Opinion on
Commitment Cost Enhancements

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Chair
Shmuel S. Oren, Member

Members of the Market Surveillance Committee of the California ISO

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1. Introduction and Summary of Recommendations

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the proposed enhancements to the procedures used to calculate start-up and minimum-load costs for electricity generators.[1] Under the CAISO's current market design, accurate estimation of these commitment costs by the CAISO is important to ensure efficiency of market operations and to avoid the exercise of market power. The ISO uses these estimated costs to cap the offer prices that are used to commit generators in its market operations, so accurate estimates are needed to ensure that the least-cost mix of resources is committed and available for dispatch. Furthermore, accurate estimates are needed because underestimated costs would impose losses on generators that might discourage generators from offering into the market because their market revenues might then fall short of their costs and raise the cost of resource adequacy procurement. Finally, overestimation of commitment costs would enable generators possessing local market power to inflate their offer prices, potentially impacting energy prices and/or bid cost recovery payments.

The price spikes and volatility experienced in the natural gas market in the winter of 2013-2014 made plain a limitation of the CAISO's procedures for adapting its commitment cost estimates to changing conditions. During days when gas prices rose sharply, the lags in updating commitment costs inherent in the current design caused the CAISO to use values in its market software that substantially underestimated actual costs, reflecting much lower natural gas prices than were actually being experienced at those times. At the same time, price offers for variable energy above minimum load, which generators lacking locational market power are free to vary in response to gas prices, instead reflected the actual (higher) expense of gas. As a result, day-ahead market schedules were distorted, as the market software would dispatch numerous generators at minimum load, which the software erroneously viewed as inexpensive, and avoided taking the higher (and more realistic) offers for energy above minimum load. Because of the inherent inef-

[1] CAISO, Commitment Costs Enhancement, Revised Draft Final Proposal, Aug. 21, 2014, www.caiso.com/Documents/RevisedDraftFinalProposalCommitmentCostEnhancements.pdf

ficiency of operating units at minimum-load, these schedules actually resulted in more gas being consumed than necessary to meet load, exacerbating already tight gas market supply conditions.

Thus there was a clear and immediate need to revise the commitment cost estimation procedure to reduce those lags and the potential inefficiencies that can result. The CAISO therefore filed proposed tariff waivers with the Federal Energy Regulatory Commission that were granted on March 14 and 21, 2014, respectively.[2] These waivers requested, respectively, that the CAISO be permitted to use updated gas price data for settlement purposes when those prices for a trading day were 150% or more of the gas price calculated pursuant to the ISO's tariff, and that the CAISO be allowed to use those updated data for market execution as well. In those waiver filings, the CAISO also committed to a stakeholder process to develop a more comprehensive approach to addressing the need for more accurate and timely commitment cost estimates. The proposal now under consideration is the result of that process.

The elements of the proposal include:

- An increase in the proxy cost cap from 100% to 125% of estimated cost, based on a pair of one day-prior gas price indices, to provide more flexibility for commitment cost offers to reflect varying costs.
- Deferral of implementation of an opportunity cost estimation methodology for limited-use natural gas units, pending further refinement and review of the methodology.
- Retain the registered cost option, which fixes the commitment cost caps for the month based on 150% of expected proxy cost for that period, on an interim basis for use-limited gas-fired resources only. Non-use-limited resources will be required to use the proxy cost option, and the ISO intends to eliminate the registered cost option for all resources once the opportunity cost methodology can be implemented.
- Retain the manual process for modifying gas prices based on a single same day gas index for the day-ahead market, triggered when a region's gas prices rises to 125% or more of the previous night's value. The proposal will also automatically switch units that use the registered cost option to the proxy cost on the day of a price spike if the manually updated proxy cost is higher than the registered cost. The switch is only active for the duration of the spike, in particular only during the days that the manual process is used.

The MSC has considered the issue of commitment cost estimates several times over the last decade, issuing its last opinion on the topic in May 2012.[3] In that and previous opinions,[4] we em-

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[2] *California Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,184 (2014), www.ferc.gov/CalendarFiles/20140314150817-ER14-1442-000.pdf, and *California Indep. Sys. Operator Corp.*,146 FERC 61,218 (2014), www.ferc.gov/CalendarFiles/20140321152127-ER14-1440-000.pdf

[3] Market Surveillance Committee of the California ISO, "Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement", May 7, 2012, www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf

[4] Market Surveillance Committee of the California ISO, Comments on Changes to Bidding Start-Up and Minimum Load, July 16, 2009, www.caiso.com/Documents/FinalOpiniononStart-

phasized that procedures for estimating and updating commitment costs have to balance the need for responsiveness to changing fuel and other costs, while limiting opportunities to take advantage of local market power to recover inflated as-bid levels of these costs. We have kept this need in mind in the process of developing the present opinion. Since the events of February 2014, the issue of commitment cost enhancements has been discussed in public meetings of the MSC on March 11, May 19, and August 22, 2014. In addition, the MSC has participated in several stakeholder calls and discussions with ISO staff.

