Opinion on
Commitment Cost Bidding Improvements

by

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I. Introduction

Electric power generation costs are characterized by nonconvexities, such as minimum load operating points and costs, start-up costs, and prohibited zones of operation. As a result, clearing prices in the California ISO markets do not always fully cover the as-bid costs of all generators, even when they are selected as part of the least-cost market solution. In the ISO market design, and indeed all organized U.S. markets, generators are allowed to submit offers that include commitment costs and prohibited zones, and the market operator will make side-payments if clearing prices would not cover the as-bid costs of a unit whose offer is accepted.

Because of the potential for local market power that would allow generators to submit and recover as-bid commitment costs that are well in excess of actual costs, or to use high bids to withhold capacity from the market, these offers need to be subject to some form of market power mitigation. In some ISO markets (the New York ISO, MISO and ISO New England), the commitment cost bids of market participants are subject to mitigation based on a variety of triggers, in which the bid submitted by the market participant will be replaced by a bid determined by the ISO.[1]

An important feature of the ISO's market design is that all commitment cost bids are subject to a bid cap determined by the ISO, without regard to the application of a market power test (which is similar to the design in PJM). The set of rules that govern what categories and levels of commitment costs can be included in generator offers is therefore an important element of the ISO market design. These rules must simultaneously address two goals. One is to allow for recovery of reasonably incurred operating costs, including opportunity costs that arise if use limitations mean that committing and dispatching a generator now could reduce its availability at later times. Achievement of this goal would encourage generators to be available when the system most needs them. The other goal is to protect the market from the potential for market power to be

[1] Some of these markets, such as the New York ISO, also have rules providing for market participants to be made whole through uplift payments in the event that inappropriate market power mitigation causes a resource to be uneconomically committed or dispatched.

exercised by a seller overstating its commitment costs or imposing unwarranted restrictions on operating parameters.

We have been asked to review the ISO's commitment cost enhancement proposal, which combines two initiatives, the Commitment Cost Enhancements Phase 3 (CCE3) proposal[2] and the Bidding Rules Enhancement (BRE) proposal.[3] These initiatives address a number of specific features of the commitment cost bidding rules. One feature concerns the definition of what costs are considered in defining bid caps; the CCE3 proposal would implement a procedure that would quantify opportunity costs associated with use limitations, and then add those costs to the caps applied to commitment costs and energy bids. The CCE3 proposal also responds to the Federal Energy Regulatory Commission (FERC) rejection of the redefinition of which generator use limitations qualify for opportunity cost treatment that the ISO proposed in the Commitment Cost Enhancements Phase 2 initiative.[4] Finally, the CCE3 proposal would make changes to several Masterfile resource characteristics and outage card procedures. Meanwhile, the BRE proposal has several features. One of them concerns offers for resources lacking a day-ahead schedule; the proposal would allow them to rebid commitment costs in the real-time market, while no longer automatically inserting bids for such resources which do not have a real-time market offer obligation. The second feature is intended to provide a safety valve in case the commitment cost bid caps do not fully cover incurred fuel costs, by giving resources a right to file for recovery of those costs by filing at FERC. A third feature concerns the gas prices used in the caps, and would allow for more flexible registration and improved formulation of fuel regions, as well as addition of greenhouse gas cost credits to base gas transportation rates in those regions. Finally, the BRE proposal would adjust how the cost of electricity consumed in start-ups costs is calculated. The overall intent of the changes proposed by the CCE3 and BRE initiatives is to improve the CAISO's calculation of commitment costs so that commitment cost bids will better reflect actual resource costs, including the opportunity costs associated with limits on resource starts, emissions or run times, while still effectively mitigating the potential for the exercise of market power.

The Market Surveillance Committee (MSC) has considered the Bidding Rules and Commitment Cost Enhancement proposals in several recent public MSC meetings, including July 15, Oct. 20, and Dec. 11, 2015 and Feb. 11, 2016. Prior to those meetings, previous ISO initiatives addressing commitment costs have been discussed at several MSC meetings and addressed in MSC

[2] CAISO, "Commitment Cost Enhancements Phase 3 Draft Final Proposal," Feb. 17, 2016, www.caiso.com/Documents/DraftFinalProposal-CommitmentCostEnhancementsPhase3.pdf

[3] CAISO, "Bidding Rules Enhancements Generator Commitment Cost Improvements, Draft Final Proposal", Feb. 10, 2016, www.caiso.com/Documents/DraftFinalProposal_BiddingRulesEnhancementsGeneratorCommitmentCostImprovements.pdf

[4] CAISO, "Commitment Costs Enhancements, Phase 2", Draft Final Proposal, Feb. 9, 2015, www.caiso.com/Documents/DraftFinalProposal_CommitmentCostEnhancementsPhase2.pdf ; FERC Order, Docket No. ER15-1875-000, Sept. 9, 2015, www.ferc.gov/CalendarFiles/20150909162131-ER15-1875-000.pdf

opinions.[5] These issues have also been discussed in many meetings between ISO staff and individual MSC members over the past several years.

In this Opinion, we focus our comments on three general issues addressed by the CCE3 and BRE proposals. The next section (Section II) summarizes our recommendations concerning those general issues, and the subsequent sections present detailed discussions of each. The first general issue is the definition of use-limits and the calculation of opportunity costs arising from those limits (Section III). The rationale for including opportunity costs in bid caps is reviewed in Section III.A, followed by a discussion of the role of contracts in defining those limitations in Section III.B. In Section III.C, we consider the ISO's proposal for calculation of opportunity costs and their inclusion in commitment cost bid caps. The particular calculation procedures have important implications for a resource's availability to energy and resource adequacy markets later in the year, as well as for possible penalties a resource might incur under the Resource Adequacy Availability Incentive Mechanism (RAAIM). In Section III.D we discuss the possible roles of RA revenues and penalties in opportunity costs. The second general issue we examine in this opinion is the general philosophy of how market power in commitment cost bidding is to be detected and mitigated (Section IV). The third and final issue we address is the proposal that generators can file for cost recovery at FERC if commitment cost payments fail to adequately cover fuel costs (Section V).

II. Summary of Recommendations

We summarize the recommendations from Sections III-V as follows:

Use Limitation Definitions

- We support the need for restrictions on the kind of limitations used in calculating opportunity costs for new resources or resources provided under newly signed contracts. However, we think the ISO should show some flexibility in its application of such restrictions as the distinction between a contractual limitation and a physical or permit limitation can be subtle.

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[5]These include:

- J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, "Final MSC Opinion on Reliability Services Phase 1 and Commitment Costs Enhancements Phase 2," Mar 23, 2015, www.caiso.com/Documents/Final_MSC_Opinion_ReliabilityServicesPhase1_CommitmentCostsEnhancementsPhase2-Mar2015.pdf
- J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, "Final MSC Opinion on Commitment Cost Enhancements," Sept. 8, 2014, www.caiso.com/Documents/MSC_FinalOpinionCommittmentCostEnhancements-Sept2014.pdf
- J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, "Opinion on Mitigation Measures for Bid Cost Recovery," Dec. 5, 2012, www.caiso.com/Documents/FinalOpinionBidCostRecoveryMitigationMeasures.pdf
- J. Bushnell, S. Harvey, B.F. Hobbs, and S. Oren, "Opinion on Bid Cost Recovery Mitigation Measures and Commitment Costs Refinement," May 7, 2012, www.caiso.com/Documents/MSCFinalOpinion-BidCostRecoveryMitigationMeasures_CommitmentCostsRefinement.pdf

- We support allowing units operating under existing contracts approved by the CPUC to include negotiated use limitations in the calculation of opportunity costs through a transition period. We would not object to expanding the transition period beyond three years.

