California ISO

California Independent
System Operator Corporation

August 19, 2016

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. ER16- ___-000

Bidding Rules and Commitment Cost Enhancements Previously Accepted on an Interim Basis

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment[1] to maintain in effect, beyond November 30, 2016, certain tariff provisions previously approved by the Commission on an expedited and interim basis.[2] Specifically, the CAISO proposes to make permanent the following Commission-approved tariff provisions to: (1) allow resources to rebid commitment costs in the CAISO real-time market if they were not committed in the day-ahead market; (2) ensure the CAISO short-term unit commitment process does not commit resources that did not submit bids into the real-time market unless they were scheduled or committed in the day-ahead or had a real-time must-offer obligation; and (3) allow scheduling coordinators to seek after-the-fact recovery of unrecovered commitment costs that exceed the commitment cost bid cap as a result of actual marginal fuel procurement costs pursuant to a FPA section 205 filing submitted to the Commission. Most stakeholders either support or do not oppose the tariff provisions contained in this filing, and the CAISO addresses in this filing the few issues raised by certain stakeholders.

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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] *See Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,224 (2016) (June 1 Order).

The CAISO respectfully requests that the Commission accept the tariff provisions contained in this filing effective November 30, 2016, *i.e.*, the date that such provisions would otherwise automatically expire pursuant to the June 1 Order.

I. Background

A. Applicable CAISO Market Provisions and Existing Tariff Authority

The CAISO administers both day-ahead and real-time wholesale electricity markets. Its tariff sets forth rules for submitting bids and self-schedules for all the CAISO markets.[3] As discussed below, the CAISO optimizes economic commitment and dispatch of generating resources in the markets it operates based in part on resources' commitment costs. The tariff also guarantees recovery of commitment costs and energy bid costs for CAISO-committed resources through the bid cost recovery mechanism.

In the day-ahead market (*i.e.*, the integrated forward market (IFM) and the residual unit commitment (RUC) process), the CAISO commits long-start units through the IFM and RUC and publishes a financially binding day-ahead schedule for IFM awards. The costs the market considers when making commitment decisions consist of the costs of starting up resources (start-up costs), the costs of running resources at their minimum operating levels (minimum load costs),[4] transition costs for resources that can operate in different configurations, and the energy bid costs for power above resources' minimum load energy.[5]

To the extent resources do not recover their start-up costs, transition costs, minimum load costs, and energy bid costs through the market, resources recover them through the bid cost recovery process based on the sum of cost components specified in the tariff that reflect the resources' unit-specific

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[3] Existing tariff section 30, *et seq.* 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), and revised tariff provisions (*i.e.*, existing tariff provisions that the CAISO proposes to revise in this filing).

[4] *See* existing tariff section 31.3; tariff appendix A, existing definitions of "Start-Up Cost" and "Minimum Load Costs."

[5] The tariff refers to these resources as "multi-stage generating resources" (MSG resources). *See* tariff appendix A, existing definitions of "Multi-Stage Generating Resources" and "Transition Cost."

performance parameters relative to their market revenues for those cost components.[6]

These resources can also submit daily bids for their start-up, minimum load, and transition costs that are between zero and a cap of 125 percent of the calculated proxy cost (the bid cap).[7] The CAISO generates cost-based bids when a scheduling coordinator does not submit a bid for a resource that is subject to a must-offer requirement, *e.g.*, a resource adequacy resource, or pursuant to the generally applicable scheduling and infrastructure bidding rules as set forth in the tariff and the business practice manual.[8]

The CAISO guarantees recovery of start-up costs, minimum load costs, transition costs, and energy bid costs for resources it commits through the bid cost recovery mechanism set forth in the tariff.[9] To the extent a resource's market revenues based on locational marginal prices are insufficient for the resource to recover such costs, the CAISO will pay the resource uplift to ensure that it recovers its costs.

B. The Aliso Canyon Tariff Amendment

On May 9, 2016, the CAISO filed the Aliso Canyon Tariff Amendment to provide the CAISO with a set of tools it could use in its markets on an interim basis to mitigate risks to reliability and market distortions posed by the limited operability of the Aliso Canyon natural gas storage facility (Aliso Canyon). Among other changes, the Aliso Canyon Tariff Amendment proposed to implement on an interim basis the following three revisions that the CAISO had designed in a separate CAISO stakeholder process:

(1) Allow a resource to rebid its resource commitment costs in the CAISO real-time market if the resource was not committed in the day-ahead market and has not already started up and is within its minimum run time range;[10]

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[6] Existing tariff sections 30.4.1.1.1(a), 30.4.1.1.2(a). Under the CAISO tariff, all resources except for those with use limitations recover their commitment costs pursuant to this "proxy cost methodology." Use-limited resources have the option of utilizing the "registered cost methodology" under which they recover their commitment costs pursuant to registered fixed values. Existing tariff section 30.4.1.2.

[7] Existing tariff sections 30.4.1.1.1(b), 30.4.1.1.2(b), 30.4.1.1.5, 30.7.9(c), 30.7.10.

[8] *See* existing tariff sections 30.7.3.4, 40.6.8; tariff appendix A, existing definition of "Generated Bid."

[9] *See* existing tariff section 11.8, *et seq.*

[10] *See* transmittal letter for Aliso Canyon Tariff Amendment at 20-23; tariff section 30.5.1(b)

(2) Ensure that the CAISO's short-term unit commitment process does not commit resources that did not submit bids into the real-time market unless they were scheduled or committed in the day-ahead or had a real-time must-offer obligation;[11] and

(3) Allow scheduling coordinators to seek, pursuant to a filing submitted to the Commission under section 205 of the FPA, after-the-fact recovery of fuel-related commitment costs that exceed the bid cap.[12]

Even though the CAISO had not intended or designed these revisions to be interim in nature, the CAISO asked the Commission to accept them (and other tariff revisions) on an expedited and interim basis to address the Aliso Canyon situation during the summer, when gas usage associated with electric generation is generally highest.[13] The CAISO also submitted tariff records for the revisions so they automatically expire on November 30, 2016. Absent Commission action to maintain their effectiveness beyond November 30, the revised tariff sections will revert to how they read before the CAISO submitted the Aliso Canyon Tariff Amendment.[14]

In the Aliso Canyon Tariff Amendment, the CAISO stated that prior to November 30, it would submit another section 205 filing or filings explaining why each of the tariff revisions should either: (1) automatically expire effective November 30; (2) remain in effect after November 30 with no modifications; or (3) remain in effect

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as revised by the Aliso Canyon Tariff Amendment. The CAISO filed the Aliso Canyon Tariff Amendment in Docket No. ER16-1649-000.

11 *See* transmittal letter for Aliso Canyon Tariff Amendment at 23-24; tariff sections 36.4 and 40.6.3 as revised by the Aliso Canyon Tariff Amendment.

12 Prior to the Aliso Canyon Tariff Amendment, the CAISO had intended to implement procedures to permit scheduling coordinators to seek after-the-fact recovery of fuel-related commitment costs. In the Aliso Canyon Tariff Amendment, the CAISO broadened these procedures to also include after-the-fact recovery of incremental fuel costs associated with energy bids. *See* transmittal letter for Aliso Canyon Tariff Amendment at 36, fn. 71; new tariff section 30.11 as implemented by the Aliso Canyon Tariff Amendment. As discussed below, the CAISO proposes to retain in its tariff after November 30 the language permitting after-the-fact recovery of fuel-related commitment costs. The CAISO will discuss with stakeholders whether other tariff provisions, such as those concerning after-the-fact recovery of incremental fuel costs associated with energy bids, should remain in effect after November 30.

13 Transmittal letter for Aliso Canyon Tariff Amendment at 40-41.

14 *Id*. at 42.

after November 30 with modifications.[15] The CAISO specifically noted that its intent was ultimately to implement these provisions on a permanent basis.

C. The June 1 Order

In the June 1 Order, the Commission accepted the tariff revisions contained in the Aliso Canyon Tariff Amendment effective on the dates requested by the CAISO, subject to the CAISO's submittal of a compliance filing within 30 days and a technical conference several months after the CAISO implements the revisions to discuss lessons learned and potential longer-term solutions.[16]

The Commission found the tariff revisions not expressly discussed in the June 1 Order, including the revisions regarding real-time rebidding of commitment costs and the revisions concerning the short-term unit commitment process (*i.e.*, the first two of the CAISO's proposed revisions), to be "just and reasonable because they constitute appropriate improvements upon CAISO's current tariff provisions that should enable CAISO to address limitations in the natural gas delivery system in southern California and facilitate fuel cost recovery by generators."[17] Therefore, the Commission accepted them on an interim basis without further modification.

The Commission also conditionally accepted the CAISO's proposed procedures for filings seeking after-the-fact recovery of fuel-related commitment costs and incremental fuel costs associated with energy bids (*i.e.*, the third revision proposed by the CAISO herein).[18] The Commission found that "because of the uncertainty and potential price volatility introduced into the market due to the limited availability of Aliso Canyon, there remains the possibility that fuel costs may exceed the amounts recoverable under CAISO's normal cost recovery provisions."[19] Although the Commission noted that "after-the-fact cost recovery cannot be a substitute for properly functioning markets," the Commission explained that "given the situation facing CAISO and the need to ensure reliable operation of the grid at just and reasonable rates, we find reasonable the interim solution to improving a scheduling coordinator's ability to recover fuel costs."[20] The Commission also stated that "long-term issues, including fuel cost recovery solutions may be raised at the technical conference established in this order."[21]

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[15] *Id.*

[16] *See* June 1 Order at PP 12-13, 104, and ordering paragraphs (A)-(D).

[17] *Id.* at P 12 & n.13.

[18] *Id.* at PP 91-96.

[19] *Id.* at P 91.

[20] *Id.* at P 92. *See also id.* at P 104.

[21] *Id.* The Commission subsequently scheduled the technical conference for September 16,

The Commission rejected certain intervenors' proposals to limit the after-the-fact filings to only those costs incurred within a specific time-frame and to impose a blanket prohibition on the ability to seek after-the-fact recovery of incurred operational flow order (OFO) penalties.[22] Further, the Commission declined to require the inclusion of gas disposal costs or OFO penalty costs within the scope of fuel costs recoverable under the provisions.[23] However, the Commission agreed that the CAISO should revise its timeline for providing information to entities seeking after-the-fact recovery and directed the CAISO to clarify in its tariff that this process applies to participants in the Energy Imbalance Market (EIM).[24]

The Commission acknowledged the CAISO's commitment to make "a section 205 filing with the Commission ahead of the [November 30] automatic expiration date to either confirm that it has determined that the provisions should expire, or to explain why the provisions should remain in effect in some form."[25]

D. Stakeholder Process for this Filing

As explained above, the three sets of tariff revisions proposed in this filing were designed to be implemented on a permanent basis and were developed independently of the issues the CAISO expected to experience due to the limited operability of Aliso Canyon. The CAISO and its stakeholders developed the three sets of tariff revisions contained herein as a subset of a larger group of proposals in the CAISO bidding rules enhancements stakeholder initiative, which began in December 2014 and was later divided into separate phases.[26] The third phase of the bidding rules enhancements initiative addressed generator

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2016. *See* Notice Rescheduling Technical Conference, Docket No. ER16-1649-000 (July 18, 2016).

[22] June 1 Order at P 93. In this regard, the Commission "acknowledge[d] the possibility of extraordinary situations under which a gas generator might be able to support a request for prudent after-the-fact cost recovery." *Id.*

[23] *Id.* at P 96.

[24] *Id*. at PP 94-95.

[25] *Id.* at P 13.

[26] Materials regarding the bidding rules enhancements stakeholder process are available on the CAISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingRulesEnhancements.aspx. These materials included a revised draft final proposal, which is also provided in attachment C to this filing. The bidding rules enhancements initiative is ongoing with regard to changes other than those proposed in this filing.

commitment cost improvements, including those proposed in this filing.[27] In the portion of the bidding rules enhancements initiative that addressed the proposals in this filing, the CAISO issued five papers, held five stakeholder conference calls to discuss them, and provided stakeholders with opportunities to submit comments on the papers. At its March 25, 2016 meeting, the CAISO Governing Board (Board) voted unanimously to authorize the CAISO to prepare and submit a filing to implement these three proposals on a permanent basis.[28]

In the stakeholder process the CAISO began in March 2016 to address the Aliso Canyon situation, the CAISO also included the three proposals approved by the Board on March 25. The CAISO worked with stakeholders to develop tariff revisions to implement the proposals on an interim basis. In connection with its stakeholder discussions regarding the Aliso Canyon situation, the CAISO issued four papers, held four stakeholder conference calls to discuss the CAISO papers and a stakeholder conference call to discuss the draft tariff revisions, and provided stakeholders an opportunity to submit comments regarding the papers and draft revisions.[29]

All of the comments in the stakeholder process for the three measures and in the Aliso Canyon Tariff Amendment proceeding regarding the proposals for real-time rebidding of commitment costs and revising the pool of bids considered in the short-term unit commitment process were supportive.[30] Most comments also supported the after-the-fact recovery proposal; although, a couple of commenters suggested clarifications or modifications to the CAISO's

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[27] This third phase of the bidding rules enhancements initiative should not be confused with another ongoing CAISO initiative called commitment cost enhancements phase 3.

[28] Materials related to the Board's authorization are available on the CAISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx. These materials include a memorandum to the Board from Keith Casey, Vice President, Market & Infrastructure Development, which is also provided in attachment E to this filing. The Board memorandum addresses the proposals contained in this filing as well as other changes coming out of the bidding rules enhancements stakeholder process and the commitment cost enhancements phase 3 stakeholder process (see http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancementsPhase3.aspx), which the CAISO will propose to implement in a future tariff amendment filing or filings pursuant to their approval by the Board on March 25.

[29] Materials regarding the Aliso Canyon stakeholder process are available on the CAISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx. A list of the key dates in the bidding rules enhancements and Aliso Canyon stakeholder processes that are relevant to this tariff amendment is provided in attachment D to this filing.

[30] See the comments on the Aliso Canyon Tariff Amendment submitted by Calpine Corporation (Calpine) at page 6, by the Financial Marketers Coalition at page 4, and by the Western Power Trading Forum and Electric Power Supply Association (WPTF/EPSA) at page 6.

proposed process.[31] The CAISO addresses in Section III of this letter the remaining issues raised by a few stakeholders.[32]

II. Proposed Tariff Revisions

A. Maintain the Effectiveness of the Tariff Provisions that Allow Resources to Rebid Commitment Costs in the Real-Time Market

Absent tariff provisions allowing resources to rebid commitment costs in the real-time market, resources are locked into day-ahead commitment cost bids in the real-time market even if the resources are not committed or scheduled in the day-ahead market.[33] Thus, scheduling coordinators have no flexibility to reflect any intervening gas imbalance limitations and their associated economic impacts on real-time gas prices in their real-time market commitment cost bids. The absence of such tariff provisions can result in inefficient resource commitment because the real-time market will incorrectly value commitment costs based on bids that do not reflect current conditions at the time of the real-time market. If the real-time market is unable to reflect changing gas system conditions, it will be incapable of dispatching resources optimally, which could threaten electric system reliability and further constrain the gas system.

Although the limited operability of Aliso Canyon heightens these concerns, they are not specific to the Aliso Canyon situation. Gas imbalance limitations and changes in gas prices between the day-ahead and real-time markets, as well as changes in gas prices between hours within the real-time market, can occur

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[31] Calpine, the Financial Marketers Coalition, and WPTF/EPSA supported the CAISO's proposal without condition. See Calpine's comments at page 6, the comments of the Financial Marketers Coalition at page 4, and the comments of WPTF/EPSA at page 6. NRG Power Marketing LLC and GenOn Energy Management, LLC (together, NRG) requested that the Commission adopt certain clarifications regarding the eligibility of gas disposal and operational flow order penalty costs for recovery and the timing of information provided by the CAISO to entities utilizing this process. See NRG's comments on the Aliso Canyon Tariff Amendment at pages 10-12. Pacific Gas and Electric Company (PG&E) requested that the Commission limit costs incurred to CAISO dispatches made during the period in which generators are unable to update their gas nominations. See PG&E's comments on the Aliso Canyon Tariff Amendment at pages 4-5. Also, Nevada Power Company and Sierra Pacific Power Company (together, NV Energy) stated that it was unclear whether the after-the-fact recovery process would apply to EIM participating resources. See the comments of NV Energy on the Aliso Canyon Tariff Amendment at pages 13-15.