Based on our review of the ISO proposal, stakeholder input, and our review of experience with similar problems in the eastern ISOs, we have reached the following conclusions about the elements of the ISO proposal:

- In general, the proposal for calculating commitment costs is reasonable from the standpoint of what can be implemented prior to this coming winter. Increasing the proxy cost calculation used to cap start-up and minimum load offers to be 125% of the calculated cost will reduce the frequency and extent to which the offer prices of suppliers lacking market power will be mitigated below the supplier's incurred commitment costs. This change in the cap will reduce the likelihood of inefficient outcomes that could adversely impact electric or gas system reliability.

- In general, resources with significant use-limitations need to either implement use plans or manage their use through commitment cost offers. We strongly prefer using such offers for this purpose, since the timing of the system's need for the resources is becoming less predictable as renewable penetration increases. The ISO's goal of developing, testing, and implementing an opportunity cost calculation methodology for use-limited natural gas units is very important, and we encourage the ISO to do so, if possible, prior to the summer of 2015, and if not, as soon as feasible thereafter.

- Because it will not be possible to implement explicit calculation and inclusion of opportunity costs in the ISO's commitment cost estimates before the winter of 2014-2015, the ISO has proposed retention of the registered cost option for use-limited units. We have considered that option and a number of alternatives, and none is fully satisfactory from the point of view of being cost reflective, providing flexibility, and protecting against market power. We conclude that, as a temporary expedient, allowing limited-use units a registered cost option based on 150% of the projected average proxy cost is an acceptable means of providing flexibility in the near term prior to implementation of the opportunity cost estimation methodology. However, we suggest an alternative approach below that in our view has advantages over the proposed temporary fix.

While the retention of the registered cost option for use-limited units is acceptable, we note that there are several advantages to instead eliminating the registered cost option and capping the of-

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UpandMinimumLoadBiddingRules.pdf; Market Surveillance Committee of the California ISO,Opinion on Changes to Bidding and Mitigation of Commitment Costs, June 4, 2010,www.caiso.com/Documents/FinalOpiniononChanges-BiddingandMitigation-CommitmentCosts.pdf fers of use-limited resources at 150% of proxy costs. There are two advantages of the latter alternative over retaining the registered cost option include the following. First, there will be efficiency benefits of greater responsiveness to changing gas prices. Second, this alternative may be simpler to implement since it eliminates the need for switching from the registered cost option to the proxy option on high gas price days, as described above, and it will facilitate the sun-setting of the registered cost criterion, which is the ultimate goal of the ISO (once an opportunity cost methodology is implemented).

We acknowledge that relative to the ISO's recommended registered cost alternative, our 150% proxy alternative for use-limited units may have some disadvantages, although we cannot assess whether they are likely to be significant or not. One disadvantage is that the 50% mark-up might allow more exercise of market power during periods when the gas price is high. The second and third disadvantages are a possible concern only if the proxy alternative would be more attractive to use-limited units (or gas units that would consider declaring themselves use-limited) than the registered cost option. The second possible disadvantage of our alternative is that beneficiaries of the proxy alternative might have an increased incentive to pressure the ISO to delay implementation of the opportunity cost method, if they believe that they would earn less once the opportunity cost method is in place. The third possible disadvantage of our alternative is that it might make use-limited designation more attractive to gas-fired units that don't actually have significant opportunity costs; if more units then declare themselves to be use-limited, then the flexibility available to the market and operators would diminish. This is because the ISO submits bids for non-use-limited resources providing resource adequacy capacity but does not do so for capacity for use-limited resources. We are uncertain of the extent to which these issues would be more of a problem for our alternative than for the ISO's proposal.

Given the urgency of having the enhancements in place prior to this winter, we will defer to the ISO's recommended course of action regarding the registered cost option if considering our proposed alternative might cause a delay in implementation, either because of software change requirements or the need for further review by stakeholders. We note that the ISO's proposed enhancements are an appreciable improvement over the system in place last winter, and it is crucial to have these enhancements implemented by the coming winter season.

