Bidding Rules Enhancements

Straw Proposal

April 22, 2015

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1. Changes from issue paper

Section 2 provides a summary of the proposals and the type of change it represents, if any.

Section 3 provides a full schedule aiming for a December 2015 Board date.

Section 5.3 was added to describe two new proposals to enhance energy bidding rules.

Section 6.2.1 is a new discussion on a survey the ISO intends to complete analyzing the conduct and impact tests that the other ISOs and RTOs use instead of bid caps for commitment cost mitigation.

Section 6.2.2 discusses the impact of the Federal Energy Regulatory Commission's Order 809 establishing new times for scheduling practices used by the interstate pipeline companies. Because the order requires a filing from the ISO, this issue will need more immediate stakeholder feedback than other issues in this proposal.

Section 6.2.4 describes proposed improvements to reflect low operational flow order constraints in the Southern California Gas Company system.

Section 6.3 was added to describe three new proposals to enhance commitment cost bidding rule.

Section 7 is a new section in this initiative but continues some of the discussions from the *Commitment Cost Enhancements Phase 1*[1] *and Phase 2*[2] Initiatives. Section 7.1 introduces differentiated bidding headroom for each component of commitment costs. This change was not possible under the timeline for *Commitment Cost Enhancements Phase 1* since that initiative aimed to incorporate changes that could be implemented on a very aggressive timeline. From *Commitment Cost Enhancements Phase 2*, section 7.2 continues the greenhouse gas discussion and section 7.3 adopts a proposed change suggested by a stakeholder to adjust the gas transportation adders depending on the location of the resource in relation to the natural gas pipeline backbone. Lastly, section 7.4 suggests improvements to the energy price index calculation pursuant to recent business practice manual clarifications.

Section 8.1 presents a proposal for reflecting resource characteristics that reflect resource adequacy showings.

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[1] http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancements.aspx

[2] http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostEnhancementsPhase2.aspx

2. Summary of proposals

Table 1
Summary of proposals

Section	Issue	Proposal	Change type
5.3.1	Changing bids after a commitment decision during an inter-temporal constraint	Settle on bid that led to the binding commitment	Tariff
5.3.2	Changing bids after a commitment decision without an inter-temporal constraint	Monitor	None
6.2.1	Commitment cost mitigation	Survey other ISO and RTO mitigation methodologies	TBD
6.2.3	FERC Order 809	Work with stakeholders to determine day-ahead market close	Section 206 filing at FERC and accompanying changes
6.3.1	Inefficient accounting for minimum load costs after a Pmin rerate	Scale minimum load costs to the rerate capacity or calculate based on heat rate	Tariff
6.3.2	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	Tariff
6.3.3	Gas price index may not reflect real-time gas purchase costs	Allow for real-time consideration of gas purchases above the gas price index	Tariff
7.1	Differentiated bidding headroom	Allow for differentiated bid caps on proxy cost items	Tariff
7.2	Greenhouse gas costs for natural gas suppliers	Follow CPUC regulation	Tariff
7.3	Adjusting gas transportation adders	Allow for differentiated adders based on proximity to backbone and other refinements	Tariff
7.4	Improvements to the energy price index calculation	Simplify and clarify existing calculation	Tariff
8.1	Proposal for resource characteristics	Allow for “market” resource characteristics in addition to physical characteristics	Tariff

3. Schedule for policy stakeholder engagement

The proposed schedule for the policy stakeholder process is below.

Date	Event
Wednesday, December 3	Issue paper posted
Wednesday, December 10	Stakeholder call
Tuesday, December 30	Stakeholder comments due
Wednesday, April 22	Straw proposal posted
Wednesday, April 29	Stakeholder meeting
Wednesday, May 13	Stakeholder comments due
Friday, June 19	Revised straw proposal posted
Friday, June 26	Stakeholder call
Friday, July 10	Stakeholder comments due
Tuesday, August 11	Second revised straw proposal posted
Tuesday, August 18	Stakeholder call
Tuesday, September 1	Stakeholder comments due
Tuesday, October 6	Draft final proposal posted
Tuesday, October 13	Stakeholder call
Tuesday, October 27	Stakeholder comments due
Thu/Fri 12/17-12/18/15	Board of Governors meeting

4. Background

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 ISO's current 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 – for example, when the market cannot incorporate a changed bid because a resource cannot respond due to an inter-temporal constraint.

The remainder of this paper is organized as follows. Section 5 compares the energy bidding rules and section 6 compares the commitment cost bidding rules of selected organized markets and describes the ISO's proposed enhancements. Section 7 proposes improvements to the commitment cost parameters currently used. Section 8 describes how resource characteristics are currently reflected in the ISO market and proposed changes. Section 9 provides the next steps.