[32] The CAISO addresses these issues in section III of this transmittal letter.

[33] Absent these tariff provisions, existing tariff section 30.5, which sets forth bidding rules for the CAISO markets, does not permit resources to change their day-ahead commitment cost bids in real-time.

irrespective of the operability of Aliso Canyon. Therefore, the CAISO proposes to maintain the effectiveness of the tariff provisions contained in the Aliso Canyon Tariff Amendment that allow a scheduling coordinator to submit new daily bids in the real-time market for commitment costs for resources or MSG configurations for which the scheduling coordinator previously submitted such bids in the day-ahead market, subject to the two exceptions discussed below.[34] These tariff provisions enable scheduling coordinators to submit new daily bids any time after the close of the day-ahead market, and the new bids apply to all remaining eligible hours of the day unless the scheduling coordinator subsequently modifies them. The increased bidding flexibility provided by these tariff revisions will enable scheduling coordinators to submit commitment cost bids that better reflect gas imbalance limitations and the associated financial impacts, as well as changes in gas commodity prices. This, in turn, will allow the real-time market to better determine the set of resource commitments needed to efficiently serve load, taking into account any gas system limitations, so that locational marginal prices send more accurate price signals to both generation and load throughout the CAISO system.

The CAISO also proposes to maintain two exceptions to this additional flexibility[35] that are necessary to preserve the integrity of day-ahead market results and alleviate the potential ability for resources to inflate their bid cost recovery.[36]

First, to preserve day-ahead commitments, the tariff provisions prohibit scheduling coordinators from rebidding their commitment costs in the real-time market for trading hours in which the resource or MSG configuration has received a day-ahead schedule or a start-up instruction in RUC, *i.e.*, when the resource has a binding RUC commitment. This exception is necessary because

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[34] Revised tariff section 30.5.1(b). This revised tariff section in the instant filing is identical to the same revised section contained in the Aliso Canyon Tariff Amendment.

[35] In addition, the CAISO's Department of Market Monitoring (DMM) has explained that it will be "closely scrutinizing changes to commitment costs in real time that coincide with bid cost recovery payments." DMM Comments on Final Aliso Canyon Gas-Electric Coordination Proposal at 9 (May 6, 2016) (DMM Comments). The DMM Comments were provided in attachment F to the Aliso Canyon Tariff Amendment.

[36] DMM Comments at 9. If the CAISO is unable to implement the two exceptions through an automated process, the CAISO will monitor the markets for rebidding of commitment costs that violates the two exceptions and will refer any tariff violations it detects to the Commission Further, the fact that the tariff revisions explicitly mention only these two prohibitions does not provide market participants a safe harbor for any other adverse market behavior that results in market inefficiencies. The same general prohibitions against market behavior that adversely impacts market outcomes specified in existing tariff section 39 will continue to apply to this and all parts of the CAISO markets. The CAISO and its DMM will continue to take all necessary and appropriate actions to address these situations.

the integrated forward market and the RUC process can consider and dispatch resources with longer start times than the resources the real-time market can consider and dispatch. Since the day-ahead and binding RUC start-up instructions are financially binding in the day-ahead, the CAISO expects such resources to prudently procure fuel to support those financially binding schedules prior to real-time. Such procurement practices will insulate them from the impact of the changes in gas prices, whether between the day-ahead and real-time markets or between hours over the electric operating day. As a result, allowing resources with binding day-ahead commitments to increase their commitment costs in real-time can lead to inefficient dispatches and distortions in the day-ahead market. If the day-ahead market had considered the increased commitment costs rebid by a resource in real-time, it might have dispatched a less expensive resource with a longer start time that, because of its longer start time, would not be available to be dispatched in the real-time market. In other words, the rebidding resource in this scenario would never have been dispatched by the day-ahead market in the first place. Further, the CAISO calculates and pays bid cost recovery separately for the day-ahead and real-time markets, so resources are fully compensated for procuring gas for day-ahead schedules.

Second, the tariff provisions prohibit scheduling coordinators from rebidding their commitment costs in the real-time market for 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 real-time market.[37] This exception is necessary because the CAISO market cannot reconsider commitment costs and de-commit a resource or transition a MSG resource from one MSG configuration to another for the duration of a minimum run time. Consequently, any increase to commitment costs during this period would inappropriately inflate bid cost recovery payments without improving the efficiency of the market dispatch.

With these exceptions, the CAISO's commitment cost re-bidding proposal strikes a just and reasonable balance between (1) providing scheduling coordinators with flexibility to reflect the economic impact of changes in gas prices between the day-ahead and real-time markets as well as changes between hours within the real-time market, and (2) preserving the integrity of day-ahead market results and preventing inflated bid cost recovery. Therefore, the Commission should allow these provisions to continue in effect after November 30, 2016.

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[37] Minimum run time means the minimum amount of time that a generating unit must stay on-line after being started up prior to being shut down, due to physical operating constraints. Tariff appendix A, existing definition of "Minimum Run Time."

B. Maintain the Effectiveness of the Tariff Provisions for the CAISO's Short-Term Unit Commitment Process

The CAISO's short-term unit commitment process looks ahead over multiple intervals to anticipate commitment needs. Absent the revisions adopted in the Aliso Canyon Tariff Amendment, that process could commit a resource in real-time even if the resource does not have a bid in the real-time market or a real-time must-offer requirement because the short-term unit commitment process considers any bid submitted in any of the CAISO markets, including the day-ahead market. Therefore, even if a resource does not submit a bid in the real-time market and does not have a real-time must-offer requirement, if it submitted a bid in the day-ahead market the CAISO may nevertheless commit it through the real-time market even if it the CAISO did not commit it in the day-ahead market.

In the bidding rules enhancements stakeholder process, the CAISO determined that it should revise its tariff to prevent the commitment of non-resource adequacy resources and use-limited resources that were not obligated to submit real-time bids in this manner because these resources have no obligation to, and have chosen not to, participate in the real-time market. Although this rationale was not tied to the operability of Aliso Canyon, the CAISO determined that implementing this change expeditiously would help reduce uncertainty with respect to real-time commitments and associated gas procurement decisions. Therefore, in the Aliso Canyon Tariff Amendment, the CAISO proposed to revise its tariff to state that the short-term unit commitment process will utilize (1) bids that are submitted in the real-time market by the scheduling coordinator for the trading hour, or (2) the clean bid[38] from the day-ahead market if the resource has a day-ahead schedule or received a start-up instruction in RUC for the trading hour, or if the resource has a real-time must-offer obligation for that trading hour. These tariff revisions aligned the short-term unit commitment process with resources' ability to rebid their commitment costs.

Given that the original rationale for these revisions was not tied to the circumstances relating to Aliso Canyon, the CAISO proposes to maintain their effectiveness, with the clarification that if a resource has a real-time must offer obligation for the applicable trading hour, and has not submitted a bid in the real-time market, the CAISO will use a generated bid for that resource.[39] This

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[38] A clean bid means a valid bid submitted by a scheduling coordinator that requires no modification. Tariff appendix A, existing definition of "Clean Bid."

[39] Revised tariff section 34.6. This revised tariff section in the instant filing is identical to the same revised section contained in the Aliso Canyon Tariff Amendment, apart from the clarification described above.

clarification ensures consistency with the CAISO tariff rule that when a resource that is required to submit a bid in a particular market fails to do so, the CAISO will use a generated bid for that resource.[40] As a result, after November 30 the short-term unit commitment process will continue not committing resources without a real-time must-offer obligation that are not bid into the real-time market unless they are scheduled or committed in the day-ahead.

The CAISO also proposes to maintain the effectiveness of a related revision from the Aliso Canyon Tariff Amendment that clarifies that the resource adequacy availability requirements apply to fast-start, short-start, and medium-start units but do not apply to long-start units or extremely long-start resources.[41] As explained in the Aliso Canyon Tariff Amendment, this clarification reflects the fact that the short-term unit commitment process commits short-start units and medium-start units in the real-time, but not long-start units or extremely long-start resources.[42] This clarification does not impose an additional obligation on medium-start units that are resource adequacy resources because the CAISO currently generates bids in the short-term unit commitment process for these resources if they bid into the day-ahead market, which they are required to do.

C. Maintain the Effectiveness of the Tariff Language that Allow Resources to Seek After-the-Fact Recovery of Commitment Costs from the Commission Pursuant to a Section 205 Filing

In the June 1 Order, the Commission accepted, on an interim basis, procedures that permit scheduling coordinators to seek after-the-fact recovery of both fuel-related commitment costs and incremental fuel costs associated with energy bids pursuant to after-the-fact filings submitted to the Commission under section 205 of the FPA.[43] The CAISO proposes in this filing to maintain the effectiveness of the procedures regarding recovery of fuel-related commitment

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[40] *See* tariff section 30.7.3.4 ("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.").

[41] Revised tariff section 40.6.3. This revised tariff section in the instant filing is identical to the same revised section contained in the Aliso Canyon Tariff Amendment. As their names imply, the different types of units listed above differ from one another based on how long they take to start up. *See* tariff appendix A, existing definitions of "Short Start Unit," "Medium Start Unit," "Long Start Unit," and "Extremely Long Start Resource."

[42] *See* existing tariff section 34.6.

[43] New tariff section 30.11. This new tariff section in the instant filing is identical to the same new section contained in the Aliso Canyon Tariff Amendment, except in the respects noted below.

costs after November 30. The CAISO always intended this provision to be available in the tariff indefinitely to allow recovery of such commitment costs resulting from actual marginal fuel procurement costs that exceed the bid cap and unrecoverable through market revenues under the CAISO's normal cost recovery provisions.[44] However, as discussed below, the CAISO is not proposing, at this time, to extend the effectiveness of the language permitting after-the-fact recovery of actual marginal fuel procurement costs associated with mitigated or generated energy bids. Broader cost recovery issues will be explored in the CAISO's stakeholder process and may be discussed at the September 16, technical conference.[45]

The CAISO also anticipates that scheduling coordinators will, in almost all circumstances, be able to recover their actual marginal fuel procurement costs pursuant to the normal tariff provisions allowing cost recovery.[46] The CAISO and stakeholders are also considering additional measures to improve recovery of costs by resources, including fuel cost recovery, in ongoing and planned stakeholder initiatives to evaluate long-term market solutions for addressing bid cost modeling of gas-fired resources in order to improve market efficiency and support sufficient cost recovery through market mechanisms and to evaluate coordination between the electric and gas markets.[47] The CAISO and stakeholders participating in these initiatives will be able to incorporate the discussion and information gathered through the September 16 technical conference in order to develop long-term solutions. The CAISO estimates that the long-term solutions will be completed by the third quarter of 2017 and implemented in the following quarter. Nevertheless, the CAISO recognizes that unexpected events, such as extreme swings in gas prices within a short timespan *(e.g.*, 24 hours) can lead to situations in which scheduling coordinators may not be able to recover all of their costs associated with the CAISO's commitment of their resources. In situations such as these, the tariff procedure will serve as an appropriate backstop measure to the extent that a scheduling coordinator believes it cannot recover its commitment costs through the normal tariff mechanisms.

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44 *See* June 1 Order at P 91.

45 *See Supplemental Notice of Agenda and Discussion Topics For Staff Technical Conference* issued in Docket NO. ER16-1649.

46 The normal tariff provisions are designed to provide resources with adequate compensation for their fuel and other commitment costs. *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,082, at PP 21, 23-24 (2013).

47 These stakeholder processes include the commitment cost enhancements phase 3 initiative, a commitment cost and Default energy bid enhancements initiative, and a future initiative on gas-electric coordination to consider long-term policies to replace the interim measures adopted pursuant to the Aliso Canyon initiative.

The CAISO's procedure closely resembles a similar procedure the Commission approved for use on a permanent basis by ISO New England (ISO-NE).[48] Like ISO-NE's procedure, the CAISO procedure will provide "a safeguard to ensure that generators . . . can recover their full low-load costs."[49] The CAISO notes that it has other Commission-approved procedures that allow suppliers to make limited cost justification filings to the Commission in the rare instance that the applicable cap or administrative price is insufficient to compensate the supplier for its actual costs.[50]

Pursuant to the proposed tariff procedure, if a scheduling coordinator representing a resource incurs, but cannot recover through the CAISO's bid cost recovery process, any actual marginal fuel procurement costs that exceed the 125-percent cap on bids for start-up costs, minimum load costs, or transition costs, the resource may seek to recover those costs through a filing submitted to the Commission pursuant to section 205 of the FPA.[51] Because eligibility for a bid cost recovery uplift is contingent on a scheduling coordinator's costs exceeding its market revenues during the applicable period, a resource electing to utilize this process must demonstrate in its filing that it would have been entitled to a bid cost recovery uplift under the CAISO tariff in the first instance. As explained in the June 1 Order, "any scheduling coordinator seeking after-the-fact cost recovery must clearly present the justification for its actions and the reasons it was unable to recover its costs," and based on the scheduling

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48 *See* ISO New England Transmission, Markets, and Services Tariff, Market Rule 1, Appendix A, Section III.A.15, available on the ISO New England website at http://www.iso-ne.com/participate/rules-procedures/tariff.

49 *See ISO New England Inc. and New England Power Pool*, 129 FERC ¶ 61,008, at P 12 (2009).

50 *See* existing tariff section 43.7.2.1.1(containing a capacity procurement mechanism (CPM) capacity price higher than the administrative price set forth in the tariff); existing tariff section 43A.4.1.1.1 (provision expected to go into effect on November 1, 2016 that will allow a supplier to cost-justify to the Commission fixed costs that exceed the CPM soft offer cap).

51 In the bidding rules enhancements stakeholder initiative, the CAISO originally suggested that it, rather than the Commission, might be able to provide after-the-fact cost recovery. After additional review, however, the CAISO determined that it was not practicable to provide the cost recovery itself. To do so, the CAISO would have had to establish objective criteria to determine if a resource qualified for after-the-fact cost recovery and to specify that recovery. The CAISO does not believe this is practical, as it would be difficult to detail before the fact all of the situations in which a resource conducted prudent procurement practices but incurred gas procurement costs it could not recover under the tariff provisions. Also, determining incurred costs would require visibility to a market participant's full portfolio of gas transactions and hedging mechanisms, which the Commission has a greater ability than the CAISO to obtain.

coordinator's presentation the Commission will "carefully consider the costs incurred prior to approving them on a case-by-case basis."[52]

As is also the case for the procedure currently in effect, the scheduling coordinator must notify the CAISO within 30 business days after the operating day on which the resource incurred any costs that it believes were unrecovered, and must submit the filing to the Commission within 90 business days after that operating day. Within 60 business days after the operating day, the CAISO will provide the scheduling coordinator with a written explanation of any effect that events or circumstances in the CAISO markets may have had on the resource's inability to recover the costs on the operating day.[53] These provisions give the scheduling coordinator a reasonable amount of time to provide notice to the CAISO and file with the Commission, and for the CAISO to provide a written explanation regarding the applicable market conditions that the scheduling coordinator will provide to the Commission as part of the materials supporting its filing.

As is currently the case, each filing the scheduling coordinator submits to the Commission 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

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52 June 1 Order at P 93.

53 The CAISO proposes to provide the scheduling coordinator with a written explanation within 60 business days after the operating day. This is consistent with the directive in the June 1 Order stating that this 60-business-day period is appropriate and should be included in the tariff on compliance. *See* June 1 Order at P 95. The CAISO does not, however, propose to include tariff language stating that the after-the-fact cost recovery provisions apply to scheduling coordinators for resources participating in the EIM. Although the June 1 Order directed the CAISO to make this change in its compliance filing (*see id.* at P 94), for the reasons explained in the CAISO's June 29, 2016 motion for clarification or, in the alternative, request for rehearing of the June 1 Order, the CAISO believes that the tariff provisions as proposed in this filing and as proposed in the Aliso Canyon Tariff Amendment already allow an EIM participating resources to seek such after-the-fact cost recovery. If the Commission rejects the CAISO's motion for clarification and alternative request for rehearing on this issue, the CAISO requests that the Commission direct the CAISO on compliance to add back the language referencing the eligibility of EIM participating resources.