Some market participants have argued for higher caps on minimum load and start-up bids to account for major maintenance costs that the ISO has ostensibly inappropriately disallowed from being included in a generator's commitment costs (the ISO market has provisions to explicitly account for these costs.) In the longer term, the ISO should continue to improve its methodology for including major maintenance costs in proxy commitment costs to better reflect costs, while continuing to ensure that only costs that vary with starts or hours of operation, not fixed costs, are included, and that the included costs are reflective of actual maintenance costs.

Finally, we conclude that the various problems involved in estimating those start-up and minimum load costs for the purposed mitigation are to a degree unavoidable when mitigating resources that possess locational market power, but the impact of errors in estimating these costs is magnified when commitment cost mitigation is applied to all units all the time without regard to whether they even potentially possess market power. This raises the question as to whether the mitigation of commitment costs within the ISO's local market power mitigation system can be limited to resources that potentially possess market power. A fundamental challenge is that, unlike Conduct-and-Impact market power mitigation systems, as used in ISO-New England, the New York ISO, and MISO,[5] identification of generators who are exercising market power by increasing start-up and minimum-load costs is less easily accomplished in the CAISO LMPM system. This is because the CAISO system is based instead on identifying non-competitive paths and assessing the marginal effects of generators located in different locations upon those paths, and these marginal effects do not account for commitment costs.

In the following sections, we detail our analysis of the ISO proposal. In Section 2, we outline some general issues in estimating commitment costs. Section 3 summarizes our assessment of the need to develop and implement a methodology to estimate opportunity costs for use-limited gas units. In Section 4 we evaluate the registered cost proposal for use-limited gas units, as well as our suggested alternative. Our evaluation of the appropriate percentage to cap offers in the proxy cost option is in Section 5. We express our support for the manual process to update gas prices in Section 6. Finally, in Section 7, we summarize the experience of other ISOs with commitment cost estimates. The trends there since 2000 have been to remove restrictions on changes in offer prices and allow additional flexibility in offer prices.

2. Costs and Cost Indices

Commitment costs represent two bid components that allow the bidders to specify the cost of generating their minimum load and the cost associated with start-up. These costs enter into the day-ahead and real-time unit commitment decisions made by the ISO. However, they are not directly remunerated unless energy revenues (day-ahead revenues in the case of resources committed in the day-ahead market, and real-time revenues in the case of resources committed in real-time including RUC) are insufficient to cover them, in which case they are used to determine the bid cost recovery payment (BCR). The ISO tariff caps the commitment costs with the objective of striking a balance between allowing bidders to recover legitimate costs while curbing the potential exercise of market power.

At present, however, these caps are applied to all bids whether or not the bidder actually has market power. Daily gas prices represent a substantial and at times highly variable and unpredictable component of commitment costs, which are not known to the CAISO at the point in time in which the commitment costs caps are calculated. Hence, the caps on these cost calculated by the ISO are based on estimated gas prices. According to the existing tariff, resources can choose one of two options for estimating gas prices:

[5] J.D. Reitzes et al., Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets, Sept. 14, 2007, www.brattle.com/system/publications/pdfs/000/004/868/original/Review_of_PJM_Market_Power_Mit_Sep_14_2007_Final.pdf?1378772136

- the "proxy cost" option, which is adjusted daily based on the gas price for the prior day, as reported by at least two natural gas indices, or
- a "registered cost" option which is locked for a month and is capped at 150% of the projected average proxy cost for the month, calculated based on a forward gas price for the month. The 50% head room is intended to accommodate forecast error and a variety of other costs discussed below that are associated with start-ups.

In its latest draft proposal, the ISO has proposed to modify the "proxy cost" option by raising the cap from 100% of the daily calculated commitment costs to 125% of the calculated proxy cost based upon two gas price indices for the cost of gas flowing on the day prior to for which the proxy cost is calculated.[6] The previous ISO proposal also indicated an intent to eliminate the "registered cost" option in order to make the commitment cost prices more reflective of up-to-date gas prices.[7]   However, because of the inability to implement an opportunity cost methodology for use-limited resources (ULRs) prior to the winter of 2014-2015, it is now proposed that the existing "registered cost" option remain available for use by ULRs until the opportunity cost methodology is put in place, with an added feature of automatic switching to the 125% proxy cost on designated price spike days if that yields a higher gas price estimate.