5. Energy bidding flexibility

5.1. Survey of ISOs/RTOs

Table 2 below compares real-time market (RTM) energy bidding rules in selected ISOs and RTOs. CAISO's rules are very flexible and allow for changes to energy bids regardless of whether there are existing day-ahead schedules. Energy bids submitted to the real-time market can be different than day-ahead market bids and can vary between hours in both the day-ahead and real-time markets. This is in line with ISO New England and MISO. NYISO and PJM have rules that largely limit market participants' ability to change between day-ahead and real-time to account for higher bid costs and/or when there is no corresponding day-ahead schedule. PJM is also proposing to allow for changes to each generator's fuel cost calculation methodology.[3]

[3] 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.

Table 2
ISO-RTO real-time market energy bidding rules

ISO/RTO	RTM close for energy bids	Rules for changing energy bids in real-time	Calculates reference levels?	Mitigation
CAISO	T-75[4]	No limit[5]	Yes	Dynamic structural test (three pivotal suppliers)
ISO-NE	T-30[6]	No limit[7]	Yes[8]	Conduct and impact test[9]; restricted from fuel price adjustment for 2 (first offense) to 6 months (second offense)[10]
MISO	T-30[11]	No limit[12]	Yes[13]	Conduct and impact test[14]
NYISO	T-75[15]	If day-ahead schedule exists, increase in bid only[16]; may revise fuel cost used to calculate reference levels[17]	Yes[18]	Conduct and impact test[19]
PJM	Day-ahead:	Can only change bids if no	Yes[24]	Structural test (three pivotal

[4] CAISO, Tariff section 30.5.1 General Bidding Rules.
[5] CAISO, Tariff section 30.5.1 General Bidding Rules.
[6] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, Ethier/Parent testimony, p. 7. Tariff amendment to become effective December 3, 2014.
[7] ISO-NE, FERC docket no. ER13-1877, July 1, 2013, Ethier/Parent testimony, p. 7. Tariff amendment to become effective December 3, 2014.
[8] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[9] ISO-NE, Market Rule 1, Section III.A.5: Mitigation.
[10] 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.
[11] MISO, Energy and Operating Reserve Markets, Business Practices Manual, BPM-002-r13, Section 8. Real-Time Energy and Operating Reserve Market Activities.
[12] MISO, Energy and Operating Reserve Markets, Business Practices Manual, BPM-002-r13, Section 8. Real-Time Energy and Operating Reserve Market Activities.
[13] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[14] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 5 Conduct Warranting Mitigation.
[15] NYISO, Open Access Transmission Tariff (OATT) - 1 OATT Definitions - 1.18 OATT Definitions – R, “Real-Time Scheduling Window.”
[16] NYISO, NYISO Tariffs - Market Administration and Control Area Services Tariff (MST) – 4 MST Market Services: Rights and Obligations, 4.4.1.2.1 Real-Time Bids to Supply Energy and Ancillary Services, other than External Transactions.
[17] NYISO, NYISO Tariffs - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures (2) - 23.3 MST Att H Criteria for Imposing Mitigation Measures (2) 23.3.1.4 Reference Levels, specifically 23.3.1.4.6.3.
[18] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[19] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.

ISO/RTO	RTM close for energy bids	Rules for changing energy bids in real-time	Calculates reference levels?	Mitigation
	16:00 EST TD-1[20] If no day-ahead schedule: 18:00 EST TD-1[21]	day-ahead schedule[22]; proposing to allow fuel policy changes intra-day[23]		suppliers)[25]

5.2. Considerations for CAISO

The ISO believes that the bid flexibility currently offered is sufficient to accommodate resources' responses to system and market conditions, where such responses may be needed to support reliability and market efficiency. However, there are instances where this flexibility is provided even when the resource cannot effectively respond. For example, resources may experience inter-temporal limitations such as during a multi-hour minimum up or down time, when it is in the process of starting-up or shutting down (*i.e.*, is below Pmin), or is already off. Resources changing real-time bids during these inter-temporal constraints may be able to increase bid cost recovery payments even though the resource cannot respond to dispatch instructions during this time.

Inter-temporal constraints coupled with flexible bidding parameters may produce unintended consequences in the ISO's optimization. For example, if a resource with a minimum down time self-provides non-spinning reserves, it can develop a bidding strategy to get the optimization to keep the resource on in order to collect bid cost recovery on uneconomic bid costs. The optimization would not be able to shut the resource down because the minimum down time would make the non-spinning reserve unavailable. The ISO cannot identify a reason why a resource would need to change its bids during an inter-temporal constraint even though the flexibility is available.

Outside of an inter-temporal constraint, the short-term unit commitment (STUC) time horizon commits resources based on bids that can be later revised up to T-75. The ISO performs STUC starting for the third fifteen-minute interval of the current trading hour extending up to the next four trading hours. Therefore, the ISO market's bid cost recovery calculations will use bid costs

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[24] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.