(4) A copy of the written explanation from the CAISO to the scheduling coordinator described above.

The CAISO believes this is sufficient information for the scheduling coordinator to include in its filing. If the Commission requires additional materials to issue an order, it can request such materials from the scheduling coordinator.

To the extent that the Commission 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 the existing tariff provisions regarding neutrality adjustments.[54]

As indicated above, the CAISO does not propose to maintain the effectiveness of the provisions currently in effect on an interim basis that allow a scheduling coordinator to seek to recover the incremental fuel costs associated with energy bids. The after-the-fact recovery procedure originally developed in the bidding rules enhancements stakeholder initiative only applied to commitment cost-associated fuel procurement costs. When the CAISO moved the proposal to the Aliso Canyon stakeholder proceeding, the CAISO and stakeholders expanded it to encompass incremental fuel costs associated with energy bids to better address the specific risks presented by the limited operability of Aliso Canyon.[55] By November 30, when the summer is long over, this temporary expansion of the procedure may no longer be needed. As part of the separate stakeholder process addressing which, if any, of the interim tariff revisions that arose in the Aliso Canyon Tariff Amendment initiative should remain in effect beyond November 30, the CAISO and stakeholders will discuss whether after-the-fact recovery of fuel costs associated with energy bids should remain in effect on a continued interim basis dependent upon the anticipated operations of Aliso Canyon.

III. Stakeholder Issues

All stakeholders either supported or expressed no position regarding the CAISO's proposal to maintain the provisions allowing resources to rebid commitment costs in the real-time market and to enhance the CAISO's short-term unit commitment process. One stakeholder stated that it supports those changes, but also proposed that the CAISO implement a higher bid cap percentage in the real-time market (*e.g.*, 150 percent of the proxy cost) and limit

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[54] For an illustrative example of how the CAISO will pay the scheduling coordinator any amounts the Commission deems recoverable, see pages 15-16 of the revised draft final proposal contained in attachment C to this filing.

[55] Transmittal letter for Aliso Canyon Tariff Amendment at 36 n.71.

rebidding to the higher bid cap. In response, the CAISO explained that any change to the existing 125-percent bid cap on commitment costs was premature, beyond the scope of the stakeholder initiative, and could only be considered in the context of a lengthier stakeholder process.

Further, the matter before the Commission is to determine whether the CAISO's proposal, not some alternative proposal, is just and reasonable. "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 alterative rate designs."[56] Therefore, "[u]pon finding that CAISO's proposal is just and reasonable, [the Commission] need not consider the merits of alternative proposals."[57] Consistent with this precedent, the Commission should accept the CAISO's proposal for the reasons explained in this filing and reject any alternative proposals.

A large majority of stakeholders also supported or expressed no position regarding retention of tariff provisions permitting scheduling coordinators to seek after-the-fact cost recovery from the Commission. However, one stakeholder argued that, as an alternative to those tariff changes, the CAISO should eliminate the commitment cost bid cap. Again, the CAISO responded that eliminating the bid cap was beyond the scope of the instant initiative and would require further vetting by stakeholders. Moreover, for the reasons explained above, the Commission should accept the CAISO's proposal as just and reasonable and not consider alternative proposals.

One stakeholder asserted that it would be premature to implement the CAISO's proposal regarding after-the-fact cost recovery because of the Commission's ongoing proceeding on energy price formation. That proceeding raises the issue of underlying cost verification for energy bids; it does not pertain

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[56] *Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,135, at P 44 n.43 (2012), quoting *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. 1984). In that same order, the Commission also explained that the revisions proposed by the utility "need not be the only reasonable methodology" and that "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 alternative proposal." *Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,135, at P 44 n.43 (citing federal court and Commission precedent). *See also New England Power Co.*, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd*, *Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (rate design proposed need not be perfect, it merely needs to be just and reasonable); *Louisville Gas and Elec. Co.*, 114 FERC ¶ 61,282, at P 29 (2006) (the just and reasonable standard under the Federal Power Act is not so rigid as to limit rates to a "best rate" or "most efficient rate" standard, but rather a range of alternative approaches often may be just and reasonable).

[57] *Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,135, at P 44.

to commitment costs. In any event, the CAISO does not believe that its proposal raises any conflicts with the Commission's energy price formation proceeding.[58] Further, the fact that the Commission accepted the CAISO's cost recovery proposal on an interim basis in the June 1 Order, and did not find that the proposal was either premature or inconsistent with the energy price formation proceeding, supports the CAISO's view.

IV. Effective Date

The CAISO respectfully requests that the Commission accept the tariff revisions contained in this filing effective November 30, 2016, 103 days from the date of this filing. The requested November 30 effective date will permit the tariff revisions to go into effect immediately after the interim tariff revisions accepted in the June 1 Order automatically expire on November 30, 2016.

V. Communications

Correspondence and other communications regarding this filing should be directed to:

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VI. 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.

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[58] See Commission issuances in Docket No. AD14-14-000.

VII. Contents of Filing

In addition to 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 contained in this tariff amendment
Attachment C	Revised draft final proposal
Attachment D	Board memorandum
Attachment E	List of key stakeholder dates

VIII. Conclusion

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission accept the tariff revisions contained in this filing effective November 30, 2016.

Respectfully submitted,

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Attachment A – Clean Tariff

Bidding Rules and Commitment Costs Enhancements

California Independent System Operator Corporation

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. A Scheduling Coordinator may submit in the Real-Time Market new daily Bids for Start-Up Costs, Minimum Load Costs, and Transition Costs 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. 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. 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;

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

(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;

(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

[No changes to the remainder of Section 30.5.1]

* * * *

30.11 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

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.

* * * *

34.6 Short-Term Unit Commitment

Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast Of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run. STUC will utilize: (1) Bids previously submitted in the RTM by the

Scheduling Coordinator for that Trading Hour; or (2) the Clean Bid from the Day-Ahead Market if the resource has a Day-Ahead Schedule or received a Start-Up Instruction in RUC for the Trading Hour; or (3) the Generated Bid if the resource has a Real-Time must-offer obligation for that Trading Hour and has not submitted a Bid in the RTM. . The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. Not all resources identified for need as a given STUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour look-ahead time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * * *

40.6.3 Additional Availability Requirements For Resources that Are Not Long Start Units or Extremely Long Start Resources

A resource that is not a Long Start Unit or an Extremely Long-Start Resource that is a Resource Adequacy Resource and that does not have an IFM Schedule or a RUC Schedule for any of its capacity for a given Trading Hour is required to participate in the Real Time Market in accordance with Section 40.6.2. Such a resource that is also a Use-Limited Resource subject to Section 40.6.4 is required, consistent with their applicable use plan, to submit Economic Bids or Self Schedules for Resource Adequacy Capacity into the Real Time Market.

The CAISO may waive these availability obligations for a resource that is not a Long Start Unit or an Extremely Long-Start Resource that does not have an IFM Schedule or a RUC Schedule based on the procedure to be published on the CAISO Website.

Attachment B – Marked Tariff

Bidding Rules and Commitment Costs Enhancements

California Independent System Operator Corporation

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. A Scheduling Coordinator may submit in the Real-Time Market new daily Bids for Start-Up Costs, Minimum Load Costs, and Transition Costs 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. 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. 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;

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

(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;

(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

[No changes to the remainder of Section 30.5.1]

* * * *

30.11 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

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.

* * * *

34.6 Short-Term Unit Commitment

Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast Of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run. STUC~~, and~~ will utilize: (1) Bids previously submitted in the RTM by the

Scheduling Coordinator for that Trading Hour; or (2) the Clean Bid from the Day-Ahead Market if the resource has a Day-Ahead Schedule or received a Start-Up Instruction in RUC for the Trading Hour; or (3) the Generated Bid if the resource has a Real-Time must-offer obligation for that Trading Hour and has not submitted a Bid in the RTM. ~~available from other CAISO Markets for that Trading Hour for these additional hours~~. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. Not all resources identified for need as a given STUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour look-ahead time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * * *

40.6.3 Additional Availability Requirements For Resources that Are Not Long Start Units or Extremely Long Start Resources

A resource that is not a Long Start Unit or an Extremely Long-Start~~Short Start~~ Resource~~Unit~~ that is a Resource Adequacy Resource and that does not have an IFM Schedule or a RUC Schedule for any of its capacity for a given Trading Hour is required to participate in the Real Time Market in accordance with Section 40.6.2. Such a resource that is also a Use-Limited Resource subject to Section 40.6.4 is required, consistent with their applicable use plan, to submit Economic Bids or Self Schedules for Resource Adequacy Capacity into the Real Time Market.

The CAISO may waive these availability obligations for a resource that is not a Long Start Unit or an Extremely Long-Start~~Short Start~~ Resource~~Unit~~ that does not have an IFM Schedule or a RUC Schedule based on the procedure to be published on the CAISO Website.

Attachment C – Revised Draft Final Proposal

Bidding Rules and Commitment Costs Enhancements

California Independent System Operator Corporation

Bidding Rules Enhancements

Generator Commitment Cost Improvements

Revised Draft Final Proposal

March 22, 2016

Table of Contents

1. Executive summary

This stakeholder process combines consideration of energy and commitment cost bidding rules to refine and improve alignment between these rules. This initiative will review the rules for energy and commitment cost bidding flexibility and resource characteristics definitions. This initiative will balance the benefits of allowing market participants to reflect actual costs through increased bid flexibility against the increased potential for inefficient market outcomes by inappropriately changed bid prices when the market cannot incorporate a changed bid because a resource cannot respond due to an inter-temporal constraint.

The initiative will explore commitment costs and their bidding rules. In the *Commitment Costs Enhancements* (CCE) initiative, the ISO implemented tariff changes that:

1. Allow the ISO, if a significant price spike occurs, to execute and settle the market using a gas price published on the morning of the day-ahead market run rather than the prior evening's calculated gas price index.

2. Increase the existing proxy cost bid cap from 100 percent of the resource's calculated proxy cost to 125 percent.

3. Eliminate the registered cost option for all resources except use-limited resources.

The Federal Energy Regulatory Commission's (FERC's) December 2014 decision approving the filing for *Commitment Cost Enhancements'* proposals provided guidance to the ISO on its efforts to improve cost recovery for gas-fired resources as expressed below:

> *"While we agree with CAISO that the current proposal represents an immediate improvement that can be implemented in time to provide generators a better opportunity to recover their costs during periods of natural gas price volatility that may occur during the 2014-2015 winter season, we expect CAISO to abide by its commitment to consider* ***longer-term market design changes*** *for commitment cost bids in conjunction with the bidding rules enhancements stakeholder initiative commenced earlier this month.[1]"*

This initiative is revisiting commitment costs for gas-fired resources to address through long-term market design changes the ability to allow for commitment cost caps, and commitment cost bids, to provide sufficient cost recovery.

Table 1 contains a summary of the Revised Draft Final Proposal discussed in the remainder of the paper.

Table 1: Summary of Proposals

Section	Issue	Proposal
	Resources without a day-ahead schedule cannot rebid commitment costs.	Allow resources without a day-ahead schedule to rebid commitment costs in the real-time market.
	The ISO market inserts day-ahead market bids into STUC for resources that are not resource adequacy	No longer insert bids for STUC for non-resource adequacy resources that do not have a day-ahead market award

[1] See FERC Order, CCE available at: http://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf.

	resources that are not scheduled in the day-ahead market and do not resubmit bids into the real-time market.	and do not resubmit bids into the real-time market.
	125% commitment cost cap and market revenues may not allow cost recovery for fuel purchase costs.	Extend a filing right at FERC for resources to seek recovery of incurred marginal fuel procurement costs exceeding the commitment cost bid cap unrecovered through market revenues.
	Gas price index may not reflect resource-specific gas transportation costs	Increase the flexibility of registering fuel regions and allow for cap-and-trade credits to the base gas transportation rates for resources with GHG compliance costs within these fuel regions.
	Gas price index does not reflect base gas transportation credits for resources with GHG compliance costs within these fuel regions	Improve formulation of fuel region where each fuel region reflects a unique combination of commodity price, base gas transportation costs, and base gas transportation cap-and-trade credits.
	Electricity price index may not reflect resource-specific start-up electricity costs	Include resource-specific start-up electricity costs in proxy costs based on wholesale projected electricity price (estimate of auxiliary power costs based on monthly GPI for unit with a heat rate of 10,000 Btu/KWh) unless resource verifies costs incurred are retail rates.

Deleted: commodity

2. Changes from draft final proposal

Deleted: revised straw

Section 1 summarizes the revised proposals, if any.

Section 3 addresses stakeholder requests and comments on the ISO's proposals.

Section 4 updates the plan for the *Bidding Rules Enhancements* initiative's stakeholder engagement.

Section 5 provides background information helpful in developing this proposal including the ISO's FERC filing requesting not to move its day-ahead market run time window earlier (Section 5.1.1), discussion about the ISO's short-term unit commitment (Section 5.1.2), the ISO's survey of other ISO's bidding rules (Section 5.1.3), proxy cost calculations used by the ISO for its commitment cost caps (Section 5.1.4), and discussion of changes to southern California's gas penalty structure (Section 5.1.5).

As discussed in the previous proposal, the ISO evaluated the possibility of modifying the current market power mitigation for commitment costs from the current 125% bid cap to either a structural or conduct and impact test regime (Revised Straw Proposal Section 6). It was determined that either method would not be effective in the ISO markets without modifications. To allow sufficient time to vet and develop an effective market power mitigation method for commitment costs, the ISO will be further exploring this with stakeholders through a subsequent phase of this initiative. Under this phase, the ISO will consider unrestricted commitment cost bidding with dynamic market power mitigation and energy bidding restrictions (Revised Straw Proposal Sections 7.1.1 and 7.1.2). The ISO removed these sections from the Draft Final Proposal and will revisit under the later phase.

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Section 6 proposes two improvements to commitment cost flexibility: (1) Section 6.1.1 proposes allowing resources that received no day-ahead award to rebid their commitment costs for the real-time market and (2) Section 6.1.2 proposes no longer generating bids in STUC for non-resource adequacy resources. ISO has revised its proposal under Section 6.1.1 to further increase flexibility by allowing rebidding of commitment costs for specified resources until the resource is committed at which time the commitment cost bids will be locked.

In its Revised Straw Proposal, Section 6 had a third proposal, which proposed resolving the inefficient accounting of minimum load costs after a Pmin rerate by calculating the actual commitment costs based on the Default Energy Bid (DEB) associated with the capacity range between the Master File (MF) Pmin and the re-rated Pmin where the incremental DEB costs are added to the bid-in minimum load costs at the re-rated Pmin level. The Draft Final Proposal for this was released on January 8, 2016 and successfully approved by the Board of Governors at February 2016 meeting.

Section 7 explores and proposes four improvements to commitment cost calculations: (1) Section 7.1 provides for after-the-fact recovery for actual commitment costs that exceed cost cap not recovered through market revenues, (2) Section 7.2 adopts a proposed change suggested by a stakeholder to adjust the gas transportation adders allowing for more flexibility in selecting gas fuel regions in the Master File to better reflect actual transportation costs, (3) Section 7.2 also continues the greenhouse gas discussion and proposes supporting different fuel regions to include cap-and-trade credits where necessary in fuel region formation, and (4) Section 7.3 improves the electricity price index (EPI) calculation to follow the methodology used under the registered cost option. Under Section 7.1, ISO revises its proposal to allow for after-the-fact cost recovery through extending a filing right at FERC (revised draft final proposal further adjusts proposal to remove any explicit exclusions of types of marginal procurement costs eligible for review under cost filing). Further the ISO adjusts its proposal to Section 7.3 by defaulting the EPI to a projected wholesale price but allowing SCs to revise this value to a retail rate pending validation.

