Bidding Rules Enhancements

Generator Commitment Cost Improvements

Draft Final Proposal

February 10, 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 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 fuel commodity 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.

2. Changes from revised straw proposal

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 is removing these sections from the current Draft Final Proposal and will revisit under the later phase.

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) 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 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. 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 7 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.

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 management 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.

[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 February 04, 2016	Board of Governors Meeting for Draft Final Proposal, correct inefficient accounting of minimum load costs after Pmin rerate
February 10, 2016	Draft Final Proposal posted
February 22, 2016	Stakeholder call
February 29, 2016	Stakeholder comments due
March 24, 2016 March 25, 2016	Board of Governors Meeting

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 $= Unit\ Conversion * \text{Heat\_Rate} * Pmin * GPI$
$\text{VOM} = \text{VOM} * \text{Pmin}$
GMC Adder = $Pmin$ * GMC
GHG Cost = $Unit\ Conversion * \text{Heat\_Rate} * Pmin$ * 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 Management 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 fuel commodity 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.

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 gas 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.

The ISO believes this proposal Scheduling Coordinators (SCs) 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 resources to recover actual net market revenue shortfall through BCR and

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

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 fuel commodity 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.

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.

The tariff will define fuel costs eligible for potential after-the-fact cost recovery as costs for gas burned for commitment costs to meet an ISO schedule or real-time dispatch. 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.

The 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

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

- 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 draft final proposal. ISO will respond 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.

Topic	Market Participant	Stakeholder Comment	ISO's Response
Allow resources without a day-ahead schedule to rebid commitment costs in RTM Allow resources without a day-ahead schedule to rebid commitment costs in RTM	Calpine	Calpine supports proposal to allow units without DAM awards to rebid commitment costs before RTM as directionally correct.	ISO's draft final proposal, Section 6.1.1, reflects its policy proposal to allow resource to rebid commitment costs in RTM. In response to both Calpine and Six Cities comments that while the Revised Straw Proposal was directionally correct it was still in sufficient to resolve gas price concerns, the ISO has revises its proposal to allow commitment costs to be rebid hourly in RTM until the unit is committed.
Allow resources without a day-ahead schedule to rebid commitment costs in RTM	Six Cities	Six Cities supports the ISO’s proposal to allow rebidding of commitment costs in RTM for the trade day but does not find the proposal sufficient to resolve the concern of gas prices changing significantly within a flow day.	
Allow resources without a day-ahead schedule to rebid commitment costs in RTM	Six Cities	Six Cities urges the ISO to reconsider and to allow rebidding of commitment costs intraday subject to the 125% cost cap. If implementation challenges prevent introducing hourly rebidding of commitment costs, request ISO revisit this proposal in a subsequent initiative.	

[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	Calpine proposes an alternative to allow for higher bid cap percentage in RTM to allow for rebidding limited to higher bid cap, for example 150% of proxy.	The ISO explored this suggestion when evaluating revision to its Revised Straw Proposal and found this suggestion to be in consistent with its position that 25% headroom is sufficient to allow for cost recovery the majority of the time and in the few instances it is not that the use of an after-the-fact recovery mechanism is appropriate.
No longer insert RTM bids for non-RA resources without day-ahead schedule who do not rebid in RTM	Calpine	We completely agree with the CAISO. A non-RA resource should never have an ISO-generated bid if no DA awards are granted, as suggested in this proposal. We encourage the CAISO to implement this change forthwith given the increasing overabundance of RA-qualified resources.	Section 6.1.2 of the draft final proposal continues to propose to no longer insert RTM bids for non-RA resources without day-ahead schedule who do not rebid in RTM.
	NRG Energy	NRG supports this recommendation.	
	PG&E	PG&E does not oppose CAISO's proposal to cease inserting STUC bids for non-RA resources.	
	PG&E	PG&E requested the ISO identify which tariff sections would be revised to accommodate policy change.	ISO's tariff revisions will likely be made in Section 6.1.2 of its tariff but this could be subject to revision pending draft tariff language process.
Provide opportunity for after-the-fact cost recovery	Calpine	Calpine supports an after-the-fact cost recovery of extraordinary gas costs.	Section 7.1 of its draft final proposal continues to propose allowing opportunity for SCs to seek after-the-fact commitment cost recovery.
	Six Cities	Six Cities supports the ISO's proposal to review after-the-fact cost recovery through the ISO rather than requiring a filing at FERC.	
	Western Power Trading Forum	Supports the proposal but notes the ISO's proposal may lead to inefficient commitment decisions since compensation for actual costs greater than 25% headroom will occur outside the market. Resource's full costs will not be taken into account in the optimization.	