Opportunity Cost Calculations

- As we have stated in previous opinions,[6] we strongly support the inclusion of opportunity costs in commitment cost and energy bid caps to replace use plans and ad hoc limits on resource availability. Inclusion of those costs will maximize the availability of resources to the market at the times they are most needed and will also maximize the flexibility that the system operators have to determine when those resources are committed and used.

- The opportunity cost calculation procedure proposed by the ISO has necessarily made some simplifications with the objective of ensuring that timely calculations and updates are feasible. Improvements to the proposed calculation procedures are possible, such as the consideration of RA costs discussed in the next conclusion. However, it is very important to implement opportunity cost-based caps as soon as practicable to ensure that operators have access to flexible resources when needed. Therefore, we believe that while advance testing of the methodology is needed, the opportunity cost calculation procedure should be implemented and then later improved as desirable and feasible adjustments to the procedure are identified. We support the ISO's proposal to evaluate the procedure's performance as experience accumulates, and to consider improvements such as fine-tuning of the 90% factor applied to limitations in the model and the frequency of cost updates.

- One improvement that may need to be considered in the future concerns resource adequacy (RA) opportunity costs. Resource opportunity costs should ideally include revenues that would be foregone in all energy, ancillary service, and resource adequacy markets. Excluding RA revenues may understate opportunity costs, which can cause overuse of a resource early in the year, and suboptimal availability later. However, determination of the correct RA opportunity costs is very difficult, given the lack of transparency in California's RA markets, and the complex relationship between RA revenues/RAAIM penalties, the number of remaining starts, operating hours, or energy, and use limitations.

  There are two features of the proposal that lessen the risk that imperfections in the initial opportunity cost calculations will cause units to prematurely run into a limitation. The first is the proposal that the opportunity cost calculation consider only 90% of the use-limitation, which will tend to increase opportunity costs. The second is the interim availability of the option of an outage-card to manage starts if a resource begins to use up starts too quickly After experience is gained on how well the new opportunity cost feature improves the efficiency of managing use-limitations, the ISO may need to modify

[6] Ibid.

the opportunity cost calculations to include appropriate estimates of RA revenues/ RAAIM penalties.

- Resources with a use-limitation should be encouraged to ration the use of their limited starts, run hours or energy to the times when they are most valued, and if they are unavailable in a given month when they are committed to providing RA, they should have a strong incentive to arrange replacement capacity. Thus, if the resource has been bidding commitment costs below the ISO opportunity cost-based cap, and if the resource then uses up enough of the use limitation such they are unavailable for RA at a later time, they should be exposed to RAAIM penalties unless arrangements for substitute capacity are made. If they bid consistent with the opportunity cost-based cap calculated by the ISO, but errors in the ISO's initial opportunity cost calculation cause the resource to be started too often, then we believe that there should be a mechanism to correct the overuse before the load serving entity (LSE) becomes subject to RAAIM penalties as a result of flaws in the ISO calculations that prematurely used up resource starts.

  We understand that the ISO proposes to address this possibility by allow scheduling coordinators to fall back to using short-term outage cards to limit resource use if the ISO opportunity cost proves too low to prevent overuse of the resource. This option will provide a balance among the needs to incent the resource to find replacement capacity, to follow ISO operating instructions, and to be able to use the resource to provide RA during the months that the resource is most needed in the event that imperfections in the opportunity cost calculations would cause the resource to use up too many of its limited starts, run hours, or MWh while following ISO instructions. Therefore, if this situation is observed to occur often, we recommend that that the RAAIM system be modified so that a portion but not all of the RAAIM penalty be waived if a resource no longer qualifies for RA because it has used up all of its use-limitation while bidding its full opportunity costs, as estimated by the ISO.

After the Fact Filing for Cost Recovery

- The ISO's proposal for after the fact cost recovery is an improvement on the current situation and would be an appropriate policy if the mechanism will very rarely be applied. It will not be an adequate policy if it turns out that market participants need to rely upon it to recover their costs in other than highly extraordinary circumstances.

Mitigation of Market Power

- One way for the ISO to reduce the potential for situations in which market participants need to rely on after the fact cost recovery would be to develop a mechanism to identify units potentially committed to manage congestion on local transmission constraints. This could then limit the application of commitment cost mitigation to such units and other resources committed out of market by ISO operators on a non-market basis.

III. Opportunity Costs

A. The Need to Include Opportunity Costs

Market power mitigation of the type used in US spot markets for electricity is premised on the ability of the ISO and market monitor to estimate variable production costs of generators with some degree of accuracy. Fuel costs are the easiest component of incremental production costs to quantify, but even estimating those can be challenging, as events in California showed in February 2014, when gas prices were high and volatile, as they were earlier during the Western power crisis. Non-fuel operations and maintenance costs are more difficult to precisely estimate, especially for wear-and-tear expenses. More difficult yet to estimate are opportunity costs, which arise when committing and operating a generator now means that fewer start-ups, running hours, or MWh will be available later in the day, month, or year.

The classic example of a resource with opportunity costs is a hydroelectric plant with significant storage; unless the reservoir is full and spilling water, using water to generate power today means that less water is available tomorrow. Analogous energy limitations can arise for certain types of environmental permits or under some types of fuel contracts. In those cases, the variable cost is not the price of fuel (which is free for hydro), but the expected revenue foregone by not generating at some other time. Environmental permits and maintenance contracts can also limit the number of starts or running hours over a period of time. If there is some probability that such a constraint will become binding, then there is an opportunity cost associated with starting up and or running a plant now, in the form of reduced revenues from not using that start or running hours later instead.

These opportunity costs can be large, and if disregarded, the result can be overuse of a use-limited generator, with the generator running out of starts, hours, or MWh before it is most needed. Efficient market operation requires that the use of limited starts, hours, or energy be allocated to the highest value periods. The ISO has previously relied on owners of limited-use resources to manage their limitations by providing use plans and making the resource available only at times specified by the resource. However, as the ISO recognizes and we have pointed out in previous opinions,[7] relying on the resource to guess when system conditions are best for committing a resource will be an increasingly difficult and intolerably inefficient means of rationing the operation of these use limited resources. This is because increased penetration of variable energy sources, including the California's goal of 50% renewables by 2030, will make it more difficult to predict when system net peaks will occur and when fast ramping resources will be needed.

The ISO foresees the need for flexible resources to offer their supply in the market at all times they might be needed. In order to manage the use-limitations of these resources without restricting their availability as under use plans, the ISO proposes to allow resources to make commitment cost and energy offers that reflect their opportunity costs. If resource offer prices reflect their opportunity costs, the ISO will have a rational basis for deciding whether a start, operating

[7] "Final MSC Opinion on Commitment Cost Enhancements," op. cit.

hour, or MWh is more valuable to the system now, or saved for later use. We agree with this philosophy of managing use limitations, as we have stated in previous opinions,[8] and believe that it will lead to much more efficient use of use-limited resources if opportunity costs are adequately approximated.