In its Revised Straw Proposal, Section 8 (Section 7 in Revised Draft Final Proposal) contained a proposal to improve the commodity price portion of the gas price index by routinely using the earliest published index for the day-ahead market associated with gas flows for the majority of ISO's operating day. Given stakeholders concerns with moving the day-ahead market timeline and recommendations to wait for FERC Order 809 to become effective in April, the ISO agrees any proposal is premature. It will further explore improving the commodity price of its gas price index after April 2016.

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The previous proposal discussed two sets of Masterfile fields for a subset of resource characteristics, maximum daily starts and ramp rates. There is an interdependency between the proposed Masterfile fields and opportunity costs being developed under Commitment Cost Enhancements – Phase 3, specifically as ISO tools for limitations which would not qualify for an opportunity cost. For ease of stakeholder discussion and tracking of related initiatives, this topic has been migrated over to the Commitment Cost Enhancements – Phase 3 initiative process.

3. Stakeholder comments

The following three sections address stakeholder requests that influenced the development of this proposal. A detailed description of all stakeholder comments and ISO responses are included in Appendix B.

3.1. Requests for periodic review of commitment costs

A stakeholder requested the ISO conduct periodic review of commitment costs. Besides this initiative, the ISO is conducting the third in a series of stakeholder initiatives to address commitment costs. Each initiative has been intended to be an incremental improvement and therefore provided an opportunity for stakeholders to review cumulative changes. The requested periodic review of commitment costs is outside the scope of the bidding rules initiative.

Another stakeholder requested the ISO should reflect cold, hot, and warm starts in proxy costs calculation. The ISO clarifies this already occurs for the proxy start-up calculation. The ISO is open to considering any additional suggested modeling improvements.

3.2. Requests to consider additional costs as marginal

Other stakeholders have requested the ISO consider additional cost inputs as marginal costs such as natural gas pooling arrangement costs, imbalance penalties, or risk premiums to cover the cost of selling natural gas at a loss when a resource procures gas and then is not dispatched by the CAISO. The ISO does not agree all of these costs reflect short-run marginal costs therefore finds it would be inappropriate to include them in its proxy cost calculations. The ISO reiterates that fuel costs included in the ISO markets should reflect marginal costs related to variable operation of the resource such as commodity fuel costs and electricity costs for auxiliary power. Instead, the ISO views these costs that are not short-run marginal costs as capacity-related costs not compensated through the ISO's energy markets as explained below in recent comments:

> *Resources critical to the reliability in the CAISO's system receive compensation for capacity obligations under resource adequacy provisions. These capacity obligations include fuel costs associated with the resources' obligations to ensure they have fuel and are available to the market as required by resource adequacy obligations. The CAISO believes, if it were to provide reimbursement for fuel costs above the bid cap, these costs should only include incremental fuel costs supporting the resource's offer as opposed to other costs related to a resource's capacity obligation such as natural gas pooling arrangement costs, imbalance penalties, or risk premiums to cover the cost of selling natural gas at a loss when a resource procures gas and then is not dispatched by the CAISO. The CAISO believes these costs are more appropriately recovered through compensation the resource receives for providing capacity as a resource adequacy resource as opposed to through the CAISO's energy markets.*[2]

Of these costs, stakeholders requested the ISO to consider reimbursement for gas procured to operate a resource where the resource was exceptionally dispatched off. The ISO sought feedback on how to account for the net cost of the gas purchase if any amount was sold. As discussed more below, the ISO has reconsidered its view that risk premium is not a short-run marginal cost but it does not believe this warrants changes to commitment cost bid caps. The CalPeak Affiliates (CalPeak) and Six Cities provided comments in response to this request. Both stakeholders support recovery of the "net cost of the gas purchase," i.e. the difference between what the generator paid for the natural gas it purchased to run and what the gas was worth immediately after it was exceptionally dispatched off.

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[2] Comments of the California Independent System Operator Corporation on Technical Workshops, Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14, pp 5-6.

The ISO has further explored how other ISOs and RTOs have treated this risk to develop a market design feature allowing for this cost recovery.

NYISO's reference level calculation, which is similar to the ISO's proxy cost calculations, allows incorporating risk premium costs. The reference cost subcategory called "Risk Premium" is not a measure of the cost to generators of volatility in incremental costs. Rather, it reflects the NYISO's expectation of the average level of an incremental net cost (other than variable operating and maintenance costs) that occurs infrequently, at irregular intervals, and whose extent may vary, on the occasions when the cost occurs. For many generators, no such reference risk premium is applicable. However, a risk premium might be appropriate to reflect infrequent situations such as cash-out risk.

NYISO defines cash-out risk in a draft version of its reference level manual as the expected incremental loss from selling back unused gas at a price below its purchase cost when DAM commitments are reduced in real-time. As explained in its manual, "The risk premium would need to incorporate the frequency and typical size of NYISO reductions in RT schedules relative to DAM schedules."[3]

After considering further, the ISO agrees this is a short-run marginal cost because the risk increases as a resource has more energy scheduled in the market. However, in evaluating a need for a risk premium against the ISO's market design, the ISO does not see a need to change the proxy cost cap to account for the premium. The ISO's commitment cost cap at 125 percent of its proxy cost calculation allows for headroom above its cost estimates for SCs to manage price risks such as cash-out risk. An appropriate use of this headroom would be to facilitate this cost recovery. The ISO proposes to not include a risk premium adder to the commitment cost calculations as the cap allows for sufficient flexibility to manage such risks.

3.3. Requests to consider improvements to GPI

Another stakeholder requested a breakup of the current three-day weekend gas "package." While the ISO does not disagree with this in concept, the ISO has also received feedback that such products for the weekend days or holidays are thinly traded and no indices are available for this trading. The ISO has concerns that calculating maximum proxy costs for commitment costs using a measure of spot price other than an index would undermine the integrity of the proxy due to its illiquidity and lack of oversight.

The ISO finds providing a 25 percent headroom on top of the natural gas day-ahead index provides sufficient opportunity for cost recovery by gas-fired resources. The ISO can continue to monitor this situation but proposes no change to the treatment of weekend package indices at the moment.

4. Plan for stakeholder engagement

The proposed schedule for the policy stakeholder process is below.

Date	Event
December 3, 2014	Issue paper posted
December 10, 2014	Stakeholder call

[3] See NYISO's Draft Reference Level Manual available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2015-06-09/agenda%206%20M-34_Reference%20Level_6_2_15%20redline%20against%20currently%20effective%20manual.pdf.

December 30, 2014	Stakeholder comments due
April 22, 2015	Straw proposal posted
April 29, 2015	Stakeholder meeting
May 13, 2015	Stakeholder comments due
November 23, 2015	Revised straw proposal posted
December 03, 2015	Stakeholder meeting
December 17, 2015	Stakeholder comments due
January 08, 2016	Draft Final Proposal, correct inefficient accounting of minimum load costs after Pmin rerate
January 14, 2016	Stakeholder call on Draft Final Proposal, correct inefficient accounting of minimum load costs after Pmin rerate
January 20, 2016	Comments due on Draft Final Proposal, correct inefficient accounting of minimum load costs after Pmin rerate
February 03, 2016	Board of Governors Meeting for Draft Final Proposal, correct inefficient accounting of minimum load costs after Pmin rerate
February 04, 2016	
February 10, 2016	Draft Final Proposal posted
February 22, 2016	Stakeholder call
February 29, 2016	Stakeholder comments due
March 24, 2016	Board of Governors Meeting
March 25, 2016	

5. Background

In its exploration of potential changes to its bidding flexibility rules, the ISO researched four areas either to be leveraged through these proposals or market rules and operations affecting the feasibility of the ISO's proposals.

As discussed in Section 5.1.1, the ISO's proposals assume its filing under EL14-22 requesting FERC approve the ISO's proposal to not change its day-ahead market window is approved.

In Section 5.1.2, the ISO provides important background on its Short-term Unit Commitment (STUC) process essential to understanding the ISO's proposals discussed in Section 6.

In Section 5.1.3, the ISO reviews its analysis of its survey of commitment cost bidding flexibility rules across selected ISOs and RTOs. The tables found in the Straw Proposal have been moved to Appendix A.

Section 5.1.4 provides information on the ISO's proxy cost calculations and its inputs referenced in the ISO's proposals in Section 7.

5.1.1.FERC order 809

FERC released a final order on April 16, 2015 (Order 809, RM14-2) establishing new times for scheduling practices used by the interstate pipelines to schedule natural gas transportation.[4] Table 2 below compares the current (black font) and revised or additional (red bolded font) nomination timelines in Central Clock Time (CCT). These changes will take effect on April 1, 2016.

Table 2: Current and FERC Order 809 gas nomination deadlines (CCT)

Nomination Cycle	Nomination Deadline (CCT)	Notification of Schedule (CCT)	Nomination Effective (CCT)	Bumping of interruptible transportation
Timely	11:30 a.m. **1:00 p.m.**	4:30 p.m. **5:00 p.m.**	9:00 a.m. Next Day	N/A
Evening	6:00 p.m.	10:00 p.m. **9:00 p.m.**	9:00 a.m. Next Day	Yes **Yes**
Intra-day 1	10:00 a.m.	2:00 p.m. **1:00 p.m.**	5:00 p.m. Current Day **2:00 p.m. effective**	Yes **Yes**
Intra-day 2	5:00 p.m. **2:30 p.m.**	9:00 p.m. **5:30 p.m.**	9:00 p.m. Current Day **6 p.m. effective**	No **Yes**
Intra-day 3	**7:00 p.m.**	**10:00 p.m.**	**10:00 p.m. effective**	**No**

The ISO provided an update to stakeholders on the impacts of FERC No. 809 on June 19, 2015.[5] The ISO did not discover sufficient benefits to gas-fired generators to justify costs of moving the day-ahead market run time window to earlier in the day. In a stakeholder process the ISO considered three alternatives and found Alternative 2, to not move the day-ahead market window, to be the most effective design for the California ISO market.[6]

Besides the order, FERC issued a companion section 206 proceeding requiring ISOs and RTOs to propose changes to their electric market scheduling timelines, or to demonstrate why changes are unnecessary after adoption of the final rule in RM14-2. The filing was due 90 days from April 16, 2015. The ISO filed its response to FERC's 206 proceeding in EL14-22 asking the Commission to find the ISO did not need to move the timing of its current day-ahead close and publication of market results forward.[7] This was based on the grounds that obtaining gas scheduling on the pipelines serving California generators is not a problem and it knows electric dispatch obligations at the time of the day-ahead evening nomination cycle. FERC accepted the ISO's proposal to not change the day-ahead market window.

[4] Federal Energy Regulatory Commission, Docket No. RM14-2-000; Order No. 809, April 16, 2015.
[5] See Proposal – FERC Order No. 809 available at:
http://www.caiso.com/Documents/Proposal_FERCOrderNo809.pdf.
[6] See Straw Proposal at 15 available at:
http://www.caiso.com/Documents/StrawProposal_BiddingRulesEnhancements.pdf
[7] See EL14-22 Filing, July 23, 2015 at 15 available at:
http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13939292

5.1.2. Short-term unit commitment

The ISO market's short-term unit commitment (STUC) process is a reliability function for committing short and medium start units to meet the CAISO real-time demand forecast. The STUC function is performed hourly and looks ahead three hours beyond the current trading hour, at 15-minute intervals beginning with the third fifteen-minute interval of the hour prior to the current trading hour. STUC uses day-ahead market commitment cost bids for all resources with day-ahead market bids and will use the most recently submitted incremental energy bid price submitted. As described in Section 6.1.2, the ISO proposes to no longer insert bids into STUC for non-resource adequacy resources that bid into the day-ahead market, received no day-ahead market schedule, and do not resubmit bids into the real-time market.

STUC cannot accept commitment costs that differ across its time intervals. Medium start units with start-up times between two and five hours can receive commitment instructions from the STUC function but not from the real-time unit commitment process (RTUC) as their start-up time extends beyond RTUC's horizon.[8]

5.1.3. ISOs Commitment Cost Bidding Flexibility Survey

The ISO surveyed various ISOs' bidding rules for commitment cost offers. This section will discuss the ISO's findings from its survey found in Appendix A that compares real-time market commitment cost bidding rules.

In CAISO, as seen in Appendix A, a resource that provides a commitment cost bid in the day-ahead must use the same commitment cost bids in the real-time market, regardless of whether or not it receives a day-ahead commitment. If the resource is not bid into the day-ahead market, the scheduling coordinator can bid commitment costs in the real-time market. Under either scenario the commitment costs are capped at 125 percent of the calculated proxy cost under the proxy cost methodology for all resources.[9] For use-limited resources only, until the ISO can calculate opportunity costs, the cap is set to 150 percent of the calculated proxy cost under the registered cost methodology.[10]

NYISO and PJM are similar to the CAISO because commitment costs are largely provided in the day-ahead timeframe. They differ from CAISO in allowing resources without a day-ahead schedule to rebid commitment costs in the real-time market. NYISO explains its rationale for not allowing full bidding flexibility for commitment costs as generally a reliability concern. NYISO notes that "for system reliability, the NYISO needs to be able to rely on the Day-Ahead commitment of Generators sufficient to serve expected real-time Load. Maintaining the Minimum Generation and Start-up Bids for Day-Ahead scheduled Generators allows the NYISO to rely on them for incremental Energy, should the need arise."[11] However, NYISO allows real-time updates to fuel prices used in the reference levels—the levels to which a resource is mitigated when it tests positive for market power. PJM is considering a similar allowance to account for intra-day gas volatility.

MISO and ISO-NE allow bidding flexibility up until 30 minutes before the operating hour. ISO-NE explains that it requires this level of flexibility because it has experienced significant reliability degradation from gas

[8] A start-up instruction produced by STUC is considered binding if the resource could not achieve the target start-up time (as determined in the current STUC run) in a subsequent RTUC run as a result of the start-up time of the resource.
[9] Assumes proposals under *Commitment Cost Enhancements Phase 1* are approved by FERC.
[10] *Ibid*.
[11] NYISO, FERC docket no. ER10-1977, July 26, 2010, p. 4.

supply constraints causing generators to not respond to dispatch. For example, ISO-NE found that "an examination, conducted in early 2012, of dispatch response performance following the 36 largest system contingency events over the last three years indicates that, on average, the response rate for New England's non-hydro generating resources was less than 60 percent of the amount requested during the events."[12]

5.1.4. Proxy Cost Calculations

Current ISO process for calculating the maximum proxy cost for start-up and minimum load cost uses a combination of cost inputs from either (1) market price publications (index prices) or (2) resource-specific registered values in the Master File. Equation 1 and Equation 2 show the proxy cost formulas used and Table 3 defines and categorizes the inputs by source as either an index price or a Master File value.[13]

Equation 1: Proxy Start-Up Costs

Start-up Cost

$$= \begin{cases} \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

Start-up Fuel Cost $= STRT\_STARTUP\_FUEL * GPI$
Start-up Energy Cost $= STRT\_STARTUP\_AUX * EPI$
GMC Adder = $Pmin$ * $(STARTUP\_RAMP\_TIME/60min) * \frac{GMC}{2}$
GHG Cost = $STRT\_STARTUP\_FUEL$* Emissions Rate * GHG Allowance Rate

Equation 2: Proxy Minimum Load Costs

Minimum Load Cost

$$= \begin{cases} \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder}, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + MMA, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

Minimum Load Fuel Cost $= Unit\ Conversion *$ Heat_Rate $* Pmin * GPI$
$\mathrm{VOM} = \mathrm{VOM} * \mathrm{Pmin}$
GMC Adder = $Pmin$ * GMC
GHG Cost = $Unit\ Conversion *$ Heat_Rate $* Pmin$ * Emissions Rate * GHG Allowance Rate

Table 3: Proxy Cost Inputs

Value Source	Value	Description

[12] ISO-NE, FERC docket no. ER13-1877, transmittal letter, July 1, 2013, p. 3.
[13] Market Instruments BPM.

