bid, in which case the CAISO extends the Self-Schedule to cover the gap; (2) for non-Resource Adequacy Resources, the CAISO will extend the Energy Bid Curve ~~using Proxy Costs~~ or, if the Scheduling Coordinator did not submit an Energy Bid Curve, use the Generated Bid to cover any capacity in a RUC Bid component, if necessary; and (3) for a Resource Adequacy Resource that is not a Use-Limited Resource, the CAISO will extend the Energy Bid Curve ~~using Proxy Costs~~ or, if the Scheduling Coordinator did not submit an Energy Bid Curve, use the Generated Bid to cover any capacity in a RUC Bid component and, if necessary, up to the full registered Resource Adequacy Capacity. The CAISO will generate a Proxy Bid or extend an Energy Bid or Self-Schedule to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule. To the extent that an Energy Bid to the HASP/RTM is not accompanied by an Ancillary

Services Bid, the CAISO will insert a Spinning Reserve and Non-Spinning Reserve Ancillary Services Bid at $ 0/MW for any certified Operating Reserve capacity. The CAISO will also generate a Self-Schedule Bid for any Generating Unit that has a Day-Ahead Schedule but has not submitted Bids in HASP/RTM, up to the quantity in the Day-Ahead Schedule. Throughout the Bid evaluation process, the Scheduling Coordinator shall have the ability to view the Bid and may choose to cancel the Bid, modify and re-submit the Bid, or leave the modified, conditionally modified or valid, conditionally valid Bid as is to be processed in the designated CAISO Market. The CAISO will not insert or extend any Bid for a Resource Adequacy Resource that is a Use-Limited Resource.

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30.7.3.4 Validation after Market Close

To the extent that a Scheduling Coordinator fails to enter a Bid for a resource that is required to submit a Bid in the full range of available capacity consistent with the bidding provisions of Section 30 or the Resource Adequacy provisions of Section 40, the CAISO will create a Bid for the Scheduling Coordinator, which is referred to as the Generated Bid. This does not apply to Load-following MSSs. The Generated Bid will be created only after the Market Close for the DAM and will be based on data registered in the Master File, and, if applicable, published natural gas pricing data and published pricing data for greenhouse gas allowances. The Generated Bid components will be calculated as set forth in Sections 30 and 40.6.8. The Scheduling Coordinator may view Generated Bids, but may not modify such Bids, unless the CAISO has approved a Reference Level Change Request for the resource's Default Energy Bid. The CAISO will provide notice to the Scheduling Coordinator of the use of a Generated Bid prior to Market Clearing of the IFM. In addition, validation of export priority pursuant to Sections 31.4 and 34.12.1 and Wheeling Through transactions pursuant to Section 30.5.4 occur after the Market Close for the DAM.

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30.7.8 Format and Validation of Start-Up and Shut-Down Times

For a Generating Unit or a Resource-Specific System Resource, the submitted Start-Up Time expressed in minutes (min) as a function of down time expressed in minutes (min) must be a staircase function with up to three (3) segments defined by a set of one (1) to four (4) down time and Start-Up Time pairs. The Start-Up Time is the time required to start the resource if it is offline longer than the corresponding down time. The CAISO shall model Start-Up Times for Multi-Stage Generating Resource at the MSG Configuration level and Transition Times are validated based on the Transition Matrix submitted as provided in Section 27.8. The last segment will represent the time to start the unit from a cold start and will extend to infinity. The submitted Start-Up Time function shall be validated as follows:

(a) The first down time must be zero (0) minutes.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the maximum Start-Up Time function, as registered in the Master File for the relevant resource.

(c) The Start-Up Time for each segment must not exceed the Start-Up Time of the corresponding segment of the maximum Start-Up Time function, as registered in the Master File for the relevant resource.

(d) The Start-Up Time function must be strictly monotonically increasing, i.e., the Start-Up Time must increase as down time increases.

For Participating Load and for a Proxy Demand Resource or Reliability Demand Response Resource, a single Shut-Down time in minutes is the time required for the resource to Shut-Down after receiving a Dispatch Instruction. For Multi-Stage Generating Resources, the Scheduling Coordinator must provide Start-Up ~~Cost~~Bids for each MSG Configuration into which the resource can be started.

30.7.9 Format and Validation of Start-Up ~~Cost~~Bids and Shut-Down Costs

For a Generating Unit or a Resource-Specific System Resource, the submitted Start-Up ~~Cost~~ Bid expressed in dollars ($) as a function of down time expressed in minutes must be a staircase function with up to three (3) segments defined by a set of one (1) to four (4) down time and Start-Up ~~Cost~~ Bid pairs. The Start-Up ~~Cost~~ Bid is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment of the Start-Up Bid will represent the cost to start the resource from cold Start-Up and will extend to infinity. The CAISO will validate the submitted Start-Up

~~Cost~~ Bid ~~function shall be validated~~ as follows:

(a) The first down time must be zero (0) minutes.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the Start-Up ~~Cost function~~Time information, as registered in the Master File ~~for the relevant resource as either the Proxy Cost or Registered Cost~~.

(c) The Start-Up Cost for each segment must ~~not~~ be non-negative ~~and must be equal to the Start-Up Cost of the corresponding segment of the Start-Up Cost function, as registered in the Master File for the relevant resource~~.

(d) The Start-Up Cost Curve must be strictly monotonically increasing non-negative staircase curves (*i.e.*, the Start-Up Cost must increase as down time increases), up to three (3) segments, which represent a function of Start-Up Cost versus down time.

(e) ~~In addition, i~~If the Proxy Cost methodology pursuant to Section 30.4.5 applies to the resource, the Scheduling Coordinator for that resource may submit a daily Start-Up Bid for which the included Start-Up Costs ~~that~~ must ~~not~~ be non-negative ~~but~~ and may be less than or equal to the resource's Default Start-Up Bid.~~sum of (i) one hundred twenty-five (125) percent of the Proxy Cost other than the portion of the Proxy Cost that consists of Start-Up Opportunity Costs, if any; and (ii) one hundred (100) percent of the portion of the Proxy Cost that consists of Start-Up Opportunity Costs; and if the resource is a Multi-Stage Generating Resource, the Scheduling Coordinator may submit a daily Bid for each MSG Configuration of the resource that must not be negative but may be less than or equal to the sum of (i) one hundred twenty-five (125) percent of the Start-Up Cost for the MSG Configuration other than the portion of the Start-Up Cost for the MSG Configuration that consists of Start-Up Opportunity Costs, if any; and (ii) one hundred (100) percent of the portion of the Start-Up Cost for the MSG Configuration that consists of Start-Up Opportunity Costs.~~

(f) For a resource that is eligible and has elected to use the Registered Cost methodology pursuant to Section 30.4.7, if a Start-Up Cost value is submitted in a Start-Up Bid, ~~for the~~

~~Start-Up Cost, it will be overwritten by~~ the CAISO will override that submitted Start-Up Cost with the Registered Cost reflected in the Master File.

(g) If no ~~value for~~ Start-Up Cost is submitted in a Bid, the CAISO will insert the ~~Master File value, as either the~~ Proxy Start-Up Cost plus the applicable Start-Up Opportunity Cost, or the Master File Registered Cost based on the methodology elected pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Start-Up Cost is submitted in a Bid, the CAISO will insert the revised Reference Level Start-Up Cost.

~~(d) The Start-Up Cost function must be strictly monotonically increasing, i.e., the Start-Up Cost must increase as down time increases.~~

(h) The Start-Up ~~Cost~~ Bid for a Reliability Demand Response Resource shall be zero (0).

(i) For Participating Loads and Proxy Demand Resources, a single Shut-Down Cost in dollars ($) is the cost incurred to Shut-Down the resource after receiving a Dispatch Instruction. The submitted Shut-Down Cost must ~~not~~ be non-negative.

(j) For Multi-Stage Generating Resources, for any MSG Configuration for which a Bid is submitted, the Scheduling Coordinator must provide the Start-Up ~~Costs~~ Bid for each MSG Configuration into which the resource can be started.

30.7.10 Format and Validation of Minimum Load ~~Cost~~Bids

30.7.10.1 In General

Scheduling Coordinators may submit a Minimum Load Bid ~~F~~for a Generating Unit or a Resource-Specific System Resource, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource, ~~the submitted Minimum Load Cost~~ expressed in dollars per hour ($/hr) ~~is~~ representing the cost incurred for operating the unit at Minimum Load as registered in the Master File or as modified pursuant to Section 30.7.10.2. The CAISO will validate the Minimum Load Bids as follows:

(a) The submitted Minimum Load Cost must ~~not~~ be non-negative. ~~In addition, i~~If the Proxy Cost methodology pursuant to Section 30.4.5 applies to the resource, the Scheduling Coordinator for that resource may submit a daily Bid for the Minimum Load ~~Cost~~ Bid that must ~~not~~ be non-negative ~~but~~ and may be less than or equal to the ~~sum of (i) one~~

~~hundred twenty-five (125) percent of the Proxy Cost value other than the portion of the Proxy Cost value that consists of Minimum Load Opportunity Costs, if any; and (ii) one hundred (100) percent of the portion of the Proxy Cost value that consists of~~ Default Minimum Load ~~Opportunity Costs~~Bid.

(b) For a resource that is eligible and has elected to use the Registered Cost methodology pursuant to Section 30.4.7, any submitted Minimum Load Cost must be equal to the Minimum Load Cost as registered in the Master File.

(c) If no Minimum Load Cost is submitted in a Bid, the CAISO will insert the Proxy Minimum Load Cost plus the applicable Minimum Load Opportunity Cost, or the Master File Registered Cost based on the methodology elected pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Minimum Load Cost is submitted in a Bid, the CAISO will insert the applicable Revised Default Commitment Cost Bid.

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30.7.10.3 [Not Used] ~~Participating Loads~~

~~For Participating Loads, the submitted Minimum Load Cost ($/hr) is the cost incurred while operating the resource at reduced consumption after receiving a Dispatch Instruction. The submitted Minimum Load Cost must not be negative.~~

30.7.11 Format and Validation of Transition Bids

The Scheduling Coordinators may submit Transition Bids for a Multi-Stage Generating Resource that must meet the following requirements:

(a) The Transition Bids are non-negative.

(b) For resources under the Proxy Cost methodology, Transition Bids must be less than or equal to the Default Transition Bids calculated under the Proxy Cost methodology.

(c) For resources under the Registered Cost methodology, Transition Bids must equal the Default Transition Bids as registered in the Master File.

(d) If no Transition Cost is submitted in a Transition Bid, the CAISO will insert the Proxy Transition Cost plus the applicable Transition Opportunity Cost, or as registered in the Master File, based on the elected methodology pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Transition Cost is submitted in a Bid, the CAISO will insert the difference between the applicable Revised Default Commitment Cost Bid (*i.e.*, revised Default Start-Up Bid) for the higher MSG Configuration minus the applicable Start-Up Opportunity Cost for the higher MSG configuration and the revised applicable Revised Default Commitment Cost Bid (*i.e.*, revised Default Start-Up Cost Bid) for the lower MSG Configuration minus the applicable Start-Up Opportunity Cost for the lower MSG configuration, plus the applicable transition Opportunity Cost. If the result of this calculation is negative for any transition between two MSG Configurations, then the Transition Cost shall be zero.

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30.11 Adjustments to Reference Levels Prior to CAISO Market Processes~~Filings to Recover Commitment-Related Fuel Costs~~

The CAISO will adjust Reference Levels prior to executing the applicable CAISO Market Processes as described in this Section 30.11. ~~If a Scheduling Coordinator incurs but cannot recover through the Bid Cost Recovery process any actual marginal fuel procurement costs that exceed (i) the limit on Bids for Start-Up Costs set forth in Section 30.7.9, (ii) the limit on Bids for Minimum Load Costs set forth in Section 30.7.10, or (iii) the limit on Bids for Transition Costs set forth in Section 30.4.1.1.5, the Scheduling Coordinator for the resource may seek to recover those costs through a FERC filing made pursuant to Section 205 of the Federal Power Act. The Scheduling Coordinator must notify the CAISO within thirty (30) Business Days after the Operating Day on which the resource incurred the unrecovered costs, and must submit the filing to FERC within ninety (90) Business Days after that Trading Day. Within sixty (60) Business Days after the Trading Day for which the Scheduling Coordinator provides notice to the CAISO per this Section, the CAISO will 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 Trading Day.~~

~~Each filing the Scheduling Coordinator submits to FERC must include:~~

~~(1) Data supporting the Scheduling Coordinator'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) A copy of the written explanation from the CAISO to the Scheduling Coordinator described above in this Section.~~

~~To the extent that 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.~~

30.11.1 Reasonableness Thresholds

The CAISO will calculate the Reasonableness Thresholds for the purpose of evaluating increases to Reference Levels pursuant to this Section 30.11.1.

30.11.1.1 General Applicability

The CAISO will calculate the Reasonableness Thresholds for all resources except for Non-Resource-Specific System Resources. The CAISO will calculate Reasonableness Thresholds for evaluating Reference Level Change Requests for Bids from resources, other than Hydro Default Energy Bids and Virtual Bids.

30.11.1.2 Calculations

30.11.1.2.1 Natural Gas-Fired Resources

For natural gas-fired resources, the CAISO will calculate the Reasonableness Threshold to equal the Proxy Cost-based Default Start-Up Bid, the Proxy Cost-based Default Minimum Load Bid, or the Variable Cost-based Default Energy Bid calculated for the specific resource, where the natural gas commodity price component determined pursuant to Section 39.7.1.1.1.3 is multiplied by: (i) one hundred twenty-five percent (125%) for days without a published daily gas price index consistent with the rules in Section 39.7.1.1.1.3, unless the CAISO has updated the natural gas commodity price used to calculate the

Reasonableness Threshold pursuant to Section 30.11.1.3, in which case the CAISO will use one hundred ten percent (110%); or (ii) one hundred ten percent (110%) for all other days. Provided, however, that the CAISO will set the Reasonableness Threshold for a specific resource to its Reference Level when it accepts a manual Reference Level Change Request as provided in Section 30.11.5.

30.11.1.2.2 Non-Natural Gas-Fired Resources

For non-natural gas-fired resources, the CAISO will calculate the Reasonableness Threshold to equal the Proxy Cost-based Default Start-Up Bid, the Proxy Cost-based Default Minimum Load Bid, or the Variable Cost-based Default Energy Bid, with the fuel or fuel-equivalent cost component of that calculation registered in the Master File being multiplied by one hundred ten percent (110%).

30.11.1.3 CAISO Updates for the Real-Time Market

After the deadline for the submissions of manual Reference Level Change Requests specified in Section 30.11.4.2, the CAISO will review the same-day gas price information on trades occurring on the Intercontinental Exchange and will review the same-day gas price information submitted in the manual Reference Level Change Requests applicable for each commodity gas region, to determine whether the same-day gas prices are ten percent (10%) greater than the gas price index the CAISO previously used to calculate the Reasonableness Thresholds.

(a) If the CAISO determines that the representative same-day gas prices are ten percent (10%) greater than the gas price index the CAISO previously used to calculate the Reasonableness Thresholds, the CAISO will:

(i) use the higher of the volume-weighted average price of same-day gas trades occurring on the Intercontinental Exchange and the volume-weighted average of all relevant verified manual Reference Level Change Requests to update the Reasonableness Thresholds for all resources within the applicable fuel region(s); and

(ii) automatically recalculate all Hydro Default Energy Bids in the applicable fuel regions.

(b) The CAISO will implement the changes to the Reasonableness Thresholds in the next available Real-Time Market interval as soon as practicable. Any updates the CAISO makes to Reasonableness Thresholds through this process will apply to the Real-Time Market throughout the remainder of the Trading Day.

30.11.1.4 CAISO Adjustments for Persistent Conditions

The CAISO may adjust the Reasonableness Thresholds for a specific resource in the event of a resource's actual fuel or fuel-equivalent costs, observed by the CAISO in the after-CAISO Market Processes review pursuant to Section 30.12, are systematically greater than the gas price indices or fuel-equivalent costs used by the CAISO in calculating the resource's corresponding Reference Levels.

30.11.2 Reference Level Change Requests

30.11.2.1 Applicability

A Scheduling Coordinator may submit a Reference Level Change Request for Default Start-Up Bids, Default Minimum Load Bids, and Default Energy Bids, as applicable. Scheduling Coordinators may not submit Reference Level Change Requests for Bids by Non-Resource-Specific System Resources. Resources under the Registered Cost methodology are not eligible for Reference Level Change Requests for Default Minimum Load Bids or Default Start-Up Bids. Scheduling Coordinators may not submit Reference Level Change Requests to recover costs associated with gas company imbalance penalties.

30.11.2.2 Requirements

All Reference Level Change Requests must be based on the Scheduling Coordinator's reasonable expectation that its daily actual fuel costs or fuel-equivalent costs for a given Trading Day will exceed the costs used by the CAISO to calculate the resource's Reference Levels, and must reflect reasonable and prudent procurement practices. All Reference Level Change Requests must be calculated using actual or expected fuel costs or fuel-equivalent costs supported by Documentation of Contemporaneously Available Information.

30.11.3 Automated Reference Level Change Requests

30.11.3.1 Applicability

Scheduling Coordinators may submit automated Reference Level Change Requests. The CAISO will evaluate automated Reference Level Change Requests prior to the time the applicable CAISO Market Process is executed based on the Reasonableness Thresholds the CAISO calculates for each resource as specified in Section 30.11.1. The Scheduling Coordinator shall not submit a Reference Level Change Request for the purpose of inflating its Default Energy Bids or Default Commitment Cost Bids beyond what these values would be if calculated based on its actual or expected costs, without applying the Default Energy Bid Multiplier or Commitment Cost Multiplier. Scheduling Coordinators shall not submit an automated Reference Level Change Request that is supported by the same Documentation of Contemporaneously Available Information submitted with a manual Reference Level Change Request that the CAISO previously denied. The CAISO shall not accept automated Reference Level Change Requests for Hydro Default Energy Bids.

30.11.3.2 Requirements

Scheduling Coordinators must calculate the Reference Levels amounts included in their Reference Level Change Requests using the same methodology used to calculate the Proxy Cost-based Default Start-Up Bid, (without applying the Commitment Cost Multiplier), the Proxy Cost-based Default Minimum Load Bid (without applying the Commitment Cost Multiplier), and the Variable Cost-based Default Energy Bid (without applying the Default Energy Bid Multiplier).

30.11.3.3 Contemporaneously Available Supporting Documentation

Although the Scheduling Coordinator does not submit Documentation of Contemporaneously Available Information when it submits an automated Reference Level Change Request, the Scheduling Coordinator must retain the Documentation of Contemporaneously Available Information. The CAISO may request the Scheduling Coordinator to provide the CAISO with Documentation of Contemporaneously Available Information pursuant to Section 30.11.3.4.