[20] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line.

[21] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line. Reflects the balancing market offer period close.

[22] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.

[23] 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.

[25] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.

that did not originally trigger commitment. None of these examples would necessarily trigger the dynamic market power mitigation. A similar problem exists for the real-time unit commitment (RTUC).

5.3. Proposal for energy bidding flexibility

The ISO has two proposals for addressing energy bidding flexibility and solutions to inefficiencies as summarized in Table 3 below.

Table 3
Summary of energy bidding proposals

Issue	Proposal
Changing bids after a commitment decision during an inter-temporal constraint	Settle on bid that led to the binding commitment
Changing bids after a commitment decision without inter-temporal constraints	Monitor

5.3.1. Changing bids after a commitment decision during an inter-temporal constraint

The ISO will continue to allow bidding flexibility up to T-75 but for bid cost recovery settle on the bid that caused the commitment decision when there is an inter-temporal constraint.

5.3.2. Changing bids after a commitment decision without an inter-temporal constraint

This behavior is the same as the previous example but without an inter-temporal constraint. As such, the resource will be able to respond to dispatch instructions and increment or decrement based on the LMP. This type of behavior may be used to legitimately reflect changing economics but may also be used to inflate bid cost recovery if there are high minimum load costs. The ISO proposes to only monitor for this behavior for now, especially in light of the proposed changes to the bid caps for minimum load and start-up costs in this proposal.

6. Commitment cost bidding flexibility

6.1. Survey of ISOs/RTOs

Table 4 below compares commitment cost bidding rules in selected ISOs and RTOs. In CAISO, a resource that provides a commitment cost (minimum load or start-up) bid in the day-ahead must use the same commitment cost bids in the real-time market, regardless if 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.[26] 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.[27]

NYISO and PJM are similar to the CAISO in that 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.”[28] 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.

[26] Assumes proposals under *Commitment Cost Enhancements Phase 1* are approved by FERC.
[27] *Ibid*.
[28] NYISO, FERC docket no. ER10-1977, July 26, 2010, p. 4.

Table 4
ISO-RTO commitment cost bidding rules

ISO/RTO	Last time to modify start-up / min load cost	Calculates reference levels?	Mitigation
CAISO	10:00 PST TD-1 / 10:00 PST TD-1	Yes	Bid caps[29]
ISO-NE	T-30 / T-30[30]	Yes[31]	Conduct and impact test[32]; restricted from fuel price adjustment for 2 (first offense) to 6 months (second offense)[33]
MISO	T-30 / T-30[34]	Yes[35]	Conduct and impact test[36]
NYISO	Day-ahead: 5:00 EST TD-1 / 5:00 EST TD-1[37] If no day-ahead schedule: T-75 /T-75[38] and may update fuel prices in reference levels[39]	Yes[40]	Conduct and impact test[41]
PJM	Day-ahead: 16:00 EST TD-1 / 16:00 EST TD-1[42] If no day-ahead schedule: 18:00 EST TD-1 / 18:00 EST TD-1[43]	Yes[46]	6 month hold on using cost- or price-based option.[47] Structural test (three pivotal suppliers)[48]

[29] Assumes proposals in Commitment Cost Enhancements Phases 1 and 2 are approved and all resources are on the proxy cost option.
[30] 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.
[31] ISO-NE, Market Rule 1, Section III.A.7: Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.
[32] ISO-NE, Market Rule 1, Section III.A.5: Mitigation.
[33] 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.
[34] 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.
[35] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 6.9 Reference Levels.
[36] MISO, Market Monitoring and Mitigation Business Practices Manual BPM-009-r7, Section 5 Conduct Warranting Mitigation.
[37] 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.
[38] NYISO, Open Access Transmission Tariff (OATT) - 1 OATT Definitions - 1.18 OATT Definitions – R, "Real-Time Scheduling Window."
[39] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3: Criteria for Imposing Mitigation Measures. Specifically section 23.3.1.4.6.9 for reference to start-up and minimum load costs, specifically section 23.3.1.4.7 for changes to the reference level for fuel, and section 23.3.1.4.6.7 for timing before real-time market close.
[40] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.3.1.4 Reference Levels.
[41] NYISO, NYISO Tariffs, Market Administration and Control Area Services Tariff, Attachment H: ISO Market Power Mitigation Measures, Section 23.1: Purpose and Objectives.
[42] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line.

ISO/RTO	Last time to modify start-up / min load cost	Calculates reference levels?	Mitigation
	Daily bidding under cost-based option; 6 month hold for cost-based option.[44] Proposing to allow intra-day changes to fuel cost methodology[45]		

MISO and ISO-NE allow bidding flexibility up until 30 minutes before the operating hour (T-30). ISO-NE explains that it requires this level of flexibility because it has experienced significant reliability degradation from gas 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% of the amount requested during the events."[49]

In all of the other ISO/RTOs sampled, the market monitoring unit either calculates or works with the ISO/RTO to calculate reference level commitment costs in conjunction with performing a market power mitigation test.