Index Price	GPI_{DAILY}	The average of index prices for the prior day-ahead index representing the market price for gas flowing on the day prior to the ISO's operating day.
Index Price	$GHG\ Allowance\ Rate$	The average of index prices based on at least two index publications either expressed as a based on futures or forward prices corresponding to December delivery or if publication provides range of prices, the volume-weighted average price for GHG price associated with DAM and RTM.
Index Price	EPI	Resource-specific daily electricity price as the maximum of a retail rate aligned to the registered fuel region and an estimated wholesale rate measured in \$/MW.
Master File	$STRT\_STARTUP\_AUX$	The Master File value for the electrical power used by a Generating Unit during startup. The Generating Unit's startup auxiliary power (in MWh) from the down time (i) to down time (i + 1).
Master File	$STARTUP\_RAMP\_TIME$	The Master File value in minutes representing the time it takes to physically ramp from zero to Pmin.
Master File	$STRT\_STARTUP\_FUEL$	The Master File value for the fuel use (in mmBTU per start) expected for the startup of a natural gas fired Generating Unit that has been off-line for a substantial period of time. The startup fuel of the Generating Unit (in mmBTU) from the down time (i) to down time (i + 1).
Master File	$Pmin$	The Master File value for the minimum sustained operating level (Pmin) at which a given configuration can operate at a continuous level.
Master File	$HEAT\_RATE$	The Master File value for the minimum load heat rate which is the emission rate of the configuration on point 1 of its heat rate MW output point at point 1, PMIN, expressed in Btu/KWh.
Master File	$GHG_{COMPLIANCE}$	The Master File value for an indicator of a resource that has a Green House Gas compliance obligation and is, therefore, eligible to recover Green House Gas allowance costs.
Master File	$Emissions\ Rate$	The Master File value for Green House Gas (GHG) emission in $mtCO_2e$/MMBtu.
Master File	MMA	The Master File value for a configuration-specific lump-sum adder value per start-up for major maintenance, if applicable.
Administrative Fee	GMC	Grid ISO Charge (GMC) comprised of CAISO Operating Costs, CAISO Other Costs and Revenues, CAISO Financial Costs, CAISO Operating Reserve Credit, and CAISO Out-of-Pocket Capital and Project Costs as a lump-sum adder.
Administrative Fee	VOM	Variable Operations & Maintenance (VOM) charge expressed in \$/MW representing non-fuel costs of running a generating unit at or above its Pmin operating level.

Conversion Factor	$Unit\ Conversion$	0.001 factor converting heat rate expressed in Btu/KWh into MMBtu/MWh.

5.1.5. Southern California low operational flow order

Within California, Southern California Gas Company and SDG&E filed applications with the California Public Utilities Commission for a proposed treatment of low operational flow order and emergency flow order requirements.[14] These changes could greatly affect the gas pipeline system in Southern California and bring it more in line with the current penalty structure in the Pacific Gas & Electric (PG&E) territory. Any policy created here should leverage these improvements.

6. Proposal for commitment cost bidding flexibility

The ISO has two proposals to increase commitment cost bidding flexibility and correct for a current inefficiency as summarized in Table 4 below.

Table 4: Summary of energy bidding proposals

Issue	Proposal
Resources without a day-ahead schedule cannot rebid commitment costs.	Allow resources without a day-ahead schedule to rebid commitment costs in the real-time market.
The ISO market inserts day-ahead market bids into STUC for resources that are not resource adequacy resources that are not scheduled in the day-ahead market and do not resubmit bids into the real-time market.	No longer insert bids for STUC for non-resource adequacy resources that do not resubmit bids into the real-time market.

6.1.1. Allow rebidding of commitment costs for resources without a day-ahead schedule

The ISO does not allow resources that bid into the day-ahead market but that received no day-ahead schedule to rebid commitment costs in the real-time market.[15] This does not allow resources without day-ahead schedules to reflect changed natural gas prices in their real-time market commitment cost bids. Not allowing resources without day-ahead schedules to rebid commitment costs in the real-time market potentially results in resources not being able to recover their commitment costs. It also potentially results in inefficient resource commitment because the real-time market will miss-value minimum load costs.

The ISO proposes to allow resources without day-ahead market schedules to rebid their commitment costs in the real-time market until committed. This policy change will affect commitment cost bidding rules by the real-time markets supporting updating commitment costs across the day for market runs until the resource is committed. This allows the market participant to evaluate any changes to its commitment cost occurring

[14] Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Low Operational Flow Order and Emergency Flow Order Requirements, June 27, 2014. Available at: http://www.socalgas.com/regulatory/documents/a-14-06-021/FINAL%20Low%20Flow%20App.pdf

[15] ISO commitment costs include start-up, minimum load, and transition costs.

after publication of the DAM results. This market rule will apply consistently to resource adequacy and non-resource adequacy units.

The ISO revises its revised straw proposal to allow for additional commitment costs flexibility during the operating day until the unit is committed because ISO determined this would not require allowing commitment costs to vary across hours in the markets but instead could be supported by updating the costs used for a given market process modelled as constant value across the time horizon. The ISO's proposal to not allow changes to commitment costs once a resource is committed alleviates any potential to inflate bid cost recovery by changing minimum load costs.

6.1.2. Inserting bids for non-resource adequacy resources that did not resubmit bids into the real-time market

The ISO market inserts day-ahead market bids into STUC for all resources, including those that are not resource adequacy resources, that are not scheduled in the day-ahead market and do not resubmit bids into the real-time market. This can result in STUC committing a non-resource adequacy resource that chose to not participate in the real-time market. This is not equitable because non-resource adequacy resources have no obligation to offer to the market. The ISO proposes to address this by no longer generating bids for STUC for non-resource adequacy resources that have no day-ahead schedule and do not resubmit bids into the real-time market.

7. Proposals for commitment cost parameters

The ISO is exploring the use of select index price inputs and the appropriate treatment of greenhouse gas (GHG) costs in the ISO's calculation of proxy commitment costs. The select index price inputs explored are:

1. Daily gas price index (GPI) used in the calculation of the default energy bids, generated energy bids, and proxy commitment (startup and minimum load) and transition cost calculations[16]:
    a. Published Gas Price
    b. Intra-state gas transportation adder
2. Electricity Price Index (EPI)

The remainder of the section discusses the ISO's proposals for adjustments to the daily gas price index (GPI) and treatment of greenhouse gas (GHG) costs found in GPI_{DAILY} due to transportation rates in Section 7.2, and the electricity price index (EPI) in Section 7.3. The ISO's proposal assumes an opportunity cost methodology is in the market and therefore the registered cost option is no longer available except to those resources that do not have sufficient LMP history. The opportunity cost bid cap will be discussed in the *Commitment Cost Enhancements Phase 3* initiative.

The ISO has four proposals to refine the inputs to the proxy cost calculation which will improve commitment cost bidding as summarized in Table 5 below.

[16] Any proposals to the basis of the GPI such as changing the index price used or adding fuel regions to reflect GHG compliance status would affect both commitment and energy costs (i.e. DEBs and generated bids).

Table 5: Summary of commitment cost calculation proposals

Issue	Proposal
125% commitment cost cap and market revenues may not allow cost recovery for fuel purchase costs.[17]	Extend a filing right at FERC for resources to seek recovery of incurred marginal fuel procurement costs exceeding the commitment cost bid cap unrecovered through market revenues.
Gas price index may not reflect resource-specific gas transportation costs	Increase the flexibility of registering fuel regions and allow for cap-and-trade credits to the base gas transportation rates for resources with GHG compliance costs within these fuel regions.
Gas price index does not reflect base gas transportation credits for resources with GHG compliance costs within these fuel regions	Improve formulation of fuel region where each fuel region reflects a unique combination of commodity price, base gas transportation costs, and base gas transportation cap-and-trade credits.
Electricity price index may not reflect resource-specific start-up electricity costs	Include resource-specific start-up electricity costs in proxy costs based on wholesale projected electricity price (estimate of auxiliary power costs based on monthly GPI for unit with a heat rate of 10,000 Btu/KWh) unless resource verifies costs incurred are retail rates.

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7.1. Provide opportunity for after-the-fact cost recovery

Given the ISO's manual price spike procedures, the day-ahead index price combined with the 125 percent proxy cost bid cap covers the vast majority of actual prices for gas purchased from the day-ahead, same day or intraday gas markets. In its Revised Straw Proposal the ISO proposed to internally support an after-the-fact recovery process. After additional review, the ISO determined the ISO must specify objective criteria to determine if a resource qualified for after-the-fact cost recovery and that recovery. The ISO does not believe this is practical as it would be difficult to detail before-the-fact all of the situations in which a resource conducted prudent procurement practices but incurred natural gas procurement costs it could not recover because of the ISO's commitment cost bid caps. In addition, determining a resource's actual gas costs could entail a high degree of judgement and visibility to the market participant's entire portfolio of gas purchases and sales.

The ISO is revising its proposal to the second option discussed in the Revised Straw Proposal, adding tariff provisions that would allow for after-the-fact cost recovery through FERC review that would allow for each case to be evaluated based on the specific facts and circumstances of that request. FERC could apply its expertise and judgment to evaluating hedging instruments the market participant holds that the ISO likely could not evaluate. The ISO would include any marginal fuel procurement costs over the commitment cost bid cap in a resettlement of bid cost recovery (BCR) for the day-ahead, residual unit commitment, or real-time market in which the ISO committed the resource. Any self-commitment periods, which includes EIM manual dispatches, would not be eligible for cost recovery.

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The ISO believes this proposal to add tariff provisions that specify how market participants file for cost recovery of net market revenue shortfalls at FERC provides the most market benefit since it both allows

Deleted: Scheduling Coordinators (SCs)

[17] Changes to the GPI will impact all reference prices calculated by the ISO including DEBs and generated bids.

resources to recover actual net market revenue shortfall through BCR and supports good utility practice by not making generators indifferent to fuel price. The ISO proposes to extend a filing right to seek recovery of net market revenues as result of incurred marginal fuel procurement costs exceeding the commitment cost bid cap unrecovered through market revenues. This would entail FERC applying its just and reasonable standard to review and find whether the market participant incurred a net market revenue shortfall because of consideration of actual procurement costs where those costs exceeded the maximum commitment cost cap.[18] Table 6 shows an example of the calculation of a resource's (Resource A) unrecovered costs and their inclusion in its BCR settlement, showing BCR before and after the costs above the cap determined by FERC are included.

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Table 6: Illustration of ISO BCR adjustment for cost recovery

	Market Bid and Award Data	***Units***	***Formula***	**Resource A**
[A]	Heat Rate	mmBtu/MW		10
[B]	Start Up Fuel	mmBtu		3000
[C]	MLE Fuel	mmBtu		1000
[D]	GPI	$/mmBtu		$5
[E]	Actual Procurement Cost	$/mmBtu		$25
[F]	Pmin	MW		100
[G]	Pmax	MW		500
[H]	Incremental Energy Award	MW		400
[I]	Incremental Energy Bid	$/MW		$50
[J]	Max Commitment Cost Cap		B + C)*D*1.25	$25,000
[K]	LMP	$/MW		$125

	Original BCR settlement	***Units***	***Formula***	**Resource A**
[L]	Bid-in Commitment Cost		B + C)*D*1.15	$23,000
[M]	Incremental Energy Costs		*([H] - [F]) * [I]*	$15,000
[N]	Total Market Cost		*[L] + [M]*	$38,000
[O]	Commitment Cost Revenues		*[F] * [K]*	$12,500
[P]	Incremental Energy Revenues		*([H] - [F]) * [K]*	$37,500
[Q]	Total Market Revenues		*[O] + [P]*	$50,000
[R]	Net Market Revenue Surplus		*[Q] - [N]*	$12,000
[S]	BCR Settlement		*IF ([Q] - [N])<0*	$0

	Adjusted BCR settlement	***Units***	***Formula***	**Resource A**

[18] A resource will not have a right to after-the fact-recovery if the actual commitment costs exceeded the resource's bid-in commitment costs but did not exceed the commitment cost bid cap.

[T]	Actual Commitment Cost	*([B]+[C])* [E]*	$100,000
[U]	Incurred Commitment Costs above Cost Cap	*[T] - [J]*	$75,000
[V]	Adjusted Commitment Costs	*[U] + [L]*	$98,000
[W]	Incremental Energy Costs	*([H] - [F]) * [I]*	$15,000
[X]	Adjusted Total Market Cost	*[V] + [W]*	$113,000
[Y]	Commitment Cost Revenues	*[F] * [K]*	$12,500
[Z]	Incremental Energy Revenues	*([H] - [F]) * [K]*	$37,500
[AA]	Total Market Revenues	*[Y] + [Z]*	$50,000
[AC]	Net Market Revenue Shortfall above Cap	*[AA] - [X]*	$63,000
[AD]	Adjusted BCR Settlement	*IF ([AA] - [X]) <0*	$63,000

Table 6 shows BCR settlement for Resource A, a peaker unit usually not dispatched in day-ahead, that procured fuel to respond to an ISO real-time dispatch at $25/mmBtu (COL E) due to gas market price spike during real-time relative to the GPI. Based on a GPI (COL D) of $5/mmBtu and commitment cost fuel quantity of 4,000 mmBtu (COL B and COL C), Resource A's maximum commitment cost cap is $25,000. Resource A bids its commitment cost into the market with a 15% adder for a bid-in commitment cost of $23,000 (COL L). Since Resource A cannot reflect its actual procurement costs (COL T) intra-market, $77,000 of commitment costs are not reflected in its bid-in commitment costs. Prior to FERC finding verifying its actual commitment costs of $100,000, Resource A has a net market revenue surplus and is not eligible for BCR.

After filing for net market revenue shortfall cost recovery at FERC, FERC finds Resource A's actual commitment costs exceeded the maximum commitment cost cap by $75,000 (COL U). ISO will adjust Resource A's bid-in MLC by adding the incurred commitment costs above cost cap (COL U) to the bid-in MLC (COL L) for an adjusted MLC (COL V) of $113,000. Given the $50,000 market revenues received, Resource A has a net market revenue shortfall of $63,000 (COL AC) and will receive BCR payment for this net market revenue shortfall. ISO proposes to include description of eligible costs for evaluation under a cost recovery filing, required documents to include in filing package to be considered acceptable filing, and description of SC and ISO's role and deadlines in process. First, the tariff will define fuel costs eligible for potential after-the-fact cost recovery as marginal procurement costs for commitment costs to meet an ISO schedule or real-time dispatch. Second, he ISO will detail in its tariff a requirement for the filing contents to include:

- Data supporting actual applicable fuel costs for applicable electrical operating day(s) including but not limited to invoices for both sales and purchases,
- Information associated with resource's participation in any gas pooling agreements,
- Explanation of why actual costs exceeded commitment cost cap, and
- ISO written explanation of applicable day's events on market participant request

Finally, the tariff will require a SC and ISO to conform to the following timeline to be eligible for filing right:

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Deleted: These incremental fuel costs will not include other fixed costs such as pooling arrangement costs and imbalance penalties, but instead only the difference in natural gas commodity price ($/MMBTU) used to set the maximum allowable proxy costs versus the invoiced actual procurement cost. ISO views gas losses as result of selling gas after resource is dispatched off as ineligible for review of cost recovery as these are not incremental costs associated with electric generation.

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- Must notify ISO within 10 business days after operating day where commitment costs above the bid cap were incurred of its intent to file for cost recovery and within 20 business days the ISO will provide SC with written explanation.
- Must submit filing no later than 60 days after operating day where excessive gas costs were incurred to be eligible for FERC review.

If FERC accepts the SC's cost recovery filing, ISO proposes to adjust the resource's BCR payments based on the incurred commitment costs above the commitment cost cap to the market where FERC determines the adjustment is most appropriate. In the ISO's example of Resource A, a FERC finding would include the amount the ISO should include in the net market revenue calculation of $75,000 and direct the ISO to include these additional costs in the RTM BCR calculation. The adjusted BCR settlement will be allocated consistent with current BCR allocation rules to the market determined by FERC.

7.2. Improve gas transportation adders

In response to Assembly Bill 32, California's Air Resources Board established the state's market-based cap-and-trade program to reduce greenhouse gas emissions.[19] "Covered entities," such as thermal generators emitting over 25,000 metric tons of carbon dioxide equivalents (MTCO2e) per year must comply. The program began on January 1, 2013 with phased compliance obligations for different parts of the economy. Thermal electric generating sources have already begun compliance.