The CCE3 proposal for treatment of opportunity costs has three broad components that we will comment on. The first is the definition of use-limitations, in particular whether contractual limitations, as opposed to physical or regulatory limitations, should be recognized. The second is the opportunity cost calculation procedures themselves. The third is the treatment of resources whose limited starts, hours, and/or energy are used up early in the year, leaving them exposed to RAAIM penalties if they have been contracted as RA.

B. Definition of Use Limitations and Treatment of Contractual Limits

One challenging issue considered in the CCE3 stakeholder process has been the development of the definition of use-limitations that would be recognized in the opportunity cost calculations and commitment cost caps. The ISO's proposed definition of use-limited resources is as follows:

> *"A resource with one or more limitation on starts, run-hours, and/or output due to environmental restrictions or design considerations, which cannot be optimally dispatched over the limitation horizon without consideration of opportunity costs.*
>
> *"Acceptable environmental restrictions are those that are imposed by regulatory bodies, legislation, or courts... Acceptable design considerations are those that are due to physical equipment limitations. A non-exhaustive list of acceptable design considerations include: restrictions documented in original equipment manufacturer recommendations or bulletins, or limiting equipment such as storage capability for hydroelectric generating resources...*
>
> *"Limitations accepted by the ISO must originate from restrictions imposed by external regulatory bodies, legislation, or courts, or due to the design of the resource. They cannot be purely contractual, such as a monthly start limitation that is well below any binding environmental limit, based on economic decisions such as staffing requirements or maintenance cost tradeoffs (e.g., to avoid catastrophic maintenance events)..."*[9]

Presently, use limits are not captured in the proxy cost calculations used to determine commitment cost bid caps, and unit owners have had to try to capture such limits in two ways. One is through a potentially higher but less flexible "registered" cost. The other is through use plans filed by the resource owner that specify which hours a unit would be available, and do not give the ISO the flexibility to commit the unit outside of those times. However, with increased renewable penetration, the times when a unit is needed to meet net load peaks or ramps is more difficult to predict, and the ISO needs that flexibility, as we have pointed out in previous opin-

[8] Footnote 5, supra.

[9] CCE3 Draft Final proposal, op. cit., Section 5.2.

ions.[10] Therefore, under the CCE3 proposal, commitment bid caps will now include estimates of the opportunity cost of the commitment and dispatch of a unit that has use limitations, as well as a limit of 125% of proxy costs. Conceptually, this is a much better way to try to account for such limits. In summary, the proposed ability to bid opportunity costs flexibly is an improvement upon the present reliance on use plans and the inflexible registered cost option, and it will complement the provision of the Reliability Services Integration Phase 1 initiative that is to be implemented this summer that restricts the ability of flexible RA resources to use use-plans to limit the hours in which they can be started and dispatched.[11]

The ISO desires to restrict such limits to verifiable physical and regulatory limits. However, in response to stakeholder input, the ISO has proposed one exception to its stated principle that limitations cannot be purely contractual:

> "*Conventional resources that, as of January 1, 2015, are on an original long-term contract individually reviewed and approved through a comprehensive regulatory process as a new build which evaluated cost implications on rate payers with a limitation on starts, run-hours, or output, will be eligible for an opportunity cost reflective of such limitation, provided sufficient supporting documentation is provided, for up to three years following the effectiveness date of opportunity costs as determined through CCE3.*"[12]

In this section, we focus our discussion on this exception.

A major concern with allowing contractual limitations to be reflected in opportunity cost calculations is the possibility that such contractual limitations could significantly but needlessly limit the flexibility available to the system if those limitations do not reflect physical and regulatory limits, resulting in higher system costs. Another concern is that contractual limitations could be used strategically as a means to circumvent market power mitigation. Under the ISO's proposed opportunity cost-based cap, contractual limitations that are significantly more restrictive than regulatory or design limitations would, in general, increase calculated opportunity costs. By including such contractual limitations in opportunity cost calculations, an RA unit would be able to enter into an RA contract that would be approved by the CPUC or other local regulatory authority and meet the CAISOs local or system capacity requirements for flexible capacity but could so limit the resource's operation that it could, in effect, be able to avoid its must-offer obligation. This outcome would be possible because the contractual limits would require it to bid higher opportunity-cost based commitment costs into the market. This could result in economic withholding of the unit from the market and potentially higher profits through the exercise of market power, if committing that unit is the lowest cost way to relieve a frequently binding transmission constraint.

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[10] "Final MSC Opinion on Commitment Cost Enhancements," op. cit.

[11] CAISO, "Reliability Services," Draft Final Proposal, Jan. 22, 2015, www.caiso.com/Documents/DraftFinalProposal-ReliabilityServices.pdf.

[12] Ibid., Section 5.3.1.

We also understand that many contracts have been entered into with limits on starts designed to reduce the cost of the maintenance contract, and thereby reduce to cost of the RA to the LSE by reducing the frequency with which major maintenance costs were incurred. Hence, such contracts are attractive to the LSE not because they enable the exercise of locational market power but because they enable the LSE to materially reduce maintenance costs with a small loss in potential energy market revenues. With improvements in the ISO's rules for calculating commitment costs over the past several years, these major maintenance costs can now be reflected in the commitment costs offers so the costs would be recovered if a resource were started often enough to raise these costs. The main issue in discussions of this issue concerns the cost and benefits of effectively requiring LSEs to renegotiate the terms of long-term RA contracts entered into before implementation of the present CCE3 proposal.

The issues relating to the strategic use of contractual limits are different when considering existing contracts than when considering new contracts. We therefore discuss these two cases separately, beginning with concerns about newly signed contracts.

Treatment of Units Operating under New Contracts

While the method of accounting for use limits will change under this initiative, the concern still remains that such limits could be used as a "loophole" that allows strategic commitment cost offers. In the future, contracts with tighter use limits will, in general, produce higher opportunity costs, thereby raising the cap on commitment cost bids. More generally, overly restrictive use limitations, regardless of motivation, decrease the flexibility and efficiency of the system. Conversely, the flexibility and efficiency of the system would also be reduced if it could not accommodate resources with use limitations.

Overall, the, inclusion of opportunity costs in bid caps is an improvement, as it allows for a more efficient treatment of such constraints for competitively bid units, as long as the tightness of the constraints is not exaggerated. Therefore it is desirable to avoid, where possible, the imposition of use limitations that are not based on design or regulatory limits nor based on costs that cannot be reflected in offer prices. To the extent a contract can be used to establish unjustifiably low use limitations, competition and efficiency could suffer.

On the other hand, one needs to ask why the LSE counter-party to such a RA contract would willingly include such use limitations. For the most part, we would not expect buyers to be enthusiastic about adding constraints to their purchase agreements that could end up inflating their own acquisition costs. Unfortunately the incentives are not always so well aligned. A load-serving entity, having procured the bulk of their energy price hedges through other contracts, could perceive any market power or lack of system flexibility caused by a reduced availability of a marginal RA resource to be someone else's problem. Such a LSE might be willing to allow more limits on the availability of the resource in exchange for slightly lower average price, potentially shifting the consequences of those limits onto others. Even more obviously, two parties that are both interested in strategically applying contract terms (e.g., two generation companies or an LSE and generator that are the same entity) could reach agreements with each other.