6.2. Considerations for CAISO

6.2.1. Commitment cost mitigation

The ISO currently provides for mitigating market power in commitment costs through established bid caps of 125 percent of calculated costs under the proxy cost option and 150 percent under the registered cost option. In response to stakeholder requests, the ISO is currently conducting a survey of ISO and RTO market power mitigation methodologies as an alternative to bid caps. This survey work will be included in the next proposal draft and may also be presented to stakeholders during a working group discussion to be announced.

[43] PJM, Manual 11: Energy & Ancillary Services Market Operations, 2.3.1 Bidding & Operations Time Line. Reflects the balancing market offer period close.
[46] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.
[47] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[48] PJM, Manual 15: Cost Development Guidelines, Section 1.6.1 Reason for Cost Based Offers: Market Power Mitigation.
[44] PJM, Manual 11: Energy & Ancillary Services Market Operations, Section 2.3.3 Market Sellers.
[45] 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.
[49] ISO-NE, FERC docket no. ER13-1877, transmittal letter, July 1, 2013, p. 3.

Through this survey, the ISO would like to understand how the mitigation methodologies are similar or differ from each other and whether that difference is to accommodate unique market characteristics, the effectiveness of each test (or how often mitigation is triggered), and whether the test considers how bid cost recovery is affected.

As noted by the Department of Market Monitoring, the ISO market faces several challenges when developing dynamic mitigation of commitment costs. The methodology will need to consider transmission and contingency constraints, exceptional dispatches, operator action to override market software, and outage re-rates amongst others.[50]

6.2.2. Capacity versus marginal fuel costs

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. There are additional capacity-related costs that are 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.*[51]

6.2.3. FERC Order 809

Federal Energy Regulatory Commission (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.[52] Table 5 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.

[50] Hildebrandt, Eric, "Dynamic mitigation of start-up and minimum load costs," August 22, 2014. Available at: http://www.caiso.com/Documents/BriefingCommitmentCostEnhancements-DMM_Presentation.pdf
[51] 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.
[52] Federal Energy Regulatory Commission, Docket No. RM14-2-000; Order No. 809, April 16, 2015.

Table 5
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 will need additional time to consider the impacts of FERC Order 809 on the ISO's existing processes and industry-wide impacts. For example, the Timely Nomination deadline is now after the close of the day-ahead market (1:00 p.m. CCT is 11:00 a.m. PT). This will impact the manual process to update the day-ahead gas price index based on an index published by the Intercontinental Exchange (ICE). Currently the ICE index publishes at approximately 10:00 a.m. PT and the ISO may be able to provide the market with some indication of a gas price spike event. However, if the ICE index publishes after the new timely cycle deadline, then the ISO will need to stop the day-ahead market run potentially an hour or more after its start. This will cause a delay in the publication of day-ahead schedules.

In addition to 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 not necessary after adoption of the final rule in RM14-2. The filing is due 90 days from April 16, 2015.

Current process philosophy

Unlike the east coast, the ISO's process is established to provide natural gas price certainty for generators bidding into the day-ahead market. Therefore, the day-ahead market bidding closes after the timely nomination cycle. The ISO then publishes market awards and generators learn of their day-ahead dispatch obligations. Generators can then use the evening nomination cycle to address any fuel scheduling imbalances. However, with the deadline change, generators in ISO may not have price certainty before the day-ahead market closes if we retain today's market deadlines.

The ISO's current process philosophy is in contrast to the east coast and FERC's Order 809's intent to provide generators with an understanding of their electric dispatch obligations before the day-ahead timely nomination cycle for gas scheduling.

Illustrative alternative processes

To facilitate a discussion with stakeholders leading to a 206 filing, the ISO proposes the following three illustrative alternative processes.

Alternative 1: Move the timing of the ISO's day-ahead market timelines to earlier in the day (*e.g.* 7 a.m. – 10 a.m. PT) so that the generators know their electric dispatch obligations before the day-ahead timely nomination cycle for gas scheduling.

Alternative 1 aligns with the intent of FERC Order 809 to provide generators with an understanding of their electric dispatch obligations before obtaining gas scheduling.

On the other hand, this is a change to the ISO's and market participants' business practices, potentially degrades load and variable energy resource forecasting efforts, and would likely make the manual process developed to update day-ahead gas prices on the day of a gas price spike infeasible.

Alterative 2: Maintain the ISO's current timing for the day-ahead scheduling process on the grounds that obtaining gas scheduling on the pipelines serving California generators is not a problem and it is sufficient to know electric dispatch obligations at the time of the day-ahead evening nomination cycle.