The ISO market rules currently reflects the costs of purchasing GHG allowances in the various bid cap for commitment costs, transition costs, and energy bids submitted by covered entities. These allowances are needed to cover their GHG emissions associated with their energy output. The various bid caps for thermal resources that have not reached the 25,000 MTCO2e threshold currently do not reflect greenhouse gas cost unless they have voluntarily enrolled in the cap-and-trade program.

Starting January 1, 2015, natural gas suppliers will also be considered covered entities for the gas delivered to California end-users, net of the amount delivered to existing covered entities.[20] The ISO followed the California Public Utilities Commission (CPUC) proceeding and contacted stakeholders to understand how GHG costs of natural gas suppliers will affect the ISO's operation.

The CPUC released its final decision on the proceeding, 'Procedures Necessary for Natural Gas Corporations to Comply with the California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms,' on October 23, 2015.[21] The CPUC's decision allows for natural gas suppliers to recover the GHG compliance costs through introducing costs into rates effective April 1, 2016. Table 7 shows forecast rate impacts of incorporating these costs into their base rates submitted under this proceeding by SoCalGas and SDG&E.

[19] Commitment Cost Enhancements Phase 2 initiative began a discussion of reviewing the ISO's procedures for considering GHG costs of its resources.
[20] California Public Utilities Commission, *Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge*, Rulemaking 14-03-003, July 7, 2014, p. 3.
[21] See California Public Utilities Commission, Rulemaking 14-03-003, issued October 23, 2015.

Table 7: SoCalGas and SDG&E Forecast Rate Impacts[22]

	SoCalGas	SDG&E
End Users Forecast Compliance Cost	$78,995	$13,169
Adjusted Average Year Throughput, Mth	4,088,158	585,560
GHG Rate $/therm	$0.01932	$0.02249

For gas transportation rates for covered entities who have a direct compliance obligation with CARB, the CPUC decision creates a GHG compliance cost credit done in a line-item credit to demonstrate exempt customers do not pay twice for natural gas GHG compliance costs. The line-item credit should be called "Cap-and-Trade Cost Exemption" according to the Decision at 42. This credit will be in addition and similarly done as the credit for AB 32 Cost of Implementation Fee (i.e. CARB fee credit).

The ISO found the decision will affect its operations by creating a need to differentiate between transportation rates paid by covered entities and non-covered entities that the ISO's GPI is based on. The ISO reviewed its current transportation adder process and accuracy of rates used for the GPI.

The GPI is based on the combination of a natural gas commodity price (SoCal Citygate, SoCal Border or PG&E Citygate) and a transportation rate specific to the resources' geographical location. Each fuel region (Col A) refers to a specific transportation rate found on the gas companies' rate schedules for electrical generation (EG). The ISO's current policy is to reflect the rates held on the EG schedules, even if there is more than one rate under the schedule, although this is not currently consistently supported by the ISO process. This is why SCE and SDG&E have two fuel regions since their schedules differentiate rates based on usage.

Table 8 below shows the ISO's analysis of its current intra-state transportation rate schedules for electric generation. The ISO found the ISO's process for providing fuel regions requires more flexibility to appropriately reflect differences in rate payments by customer types.

Table 8: ISO's Fuel Region Rates

A	B	C	D	E	F
				Effective April 1, 2016	
ISO's Fuel Regions	Intra-state Transporation Rates ($/therm)	AB 32 CARB Fee Credit	Cap and Trade Exemption' Credit	Effective Rate for Covered Entities	Effective Rate for Non-covered Entities
PGE (Backbone level rate)	0.00915	0.00056		0.00859	0.00915
PGE2 (Other Customers Rate)	0.02921	0.00056		0.02865	0.02921
SCE1 (<3 million therms/year)	0.10554	0.0011	*0.01932*	0.08512	0.10554
SCE2 (> 3 million therms/year)	0.03688	0.0011	*0.01932*	0.01646	0.03688
SDG&E1 (<3 million therms/year)	0.105420	0.00041	*0.02249*	0.08252	0.105420
SDG&E2 (> 3 million therms/year)	0.036380	0.00041	*0.02249*	0.01348	0.036380

The table contains the following information for each fuel region:

[22] See California Public Utilities Commission, Rulemaking 14-03-003, issued October 23, 2015.

- **Intra-state Transportation Rates ($/therm) (Col B):** Transportation rates found on the gas companies' electric generation schedules

- **AB 32 CARB fee credit (Col C):** Line-item credit to base rate applicable to customers identified by CARB as being directly billed for CARB administrative fees.

- **'Cap and Trade Exemption' Credit (Col D):** PUC R.14-03-003 decision created line-item credit to recover GHG compliance costs through introducing costs into rates effective April 1, 2016[23].

- **Effective Rate for Covered Entities (Col E):** ISO's estimate of gas transportation rate for customers directly billed by CARB effective April 1, 2016.

- **Effective Rate for Non-covered Entities (Col F):** ISO's estimate of gas transportation rate for customers not directly billed by CARB effective April 1, 2016.

The ISO found a need for adjustments to the Master File Fuel Region values. PG&E brought to the ISO's concern that its schedule has more than one rate based on a network location criteria. The rate for resources connected directly to the backbone transmission network is shown Table 8 highlighted in yellow to emphasize this rate is currently not available to the ISO's resources for these customers.

The ISO also found a need to differentiate rates based on whether a resource is covered or non-covered. The changes to rate structures from cap-and-trade regulations, will have a substantial impact. For example in SDG&E's territory, the intra-state gas transportation rates will be different by 0.0229 $/therm or 0.23 $/MMBtu. If the ISO does not differentiate the rate it pays to covered entities from non-covered, the various bid caps will overstate GHG costs since covered entities' proxy cost calculations already include compliance costs.[24]

The ISO proposes two changes to its current process for fuel regions. First, the ISO proposes to create a more flexible process for scheduling coordinators to request adjustments to the fuel region values for registration in the Master File to better represent resource-specific costs. Second, the ISO will create two values for each fuel region to differentiate rates paid by covered and non-covered entities, where applicable. This new flexibility supports regionalization efforts and new EIM entities fuel region formation.

Under the new process, scheduling coordinators can introduce a new resource-specific fuel region by submitting a request to add a new fuel region to Masterfile field. A fuel region will be defined as a unique combination of commodity price, transportation rate, and cap-and-trade credit. The fuel region will be validated and considered appropriate if invoices support delivered gas prices which are approximately aligned with prices of proposed fuel region.

The validation process will evaluated if:

- Commodity price is geographically appropriate to resources physical location,
- Base gas transportation rates can be supported by invoices, and
- Cap-and-trade credits can be supported by covered entities list and/or invoices.

If a SC schedules its gas on the Kinder Morgan pipeline, the stakeholder can submit a request to the ISO to include Kinder Morgan's schedule for electrical generation to the selections in the fuel region field. In

[23] SCE & SDG&E's estimated rate impacts from under the proceeding.
[24] See Section 5.1.4 for the proxy cost calculations to see how GHG costs are incorporated.

order to successfully add a new value for the Master File field, the ISO would need a scheduling coordinator to submit its base gas retail invoice and associated transportation schedule during its request. The ISO will program the new fuel region value into the Master File field. Consistent with current practice, the ISO will review the schedule rates semi-regularly to reflect any changes in rates.

Through this stakeholder process, it has come to light that some entities may ship its fuel across more than one pipeline company. The ISO finds establishing unique fuel regions based on these companies and allowing the resource to update iteratively would introduce an overly burdensome validation process. The ISO proposes on resource request to define a resource-specific fuel region representing a combined commodity price or combined base gas transportation rate based on a weighted average. Where the combined price or rate is weighted by the percent of volumetric usage[25] shipped by each company in the prior month, if available, and averaged to represent a reasonable estimate of resource-specific costs. Anticipating the appropriate weighted average costs is fairly static, ISO propose to limit revisions to weights annually.

For fuel region changes between regions specified for covered or non-covered entities, the ISO will validate the initial registration and any subsequent changes against the Air Resources Board's covered entities list. Any selection of a fuel region specified for covered entities will be validated against this list and rejected outright if an entity is not listed. Similarly, if a resource registers for a fuel region specified for non-covered entities and it is found on the covered entities list, the Master File change will be rejected. The ISO will validate the selection of a fuel region versus the GHG flag used to add GHG compliance costs to its estimated commitment and energy costs. If a resource is listed on the ARB covered entities list, the GHG flag must be selected whereas if a resource is neither listed on ARB's list nor the ISO managed list it cannot register for a covered entity fuel region nor select GHG flag.

7.3. Improve the electricity price index calculation

After reviewing stakeholder feedback on the ISO's questions from the Straw Proposal[26], the ISO proposes a process change to the commitment costs methodology for maximum proxy cost start-up costs that will continue to follow existing tariff language found in Section 30.4.1.1.1(a). The ISO found the EPI to be unduly burdensome to stakeholders to project the prices used by the ISO. ISO's proposal to improve its EPI will introduce new flexibility supporting regionalization efforts and new EIM entities auxiliary cost estimates.

The ISO believes calculation of auxiliary proxy costs should have a consistent methodology as that used for registered cost and EIM resources. This will both improve ISO operations and alleviate stakeholder concerns as the methodology is transparent and provides a robust estimate of projected electricity price.

The ISO proposes to add a new Master File values for resource-specific electric region and an electric region type attribute of default or retail. This allows for better alignment between projected wholesale prices or retail prices than afforded relying on fuel region. In addition, the ISO will determine the resource-specific electricity price for auxiliary power by defaulting the electric region to a projected wholesale price. The projected wholesale price calculation will be based on projected electricity price during unit start-up or cost of auxiliary power provided by the generator based on a unit with a heat rate of 10,000 Btu/KW (i.e. product of the start-up auxiliary energy by the monthly GPI by a factor of 10).

[25] Volumetric usage must be supported by some retail invoice or commodity price trade records.

[26] Table 9, Straw Proposal at 23.

In the event a resource does not pay wholesale prices for its auxiliary power and can support this with invoices from an electric retail company, the ISO will revise the electric region type to a retail value and estimate its proxy costs with electric retail rate schedules.

If new electric regions and associated wholesale or retail rate schedules need to be maintained as new entities join the market, these requests will follow the same procedure as those for requesting new fuel region selections.

8. Next Steps

The ISO will discuss this Draft Final Proposal with stakeholders at a call on February 22, 2016. Stakeholders should submit written comments by February 29, 2016 to InitiativeComments@caiso.com.

Appendix A: Survey of Commitment Cost Bidding Rules

ISO/RTO	Last time to modify commitment costs	Calculates reference levels?	Mitigation
CAISO	10:00 PST TD-1 / 10:00 PST TD-1	Yes	Bid caps[27]
ISO-NE	T-30 / T-30[28]	Yes[29]	Conduct and impact test[30]; restricted from fuel price adjustment for 2 (first offense) to 6 months (second offense)[31]
MISO	T-30 / T-30[32]	Yes[33]	Conduct and impact test[34]
NYISO	Day-ahead: 5:00 EST TD-1 / 5:00 EST TD-1[35] If no day-ahead schedule: T-75 /T-75[36] and may update fuel prices in reference levels[37]	Yes[38]	Conduct and impact test[39]
PJM	Day-ahead: 16:00 EST TD-1 / 16:00 EST TD-1[40] If no day-ahead schedule: 18:00 EST TD-1 / 18:00 EST TD-1[41] Daily bidding under cost-based option; 6 month hold for cost-based option.[42] Proposing to allow intra-day changes to fuel cost methodology[43]	Yes[44]	6 month hold on using cost- or price-based option.[45] Structural test (three pivotal suppliers)[46]

[27] Assumes proposals in Commitment Cost Enhancements Phases 1 and 2 are approved and all resources are on the proxy cost option.
[28] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, proposed tariff section III.1.10.9: Hourly Scheduling. Tariff amendment to become effective December 3, 2014.
[29] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[30] ISO-NE, Market Rule 1, Section III.A.5: Mitigation.
[31] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, proposed tariff section III.A.3.4: Fuel Price Adjustments. Tariff amendment to become effective December 3, 2014.
[32] MISO, Tariff Module C: Energy and Operating Reserve Markets, Section 40.2.5(b): Required Generation Offer and Demand Response Resource - Type II Offer Components.
[33] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 6.9 Reference Levels.
[34] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 5 Conduct Warranting Mitigation.
[35] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff (MST) – 4 MST Market Services: Rights and Obligations, 4.2.1 Day-Ahead Load Forecasts, Bids and Bilateral Schedules.
[36] NYISO, Open Access Transmission Tariff (OATT) - 1 OATT Definitions - 1.18 OATT Definitions – R, "Real-Time Scheduling Window."
[38] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[39] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.

Appendix B: Stakeholder Comments Summary

ISO's summary of stakeholder comments contains those comments on the ISO proposals contained in this revised draft final proposal. ISO responded to stakeholder comments on resource characteristics section from Revised Straw Proposal in the *Commitment Cost Enhancements 3* draft final proposal and the remaining section of this initiative not addressed in this paper during a later phase.

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Topic	Market Participant	Stakeholder Comment	ISO's Response
Make changes to the natural gas transportation rates and to the electricity prices used in calculating resources' costs for commitment cost bid caps.	Department of Market Monitoring (DMM)	Supports	ISO acknowledges and appreciates the support for these proposed cost estimate enhancements.
	Northern California Power Agency (NCPA)	Supports	
	Pacific Gas & Electric (PG&E)	Supports	
	Six Cities	Supports	
	Southern California Edison (SCE)	Supports	
	Calpine	Supports	
	NRG Energy, INC (NRG)	Supports	
Resources without a day-ahead schedule can re-bid commitment costs in real-time, and for non-resource adequacy resources, no longer automatically insert bids into the real time unit commitment process.	Department of Market Monitoring (DMM)	Supports	ISO acknowledges and appreciates the support for this proposed enhancement to its commitment cost bidding rules. While ISO appreciates the alternative suggestion to apply different market power mitigation bid caps to commitment cost offers it finds any changes to its market power method is premature. A proposed change to its method
	Northern California Power Agency (NCPA)	Supports	
	Pacific Gas & Electric (PG&E)	Supports	
	San Diego Gas & Electric (SDG&E)	Supports	
	Six Cities	Supports	
	Southern California Edison (SCE)	Supports	
	CalPeak Affiliates	Supports	

[39] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.
[40] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line.
[41] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line. Reflects the balancing market offer period close.
[42] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[43] PJM, Gas Unit Commitment Coordination 2014/2015 Winter Scope Proposal Review, October 30, 2014, p. 5. Available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-11-gas-unit-commitment-presentation.ashx.
[44] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.
[45] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[46] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.

	Calpine	Supports - Proposes enhancements to proposal that would allow for higher bid cap percentage in RTM to allow for rebidding limited to higher bid cap, for example 150% of proxy.	requires a longer stakeholder process.
	NRG Energy, INC (NRG)	Supports	
Provide market participants the opportunity to recover actual costs incurred above the commitment cost bid cap by filing at FERC.	Department of Market Monitoring (DMM)	Conditional support. Any process, even at FERC, requires strict and clear guidelines	The ISO believes its proposal to allow for resources to request that FERC approve reimbursement for gas costs above the commitment cost bid cap is a reasonable alternative to eliminating its commitment cost bid cap. Eliminating the commitment bid cap will take further vetting to determine if it's a viable alternative for the ISO market and any potential implementation would be some time in the future. A resource can incur commitment costs above the cap even on days the ISO has not implemented its procedure for large day-over-day gas price increases as gas prices may increase after the time of the day-ahead market. ISO believes FERC more appropriately suited to determine if it is just and reasonable to reimburse costs above the cap because it can make subjective determinations about specific circumstances and can more readily obtain information to determine the actual costs incurred. In light of the reduced storage in Southern California and the potential new balancing penalties
	Pacific Gas & Electric (PG&E)	Opposes as premature. FERC proceeding initiated on energy price formation, which while not addressing commitment costs, does broach the underlying cost verification for energy bids and could inform this proposal.	
	Six Cities	Supports. Proposes modification to allow operational flow order costs, stranded gas costs, and balancing penalties to be recoverable as well.	
	Southern California Edison (SCE)	Support for cost incurred on days where the ISO implements its manual process to update gas prices used by the day-ahead market in the event of a large day-over-day increase.	