To be clear, it is likely that few if any RA contracts signed by load serving entities have contractual provisions that would permit the exercise of market power in the energy markets, in part because most buyers would be more interested in reducing, rather than increasing, the potential for the exercise of market power. Moreover, in the case of restrictions in contracts for new capacity such as that procured in the CPUC long-term procurement process, it would not be a simple matter to identify contract restrictions that would enable a yet to be built unit to exercise locational market power on a local transmission constraint in future years. However, some members of the MSC believe that the CAISO should not put itself in a position of applying different standards to similar contracts based upon the regulatory status of the LSE. We agree that limitations negotiated in contracts signed from this point forward should at the very least be subject to more scrutiny than they apparently have in the past.

The ISO is proposing that all use limitations be backed by a demonstrated physical or environmental requirement. We expect that even these attributes will prove to be less cut-and-dried than envisioned in the proposal. Therefore the ISO should expect the need to show some flexibility in its review of such conditions. We agree that strategic contracting is less of a concern with contracts vetted and approved by a state regulatory agency, such as the California Public Utilities Commission. It is therefore appropriate to show deference to the evaluations of a state regulatory agency with respect to contracts and contract provisions impacting their rate payers, but not to the extent that those contract terms would permit the exercise of market power or otherwise raise system costs at the expense of other customers. These issues will be increasingly important as the energy imbalance market expands to multiple jurisdictions.

Treatment of Units Operating under Existing Contracts

The issues for existing contracts (those negotiated and approved before this year) are somewhat different. Because the translation of use limitations to higher commitment cost bids is a new feature, it is reasonable to assume that such limitations were not negotiated with an eye toward circumventing the new rules. Further, the bulk of these contracts have been subject to review by the California Public Utilities Commission, which brings a perspective of protecting all ratepayers of California investor-owned utilities, or in the case of utilities participating in the Western EIM, by their respective state commissions. Therefore much of the logic behind disregarding contractual limitations does not apply to existing contracts. We therefore support the CAISO's recent relaxation of its position on contractual limitations. The ISO now proposes honor such restrictions in calculating opportunity costs for a three year transition period. This is a positive step, but we would not be opposed to a longer transition period for existing contracts.

On the other hand, the ISO believes that some limitations that are in place appear to be excessive and that the efficiency of the system would benefit from relaxing these limitations. If true, some "nudge" in the direction of renegotiating some limitations would improve the situation, and the transition approach could provide that nudge. Some stakeholders worry that a firm deadline could put them in a disadvantageous bargaining position. The CPUC notes that the some contracts "of a very limited quantity" go out farther than three years, and it asks that contractual use limitations be honored in the calculation of opportunity costs for the lifetime of the contracts.[13] We support the concept of a transition period, but we have not undertaken any assessment of the cost to rate-payers of renegotiating these contracts relative to the benefits, nor are we aware of any such assessment by the ISO.

To summarize, we agree that a phase out of contractual based limitations is appropriate, either prospectively or also applied to existing contracts after a transition period, but should be approached in a manner that meets reliability needs without imposing undue transition costs on ratepayers. We anticipate this will require some flexibility on the part of the CAISO as the distinction between a physical and a contractual limitation can at times be subtle.

Last, we note that a big part of the problem with respect to use limitations stems from a gap between the flexibility ISO says it needs on an annual basis from unit commitment and the flexibility it currently requires through its monthly RA process. It is not surprising that if a LSE can get a better price on energy from a unit if it agrees to start limitations, they would be willing to sign such contracts if they are deemed to satisfy their RA obligations. This is not a market power concern, but rather a problem of why the operators of such flexible units do not see sufficient value from short-term markets such that they would not find it profitable to provide frequent starts, and why the RA process does not adequately differentiate between units that are and those that are not willing to provide that flexibility.

C. Opportunity Cost Calculation Procedures

Concerning the calculation of opportunity costs, the proposed unit commitment model for calculating operating costs will allocate a unit's limited starts, hours and/or energy over the relevant period of time, the relevant period depending on whether the limitations are monthly, annual, or apply to some other period. We have consulted with the staff to ensure that important constraints that affect opportunity costs of fossil-fueled generators will be included in the calculation of opportunity costs.[14] The ISO proposes to estimate resource opportunity costs by committing and dispatching the resource, subject to use limitations and other physical constraints (e.g., capacity ramp, minimum down times) to maximize resource profit against a single time series of simulated real-time (15 minute) prices. These simulated real-time prices would be based on historical nodal prices at the plant's location, adjusted for gas prices changes and for prices of electricity futures in California.

We comment on nine of the specific features of the calculation procedures as follows:

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[13] CPUC Staff Comments on CCE3 Draft Final Proposal, www.caiso.com/Documents/ CPUCStaffComments-CommitmentCostEnhancementsPhase3DraftFinalProposal.pdf

[14] For a review of unit commitment model formulations based on prices, which form the basis of this model, see, e.g., B.F. Hobbs, M.H. Rothkopf, R.P. O'Neill, and H.-p. Chao, eds., *The Next Generation of Electric Power Unit Commitment Models*, Kluwer Academic Publishers, Boston/Dordrecht/ London, 2001.

1. *Exclusion of hydroplants.* PG&E, SCE, and others have been developing highly complicated stochastic hydropower allocation algorithms since at least the 1980s. These models account for uncertain inflows, environmental discharge limits, upstream-downstream relationships, over year storage, and other constraints and non-hydropower objectives in optimizing the use of the resources.[15] In these models, the "value of water" can differ greatly from facility to facility, and over time as well, and is very complicated to calculate. We agree that these complexities of these procedures, together with their intensive data requirements, mean that it would neither be practical nor desirable for the ISO to duplicate that effort in order to calculate opportunity costs for hydroplants. Hence it is preferable for the CAISO to allow the hydro resource owner to develop the proposed opportunity costs and for the CAISO to review those estimates for reasonableness as it would any other negotiated opportunity costs.

2. *Exclusion of daily limitations.* For short-start units, decisions to start a unit early in the day may involve an opportunity cost if the number of daily starts is limited. If this is the case it may be better to husband starts for use later in the day to accommodate net load peaks or ramps during the later portion of the day. The ISO's day-ahead market takes account of these trade-offs when it determines day-ahead market schedules, but the ISO's RTPD market software does not currently have a long enough time horizon to account for these tradeoffs within the model. It is therefore important to not allow RTPD's foreshortened time horizon to result in the using up of allowed starts early in the day in situations in which the starts would be far more valuable later that day.

   However, there are at least three reasons to not try to take account of these daily limitations in the ISO's proposed opportunity cost calculations:

   a. First, it is our understanding that most daily limitations that are currently included in the masterfile for resources in the ISO footprint and that are accounted for using use plans are not real physical or regulatory limits on the number of starts per day. Instead they are usually used by resource owners to ration starts over longer periods of time. The right way to deal with longer term constraints is to calculate the monthly, seasonal, or annual opportunity costs as the ISO proposes, which will then be considered in the market software when determining the schedule for a particular day. This will be more efficient than accounting for the longer limits in arbitrary daily constraints. The optimal use of a resource may be to have several starts in some days and none in others, depending on system conditions. This switch to including estimated opportunity costs in the start up costs is intended to allow units with limited starts to be used to meet unpredictable system needs more efficiently than was been possible with the current framework for managing these limits.

