Commitment Cost Enhancements

Revised Straw Proposal

June 10, 2014

Table of Contents

1. Changes from Issue Paper/Straw Proposal

Section 3 – The schedule has been modified to allow for an additional paper.

Section 5.3 – Provides additional clarifications on details on the manual process.

Section 5.4 – Consolidates into this initiative the opportunity cost calculation methodology for use-limited resources.

Section 6 – New section that details processes and practices that will be maintained and additional items for discussion such as intra-day gas costs.

Section 7 – Discusses topics for the bidding rules initiative.

2. Background

During the winter season of 2013-2014, the ISO energy market experienced abnormally volatile and high natural gas price spikes. For example, on February 4, 2014 at 9:50 p.m., the natural gas index prices applicable to resources in the ISO markets ranged from $7.63/MMBtu to $8.62/MMBtu. But by February 5, 2014 at 10:01 a.m., those prices had increased to a range of $12.29/MMBtu to $23.53/MMBtu.

In light of the sudden increase in gas prices, the ISO was not able to reflect the gas price spike in its resource commitment decisions. The ISO calculates the start-up and minimum load costs for resources under either the "proxy cost" or "registered cost" option selected by the resource. For resources under the proxy cost option, the ISO is required to rely on at least two natural gas price indices published the day prior to running the day-ahead market, per tariff section 39.7.1.1.1.3. For the registered cost option, the gas price is based on a monthly forward projection and the total registered cost is limited to no more than 150% of the projected proxy costs. Resources selecting the registered cost option must remain under that option for 30 days, unless the proxy costs are higher than registered. Lastly, the ISO tariff specifies, per section 30.4.1.2, that a registered cost option resource that switches to the proxy cost option must remain under the proxy cost option for the remainder of the 30-day period.

To address the potential for additional natural gas price spikes for the duration of the winter season, on March 6, 2014 the ISO filed with the Federal Energy Regulatory Commission (FERC) a proposed tariff waiver of the above referenced two sections until April 30, 2014. In the tariff waiver filing, the ISO also committed to commence a stakeholder process in April to address the issues raised by gas market conditions and to more comprehensively develop an interim solution that can be implemented in the fall if such solutions do not require substantial system changes. FERC granted the ISO's tariff waiver on March 21, 2014.[1]

There are two additional processes that deserve mention here:

[1] *California Indep. Sys. Operator Corp.*,146 FERC 61,218 (2014).

- First, the ISO has existing board-approved policy to specifically address inclusion of operational flow order penalties under specific circumstances. The ISO has not yet submitted tariff changes to FERC to implement that policy because it needs to clarify the definition of operational flow orders covered by the policy. The ISO will do that as part of the tariff development process for the operational flow order policy concurrent with this stakeholder initiative.

- Second, on March 20, 2014, the FERC released a notice of proposed rulemaking (NOPR) to address coordination and scheduling practices of the interstate natural gas pipeline companies and the electricity industry.[2] The NOPR provides the natural gas and electricity industries six months to reach a consensus. While the NOPR is not directly related to commitment cost pricing in the ISO market, issues discussed there may overlap with the proposal in this initiative.

3. Schedule for policy stakeholder engagement

The proposed schedule for the policy stakeholder process is listed below. We have added an additional paper in order to discuss new elements of the proposal.

Date	Event
Wed 4/30/14	Issue paper/straw proposal posted
Wed 5/7/14	Stakeholder call
Wed 5/21/14	Stakeholder comments due
Tue 6/10/14	Revised straw proposal posted
Tue 6/17/14	Stakeholder call
Tue 7/1/14	Stakeholder comments due on revised straw proposal
Tue 7/15/14	Second revised straw proposal posted
Tue 7/22/14	Stakeholder call
Tue 7/29/14	Stakeholder comments due on second revised straw proposal posted
Tue 8/12/14	Draft final proposal posted
Tue 8/19/14	Stakeholder call
Tue 8/26/14	Stakeholder comments due on draft final proposal
Thu/Fri 9/18-9/19/14	Board of Governors meeting

4. Initiative scope

Under this initiative, the ISO intends to adopt more updated natural gas costs in resources' minimum load and start-up costs prior to the 2014-2015 winter season. Accordingly, the ISO is

[2] http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf

proposing a straightforward means to achieve this solution but the ISO will still need to assess whether it can implement the proposal before next winter.

For more comprehensive, long-term solutions with greater implementation impacts, the ISO will commence the bidding rules initiative in the third quarter of 2014. This future initiative will explore a broader array of bidding rules in the ISO market including for energy and commitment costs.

5. Proposal

In 2012, the ISO conducted the *Commitment Cost Refinements, 2012* stakeholder process[3] and consequently implemented the following changes:

1. Reduced the registered cost option cap from 200% to 150% of the calculated proxy cost; and
2. Included the following costs into the proxy cost calculation: major maintenance, greenhouse gas (GHG), and components of the grid management charge.

The registered cost option exists in order to strike a balance between allowing more accurate cost recovery and limiting potential market power abuse. The original proposal in the 2012 stakeholder process would have reduced the cap to 125%. This was subsequently raised to 150% out of concerns such as the potential volatility and illiquidity in the nascent GHG market, the use of futures gas prices averaged over each month rather than a more variable daily price, and natural gas balancing charges that are not included in the cost categories. On the other hand, the cap was reduced from 200% and the 30-day hold for the registered cost option was retained to mitigate market manipulation, such as the potential to inflate bid cost recovery payments by strategic behavior designed to operate resources at minimum load.[4] In addition, the ISO currently does not have a market power mitigation methodology explicitly for start-up and minimum load costs other than this 150% cap. As the Department of Market Monitoring notes:

> *Another option that has been discussed in the past has been to automatically apply mitigation only when it is determined that a unit may have local market power – such as the ISO's automated procedures for energy bid mitigation. In practice, however, units may have market power as a result of various capacity constraints that require units to be committed and operating at least at minimum load. These constraints include the minimum online constraints (MOCs) and new constraints being added through the flexible ramping product and the contingency modeling enhancements. Unlike transmission constraints used to*

[3] http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx
[4] See "Chapter 7: Market Competitiveness and Mitigation" in Department of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, April 2014.

> *determine if energy bid mitigation should be triggered, these other constraints are much more complex and may not be binding when market power may occur.*[5]

In the 2012 stakeholder process and in recent comments to the FERC regarding the ISO's tariff waiver, numerous stakeholders have voiced a preference to bid in their start-up and minimum load costs in order to better reflect daily natural gas prices and other costs. The ISO agrees that to the extent practical, market participants should be allowed to reflect and manage their costs through bidding. The ISO wants more up-to-date gas prices reflected in the market optimization to ensure market efficiency. For example, on February 6th, the price differential between commitment costs and incremental energy bids committed a number of resources to minimum load in lieu of dispatching them for incremental energy. However, this flexibility needs to be balanced against robust bidding rules and implementation and monitoring burden. In order to maintain this balance but provide greater flexibility, the ISO proposes to increase the proxy cost option bid cap and eliminate the registered cost option.

5.1. Increase proxy cost option cap

The ISO proposes to retain the proxy cost option, but modify it, because it already has the daily bidding functionality that stakeholders have requested and better reflects more current natural gas costs. The proxy cost option is based on at least two daily gas price indices rather than a fixed projected price under the registered cost option. The ISO proposes to retain the use of gas price indices because it helps to mitigate market power abuse and provides consistency with other ISO market process such as generated bids for physical resources and the calculation of default energy bids. Therefore, modifying the proxy cost option to allow for added flexibility would have fewer implementation impacts than modifying the registered cost option.