30.11.3.4 Evaluation of Automated Reference Level Change Requests

If the Reference Level change submitted by the Scheduling Coordinator for a resource in the automated Reference Level Change Request is equal to or less than the applicable Reasonableness Threshold for the resource, the CAISO will approve the Revised Default Commitment Cost Bid and Revised Default Energy Bid. If the Reference Level change submitted by the Scheduling Coordinator for a resource in the automated Reference Level Change Request process exceeds the applicable Reasonableness Threshold for the resource, the CAISO will approve the revised Reference Level to equal the resource's Reasonableness Threshold.

30.11.3.5 CAISO Audit of Automated Reference Level Change Requests

(a) **Audit Process**. The CAISO may audit a Scheduling Coordinator that submits an automated Reference Level Change Request at any time and may request the Scheduling Coordinator to provide the CAISO with its cost calculations and Documentation of Contemporaneously Available Information. In response to a CAISO audit request for information related to the audit, the Scheduling Coordinator must respond with the requested information within five (5) Business Days of the CAISO's request. The CAISO will evaluate the submitted information and determine whether it supports the Scheduling Coordinator's automated Reference Level Change Request within ten (10) Business Days of receipt of the Scheduling Coordinator's cost calculations and Documentation of Contemporaneously Available Information.

(b) In the event the CAISO determines the submitted information does not support the Reference Level Change Request, the Scheduling Coordinator may request CAISO ADR Procedures as specified in Section 13 of the CAISO Tariff within five (5) Business Days of the CAISO's response. If the Scheduling Coordinator requests CAISO ADR Procedures, the Scheduling Coordinator will not be permitted to submit automated Reference Level Change Requests for the affected resource as specified in Section 30.11.3.4(c) while the CAISO ADR Procedures are pending. If the CAISO ADR Procedures confirm that the Documentation of Contemporaneously Available Information did not support the Scheduling Coordinator's automated Reference Level Change Request, the Scheduling Coordinator will be prohibited from submitting automated Reference Level Change Requests until the time period specified in Section 30.11.3.4(c) has elapsed.

(c) **Consequence for Failure to Comply with CAISO Requirements**. If the CAISO determines that the Documentation of Contemporaneously Available Information submitted by the Scheduling Coordinator does not support a conclusion that the Scheduling Coordinator's actual or expected fuel costs, or fuel-equivalent costs, for a resource as calculated in Section 30.11.2.2 were higher than those the CAISO used to determine the resource's Reference Levels:

(1) The CAISO shall prohibit the Scheduling Coordinator from making any automated Reference Level Change Requests for the affected resource for sixty (60) days from the time the CAISO informs the Scheduling Coordinator that it did not submit Documentation of Contemporaneously Available Information that supports the Scheduling Coordinator's automated Reference Level Change Request.

(2) Any subsequent determination that the Scheduling Coordinator did not submit Documentation of Contemporaneously Available Information that supports its automated Reference Level Change Request will result in the CAISO prohibiting the Scheduling Coordinator from making any automated Reference Level Change Requests for the affected resource for one hundred eighty (180) days from the time the CAISO informs the Scheduling Coordinator of the subsequent failure to submit Documentation of Contemporaneously Available Information that supports its automated Reference Level Change Request.

30.11.4 Manual Reference Level Change Requests

30.11.4.1 Applicability

Scheduling Coordinators may request a manual Reference Level Change Request when the Scheduling Coordinator's actual or expected fuel costs or fuel-equivalent costs exceed the fuel or fuel-equivalent costs the CAISO used to calculate a resource's Reference Level by the greater of ten percent (10%) or $0.50/MMBTU, as applicable. The Scheduling Coordinator may submit a manual Reference Level Change Request for:

(a) Default Energy Bids, Default Start-Up Bids, and Default Minimum Load Bids for natural gas-fired resources; and

(b) Default Energy Bids for non-natural gas-fired resources.

30.11.4.2 Requirements

Scheduling Coordinators must submit any manual Reference Level Change Requests by 8:00 a.m. of the Business Day on which the applicable CAISO Market is executed. Scheduling Coordinators must submit in their manual Reference Level Change Requests their actual or expected fuel costs that they request the CAISO to validate and to be used to calculate their resource's Reference Levels. For gas-fired resources, the Scheduling Coordinator must submit the gas fuel cost only and not include the gas transportation cost. Upon submission of a manual Reference Level Change Request, the Scheduling Coordinator must submit Documentation of Contemporaneously Available Information that shows that its resource's actual or expected fuel costs or fuel-equivalent costs exceed the fuel or fuel-equivalent costs used to calculate the resource's Reference Level.

30.11.4.3 Evaluation of Manual Reference Level Change Requests

The CAISO will evaluate requested fuel costs submitted in the manual Reference Level Change Requests based on information submitted by the Scheduling Coordinator and any other available evidence of current costs that applies to the Reference Level Change Request: (1) as practicable prior to the execution of the applicable Day-Ahead Market; and (2) as soon as practicable after submission of the manual Reference Level Change Request for the Real-Time Market. This evaluation will consist of whether the submitted information supports a change in the Reference Level. If the fuel cost submitted in the manual Reference Level Change Request is accepted, the CAISO will recalculate the Reference Level using the accepted actual or expected fuel costs (without applying the Commitment Cost Multiplier or the Default Energy Bid Multiplier). The CAISO will apply the Revised Default Commitment Cost Bid and Revised Default Energy Bid for use in the CAISO Market Processes and for Settlement purposes as specified in Section 30.11.5. If the CAISO does not accept the submitted actual or expected fuel costs, the CAISO will make no changes to the Reference Level.

30.11.5 Application of Revised Reference Level

For the Day-Ahead Market, the Revised Default Commitment Cost Bids and Revised Default Energy Bid will apply to the applicable Trading Day of the Day-Ahead Market. For the Real-Time Market, the Revised Default Commitment Cost Bids and Revised Default Energy Bid will apply from the Real-Time Market Trading Hour for which it is practicable for the CAISO to apply the change until the last Trading Hour of the Trading Day for which the Reference Level Change Request was specified. The CAISO will not update the applicable Reasonableness Threshold when it accepts an automated Reference Level Change Request. The CAISO will update a resource's applicable Reasonableness Threshold to equal the resource's Reference Level when it accepts a manual Reference Level Change Request. The Scheduling Coordinator may submit an application for after-CAISO Market Process adjustments pursuant to Section 30.12 for any costs not verified through the automated Reference Level Change Request process or that were rejected through the manual Reference Level Change Request process.

30.11.6 Hydro Default Energy Bids

In the event a Scheduling Coordinator that controls both a hydro resource and a natural gas-fired resource in the same gas fuel region submits a manual Reference Level Change Request for both the hydro resource's Hydro Default Energy Bid and the natural gas-fired resource's Reference Level, and the CAISO accepts the manual Reference Level Change Request for the natural gas-fired resource, the CAISO may also update the natural gas price used in the calculation of a hydro resource's Hydro Default Energy Bid when the CAISO adjusts the gas price used in the Reasonableness Thresholds for the entire gas fuel region in which the hydro resource is located pursuant to Section 30.11.1.

30.12 After-CAISO Market Process Cost Recovery~~[Not Used]~~

30.12.1 Applicability ~~[Not Used]~~

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 amounts in a Reference Level Change Request that were not approved pursuant to Section 30.11. Scheduling Coordinators may not request additional uplift payments under this section to cover costs associated with gas company imbalance penalties.

30.12.2 Notice ~~[Not Used]~~

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.

30.12.3 Supporting Documentation ~~[Not Used]~~

Scheduling Coordinators must submit supporting documentation 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 ~~[Not Used]~~

30.12.4.1 Process

If the Scheduling Coordinator requests that the CAISO evaluate the costs specified in Section 30.12.1, 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 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 using revised Bid Costs 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

If the CAISO is unable to verify within the sixty (60) Business Day period that the resource's incurred costs are eligible for evaluation pursuant to this Section 30.12.4, the 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, the Scheduling Coordinator may 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

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

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.

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31.3.1 Market Clearing and Price Determination

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31.3.1.3 Reduction of Self-Scheduled LAP Demand

In the IFM, to the extent the market software cannot resolve a non-competitive Transmission Constraint utilizing Effective Economic Bids such that self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-~~p~~Priced

Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-~~p~~Priced Quantity to be adjusted, will be:

(a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Resource~~Unit~~ or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR Resource~~Unit~~ or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM process.

(b) Relax the constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

31.3.1.4 Eligibility to Set the Day-Ahead LMP

All Generating Units, Participating Loads, non-Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, System Resources, System Units, or Constrained Output Generators subject to the provisions in Section 27.7, with Bids, including Generated Bids, that are unconstrained due to Ramp Rates, MSG Transitions, Forbidden Operating Regions, or other temporal constraints are eligible to set the LMP, provided that (a) the Schedule for the Generating Unit or Resource-Specific System Resource is between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid;~~,~~ or (b) the Schedule for the Participating Load, non-Participating Load, Proxy Demand Resources, Reliability Demand Response Resources, ~~n~~Non-Resource-Specific System Resource, or System Unit is between zero (0) MW and the highest MW value in its Economic Bid or Generated Bid. If (a) a resource's Schedule is constrained by its Minimum Operating Limit or the highest MW value in its Economic Bid or Generated Bid;~~,~~ (b) the CAISO enforces a resource-specific constraint on the resource due to an ~~Legacy~~ RMR Dispatch of a Legacy RMR Unit or Exceptional Dispatch;~~,~~ (c) the resource is constrained by a boundary of a Forbidden Operating Region or is Ramping through a Forbidden Operating Region;~~,~~ or (d) the resource's full Ramping capability is constraining its inter-hour change in

Schedule, the resource cannot be marginal and thus is not eligible to set the LMP. Resources identified as MSS Load following resources are not eligible to set the LMP. A Constrained Output Generator will be eligible to set the hourly LMP if any portion of its Energy is necessary to serve Demand.

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31.5.6 Eligibility for RUC Compensation

All RUC Capacity is eligible for the RUC Availability Payment except for: (i) RMR Capacity from RMR Resources; (ii) Resource Adequacy Capacity; and (iii) RUC Capacity that corresponds to the resource's Minimum Load, which is compensated through the Bid Cost Recovery as described in Section 11.8. Resources not committed in the IFM that are committed in RUC, including Condition 1 Legacy RMR Units that were not designated for ~~Legacy~~ RMR Dispatches and Resource Adequacy Resources, are also eligible for RUC Cost Compensation, which includes Start-Up, Transition Costs, and Minimum Load Cost compensation, and Bid Cost Recovery, subject to the resource actually following its Dispatch Instructions as verified by the CAISO pursuant to procedures set forth in the Business Practice Manuals.

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34.7 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four (4) seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements and Uncertainty Requirements over the applicable forward-looking time period of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast ~~O~~of CAISO Demand or forecast of EIM Demand, adjusted as necessary by the CAISO or EIM operator to reflect scheduled

changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTDD and RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Submissions to Self-Provide an Ancillary Service;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire forward-looking time period, the Dispatch for the target Dispatch Interval will be affected by: (a) Dispatch Instructions in prior intervals;~~,~~ (b) actual output of the resource;~~,~~ (c) forecasted conditions in subsequent intervals within the forward-looking time period of the optimization;~~,~~ and (d) operational constraints of the resource, such that a resource may be dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval, considering the applicable MSG Configuration;

(7) Through Start-Up Instructions the CAISO may instruct resources to ~~s~~Start~~- u~~Up or ~~s~~Shut-~~d~~Down, or may reduce Load for Participating Loads, Reliability Demand Response Resources, and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted Bids, Start-Up ~~Cost~~Bids and Minimum Load ~~Cost~~Bids, Pumping

Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only start up resources that can start within the applicable time periods of the various CAISO Markets Processes that comprise the RTM;

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy;~~,~~ (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM;~~,~~ (c) the Generating Unit is not providing Regulation or Spinning Reserve;~~,~~ and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves;

(10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Target remains within the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

(11) For Multi-Stage Generating Resources the CAISO will issue Dispatch Instructions by Resource ID and Configuration ID;

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition ~~Cost~~Bids, and Minimum Load ~~Cost~~Bids, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Run Time and Minimum Down Time defined for each

MSG configuration and Minimum Run Time and Minimum Down Time at the Generating Unit.

(13) The CAISO may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either: (a) after issuance of a warning; (b) during stage 1, stage 2, or stage 3 of a System Emergency; or (c) for a transmission-related System Emergency.

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34.11 Exceptional Dispatch

The CAISO may issue Exceptional Dispatches for the circumstances described in this Section 34.11, which may require the issuance of forced Shut-Downs, forced Start-Ups, or forced MSG Transitions and shall be consistent with Good Utility Practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the CAISO Operator into the Day-Ahead or RTM optimization software so that they will be accounted for and included in the communication of Day-Ahead Schedules and Dispatch Instructions to Scheduling Coordinators. Exceptional Dispatches are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch. When considering the issuance of an Exceptional Dispatch to RA Capacity, the CAISO shall consider the effectiveness of the resource from which the capacity is being provided, along with Start-Up ~~Cost~~Bids, Transition ~~Cost~~Bids, and Minimum Load ~~Cost~~Bids, as adjusted pursuant to Section 30.7.10.2, if applicable, when issuing Exceptional Dispatches to commit a resource to operate at Minimum Load. When the CAISO issues Exceptional Dispatches for Energy to RA Capacity, the CAISO shall also consider Energy Bids, if available and as appropriate. Additionally, where the Exceptional Dispatch results in a CPM designation, the CAISO shall make CPM designations of Eligible Capacity for an Exceptional Dispatch by applying the criteria and procedures specified in Section 43A.4.

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39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for capacity of non-Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 will be limited to one hundred fifty ~~150~~ percent (150%) of the Projected Proxy Cost. The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for capacity of Multi-Stage Generating Resources that are eligible and elect to use the Registered Cost methodology in accordance with Section 30.4 will be limited to ~~150~~ one hundred fifty percent (150%) of the Projected Proxy Cost for each MSG Configuration of the resources. The Projected Proxy Cost for natural gas-fired resources will include a gas price component, a major maintenance expense component, if available, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6. The Projected Proxy Cost for non-natural gas-fired resources will be based on costs provided to the CAISO pursuant to Section 30.4.5.2~~1.1.2~~, a major maintenance expense component, if available, a volumetric Grid Management Charge component, and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 39.6.1.6.

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas-fired resources, the CAISO will calculate a gas price to be used in establishing ~~maximum~~ Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids after the twenty-first (21st) day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators for natural gas-fired Use-Limited Resources electing to use the Registered Cost methodology set forth in Section 30.4.7 until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California

delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery points, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the ~~caps for~~ Default Start-Up Bids and Default Minimum Load ~~Cost~~Bids for Use-Limited Resources electing to use the Registered Cost methodology set forth in Section 30.4.7. The most geographically appropriate prices will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set forth in the Business Practice Manual will be added to the baseline gas price for each Use-Limited Resource that elects to use the Registered Cost methodology set forth in Section 30.4.7 to create a final gas price for calculating the ~~caps for~~ Default Start-Up Bids and Default Minimum Load ~~Cost~~Bids for each such resource.

For non-natural gas-fired resources, the Projected Proxy Costs for Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids will be calculated using the information ~~contained~~ as registered in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

39.6.1.6.2 Projected Greenhouse Gas Allowance Price

For resources that are registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a projected Greenhouse Gas Allowance Price component to be used in establishing maximum Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids after the twenty-first (21st) day of each month and will post it on the CAISO Website by the end of that month. The projected Greenhouse Gas Allowance Price component will be applicable for Scheduling Coordinators on behalf of eligible Use-Limited Resources electing to use the Registered Cost methodology until a new projected Greenhouse Gas Allowance Price component is calculated and posted on the CAISO Website. The projected Greenhouse Gas Allowance Price component will be calculated by averaging the applicable daily Greenhouse Gas Allowance Prices calculated over the first twenty (20) days of the month using the methodology set forth in Section 39.7.1.1.1.4.

39.6.1.6.3 Major Maintenance Expense Component

The major maintenance expense component is determined based on the process set forth in Section 30.4.5~~1~~.~~1.~~4.

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39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a volumetric Grid Management Charge adder plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, by multiplying the sum by the Default Energy Bid Multiplier~~adding ten percent (10%) to the sum~~, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel or fuel-equivalent cost plus a volumetric Grid Management Charge plus a greenhouse gas cost adder if applicable, multiplying the sum by the Default Energy Bid Multiplier~~adding ten percent (10%) to the sum~~, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any.

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39.7.1.1.1.2 Non-Natural Gas-Fired Resources

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel or fuel equivalent costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty ~~(80)~~ percent (80%) of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. The CAISO will include, if applicable: (i) greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource; ~~and~~ (ii) variable operation and maintenance cost; and (iii) a volumetric Grid Management Charge adder that consists of: (a~~i~~) the Market Services Charge; (b~~ii~~) the System Operations Charge; and (c~~iii~~) the Bid Segment Fee divided by the MW in the Bid segment. Cost curves shall be stored, updated, and validated in the Master File.

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39.7.1.1.2 Variable Operation and Maintenance Cost Under the Variable Cost Option

The default value for the variable operation and maintenance cost portion will vary by fuel source or technology as follows: (1) solar $0.00/MWh; (2) nuclear $1.00/MWh; (3) coal $2.00/MWh; (4) wind $2.00/MWh; (5) hydro $2.50/MWh; (6) natural gas-fired combined cycle and steam units $2.80/MWh; (7) geothermal $3.00 WMh; (8) landfill gas $4.00/MWh; (9) combustion turbines and reciprocating engines $4.80/MWh; and (10) biomass $5.00/MWh. Resource~~-~~-specific values may be negotiated with the CAISO or the Independent Entity charged with calculating the Default Energy Bid. Default operation and maintenance values as well as any negotiated values will also be used to calculate Default Minimum Load ~~Cost~~Bids pursuant to Section 30.4.

39.7.1.1.3 Variable Energy Opportunity Costs Under the Variable Cost Option

The CAISO will determine eligibility for Variable Energy Opportunity Costs for Use-Limited Resources pursuant to Section 30.4.~~1.1.~~6.

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39.7.1.3.1 Submission Process

Scheduling Coordinators that elect the Negotiated Rate Option for the Default Energy Bid shall submit a proposed Default Energy Bid along with supporting information and documentation as described in a BPM. Within ten (10) Business Days of receipt, the CAISO or an Independent Entity selected by the

CAISO will provide a written response. If the CAISO or Independent Entity accepts the proposed Default Energy Bid, it will generally become effective within eleven (11) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO or Independent Entity selected by the CAISO does not accept the proposed Default Energy Bid, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates sixty (60) days following the date of submission of a proposed Default Energy Bid by a Scheduling Coordinator. If at any time during this period, the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator agree upon the Default Energy Bid, it will generally become effective within eleven (11) Business Days of the date of agreement and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the sixty (60)-day period the CAISO or Independent Entity selected by the CAISO and the Scheduling Coordinator fail to agree on the Default Energy Bid to be used under the Negotiated Rate Option, the Scheduling Coordinator has the right to file a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the sixty (60)-day period following the submission of a proposed negotiated Default Energy Bid by a Scheduling Coordinator, and pending FERC's acceptance in cases where the CAISO or Independent Entity selected by the CAISO fail to agree on the Default Energy Bid for use under the Negotiated Rate Option and the Scheduling Coordinator filed a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to Section 39.7. If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of these options, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5.