Alternative 2 does not require the ISO or market participants to change our current business practices and preserves the current load and variable energy resource forecasting timelines.

On the other hand, this does not align with the intent of FERC Order 809. While the manual process may still be used, the ISO will not be able to provide the market with any advanced notice of a gas price spike.

Alternative 3: Move the timing of the ISO's day ahead market timelines to later in the day (*e.g.* noon to 3:00 p.m. PT), so that gas-fried resources learn their day-ahead dispatch obligations after the timely nomination and use the evening nomination cycle at 4:00 p.m. PT to address any fuel scheduling imbalances.

Alternative 3 could enhance the ability to forecast load and variable energy resource output in the day ahead time frame and the ISO can retain the manual process to update day-ahead gas prices on the day of a gas price spike event.

On the other hand, this is a change to the ISO's and market participants' business practices, this does not align with the intent of FERC Order 809, and leaves less time for scheduling coordinators to address scheduling imbalances in the evening nomination cycle.

6.2.4. Southern California low operational flow order

Within California, Southern California Gas Company and San Diego Gas & Electric Company filed an application with the California Public Utilities Commission for a proposed treatment of low operational flow order and emergency flow order requirements.[53] These changes could greatly impact the gas pipeline system in Southern California and bring it more in line with the current penalty structure in the Pacific Gas & Electric territory.

Any policy created here should leverage these improvements.

6.3. Proposal for commitment cost bidding flexibility

The ISO has three proposals to increase commitment cost bidding flexibility and correct for a current inefficiency as summarized in Table 6 below.

Table 6
Summary of energy bidding proposals

Issue	Proposal
Inefficient accounting for minimum load costs after a Pmin rerate	Scale minimum load costs to the rerate capacity or calculate based on heat rate
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
Gas price index may not reflect real-time gas purchase costs	Allow for real-time consideration of gas purchases above the gas price index

6.3.1. Inefficient accounting for minimum load costs after a Pmin rerate

The ISO system treats the minimum load cost as a fixed dollar amount. An inefficiency arises if the minimum load (Pmin) of the resource is rerated to a higher MW level than registered in the Master File. This can lead to an unintended change in the economics of the resource. An example is provided below in Table 7. Resource A and B are exactly the same resource except that Resource B has higher bid costs of $50/MWh versus $30/MWh (shown in row [E]). Resource A increases its Pmin from 100 MW to 185 MW. Since the minimum load costs remain the same, the minimum load cost per MWh (shown in row [F]) decreases from $10/MWh to only $5/MWh. The total cost of Resource A with a rerated Pmin unscaled is now below the total cost

[53] 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

of Resource B, which had higher energy bids (shown in row [I]). To correct for this inefficiency, the ISO has two proposals. The first is to scale the minimum load cost based on the original minimum load cost per original Pmin MW as calculated in Table 7. This is shown in the last column where a $10/MWh minimum cost (row [F]) is applied to the new rerated Pmin of 185 MW (row [A]) to produce a new minimum load cost of $1,850 per hour (row [D]).

Table 7
Example of Pmin rerate and minimum load cost

	Data	Formula	Resource A	Resource B	Resource A w/ Pmin rerate - no scaling	Resource A w/ Pmin rerate & scaling
[A]	Pmin		100 MW	100 MW	185 MW	185 MW
[B]	Pmax		300 MW	300 MW	300 MW	300 MW
[C]	Capacity above Pmin	*[B] - [C]*	200 MW	200 MW	115 MW	115 MW
[D]	Min load cost		$1,000 per hour	$1,000 per hour	$1,000 per hour	$1,850 per hour
[E]	Bid cost		$30 per MWh	$50 per MWh	$50 per MWh	$50 per MWh
[F]	Min load cost / MWh	*[D / [A]*	$10 per MWh	$10 per MWh	$5 per MWh	$10 per MWh
[G]	Min load cost / hour		$1,000	$1,000	$1,000	$1,850
[H]	Total bid cost / hour	*[C] x [E]*	$6,000	$10,000	$5,750	$5,750
[I]	Total cost	*[G] + [I]*	$7,000	$11,000	$6,750	$7,600

The second proposal is to calculate the actual costs based on the heat rate of the resource. This same information is used for constructing the default energy bid curve. The ISO seeks feedback on the accuracy of both approaches.

6.3.2. Resources without a day-ahead schedule cannot rebid commitment costs

The ISO proposes that any resource that did not receive a day-ahead schedule or residual unit commitment be allowed to rebid commitment costs into the real-time market. Currently the short-term unit commitment cannot accept minimum load or start-up costs that differ across the hours in real-time time. Therefore, the rebidding opportunity would need to occur at T-75 at the latest.