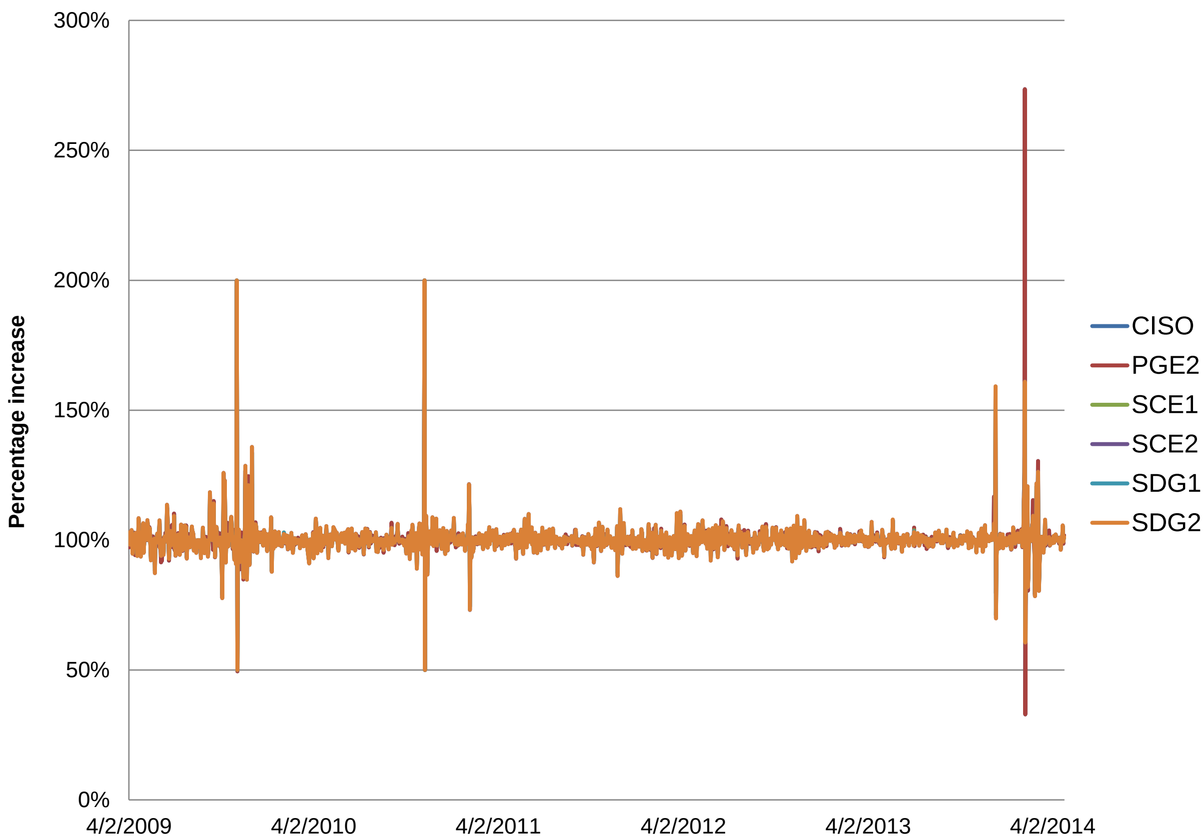
The ISO proposes to increase the proxy cost option cap from 100% of the daily calculated cost to 125% as explained below. All other characteristics of the proxy cost option would remain the same as detailed in Section 6. Though we propose to increase the cap, the ISO does not believe there is a need at this time to require any additional *ex post* cost verification. We believe that market participants can effectively manage their costs by bidding in their appropriate minimum load and/or start-up costs on a daily basis. A daily *ex post* cost verification regime for costs exceeding 100% of proxy (but under the proposed proxy cap of 125%) would also create a greater monitoring burden and be potentially disruptive if submitted costs are not accepted and market resettlement is required. For example, the Department of Market Monitoring notes that "if rules are modified to allow participants to submit their own start-up and minimum load bids without any specific limits, some form of mitigation will still be needed. After the fact review of bids would be very administratively burdensome, and would not

[5] Department of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, April 2014, page 262.

mitigate the distortion in the market that would have already occurred due to use of the unmitigated bids."[6]

An increase in the bid cap will provide flexibility to account for a variety of costs such as normal gas price volatility and the one day lag in the gas price indices used in the day-ahead market. The figure below shows the day-over-day percentage increase in natural gas prices for each of the ISO gas regions. The figure shows that gas price volatility has been rare in the ISO market since the beginning of MRTU.

Figure 1
Day-over-day percentage increase in natural gas price (April 2009 - April 2014)



The table below is derived from the figure above and only shows the trade dates when the day-over-day percentage increase exceeds 120% in any gas region. The increase is not necessarily uniform over the entire ISO. Overall, there have been seven instances where the increase

[6] Department of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, April 2014, page 262.

exceeded 125% (shown in light blue) but only two instances of extreme price spikes of over 200%, including the February 6th event (shown in darkest blue with white font).

Table 1
Day-over-day gas prices increases over 120% (April 2009 - April 2014)

Trade Date	CISO	PGE2	SCE1	SCE2	SDG1	SDG2
10/6/2009	119%	119%	124%	126%	124%	126%
10/8/2009	123%	123%	121%	123%	121%	123%
11/1/2009	198%	198%	200%	200%	200%	200%
11/18/2009	127%	127%	127%	129%	127%	129%
11/24/2009	125%	125%	120%	121%	120%	121%
12/1/2009	122%	122%	134%	136%	134%	136%
11/7/2010	200%	200%	200%	200%	200%	200%
2/3/2011	102%	102%	120%	122%	120%	121%
12/10/2013	120%	120%	156%	159%	156%	159%
2/5/2014	126%	126%	118%	119%	118%	119%
2/6/2014	274%	274%	159%	121%	159%	121%
3/1/2014	105%	105%	121%	122%	121%	122%
3/4/2014	130%	130%	125%	126%	125%	126%
Instances:						
>=125%	7	7	7	7	7	7
>=150%	3	3	4	3	4	3
>=200%	2	2	2	2	2	2

In addition to gas price spikes, there may be other costs that are not perfectly accounted for under the proxy cost option. For example, the increased cap can account for variations in the standard resource-specific costs that are used in the Master File, such as the variable O&M. The increased bid cap will allow participants to capture the vast majority of observed natural gas price volatility and additional costs.[7] This meets the ISO objective to ensure on the whole that resources are appropriately compensated for their costs and aligns with other market design changes. For the reasons stated above, the ISO proposes initiative proxy cap of 125%.

The cap need not be as high as the registered cost cap because that option relied on a fixed natural gas forecast and required the resource to remain with the same cost for at least 30 days. Furthermore, increased bidding flexibility should be considered in the context of other market changes. On May 1, the ISO implemented bid cost recovery changes, including the separation of day-ahead and real-time bid cost recovery which is expected to attract more real-time economic bids by providing more cost recovery in the day-ahead. While there are some new safeguards in the recently approved bid cost recovery tariff amendments, they do not expressly create a market power mitigation methodology for commitment costs or an uninstructed deviation penalty. It will be important to see the market impacts of these changes.

[7] Note that a 125% increase in natural gas prices will result in a total cost increase of less than 125% because of other costs included in the start-up and minimum load cost calculations.

Though the increased proxy cap will be effective on most days, it would not be able to capture extreme price spikes like those observed on February 6th. Therefore, the ISO proposes to retain the manual operations as described in the tariff waiver to update the natural gas price index using the single ICE index, which is published at approximately 10 am. This would potentially delay the close of the day-ahead market.[8] See Section 5.3 below for more details. In the next section, we discuss the proposed elimination of the registered cost option. If this occurs, then the manual process developed to implement the requirements under the tariff waiver obtained earlier this year to switch eligible resources from registered to proxy would not be needed.