Any negotiated Default Energy Bid for a resource that includes an opportunity cost component as of April 1, 2019, will remain in effect, subject to the CAISO's renegotiation rights pursuant to Section 39.7.1.3.2.1, unless the Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.~~1.1.~~6.1.2. If a Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.~~1.1.~~6.1.2, the Scheduling Coordinator must either elect the Variable Cost Default Energy Bid or the CAISO will renegotiate the negotiated Default Energy Bid to, at a minimum, utilize the Variable Energy Opportunity Cost as a component of the negotiated Default Energy Bid in place of any previously negotiated Opportunity Cost value.

39.7.1.3.2 Negotiated Values and Informational Filings

39.7.1.3.2.1 Renegotiation of Values

The CAISO may require the renegotiation of any components including adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.5~~1~~.~~1.~~1, 30.4.5~~1~~.~~1.~~2, and 30.4.5~~1~~.~~1.~~4, any Opportunity Costs negotiated pursuant to Section 30.4.~~1.1.~~6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operation and maintenance adders negotiated pursuant to Section 39.7.1.1.2, that have become outdated, are possibly erroneous, or for which the Scheduling Coordinator has changed. In the renegotiation process, the CAISO may review and propose modifications to such values, and may require the Scheduling Coordinator to provide updated information to support continuation of such values.

39.7.1.3.2.2 Informational Filings with FERC

The CAISO shall make an informational filing with FERC of any adders or interim adders for major maintenance expenses determined pursuant to Sections 30.4.5~~1~~.~~1.~~1, 30.4.5~~1~~.~~1.~~2, and 30.4.5~~1~~.~~1.~~4, any Opportunity Costs calculated pursuant to Section 30.4.~~1.1.~~6.2 or negotiated pursuant to Section 30.4.~~1.1.~~6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, any temporary Default Energy Bids established pursuant to Section 39.7.1.5, or any custom operations and maintenance adders negotiated pursuant to Section 39.7.1.1.2, no later than seven (7) days after the end of the month in which the Default Energy or operations and maintenance values were established.

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40.6.8 Use of Generated Bids

(a) **Day-Ahead Market.** Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market.

(b) **Real-Time Market.** Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market.

(c) **Partial Bids for RA Capacity.** If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage.

~~(d) **Calculation of Generated Bids.** A Generated Bid for Energy will be calculated pursuant to Sections 30.7.3.4 and 30.7.3.5. A Generated Bid for Ancillary Services will equal zero dollars ($0/MW-hour).~~

(d~~e~~) **Exemptions.** Notwithstanding any of the provisions of Section 40.6.8, for the following resource types providing Resource Adequacy Capacity, the CAISO only inserts a Bid in the Day-Ahead Market or Real-Time Market where the generally applicable bidding rules in Section 30 call for bid insertion: Use-Limited Resource, Non-Generator Resource, Variable Energy Resource, Hydroelectric Generating Unit (including Run-of River resources), Proxy Demand Resource, Reliability Demand Response Resource, Participating Load, including Pumping Load, Combined Heat and Power Resource, Conditionally Available Resource, Non-Dispatchable Resource, and resources providing Regulatory Must-Take Generation.

(e~~f~~) **NRS-RA Resources.** The CAISO will submit a Generated Bid in the Day-Ahead Market for a ~~n~~Non-Resource-~~-~~Specific System Resource in each RAAIM assessment hour, to the extent that the resource provides Resource Adequacy Capacity subject to the requirements of Section 40.6.1 and does not submit an outage request or Bid for the entire amount of that Resource Adequacy Capacity. Aside from where the generally applicable bidding rules in Section 30 call for Bid insertion, the CAISO will not submit a Generated Bid in the Real-Time Market for a Non-Resource-Specific System Resource that fails to meet its bidding obligations under Section 40.6.2. A Bid inserted for the Real-Time Market pursuant to the generally applicable bidding rules in Section 30 may not necessarily cover the full Real-Time Market obligation under Section 40.6.2 and the resource may thus remain exposed to Non-Availability Charges.

40.6.8.1 Generated Bids for NRS-RA Resources

Generated Bids to be submitted by the CAISO pursuant to Section 40.6.8 for ~~n~~Non-Resource-Specific System Resources that provide Resource Adequacy ~~c~~Capacity shall be calculated in accordance with this Section 40.6.8.1.

40.6.8.1.1 Calculation Options for Generated Bids

The Scheduling Coordinator for each ~~n~~Non-Resource-~~-~~Specific System Resource that provides Resource Adequacy Capacity shall select the price taker option, LMP-based option, or negotiated price option as the methodology for calculating the Generated Bids to be submitted by the CAISO under Section 40.6.8 for both the DAM and RTMs. If no selection is made, the CAISO will apply the price taker option to calculate the Generated Bids. For the first ninety (90) days after a resource becomes a ~~n~~Non-Resource-Specific System Resource, the calculation of Generated Bids for Resource Adequacy capacity is limited to the price taker option or negotiated price option.

40.6.8.1.2 Price Taker Option

The price taker option is a Generated Bid of $0/MWh plus the CAISO's estimate of the applicable ~~g~~Grid ~~m~~Management ~~c~~Charge per MWh based on the gross amount of MWh scheduled in the DAM and RTM.

40.6.8.1.3 LMP-Based Option

The LMP-based option calculates the Generated Bid as the weighted average of the lowest quartile of LMPs, at the Intertie point designated for the ~~n~~Non-Resource-Specific System Resource's Resource Adequacy Capacity in the Supply Plan, during periods in which the resource was dispatched in the preceding ninety (90) days for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Generated Bid curve. Each Bid segment created under the LMP-based option for Generated Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP-based Generated Bid. The feasibility test is designed to avoid excessive volatility of the Generated Bid under the LMP-based option that could result when calculated based on a relatively small number of prices. If the Scheduling Coordinator for the ~~n~~Non-Resource-~~-~~Specific System Resource elects the LMP-based method, it must additionally select either the price ~~-~~taker method or the negotiated-rate method as the alternative calculation method for the Generated Bids in the event that the feasibility test fails for the LMP-based method.

* * * * *

40.6.8.1.5 Partial Bids

If a Scheduling Coordinator for a ~~n~~Non-Resource-Specific System Resource that provides Resource Adequacy Capacity submits a ~~b~~Bid for a MW quantity less than the Resource Adequacy Capacity identified in the resource's Supply Plan, the CAISO will insert a Generated Bid only for the remaining Resource Adequacy Capacity by extending the last segment of the resource's bid curve to the full quantity (MWh) of the Resource Adequacy obligation.

40.6.8.1.6 [Not Used]

* * * * *

Appendix A

Master Definitions Supplement

* * * * *

- Bid Costs

The costs for resources manifested in the Bid components submitted, which include the Start-Up Bid Cost, Minimum Load Bid Cost, Energy Bid Cost, Transition Bid Cost~~s~~, Pump Shut-Down Cost, Pumping Cost, Ancillary Services Bid Cost, and RUC Availability Payment.

* * * * *

- Commitment Cost Multiplier

The percentage amount by which the Proxy Costs are multiplied in calculating the Default Commitment Cost Bids, which is equal to one hundred twenty five percent (125%).

* * * * *

- Conditionally Available Resource

A resource that has demonstrated to the CAISO's reasonable satisfaction that it has one or more regulatory or operational limits that are not eligible use limits pursuant to Section 30.4.~~1.1.~~6.1.1 and that faces frequent and recurring periods of unavailability because of those limitations. A resource can be both a Conditionally Available Resource and a Use-Limited Resource if it has eligible use limits and also meets the definition of a Conditionally Available Resource.

* * * * *

- Default Commitment Cost Bids

Default Commitment Cost Bids are Default Start-Up Bids, Default Minimum Load Bids, and Default Transition Bids.

*****

- Default Energy Bid

The cost-based Energy Bid Curve calculated by the CAISO pursuant to Section 39, and used, among other things, in Local Market Power Mitigation ~~pursuant to Section 39~~.

*****

- Default Energy Bid Multiplier

The percentage amount by which the variable costs used to calculate the Default Energy Bid under Variable Cost Option are multiplied, which is equal to one hundred ten percent (110%).

- Default Minimum Load Bid

The CAISO's calculation of a resource's Minimum Load Cost pursuant to Section 30.4.

*****

- Default Start-Up Bid

The CAISO's calculation of a resource's Start-Up Cost Curve pursuant to Section 30.4.

*****

- Default Transition Bid

A resource's Transition Costs calculated by the CAISO pursuant to Section 30.4.

*****

- Documentation of Contemporaneously Available Information

Documents that exist when a Reference Level Change Request is submitted that show the price of fuel or fuel-equivalent is based on next-day procurement for the Day-Ahead Market, and is based on same-day or next-day procurement for the Real-Time Market, except for non-standard gas trading days, in which case the documents must show the price of procurement for fuel or fuel-equivalent no sooner than the most recent standard gas trading day. Such documentation may include: quotes from natural gas suppliers; gas purchase invoices; evidence of a bid price that was part of an unsuccessful good faith effort to purchase fuel or fuel-equivalent; or other appropriate documentation demonstrating fuel costs or fuel-equivalent costs.

* * * * *

- Energy Bid Cost

An amount equal to the integral of the Energy Bid for resources ~~that have been selected through the IFM or RTM,~~ operating above PMin.

* * * * *

- Generated Bid

A post-market Clean Bid generated by the CAISO, using the applicable Default Energy Bid and Default Commitment Cost Bids, in accordance with the provisions of Section 40 or other applicable provisions of the CAISO Tariff when a Bid is not submitted by ~~the~~ a Scheduling Coordinator and is required for a ~~r~~Resource ~~a~~Adequacy requirement, an Ancillary Services Award, a RUC Award, a Day-Ahead Schedule, or as required by Section 30.7.3.5.

* * * * *

- IFM AS Bid Cost

The Bid Cost for Ancillary Service capacity a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.6.

* * * * *

- IFM Energy Bid Cost

The Energy Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.5.

* * * * *

- IFM Minimum Load Cost

The Minimum Load Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.2.

* * * * *

- IFM Pump Shut-Down Cost

The Pump Shut-Down Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.3.

* * * * *

- IFM Pumping Cost

The Pumping Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.4.

* * * * *

- IFM Start-Up Cost

The Start-Up Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.1.

* * * * *

- IFM Transition Cost

The Transition Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.2.1.7.

* * * * *

- Minimum Load Bid

The Bid component that indicates the Minimum Load Cost for the Generating Unit, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource specified by a non-negative number in dollars per hour ($/hr), which applies for the entire Trading Day for which it is submitted. Minimum Load Bids are subject to modification pursuant to the rules specified in Sections 30.7.10 and 30.11.

- Minimum Load Bid Cost

The Minimum Load Costs submitted in a Minimum Load Bid as modified pursuant to Sections 30.7.10 and 30.11 used for purposes of clearing the applicable CAISO Market Process and for Bid Cost Recovery.

- Minimum Load Costs

The costs a Generating Unit, Resource-Specific System Resource, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource incurs operating at Minimum Load, which in the case of Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource ~~may~~ must ~~not~~ be non-negative~~. Minimum Load Costs~~ and may be adjusted pursuant to Section 30.7.10.2, if applicable.

* * * * *

- Minimum Load Opportunity Costs

An adder consisting of the estimated profits foregone by a Use-Limited Resource with a limitation on its number of run-hours that satisfies the definition of a Use-Limited Resource and applies for a time period that satisfies the requirements of Section 30.4.~~1.1.~~6.1, if the Use-Limited Resource had one less run-hour in the time period.

* * * * *

- Non-Resource-Specific System Resource

A System Resource that is not a Resource-Specific System Resource.

* * * * *

- Projected Proxy Cost

A calculation of a resource's Default Start-Up ~~Cost~~Bids and Default Minimum Load ~~Cost~~Bids for a prospective period used to determine the maximum Registered Cost for the resource, as set forth in Section 39.6.1.6 for a thirty (30)-day period pursuant to Section 30.4.

* * * * *

- Proxy Cost

The Proxy Start-Up Costs, Proxy Transition Costs, or Proxy Minimum Load Costs ~~cost basis~~ of a generating resource for which the operating cost is calculated as an approximation of the actual operating cost pursuant to Section 30.4.5~~1.1~~.

* * * * *

- Proxy Minimum Load Cost

A resource's Minimum Load Costs, calculated pursuant to the methodology specified in Section 30.4.5.

- Proxy Start-Up Cost

A resource's Start-Up Costs, calculated pursuant to the methodology specified in Section 30.4.5.

- Proxy Transition Cost

A resource's Transition Costs, calculated pursuant to the methodology specified in Section 30.4.5.

* * * * *

- Reasonableness Threshold

The cost-based criteria the CAISO uses to evaluate Reference Level Change Requests through an automated process, which represents a reasonable cost-based Energy Bid, Start-Up Bid, and Minimum Load Bid, calibrated to a resource's costs as described in Section 30.11.

* * * * *

- Reference Levels

A Default Start-Up Bid, Default Minimum Load Bid, and Default Energy Bid.

- Reference Level Change Request

A change requested by a Scheduling Coordinator to a resource's Reference Levels pursuant to Section 30.11.

* * * * *

- Registered Cost

The cost basis of a generating resource for which the operating cost is determined from registered values pursuant to Section 30.4.7~~1.2~~.

* * * * *

- Revised Default Commitment Cost Bids

Default Commitment Cost Bids produced as part of an accepted automated or manual Reference Level Change Request, which are calculated without including the Commitment Cost Multiplier.

- Revised Default Energy Bid

The Default Energy Bid produced as part of an accepted automated or manual Reference Level Change Request, which are calculated without including the Default Energy Bid Multiplier.

* * * * *

- RTM AS Bid Cost

The Bid Cost ~~of a BCR Eligible Resource~~ for Ancillary Service capacity ~~in the RTM~~ a Scheduling Coordinator may be eligible to recover pursuant to Section 11.8.4.1.6.

* * * * *

- RTM Energy Bid Cost

The Energy Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.5.

* * * * *

- RTM Minimum Load Cost

The Minimum Load Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.2.

* * * * *

- RTM Pump Shut-Down Cost

The Pump Shut-Down Cost a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.3.

- RTM Pumping Cost

The Pumping Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.4.

* * * * *

- RTM Start-Up Cost

The Start-Up Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.1.

* * * * *

- RTM Transition Cost

The Transition Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.4.1.7.

* * * * *

- RUC Minimum Load Cost

The Minimum Load Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.3.1.2.

* * * * *

- RUC Start-Up Cost

The Start-Up Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.3.1.1.

- RUC Transition Cost

The Transition Bid Costs a Scheduling Coordinator may be eligible to recover through the Bid Cost Recovery process, calculated pursuant to Section 11.8.3.1.4.

* * * * *

- Start-Up Bid

The Bid component that indicates the Start-Up Time and Start-Up Cost curves for the Generating Unit, which applies for the entire Trading Day for which it is submitted. Start-Up Bids ~~Cost curves~~ are subject to modification pursuant to the rules set forth in Sections 30.7.8 and 30.11.~~strictly monotonically increasing non-negative staircase curves, up to three segments, which represent a function of Start-Up Cost versus down time.~~

- Start-Up Bid Cost

The Start-Up Costs submitted in a Start-Up Bid as modified pursuant to Sections 30.7.8 and 30.11, and used for purposes of the determination of Bid Cost Recovery.

* * * * *

- Start-Up Cost Curve

The format of the Start-Up Bid or the Default Start-Up Bids that must be strictly monotonically increasing non-negative staircase curves, of up to three (3) segments, which represent a function of Start-Up Cost versus down time.

* * * * *

- Start-Up Opportunity Costs

An adder consisting of the estimated profits foregone by a Use-Limited Resource with a limitation on its number of starts that satisfies the definition of a Use-Limited Resource and applies for a time period that satisfies the requirements of Section 30.4.~~1.1.~~6.1, if the Use-Limited Resource had one less start in the time period.

* * * * *

- [Not Used] ~~Subset of Hours Contract~~

~~A contract between a Load Serving Entity and a non-Resource-Specific System Resource that requires the resource to make Resource Adequacy Capacity available to the CAISO on designated days and/or during a specified number of hours, less than seven (7) days a week, twenty-four (24) hours a day.~~

*****

- Transition Bid

The Bid component that indicates the Transition Cost to transition a Multi-Stage Generating Resource from one MSG Configuration to another. Transition Bids are subject to modification pursuant to the rules specified in Section 30.7.11.

- Transition Bid Cost

The Transition Cost submitted in a Transition Bid as modified pursuant to Sections 30.7.8 and 30.11, and used for purposes of Bid Cost Recovery.

*****

- Transition Opportunity Cost

Costs derived from the number of Start-Ups required for the Multi-Stage Generating Resource to achieve a specific MSG Configuration.

*****

- Use-Limited Resource

A resource demonstrated to be a Use-Limited Resource pursuant to Section 30.4.~~1.1.~~6.1.1.

*****

- Variable Energy Opportunity Costs

An adder consisting of the estimated profits foregone by a Use-Limited Resource with a limitation on its Energy output that satisfies the definition of a Use-Limited Resource and applies for a time period that satisfies the requirements of Section 30.4.~~1.1.~~6.1, if the Use-Limited Resource had one less megawatt-hour of Energy output in the time period.

*****

APPENDIX G

Pro Forma Reliability Must-Run Contract

* * * * *

ARTICLE 6

OBLIGATIONS TO PARTICIPATE IN CAISO MARKETS

6.1 Must-Offer Obligation

(a) All Units are subject to all applicable CAISO Tariff provisions based on resource type and all applicable Resource Adequacy CAISO Tariff provisions, including the must-offer obligation to submit Energy, Ancillary Services, and Residual Unit Commitment bids for all RMR Contract Capacity in all hours as applicable. Consistent with Section 40 of the CAISO Tariff, Units subject to this Agreement will be subject to Resource Adequacy bid generation provisions unless otherwise exempted pursuant to CAISO Tariff Section 40.

(b) All Units must seek to establish a major maintenance adder pursuant to CAISO Tariff Section 30.4.5~~1~~.~~1.~~4.

(c) If the Unit has an eligible use limit Owner must establish an Opportunity Cost, if applicable under CAISO Tariff Section 30.4.~~1.1.~~6. In addition, Owner must provide on Schedule L, on an annual basis, the number of remaining start-ups, run hours and MWhs for each Unit prior to the need for Capital Items to perform major maintenance. If the resource can safely provide the reliability service that is needed for the Contract Year in issue, CAISO may direct Owner to include these limits in the Opportunity Cost calculation process established under CAISO Tariff Section 30.4.~~1.1.~~6.