[15] An earlier version of PG&E's system is described in J. Jacobs, G. Freeman, J. Grygier, D. Morton, G. Schultz, K. Staschus, and J. Stedinger, "SOCRATES: A System for Scheduling Hydroelectric Generation under Uncertainty," *Annals of Operations Research*, December 1995, Volume 59, Issue 1, pp. 99-133.

b. Second, the ideal way to calculate daily opportunity costs would be to extend the time horizon of the real-time pre-dispatch model, at least in some approximate way, so that the daily limitation can be explicitly imposed and its associated opportunity costs endogenously calculated. Although a deterministic RTPD model may underestimate opportunity costs (including option values associated with reserving starts) because it doesn't consider uncertainty in forecasts or multiple scenarios, neither would the opportunity cost calculation procedures that are practical to implement in the near future. The ISO has indicated that it will be consider implementing this horizon extension approach in the future along with other possible enhancements to the real-time markets, but this may not even be necessary if all start limits turn out in practice to be based on longer periods.[16]

c. Third, if daily start limits were not directly modeled in the real-time commitment software, they could in theory be accounted for by calculating daily opportunity costs. Such calculations for daily limitations would by their nature need to be repeated every day and, ideally, updated as the day progresses. Moreover, this approach might require development of different kinds of models for days at different times of the year or other known differences in system conditions. Development and implementation of such models is impractical in the near term. Opportunity costs that could be calculated from day-ahead (IFM) runs could be used as a starting point, but would still need to be updated over the day, and would not reflect option values associated with more volatile real-time prices.

If there are cases in which a unit has a daily physical or regulatory-based start limit, the ISO proposes to let operators use their discretion and information from day-ahead markets either to block sub-optimal real-time starts, or to prevent shut-downs that would prevent a valuable start from being available later. Although this approach is non-systematic and potentially less optimal than other approaches that could be developed, we believe it is better to apply it to the very few resources that appear to possibly have a real daily start limit rather than to develop a complex procedure that may be applicable to very few units and could be superseded in the future by extensions in the outlook of RTPD software if the number of resources with such daily limits grows. If such changes become appropriate, we urge the ISO, in particular, to consider means by which the look-ahead of the RTPD commitment software can consider the full day, or at least the portion of the day in which additional starts may be needed.

3. *Use of real-time prices.* A single time series of RTPD prices for the year (or other relevant period) is to be used in the opportunity cost calculations. Use of real-time prices, rather than day-ahead prices, is appropriate for the short start units that would constitute the bulk of use-limited resources because their actual commitments are usually in response to real-time not IFM prices and much of their opportunity cost is likely to reflect their use in response to real-time shocks and the associated real-time price volatility. (Such short-start units can get IFM schedules, but the IFM schedules can be modified in RTPD, so it

[16] Section 6.1, CCE3 proposal, op. cit.

is the real-time prices that are relevant for the actual scheduling.) However, for the handful of long-start units that are expected to qualify for inclusion of opportunity costs in their offers, we suggest that day-ahead prices be used instead, since they are predominantly committed and settled in the IFM and their commitment cannot be altered in RTPD. Although the ISO has experienced small differences between average IFM and RTPD energy prices, these differences might change in the future. Furthermore, due to the presence of virtual bidding, those differences are likely to be very small relative to the magnitude of commitment offer caps.[17]

4. *Use of a single scenario of prices.* The use of a single set of quarter-hourly RTPD realizations under a single set of assumed gas prices will likely underestimate opportunity costs because it will miss the option value associated with holding starts/run hours/energy for extreme but possible situations that could result in very high prices or even load interruptions.[18] Ideally, a fuller range of possible conditions would be considered as multiple scenarios in a stochastic model.[19] As a practical alternative, the CAISO could evaluate the performance of the proposed methods over time and make adjustments that will im-

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[17] That real-time and day-ahead prices are very similar in expectation does not imply that it does not matter which set of prices are used to determine opportunity costs for long-start units. Consider the following example. Say that three days have similar day-ahead prices, say \$50, \$51, and \$52, respectively, for days A, B, and C. But because of the volatility of real-time prices, it turns out that same days have real-time prices of \$80, \$51, and \$32, respectively. (Note that the deviations from day-ahead prices average out to zero, consistent with the assumption that real-time prices on average come very close to day-ahead prices.) Assume that the unit only has one start available, and its out-of-pocket cost is \$40. Scheduled against day-ahead prices, the unit would be scheduled for day C, and the marginal opportunity cost would be \$52-\$40, or \$12. But if the opportunity cost was based on scheduling the unit against real-time prices, then the unit would be scheduled in day A, and the calculated opportunity cost would be \$80-\$40 = \$40. Because real-time prices are more volatile than day-ahead prices, and a slow start unit cannot wait until real-time to be started, use of real-time prices in the calculations will tend to overstate the opportunity cost of a slow-start unit, even if on average real-time and day-ahead prices are equal.

[18] Mathematically, a downward bias in opportunity costs results from using a single time series of prices based on expected supply and demand conditions, because system costs (including outage costs) tend to be a convex (upward bending) function of net load. As a result, prices (and thus opportunity costs) calculated considering the probability of extreme scenarios of high and low net loads will have a higher probability-weighted average than prices based on expected net load conditions. Although the ISO's proposed calculation method does not infer prices from fundamental supply and demand conditions, the use of prices from a previous year could understate the risk of very high price periods, and thus understate opportunity costs.

[19] An example of the explicit consideration of uncertainty in opportunity cost calculations in another context, see S.S. Oren and S.A. Smith, "Design and Management of Curtailable Electricity Service to Reduce Annual Peaks," *Operations Research*, Vol. 40, No. 2 (1992), pp. 213-238. For a general discussion of including uncertainty in opportunity cost calculations, see D. Chattopadhyay and S. Schnittger, *Estimating Opportunity Cost for Energy Limited Plants: Practice, Modelling and Input Issues*, Concept Economics, Kingston, Australia, Prepared for the Australian Energy Market Commission, Aug. 11, 2008. www.aemc.gov.au/getattachment/0062b80d-09d2-4a8b-a060-9bc4df57d634/Concept-Economics-report-Estimating-Opportunity-Co.aspx

prove the quality of the opportunity cost calculations. [20] Although the use of such stochastic models may be feasible in the future, at this time it is more practical to use the simpler model and build some conservatism into the model by using the ISO's proposed 90% derating of use limitations, which will tend to increase opportunity costs.

5. *Adjustment for future gas and electricity prices.* Changes in gas prices are a major reason for changes in real-time prices from year to year. The ISO's proposed procedure to account for the impact of changes in expected gas prices is to adjust past prices based upon an inferred heat rate and projected gas prices is broadly reasonable. Fluctuations in power prices result also from other factors, such as hydropower conditions, weather impacts upon load, and plant outages, that are not controlled for by this methodology. The ISO proposes to account for these other factors with a further adjustment based on projected future energy prices.[21] An important issue to be dealt with is the choice of future power price indices and how those are to be corrected for gas price differences so as to avoid double counting. The performance of these adjustments has not been tested and their performance is one of the uncertainties concerning how the ISO opportunity cost methodology will perform when it is implemented.