6.3.3. Gas price index may not reflect real-time gas purchase costs

Should the ISO not adopt a more flexible bidding policy with its accompanying market power mitigation methodology, the ISO proposes to allow for real-time consideration of gas purchases above the gas price index used in the real-time market. The ISO will work with stakeholders to discuss how a process can be developed based on the following guidelines:

1. This process is to be used when the scheduling coordinator must procure incremental natural gas in real-time at a price above the gas price index plus the natural gas headroom. "Real-time" refers to purchases made during an intra-day nomination cycle.
2. The process will be an after-the-fact validation subject to documentation and verification and based on a threshold.
3. Documentation may include receipts and the ISO may verify each document provided.
4. The ISO will reimburse scheduling coordinators for higher gas price purchases if the purchases are within a threshold. The ISO will establish a threshold based on historical natural gas trades for the appropriate day and market. The threshold should be based on several sources, similar to how the current gas price index is calculated. If the sources indicate that gas trades for that particular day and market were thin, an alternative threshold may be used. The threshold may be based on a statistical analysis, percentile rankings, or other analysis as appropriate.
5. Any allowed increase in natural gas costs will be included in bid cost recovery.

The following example incorporates each guideline above. Scheduling Coordinator A receives a real-time market award for its short-start unit to run during the hours of 22:00 to 24:00 on April 22, 2016. This market award does not overlap with any day-ahead award and the scheduling coordinator needs to procure incremental natural gas in the Intra-day 3 market. Scheduling Coordinator A procures gas at a price that is above the real-time gas price index plus the headroom.

After the fact, Scheduling Coordinator A provides the ISO with documentation to support its purchase. The ISO verifies the documentation and compares the scheduling coordinator's purchase price to natural gas trades in the Intra-day 3 market for April 22, 2016. The ISO finds that Intra-day 3 was very thinly traded on this day and expands the comparison, as appropriate, to include all Intra-day trades for that day. The ISO approves the scheduling coordinator's purchase based on a pre-established threshold. The threshold may approve or cap the scheduling coordinator's allowed natural gas price.

Scheduling Coordinator A will have its costs resettled for its short-start unit for the real-time award between 22:00 and 24:00 on April 22, 2016. The resettlement will then be included in the ISO's bid cost recovery calculations.

The ISO will work with stakeholders in this initiative to determine each element of this guideline including acceptable documentation, verification checks, and determining the threshold.

Additionally, the ISO may consider reimbursement for gas procured to operate a resource but the resource was exceptionally dispatched off. The ISO seeks feedback on how to account for the net cost of the gas purchase if any amount was sold.

7. Commitment cost parameters

This section addresses several topics of concern suggested by stakeholders.

A stakeholder requested periodic review of commitment costs. The ISO has initiated a series of stakeholder initiatives to address commitment costs. Each is intended to be an incremental improvement and therefore provides an opportunity for stakeholders to review cumulative changes. The ISO suggests that stakeholders actively participate in these existing processes.

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 indices for the weekend days or holidays are thinly traded. The ISO can continue to monitor this situation but does not propose any changes at the moment.

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

For now, the ISO proposes to retain use of the gas price index as we evaluate the impact of the recent FERC order.

The remainder of this section addresses additional comments provided by stakeholders and the proposals for each. The topics include differentiated bidding headroom, greenhouse gas costs for natural gas suppliers, differentiating types of starts, adjusting gas transportation adders depending on the location of the resource on the gas transmission system, and improvements to the calculation of the energy price index.

7.1. Differentiated bidding headroom

The ISO proposes to differentiate the bidding headroom (*i.e.*, the difference between allowable commitment cost bid amounts and ISO-calculated costs) for each item included in the proxy cost calculation as shown in Table 8 below. Much of the reason for the current headroom is to account for natural gas price variations though the ISO-calculated costs includes items besides natural gas costs. We seek stakeholder feedback on each of the items below. The proposal assumes that an opportunity cost methodology is in the market and therefore the registered cost option is no longer available. The opportunity cost bid cap will be discussed in the forthcoming *Commitment Cost Enhancements Phase 3* initiative.

Natural gas - The ISO proposes to maintain the current headroom on natural gas costs pursuant to the reasons provided in the *Commitment Cost Enhancements Phase 1* initiative.

Greenhouse gas - Since the introduction of the greenhouse gas market, prices have been very stable. Nonetheless, the ISO proposes to retain a 110 percent cap to account for any variations from the index used in the ISO's cost calculations.

Grid maintenance charge (GMC) – The ISO does not believe there is a reason to allow for any additional headroom on this charge.

Major maintenance adder – These costs are already negotiated amounts and have already been subject to validation and benchmarking. The ISO does not believe there is a reason to allow for additional headroom.