(d) Owner has the obligation to submit marginal cost-based bids that include 100 percent of Commitment Costs using the Proxy Cost Methodology set forth in CAISO Tariff Section 30.4.5~~1.1~~, including any major maintenance adder and Opportunity Cost using limits established under Section 6.1(c) and calculated pursuant to CAISO Tariff Section 30.4.5~~1.1~~. Marginal cost-based Commitment Cost and Energy Bids must be based on the same cost-based components used in CAISO's generated Proxy Costs and Variable Cost Default Energy Bids set forth in the CAISO Tariff and applicable CAISO BPM, plus 100 percent of any approved adders. Cost-based Ancillary Services and Residual Unit Commitment bids must equal $0/MW. Units may not exercise any bidding flexibility with respect to Commitment Cost or Energy bidding with the exception of fuel costs, where the fuel cost component can be higher than the price reflected in the CAISO Gas Price Index if the actual fuel costs exceed the Gas Price Index. The Owner shall procure all required fuel for operation of the Unit using prudent and good utility practice.

(e) For Units exempt from bid insertion, CAISO will monitor compliance with the bidding obligation.

(f) If the Unit has eligible use-limits under the CAISO Tariff or this Agreement, CAISO may order Owner to submit an appropriate outage card pursuant to the applicable CAISO BPM if CAISO determines that participation in CAISO Markets would impair CAISO's ability to dispatch the Unit to meet reliability needs at other times during the Contract Year.

* * * * *

APPENDIX II

Market-Based Rate Authority Suspension

4. Minimum Load, Start-Up, and Transition Costs

4.1. The Scheduling Coordinator responsible for submitting the resource's Minimum Load and Start-Up Costs for the resources of Market Participants subject to this Appendix will not be entitled to select the Registered Cost option available under Section 30.4.7~~1.2~~ and can only select the Proxy Cost option as specified in Section 30.4.5~~1.1~~ of the CAISO Tariff for their Minimum Load and Start-Up Costs.

4.2. If the resource is registered with the CAISO as a Multi-Stage Generating Unit resource, the Scheduling Coordinator may only register a Transition Cost of $0 per MW hour.

4.3. If the resource lacks a Start-Up or Minimum Load Cost in any market intervals, the CAISO will insert the Start-Up or Minimum Load Costs calculated based on the Proxy Cost option.

Attachment C – Second Revised Draft Final Proposal

Commitment Costs and Default Energy Bid Enhancements

California Independent System Operator Corporation

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

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[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.

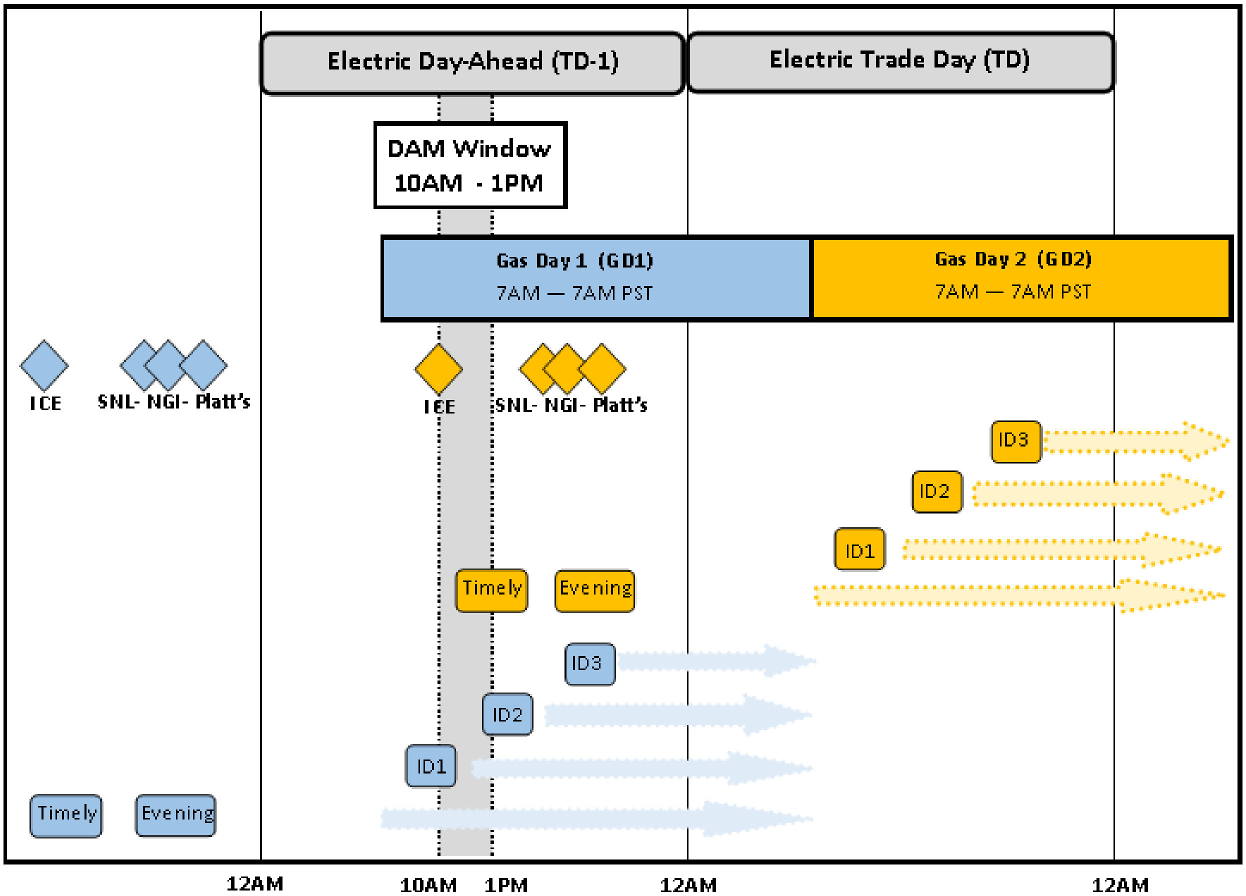

Figure 1: Gas and Electric Day Timelines effective April 1, 2016 (Order 809)

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.

Revising bid-in market based offer for MLC to an hourly component would allow for the values to vary across hours as shown by hourly bids and allowing SC to select hours to participate

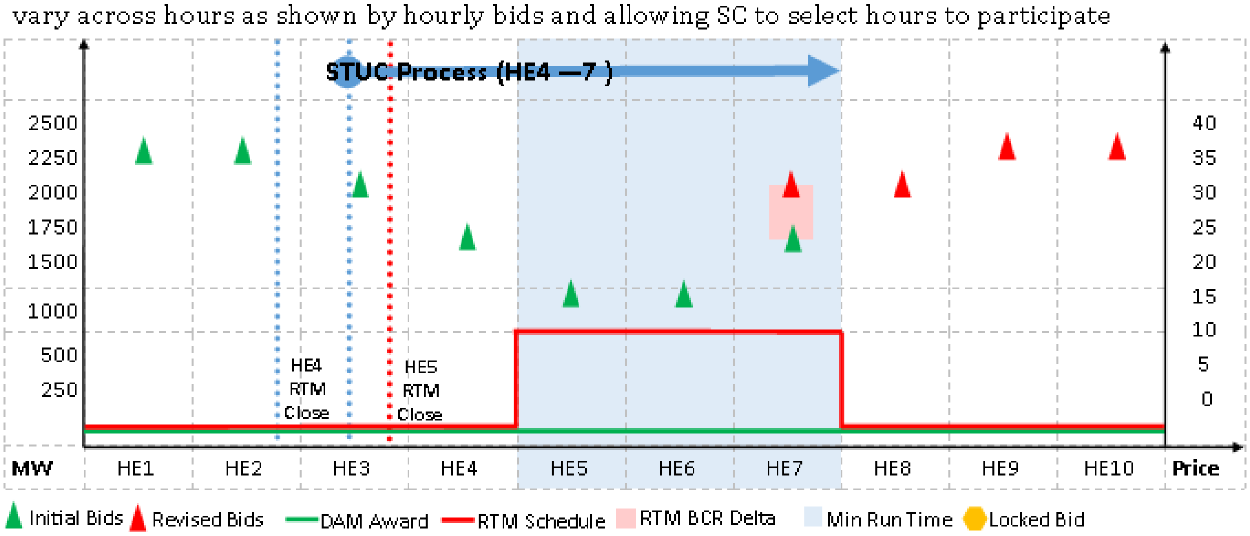

Figure 2: Illustration of proposed change for hourly minimum load

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.

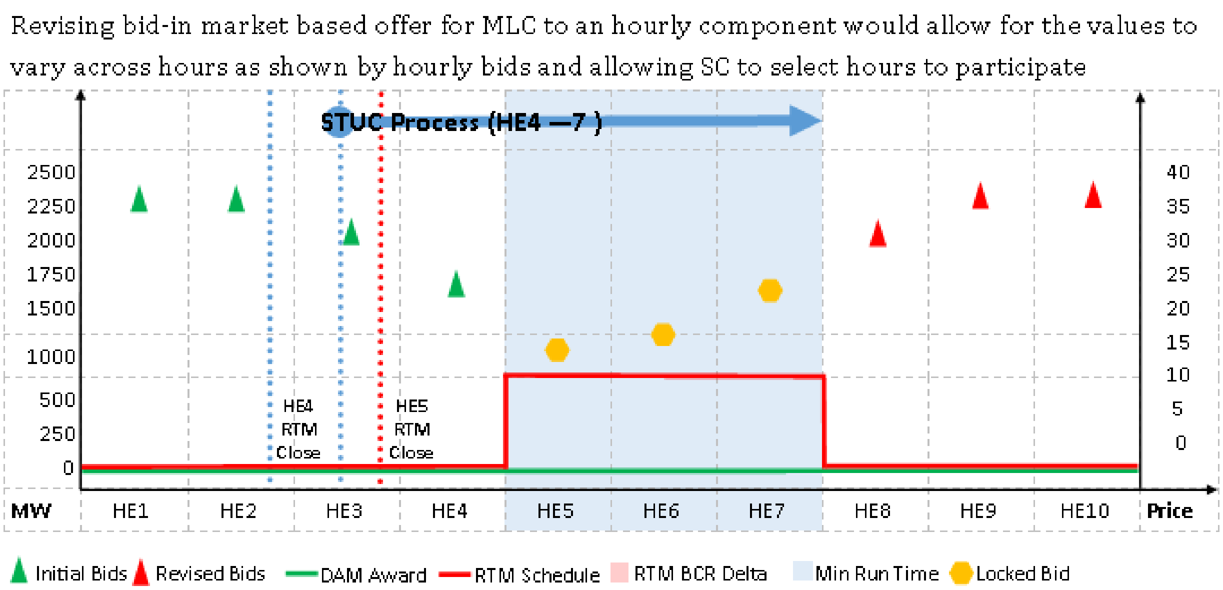

Figure 3: Illustration of rebidding rules on proposed change, no changes inside intertemporal constraints

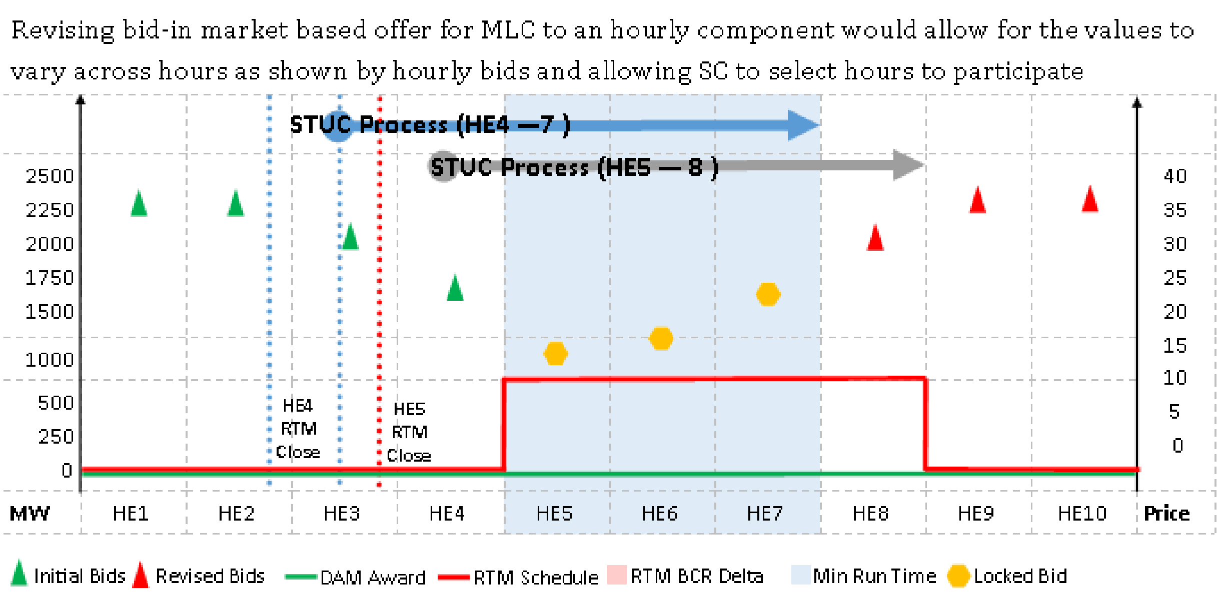

Figure 4shows the next STUC run for hours ending 5 through 8. In this run the market accepts the revised minimum load bid at the higher level of $2,000/hour for hour ending 8. If unmitigated, the market will use this value in the assessment of the unit's economics. This is appropriate because the unit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

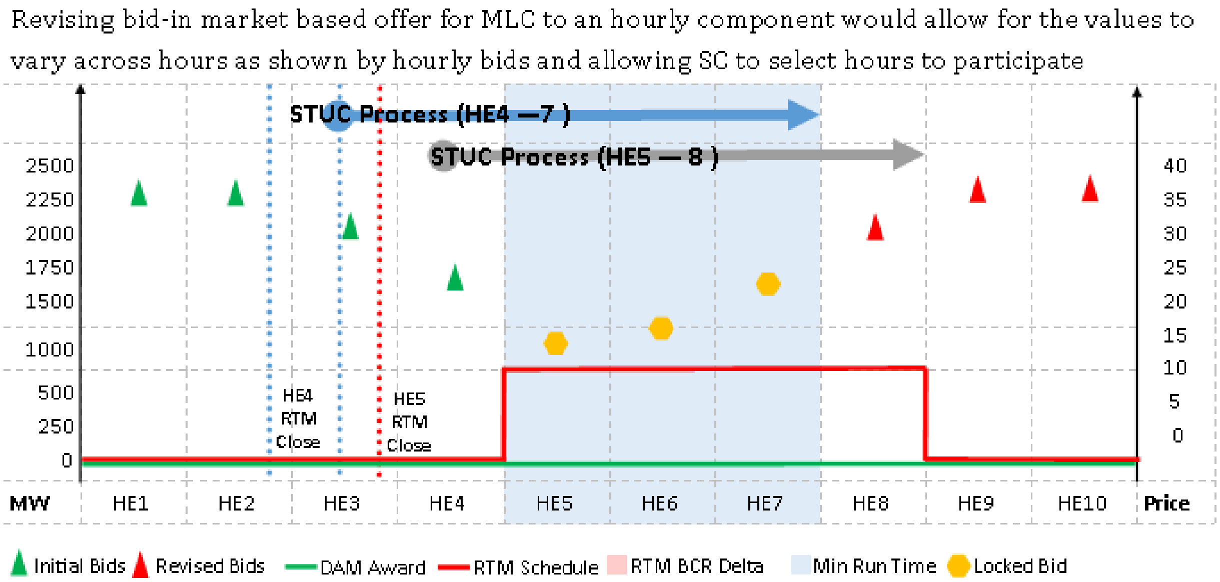

Figure 4: Illustration of rebidding rules on proposed change, changes outside of intertemporal constraints

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.

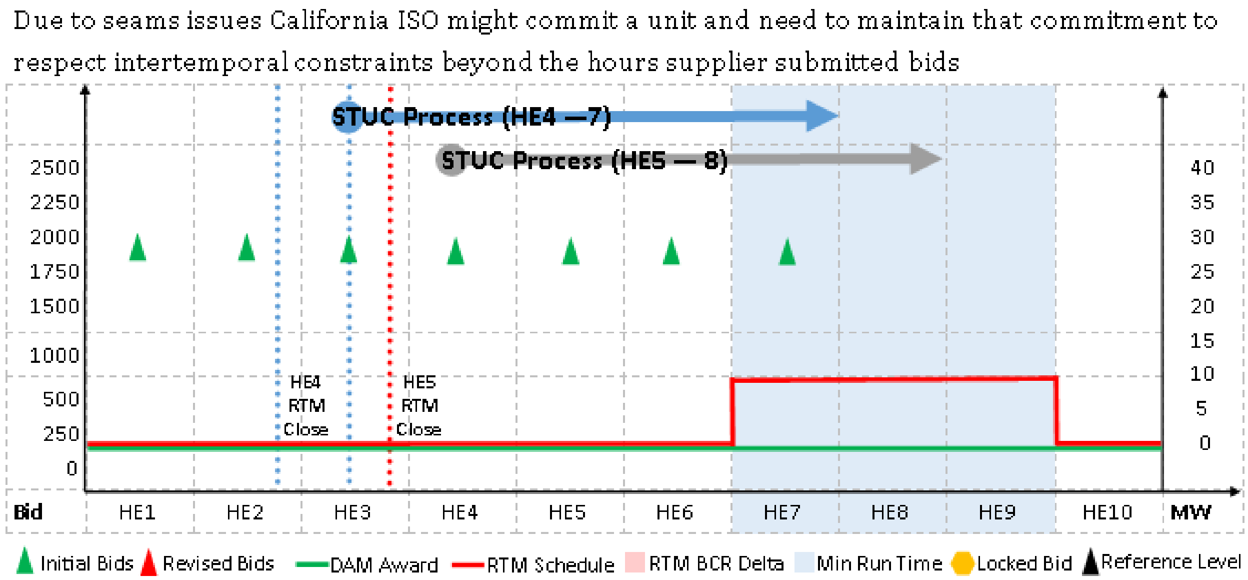

Figure 5: Illustration of need to dispatch even if no bid

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).

[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

[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

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[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.

Verify demand response resources under FERC Order No. 831

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.

Reliability Demand Response Resources (RDRR) under FERC Order No. 831

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

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

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 = $MIN\_GEN * GMC$

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

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> $HEAT\_HEAT\_RATE_{Point1}$, $HEAT\_AVG\_COST_{POINT1}$[30], MIN_LOAD_COST[31], 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.

[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.

California ISO Defined or Negotiated Values: 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

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

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:

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

California ISO Defined or Negotiated Values: 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

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

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.

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[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.