6. *Inclusion of multiple constraints.* Nested constraints (monthly as well as annual, for instance) present some practical difficulties, but can be included by the proposed methodology as described by the ISO.[22] Rolling constraints, such as a 12 month limitation on starts that applies to every 12 month period (Jan-Dec; Feb-Jan; Mar-Feb., etc.) are conceptually more difficult. This is in part because there would be 12 constraints acting at once which might slow down execution times, and because these constraints mean that, in theory, tight supply conditions 2 or more years down the road could affect today's op-

[20] To this point, no analysis has been done to assess how the proposed methodology would have performed in other years or over a broader set of units. When the CAISO actually begins to apply the opportunity cost methodology and observe the outcomes, it is likely that it will begin to identify improvements that could be made and the very process of carrying out the calculations over time will allow the CAISO and resource owners to observe how the performance of the opportunity cost calculation varies from year to year with conditions.

[21] This procedure is discussed in Section 7.1.1 of the CAISO's CCE3 Revised Straw Proposal (Nov. 3, 2015, www.caiso.com/Documents/RevisedStrawProposal-CommitmentCostEnhancementPhase3.pdf)

[22] There is one slight correction that is needed to the procedure for dealing with simultaneously monthly and annual constraints. In the last paragraph of Section 7.1.2.1 of the CCE3 proposal, it is stated that "(t)he estimated opportunity cost for January that can be reflected in the start-up cost bid is the difference of the January profits from the two model runs" (a run with the original use limits, and a second run with one less start in January and one less for the year). For that example, the correct calculation is instead the difference of the annual profit. This can be seen by considering what would happen if the January constraint is not binding, but the annual constraint is binding; then January profits might not change (the number of starts scheduled by the model for that month might not change), but annual profits would likely shrink when both constraints are reduced by one start. The relevant opportunity cost of a start in January might be a foregone start later in the year, if January's monthly constraint is not binding.

portunity costs.[23] The ISO proposes to only consider two constraints in this rolling case (the 12 month constraint ending in the present month plus the 12 month constraint starting in the present month).

We have conducted simple numerical tests of this procedure and have found that the opportunity costs resulting from omitting constraints might be somewhat understated by only considering some of the rolling 12 month constraints that a unit is subject to. Therefore, we encourage the ISO to include as well the other 10 annual constraints that the resource would be subject to, if computational time permits. Since model execution time is not known now, another possibility is to start with just the two constraints and then check if other constraints are violated. If other constraints are significantly violated by the calculated distribution of starts over the year, the extra constraint(s) can be imposed and the model run again. It is expected that unit owners will monitor all of these limits and can inform the ISO of the need to include different constraints in the model if they become the most binding constraint. Hence, this, like other approximations in the ISO opportunity cost calculations, will be less serious if the ISO is able to rerun the model for units that are using up too many starts/running hours/MWh too quickly.

7. *Updating of estimates.* If a unit's limited starts/running hours/energy are used up more quickly or slowly than the unit commitment opportunity cost calculations project, or if fuel prices or generator outages depart from what is expected, then the opportunity costs of a unit's starts/running hours/energy will also change. Because it is not clear what the computational and staff costs associated with the opportunity cost estimation procedures will be, the ISO is proposing that updates be performed only monthly. Since the calculations can be carried out in parallel for multiple units (since they are done one unit at a time), it could be that the computational time required is negligible, and updates could be done more often, if the process can be automated. We suggest that the ISO monitor the rate at which limited starts/hours/energy are consumed, and if significant deviations from what is anticipated occur, then the ISO consider running the model more frequently. Similarly, if other system conditions change that would be expected to significantly affect price, a more frequent updating should be considered.

8. *Inclusion of revenues from ancillary services.* In theory, the opportunity cost of a start or operating hour is not just the foregone energy revenues later on, but also foregone revenues from other markets, including ancillary services and RA. In theory, potential ancillary services revenues could be included in the opportunity cost calculations, which would slow model execution, but given their relatively low prices, it is possible that the resulting increase in opportunity costs might be small. However, we have not seen any calculations of the possible magnitude of foregone ancillary service revenues. It would be useful to have a simple historical calculation of average ancillary service margin per

[23] For instance, if the summer of 2017 is anticipated to have very high prices, this may result in a large opportunity cost for starts in fall 2016 (because of, e.g., the Sept. 2016-Aug. 2017 constraint), which in turn would affect opportunity costs for starts in March 2016 (because of the March 2016-Feb. 2017 constraint).

start for use-limited resources. Such an estimate could be added to the energy market opportunity cost if significant. We encourage the ISO to simulate the effect of including ancillary service revenues in the model to assess whether they could significantly affect opportunity costs; if so, the ISO could consider including those revenues in revised versions of the opportunity cost model.

9. *Inclusion of revenues or penalties from the RA market*. Use of starts/hours/energy today may not only cost a unit by depriving it of spot market revenues at some future date, it may also cause a unit to be ineligible to provide RA in future months that has been designed as an RA unit. For instance, a hot summer with high energy prices might result in a peaker using up all of its annual starts before the autumn, even though it has contracted to provide RA in a later month. In that situation, it will either have to find substitute capacity to provide the RA it had been contracted for, or pay a RAAIM penalty. In theory, the expected cost of substitute RA or RAAIM penalties should be considered in the opportunity cost calculations for units subject to annual use-limitations that have committed to selling RA later in the year. In practice, this expected cost would be difficult to quantify, because RA is a monthly capacity product, while starts/hours/energy are computed on a daily basis in the opportunity cost determination procedure, so the relationship between generator use and later qualification to provide RA is not clear-cut and easy to calculate.

   As we have stated in other opinions, and as is widely accepted as a principle of good market design, spot markets should be designed such that they provide the great bulk of a resource's gross margin (and thus the incentive for investment), with RA markets providing a small back-up role.[24] We have argued that spot markets should be designed so that energy, flexible ramping, and ancillary should reflect the social value of load balance violations. If this market design goal is achieved, then RA prices should be relatively low, and omitting RA costs from opportunity cost calculations will make little difference. However, there are still restrictions on the spot market, such as the inability of prices to rise to the value of lost load in situations where load has a high probability of being shed, that imply that there will be "missing money" and RA prices should be positive.

   We, however, believe that the omission of RA costs from the opportunity cost calculations could pose a risk of over using generators early in the year relative to the optimal way of meeting the ISO's energy and RA needs over the entire year. Therefore, we recommend that simulations be conducted, using the opportunity cost software, of alternative ways to include RA-associated costs to assess whether they might be significant and practical to include. Meanwhile, it will be important to monitor the use of a unit and to consider whether overuse, relative to the value of RA and energy later in the year, is continuing. The application of the 90% derating factor to the use-limitation, and the temporary availability of outage cards to units that are overused will serve to lessen, if not elim-

[24] J. Bushnell, S. Harvey, B.F. Hobbs, and S.S. Oren, "Opinion on Flexible Resource Adequacy Criteria and Must-Offer Obligation," Market Surveillance Committee of the CAISO, March 11, 2014, www.caiso.com/Documents/FinalOpinion-FlexibleResourceAdequacyCriteriaMustOfferObligation.pdf

inate the risks of overuse because of the omission of RA from the opportunity cost calculations.