Non-fuel related costs – These costs may be pumping costs or other start or minimum load costs not captured by natural gas costs. The ISO does not expect these costs to be as volatile as natural gas costs and therefore proposes a 110 percent bid cap.

Default variable operation and maintenance (VOM) cost – Scheduling coordinators are allowed to negotiate a cost with the ISO. Therefore, the ISO proposes no additional headroom on the default values.

Auxiliary energy – The energy price index may not be updated when actual rates change so the ISO proposes a 110 percent bid cap. This may be revised, however, depending on changes that may be made to the calculation of the energy price index. See Section 7.4 below for a discussion on proposed improvements to the ISO's calculation of the energy price index.

Table 8
Proposed differentiated bid caps for commitment cost components

	Current	Proposed
Natural gas	125%	125%
Greenhouse gas	125%	110%
GMC	125%	100%
Major maintenance adder	125%	100%
Non-fuel related costs	125%	110%
Default VOM	125%	100%
Auxiliary energy	125%	110%

For implementation, a stakeholder suggested that bids can be made based on percentages rather than total dollar amounts. The ISO sees value in having this functionality and seeks stakeholder feedback on this change in the bidding process.

7.2. Greenhouse gas costs for natural gas suppliers

This discussion originated in the *Commitment Cost Enhancements Phase 2* initiative.

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. "Covered entities," such as thermal generators, emitting more than 25,000 metric tons of carbon dioxide equivalents (MTCO2e) per year are required to 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.

Starting January 1, 2015, natural gas suppliers will also be considered covered entities for the amount of gas delivered to California end-users, net of the amount delivered to existing covered entities.[54]

The ISO currently allows covered entities to reflect greenhouse gas costs in commitment costs. Thermal resources that have not reached the 25,000 MTCO2e threshold cannot include a greenhouse gas cost or will have to voluntarily enroll in the cap-and-trade program. Depending on how the regulations are changed, the ISO has two main options in the future:

1) When natural gas suppliers become covered entities, the greenhouse gas costs incurred may be passed on to natural gas-fired generators that do not meet the emission threshold. Therefore, all natural gas-fired resources will have greenhouse gas costs. Correspondingly, the ISO proposes to allow all natural gas-fired resources to reflect greenhouse gas costs in commitment costs. This assumes that greenhouse gas costs are *not* reflected in the gas price indices used.[55]
2) On the other hand, if the cost of greenhouse gas is already reflected in the gas price indices, no generators will need an explicit adder for these costs. Instead, the ISO will simply reflect the natural gas costs.

The California Public Utilities Commission is currently assessing the impact of greenhouse gas compliance on natural gas suppliers.[56] On December 18, 2014 the Commission adopted a decision that defers several key issues from the current Phase 1 process to Phase 2 of the proceeding.[57] A proposed decision on Phase 2 is expected in June 2015.[58]

It is also unclear whether the gas price indices in future will reflect greenhouse gas costs. In the meantime, the ISO understands that there are greenhouse gas rebates available to covered entities that would lower the cost of natural gas purchased. The ISO would like to learn more about how these rebates are currently accounted for and whether there is currently any double counting of greenhouse gas costs.

The outcome of this proposal will impact commitment cost calculations and will need careful consideration of energy imbalance market resources. However, given the current regulatory uncertainty, the ISO proposes no policy changes until there is clearer direction from the Commission. The ISO needs more regulatory clarity in order to propose market design changes

[54] 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.
[55] Policy change.
[56] See California Public Utilities Commission, Rulemaking 14-03-003, filed March 13, 2014.
[57] California Public Utilities Commission, Decision Resolving Phase 1 Issues and Addressing the Motion for Adoption of Settlement Agreement, Rulemaking 14-03-003, December 18, 2014.
[58] California Public Utilities Commission, Assigned Commissioner's and Administrative Law Judge's Ruling and Scoping Memo for Phase Two, Rulemaking 14-03-003, January 29, 2015.

that will be acceptable to the Federal Energy Regulatory Commission. In the meantime, the ISO will consider the implementation impacts based on the options noted above and how soon the changes can be made once a decision is adopted.

7.3. Adjusting gas transportation adders

A stakeholder suggested that the ISO should differentiate gas transportation adders on the PGE system between resources connected directly to the backbone transmission network (at a lower rate) than the local gas transmission network (at a higher rate).

The ISO agrees with the stakeholder and proposes to make such a differentiation. The ISO would like to understand if the information is readily available from scheduling coordinators and whether there is a similar differentiation for other pipeline systems.

For SCE and SDGE gas regions, the ISO may also revisit the current methodology for establishing these regions. The ISO seeks stakeholder feedback on improvements to the current process.