Both the 25% headroom on proxy cost and the 50% in the registered costs calculation serve to accommodate potential underestimation of a variety of start-up and other commitment-related costs and gas prices, including:

- GHG cost error due to differences between GHG cost indices and the actual price of purchased allowances
- Gas price error due to the one day lag in gas price indices
- Gas price error due to intraday gas price volatility
- Uncertainty in imbalance penalties on gas supply due to intraday dispatch decisions
- Start-up and minimum load-related variable O&M costs, including major maintenance costs

Some of these costs are included in the proxy cost calculation in accordance with the CAISO 2012 Commitment Cost Refinement.[8] Furthermore, most uncertainties regarding the GHG market have been resolved. However, the allowed headroom provides a margin to accommodate errors in measuring these cost components.

Some stakeholders' comments propose that mis-estimation of start-up and minimum load costs be compensated for through *ex post* bid cost recovery when those costs are underestimated due to gas price volatility, particularly intraday gas price variability. We agree with the ISO that such *ex*

[6] California ISO, Commitment Cost Enhancements, Revised Draft Final Proposals, August 21, 2014, p. 7.

[7] California ISO, Commitment Cost Enhancements, Draft Final Proposals, August 12, 2014, section 5.2 pp. 10-13

[8] California ISO, Draft Final Proposal, Commitment Costs Refinements 2012, April 11, 2012, www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf

post calculation might be very burdensome for the ISO. More importantly in our opinion, market efficiency requires that such costs be reflected in offers and in the resulting commitment decisions and market prices, not recovered out of market uplift. On the other hand, we agree with stakeholder comments arguing that certain cost components, particularly major maintenance cost, vary among resources and to the extent possible should accurately reflect each resource's actual costs.

With regard to errors in measuring commitment costs due to intraday gas price volatility and the one day lag of the gas price indices, the ISO provided statistical evidence that the 25% headroom has generally been sufficient over the last several years to cover most of the gas price estimation error associated with such gas price variability.[9] In order to address the days with large gas price changes when the 25% headroom will likely not be sufficient, the CAISO proposes a manual override of the proxy cost cap on commitment costs on days when the gas price, in any region, increases overnight by more than 25%. The manual override involves a delay of the day-ahead market and use of only one price index, the Intercontinental Exchange (ICE) gas price index to determine the gas component of the proxy cost for that day. The CAISO should explore whether such an approach would be a viable long term approach to the goal of employing more up to date gas price information in the day-ahead market.

Major maintenance costs (MMCs) continue to be a contentious issue due to lack of sufficient engineering data to validate contractual start-up related maintenance charges. Further, maintenance contracts can be complex, and it is not straightforward to identify and separate the fixed and variable components of these costs. The registered cost option provided headroom to allow resources to recover additional MMC in their start-up cost bids. To the extent that those resources are also ULRs, the extension of the registered cost option will continue to be available to resolve this issue. However, we recommend that the CAISO improve the representation of MMCs. Furthermore, if a generator possesses local market power, its incentive to negotiate lower MMCs might be increased under a more transparent process for review and approval of MMCs.

Opportunity cost is an important component of start-up cost that gives use limited resources the ability to control the use of a unit's limited starts, energy, and/or hours through economic bids. The absence of such control leads to inefficient dispatch, for example the burning up of too many starts early in a season. We further discuss this issue below. The temporary retention of the registered cost option with 50% headroom above the expected proxy cost or alternative temporary adders we discuss for ULRs, should continue to allow sufficient headroom for resources to reflect their self-determined opportunity cost in their start-up bids. However, there are alternative approaches that could better utilize the new proxy-cost framework, discussed in Section 4, below.

[9] See California ISO, Commitment Cost Enhancements, Revised Draft Final Proposals, August 21, 2014, pp. 7-9.

3. Opportunity Cost Method

Use-limited resources have historically rationed their limited starts, run-hours, or energy primarily through limiting the periods for which they bid into the ISO markets consistent with use plans that specified the limitations of committing and dispatching these resources. However, as more renewables enter the system, the times when such resources would best be used has become increasingly unpredictable, and it is preferable that the ISO market be given the flexibility to call on those resources at any time of need. This can be accomplished, while respecting the use limits, by increasing commitment cost or energy bids (in the case of limited starts/hours or energy, respectively) to reflect the opportunity cost of using a resource in a given interval rather than conserving the starts/hours/energy for a later time. We understand that some operators of use limited resources have used the registered cost option to allow them to reflect their estimate of opportunity costs in their start-up or minimum load cost bids.