<u>California ISO Defined or Negotiated Values:</u> 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

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

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

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).

$$\textbf{\textit{Minimum Load Fuel Cost}} = 110\% * (Unit\ Conversion * HEAT\_AVG\_COST_{POINT1} * MIN\_GEN + MIN\_LOAD\_COST)$$

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:

$$WC_{l,j}^{CCM} = \sum_{i=1}^{n} \big[SF_{l,i} * \big(\min(DOP_{i,IC} + RR_i * 15 * N, ENGYMAX_i) - \delta \max(DOP_{i,IC} - RR_i * 15 * N, ENGYMIN_i)\big)\big]$$

$$WC_{clc,j}^{CCM} = \sum_{i=1}^{n} \big[SF_{clc,i} * \big(\min(DOP_{i,IC} + RR_i * 15 * N, ENGYMAX_i) - \delta min\big[\max(DOP_{i,IC} - RR_i * 15 * N, ENGYMIN_i) + RR_i * 20, ENGYMAX_i)\big]\big)\big]$$

$Where \; \delta = \{0,1\}$

$DOP_{i,IC} - RR_i * 15 * N \leq ENGYMIN_i \rightarrow \delta = 0$

$DOP_{i,IC} - RR_i * 15 * N > ENGYMIN_i \rightarrow \delta = 1$

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:

$$SPCF_{k,j,i}^{PPSCCM} = SF_{k,i} * \delta \max(DOP_{i,t-1} - RR_i * 15, ENGYMIN_i)$$

$$SPCF_{ckc,j,i}^{PPSCCM} = SF_{ckc,i} * \delta min\left[\max\left(DOP_{i,t-1} - RR_i * 15, ENGYMIN_i\right) + RR_i * 20, ENGYMAX_i)\right]$$

$$Where \; \delta = \{0,1\}$$

$$DOP_{i,IC} - RR_i * 15 * N \leq ENGYMIN_i \rightarrow \delta = 0$$

$$DOP_{i,IC} - RR_i * 15 * N > ENGYMIN_i \rightarrow \delta = 1$$

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.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

Attachment D – CCDEBE Board Memo

Commitment Costs and Default Energy Bid Enhancements

California Independent System Operator Corporation

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

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.

California ISO

		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."	

California ISO

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

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

by

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

Members of the Market Surveillance Committee of the California ISO

March 5, 2018

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_LocalMarket-PowerMitigationEnhancements-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.

[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]

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[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

[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.

[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

[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 E – LMPME Board Memo

Commitment Costs and Default Energy Bid Enhancements

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

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

Date: March 20, 2019

Re: **Decision on local market power mitigation enhancements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Management proposes several market enhancements to address market participant concerns that the ISO market's current market power mitigation process can result in the dispatch of resources at prices below their costs. This issue is particularly acute in the Western Energy Imbalance Market because of the Northwest's numerous hydro resources that have opportunity costs for energy sales because of their water limitations. Suppliers operating these resources may have disincentives to offer these needed flexible hydro resources to the EIM if they cannot reflect their costs.

First, Management proposes to create a standard default energy bid for hydro resources. The ISO's market power mitigation process reduces a market participant's submitted energy bid to a resource's default energy bid, calculated by the ISO, in the event it detects market power. Default energy bids are intended to reflect a resource's actual marginal costs of energy. Management proposes a new option for default energy bids specifically designed for hydro resources that better estimates these resources' actual costs, which typically consist of opportunity costs reflecting their limited water availability. Today, the ISO typically calculates default energy bids for hydro resources using formulas developed through confidential individual negotiations under negotiated default energy bid provisions. Market participants state that the current default energy bid formulas do not always account for the many frequently changing factors affecting water availability and can fail to account for the true value of their stored water.

Management's proposed hydro default energy bid accounts for the variability in the many factors affecting water availability and for market participants' ability to make bilateral sales of energy from these resources at a different location than the resource. This component is particularly important for suppliers that participate in the bilateral energy market in addition to the EIM. This standard hydro resource default energy bid provides the overall market with transparency into these resources' default energy bids and provides a standard starting point for any hydro resource negotiated default energy bids.

Second, Management proposes enhancements to the ISO's market power mitigation process to limit instances of resources being dispatched for additional energy only because the market power mitigation process mitigated the supplier's submitted bid to a resource's default energy bid.

These enhancements to the market power mitigation process include a proposal to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO under certain bid mitigation circumstances. This element falls under the EIM Governing Body's primary decisional authority as it applies to balancing authority areas other than the ISO.

The default energy bid and market power mitigation process enhancements described above are particularly important to encourage participation in the voluntary EIM. It is important to ensure that the market dispatches hydro resources based on their actual costs so that suppliers are encouraged to make these valuable, clean flexible resources available to the ISO market. Not only do hydro resources provide carbon-free energy, but they are also valuable in managing the variability of other renewable resources.

Regarding gas-fired resources, Management also proposes enhancements that will allow the ISO market to use more up-to-date natural gas cost information to calculate default energy bids and commitment cost bid caps. Management's proposed enhancements modify an approach the ISO Board of Governors approved last year but Management has not yet filed with the Federal Energy Regulatory Commission.[1]

Finally, Management proposes to amend the listed natural gas price indices to reflect that the names of these indices have changed.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the local market power mitigation enhancements proposal described in the memorandum dated March 20, 2019; 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 proposal described in the memorandum, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.***

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[1] Management has not yet filed to implement the changes approved by the Board of Governors because it delayed implementation until Fall 2019.

Management presented this local market power mitigation proposal to the EIM Governing Body on March 12, 2019. The EIM Governing Body approved Management's proposal to limit the EIM from dispatching additional energy from resources in balancing authority areas outside of the ISO under certain bid mitigation circumstances. This element of Management's proposal is on the ISO Board of Governor's consent agenda. The EIM Governing Body will also be providing advisory input to the Board regarding the remaining elements of this proposal.

PROPOSAL

The following sections describe Management's proposal.

Hydro resource default energy bid

Management proposes to create a new default energy bid category specific to hydro resources with water storage. Management's proposed hydro resource default energy bid provides a reasonable estimate of hydro resources' opportunity costs due to their water availability limitations. This design acknowledges that the ISO cannot precisely determine a hydro resource's available water supply and attempting to do so could interfere with suppliers' operation of their water systems.

Hydro resources with a limited water supply have opportunity costs because they can only produce a limited amount of energy over a given time period. This opportunity cost represents the revenue a resource would receive if it conserves its water supply so that it can produce energy when prices are highest and energy is most valuable to the system. For example, if a resource only has enough water to produce energy during one month of the year, and energy prices in the highest-priced month are $75/MWh, the resource would have a $75/MWh opportunity cost.

There is not an existing standard default energy bid option to account for hydro resources' opportunity costs. Accounting for opportunity costs currently requires suppliers and the ISO to agree on a negotiated default energy bid, which has been problematic for many suppliers because the current default energy bid negotiation process has not resulted in default energy bids that accurately account for the value of their stored water.

Market participants have stated that there is a high degree of subjectivity in interpreting the output of the models that they use to calculate the water available for energy generation each day and their resources' resultant opportunity costs. They have explained that these models are complex because they estimate water availability based on many factors that affect both reservoir inflows and outflows. These can include weather, upstream and downstream conditions including the status of other reservoirs in a hydro system, and legal restrictions and obligations such as flow restrictions due to wildlife and other water use considerations. They have also stated that the amount of water they have available to support offers for energy to the EIM can also depend on their own electrical load they have to serve each day.

Because of these factors, the amount of water they have available to offer energy to the ISO market, including the EIM, can vary day-to-day, and even within the day, which means their opportunity costs can be highly subjective because they cannot be precisely calculated even with complex models. This can make it impractical to calculate a specific hydro resource's opportunity cost with a high degree of precision, even using a negotiated default energy bid. Consequently, Management proposes a standard hydro default energy bid that approximates a resource's opportunity costs by considering current gas prices and the resource's water storage horizon. This approach does not attempt to precisely model each resource's operation, but is rather based on the typical operation of a typical hydro resource.

A hydro resource's opportunity costs should also reflect the supplier's ability to make bilateral energy sales outside of the ISO market at other locations besides the resource's location. This would be the case if the supplier has Open Access Transmission Tariff rights to transmission from the resource's location to a different geographic location where it makes sales. The opportunity cost would reflect the sales price at the different geographic location. This issue is particularly acute in the EIM because EIM participants often sell energy from their hydro resources outside of their respective balancing authority areas. Management's proposed hydro resource default energy bid also reflects this opportunity cost.

Management proposes that the hydro default energy bid for a resource be calculated each day as the highest of the following three components:

- Short-term: this component reflects a hydro resource's opportunity costs due to short-term water availability limitations, ensuring the ISO market does not dispatch a hydro resource too often on any particular day. Even if a hydro resource has long-term water storage, it may have a limited amount of water available over the day on some or all days.

- Long-term/geographical: this component reflects a hydro resource's opportunity costs due to long-term water storage or the supplier's ability to make sales at another geographic location. This component ensures the ISO market will not dispatch a hydro resource conserving its water if energy prices are anticipated to be higher in a future month or are higher in the bilateral market at another geographic location.

- Gas floor: this component accounts for the supplier's energy replacement costs if the ISO market's dispatch exhausts a resource's short-term water availability. It also helps ensure the ISO market does not dispatch a hydro resource such that it exceeds its short-term water availability limitations in the event real-time energy prices are significantly higher than the day-ahead index used by the short-term component.

The hydro resource default energy bid uses the highest of these three components, which represents the limitations that are applicable on a particular day. For example, if the short-term component is highest, then energy prices are high on that day and the short-term component should set the level of the default energy bid so that the ISO market respects the resources' short-term limitations.

The short-term component approximates a resource's short-term opportunity costs based on anticipated energy prices ranging from the next day to the next month. Management proposes to set the default energy bid at a high enough price so that the ISO real-time market does not dispatch the resource more than four hours per day. Market participants generally came to a consensus that four hours per day represents a reasonable approximation of most hydro resources' short-term water limitations. The market will calculate this price using the higher of the day-ahead, balance of month, or upcoming month energy prices from published bilateral market energy price indices. These prices will be from a fixed trading hub for each resource that is most representative of its EIM prices. The short-term component is then determined by increasing the price by a multiplier designed to limit the market dispatch of most hydro resources to no more than four hours per day.[2]

The long-term/geographical component uses the higher of day-ahead, balance of month, or upcoming month energy prices looking out for the number of months equal to the hydro resource's storage horizon. A resource's storage horizon will be the number of months, up to 12, between the times the hydro resource's water reservoir is historically at peak levels. This is the maximum amount of time that using water to produce energy affects a hydro resource's ability to produce energy in the future.

The gas floor component calculates the price of energy from a gas resource based on the natural gas published index price for the hydro resource's location and based on a typical natural gas-fired turbine generator's fuel consumption.

Limit dispatch at mitigated bid prices

Currently, the ISO market may dispatch a resource to provide energy when the resource appears economic because the market power mitigation process reduced the supplier's submitted bid price to a resource's default energy bid. Even with the proposed hydro default energy bid, there is the potential that the default energy bid may not fully account for a supplier's costs. Consequently, Management proposes two enhancements that will reduce the frequency with which the EIM dispatches resources because it reduced the supplier's submitted bid to the resource's default energy bid. The first of these enhancements falls under the EIM Governing Body's primary decisional authority and was approved by the EIM Governing Body on March 12, 2019.[3]

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[2] Based on current market conditions the multiplier is currently 1.4.

[3] Background on that element can be found in Management's March 5, 2019 memo to the EIM Governing Body https://www.westerneim.com/Documents/DecisionsLocalMarketPowerMitigationEnhancementsProposal-Memo-Mar2019.pdf

The second of these enhancements will prevent the ISO market from dispatching a resource to export power from a transmission-constrained region at mitigated bid prices only because the market detected market power when power was being imported to the region in an earlier market interval. These regions can include EIM balancing authority areas or other transmission-constrained regions, including within the ISO balancing authority area.

This situation is undesirable because the ISO market should not force a supplier to sell energy at mitigated bid prices in market intervals in which it does not detect market power. These enhancements will prevent this result by ensuring mitigated bid prices are at least as high as competitive prices outside of the region and by preventing the market from automatically mitigating a resource's energy bids in subsequent real-time market intervals when it detects market power in a single interval.

Natural gas prices

Management also proposes enhancements to allow the ISO market to use more up-to-date natural gas cost information to calculate default energy bids and commitment cost bid caps. These enhancements are focused on gas-fired resources but are also applicable to the gas floor component of the hydro default energy bid.

The ISO market calculates default energy bids for gas-fired resources based on published natural gas price indices. A supplier's actual gas costs may be higher than a published price if there is gas price volatility or if gas prices at the standard trading hubs that the published indices are based on are not representative of the prices at a particular resource's location.

Under enhancements approved by the ISO Board of Governors in 2018, but not yet filed with the Federal Energy Regulatory Commission, suppliers would be able to request that the ISO calculate a resource's default energy bid or commitment cost bid cap using the supplier's actual gas costs if they are greater than the published index price. This approach would be allowed to the extent the price change was no greater than 25 percent more than the published index price for Mondays and days after holidays and no greater than 10 percent more than the published index price for other days.

Management proposes to modify the above-described approach. For the real-time market, Management proposes that rather than using the fixed criteria of 25 percent and 10 percent more than the published index price, the ISO will approve supplier requests based on a gas price index published on the morning of the real-time market, and based on requests from suppliers for the ISO to review their gas procurement costs for a specific resource. These provisions would also extend to the day-ahead market.

The updated gas prices would also be used to calculate the gas floor component of the hydro resource default energy bids.

Management also proposes to change the gas price index the ISO market uses to calculate default energy bids and commitment cost bid caps for Mondays. The market currently uses a gas price index for Mondays based on purchasing gas in a package on Friday for delivery over the weekend and on Monday. However, suppliers can purchase gas separately for Mondays when demand for gas is especially higher than over the weekend. The gas price index publishers publish a separate Monday gas price when this occurs. Management proposes to use this Monday gas price when it is published and represents sufficiently liquid trading.

Finally, Management proposes to amend the natural gas price indices listed in the tariff to reflect that the names of these indices have changed.

STAKEHOLDER POSITIONS

Stakeholders generally strongly support Management's proposed hydro default energy bid, particularly those that operate hydro resources in balancing areas participating in the EIM outside of the ISO balancing authority area. They state that the proposed hydro default energy bid provides a reasonable estimation of hydro resources' opportunity costs and will prevent the ISO market's dispatch from interfering with their water management.

The ISO Department of Market Monitoring agrees with the general framework of the hydro default energy bid, but does not believe that the hydro default energy bid should incorporate prices at different locations than a resource's location. They state that this pricing aspect inappropriately mixes the value of transmission with energy prices. For example, for the ISO balancing authority area, the current ISO market nodal energy prices, reflecting energy value, are separate from transmission's value that the congestion revenue rights market reflects.

While Management agrees DMM's observation is true at a theoretical level, in practice not allowing suppliers to reflect the opportunity cost of sales at other locations would interfere with the bilateral market. Suppliers point out their energy sales for deliveries at locations other than their hydro resource's location are nonetheless linked to the output of that hydro resource. This is because energy purchasers often specifically purchase energy produced by hydro resources to meet carbon reduction goals. In addition, suppliers point out that in practice, in the bilateral market, transmission's value cannot be separated from energy's value because there is not a robust market for their unused transmission.

The ISO Department of Market Monitoring also opposes Management's proposal to base hydro resources' default energy bids on a storage horizon value that does not change throughout the year. They maintain this approach can inappropriately inflate a resource's default energy bid in the later months of the year when the horizon could extend past the winter months when a reservoir could no longer store water and the operator would instead have to let it flow through the reservoir.

Management believes its proposal for using a fixed storage horizon reasonably balances the practical considerations of implementation complexity and the difficulties in precisely modeling every hydro resource's operation. For example, there is the possibility that some hydro resources do not face maximum storage limitations each year. In addition, any default energy bid price inflation due to using a fixed storage horizon will be small and market power is not as much of a concern in the later months of the year as it is in other months. Nevertheless, Management will monitor default energy bids produced under this approach and suppliers submitted bids to ensure this is the case.

Stakeholders generally support the provisions to increase the accuracy of the natural gas prices the ISO market uses to calculate default energy bids and commitment cost bid caps.

The ISO Market Surveillance Committee generally supports Management's proposal, stating that the benefits of Management's proposal outweigh any drawbacks. However, they suggest that, in order to include a remote bilateral trading hub in a default energy bid, suppliers should have to demonstrate their transmission rights are not already fully committed and cannot be sold if unused.

In response to the Market Surveillance Committee's suggestion that suppliers should have to demonstrate their transmission rights to a remote location are not already fully committed, Management commits to incorporate this requirement in the tariff provisions implementing its proposal. Management believes suppliers have already presented information in this initiative's stakeholder process demonstrating there generally is no ability to bilaterally sell such unused transmission rights.

Attachment A presents a summary of stakeholder comments and Management's responses.

The Market Surveillance Committee provided a formal opinion on Management's proposals, which is included as Attachment B.

CONCLUSION

Management requests the Board of Governors approve this proposal. The local market power mitigation enhancements proposal will encourage flexible resources to participate in the ISO and EIM market and improve the accuracy of the ISO's market power mitigation provisions, which will lead to more efficient real-time market price formation.

California ISO

Attachment A

Stakeholder Process: Local Market Power Mitigation Enhancements Proposal

Summary of Submitted Comments

Stakeholders submitted four rounds of written comments to the ISO on the following dates:

- Round One: Issue Paper and Straw Proposal comments received 10/4/18
- Round Two: Supplemental Issue Paper and Straw Proposal comments received 10/18/18
- Round Three: Revised Straw Proposal comments received 12/10/18
- Round Four: Draft Final Proposal comments received 2/11/19

Parties that submitted written comments: Bonneville Power Administration, Chelan County Public Utility District, Deseret Power, Department of Market Monitoring, Idaho Power Company, Middle River Power, National Hydro Association, NRG Energy, NV Energy, PacifiCorp, Pacific Gas & Electric, Portland General Electric, Public Generating Pool, Powerex, Public Power Council, Puget Sound Energy, Southern California Edison, Seattle City Light, Six Cities, and Western Power Trading Forum.