D. Responsibility for RA Showings and RAAIM Penalties

The integrity of the RA system depends in part on resources that are designed as providing RA as actually being available for dispatch. Thus, if a resource has been committed to provide RA in months late in the year, but has used up its use-limited starts, running hours and/or energy earlier in the year, then this resource should not be used to satisfy RA obligations in those later months. This is the principle that the ISO expresses in Section 10.2 of its proposal.

Several stakeholders have expressed concern over this provision of the proposal, especially as it applies to the situation in which a resource has been submitting commitment cost bids at the cap, which includes the ISO's estimate of opportunity costs later in the year. We consider four situations, which are the possible combinations of the following two conditions:

1. Has the resource bid its commitment costs at the ISO-specified cap, or not?

2. Were the ISO's estimates of opportunity costs too low relative to actual opportunity costs, or not?

First, if the resource has been bidding appreciably below the ISO-allowed level, then it is reasonable to presume that it bears at least part of the responsibility for too many starts or running hours or too much energy being consumed early in the year. Higher commitment cost bids would have conserved more starts/running hours/energy for later in the year. This is the case whether or not the ISO underestimated the actual opportunity costs. We recommend that in this case if the resource turns out to be ineligible to provide RA in later months, even though it has been contracted to do so, it is appropriate for the resource to pay the RAAIM penalty or, preferably, arrange for substitution by other resources.

On the other hand, if the ISO's estimates of opportunity costs were accurate or too high, and the resource's offers were consistently at the commitment cost cap, then if the starts/running hours/energy limits are reached prior to months in which the resource has been committed for RA, this is a strong indication that the best use of the resource is in the earlier months and that it should not have been designed for RA in the late months. The ISO market software, in that case, will have indicated that the resource is more valuable for meeting load earlier in the year. That is, if fewer starts/hours/energy were allocated to the early months in order to conserve them for later, then the system cost increases early on would exceed the cost savings in later months. This outcome indicates that the resource should not have been designated as RA in those later months, and that it would have been better to instead designate other resources. It also indicates that the cost of replacement capacity in the later months will be less than the additional energy market revenues gained by using all the starts/hours/energy in the earlier months. The market is likely to be less tight in those later months, so that the cost of replacement capacity will likely be below the RAAIM penalties incurred if no substitute capacity is found.

The final case is where the ISO has underestimated the opportunity costs and the resource consistently offered commitment costs at the cap. If under more accurate opportunity costs the resource would not have run out of starts/running hours/MWh, then the ISO's underestimates are responsible for the resource being unavailable in later months. It is still highly important in this situation that the resource have an incentive to arrange for substitute resources; simply waiving the entire RAAIM in that case would eliminate that incentive. Therefore, one possible compromise is that a reduced RAAIM be imposed only in the situation in which the resource has used up its starts/running hours/MWh even though it has followed the ISO's overly low opportunity costs. Unfortunately, this would introduce complications, requiring the ISO to investigate whether the opportunity costs were too low and whether the resource bid consistent with the caps. Therefore, we instead suggest maintaining the RAAIM penalties even in this situation for the time being. We think that the frequency of this situation is relatively small, given the following:

- The ISO proposes to reduce the starts/run hours/MWh limitations by 10% in the opportunity cost calculations as a buffer, which should raise opportunity costs, and

- The ISO proposes to implement an outage card alternative as an interim measure for managing these limitations if the resource is coming close to running out.

However, the ISO should closely monitor the performance of the system, in terms of the quality of the opportunity costs and its effectiveness in husbanding starts/run hours/MWh for the most valuable times. If this situation occurs often, then a modification to the RAAIM penalty should be considered.

IV. Mitigation of Market Power

As discussed above, high commitment cost bids can be used as a means of withholding a unit from the market or extracting excess uplift payments if the resource must be committed to manage a local reliability constraint. These bids are not currently subject to the same process for the application of local market power mitigation that is applied to energy bids. Instead, no locational market power test is applied, the ISO caps the commitment cost bids of all units. The changes discussed in this opinion will modify the way those caps are calculated, but the ISO will continue to apply bid caps to all units, without regard to the potential for the exercise of locational market power, limiting such bids to no more than 125% of ISO's estimate of costs ("proxy cost").[25]

The general application of a single bid cap formula to all units, whether or not there is any potential for the exercise of locational market power is a very blunt method for limiting the exercise of market power. The Department of Market Monitoring and the ISO have argued that the constraints imposed by the current bid cap formula for commitment costs generally does not preclude suppliers from submitting offers reflecting their costs because the head room provided by

[25] Under the CCE3 proposal, use-limited units can also add opportunity costs to their bids in addition to the 125% cap on other costs.

the 25% cushion over cost estimates has almost always been sufficient to permit cost-based offers. Moreover, the current proposals include several improvements in the calculation of the commitment cost bid cap that will reduce the frequency with which ISO suppliers are unable to reflect their costs in their commitment cost offer prices Hence, resource owners who would be subject to these limits support this initiative as providing them with more flexibility and more accurate estimates of their cost than the previous methods.

However, while this method may produce acceptable outcomes under the current market conditions, there are reasons to be concerned that a more targeted mitigation approach will eventually be needed. These reasons include proposed changes in the OFO rules of Southern California Gas which may lead to more volatile gas prices, the continued expansion of the Western EIM into regions in which liquid transparent gas price indexes may not be available at some generator locations, and ongoing changes in both the California and more general WECC resource mix which may contribute to increased gas price volatility.

While some changes would be necessary in the ISO's current local market power mitigation design in order to trigger mitigation of commitment costs when transmission constraints bind, it would be possible to trigger mitigation using a constraint by constraint approach similar to that used to trigger mitigation of energy offer prices. Although the commitment of an additional generating unit at minimum load may relieve a transmission constraint so that the constraint triggering the commitment of a generating unit would not be binding in the energy dispatch, the transmission constraint that triggered the commitment might be readily identified in the RTPD run in which the resource was committed, and shift factors would be calculated for the transmission constraint. Hence, the ISO would be able to identify the set of transmission constraints that could possibly have caused a resource to be committed and apply mitigation on that basis.[26] While it would be somewhat complex to carry out the full 3 pivotal supplier calculation for commitment impacts in exactly in the same manner as for transmission constraints that bind in the energy dispatch, there are a couple of approaches the ISO could implement.

One approach would be for the ISO to test whether resources committed in the LMPM pass relieve congestion on any active constraint within the Balancing Authority Area in which the resource is located and apply commitment cost mitigation to any such units, but to not apply mitigation to the commitment cost offers of resources that did not relieve congestion on a local constraint. With such an approach, the ISO would not commit generation in the Nevada balancing authority area based on mitigated commitment costs if there are no binding constraints in Nevada on which the resource could possibly exercise market power.

A second more complex approach would be to apply the 3 pivotal supplier test based on the full amount of relief provided by the resources of each scheduling coordinator on the constraints in

[26] The relevant transmission constraint will be one of the constraints that are generated in the RTPD iterations as a result of the AC load flow feasibility checks. The constraint would be one of the ones added between the last RTPD iteration that did not commit the unit in question, and the subsequent iteration in which the unit was first committed. However, it may be easiest simply to evaluate all the constraints that are included in the last iteration, since constraints, once added in an iteration, are not removed in subsequent iterations.

the constraint set with the Balancing Authority Area. This would potentially over mitigate because the full amount of relief provided by the commitment of the unit might not have been needed, but even such an over broad test would be less broad than mitigating units even when there are fringe suppliers able to completely replace all the relief provided by the large three suppliers.