Opportunity costs are difficult to estimate, depending as they do on the probability distributions of relevant energy prices over the relevant time period (usually a month or season) and operating limitations of the resource. If all local markets were competitive, the ISO could rely on competitive forces to incent resources to submit offers that reflect their best estimates of opportunity costs, which has the additional benefit of providing information to the market about market parties' expectations for future prices. However, the presence of market power together with the present lack of a methodology for the ISO to estimate opportunity costs means that the ISO would not be able to distinguish high commitment cost offers that are based on the resource owner's estimate of opportunity costs from high offers that are an attempt to exercise market power.

In order to permit limited-use resources (especially gas-fired resources) to include opportunity costs in commitment cost offers while restraining the exercise of market power, the ISO has proposed to estimate the opportunity costs of limits on starts, run-hours, and energy output through a procedure that allocates them over a month or other period in a way that maximizes anticipated net revenues to the resource. This can be done through an optimization procedure that considers possible trajectories of prices and how the resource would be committed and dispatched against those prices. The optimization can then be re-run with fewer or more starts and run-hours in order to assess the loss of net revenue that would occur if one more start or run-hour is consumed, and this would represent the resource's marginal opportunity costs. The optimization also automatically calculates the marginal net revenue of additional energy, in the case of energy-limited plants.

There are a number of theoretical and practical complications involved in this computation, including what distributions of prices to use, the computational burdens of considering real-time prices for 15 minute intervals, the treatment of multiple use-limitations as well as more complicated limitations such as the Delta dispatch limits, and the impact of forecast uncertainty on actual operations. The ISO has proposed a relatively practical approach that should yield reasonable estimates. However, the ISO has concluded, based on stakeholder comments, that more development and review is required before implementation.

We support the development of a defensible opportunity cost estimation methodology and the incorporation of those estimates in proxy costs in order to promote more efficient and flexibility operation of use-limited resources. We look forward to cooperating with the ISO in this development process, and recommend that the process be completed rapidly.

4. Registered Cost Option

Perhaps the most contentious aspect of the proposal has been the availability of a registered cost option as an alternative method for setting commitment costs. Traditionally concerns with market power have been dealt with one of two ways. First, bids have been restricted levels relatively close to estimates of actual costs "proxy costs," and allowed to fluctuate with an index of natural gas prices. It has been the gaps in this proxy cost calculation that have driven the need for this initiative.

The second method for limiting market power in commitment cost bids has been to restrict how frequently such costs could be adjusted. This is known as the registered cost option in the ISO process. Firms are allowed more freedom to set their offer levels, but are not allowed to adjust those offers for at least one month. This restriction has been aimed at preventing the exercise of locational market power by adjusting commitment cost bids based on market conditions. For example, absent a restriction, a firm could bid cost-reflective commitment costs during very competitive periods, but if there were a transmission or generation outage, that firm could significantly raise (or lower) these bids in conjunction with energy bids to exercise market power during those few less competitive days. However, we note that if any generating unit with a significant amount of capacity above its Pmin can, in effect, lower its minimum load bid by providing a zero or even negative bid for the first few MW above its Pmin. The ability to adjust offer prices up and down in this manner dampens the disincentive to register a high minimum load cost.

The CAISO has in the past applied the reasoning that restricting the ability to adjust bids to market conditions can mitigate market power, particularly in response to unexpected transmission or generation outages.[10] These measures can be costly in terms of efficiency, however, if the underlying costs are rapidly changing. Under those conditions, rigidities in the offer prices prevent firms from adjusting their offers in response to increases in their costs. Therefore restrictions on adjustments to offer prices are most appealing in circumstances where demand may be changing frequently but costs are relatively stable.

In practice, the registered cost option has been utilized by many plants, in some cases apparently because the automatic adjustments in the proxy costs do not adequately capture the variation in their actual costs. One of the major culprits in this mismatch between indexed and actual costs is use-limitation constraints. The costs of these constraints are based upon the opportunity cost of using up these limited resources (starts, run-hours, or energy).

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[10] See "Comments on Changes to Start-up and Minimum Load Bidding Rules," California ISO Market Surveillance Committee, April 2009, www.caiso.com/Documents/FinalOpiniononStart-UpandMinimumLoadBiddingRules.pdf .

Ideally, these opportunity costs would also be included in a proxy costs and allowed to vary along with gas costs. However, these opportunity costs are plant specific and much more difficult to design an appropriate proxy cost for, in large measure because they depend upon expectations for future prices. The CAISO explored implementing an opportunity cost methodology in this proposal but decided to defer doing so pending further development and stakeholder review of the methodology.

Absent a value for opportunity cost element in the proxy cost, some stakeholders believe that there is at times insufficient headroom under the 125% cap to capture these opportunity costs for use-limited resources. In response to these concerns, the ISO has decided to recommend retention of the registered cost option for use-limited resources. This would allow these resources to submit an offer price up to 150% of measured proxy costs, but would require those resources to maintain that offer at a constant level for one month.