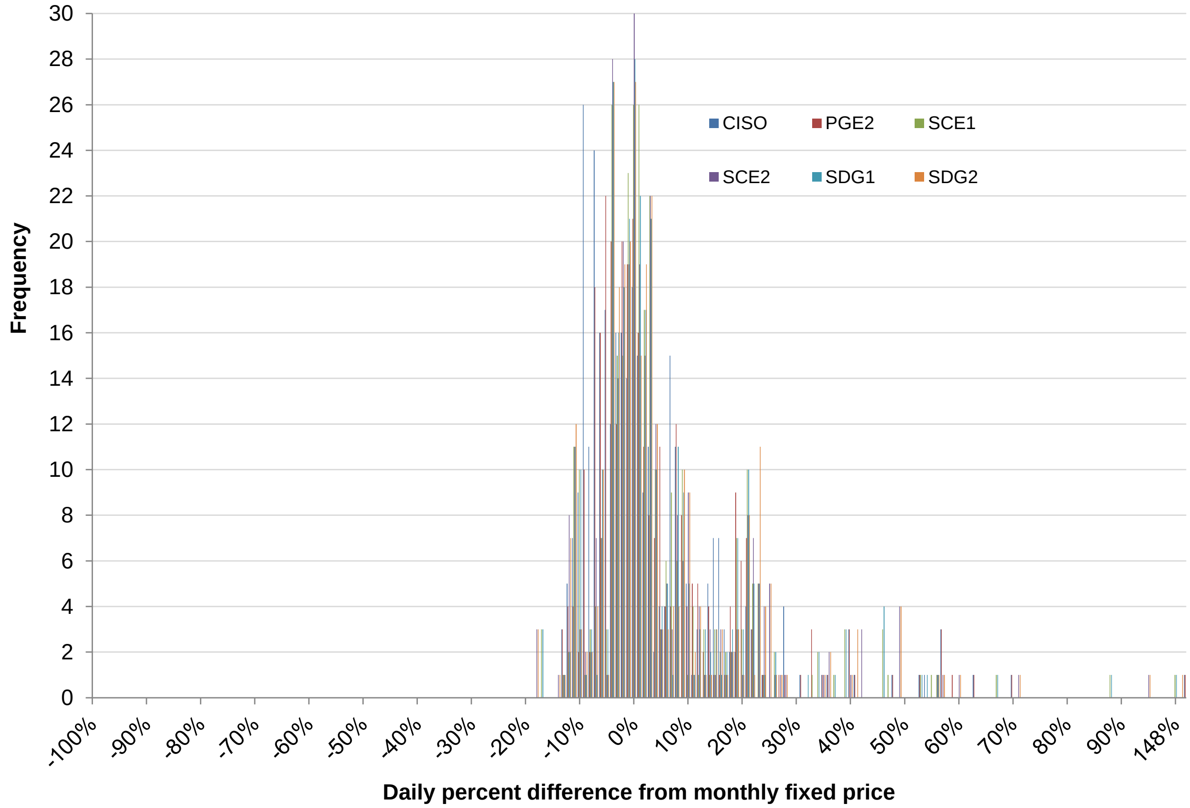
5.2. Eliminate registered cost option

The 2012 stakeholder initiative also contemplated the elimination of the registered cost option. At the time it was deemed necessary to retain this option in light of the start of the GHG market and the numerous market design changes being discussed (such as separation of the day-ahead and real-time bid cost recovery). As those milestones have passed, it is appropriate now to revisit this issue.

With improvements to the proxy cost option, we view the existing registered cost option to be largely obsolete. Both cost options would have identical inputs except that the proxy cost option has a more updated natural gas price. Figure 2 below counts the number of times the daily gas price was above or below the monthly fixed gas price per region from June 2013 through April 2014. This frequency is distributed along the x-axis based on the percentage increase or decrease. The figure clearly shows that for all regions and for the majority of days, the daily gas price is above the monthly fixed price. In other words, the high bid cap on the registered cost option largely absorbs the upward price volatility that is not reflected on the whole in the monthly fixed price during this period.

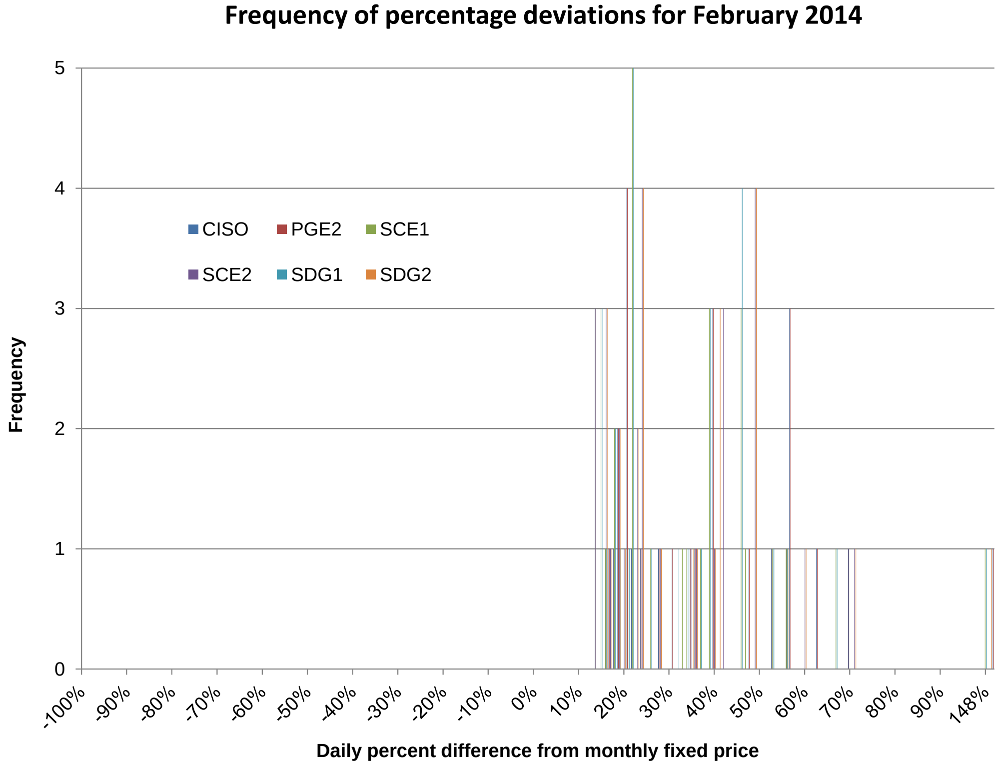
[8] The FERC NOPR seeks to start the gas day earlier which may allow the gas price indices to publish earlier in the day. On the other hand, the FERC NOPR also seeks to delay the close of the timely nomination cycle which can have the opposite effect.

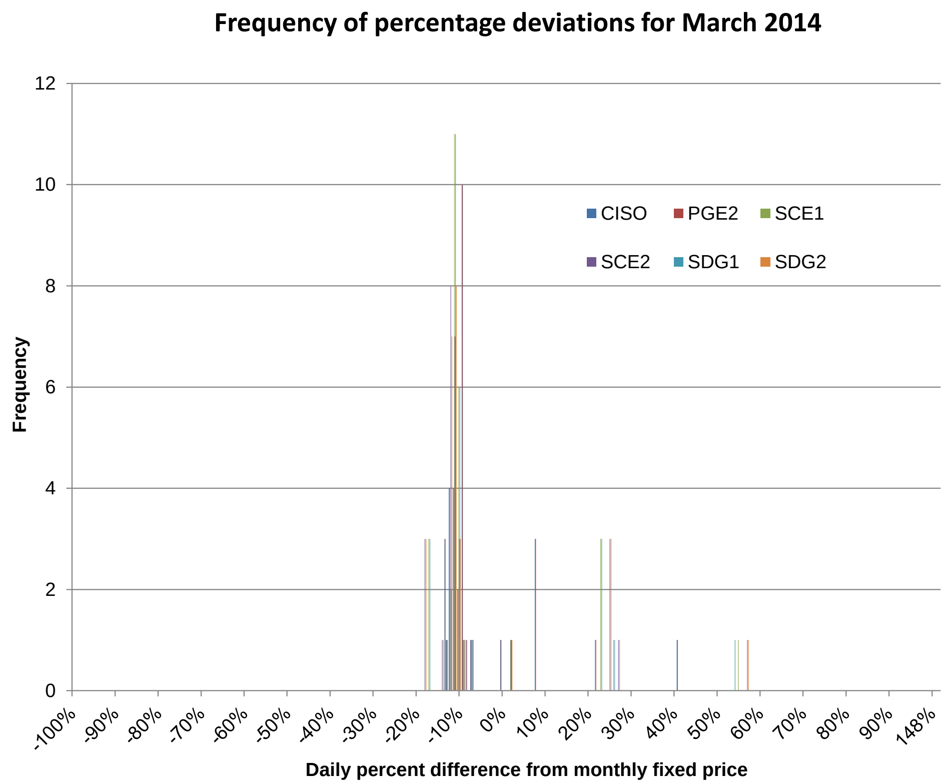
Figure 2
Frequency of percentage deviations between the daily and monthly fixed gas price (June 2013 – April 2014)



The following pair of charts in Figure 3 highlights the lag in the monthly fixed price. The chart on top shows that in February 2014, the daily gas prices were *always* higher than the fixed monthly price. For February 6th, the day of the extreme gas price spike, the daily gas price increase over the fixed monthly price was 364% for the CISO and PGE2 gas regions. March 2014 shows the opposite situation. Likely as a result of high gas prices in February, the monthly fixed price for March increased on average by $1/MMBTU. However, the March 2014 chart on the bottom shows that the daily gas prices trended lower as shown by the cluster of events around the -10% range.

Figure 3
Comparison of February and March 2014 deviation frequency





Implementation-wise, revisions to the registered cost option such as adding a bidding functionality or reducing the 30-day hold will require more systems and process changes. In fact, reducing the 30-day hold may well require a reduction in the current bid cap of 150%, moving the registered cost option closer to proxy.