The first approach would avoid committing resources based on mitigated commitment costs in one BAA in order to meet load in other BAAs for which there are many alternative sources of power.

A more fundamental change in market power mitigation procedures that could be used to identify generators who are exercising market power through commitment cost bids, and to exempt those who are not from the commitment cost cap is the conduct-and-impact type of procedure used by the Mid-Continent, New York and New England ISOs.[27] This would represent a very large change in both the philosophy and calculation procedures that would dramatically affect many features of the ISO local market power mitigation design and require substantial changes in its software. The effectiveness of the conduct-and-impact tests also depends on where the "guardrails" should be placed for defining conduct that might constitute market power, and for defining when the impact on market prices and bid cost recovery. We do not recommend consideration of a change to the conduct-and-impact system simply for application to commitment costs. Such a change should be considered only in the context of a comprehensive review of market power mitigation procedures.

V. After the Fact Filing for Cost Recovery

Because the ISO limits all commitment cost bids by caps that are based in part on imperfect indices of gas costs, there is a potential for a resource to be committed based on a ISO calculated bid that is less than the resource's actual incremental costs. In addition, because of current restrictions on the ability of a resource to raise its commitment offer after it is submitted in the day-ahead market, a resource may submit a commitment cost offer that is less than the cap, then be unable to raise it to reflect real-time gas costs if the resource does not receive day-ahead market schedule but is committed in real-time by the ISO.

Many elements of Bidding Rule and Commitment costs initiatives are designed to reduce the potential for a resource to be committed based on an offer determined by the ISO that is less than its actual costs. For example, the abovementioned restriction on raising commitment bids after the day-ahead market will be eliminated for resources not receiving a day-ahead schedule under the BRE proposal. However, there remains a potential for resources to be uneconomically committed, and hence operate at a loss, if their compensation was based on the commitment costs calculated by the ISO. This outcome is most likely to result from proxy commitment costs calcu-

[27]FERC, *Staff Analysis of Energy Offer Mitigation in RTO and ISO Markets, Price Formation in Organized Wholesale Electricity Markets*, October 2014, Docket No. AD14-14-000 www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf

lated by the ISO based on understated gas costs, either because of changing market conditions or because of a lack of a reliable gas price index for the locations at which particular resources purchase gas.

One element of the Bidding Rules initiative would address the potential for resources to incur large losses as a result of being uneconomically committed by the ISO based on understated gas costs. This element would give market participants the right to file at FERC for recovery of commitment costs in excess of the commitment cost bid cap due to differences between the actual procurement gas cost and the gas price estimate used by the ISO to determine the bid cap. This change has a number of potential benefits for ISO markets and market participants:

- Reducing the potential for large losses resulting from gas purchase costs that would not be recovered in market prices may help gas fired generators with limited credit buy gas to cover ISO schedules during stressed system conditions;

- Reducing the potential for large losses resulting from gas purchase costs arising from ISO instructions may make generators more willing to voluntarily participate in the western EIM.

- That reduction in risk for gas acquisition cost losses should also tend to reduce RA costs in California, perhaps by more than the actual uplift costs reimbursed; and

- That reduced potential for large losses should make gas fired generators more willing to make high cost gas purchases to support real-time dispatch needs.

On the other hand, as market participants have recognized, taking this approach has potential downsides:

- It is possible that the gas costs incurred by the supplier will turn out to be higher than what the market software took into account in the commitment decision, and that ratepayers would have been better off had the resource not been committed;

- It is possible that the rules governing the recovery of excess gas purchase costs would undermine the incentive of the affected resource owner to purchase gas at least cost in transactions expected to be covered by the cost recovery rule; and

- It is possible that the rules governing the recovery of excess gas purchase costs would adversely affect the general gas purchasing incentives of gas fired resources, such as discouraging forward hedging, which could incent delays in purchasing gas until real-time.

The first of these potential downsides is unavoidable under the current design in which offer prices are capped so that actual unconstrained cost-based offer prices are not visible to ISO operators. The second and third potential problem areas could be avoided by developing detailed rules governing the application of the cost recovery. However, the ISO has concluded that the development and application of rules by the ISO would require that the ISO specify objective criteria for after the fact cost recovery that would be difficult to detail in advance and would require a high degree of judgment and an evaluation of market participant's portfolio of gas purchases and sales. The ISO reasons that, since FERC will be the ultimate arbiter of such subjective judgments, and will have access to more information, FERC is better positioned to carry out this evaluation. Therefore, the ISO proposes that FERC determine what rules would be applied as situations arise.[28]

The ISO's approach will work well as long as the ISO is correct that these rules will rarely if ever need to be applied and this also what market participants expect, so that the lack of rules governing cost recovery does not lead to inefficient behavior. The ISO's Department of Market Monitoring has extensively analyzed historical gas purchase price data available from ICE and found that there are very few instances in the past several years in which differences between actual gas transaction prices and lagged index prices would have by themselves have prevented suppliers from fully reflecting their gas costs in offers that did not exceed the ISO cap.[29]

Moreover, the ISO has implemented or proposed changes to make it less likely that gas fired generators will be unable to reflect their actual gas acquisition costs in offer prices. One change would delay the IFM in the event of large changes in gas prices to allow the use of default energy bids calculated based on more current fuel prices. Another change, which is proposed by the BRE initiative, would allow resources that have not yet been committed to raise their offer up to the cap prevailing in real-time.[30]

However, it must be kept in mind that the DMM's analysis only covered the gas trading points for generation located in California and it is uncertain at this point in time whether reliable gas price index data will even be available for all of the gas fired generators that might potentially participate in the Western EIM. Further, it is not known how volatile these prices may be when the pipeline system is constrained. In addition, the changes in operational flow order policies that SoCal Gas has filed at the California Public Utilities Commission are motivated in part by a perception that non-core gas consumers, including gas fired generators, have leaned on SoCal Gas when the gas market is tight, including times when the PG&E system is constrained. In consequence, the changes in operational flow order policies may lead to more volatile gas prices when non-core gas consumers are unable to lean on SoCal Gas for supply to the same extent.[31]

If indeed it turns out that gas prices become more volatile, we are concerned that the lack of clearly defined rules for cost recovery under the ISO proposal has the potential to deter participation in the western EIM and lead to other inefficient outcomes if gas fired generators come to expect that they would need to seek cost recovery under these rules in other than very extraordi-

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[28] BRE Proposal, op. cit., Section 7.1.

[29] California ISO, Department of Market Monitoring, "Report on Natural Gas Price Volatility," September 21, 2015, www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf.

[30] See BRE Draft Final Proposal, op. cit., Section 6.1.1

[31] See the discussion on pp. 1-4 of "Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) for Low Operational Flow Order and Emergency Flow Order Requirements," June 27, 2014, available at: www.socalgas.com/regulatory/documents/a-14-06-021/FINAL%20Low%20Flow%20App.pdf.

nary circumstances. A long run approach to these issues that would be more robust in its operation both in California and across the expanding footprint of the Western EIM would be to develop an approach to market power mitigation that would enable the ISO to limit the capping of commitment cost offers to circumstances in which the resources have the potential to exercise locational market power, as opposed to imposing these caps on all resources.