	CalPeak Affiliates	Believes ISO should eliminate commitment cost bid cap instead.	and in response to the comments summarized above, ISO revised its draft final proposal so that the ISO tariff would not preclude a market participant from demonstrating to FERC that other types of costs such as imbalance penalties, operational flow order penalties, and stranded gas costs.were reasonably incurred and should be reimbursed. ISO does not believe its proposal is inconsistent with the FERC proceeding initiated on energy price formation as that proceeding address energy above minimum load, not commitment costs.
	Calpine	Supports	
	NRG Energy, INC (NRG)	Supports. Proposes modification for generator that cannot procure gas to follow CAISO dispatch instructions at any price and consequently cannot avoid operational flow order charges to allow these costs to be recovered through the filing process.	
	NV Energy	Opposes. CAISO has not adequately provided basis for deferring to FERC, it's not a just and reasonable mechanism, and would require investment of resources and no incidental benefits.	
	Western Power Trading Forum (WPTF)	Supports. Notes support for other costs such as stranded gas, balancing penalties, and operational flow order penalties to be covered under filing right.	

Attachment D – Board Memorandum

Bidding Rules and Commitment Costs Enhancements

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

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

Date: March 17, 2016

Re: **Decision on commitment cost bidding improvements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

Resource commitment costs include the costs of starting up a resource and the costs of running a resource at its minimum operating level so that it is available for dispatch. Efficient resource commitment by the ISO market relies on the ability of market participants to submit bids that reflect accurate commitment costs which, in turn, also ensures market participants recover these costs. In 2014 and 2015, the Board approved Management proposals to improve the accuracy of commitment costs used in the ISO market.

The ISO has continued to identify enhancements to further improve market participants' ability to accurately reflect commitment costs in the ISO market and to manage the market's use of their resources. At the same time the ISO has seen a proliferation of resources registering as "use-limited," currently representing 35,000 MW. The current market rules for submitting bids into the market for use-limited resources, including for their commitment costs, are different than for other resources to reflect their use limitations.

In this proposal, Management asks the Board to approve a set of market enhancements that improve market participants' ability to more accurately reflect resources' commitment costs, better ensure recovery of actual costs, and better manage their use by the market. Specifically, the enhancements in this proposal include:

- Use-limited resources will be eligible for a calculated opportunity cost to include in their daily commitment cost bids, which will allow the market to recognize their use limitations that extend over a longer period of time than the daily markets, such as annual limitations. This will allow the ISO to eliminate the "registered cost" option for bidding resource commitment costs, which is a less efficient means of reflecting these costs in the market.

In connection with this enhancement, Management proposes to revise the definition of “use-limited” resource to align it with resources that need an opportunity cost included in their commitment costs to be efficiently dispatched throughout the year. Management also proposes corresponding changes to the resource adequacy availability incentive mechanisms to address when use-limited resources reach their use limitations, as well as revising the process for registering use-limited resources and the annual process for evaluating use limits.

- Market participants will have greater flexibility to reflect preferred operating values in the ISO’s master file, including maximum daily starts, maximum daily multi-stage generator transitions, and ramp rates. Currently, these values must reflect only physical characteristics.

- Market participants will have the ability to re-bid commitment costs in the real-time market when a resource has not been committed in the day-ahead market. Currently, resources are locked into using their day-ahead bid in the real-time market even if the resource had not received a day-ahead schedule. In addition, the ISO will no longer automatically insert bids into the real-time market’s short-term unit commitment process for non-resource adequacy resources in the event a market participant submits bids for a resource into the day-ahead market but not the real-time market.

- Market participants will have the opportunity to file with the Federal Energy Regulatory Commission to recover commitment costs that exceed the commitment cost bid cap and result in a net revenue shortfall over the day considering all market revenue.

- The ISO will make various changes to natural gas transportation rates and to the electricity price used to calculate resources’ costs used in commitment cost caps and default energy bids used by the market.

Management proposes the following motion:

Moved, that the ISO Board of Governors approves the commitment cost bidding improvements proposal, as described in the memorandum dated March 17, 2016; 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 proposed tariff change.

DISCUSSION AND ANALYSIS

Background

Market participants can currently select between two options for bidding a resource's start-up, multi-stage generator transition costs, and minimum operating level costs (collectively referred to as "commitment costs"):

- The "registered cost option" allows market participants to bid up to 150 percent of a projected cost calculated by the ISO and is fixed for 30 days. The ISO bases the projected price based on monthly natural gas futures prices. To mitigate market power, this relatively high 150 percent bid cap is balanced with a requirement that the bids are fixed for 30 days. The ISO market rules currently allow only use-limited resources to be under the registered cost option. As discussed in more detail below, the higher cap allows them to include opportunity costs reflecting their limited starts or run hours. However, this option does not provide the ability to reflect current daily natural gas prices in commitment cost bids which can result in the inefficient commitment of resources.

- The "proxy cost option" allows market participants to submit daily bids up to 125 percent of costs calculated by the ISO using a daily gas price index. This option results in a more efficient resource commitment, and better ensures cost recovery, because it more accurately reflects current natural gas costs.

Proposed changes

Management proposes several market enhancements to ensure both the ISO and market participants have the ability to accurately reflect costs in the market. These enhancements will improve efficient resource commitments, optimally commit use-limited resources, and provide more effective risk management tools while maintaining reliability.

Use-limited resources

Management proposes that use-limited resources will be eligible for a calculated opportunity cost to include in their daily commitment cost bids, which will allow the market to recognize their use limitations that extend over a longer period of time than the daily markets, such as annual limitations. This will allow the ISO to eliminate the "registered cost" option for bidding resource commitment costs, which is an inefficient means of reflecting these costs in the market.

Use-limited resources have start and run limitations due to environmental or other operational restrictions. These restrictions extend beyond a one-day period, and therefore cannot be explicitly recognized in the ISO market commitment decision. For example, an environmental restriction may limit a resource's run time over a single month to only 200 hours. However, the ISO's day-ahead market only considers a single day. The ISO's optimization does not currently take into account that dispatching a resource in the current day may restrict its ability to run later in the month. When the resource runs in lower-priced hours, it incurs an opportunity cost to the extent it is not available in higher priced hours.

Including opportunity costs in commitment costs, however, can allow the ISO market to optimally commit these resources by considering the limitations that extend beyond a single day, such as over a month or a year. The ISO will determine resource-specific opportunity costs for limitations of use-limited resources by modelling the market commitment of these resources based on projected locational marginal prices. The ISO will update these opportunity costs monthly throughout the year to reflect the each resource's actual commitment by the market.

In conjunction with this enhancement, Management proposes to change the definition of "use-limited resource" to specify that these are resources that need an opportunity cost to have their commitment optimized through the market. Other resource types that in the past were considered "use-limited" but are not fully available at all times, such as variable energy resources and demand response resources, will continue to be exempt from the ISO's automatic bid insertion that use-limited status previously provided them.

The Board approved similar revisions to the "use-limited resource" definition last year. At that time, Management clarified that the proposed and existing interpretation of the "non-economic" limitations that would qualify a resource to be use-limited did not include purely contractual limitations. Notwithstanding, Management also committed to exploring appropriate solutions for market participants to manage resources' contractual limitations. However, FERC rejected the ISO's proposed revised definition of "use-limited resource" primarily on the basis that there was a lack of clarity concerning the term "non-economic" as it applies to limitations, a term in the existing definition. Management worked with stakeholders to further clarify the "use-limited resource" definition for this proposal. The revised definition continues to exclude contractual limitations as the basis for a resource to be considered use limited and qualify for opportunity costs in their commitment cost bid cap. Management maintains its longstanding position that economic limits like those originating from contracts, such as power purchasing or tolling agreements, are not acceptable limitations for establishing an opportunity cost adder to a resource's commitment cost bid cap. These limitations exist not as a result of restrictions imposed by external statutes or regulations, but rather reflect economic trade-offs made by the contracting parties. If the ISO were to accept contractual limitations to deem a resource eligible for an opportunity cost, it would provide market participants the ability to both physically and economically withhold resources from the market while bypassing the market power mitigation processes in place. This in turn could lead to market inefficiencies and market power concerns that would go unmitigated.

However, Management recognizes that long-term contracts that were approved through a robust regulatory process, prior to initial discussions of the ISO allowing opportunity costs for such limitations, would not reflect attempts to exercise market power. Management proposes a limited exception of contractual limitations that meet specified criteria for a three-year transitional period. Management proposes limitations in long-term contracts that have been approved by a local regulatory authority, such as the California Public Utilities Commission, and were entered into prior to January 1, 2015, can qualify for the temporary exemption. Given the uncertainty of the quantity of capacity that will be captured by the provision, and increasing flexibility needs of the markets, Management cannot fully assess the market impacts of extending the provision beyond three years at this time. However, Management does commit to evaluate, prior to the end of the three year period, potential market and reliability impacts if the provision were to be extended at that time. Moreover, as discussed further below, Management's proposal to allow market participants to reflect preferred operating values for certain resource characteristics, instead of mandating that they reflect physical operating limits, will allow market participants to manage contractual limitations that do not fall under this exception.

Finally, the proposed changes related to use-limited resources and demand response resources will consider these resources under the resource adequacy availability incentive mechanism starting the beginning of the subsequent month after reaching a use limitation.[1] This enhancement will help to ensure that all resources offered as resource adequacy resources are available for dispatch.

Resource characteristics

The tariff currently requires resource characteristics submitted to the ISO's master file used by the market to reflect only actual physical limitations. However, Management realizes that market participants may want the market optimizations to consider resource characteristics that are based on other considerations such as avoiding excessive wear and tear of the resource or operating within contractual limitations.

Management proposes to provide generators flexibility to reflect these preferred resource characteristic values by adding an additional market field in the master file for certain characteristics, in addition to the existing field that will continue to reflect purely physical characteristics. These resource characteristics include maximum daily starts, maximum multi-stage generator daily transitions, and ramp rates. In conjunction with this change, market participants will no longer be able to specify ramp rates in energy bids.

The preferred operating values will be used in the market under normal system conditions while the purely physical capability limits will only be accessed by operations manually under stressed system conditions for an exceptional dispatch.

Finally, to address concerns regarding potential market power and anomalous effects in the real-time market, resources will be restricted from submitting less than two starts per day as

[1] The resource adequacy availability incentive mechanism penalizes or rewards resources based on their performance in meeting their resource adequacy must offer obligations.

a preferred resource characteristic unless the resource is only physically capable of one start per day. There will be an exception process for resources nearing the end of their life for which limiting starts to once per day is reasonable. It is desirable for the real-time market to be able to start resources twice a day because the real-time market optimization only looks out four and a half hours and may start a resource for the morning peak that is also needed for the evening peak.

Recovery of commitment costs that exceed the commitment cost bid cap

Market participants have pointed out that, although very infrequent, sometimes actual natural gas prices exceed the ISO's calculated commitment cost bid cap. To address this issue, Management proposes to add tariff provisions that will allow market participants to seek after-the-fact FERC approval of actually incurred commitment costs that exceed the bid cap. The ISO would then reimburse the FERC-approved costs through its bid cost recovery mechanism. As a result, the market participant would only be reimbursed for these costs to the extent the resource had a net revenue shortfall over the day, considering its total market revenue.

FERC would apply it's just and reasonable standard to determine whether the market participant reasonably incurred commitment costs that exceeded the bid cap to meet an ISO dispatch instruction. Management proposes that FERC conduct this review because having the ISO perform this function is not practical, as it would require establishing specific, objective criteria for such a reimbursement, for which it is not reasonable to enumerate all potential situations before-the-fact. Also, determining incurred costs would require visibility to a market participant's full portfolio of natural gas transactions and hedging mechanisms that FERC has a greater ability to obtain.

Real-time market commitment cost bidding

Currently, market participants don't have the ability to reflect the most recent natural gas prices in the real-time market if they bid the resource into the day-ahead market. Resources are locked into their day-ahead commitment cost bids when bidding in the day-ahead market even if the resource had not received a day-ahead schedule. Management proposes to allow resources without a day-ahead schedule to update their commitment cost bids for use in the real-time market to better reflect current costs.

Management also proposes to clarify the tariff so the real-time market's short-term unit commitment process no longer automatically uses day-ahead commitment cost bids in the real-time market for non-resource adequacy resources or resource adequacy resources without a real-time market offer obligation.

Changes to natural gas transportation rates and auxiliary energy electricity price

Finally, Management proposes various changes to improve the accuracy of natural gas transportation rates and generator auxiliary energy electrical processes used to calculate resources' costs used in commitment cost caps and default energy bids used by the market. This includes creating a process for market participants to request an additional fuel region to include a gas transportation rate, including costs and credits, more representative of expected resource-specific costs based on the geographic location of the resource and whether the resource has a greenhouse gas compliance obligation. These changes will also introduce a process for estimating resource-specific start-up auxiliary power costs.

POSITIONS OF THE PARTIES

Management has worked with stakeholders to develop the opportunity cost methodology over the past three years. Although most stakeholders support the opportunity cost concept, several concerns remain regarding the details of its implementation and the "use-limited resource" definition. Of particular concern is Management's position that the proposed "use-limited resource" definition does not include contractual limitations. In addition, a number of stakeholders oppose Management's proposal to require market participants to list at least two maximum daily starts for a resource in the master file preferred operating characteristics field unless the resource physically is only capable of one daily start.

Concerns regarding the opportunity cost implementation details mostly revolve around whether the modeled opportunity costs will be correct and not lead to a resource's maximum starts or run hours being used up before the end of the year. Management has responded to this concern by incorporating a "buffer" in the way the opportunity cost model will model resources. Also, Management added provisions that allow a market participant to temporarily declare a resource unavailable without incurring penalties under the resource adequacy availability incentive mechanism in the event the market is using a resource more frequently than anticipated by the opportunity cost model. Management believes that these provisions provide significant safeguards to ensure the opportunity cost is implemented in a way that will effectively manage resource use limitations.

Some stakeholders are concerned about the "use-limited resource" definition because it would not provide default use-limited status to storage, demand response, and hydro resources. Stakeholders expressed similar concerns when the Board approved changes to the definition last year. Management has explained that resources no longer deemed use limited by default can still qualify to be use limited if they meet the revised criteria. Management has also explained that the new definition for use-limited resources will not impact these resources, as they have other tools to reflect their use limitations and furthermore do not have start-up and minimum load commitment costs that could potentially need an opportunity cost adder.

Some stakeholders contend that Management's proposal to restrict resources from submitting less than two starts per day as a preferred resource characteristic conflicts with the resource adequacy flexible capacity requirements that allow a portion of the flexible capacity requirement to be met by resources with one start per day. First, Management does not believe this is inconsistent with the flexible capacity requirements that were designed to accommodate resources with a physical start limitation of one per day. Under the current market provisions, resources are required to accurately submit their full physical start limitations regardless of the resource adequacy product they are shown to provide. Therefore, Management's proposal provides increased flexibility in reflecting start limitations. Next, the flexible resource adequacy requirements do not consider market power impacts or the potential interaction with the real-time market outlined earlier in this memorandum in which the real-time market's four and a half hour look ahead may start a resource for the morning peak that is also needed for the evening peak.

Some stakeholders are concerned that Management's proposal for a limited exception for contractual limitations does not go far enough. They would like to see the exception cover the full term of the contract. Management believes that the three year transition period, which was originally proposed by the California Public Utilities Commission, is appropriate as it providers stakeholders time to modify the contractual terms to better align with the ISO's market design and the flexibility needs of the system.

A stakeholder comment matrix is included as Attachment A. The Market Surveillance Committee provided a formal opinion on Management's proposals and is included as Attachment B. The Department of Market Monitoring provided comments in their Market Monitoring Report which is included in the informational reports of the March Board materials.