With the elimination of the registered cost option, all resources will need to use the proxy cost option for minimum load and start-up costs. Providing a single, flexible option will also streamline the ISO's existing processes.

5.3. Retain manual process from tariff waiver

As mentioned in Section 5.1 above, the ISO intends to retain the majority of the manual process as described in the tariff waiver. This manual process only impacts the day-ahead market and attempts to correct for the lag in updating the gas price indices used in the optimization. The ISO would prefer a non-manual solution but may not be able to implement one before the next winter season. We continue to explore options to automate this process or implement a superior option.

In the meantime, we propose that the manual process be triggered when natural gas prices for any region are more than 125% of the gas price for that region from the previous night.[9] Currently, the final gas price that the ISO uses for each gas region is based on at least two gas price indices.[10] These gas prices are updated between 7:00 p.m. and 10:00 p.m. Pacific Time to be used the following day in the day-ahead market optimization. The ISO proposes to monitor the intra-day gas prices the morning of the day-ahead market optimization for any significant movements in the gas price in any one of the ISO's six gas regions. Though the ISO will monitor intra-day gas prices, we will still rely on the use of a gas price index. The only one available the morning of the day-ahead market optimization is the Intercontinental Exchange (ICE) index. The ISO tariff currently requires the use of two or more indices and the use of the single ICE index is a departure from current practice. However, the ISO believes that the manual process will be exercised rarely. If by the time the ICE index is published (at approximately 10:00 a.m.) and the natural gas price for any of ISO's six gas regions is greater than 125% of the gas price used in the previous night, the ISO would delay the day-ahead market, update the gas prices with the ICE index numbers in the default energy bids, proxy cost calculation, and generated bids, and allow market participants to (re)submit all bids. In summary, the major steps are:

[9] For example: $4.00/MMBtu x 125% = $5.00/MMBtu so the manual process will be triggered if the gas price is greater than $5.00/MMBtu.
[10] See tariff section 39.7.1.1.1.3.

1. Day 1
   a. Between 19:00 and 22:00 Pacific Time update gas prices per current process in preparation of the day-ahead market run.
2. Day 2
   a. Before 10:00 monitor the intra-day gas prices and if gas prices are trending upwards, put internal processes and ISO markets on alert for potential update to the gas price index and delay in close of the day-ahead market.
   b. Approximately 10:00 – if the ICE index does not have prices that are greater than 125% of the previous night's, no change to current process and day-ahead market closes.
   c. Approximately 10:00 – if the ICE index has prices that are greater than 125% of the previous night's, proceed to:
      i. Notify participants of delay in day-ahead market close and suspend bidding temporarily
      ii. Update the gas price index used in default energy bids, proxy cost calculations, and generated bids
      iii. Notify participants that day-ahead market is open for (re)bidding and new time for close of the day-ahead market
      iv. Run optimization and publish awards

We note that the 125% proxy cap is on all costs, not just natural gas and that may create some overlap in cost accounting. However, the ISO's proposal aims to simplify the implementation and administrative burden of calculating the exact percentage for every resource and cost type.

The manual process approved in the tariff waiver also provides for comparing registered to proxy costs. Since the ISO proposes to eliminate the registered cost option, we will not retain this part of the process.

Lastly, stakeholders have asked for a permanent switch to use the ICE index. However, as the timing above shows, this would require a permanent shift in the day-ahead market process and is considered a major implementation impact. ISO continues to monitor broader industry discussions of aligning the gas and electric day that may result in a shift in the day-ahead market processes. Moreover, the use of a single gas price index is a departure from the current tariff and would require more detailed and careful consideration.

5.4. Opportunity costs for gas-fired use-limited dispatchable resources

In the Market Surveillance Committee opinion on the *Commitment Cost Refinements 2012* initiative, the committee members noted that it would be appropriate to consider opportunity costs for use-limited resources due to limitations upon starts and run-hours.[11] Use-limited

[11] http://www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf

resources include resources with environmental or significant operational limits.[12] While some resources are deemed use-limited, most apply for use-limited status by submitting a required use plan, which specifies the start, hours of operation, and energy generation limitations.[13] A concern expressed by the Market Surveillance Committee concerning reliance on bids submitted based on a required use plan is that such plans could result in inefficient use of a unit's limited starts, hours, or energy.[14] For instance, as wind penetration increases, the times at which such a unit would be optimally dispatched might occur more frequently during off-peak periods which cannot be anticipated by inflexible monthly use plans. It would be inefficient for use-limited units to withdraw themselves from the market during many hours in that manner. The MSC concluded that it would be more efficient to instead allow high start-up and minimum load bids that reflect opportunity costs of operation, which then gives flexibility to the market software to determine whether or not it is worthwhile to run the units. In addition, some stakeholders are concerned that the elimination of the registered cost option will limit their ability to reflect opportunity costs, even under the proposed 125% proxy cost cap. Though resource adequacy use-limited resources currently do not have a must offer obligation where the ISO inserts generated bids, they do need to bid into the ISO market in order to meet their availability requirements. Therefore, the ISO has been studying methods for inclusion of opportunity costs in bids so that these resources can bid into the market in all hours corresponding to their RA obligation, while being dispatched consistently with their use plan. A methodology to account for opportunity costs was introduced by the Market Surveillance Committee and discussed in other ISO initiatives.[15] In response to stakeholder concerns just mentioned, the ISO will consolidate the proposed opportunity cost methodology into this stakeholder process and explore application of it to gas-fired use-limited dispatchable resources first.[16] Though a full assessment is still needed, the ISO proposes to address this issue now because we believe it would have limited implementation impact and provides stakeholders the benefit of a phased approach to various market design changes as explained in the next section.

5.4.1. Coordination with other initiatives

The figure below captures at a high level the various market design elements that will impact resources that apply for use-limited status via a required use plan.[17] As the figure shows, the

[12] See Appendix A in the ISO tariff for the definition of use-limited resources.
[13] Based on tariff section 40.6.4.1, hydroelectric generating units, proxy demand resources, reliability demand response resources, and participating load, including pumping load, are deemed to be use-limited and therefore not required to submit a use plan.
[14] See Market Surveillance Committee meeting documents for November 15, 2013 available at: http://www.caiso.com/Documents/Presentation-MSC-FRACMOO_OpportunityCost-Hobbs.pdf. The opportunity cost methodology for use-limited resources was also discussed in the Flexible Resource Adequacy Criteria and Must-Offer Obligation initiative and was originally scheduled to be included in the Reliability Service initiative.
[15] *Op. cit.*
[16] This methodology may be expanded to other use-limited resources at a later time.
[17] Based on tariff section 40.6.4.1, hydroelectric generating units, proxy demand resources, reliability demand response resources, and participating load, including pumping load, are deemed to be use-limited and therefore not required to submit a use plan.

ISO proposes to eliminate the registered cost option that is currently available and replace it with a single proxy cost cap at 125% and complete developing the opportunity cost methodology in this *Commitment Cost Enhancements* initiative. The ISO intends to make the implementation changes in time for the winter season of 2014-215. On the other hand, the *Reliability Services* initiative will discuss must offer obligations for use-limited resources for a later implementation, no later than the beginning of 2016. The phasing of these design elements for use-limited resources helps incorporate an opportunity cost adder earlier and allows market participants to test and fine tune the calculation before affected use-limited resources have an expanded must offer obligation.

Figure 4
Design elements impacting use-limited resources

Initiative	**Current**	**Winter 2014-2015**	**Spring-Winter 2015**	**2016**
Commitment cost enhancements	Registered at 150%; proxy at 100%	Proxy at 125%; opportunity cost adder		
Reliability services				Must offer obligation

5.4.2. Opportunity cost methodology overview

The ISO has developed a unit commitment optimization model based on the proposed methodology presented by the Market Surveillance Committee to calculate the opportunity cost of each limitation. The model will optimally commit and dispatch each resource given its use-limitations and operational constraints against generation node-specific forecasted real-time prices over a given time period. The difference in profit from changes in dispatch due to each limitation will be the calculated opportunity cost.