This option is far from ideal, but we see no obviously better near-term solution. The concern is that plants possessing market power will be able to raise their start-up and minimum load costs by an additional 25%, while plants lacking market power will be unable to reflect their actual costs in their offer prices when gas prices rise materially during a month.[11] A plausible alternative to the registered cost option is a condition, applicable only to use-limited resources, that would allow them to bid up to 150% of proxy costs, rather than the current 125% cap.[12] The main difference between the current proposal and this option would be that use-limited plants could adjust their bids much more frequently than under the registered cost option.

The advantage of the relaxed proxy-cost cap would be to allow units better align their offers to costs. This disadvantage is that it would also give units possessing locational market power more latitude to use commitment cost offers to exercise that market power. We are not in a position to adjudicate the proper balance of this trade off. However, according to data provided to us by the CAISO, there are approximately 6500 MW of gas-fired capacity currently classified as use-limited in the system, of which about two-thirds has opted for the registered cost option. It is reasonable to expect that some of these plants would be in a position to exercise market power in at least some market conditions.

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[11] Although, as noted in a previous footnote, offering a low or negative price for a few MW above the Pmin means that there is actually little risk of being stuck with a too-high registered minimum load cost.

[12] Another option would be to retain the structure of the proxy-cost option, but allow only use-limited units to combine it with an added “registered” opportunity cost that would be fixed for 30 days. This opportunity cost adder would be capped at 25% of the expected value of proxy costs. In this way, all gas units would have the bulk of their costs indexed to gas prices, but those use-limited units would have the ability to specify an added opportunity cost that would remain fixed over 30 days. A disadvantage of this option is that it is more complex than the 150% proxy cost alternative. The market software changes that would be required by this option mean that it would not be possible to implement this option for the coming winter. Thus, it would only be feasible in the longer-term, should there be delays in implementing the opportunity cost methodology planned by the ISO. Further, in effect, it would not greatly restrict the ability to vary commitment cost bids because only a small portion of the commitment costs would be restricted by this adder.

The above suggested options which retain the 125% proxy cost for all resources with added temporary headroom for ULR could simplify the implementation by eliminating the need for the proposed automatic switching of resources from the "registered" option to the "proxy" option on price spike days if the 125% of proxy exceeds the registered cost. Furthermore, since the ultimate CAISO objective is to phase out the registered option, it is better to do it now.

We recognize that introducing the new option of a 150% proxy for ULR at this late stage could delay implementation of this and other important measures included in the proposal, which are needed before the winter high gas cost season. We also recognize the concern that the options we suggest might make use-limited designation more appealing for gas-fired resources that presently lack that designation and would request the use-limited designation under this other approach. Because such designation would remove the ability of the ISO to automatically insert bids for the resource as part of its must-offer obligation, increasing the amount of use-limited capacity would lessen the flexibility available to the market and operators.

5. Percentage Headroom for Proxy Costs

The 25% margin over estimated proxy costs employed by the CAISO proposal is necessarily imperfect. The 25% margin would allow the exercise of market power by those that have market power when gas prices are accurately measured by the index, but constrain offers to be less than costs when gas prices change substantially from day to day or between day-ahead and real-time in the case of units committed during the operating day. The California ISO's straw proposal for calculating commitment costs is therefore not perfect but is reasonable from the standpoint of what can be implemented prior to this coming winter:

- Increasing the proxy cost calculation used to cap start-up and minimum load offers to 125% of the calculated cost will reduce the frequency and extent to which the offer prices of suppliers lacking market power will be mitigated below the supplier's actual gas costs.
- This change in the cap will reduce the likelihood of inefficient outcomes which could adversely impact electric or gas system reliability.

These changes will not be adequate in the long-run, however, and the California ISO needs to continue moving forward to implement additional changes.

- A 125% cap based on the proxy cost will at times overstate costs and enable suppliers possessing market power to raise their offer prices and potentially receive additional uplift payments or energy market revenues.
- On the other hand, a 125% cap based on the proxy cost may not be large enough to cover all variations in gas costs nor to cover the start-related costs or opportunity costs of all resources.