Stakeholder comments are posted at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalMarketPowerMitigationEnhancements2018.aspx

Other stakeholder efforts include:

- Technical workshop meeting, 4/30/18
- Technical workshop meeting, 7/19/18
- Issue Paper and Straw Proposal conference call, 9/19/18
- Working group meeting, 10/10/18
- Revised Straw Proposal conference call, 11/28/18
- Draft Final Proposal conference call, 1/23/19

Market participant	New default energy bid (DEB) option for hydro resources	Enhancement to prevent dispatching resources to export power from constrained region at mitigated bid prices only because of market power when importing in earlier interval	Enhancements to processes for updating commitment cost bid caps and DEBs
Bonneville Power Administration	Strongly supports because hydro DEB adequately captures relevant factors of opportunity costs calculations for hydro resources.	Supports because enhancement improves mitigation accuracy.	Supports ability to update gas floor component of hydro default energy bid to reflect current gas prices. No comment on other elements.
Chelan County Public Utility District	Supports because proposed hydro DEB reasonably reflects a variety of hydro resources' opportunity costs.	No comment	No comment
Department of Market Monitoring	Conditionally supports but believes including opportunity costs of bilateral sales at other than a resource's location inappropriately includes transmission value in DEB. Also believes fixed storage horizon may overstate opportunity costs because it can extend beyond a hydro cycle.	Supports because enhancement improves mitigation accuracy.	Supports because enhancements include updating real-time market commitment cost bid caps and default energy bids with current gas prices.
Idaho Power Company	Supports proposed hydro DEB framework, but believes multipliers for gas floor, short-term, and long-term components are too low.	Generally supports	No comment
Middle River Power	No comment	No comment	Supports and encourages the ISO to implement the proposal to use a "Monday-Only" index as soon as possible.

Market participant	New default energy bid (DEB) option for hydro resources	Enhancement to prevent dispatching resources to export power from constrained region at mitigated bid prices only because of market power when importing in earlier interval	Enhancements to processes for updating commitment cost bid caps and DEBs
NRG Energy	No comment	No comment	Supports and encourages the ISO to implement the proposal to use a “Monday-Only” index as soon as possible.
NV Energy	Supports, but believes in addition to hydro resources, DEBs for use-limited gas resources should also include opportunity costs of bilateral sales at other than a resource’s location.	Generally supports, but believes Management’s proposed 10 cent maximum amount for an adder to mitigated bid prices to ensure mitigated prices are at least as high as competitive prices outside of a mitigated region is too high. They point out it is greater than a similar adder, which is 1 cent, that the EIM market applies to costs of energy transfers between EIM balancing authority areas so that it selects the most direct transfer path.	No comment
PacifiCorp	Supports because proposed hydro DEB acknowledges both short- and long-term opportunity costs of hydro resources with storage.	Supports	Supports
Pacific Gas and Electric	Supports, stating proposed DEB will more accurately reflect hydro resources’ costs	Supports because enhancement improves mitigation accuracy.	Supports

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Portland General Electric	No comment	Supports	No comment
Public Generating Pool	Strongly supports because proposed hydro DEB recognizes short- and long-term limitations and provides an adequate DEB price that ensures minimal inefficient dispatch	Supports	No comment
Powerex	Strongly supports, notes including opportunity costs of bilateral sales at other than a resource's location is particularly important. Maintains more than one trading hub should be included in short-term component in some circumstances.	Supports because enhancement improves mitigation accuracy.	No comment
Public Power Council	Supports, particularly including DEB gas floor component based on average peaking gas generator cost.	Supports	No comment
Puget Sound Energy	Supports	Supports	Supports
Southern California Edison	Supports	Supports, states proposed maximum 10 cent mitigated bid adder is minimal and will not negatively impact locational marginal prices.	Supports, but requests clarification of the criteria the ISO will use to determine if a gas price index represents a sufficient amount of

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			trading so that it is appropriate to use to establish commitment cost bid caps and default energy bids.
Seattle City Light	Supports, particularly including opportunity costs of bilateral sales at other than a resource's location.	Supports	No comment
Six Cities	Supports	Supports	Supports, but requests the ISO clarify how it will account for gas costs for Mondays when the "Monday-Only" index is not available.
Western Power Trading Forum	Supports proposal but believes, in addition to hydro resources, DEBs for gas resources should also reflect opportunity costs of bilateral sales at other than a resource's location and should also reflect daily limitations.	Supports	Supports and encourages the ISO to implement the proposal to use a "Monday-Only" index as soon as possible. Requests clarification of the criteria the ISO will use to determine if a gas price index represents a sufficient amount of trading such that it is appropriate to use to establish commitment cost bid caps and default energy bids.
Management's response	Management believes it is appropriate to include opportunity costs of bilateral sales at other than a resource's location because energy sales at locations other than hydro	Management will specify in the tariff language to implement this enhancement that the maximum adder to mitigated bid prices will be 1	Management will develop criteria the ISO will use to determine if a gas price index represents a sufficient amount of trading such that it is

Market participant	New default energy bid (DEB) option for hydro resources	Enhancement to prevent dispatching resources to export power from constrained region at mitigated bid prices only because of market power when importing in earlier interval	Enhancements to processes for updating commitment cost bid caps and DEBs
	resources' locations are typically linked to the output of the hydro resource. Energy purchasers often specifically purchase energy produced by hydro resources to meet carbon reduction goals. In addition, suppliers point out that in the bilateral market, transmission's value cannot be separated from energy's value because there is not a robust bilateral market for unused transmission. Management also believes its proposal for using a fixed storage horizon reasonably balances the practical considerations of implementation complexity and the difficulties in precisely modeling every hydro resource's operation. For example, there is the possibility that some hydro resources do not face maximum storage limitations each year. In addition, any default energy bid price inflation due to using a fixed storage horizon will be small and market power is not as much of a concern in the later months of the year as it is in other months. Management does not believe it is appropriate to include more than one hub in the short-term floor component of the DEB. This component is intended to account for	cent, rather than 10 cents. As NV Energy points out, this will be consistent with a similar adder the EIM applies to energy transfer costs. Management will determine the actual adder the EIM will use through market optimization tuning prior to implementation.	appropriate to use to establish commitment cost bid caps and default energy bids. It will establish this criteria consistent with existing FERC rules and will document the criteria in the tariff and/or in the appropriate business process manual. Management clarifies it will retain the existing 25 percent "reasonableness threshold" for suppliers to request adjustments to a resource's commitment cost bid caps and default energy bids for Mondays when the "Monday-Only" index was not used. The Monday-Only index is not used if it is not published or does not meet liquidity requirements. Management is submitting a separate tariff amendment to FERC so that the ISO can use the "Monday-Only" index for the day-ahead market over this summer. It will do this as a modification to temporary tariff provisions to update gas prices used for the day-ahead market the Board previously authorized.

California ISO

Market participant	New default energy bid (DEB) option for hydro resources	Enhancement to prevent dispatching resources to export power from constrained region at mitigated bid prices only because of market power when importing in earlier interval	Enhancements to processes for updating commitment cost bid caps and DEBs
	short-term water availability limitations to ensure the ISO market does not dispatch a hydro resource too often on any particular day. It is not intended to directly reflect opportunity costs of sales outside the ISO market. Rather, it accounts for dispatch at EIM prices based on day-ahead bilateral prices at a representative hub and using multiplier. Management designed it based on the historical relationship of prices at single hubs to EIM prices. Applying the hydro DEB to gas resources is not appropriate because its components were designed to specifically reflect hydro resource limitations and the stakeholder process did not consider gas resource limitations. Any modifications to gas resource DEBs would have to be considered in a future stakeholder process.		

Opinion on
Local Market Power Mitigation Enhancements

by

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

Members of the Market Surveillance Committee of the California ISO

March 6, 2019

I. Introduction and Summary

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the ISO's proposed Local Market Power Mitigation (LMPM) Enhancements.[1] The initiative leading to this proposal has been addressed during MSC meetings on Aug. 3, 2018, Sept. 28, 2018, Dec. 7, 2018, and Jan. 25, 2019.

This Opinion is structured as follows. Background material (Section I.A) and a summary of our recommendations (Section I.B) are provided in this introduction. Then three major features of the proposal are addressed in subsequent sections. First, in Section II, we consider the proposed addition of constraints in the Energy Imbalance Market (EIM) real-time markets to limit changes in between-balancing authority (BA) flows that would result from mitigation of supply offers. We identify several possible unintended consequences of those limits that should be monitored. Then, in Section III, the proposed definition of default energy bids (DEBs) for hydropower resources is considered. We comment on several issues, including how far in the future that forward hub prices should be considered in defining the DEB, and the use of distant hubs in the DEB calculation and how opportunity costs of transmission are treated.
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I.A Background

The CAISO's LMPM design is structured to identify the potential for the exercise of locational market power in meeting load within constrained regions within the ISO footprint, and within BAs in the EIM fifteen-minute and five-minute energy markets. The Appendix to the ISO's draft final proposal[2] summarizes the mechanics of the present LMPM procedures. Its basic features are a test to detect market power on uncompetitive transmission constraints within the ISO and between BAs in the EIM. The tools used for that detection include dynamic competitive

[1] Local Market Power Mitigation Enhancements, Draft Final Proposal, Updated Jan. 31, 2019, www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements-UpdatedJan31_2019.pdf

[2] Ibid., Appendix.

path assessment based upon a three pivotal supplier test for supply to relieve congestion into individual BAs within the constrained area. If removal of the three largest suppliers means that it is not feasible to meet load in an area, then those suppliers are collectively pivotal, and the LMPM procedure designates them noncompetitive. Then, for each resource, the components of the LMP that are associated with noncompetitive transmission constraints.

The present LMPM system is the cumulative result of a number of expansions and revisions of the original LMPM system under the Market Redesign and Technology Upgrade system implemented in 2008. The MSC prepared several opinions since then that discussed the various reforms proposed by the ISO:

- In our 2014 Opinion on LMPM Implementation in the EIM,[3] 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. The ISO subsequently made changes in how the test was applied as more BAs joined, as the original methodology was not applicable to multiple BAs.
- In 2011, we reviewed the ISO's proposed Dynamic Competitive Path Assessment procedures.[4] 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.
- The MSC has prepared several Opinions addressing ISO proposal to modify procedures for mitigating commitment costs offers in the ISO's LMPM procedures.[5,6,7,8,9,10,11,12] Is-

[3] 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-LocalMarketPowerMitigationImplemenation-EnergyImbalanceMarket-July7_2014.pdf

[4] 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

[5] J. Bushnell, S. Harvey, and B. Hobbs, "Opinion on Commitment Costs and Default Energy Bid Enhancements (CCDEBE)," March 5, 2018, www.caiso.com/Documents/MSCOpinionCommitmentCost-DefaultEnergyBidEnhancements-Mar5_2018.pdf

[6] 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

[7] 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

[8] 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

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

sues addressed in those opinions include the need to extend LMPM procedures to encompass commitment costs as well as energy offers; the detection of local market power in commitment cost offers, estimation of opportunity costs, adjustment of natural gas price indices, and revision of bid cost recovery rules.

In addition to the above opinions, in response to a FERC request, the MSC in 2013 prepared a report on the appropriateness of the 3-pivotal supplier test and other competitive screens in LMPM procedures.[13] In that report, we analyzed CAISO data, and concluded that there is no compelling justification for changing the three pivotal supplier screen in the LMPM competitive path assessment at that time. 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. This report was compiled prior to the operation of the EIM and did not address the issues involved in applying the 3-pivotal supplier test within the EIM.

The present proposal to enhance the LMPM system addresses several issues that have arisen since LMPM was expanded to encompass the EIM. The primary issue is greater uncertainty in estimates of variable costs of generation, which makes the setting of DEBs more difficult, increasing the risk of both over- and under-mitigation. Over-mitigation can result in overuse of limited energy resources and disincentives for participation in the voluntary EIM markets. Under-mitigation poses a risk of market power exercise. This greater uncertainty is the result of lower quality of information on natural gas supply costs in many EIM BAs, and the inherent nature of long-term hydropower storage, which makes opportunity costs dependent on uncertain future inflows and market conditions. Market power mitigation cannot function without estimates of variable costs, and so the ISO must estimate them; in choosing their values, the degree of uncertainty, as well as the consequences of possible over- vs. under-mitigation need to be weighed. In addition, there are issues in defining competitive supply that can potentially flow into a BA, which can affect whether supply in BA is declared noncompetitive and subject to mitigation.

The ISO's LMPM enhancements proposal has a number of features designed to address the need for DEBs in the EIM and the uncertainty involved in their estimation. These features can be classified as either DEB- or quantity-oriented.

The features that address DEBs focus on improving estimates of natural gas costs and long-term energy market prices that determine opportunity costs for the large amount of hydropower facilities that exist in many EIM BAs. We comment in detail on several of the offer/DEB-oriented

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[11] 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

[12] 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

[13] 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

aspects of the LMPM enhancements proposal in Sections III and IV, with our conclusions and recommendations summarized in the next subsection (Section I.B).

Meanwhile, the quantity-oriented features in essence attempt to limit the risk of overuse from too low DEBs by attempting to indirectly restrict the upward dispatch of mitigated resources in a BA if that supply expansion would either (a) change that BA from an importing to an exporting region, or (b) increase net exports from that region, if it is an exporting region. The export limit seeks to ensure that to the extent that a BA needs supply from another BA to balance load and generation (as determined in the market power mitigation run), that supply will be sold at a price that reflects the application of market power mitigation. But the export limit will constrain the extent that a BA can rely on purchases of power at mitigated prices to replace additional output of its own generation in the market run. Our assessment of these quantity-focused features of the LMPM enhancements is in Section II, with our conclusions summarized in Section I.B, next.

I.B. Summary of Recommendations

Limits on Transfers among BAs When Offers are Mitigated. Our recommendation on imposing limits on changes in inter-BA transmission flows as a measure to avoid the risk of overuse of mitigated resources whose DEBs have been underestimated is as follows. As long as these export restrictions are not applied as a matter of course but are available as a last resort to a BA in which application of mitigation is resulting in power being exported for less than its cost, we accept the availability of these restrictions as being an acceptable price to pay for encouraging EIM entities to participate in the EIM with a broader set of resources. They are a blunt but potentially necessary instrument to lower the risk of adverse efficiency and reliability consequences of understated DEBs.

However, we do not agree with the blanket statement of the proposal that "it is not appropriate to export greater quantities at the mitigated price than what was originally scheduled in the market power mitigation run."[14] We believe that *if* DEBs are a reasonable approximation of variable cost (including opportunity costs) then the application of market power based on those DEBs would be appropriate, whether or not it resulted in exports or an increase in exports.

We note that limiting exports in the market run based on levels calculated by the mitigation run could have unintended consequences. These could include:

- limiting the effectiveness of market power mitigation in some circumstances;
- overly restricting the use of flexible ramp resources to meet unexpected changes in net load in other BAs between the advisory and binding RTD that could reduce EIM benefits in general and the EIM flexible capacity diversity benefit in particular, and potentially lead to wealth transfers between the owners of resources located within the BA implementing the export limit and the BA operator; and

[14] Draft Final Proposal, op. cit., p. 5. This statement in the proposal should be understood as excepting increases in exports due to upward dispatch of resources scheduled as flexible ramping product.

- the use of advisory interval flows in the mitigation run for an advisory interval to define limits in the binding interval of the next market run of the real-time (5 minute) dispatch market.

Since an EIM BA can choose to impose or not impose these limits, we hope that EIM entities will not have a need to do so often. If they are imposed frequently, this will have the consequences noted above, and make EIM prices more difficult to predict by increasing the complexity of the network constraints and thus congestion cost calculations. Frequent use should be viewed as a signal that there may be a continuing issue with DEB accuracy that the ISO needs to address. Alternatively, if it is concluded that the DEBs involved are accurate or even somewhat high, it might be an indication that a BA is either attempting either to exercise market within a constrained EIM subregion, or to benefit a subset of market parties in its area by decreasing energy prices but also earning congestion rents on the limits. This implies that the use and impacts of these limits needs to be carefully monitored and action taken if this option is utilized on more than a sporadic basis and by more than one EIM entity at a time.

Default Energy Bids for Hydropower Offers. Regarding the calculation of hydropower DEBs, we support the general procedure, but recognize its imperfections and limitations. One limitation is the potential use of future energy prices to set opportunity costs at times of year beyond the time when reservoirs are expected to refill and spill in the case of larger storage reservoirs. This may not be not the situation in all years, but during wet years, a reservoir that is likely to spill in the spring should not be able to use late summer power prices to determine DEBs early in the previous winter. Conversely, in dry years, some reservoirs may have higher opportunity costs in the summer then estimated by the proposed methodologies. However, due to the complexity and lack of transparency of hydro operations and constraints, the large uncertainties surrounding inflows and future energy prices, and the changes in generation use that will come with the expansion of the EIM, we are not confident that a more accurate and practical design can be developed at this point in time. Therefore, we support implementation of the proposed procedure, while recognizing its imperfections, and we further recommend that the ISO should monitor its performance over time, and make improvements based on what is learned. If offers are often at the DEBs, this might be either an indication that DEBs are too low, or alternatively indicate that there is a potential for the exercise of market power if close examination of the DEBs indicates that they are well above a particular resource's opportunity cost.

One element of the California ISO's proposed opportunity cost calculation for hydro resources with storage is the use of forward power prices. It is necessary for the ISO to use forward prices at trading hubs to determine forward prices for use in the DEB procedure. This is because forward prices with acceptable liquidity are available only at a limited number of regional hubs. In many cases, the hydro resources are not located at a trading hub so the ISO's proposed designs includes rules for determining which trading hub should be relied on to provide forward prices for calculating opportunity costs for each resource. The actual relationship between resource locations and their trading opportunities is complex; there is no simple rule that can be used to accurately measure these relationships, and some resources may have opportunity costs that reflect forward prices at multiple trading hubs.

The CAISO proposes to address these complexities involving trading opportunities in estimating opportunity costs by defining a default trading hub for each balancing area.[15] In addition, the California ISO will allow a market participant to select additional trading hubs for use in this calculation if the market participant can "show the CAISO firm transmission from the resource to one of these hubs or an electrically similar location."[16] However, we do not support the use of distant hub prices in the calculation of the DEB merely if firm transmission rights are held.

In an efficient and liquid wholesale market, the opportunity costs presented by future export opportunities, or sales at "distant hubs", would be fully captured in local futures prices. The difference between the local and distant futures price would reflect the costs of transmitting the power to the distant hub. Therefore, in a fully integrated transmission market, such as the CAISO's internal market, the futures price at the local hub would be the appropriate price upon which to base opportunity costs. If, however, the transmission market is *not* efficient or liquid, the above logic can break down. First, there may be no hub near to the resource. Second, a distant hub price could represent a legitimate opportunity cost *if* transmission rights from the resource to the hub have a use-it-or-lose-it character, are likely to be in surplus, and are not easily marketed to other participants. Some stakeholders have pointed to exactly these kinds of inefficiencies in arguing for the use of a distant hub.

Therefore, the CAISO's proposed use of a distant hub is appropriate if a participant can be plausibly shown to possess export opportunities, through the ownership of transmission rights, that are not readily transferable to others and would otherwise have no value to the owner, or if there is no hub located near to the resource. The question then becomes, how can stakeholders demonstrate this and how strict a burden of proof should be required? In this sense, while we concede the merits of the general concept, we do not feel that the mere ownership of transmission rights should be sufficient evidence to allow a firm to base all its default energy bids upon a distant hub. The conceptually correct test would be whether the supplier typically makes incremental sales supported by its hydro generation at the distant hub at times when prices are high at the distant hub. While the ownership of firm transmission rights from the supplier's resources to the distant hub might be one element of such a showing, the mere ownership of a token amount of firm transmission to the distant hub does not establish that incremental supply can be sold at market prices at the distant hub.