The figure below provides an overview of the major components needed to calculate and utilize the opportunity cost estimates, including the inputs, calculation procedures, outputs, and the usage of the outputs. Under the "inputs" column, the optimization model will rely on use plans provided to the ISO, master file characteristics,[18] and applicable commitment and variable energy costs to provide a resource- and limitation-specific opportunity cost. This cost is based on calculating the profit (or gross margin) that is foregone in some future interval if one less start, one less operating hour, and/or one less MWh is available, as appropriate. In order for the model to calculate the profit, we will use historical implied heat rates, and recent natural gas and greenhouse gas prices to simulate a distribution of the node-specific locational marginal prices for the resource. For start-up and minimum load opportunity costs, the optimization model will

[18] The model accounts for each resource's minimum run time and minimum down time. It does not consider maximum daily starts if it has a start-up limitation in its use-limitation plan.

use these inputs to calculate the difference between the profits of two model runs: a base run, and run in which the start-up or run hour limitations are tightened by one unit. The difference in the objective function (the generating unit's profit) will be the opportunity cost of that resource's limitation. As noted under the "outputs" column, the model will provide for each resource a specific opportunity cost for each limitation it has over a specific period of time (*e.g.*, month or year). Lastly, the opportunity costs will be adders to the proposed 125% proxy cap, and can effectively increase the bid cap for these resources. This provides resources with the flexibility to reflect these costs but also manage the limitations through bidding.

Figure 5
Opportunity cost methodology overview

Model inputs	Optimization model	Model outputs
• Use plan limitations • Unit characteristics • Historical commitment costs • Historical implied heat rate • Natural gas prices • Greenhouse gas prices	Unit commitment optimization model over future time period (*e.g.*, month) based on simulated node-specific LMPs	Separate resource specific opportunity costs for start-up, minimum load, and energy, as appropriate. Will be provided as adders that effectively increases the bid cap for each specific opportunity cost, by resource

The proposed methodology will not be able to address every use-limitation but the methodology can be refined over time and tested well before there is a must offer obligation. For this coming winter, the ISO proposes to apply this methodology to all use-limited dispatchable natural gas-fired resources.

The subsections below will discuss each of the columns in Figure 5 in greater detail.

5.4.3. Model inputs

This section discusses resource characteristics and market inputs to the optimization model.

The ISO will rely on submitted use plans to determine the type of limitations that applies to each dispatchable, natural gas-fired use-limited resource. The ISO will also use master file characteristics such as the minimum load and maximum capacity of the resource. Due to modeling limitations, the ISO will not be able to model multi-stage generating resources at this time but seeks to improve our modeling capability. The variable energy cost will be based on the average heat rate and gas price index plus the O&M adder. For commitment costs, the ISO will use the prior month's proxy start-up and minimum load costs.

Scheduling coordinators will need to know their resource-specific opportunity costs for the month or year prior to the start of that period in order to reflect the costs in their bidding. Therefore the opportunity cost of each limitation will have to be calculated in advance of the time period based on simulated future prices that reflect past patterns and variability of prices, while being adjusted to reflect most recent price levels. The ISO will simulate real-time prices by determining an implied marginal heat rate for each location on the network having a use-limited resource based on real-time energy prices from the same time period the previous year. That is, each interval's and location's LMP is assumed to reflect the heat rate of some marginal unit, and that heat rate can be inferred from the prices of gas and emissions allowances at that time and place. This procedure will allow the implied heat rate to inherently capture real-time price volatility which will then be used to forecast prices for the current given time period. For example, if the ISO is estimating November 2013 prices, we will use November 2012 real-time energy prices, greenhouse gas costs, and daily natural gas prices. This will generate an implied heat rate for every real-time interval, which will then be used to forecast November 2013 real-time energy prices for a given resource.

Implied heat rate, $ImpHR_{i,t-1}$, will be determined as follows:

$$\mathrm{Im}\,pHR_{i,t-1} = \frac{LMP_{i,t-1}}{NatGasP_{l,t} + (GHGas_{t-1} * EmRate)}$$

Where

$\mathrm{LMP}_{\mathrm{i,t\text{-}1}}$	is the real time energy price at pnode *i* from the previous year's period, *t-1.*
$\mathrm{GHGas}_{\mathrm{t\text{-}1}}$	is the greenhouse gas allowance price from the previous year's period, *t-1*.
EmRate	is the emissions rate per MMBtu of gas, which is $.053165\mathrm{mtCO_2e/MMBtu}$
$\mathrm{NatGasP}_{\mathrm{l,t\text{-}1}}$	is the daily natural gas price from the region *l* of pnode *i* and the previous year's period, t-1

Once the implied heat rate is calculated, the simulated energy prices for the given time period can be determined. The implied heat rate will be multiplied by the average natural gas price of the preceding month.[19] To that, an estimated greenhouse gas cost will be added back in. Since unit commitment and de-commitment decisions are made based on the 15-minute real-time unit commitment process prices, the ISO proposes to use forecasted 15-minute real-time prices in the model, plus an adder.[20] The ISO proposes an adder of a 10% increase.

[19] Further analysis can be conducted on whether futures prices would be more appropriate or provide better visibility even though the prices would reflect limited daily volatility.

[20]The adder will be included to account for the difference in forward looking 15 minute prices, which are used to make commitment decisions, and the market binding 15 minute prices, and any other forecast error that may result in lower forecasted energy prices.

Simulated 15-minute real-time energy prices will be generated as follows:

$$LMPi,t = ImpHR_{i,t-1} * \left(NatGasF_{\ l,t} + (GHGasF_t * EmRate)\right) * 110\%$$

Where:

$LMP_{i,t}$	is the forecasted real time price at pnode *i* for interval *t*
$ImpHR_{i,t-1}$	is the calculated implied heat rate at pnode *i* from a base period, *t-1*
$NatGasF_{l,m}$	is the average natural gas price of the preceding month for region *l*
$GHGasF_{t,m}$	is the average greenhouse gas allowance price of the preceding month.
$EmRate$	is the emissions rate per MMBtu of gas, which is $.0530731\ mtCO_2e/MMBtu$

5.4.4. Optimization model

This section discusses the underlying methodology and how this is reflected in the optimization model.

An opportunity cost will be calculated for each limitation that the resource has defined in its use plan. All current limitations that will be modeled can be categorized as start-up, operation hours, or energy limitations. For start-ups and run hours, where the affected variables in the optimization are binary variables (0-1), the opportunity cost is calculated as the difference between the profits of two model runs: a base run, and run in which the start-up or running hours limitations are tightened by one (or more) unit(s). The difference in the objective function (the generating unit's profit) will be the opportunity cost of that resource's limitation. For MWh energy limitations, the optimization automatically yields a shadow price on that constraint, which is its opportunity cost. This is possible because that constraint is limiting continuous variables rather than binary variables. The following subsections will discuss the methodology for modeling each of these limitations.

5.4.4.1. Start-up limitations

Resources with limited starts will have a start-up opportunity cost calculated for the modeled time period, (*e.g.*, month, year). The ISO will conduct a base run of the profit maximizing model with all starts and calculate the total profits over the study time period. The ISO will run the model again with one less start. The difference in profits between the two runs is the opportunity cost.

Further analysis can be conducted on whether this basic approach is sufficient or if it is appropriate to use an average over more runs, because the calculated opportunity cost might be volatile. Take for example a resource with 15 starts per month. Three opportunity costs can be calculated. One based on the difference in profits with 15 and 14 starts; the second based on the difference in profits with 14 and 13 starts; the third based on the difference in profits with 13 and 12 starts. The average of all three opportunity costs will be the final calculated opportunity cost which can then be incorporated into start-up costs. Yet another methodology will average the difference in profits between 16 and 14 starts. The precise methodology can be refined with stakeholder input.

5.4.4.2. Run hour limitations

Resources with a limitation on operation hours per time period will have a run time opportunity cost calculated for the modeled time period, (*e.g.*, month, year). Similar to the start-up opportunity cost, the run time opportunity cost will be determined by comparing maximized profits from having all run hours to having one less run hour. As noted above, there may be modifications to this basic approach.

5.4.4.3. Energy generation limitations

Resources with a maximum generation level per time period will have an opportunity cost calculated for the last megawatt of generation. Since this is not a discrete decision in the optimization model, the shadow value on this constraint is the opportunity cost of the last megawatt. Therefore this will only require one model run. The shadow value on this constraint is in $/MWhs so this cost will be added on to the variable energy cost component used in calculating the default energy bid, shifting the entire curve upward by the $/MWh shadow value. Again, we propose to apply this methodology first to dispatchable, natural gas-fired use-limited resources.

5.4.5. Model outputs

The calculated opportunity costs will be an adder to the proposed 125% proxy cap for start-up and minimum load costs. Therefore the bid cap (calculated separately) for start-up and minimum load costs is: 125% of proxy cost plus opportunity cost adder. The scheduling coordinators will then be able to bid in start-up and minimum load costs up to the calculated opportunity cost associated with each limitation.