6. Manual Process to Update Gas Prices

The proposed changes go a long way towards achieving the goal of making commitment costs caps more reflective of actual costs and of up-to-date gas prices. However, they do not entirely solve the problems that led to the February 6, 2014 events that triggered this initiative. There is still a one day lag between the gas market index prices used to determine commitment costs and the price of gas purchased to supply power scheduled in the electricity day-ahead market. Furthermore, this gas price index price is also disconnected from the cost of gas purchased during the operating day by units committed in real-time. As a result of this lag, sudden large spikes in gas prices cannot be accounted for in the commitment cost caps used by the ISO in its day-ahead and real-time markets and the magnitude of these spikes can exceed the headroom in the proxy cost calculation. Fortunately, such events have been relatively rare in recent years and it is possible that they will continue to be rare outliers.

However, these events will likely recur and there is no assurance that they will be as rare has they have been in recent years. For this reason, the ISO proposes to address the potential for such occurrences by requesting a continuation of the FERC waiver which allows for a manual override during price spike days. The current ISO proposal characterizes such days as instances in which morning gas prices exceed the prices reported the night before for trading during the prior day by 25% or more. The ISO will monitor the gas prices reported each evening between 19:00 and 22:00 Pacific time for trading during that day and prices in the gas market the following morning before 10:00 Pacific time to detect such occurrences. On such gas price spike days, the CAISO will use a single ICE index that is available slightly after 10:00 am Pacific time to determine if it indicates prices of 125% or more of those reported the previous evening in any ISO area, in which case the manual override process will be triggered. Such an override will involve delaying the close of the day-ahead market, updating the proxy costs using the ICE index for that day and notifying participants that the day-ahead market is open for rebidding.

While such a manual procedure is not ideal, it will address the need for using up to date gas prices when the one day lag in the gas price used to calculate commitment costs is unacceptable, and it will prevent commitment and dispatch anomalies such as the February 6 event. Furthermore, implementing any alternative solution that would allow better coordination between the day-ahead market and gas market would require major system changes that are infeasible in the short run. However, in the long run, the ISO should evaluate the possibility of permanently shifting the closing of the day-ahead market to a later time, the use of a single gas price index, or other changes that could facilitate coordination between gas markets and day-ahead electricity market. We understand that these kind of issues are being considered by FERC under the gas-electricity proceeding that is currently underway.[13]

[13] See Order Initiating Investigation into ISO and RTO Scheduling Practices and Establishing Paper Hearing Procedures, March 20, 2014, 146 FERC ¶61,202 and Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, March 20, 2012, 146 FERC ¶61,201

7. Lessons from Other ISOs

The eastern ISOs face similar problems of gas price volatility resulting in inaccurate commitment cost estimates, and they handle the issue in a variety of ways summarized below. The trend in these markets since 2000 has been uniformly in the direction of removing restrictions on changes in offer prices and allowing additional flexibility in offer prices.

ISO New England. ISO New England's LMP market implemented in March 2003 limited changes in minimum load and start-up cost offers to specified periods twice a month. [14] The inability of gas fired generators in New England to submit offer prices reflecting their actual start-up and minimum load costs was likely the reason that most or all of the 2327 megawatts of capacity that declared on economic outage during the January 2004 cold snap did not offer their supply in the day-ahead market. [15] As a result, the rule prohibiting changes in start-up and minimum load costs except during these two periods was eliminated as part of the settlement agreement in Docket ER05-508-000, filed September 8, 2005,[16] being replaced with the current rule which permits daily changes.[17]

ISO New England's market design also requires that offer prices be the same over all hours of the day and only permits changes in offer prices between the day-ahead market and real-time in the re-offer period following the posting of day-ahead market results.[18] This rule is due to be eliminated this winter, bringing the New England market design in line with the California ISO, MISO and New York ISO designs in this respect.

PJM. PJM's single settlement LMP market implemented in April 1998 limited changes in price (i.e., market) based minimum load and start-up cost offers to every six months. PJM also requires resources to submit "cost" based bids. [19] Similar to the California ISO, PJM allows these minimum load and start-up offers based on cost, as measured by a specified formula, to change daily in accord with that formula.[20]

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[14] See ISO New England Manual for Market Operations, Manual 11, February 5, 2003 section 2.5.3 (12) p. 2-11.

[15] ISO New England, Market Monitoring Department, "Final Report on Electricity Supply Conditions in New England during the January 14-16 2004 'Cold Snap'," October 12, 2004 .

[16] See Market Rule 1, Section III.H.3.4(c)(ii)(5)

[17] See ISO New England, Manual for Market Operations, M-11, revision 15 December 2, 2005, Section 2.5.3 (12) and subsequent revisions. ISO New England has a variety of rules regarding these changes, such as a requirement that offers used to commit a resource remain in effect over the duration of its minimum run time.