We also think that there should be a showing that such rights cannot be sold at a reasonable price, used to support spot sales, or otherwise earn revenues that would represent an opportunity cost for selling at the distant market. If the use of firm transmission rights to support sales at the distant hub would have an opportunity cost at the time of year when prices at the distant hub would be used to calculate hydro opportunity costs, this opportunity cost of transmission should be deducted from the distant hub prices in the DEB calculation. Indeed, if the transmission and energy spot markets are reasonably liquid, the local hub price is likely to be an adequate approximation of the distant price minus the opportunity cost of transmission for resources located at

[15] Ibid., pp. 37-38.

[16] Ibid., p. 38

the local hub. This is also true even if there is a green premium at the distant hub, as long as there is competition in the green energy market.

Stakeholders have argued that inefficiencies in bilateral markets for transmission, energy, and green energy markets mean that these conclusions do not hold at present. Our recommendation is the following: as a condition for using a distant hub's energy prices in a DEB calculation, the resource owner should provide information on the opportunity cost of transmission rights it holds. If a resource owner wants to argue that the opportunity cost of the firm rights it holds is zero over the relevant time frame of the DEB calculation, and that some of those rights would go unused if the resource produces energy in today's real-time market instead of waiting, the owner should provide evidence for this assertion to the ISO. Alternatively, the owner should suggest a value for those rights that is based on verifiable information. We do not believe that the ISO should, as a default, assume this value is zero just because the owner possesses firm rights.

Furthermore, we are reluctant to endorse a perspective that says that because market imperfections exist that prevent efficient trading of renewable energy credits, transmission, and energy, the ISO should help embed these inefficiencies in the West by providing an incentive to maintain those inefficiencies in order to support higher DEBs. We would rather see incentives provided to increase the liquidity of these markets. It is for this reason that we recommend that an estimate of the opportunity cost of transmission rights be deducted from prices at distant hubs if those prices are to be included in the DEB formula.

However, we recognize that estimation of the value of bilateral transmission rights is likely to be difficult, and that it may be impractical to do so at present. One significant complication in applying the opportunity cost of transmission rights to a distant hub from the local hub, even if that cost could be estimated, is that some resources may not be located at or electrically close to their assigned "local" hub. Consequently, their opportunity cost of point-to-point firm rights that would enable them to convey their power to the distant hub will be difficult to determine, since the likelihood of a liquid market for such rights from their location is even lower than between recognized hubs in the West. Another complication is that transmission rights might be traded for particular hours that might not correspond to when the resource would sell the energy that corresponds to the opportunity cost being calculated. All these complications mean that the value of transmission rights would be difficult to estimate and verify. However, this does not obviate our basic point: transmission rights should be presumed to have some opportunity cost that should be deducted from prices at the distant hub, and the burden should be upon the resource that wants to use a distant hub to propose and document the basis for such a cost. We do not recommend that the ISO itself estimate these costs.

If it is impractical to estimate the opportunity costs of transmission rights, or to require market parties to do so as a condition of using distant hub prices in the DEB calculations, we recommend that the ISO continue to examine questions concerning the value of firm transmission rights and their relevance to hydropower opportunity costs. First, does reliable data exist on the value of firm transmission rights for delivery to major western trading hubs? Second, does that data provide the basis for useful checks upon avoided cost estimates provided by resource owners? Stakeholders have provided comments asserting that there is little value in unused rights and no liquid market to sell them. This raises additional questions such as: are unused rights the norm, or the exception? If they are the norm, then why do the owners of those rights consistently acquire more than are needed? If they are not the norm and so rights are usually fully used, at what times do they tend to be fully used? At such times, there is in fact an opportunity cost, if only in the form of alternative uses that the owner could put them to. If they tend to be fully used during times of peak energy prices at distant hubs, this would indicate that those prices should not be used to determine energy opportunity costs in DEB calculations.

Despite the above concerns with some of the details of DEB calculation for hydropower plants, we do support the general approach that is proposed based upon gas costs and forward prices for energy. The risk that the DEBs are too low is partially mitigated by the flow restrictions discussed above, as well as the option that resources have for customized negotiated. DEBs. We prefer that the forward prices used in the DEB calculations be adjusted, if practical, by opportunity costs for transmission provided by resource owners and checked by the ISO, as described above. If this is not practical, we would support implementation of the proposal, at least for the near term, but the CAISO should continue to work to refine this aspect of the proposal.

Other Recommendations. Concerning some other aspects of the proposal, the MSC supports the proposed changes in how the competitive LMP will be used in the calculation of mitigated bids. An example is the use of that LMP plus a small value at the mitigated bid, if greater than the DEB in order to lower the risk of a large increase in the resource's schedule in the market run. The committee also supports the procedures proposed for updating gas prices, given the quality of price data that is likely to be available in non-CAISO BAs.

II. **Changes to Real-Time Market Power Mitigation Process**

II.A General Comments Concerning Imposition of Quantity Limitations in Market Run in Order to Limit Risk of Uneconomic Expansion of Output

If a resource's offer price is mitigated, it may be dispatched to higher output level in the market run (where its offer is set to the DEB) relative to its dispatch in the mitigation run of the market software (which uses the unmitigated offer). If the DEB materially understates the resource's actual marginal cost, the increased output may be inefficient, since this increase could be at the expense of other supplies whose costs are lower than the true cost of the mitigated resource. In the case of limited energy resources, a consequence could be overuse of the resource, leaving too little energy for later. Such an outcome could have adverse reliability impacts if, for example, a dry, hot summer results in higher than expected loads while at the same time too little water has been saved to meet those loads because understated DEBs caused the water to be used to replace lower cost thermal generation earlier in the summer.

The proposal would lessen the risk of uneconomic expansion of output by limiting changes in the net overall exports of the resource's BA as follows, if the exporting BA elects to impose those limits.

- If the BA is importing on net in the market power mitigation run, it will be constrained from becoming a net exporter in the market run, except to the extent that those exports come from flexible ramping product awards.[17]
- If the BA is exporting on net in the market power mitigation run, it will be constrained from exporting more in the market run, except to the extent that those export increases come from flexible ramping product awards.

It is implicitly assumed that the changes in net flows from or to the BA between the market power mitigation pass and the market pass are directly related to changes in the dispatch of mitigated resource(s) in that BA or flexiramp resources.[18] Although the mitigated resource with a DEB that is less than its actual cost might experience some uneconomic increase in output between the market power mitigation pass and the market pass as a result of the application of market power mitigation, the amount of the increase is intended to be limited by these inter-BA flow restrictions. Thus, this rather blunt instrument can be viewed as an escape valve that provides some assurance to EIM entities that if DEBs get seriously out of line with actual costs for some resources, there will be some protection against uneconomic overuse of those resources.

Some MSC members believe that an implicit assumption of this quantity limitation is that if mitigation would result in decreasing a bid so much that the resource's BA would flip from importing to exporting, then this would be evidence that a DEB is too low relative to actual costs, and market inefficiencies would likely result.

We have the following observation regarding this possible assumption. If the mitigated supplier's BA imports are congested such that local prices are higher than in export markets, then it is well-known from economic theory of power markets that a supplier with low costs within an importing market might choose to raise its offer sufficiently such that imports hit their upper bound, allowing local prices to increase.[19] In fact, it can be profit-maximizing for a large producer that is not subject to market power mitigation to adopt such a strategy even if under competitive pricing its region would be exporting rather than importing.[20] If such a supplier is mitigated, the resulting dispatch might not only decrease imports, but also change the region from an importing to an exporting region, which can be more efficient. The upshot is that mitigation that results in a switch from net imports to net exports for a BA within a constrained region or expansion of exports is not, in theory, sufficient to show that a DEB is too low if the supplier may possess market power but does not believe it would be subject to effective market power mitigation. Blanket restrictions on increases in a BA's exports between the market power mitigation

[17] Ibid., Section 6.1.1.

[18] Of course, due to complex network effects, it is possible that some of the change in flows is actually a result of increased output from non-mitigated resources within the BA, but the magnitude of these changes is implicitly considered to be small by the proposal.

[19] E.g., Borenstein, S., Bushnell, J. and Stoft, S., 2000. The competitive effects of transmission capacity in a deregulated electricity industry. *RAND Journal of Economics*, *31*(2), pp.294-325; Gabriel, S.A., Conejo, A.J., Fuller, J.D., Hobbs, B.F. and Ruiz, C., 2013, *Complementarity Modeling in Energy Markets*, Springer, NY, Ch. 7.

[20] Ibid.

pass and the market pass in order to prevent over-dispatch of energy-limited resources will not necessarily increase market efficiency.

We note that that this is one reason why internal ISO resources are not proposed to have the option of such quantity restrictions on exports from subareas within constrained regions within the ISO.[21] However, there are three crucial differences between non-ISO BAs and within-ISO constrained areas that make these quantity limitations reasonable for the EIM.

- First, there may be much more uncertainty concerning costs in other BAs. This is due, first, to the poorer quality of public data on natural gas costs for individual resources not located at major natural gas trading hubs outside the CAISO and, second, the presence of substantial amounts of hydro resources whose opportunity costs are very difficult to estimate. There is a significant risk of adverse efficiency and reliability impacts when mitigation is triggered and applied if DEBs materially understate costs.
- Second, EIM markets are voluntary markets and understated DEBs will not only result in reduced market efficiency due to inefficient dispatch decisions, the mere potential for understated DEBs can reduce economic efficiency by reducing participation in the EIM. Hence, a balance is necessary between the risk of discouraging participation by market parties in the EIM (and the resulting possible loss of market efficiency) and any theoretical market efficiency improvements from mitigated resources being used, in effect, to meet load in other BAs. Thus, if a BAA wanted to limit its exports if mitigated, it could do so on its own either by not offering the generation capacity voluntarily in the first place (aside from the requirement to offer sufficient flexible capacity). We also understand that some Transmission Owners can limit the transmission capacity they offer for use in the EIM. The ISO cannot prevent such unilateral actions by a BA, so giving the BA an option to request that the ISO to impose export constraints will be more transparent and might avoid risks of even less efficient outcomes if instead the BA doesn't make capacity available in the first place.
- Third, generation used by the large regulated load serving entities within California is generally exempted from energy offer price mitigation but the application of the 3-pivotal supplier test within the EIM does not take account of load serving obligations and is applied at the BA level, rather than across the entire constrained region, with the consequence that there is more potential in the EIM region outside the CAISO for the application of market power mitigation to resources lacking market power.[22]

[21] Another reason is that the DEB floor within the ISO is at the competitive LMP for the market, which is intended to avoid the outcome in which mitigation results in exports from the constrained region that triggered mitigation. The competitive LMP, however, will not limit exports from particular subregions within the constrained region, which is the effect of the export limits proposed by the CAISO. Note that the DEB floor outside of the ISO is also the competitive LMP, which is intended to avoid exports from constrained regions in the EIM.

[22] The CAISO uses a 3-pivotal supplier test to determine whether there are uncompetitive paths between BAs, and if supplies within BAs should be mitigated. Some stakeholders have observed that the way in which the test is used, the application of the 3-pivotal supplier test separately to each BA within a constrained region may result in more frequent mitigation than is appropriate, because it does not account for competition from supply in other BAs within the constrained area when it consists of more than one BA. Furthermore, the application of the pivotal supplier test does not take into account load-serving obligations. For instance, there could be 12,000 MW of load in a region, 11,970 MW of which is served by, say, the base schedules of 5 vertically integrated suppliers, while 1000 MW of

We are sympathetic to stakeholder concerns that a process that allows BAs to elect such quantity limits has the potential to adversely affect the short-run efficiency of the markets.[23] However, we believe that as long as the EIM supply capacity and, perhaps, transmission are offered voluntarily, providing EIM entities with the option to impose this constraint is a less worse outcome than the application of mitigation based on underestimated DEBs that would reduce participation in the EIM and risks magnifying the inefficiencies that could result from too-low DEBS.

II.B. Potential for Unexpected Consequences

For two reasons, there is significant risk of unintended consequences from the export limit. First, the imposition of inter-BA constraints is a blunt instrument to limit the risk that particular mitigated resources will be overused due to too-low DEBs. Second, as DMM observed,[24] whenever a market sets a schedule based on one set of inputs (unmitigated offers in the EIM mitigation run would set the limits on exports) while prices are based on another set of inputs (mitigated offers in the market run), there is a possibility of providing incentives to strategically bid or otherwise attempt to affect market outcomes. We discuss some possible unintended consequences below.

Effects on BA Prices and Distribution of Congestion Rents. One set of unintended consequences results from the BA-wide impacts of the export constraint upon prices, and the distribution of congestion rents from the export constraint. BAs may have resources owned by several entities. If an imposed export constraint has a positive shadow price, then vertically integrated utilities who act as the BA will see lowered prices for their supply resources, which will be more or less compensated by lower prices paid by its consumers as well accrual of congestion rents from the export limitation. If there are a significant amount of resources that are independently owned within the BA, then there will be a significant monetary transfer from those resources (which will receive lower prices but, in theory, no share of the congestion rents) to the vertically owned utilities. In theory, the BA and the independent resources could strike a bargain, but we

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additional supply is available from other sources in the EIM to meet the last 30 MW of imbalance demand. In this circumstance, the pivotal supplier test would be failed by a wide margin, but in fact the vertically integrated utilities cannot withdraw the supply used to cover their base schedules and leave their 11,970 MW of load unserved. Another logical shortcoming is that import capability from other BAs is not considered in the residual supply calculation used by the test if the constrained region is broader than a single BA, which would also tend to inflate the frequency of the test failing and mitigation being imposed.

These weaknesses of the current mitigation design have not been a serious issue to date because it is only with the expansion of the EIM that the potential for constrained regions that include multiple balancing areas and larger number of suppliers has begun to develop. It will become more important to address these issues as the EIM continues to expand, and addressing them may reduce the need to apply the export limit.

[23] E.g., "*NV Energy does not support the CAISO's updated design principle to address economic displacement due to concerns that the rule inappropriately allows a participating EIM entity to elect to 'pull capacity out of the market that it had previously offered voluntarily, during periods of mitigation.' NV Energy suggests that by allowing participants to withdraw capacity during intervals of mitigation, the CAISO will be allowing occurrences of non-competitive outcomes*" (Draft Final Proposal, op. cit., p. 12).

[24] "Local Market Power Mitigation Enhancements Revised Straw Proposal, Comments by Department of Market Monitoring," December 10, 2018 , p. 2.

note that the outcome of any negotiation is uncertain, and the vertically integrated utilities start from a favored position.[25]

Thus, we have a concern that a BA run by a vertically integrated utility could increase economic benefits to its consumers (accounting for revenues received by its resources and congestion rents) by using the export limitations to, in effect, decrease prices to its consumers while at the same time restricting exports and possibly exercising market power with respect to neighboring BAs. The incentive to do so would be greater if a significant portion of this BA's supply was from generation it does not own.[26]

However, we also note that because the EIM is voluntary a BA could achieve roughly the same outcome simply by offering less transmission, and that the EIM revenues are likely to be a small portion of the independent resource's revenue stream; the latter of course can (and we hope would) change under the proposed day-ahead market enhancements now under development. We also note that the crediting of congestion rents is a FERC jurisdictional issue. In addition, if there is evidence that an EIM entity is abusing export limits in order to exercise buyer-side market power, then the ISO could file with FERC to end the use of this option for that entity. There would be no such concern for BAs in which there is no independent generation that does or could participate in the EIM.

Possible Reduced Effectiveness of Flexible Ramp Product. A second set of unintended consequences could be to limit the effectiveness of flexible ramp product in one BA to assist with unexpected ramps in other BAs. Therefore, we recommend adjustment of the constraint on p. 25 of the proposal to ensure that the flexibility of the system is not compromised by too tight of a right-hand side. In particular, consideration should be given to eliminating the *FRUR'* term from that equation, since our interpretation that all of the flexibility-up resources required for a given BA are intended to support not just its own flexibility needs but also to provide support for the rest of the EIM when not needed internally. If the ISO prefers to be cautious and not do so, then on-going monitoring of the performance of the flexible ramping product in the EIM should include consideration of whether export limits result in consistent holding back of BA flexiramp capacity that is turned out to be unneeded by that BA. More generally, we reiterate that the export limits should be used rarely if at all if DEBs are appropriately calculated, and that if a BA chooses to invoke it frequently then that is indication of a problem that needs to be fixed.

[25] A counter argument is that the allocation of the congestion rents is covered by the EIM entities' FERC tariff, and hence anyone who is adversely impacted can raise the issue at FERC. Therefore, it can be argued that this issue is not a problem the CAISO needs to address or even should address. However, even given this FERC oversight, the issue exists and FERC oversight of the BAA operators tariff does not address the distribution of rents between BAs.

[26] In a presentation at the Jan. 25, 2019 MSC meeting, it was shown that in some circumstances there could be multiple sets of prices consistent with a market dispatch under the inter-BA limits, and that there would be clear motivation for the BA with the mitigated resource to obtain one of the set of prices rather than the other. ISO staff expressed the opinion that, in reality, the potential for multiple sets of prices to be consistent with a dispatch (technically termed a "degenerate" solution) is relatively small and can be dealt with in the existing software by small adjustments of the constraints.

Inter-Interval Consequences in RTD. A third set of unintended consequences could arise from changes in market conditions from one 5-minute interval to the next in the real-time dispatch (RTD) market. The present proposal would base the inter-BA flow limitations in one interval's binding market run upon the advisory interval's results for the previous interval. The result could be overly tight constraints on inter-BA transfers in the market run because of changes in load or supply availability from the previous advisory dispatch for the same interval. This could perversely result in the application of mitigation causing prices in the market dispatch to be raised above the level that would have prevailed had there been no mitigation.

These unintended consequences only arise if EIM entities find it necessary to actually exercise their option to impose the export limit, while the existence of the option to implement the export limit if DEBs are materially understated has the potential to increase participation in the EIM without the limit ever being utilized. Hence, we can support the availability of this option to encourage participation in the EIM, with the following caveat: if the ISO observes EIM entities making extensive use of this option, that is a sign of potential inefficiency that the CAISO needs to address by identifying and correcting the underlying problem.

Concern about Interaction of Mitigation in the Fifteen Minute and RTD Markets. Concern has been expressed by DMM about possible inefficiencies resulting from over-mitigation through too-low DEBs in the 15-minute market, followed by the mitigated resource finding it optimal to buy back its obligation in RTD, even if RTD prices are higher than 15-minute prices.