7.4. Improvements to the energy price index calculation

The calculation of the energy price index is described in the proposed update to the Market Instruments Business Practice Manual.[59]

The ISO is also in the process of making the energy price index available to stakeholders via the ISO's current data transparency efforts. The ISO expects the information to be available in Q4 2015. In the meantime, resource-specific information is available on request by contacting: epi@caiso.com.

The discussion in this stakeholder initiative is to propose improvements to the current calculation. The ISO has identified several topics that may benefit from greater analysis as listed in Table 9 below.

[59] PRR 829: Electricity price index calculation. See http://bpmcm.caiso.com/Pages/default.aspx

Table 9
Energy price index analysis topics

Current approach	Questions
Retail electricity rates are assigned based on the fuel region	Are the regions always aligned?
Pay the higher of retail electricity rate or LMP	Does the "higher of" approach need to be reviewed? Can the ISO establish what the resource actually pays? Should the retail rates be updated more frequently or are the rates relatively static?
Forward wholesale monthly price projections are based on five minute RDT prices. On-peak hours are calculated for each season as the average of the top 8 peak hours within each day and multiplied by a future price conversion factor. Off-peak hours are averaged over the entire year multiplied by a future price conversion factor. Future price conversion factors are between 100% and 150%.	Should the LMP be based on the appropriate commitment period prices instead of the RDT? Should there be different approaches for calculating on-peak and off-peak prices? Should the future price conversion factors be adjusted?
Currently SDG&E resources use the SCE rate	Should resources in the SDG&E territory use different retail rates?

The ISO seeks stakeholder feedback on the topics for analysis as well as additional improvements to the current calculation.

8. Resource characteristics review

Resource characteristics are submitted to the Master File based on the generator resource data template.[60] Valid inter-temporal constraints, such as minimum up and down times, and other resource characteristics are the foundation for effective bidding rules. The ISO currently requires scheduling coordinators to provide information reflecting physical characteristics. Specifically, the tariff requires:

> ***4.6.4 Identification Of Generating Units***
>
> *Each Participating Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the CAISO. All information provided to the CAISO regarding the operational and technical constraints in the Master File shall be accurate and actually based on physical characteristics of the resources except for the Pump Ramping Conversion Factor, which is configurable.*

[60] See http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx link to the excel file for the most recent Generator Resource Data Template.

Many of the resource characteristics are difficult to verify as they may legitimately require some engineering and economic judgment to balance excessive wear and tear and the technical capabilities of the resource. The ISO believes that the vast majority of resource characteristics should be static over a period of time reflecting resource vintage and use.

8.1. Proposal for resource characteristics

The ISO proposes two sets of Master File values. The first set consists of all the existing resource characteristics and these must be based on the physical characteristics of the resources, per the current tariff description. These characteristics will be kept as validation data and will be referred to in this paper as "physical" characteristics.

The second set is a subset of resource characteristics that will be used in the ISO market for normal operations. At minimum, these characteristics must support resource adequacy showings. These values may be different than the first physical set and will be referred to in this paper as "market" characteristics. The ISO questions whether non-resource adequacy resources may reflect market characteristics and seeks stakeholder feedback.

The ISO proposes daily starts and minimum up and down time as the first three priority resource characteristics to analyze, as shown in Table 10.

Table 10
Illustrative example of physical versus market characteristics

Illustrative Resource A providing flexible RA category 1			
Characteristic	**Physical value**	**Market value**	**Notes**
Daily start	4 starts per day	2 starts per day	• Physical value should change rarely • Physical value may be used for reliability • Market value should only decrease with RA showing • Market value may increase up to physical value
Minimum up time	60 min	60 min	*Same as above*
Minimum down time	60 min	*Same as above*	*Same as above*

If there is a need to exceptionally dispatch, the ISO proposes to have available to operators the physical characteristics of the resource. On the other hand, if the resource is providing ancillary services, the ISO proposes to allow the resource to use market resource characteristics. This is acceptable, for example, because the flexible capacity requirements include a component to account for the single largest contingency.[61]

More characteristics may be added but will need to be coordinated with other efforts affecting such as those establishing requirements for resource adequacy showing such as the second phase of the *Reliability Services Initiative*. Other characteristics that may be reviewed include the minimum and maximum operating levels, configuration transition times, and definition of the forbidden operating range.

The ISO seeks feedback on the proposal to create a set of market characteristics and the first three suggested characteristics.

9. Next steps

The ISO will discuss this straw proposal with stakeholders at an in-person meeting on April 29, 2015. Stakeholders should submit written comments by May 13, 2015 to InitiativeComments@caiso.com.

[61] Meeusen, K., *Flexible Resource Adequacy Criteria and Must-Offer Obligation: Revised Draft Final Proposal*, Section 5.1.1 Allocating the Maximum of the Most Severe Single Contingency or 3.5 Percent of Forecasted Peak Load, March 7, 2014.