5.4.6. Initial results

The ISO has already developed and started testing models for several dispatchable gas-fired use-limited resources using the methodology described above. The price simulation and opportunity cost model methodologies were tested for two resources using 2013 as the forecasting year. Comparisons between the forecasted and actual 2013 energy prices are shown below, which is then followed by a discussion on the calculated opportunity costs using the 2013 forecasted prices.

5.4.6.1. Simulated future real-time prices

To determine how accurate the proposed methodology for simulating prices is, the ISO applied the methodology outlined above to simulate 2013 real-time energy prices, based on the implied heat rates for 2012. Two sets of prices were generated, one for a northern and for a southern node. The two price distribution charts below compare the simulated 2013 real time energy prices to the actual real time energy prices at the same nodes.

Overall, the methodology produced reasonable distributions for 2013 energy prices in both the north and the south. In both locations, there is a small percentage of hours (less than 5%) where the simulated price is significantly higher than the actual price. This is attributed to inconsistent congestion patterns from one year to the next. As explained later, the price simulation methodology uses the prior year's energy prices to calculate an implied heat rate. When congestion increases (or decreases) the prior year's energy prices, a higher (lower) implied heat rate is used to estimate the prices. If the same congestion pattern does not materialize in the forecasted time period, the forecasted prices can be higher (or lower) than actual market prices due to the higher (lower) implied heat rate used to forecast.

If the methodology was to systematically overstate or understate prices, this would possibly translate into biases in the estimated opportunity costs. For instance, for a unit with very tight restrictions on operations, the estimated opportunity cost might be based on prices in the hours shown in the figures below when simulated and actual prices diverge, as shown in Figure 7and Figure 10. The behavior of simulated and actual price distributions will be monitored to assess whether such systematic differences arise in the future.

Figure 6
North node: price distribution curves for 2013 real-time energy prices, all

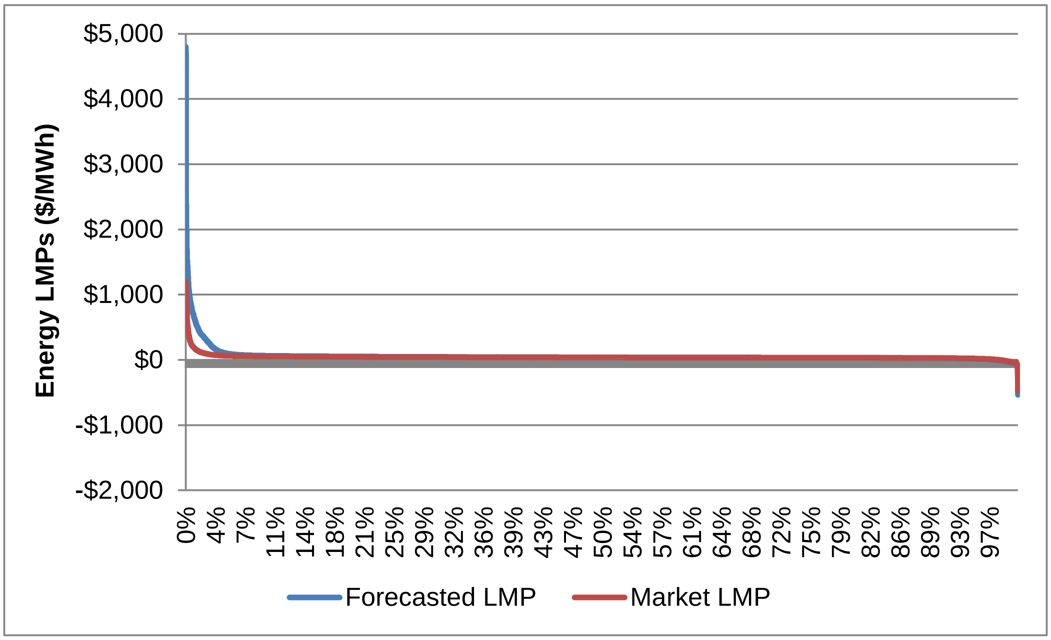


Figure 7
North node: price distribution curves for 2013 real-time energy prices, <5%

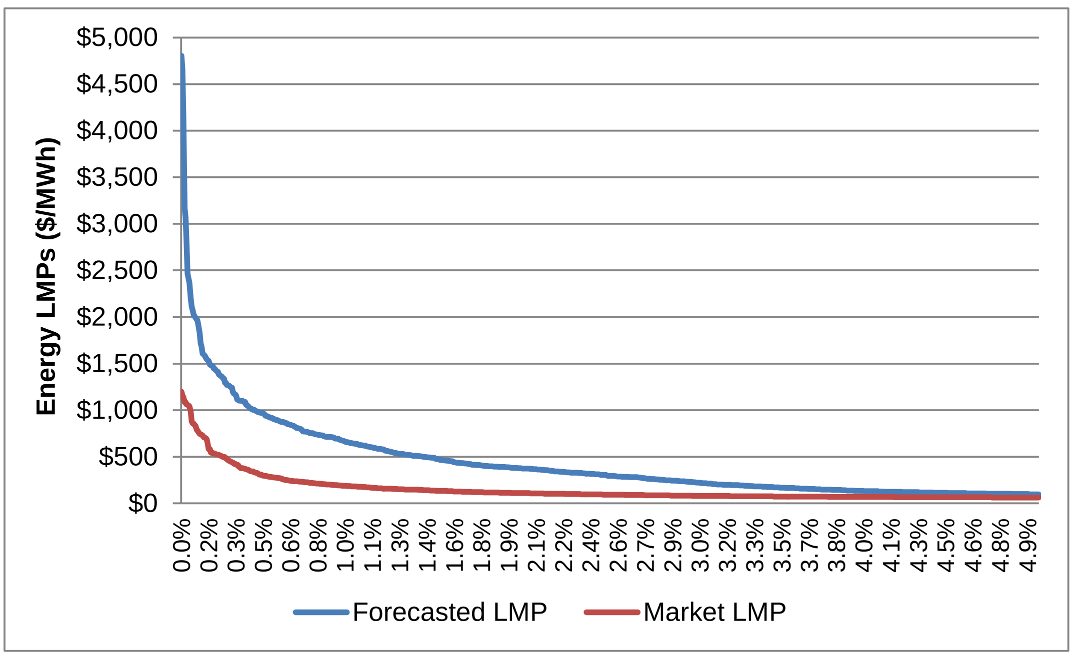


Figure 8
North node: price distribution curves for 2013 real-time energy prices, >99%

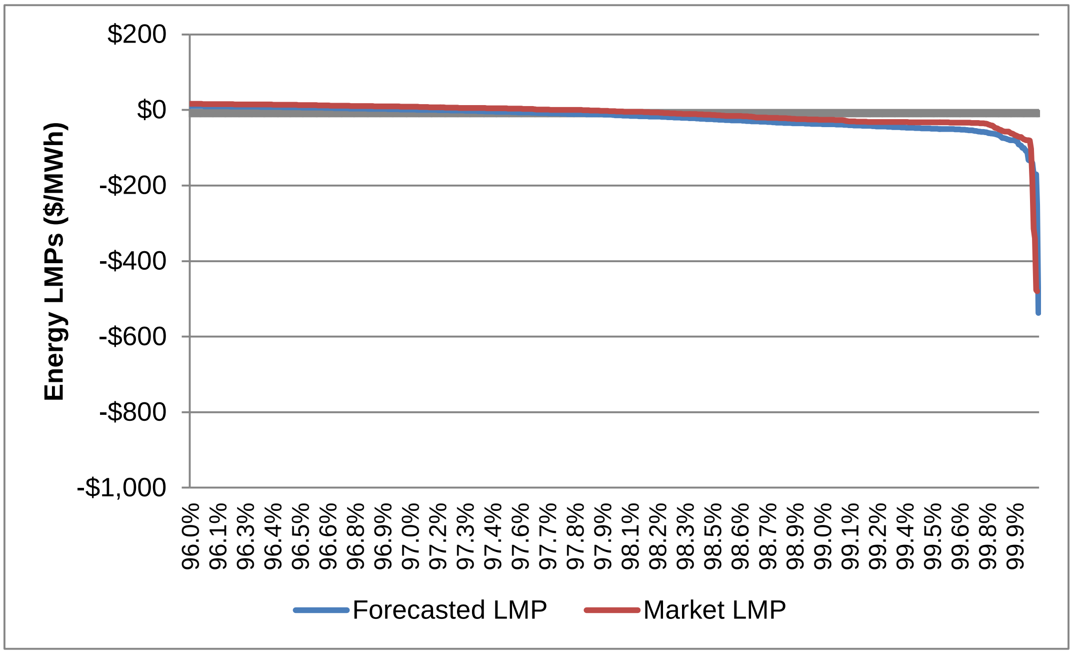


Figure 9
South node: price distribution curves for 2013 real-time energy prices, all