While the proposed modifications in the way the competitive LMP is updated could indeed result in a supplier buying back power sold at prices impacted by offer price mitigation in the FMM at higher prices in the 5-minute market, this would be the preferable outcome for the supplier if its offer price in the latter market reflects the value of the power. The seller would incur losses from the sale of power at mitigated prices in the FMM, but the losses would be reduced by being able to buy back the power for less than its value (i.e., the purchase price would be less than or equal to its offer price) to the market participant in the 5-minute market.

For example, suppose offer price mitigation were applied to a hydro resource in the FMM requiring that water worth $100 be used to generate power that would be sold at price of $30. If the seller's offer price was similarly mitigated to $30 in the real-time market, the water would be used to generate power and the resource owner would lose $70 as a result of its offer price being mitigated to less than the value of the water. If, however, the competitive LMP rose to $60 in the 5-minute market, the seller's offer price would be $60 in RTD, rather than $30 in the FMM. If the clearing price was $50 in RTD, the seller would not be dispatched at the $60 offer price and would instead buy back its FMM schedule at a $50 price. The sale of power at $30 in FMM, then buying the power back at $50 in RTD would cause the supplier to lose $20, but this $20 loss is much less than the $70 it would lose if it had to release water worth $100 to generate power worth only $30.[27]

[27] The updating of the competitive LMP would reduce the profits of suppliers seeking to exercise market power, but the ISO should be concerned with the impact of mitigation on suppliers offering supply at their cost, not suppliers seeking to exercise market power. Thus, if the actual costs of the suppler in the example above was $30, then it would lose $20 buying back its output at a price of $50, but the supplier could avoid this loss by offering its supply at its actual cost.

It would of course be preferable to set more appropriate default energy bids so water with a value of $100 would not be scheduled to generate power worth only $30 in the FMM. Other parts of the proposed design seek to improve DEBs so this happens less often. But as long as there is a potential for default energy bids to understate the actual value of energy limited resources, it will be economically efficient to update the competitive LMP in RTD, and this updating will also reduce the losses of suppliers that offer their output at prices that reflect their costs.

III. DEB Option for EIM Use-Limited (Hydropower) Resources

III.A. General Comments

With the expansion of the EIM to encompass BAs in the Pacific Northwest and Canada that have a substantial amount of hydro resources, it is necessary to tackle the very difficult conceptual issue of assessing the opportunity costs of such resources. DEBs are needed for the application of market power mitigation, but estimating hydro opportunity costs can be fiendishly difficult, particularly in the face of within-day environmental and hydraulic operating constraints, especially for resources in series (cascading); longer-term uncertainties in inflows and market prices; and possible premiums that hydro resources can earn in certain markets because of their fossil-fuel free nature. Any procedure to set DEBs for such resources has to balance the risk of setting DEBs that understate opportunity costs, leading to inefficient overuse of hydro resources (e.g., high generation early in the summer, leaving inadequate water in storage for later summer and fall) and discouragement of participation in the EIM with the risk of setting DEBs that are so high they permit the exercise of material market power.

A crucial question is whether the penalties for over-mitigation and under-mitigation are asymmetric. Since the EIM is voluntary and all participants are required to have enough supply to cover their base schedules, we believe that this is one factor favoring DEBs that may err somewhat on the high rather than low side. This is because we share the concern that DEBs that are too low will motivate hydro owners to remove some of their flexible resources from the EIM dispatch and use them to support base schedules that foregoes the value of their flexibility. From the entire region's point of view, this would make less efficient use of these resources and undermine the essential goal of closer integration of the West's power markets in order to facilitate the integration of large amounts of renewable energy.

We agree with the Department of Market Monitoring that the proposed general approach to calculating hydro DEBs is broadly reasonable.[28] There are, however, important details as there are in any market power mitigation system, and we comment on three of them below.

[28] "The general approach that the ISO has proposed for its new hydro resource default energy bid option is very similar to the approaches that have been used for some time in negotiated DEBs for similar resources. Therefore, DMM is supportive of the overall approach." DMM Comments, op. cit., p. 4.

III.B. Length of Time

The hydro DEB procedure would differentiate between short-term (small storage) and long-term (large storage) resources, with the former having a time horizon of weeks to a few months over which it can allocate stored water, and the latter having a year (or even longer) time horizon. For the latter, it is proposed to consider forward prices as far as twelve months in the future.

As a basic principle, if it can be predicted when in the future the reservoir will either be full and spill, then prices in periods beyond that time cannot represent opportunity costs, because water unused now cannot be saved to be used at those times. We note that determining the appropriate pricing horizon can be difficult, because of uncertain inflow forecasts. The proposal assumes that 12 months is the maximum horizon for long term storage resources, and that one month is the minimum horizon for resources with less storage. These values are quite rough approximations of the actual horizon because in reality the expected number of months until spill or emptying depends on the month of the year. For instance, it is much shorter at the beginning of the winter, a handful of months before the spring melt, than it is at the end of the spring freshet when the summer and fall still lie ahead. The simplified approach also does not account for the storage status. A near-empty reservoir during a winter with low snow pack will be much less likely to need to spill in the coming spring compared to a half-full reservoir during a high snow pack year. Similarly, a large reservoir with low water levels in June in a low hydro year will need to apply higher opportunity costs than if the reservoir had a high water level at the end of June.

A system in which the storage time horizon depends on the month of the year and how much water is in storage relative to typical conditions would be much more complicated than what the ISO proposes. We suggest however that as a first approximation that the calculation of the opportunity cost of long term storage could be limited to a time horizon that ends at the conclusion of the next high inflow season (spring freshet) and not be extended to include forward prices for the following summer, unless reservoir levels are unusually low so that spillage during the inflow season is unlikely.[29] If this is too complex to implement immediately, we suggest that it be analyzed after implementation of the present proposal to see whether it might make a significant difference in DEBs. However, if such a tailored system would increase the risk of underestimated DEBS and thus resource overuse, then the simpler (and more generous) present proposal can be retained.

We recommend that the CAISO implement the proposed DEB procedure (perhaps modified somewhat to reflect month of the year, as suggested above), closely monitor how it is performing, and be prepared to make changes over time as issues are identified. Given the complexity of hydro operations and its constraints, and large uncertainties in future flows and prices, it is unreasonable to expect that the CAISO's initial design will work exactly as intended to accurately estimate opportunity costs.

[29] Another important detail in these designs is the timing of recalculation of opportunity costs. Opportunity costs calculated based on forward prices will decline after the peak month prior to the next spill cycle, but actual opportunity costs may remain high because less water will be left in storage to cover the remaining period. The CAISO will need to work out how to handle this effect if it recalculates opportunity costs on a daily basis without considering the amount of water left in storage.

III.C. Use of Alternate Pricing Hubs

A vexing problem is which pricing hub should be relied on to provide monthly forward power price indices as proxies for the opportunity costs upon which hydro generation DEBs would be based. This issue has two aspects.

The first aspect concerns resources that are not located at a liquid trading hub for which assessments of forward prices are available. It may not be clear which hub is most relevant for determining opportunity costs; the geographically closest hub may be not be accessible regularly due to congestion. Or a resource may be able to switch sales between hubs as flow directions, prices and congestion change, as is expected to occur as often as twice daily or more as solar resources increase in California. A reasonable approach in such situations is for the resources to document, based, e.g., on past sales and congestion patterns, which hub or hubs are relevant. This is, however, a time-consuming option that would take significant resources to administer by the ISO.

The second aspect concerns the use of multiple hubs, especially more distant hubs. Stakeholders have argued that if a resource owner has firm transmission rights to a distant hub, then prices at that location can be the relevant opportunity cost, if higher than local prices. DMM has disagreed, arguing that if energy can be freely bought and sold both at the location of the resource and at the remote hub used for the forward price then, in effect, then the use of such rights to sell power at the distant hub has an opportunity cost that should be deducted from the power value at distant locations when calculating the opportunity cost of hydro generation. Stakeholders and the ISO's rebuttal of that position have pointed to the illiquidity of energy markets for resources not located at trading hubs who may not be able to buy the power needed to use their transmission rights; the predominance of multi-hour block sales of energy; and the premium that green energy obtains in some markets rather than others.

We disagree with the statement in the draft final proposal that "(i)f a resource owner has firm transmission availability to sell energy at multiple locations, these would be missed opportunities for energy sales at any of these hubs. Therefore the maximum price at any of those hubs should be included in the resource's default energy bid."[30] This assumes that there will be unused transmission rights: i.e., "use it or lose it", such that if unused they can't be sold to someone else at a reasonable price, While this may often be the case for firm transmission source at resources not located at trading hubs, there is also an implicit assumption that the amount of rights exceeds the amount of power sold to the remote hub by the resource on days with high prices at the distant hub, so that the transmission has zero opportunity cost and incremental power generated with hydro generation could be sold at the distant hub. Just because a resource owner holds some amount of long-term firm transmission rights doesn't mean that there are any to spare at zero marginal cost that could be used to support more sales, nor does it mean those rights can't be sold to someone else.

[30] Final draft proposal, op. cit., p. 13

It is likely to be the case that transmission rights markets, as well as markets for spot power are illiquid for resources not located at trading hubs. Nevertheless, in general, we are reluctant to have the ISO recognize and reward any inefficient incentives that result from inefficient transmission rights systems, for fear that this would encourage perpetuation of these inefficiencies. We do not believe that two identically situated generators should get different opportunity costs just because one went out and acquired some firm transmission rights. If spare illiquid rights exist such that distant hub energy prices become relevant opportunity costs, we would rather that the ISO encourage market parties to seek ways to make transmission rights and energy markets more liquid in the interest of improving the functioning of the West's markets.

We now address the justification based on illiquid markets for green power/renewable energy credits, such that green power receives a credit in one market but not in another. Under what circumstances might a premium for green power in one location and absence in another mean that multiple locations should be considered?   If there are multiple green resources competing for transmission rights to a hub where such resources get a premium, then in the liquid transmission rights markets we would like to see encouraged, the transmission price would reflect that and/or traders would be willing to buy green power at the local location and resell it elsewhere, so that that a green resource would realize the same net revenues locally as in the more distant market. We recognize that this is not the situation presently in the West. However, we are skeptical of rules that might allow a resource in the Pacific Northwest to make very high offers in the winter based on high Palo Verde prices in the summer, including a possible green premium. Furthermore, it is California that presently pays green premiums most consistently, and transmission rights into California in essence face a liquid transmission market because interties are priced by the ISO's locational marginal pricing system both for day-ahead and real-time sales, so this argument is not relevant in that case.

Our recommendation is as follows. It is necessary in many cases for resources to be able to use distant hubs to determine forward prices for use in the DEB procedure because there may be no nearby hub that is relevant. We agree with the ISO that the holding of firm transmission rights is a relevant factor to consider in deciding what distant hubs to consider. However, we recommend that use of distant hub prices not be allowed as a default or under just a showing of firm transmission rights, but that there be a greater showing burden be placed on resources that want to use further hubs in addition to much nearer hubs. This burden should include a demonstration to DMM's satisfaction that the transmission rights are in fact "use it or lose it" with zero opportunity cost through the relevant time horizon. This is fundamentally a market definition question, and the ISO is trying to develop simple rules to define these markets when a complex economic analysis would actually be necessary. We appreciate the need for transparency, predictability, and practicality of market rules, but we believe that the present proposal is overly generous in terms of what is required of a resource owner in order to use distant hubs.

III.D. Other Issues

Regarding the calculation and proposed use of a 140% multiplier for forward energy prices, we don't have any justification to propose an alternative multiplier as being obviously better. For instance, we don't have empirical evidence that 4 hours/day is the correct duration of production to consider when calculating the probability of overuse under a given multiplier. We can well imagine that it is too few hours for many resources for much of the year, but too many hours for the same resource during, e.g., late summer. We are reluctant to recommend a more complicated method--for instance considering different number of hours in different months of the water year--since that would multiply the number of somewhat arbitrary assumptions without assurance that better outcomes would occur.

Therefore, we suggest monitoring outcomes under the design proposed by the ISO (including examining the hours per day that different resources run and the rate at which reservoirs are depleted) with the object of assessing whether the multipliers used are broadly reasonable and cover the risk of overuse for the great bulk of resources. This recommendation is consistent with the draft final proposal's statement that "this default energy bid is not necessarily meant to be sufficient for all resources, particularly those with very limited water availability, but rather a solution that may work for most hydro resources. In cases where this default energy bid is insufficient, the CAISO will continue to offer Commitment Cost Enhancements – Phase 3 opportunity cost adders and negotiated default energy bids."[31] We further suggest that a less generous multiplier be used if a resource is consistently run above levels required for environmental flows or for other non-power uses for many more than 4 hours per day. Also, it might be reasonable to use average daily gas prices for such resources rather than peak gas prices, as proposed in the draft final proposal, but not in earlier versions.[32]

[31]Ibid., p. 17.

[32]Ibid., Section 6.3.1

Attachment F – List of Key Stakeholder Dates

Commitment Costs and Default Energy Bid Enhancements

California Independent System Operator Corporation

<u>**List of Key Dates in the Stakeholder Process for this Tariff Amendment**</u>

Date	Event/Due Date
November 18, 2016	CAISO issues paper entitled “Commitment Costs and Default Energy Bid Enhancements Issue Paper”
November 22	CAISO hosts stakeholder conference call that includes discussion of paper issued on November 18 and presentation entitled “Commitment Costs and Default Energy Bid Enhancements”
December 9	Due date for written stakeholder comments on paper issued on November 18
March 30, 2017	CAISO hosts working group meeting
April 20	CAISO hosts working group meeting
June 30	CAISO issues paper entitled “Commitment Costs and Default Energy Bid Enhancements Straw Proposal”
July 6	CAISO hosts stakeholder meeting that includes discussion of paper issued on June 30 and presentation entitled “Commitment Costs and Default Energy Bid Enhancements (CCDEBE)”
July 20	Due date for written stakeholder comments on paper issued on June 30
August 2	CAISO issues paper entitled “Commitment Costs and Default Energy Bid Enhancements Revised Straw Proposal”
August 3	CAISO hosts technical working group meeting that includes discussion of paper issued on August 2 and presentation entitled “Commitment Costs and Default Energy Bid Enhancements – Revised Straw Proposal and Technical Workshop”
August 15	Due date for written stakeholder comments on paper issued on August 2
August 23	CAISO issues paper entitled “Commitment Costs and Default Energy Bid Enhancements (CCDEBE) Draft Final Proposal”
August 30	CAISO hosts stakeholder conference call that includes discussion of paper issued on August 23 and presentation entitled “Commitment Costs and Default Energy Bid Enhancements – Draft Final Proposal”
September 11	Due date for written stakeholder comments on paper issued on August 23
December 21	CAISO hosts stakeholder conference call that includes presentation entitled “Commitment Costs and Default Energy Bid Enhancements – Revised Draft Final Proposal”

Date	Event/Due Date
January 5, 2018	CAISO issues updated version of presentation entitled “Commitment Costs and Default Energy Bid Enhancements – Revised Draft Final Proposal”
January 31	CAISO issues paper entitled “Commitment Costs and Default Energy Bid Enhancements (CCDEBE) – Revised Draft Final Proposal”
February 1	CAISO hosts stakeholder conference call that includes discussion of paper issued on January 31 and presentation entitled “Commitment Costs and Default Energy Bid Enhancements – Revised Draft Final Proposal”
February 27	Due date for written stakeholder comments on paper issued on January 31
March 2	CAISO issues paper entitled “Commitment Costs and Default Energy Bid Enhancements (CCDEBE) – Second Revised Draft Final Proposal”
May 10, 2019	CAISO issues draft tariff revisions to implement the commitment costs and default energy bid enhancements
May 28	Due date for written comments on draft tariff revisions issued on May 10
June 11	CAISO hosts stakeholder conference call that includes discussion of draft tariff revisions issued on May 10 and presentation entitled “Commitment Costs and Default Energy Bid Enhancements – Draft Tariff Language”
August 13	CAISO issued updated versions of draft tariff revisions to implement the commitment costs and default energy bid enhancements, and a matrix showing the CAISO’s responses to stakeholder comments on the draft tariff revisions issued on May 10

February 12, 2020	CAISO issues updated version of draft tariff revisions to implement the commitment costs and default energy bid enhancements
February 24	Due date for written stakeholder comments on draft tariff revisions issued on February 12
February 27	CAISO hosts stakeholder conference call that includes discussion of draft tariff revisions issued on February 12 and presentation entitled "Commitment Cost and Default Energy Bid Enhancements Resubmittal 2020"
March 19	CAISO hosts stakeholder conference call that includes discussion of draft tariff revisions issued on February 12 and presentation entitled "Commitment Cost and Default Energy Bid Enhancements Stakeholder Briefing"
March 26	Due date for written stakeholder comments on materials presented in the March 19 stakeholder conference call
May 13	CAISO issues updated version of draft tariff revisions to implement the commitment costs and default energy bid enhancements
May 20	CAISO hosts stakeholder conference call that includes discussion on draft tariff revisions issued on May 13 and presentation entitled "Commitment Cost and Default Energy Bid Enhancements"
June 5	CAISO issues updated version of draft tariff revisions to implement the commitment costs and default energy bid enhancements

List of Key Dates in the Stakeholder Process for the LMPME Tariff Amendment

Date	Event/Due Date
September 13, 2018	CAISO issues paper entitled "Local Market Power Mitigation Enhancements Issue Paper/Straw Proposal"
September 19	CAISO hosts stakeholder conference call that includes discussion of paper issued on September 13 and presentation entitled "Local Market Power Mitigation Enhancements Issue Paper/Straw Proposal"
October 3	Due date for written stakeholder comments on paper issued on September 13
October 10	CAISO hosts working group meeting
October 17	Due date for written stakeholder comments on working group meeting held on October 10
November 16	CAISO issues paper entitled "Local Market Power Mitigation Enhancements Revised Straw Proposal"
November 28	CAISO hosts stakeholder meeting that includes discussion of paper issued on November 16 and presentation entitled "Local Market Power Mitigation Enhancements Revised Straw Proposal"
December 7	Due date for written comments on paper issued on November 16
January 16, 2019	CAISO issues paper entitled "Local Market Power Mitigation Enhancements Draft Final Proposal"
January 23	CAISO hosts stakeholder conference call that includes discussion of paper issued on January 16 and presentation entitled "Local Market Power Mitigation Enhancements Draft Final Proposal"
January 30	Due date for written comments on paper issued on January 16
January 31	CAISO issues paper entitled "Local Market Power Mitigation Enhancements Draft Final Proposal (Updated)" and responses to stakeholder comments
April 17, 2019	CAISO issues draft tariff revisions to implement the local market power mitigation enhancements
April 30	Due date for written comments on draft tariff revisions issued on April 17
May 8	CAISO hosts stakeholder conference call that includes discussion of draft tariff revisions issued on April 30 and presentation entitled "Local Market Power Mitigation Enhancements Details"
May 29	CAISO issued updated versions of draft tariff revisions to implement the local market power mitigation enhancements, and a matrix showing the CAISO's responses to stakeholder comments on the draft tariff revisions issued on April 17