CONCLUSION

Management requests Board approval of the proposal discussed above. The proposed changes will result in more efficient resource commitments, ensure generators are adequately compensated for their commitment costs, and enable more frequent, consistent participation from resources with external limitations all while improving system reliability.

Attachment A

Stakeholder Process: Commitment Cost Bidding Improvements

Summary of Submitted Comments

Two stakeholder initiatives are consolidated into one memo as both propose market improvements to ISO treatment of commitment costs.

Stakeholders submitted four rounds of written comments to the ISO under the Commitment Cost Enhancements Phase 3 stakeholder initiative on the following dates:

- Round One (comments following technical workshop session), 07/20/15
- Round Two (comments Straw Proposal), 9/8/15
- Round Three (comments on Revised Straw Proposal), 11/23/15
- Round Four (comments Draft Final Proposal), 3/2/16

Stakeholders also submitted comments on the opportunity cost model as part of the Commitment Cost Enhancements and Commitment Cost Enhancements Phase 2 stakeholder initiatives. They also submitted comments on the revised "use-limited resource" definition as part of the Commitment Cost Enhancements Phase 2 stakeholder initiative.

Stakeholders submitted seven rounds of written comments to the ISO under the Bidding Rules Enhancements stakeholder initiative on the following dates:

- Round One (comments on Issue Paper), 12/30/14
- Round Two (comments on FERC Order 809 Filing Proposal), 05/06/14
- Round Three (comments on Straw Proposal), 05/13/15
- Round Four (comments on FERC Order 809 Filing Proposal), 05/27/15
- Round Five (comments on Revised Straw Proposal), 12/17/15
- Round Six (comments on Draft Final Proposal, Minimum Load Costs), 01/20/16
- Round Seven (comments on Draft Final Proposal, Generator Commitment Cost Improvements), 02/29/16

Stakeholder comments were received from:
California Department of Water Resources (CDWR), California Large Energy Consumers Association (CLECA), California Public Utilities Commission (CPUC), CalPeak Power and Malaga Power, Calpine, Cogeneration Association of California and the Energy Producers and Users Coalition (CAC-EPUC), Department of Market Monitoring (DMM), Joint Parties, Northern California Power Agency (NCPA), NRG Energy (NRG), NV Energy, Pacific Gas & Electric (PG&E), Powerex, San Diego Gas & Electric (SDG&E), Shell Energy, Six Cities, Southern California Edison (SCE), Viasyn, Vitol, Wellhead, Western Power Trading Forum (WPTF), Xcel Energy

Stakeholder comments are posted at:
Commitment Cost Enhancements Phase 3: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancementsPhase3.aspx
Bidding Rules Enhancements:
http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingRulesEnhancements.aspx

Other stakeholder efforts include:

Commitment Cost Enhancements Phase 3:

- Technical Workshop, 7/20/15
- Conference Call, 8/31/15
- Conference Call, 11/9/15
- Conference Call, 2/25/16

Bidding Rules Enhancements:

- Conference call, 12/10/14
- Meeting, 04/29/15
- Conference call, 05/15/15
- Meeting, 12/03/15
- Conference Call, 01/14/16
- Conference Call, 02/22/16

Management proposal						
Comments of following Market Participants	**Use-limited resources that qualify for such status per the revised definition will be eligible for an opportunity cost include in daily commitment cost bids.**	**A temporary exception for contractual limitations to qualify for an opportunity cost.**	**Allow resources to reflect both a market based and physical based capability value for a subset of resource characteristics, subject to minimum values.**	**Make changes to the natural gas transportation rates and to the electricity prices used in calculating resources' costs for commitment cost bid caps.**	**Resources without a day-ahead schedule can re-bid commitment costs in real-time, and for non-resource adequacy resources, no longer automatically insert bids into the real time unit commitment process.**	**Provide market participants the opportunity to recover actual costs incurred above the commitment cost bid cap by filing at FERC.**
California Department of Water Resources (CDWR)	Requests the ISO retain the default use-limited for hydro and participating load due to potential implications on CDWR's resources.	No position	Does not support requiring the physical based capability value to be based on maximum physical capability because it does not allow engineering judgement to protect equipment.	No position	No position	No position
California Public Utilities Commission (CPUC)	Supports the concept of providing an opportunity cost but questions how resources would demonstrate the need for an opportunity cost.	Supports the exception but now requests it be extended for the life of the contract	Does not support the start per day minimum of two; It is above must offer obligations for some RA flexible capacity categories and may be unreasonable for demand response.	No position	No position	No position

California Large Energy Consumers Association (CLECA)	Concerned about the impact on resources currently use-limited by default, specifically demand response resources that will no longer be use-limited and the change in treatment under the resource adequacy availability incentive mechanism.	No position	No position	No position	No position	No position
Cogeneration Association of California and the Energy Producers and Users Coalition (CAC-EPUC)	Concerned the policy excludes combined heat and power (CHP) resources as they might not have an opportunity cost in capacity above regulatory must take.	No position	No position	No position	No position	No position
Joint Demand Response Parties	Appreciates the clarification but continues to be concerned, specifically about demand response resources that will no longer be use-limited and the change in treatment under the resource adequacy availability incentive mechanism..	No position	No position	No position	No position	No position
Department of Market Monitoring (DMM)	DMM supports the effort to develop opportunity cost adders but remains concerned about relying on negotiation process for potentially a large subset of resources.	DMM is concerned with the impact these exemptions will have on the overall market efficiency and flexibility.	Supportive of the approach and minimum of two starts per day for max daily starts and transitions.	Supports	Supports	Conditional support. Any process, even at FERC, requires strict and clear guidelines

Northern California Power Agency (NCPA)	Supports the concept of providing an opportunity cost.	No position	Supports maintaining a single set of capability values to reflect sound engineering and economic judgement.	Supports	Supports	No position
Pacific Gas & Electric (PG&E)	Supports the concept but does not support the revised use-limited definition as it may cause confusion for market participants.	Appreciates the provision; requests the exception be for the life of the contract.	Does not support the minimum of two starts per day as it may place additional burden above RA requirements.	Supports	Supports	Opposes as premature. FERC proceeding initiated on energy price formation, which while not addressing commitment costs, does broach the underlying cost verification for energy bids and could inform this proposal.
San Diego Gas & Electric (SDG&E)	Supports the opportunity cost methodology but concerned about the lack of detail in some elements. Requests storage be included as an example.	Does not agree with the proposed cut-off date in the provision nor providing the exception for only three years.	Does not agree with the minimum of two starts per day. No longer meets the original intent nor is it aligned with must offer obligations.	No position	Supports	No position
Six Cities	Supports the ISO providing an opportunity cost and modification to outage cards for demand response resources, but would prefer to see more frequency updates of the calculation.	No position	Supports with additional clarification regarding the physical values still being able to reflect environmental restrictions.	Supports	Supports	Supports. Proposes modification to allow operational flow order costs, stranded gas costs, and balancing penalties to be recoverable as well.

Southern California Edison (SCE)	ISO should consider the possibility of commitment costs for Proxy Demand resources.	Appreciates the provision; requests the exception be for the life of the contract.	Does not support the minimum of two starts per day; should be aligned with RA categories	Supports	Supports	Support for cost incurred on days where the ISO implements its manual process to update gas prices used by the day-ahead market in the event of a large day-over-day increase.
CalPeak Affiliates	No position	No position	No position	No position	Supports	Believes ISO should eliminate commitment cost bid cap instead.
Calpine	No position	No position	No position	Supports	Supports - Proposes enhancements to proposal that would allow for higher bid cap percentage in RTM to allow for rebidding limited to higher bid cap, for example 150% of proxy.	Supports
NRG Energy, INC (NRG)	Suggests other reasons to allow negotiations for opportunity costs and notes resources should not be penalized under the RA availability incentive mechanism if bids reflected opportunity cost.	Appreciates the provision but urges the exception not be limited to three years.	Supports and asks for additional clarity for when one start per day is acceptable.	Supports	Supports	Supports. Proposes modification for generator that cannot procure gas to follow CAISO dispatch instructions at any price and consequently cannot avoid operational flow order charges to allow these costs to be

						recovered through the filing process.
NV Energy	Supports the concept of providing opportunity cost adders but believes the use-limited definition is too restrictive.	No position	Generally supports the idea but does not support the minimum of two starts per day on EIM resources.	No position	No position	Opposes. CAISO has not adequately provided basis for deferring to FERC, it's not a just and reasonable mechanism, and would require investment of resources and no incidental benefits.
Western Power Trading Forum (WPTF)	No position	No position	No position	No position	No position	Supports. Notes support for other costs such as stranded gas, balancing penalties, and operational flow order penalties to be covered under filing right.

Management Response	Management sees this proposal as a significant improvement over the current process for managing use-limitations of use-limited resources. The proposal provides significant efficiency and reliability gains. The definition for use-limited resources identifies, and provides, resources an opportunity cost for limitations that cannot be optimized in the daily market horizon, resulting in more optimal commitment and management of these resources. Any resource can apply for use-limited status, and thus be eligible for an opportunity cost, based on the revised definition. The proposal also ensures that resources that are currently use limited by default, such as demand response, are not impacted by the change in status to non use limited. Exempting resources from the RA availability incentive mechanism after they exhaust their starts would eliminate the incentive to replace these resources, which are needed for reliability. Management understands demand response programs are currently in a significant transition period and have	Flexibility requirements will continue to increase as more renewable resources are added to the system. While contractual limitations on number of starts and other unit characteristics may have been reasonable under historical system conditions, they will become increasingly binding as flexibility needs increase. The temporary exception provides market participants time to determine the most cost effective method to acquire more flexibility, which may be renegotiating the contracts rather than	Management wants to take this opportunity to clarify that under the current tariff, the resource capability fields are required to represent physical abilities of the resource. The intent of this proposal is to provide additional flexibility to allow operating parameters used by the market to reflect preferred values, which can provide another means to manage resource constraints that do not qualify for use-limited status or are not explicitly modeled in the market. The minimum of two starts per day does not expand the must-offer obligation of RA flexible capacity resources. The flexible capacity categories and their associated required minimum number of starts per day define minimum requirements to qualify for the categories in RA showings and not the must-offer requirement. The two start per day minimum is to address market power concerns that RA requirements are not intended to address. Requiring two starts per day for EIM resources does not create a must-offer	Management acknowledges and appreciates the support for these proposed cost estimate enhancements.	Management acknowledges and appreciates the support for this proposed enhancement to its commitment cost bidding rules. While Management appreciates the alternative suggestion to apply different market power mitigation bid caps to commitment cost offers it finds any changes to its market power method is premature. A proposed change to its method requires a longer stakeholder process.	The ISO believes its proposal to allow for resources to request that FERC approve reimbursement for gas costs above the commitment cost bid cap is a reasonable alternative to eliminating its commitment cost bid cap. Eliminating the commitment bid cap will take further vetting to determine if it's a viable alternative for the ISO market and any potential implementation would be some time in the future. A resource can incur commitment costs above the cap even on days the ISO has not implemented its procedure for large day-over-day gas price increases as gas prices may increase after the time of the day-ahead market. Management believes FERC more appropriately suited to determine if it is just and reasonable to reimburse costs above the cap because it can

	not considered the change in the resource adequacy availability incentive mechanism for the 2017 deliverability period. Therefore, Management commits to coordinating with demand response providers to time the implementation of the proposed change in the availability incentive mechanism for demand response to take into account having sufficient time for reflection of future RAAIM/replacement obligations. While management appreciates additional detail may need to be worked out in the future for certain demand response and storage resources, there are not any such resources currently in the ISO market that would require an opportunity cost. Management is addressing the needs of storage resources in the Energy Storage and Distributed Energy Resource initiative. Proxy demand response resources could register for use-limited status if a case can be made that such status is warranted.	obtaining new resources. Prior to the end of the proposed provision period, Management will evaluate the market and reliability impacts if contracts under the provision were provided the exception beyond the current three-year period, and consider changes at that time. The proposed cut-off date captures contracts that underwent regulatory review and were effective prior to opportunity cost discussions.	requirement – these resources have no such requirement. It only ensures the market has access to starts so it can start-up and shutdown these resources appropriately. For example, if only one start per day is listed, the market may be forced to leave a resource on throughout the day to ensure it is available for the evening load ramp.			make subjective determinations about specific circumstances and can more readily obtain information to determine the actual costs incurred. In light of the reduced storage in Southern California and the potential new balancing penalties and in response to the comments summarized above, Management revised its draft final proposal so that the ISO tariff would not preclude a market participant from demonstrating to FERC that other types of costs such as imbalance penalties, operational flow order penalties, and stranded gas costs.were reasonably incurred and should be reimbursed. Management does not believe its proposal is inconsistent with the FERC proceeding initiated on energy price formation as that proceeding address energy above minimum load, not commitment costs.

Attachment E – List of Key Stakeholder Dates

Bidding Rules and Commitment Costs Enhancements

California Independent System Operator Corporation

List of Key Dates in the Stakeholder Process for this Tariff Amendment

Date	Event/Due Date
December 3, 2014	CAISO issues paper entitled “Bidding Rules Enhancements Issue Paper”
December 10, 2014	CAISO hosts stakeholder conference call that includes discussion of paper issued on December 3
December 30, 2014	Due date for written stakeholder comments on paper issued on December 3
April 22, 2015	CAISO issues paper entitled “Bidding Rules Enhancements Straw Proposal”
April 29, 2015	CAISO hosts stakeholder conference call that includes discussion of paper issued on April 22 and presentation entitled “Bidding Rules Enhancements Straw Proposal Discussion”
May 13, 2015	Due date for written stakeholder comments on paper issued on April 22
November 23, 2015	CAISO issues paper entitled “Bidding Rules Enhancements Revised Straw Proposal”
December 3, 2015	CAISO issues paper entitled “Bidding Rules Enhancements Revised Straw Proposal v.2”
December 3, 2015	CAISO hosts stakeholder meeting that includes discussion of papers issued on November 23 and December 3 and presentation entitled “Bidding Rules Revised Straw Proposal”
December 17, 2015	Due date for written stakeholder comments on paper issued on December 3
February 10, 2016	CAISO issues paper entitled “Bidding Rules Enhancements Generator Commitment Cost Improvements Draft Final Proposal”
February 22, 2016	CAISO hosts stakeholder meeting that includes discussion of paper issued on February 10 and presentation entitled “Generator Commitment Cost Improvements Bidding Rules Enhancements”
February 29, 2016	Due date for written stakeholder comments on paper issued on February 10
March 17, 2016	CAISO issues paper entitled “Aliso Canyon Gas-Electric Coordination Issue Paper"
March 22, 2016	CAISO issues paper entitled “Bidding Rules Enhancements Generator Commitment Cost Improvements Revised Draft Final Proposal”
March 23, 2016	CAISO hosts stakeholder meeting that includes discussion of paper issued on March 17 and presentation entitled “Aliso Canyon Gas-Electric Coordination"
March 30, 2016	Due date for written stakeholder comments on paper

Date	Event/Due Date
	issued on March 17
April 15, 2016	CAISO issues paper entitled “Aliso Canyon Gas-Electric Coordination Straw Proposal"
April 19, 2016	CAISO Market Surveillance Committee holds stakeholder conference call that includes discussion of paper issued on April 15
April 21, 2016	Due date for written stakeholder comments on paper issued on April 15
April 26, 2016	CAISO issues paper entitled “Aliso Canyon Gas-Electric Coordination Draft Final Proposal"
April 27, 2016	CAISO hosts stakeholder conference call that includes discussion of paper issued on April 26 and presentation entitled “Aliso Canyon Gas-Electric Coordination Discussion”
April 28, 2016	Due date for written stakeholder comments on paper issued on April 26
April 29, 2016	CAISO issues draft tariff revisions to implement interim Aliso Canyon tariff changes
May 3, 2016	CAISO hosts stakeholder conference call that includes discussion of draft tariff revisions issued on April 29
May 3, 2016	Due date for written stakeholder comments on draft tariff revisions issued on April 29
May 4, 2016	CAISO issues paper entitled “Aliso Canyon Gas-Electric Coordination Revised Draft Final Proposal"