[18] See ISO New England Manual for Market Operations, Manual 11, October 6, 2013, Section 2.5.3 (7), (11), (13), and (15) pp. 2-15 to 2-16.

[19] PJM Energy and Ancillary Services Market Operations, Manual 11, January 21, 2014, Section 2.3.3, p. 16.

[20] Ibid.

These cost-based offers are determined by the market participant in accord with PJM Cost Development Guidelines.[21] The methodology used to calculate cost-based offers may be changed no more than once per 12 months, subject to review by the PJM market monitor.[22]

PJM's market design also requires that offer prices be the same over all hours of the day. Like ISO New England, the PJM design only permits changes of offer prices between the day-ahead market and real-time in the re-offer period following the posting of day-ahead market results.[23]

PJM's restrictions on offer price changes make it impossible for gas fired generators to adjust their offer prices during the operating day to manage their gas supply or to reflect the cost of buying gas in the intra-day market. These restrictions have likely contributed to the high level of outages due to "lack of fuel" that the PJM market monitor has noted in recent years.[24]

PJM's restriction to a single offer price over all hours in the day-ahead market may seem innocuous because gas is nominally purchased on a daily basis. However, in practice this restriction causes problems scheduling gas when the gas pipeline system is constrained for the following two reasons.

- The electric day spans two gas days, which can have differing market conditions when gas pipeline daily balancing requirements are in effect.
- When gas pipelines are enforcing hourly takes, the actual delivered cost of gas will likely vary from hour to hour because obtaining gas to meet load over the peak hours will require buying gas delivered in other hours that would have to be resold or used later at a loss.

Mid-Continent ISO. The MISO provides considerable flexibility in offer prices:

- Start-up cost offers can change daily.[25]
- Energy offer curves and no load costs can change hourly.[26]

New York ISO. The New York ISO has allowed resources to change their start-up and minimum load offer prices from day to day since its start-up in November 19, 1999.[27]

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[21] PJM Cost Development Guidelines, Manual 15, August 1, 2013, Section 2.3, p. 9.

[22] Ibid.

[23] PJM Energy and Ancillary Services Market Operations, Manual 11, January 21, 2014, Section 2.3.3, pp. 15-16.

[24] Monitoring Analytics, 2013 State of the Market Report for PJM, Vol. 2 March 13, 2014 p. 192; 2012 State of the Market Report for PJM, Vol. 2, March 14, 2013 pp. 163-165.

[25] See MISO Energy and Operating Reserve Markets Business Practices Manual, Exhibit 4-10, pp. 82-83, Feb 4, 2014, Section 4.2.3.2.4, p. 88.

[26] Ibid.; also Section 4.2.3.2.1, pp. 85-86.

- Start-up and minimum load offer prices can also vary over the hours of the day. This flexibility is most often used to reflect the cost of starting units with multi-hour minimum run times late in the day. It can also be used by cogeneration resources to reflect the cost of changes to their normal operating schedule.[28]
- However, minimum generation bids and start-up costs cannot be increased in real-time above the day-ahead market offer for any hour in which the resource received a day-ahead market schedule.[29]

Since November 19, 1999 the New York ISO has allowed offer prices for incremental energy to vary from hour to hour and has allowed resources to raise their offer prices on capacity not scheduled in the day-ahead market in real-time, with offer prices submitted 75 minutes prior to the start of the operating hour.[30]

Beginning on October 1, 2010, the New York ISO also allowed resources to raise their energy offer prices in real-time for capacity that was scheduled in the day-ahead market.[31]

- There are a variety of rules governing the calculation of bid production cost guarantees when offer prices are raised.
- There are a variety of rules regarding the submission of virtual bids by market participants controlling resources that raise their offer prices in real-time.

In parallel, the New York ISO implemented changes basing real-time offer price mitigation on gas prices submitted by the market participant.[32]

At the end of June 2014 the New York ISO implemented rules changing the way offer prices mitigation is applied to units in the day-ahead market.[33]

- Offer price mitigation is now based on a gas price submitted by the market participant;
- The submission of inaccurate fuel cost information is subject to penalties.

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[27] See New York ISO Services Tariff Attachment D.

[28] Ibid.

[29] See New York ISO Transmission and Dispatching Operations Manual, October 2012, Section 5.1.1, p. 52.

[30] Ibid.

[31] See Docket ER10-1977, July 26, 2010

[32] See Docket ER10-2062, July 30, 2010

[33] See New York ISO April 17, 2014 filing in Docket ER14-1735-000 and FERC letter Order of June 27, 2014.