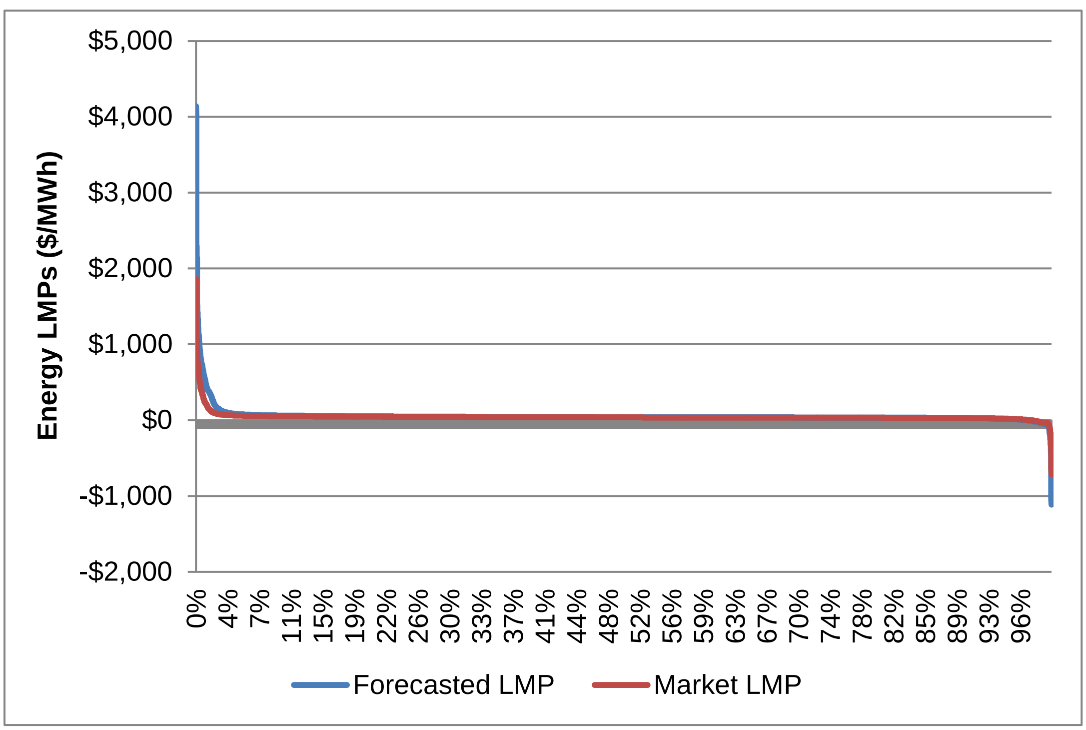


Figure 10
South node: price distribution curves for 2013 real-time energy prices, <5%

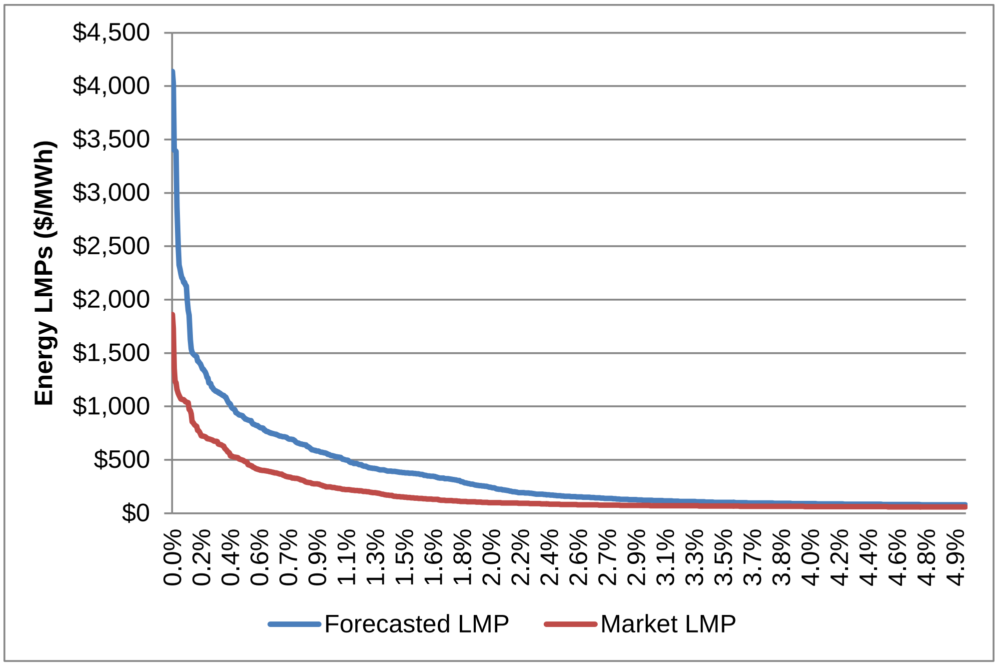
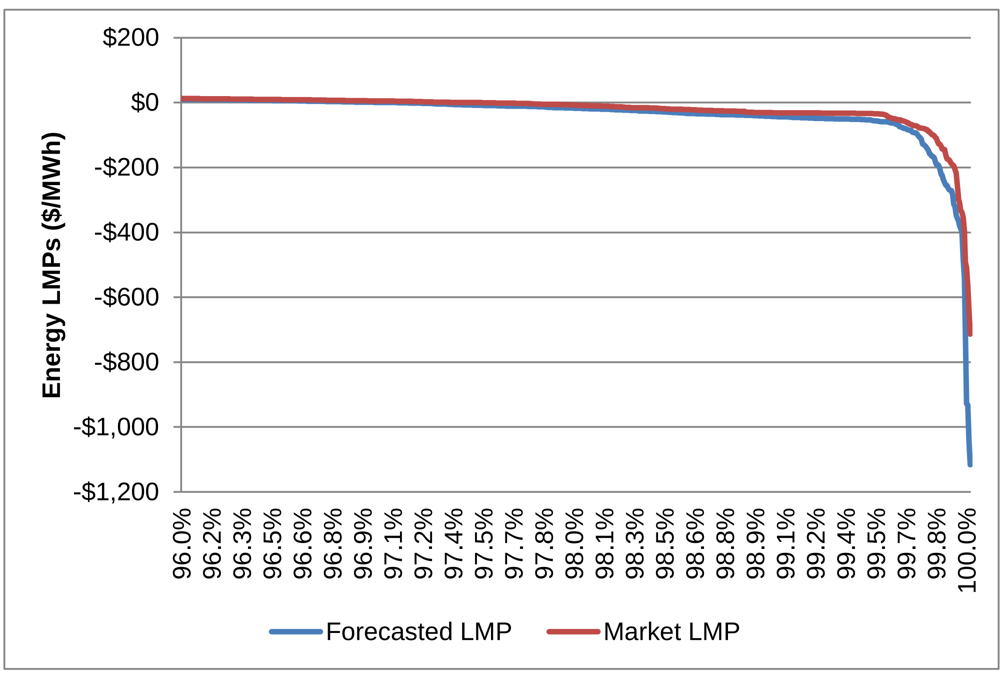


Figure 11
South node: price distribution curves for 2013 real-time energy prices, >99%



5.4.6.2. Opportunity cost calculation and back-casting

The ISO calculated the opportunity costs for five dispatchable, natural gas-fired use-limited resources. Of those, only two had opportunity costs and we provide below a back-cast for these units to compare how it would have been dispatched with and without the calculated opportunity costs. For Resource 1, we first assume that the resource has start-up and minimum load costs of 100% of proxy. This is a conservative assessment because this is more restrictive than the proposed proxy cap of 125%. We then calculated the opportunity cost of the resource's monthly limitations based on the 2012 implied heat rates and monthly natural gas and greenhouse gas costs per our methodology above. Resource 1 has both a monthly start-up and run hour limitation and each was analyzed separately.[21] Based on the generated real-time prices, there were opportunity costs for both limitations. As discussed in Section 5.4.6.1, simulated and actual real-time prices were very close but diverged slightly as the locational marginal prices were higher in 2012, likely due to higher overall congestion (see Figure 7 and Figure 10).