	PG&E	PG&E is concerned about incentive structure created by establishing such a process. For example, it would not encourage gas generators to plan and procure gas in advance of operating day. PG&E is also concerned the use could become more frequent than ISO anticipates ultimately increasing ratepayer costs.	ISO re-evaluated whether the 25% headroom renders an after-the-fact recovery unnecessary and again found that while the 25% headroom is sufficient for commitment cost recovery in many instances, there remains the risk of extreme instances resulting in commitment cost under-recovery. In these events when commitment costs are the result of an ISO dispatch, it is necessary to provide some venue for additional cost recovery.
	PG&E	PG&E views this as largely an accounting exercise and not necessary given 25% headroom and gas storage opportunities.	
	Calpine	ISO should carefully describe requirements for invoicing specificity. Many market participants buy gas for a portfolio of resources, and the invoice will not necessarily be generation resource-specific. Calpine argues incremental purchase invoices for incremental dispatch decisions should be sufficient evidence since gas is bought on a portfolio basis and not resource-specific.	In Section 7.1 of this draft final proposal, the ISO expands on the details it would define in the tariff and require a SC to submit in order to be reviewed for a BCR adjustment based on actual incurred costs above commitment cost cap.
	Six Cities	Six Cities comments that the validation process should limit adjustments to volume of gas necessary to respond to real-time dispatch.	Section 7.1 of the ISO's draft final proposal further clarifies that the validation process should limit adjustments to BCR based on incurred costs associated with fuel purchases necessary to respond to real-time dispatch.
	Western Power Trading Forum	ISO's proposal only allows cost recovery and not any additional headroom to account for risks therefore WPTF proposes to allow recovery of 110% of demonstrated costs.	The headroom on ISO's proxy costs estimates to account for risks of procurement is appropriate since proxy costs are estimates where as those risks will either be realized or not in the actual procurement costs. For this reason among others, the appropriate basis for incurred commitment costs above the cost cap comes from the actual procurement costs.

	NRG Energy	Clarify how Operational Flow Order (OFO) "penalties" would be treated under proposal	As described in Section 7.1 of the ISO's draft final proposal, costs outside of increased actual costs resulting from commodity price of procured fuel to meet an ISO incremental instruction is not eligible for after-the-fact recovery under the ISO's proposal.
	NRG Energy	NRG proposes that sufficient cost recovery includes cost recovery for abnormal circumstances such as gas curtailment, operational flow order (OFO) penalties, or price volatility events. NRG would like to reflect OFO penalty costs either through market bids or the proposed "after-the-fact" cost recovery.	
	Six Cities	Six Cities supports recovery of costs for: (1) Stranded gas procured to respond to ISO dispatch that is subsequently exceptionally dispatched down or off, (2) balancing penalties to the extent penalty is a result of an ISO dispatch that is one half hour prior to the close of the last gas trading/scheduling cycle (ie burns on or after 2:30 PM flow day), and SoCalGas Low OFO penalties for burning gas during a Stage 2 through Stage 5 low OFO or EFO exceed 125% commitment cost cap.	
	Six Cities	Establish documentation requirements for after-the-fact recovery review in advance and clearly detail in BPM.	Section 7.1 of the ISO's proposal details documentation requirements in order to be eligible for cost recovery review.
	Six Cities	If a process was supported through FERC, the documentation requirements should be established in advance and clearly documented in the BPM.	
	NRG Energy	Explore a mechanism to allow market participants to recover OFO penalties	

	NRG Energy	NRG requested the ISO confirm its understanding of its proposal to allow for opportunity of cost recovery where the CAISO provides for after-the-fact recovery of costs above 25% bid cap where: (1) a SC can invoice the CAISO for the cost of gas procured when the cost of that gas is more than 25% above the GPI used and (2) a SC need not bid SUC or MLC at the cap in order to invoice for costs greater than 125%.	ISO confirms these two conditions as described by NRG are consistent with the ISO's proposal but clarifies it has revised and expanded on the details associated with after-the-fact recovery in the draft final proposal.
Improve gas transportation rates	Calpine	Calpine supports the proposal.	Given broad support for ISO supporting fuel region formation allowing resources to more accurately reflect costs, the ISO continues to propose in Section 7.2 of its draft final proposal improvements to its gas transportation rates.
	Northern California Power Agency	NCPA supports the proposal. While the differential between PG&E rates when a generator is connected to eh backbone versus local transmission is currently at a 15 cents differential, a pending rate case at the CPUC could increase this differential drastically to detriment of generators connected to PG&E local transmission system. NCPA implores the ISO to keep abreast of changes to gas transportation rates and to reflect them in commitment cost calculations in a manner consistent with market participant's costs.	
	NRG Energy	NRG supports this recommendation.	
	Six Cities	Six Cities supports this proposal.	
	Southern California Edison	SCE is supportive of a more flexible gas transportation adder to differentiate GHG costs.	
	Calpine	Calpine supports the proposal.	

Improve the electricity price index calculation	Six Cities	Six Cities supports establishing standardized approach for calculating the cost of start-up auxiliary energy.	Under Section 7.3 of its draft final proposal, the ISO continues to propose a revision to the methodology for calculating the projected wholesale price to make its calculation consistent with the calculation used for registered or EIM resources for this projected wholesale price.
	NRG Energy	NRG does not support the ISO's proposal for ensuring sufficient cost recover of auxiliary power. While NRG does not object to the CAISO using a uniform methodology for start-up power costs, the proposal would result in generators failing to recover auxiliary start-up costs since retail rates are substantially higher than wholesale power prices.	In light of the concerns and examples raised in NRG Energy and SCE's comments, the ISO revised its proposal for improving the EPI in the draft final proposal Section 7.3. Under the draft final proposal, resources will be able to value auxiliary power using electric retail rates if it can support the retail rate is its actual costs through invoices.
	Southern California Edison	SCE opposes the ISO's proposal since it has found EPI to be more reflective of its actual costs.	