For the back-cast, we simulated two cases: one with and one without opportunity costs. In the first case, we removed the use limitations and we record the number of starts and run hours used when the resource is dispatched against actual 2013 prices, assuming it has a start-up and minimum load cost of 100% proxy and no opportunity cost. In the comparison case, we then rerun the model, this time adding the entire calculated opportunity costs for start-up and minimum load to 100% of their respective proxy costs.

The figure below compares the two cases for Resource 1 for every month. The data is presented as the percentage of starts or run hours to its respective limitation. For example, in column [1A] for January, the resource would have used 188% of the allowed starts. On the other hand in column [1C], the addition of the full opportunity cost for start-ups reduced the number of starts to 63% of allowed starts, showing that the calculated cost is providing enough flexibility to ensure the resource does not violate its use limitations. Similarly, the run hour percentages without opportunity costs under column [1B] are higher than the percentages under column [1D].[22]

Again, the opportunity cost is provided as a cap so the resource's scheduling coordinator can bid in lower start-up and minimum load costs to manage its limitation. In this case, the scheduling coordinator would likely lower the start-up and minimum load costs below the level allowed, assuming it was behaving competitively.

[21] The actual number of starts and run hours are not provided to protect the confidentiality of the resource.
[22] Note that the simulation to calculate run hour limitation opportunity costs produced non-zero values in only some months. However, all of the percentages in column [1B] in Figure 12 are below 100% because dispatch was lower using 2013 actual real-time prices than simulated 2012 real-time prices.

Figure 12
Resource 1: sample comparison of opportunity cost impact

	100% Proxy cost only		100% Proxy cost with opportunity cost	
	Percent of start-up limitation used	Percent of run hour limitation used	Percent of start-up limitation used	Percent of run hour limitation used
	[1A]	[1B]	[1C]	[1D]
Jan	188%	24%	63%	11%
Feb	338%	50%	100%	26%
March	225%	31%	25%	4%
April	325%	53%	13%	3%
May	250%	47%	38%	23%
June	100%	17%	0%	0%
July	138%	19%	0%	0%
August	275%	61%	25%	7%
September	150%	21%	0%	0%
October	313%	51%	63%	29%
November	150%	29%	13%	1%
December	225%	43%	25%	6%

Repeating the process for Resource 2, the data in the figure below show very similar results to Resource 1 with a few notable exceptions. First, the percent of start-ups used in column [2C] exceeds 100% in the first three months. Since our analysis is conservatively based on only 100% of proxy plus opportunity costs, the percentages would likely change to below 100% if the proposed 125% proxy cap was used. However, if this was a condition change in the market, this may be an example of when an intra-month rerun is appropriate. Second, the percentages for run hour limitations used in column [2D] for March and December are higher than the percentages for the same months in column [2B]. This difference can be explained by the interplay between start-ups and run hour limitations in the optimization. For these months, and in fact for other months as well, the calculated opportunity cost was zero for run hour limitations but non-zero for start-up costs. Since the start-ups were more binding, the unit commitment in the rerun case with opportunity costs decided to keep the unit online to avoid having to incur the high start-up costs again. This results in greater use of the allowed run hour limitation in the rerun case. Nonetheless, the percentages are all below 100%

Figure 13
Resource 2: sample comparison of opportunity cost impact

	100% Proxy cost only		100% Proxy cost with opportunity cost	
	Percent of start-up limitation used	Percent of run hour limitation used	Percent of start-up limitation used	Percent of run hour limitation used
	[2A]	[2B]	[2C]	[2D]
Jan	150%	50%	105%	47%
Feb	110%	41%	105%	40%
March	155%	55%	110%	58%
April	115%	35%	40%	25%
May	85%	46%	35%	19%
June	55%	37%	40%	23%
July	105%	50%	30%	27%
August	105%	87%	80%	67%
September	110%	46%	85%	45%
October	125%	58%	90%	50%
November	85%	41%	45%	26%
December	105%	63%	30%	72%

5.4.7. Additional considerations for the optimization model and process

The ISO is improving its current prototype. The model currently can reflect monthly limitations and we expect to be able to expand that to an annual optimization as well. The model currently will not be able to reflect multi-stage generators and we have not modified the model to reflect other opportunity costs or other generation types. We will consider additional improvements at a later stage.

The ISO is currently proposing to run the model on a monthly basis. More frequent updates are anticipated if certain significant changes occur such as: the resource's usage differs appreciably from what was projected in the model run; if energy or fuel prices deviate appreciably from what was assumed in the original model run; or there are resource changes that affect the model output such as changes reflected in the master file or use plan. Note that not all significant changes may trigger a rerun. For example, if natural gas prices are lower than what was modeled (and therefore reduces market prices and costs), the ISO may not need to rerun the model since the calculated opportunity cost will be provided as a bid cap. Therefore, the resource could bid lower to manage its use limitations.

6. Maintaining existing processes and topics for further consideration

To the extent possible the ISO would like to maintain existing processes and practices such as:

- Daily bidding remains available under proxy costs.

- No change in proxy bids between the day-ahead and real-time, *i.e.*, a single minimum load or start-up cost will be used for the Trade Date.
- Maintain use of the natural gas price indices in the day-ahead and real-time optimizations.
- This proposal does not automatically modify any negotiated costs such as major maintenance adders. However, opportunity costs for dispatchable, natural gas-fired use-limited resources may be replaced by the proposed methodology.
- No *ex post* cost verifications for costs within the 125% proposed proxy cap

The ISO seeks to improve its commitment and dispatch and ensure on the whole that resources are appropriately compensated for their costs. We believe that the ISO's proposal provides this balance. Some stakeholders have noted that additional consideration is needed for the recovery of intra-day gas costs.[23] Since we cannot implement any real-time bidding functionality for this winter, some stakeholders have suggested that the ISO can reimburse the scheduling coordinator for intra-day gas costs incurred. This is not ideal since it would undermine efficient market dispatch. However, the ISO reiterates its request for more data in order to make an informed judgment. Some stakeholders have provided limited data (*e.g.*, intra-day gas costs for the gas price spike day of February 6, 2014) to show that some intra-day gas costs are particularly high. However, the ISO would like more comprehensive data such as:

- What were the intra-day gas prices and costs incurred by units that had a real-time-related commitment (*e.g.,* real-time only commitment to minimum load or real-time exceptional dispatch) versus the gas price index? Note the ISO is seeking actual costs incurred versus simply the intra-day gas prices. We prefer the data to be provided for at least a year to analyze trends and overall impact to the resource.
- How would the increased bid cap be considered with out-of-market intra-day gas cost recovery? For example, should the proxy cap be reduced to 100% for any resource that also receives this type of cost recovery? The ISO would also propose that the costs be considered in bid cost recovery.
- What happens when natural gas prices are lower in the intra-day than day-ahead?
- Who would be responsible for validating out-of-market intra-day gas costs? Aside from real-time-related commitments, when else would recovery of out-of-market intra-day gas costs be allowed or under what specific conditions?
- Would recovery of out-of-market intra-day gas costs discourage hedging (either financial or physical)?
- Would the overall FERC effort to align the electric and natural gas days help to alleviate the stakeholder concerns about intra-day gas price volatility and illiquidity?

The ISO would appreciate more comprehensive data in order to engage in an informed discussion. At this point, we have some evidence that intra-day costs can be higher than during

[23] The ISO limits this discussion to intra-day commodity costs.

the timely and evening nomination cycles but we do not know the extent to which this impacts stakeholders over time.

7. Topics for the bidding rules initiative

The ISO will start a more comprehensive bidding rules initiative in Q3 2014. In this initiative we expect to discuss topics that cannot be adequately addressed here such as:

- Reflection of intra-day natural gas costs (either through greater bidding flexibility or directly invoicing for certain gas costs) and the market rules and implementation changes needed to support it;
- Expressing support for breaking up the current three-day weekend gas “package” into separate Saturday/Sunday and Monday packages; and
- Creating a process to periodically review the cost cap to ensure that it still enables headroom for market participants to accurately reflect their natural gas costs.

8. Next Steps

The ISO will discuss this straw proposal with stakeholders during a call to be held on June 17, 2014. Stakeholders should submit written comments by July 1, 2014 to ComCosts2@caiso.com.