Draft Final Proposal

Commitment Costs Refinements 2012

April 11, 2012

Commitment Costs Refinements 2012

Prepared for discussion at a stakeholder meeting – April 18, 2012

Table of Contents

1 Introduction and background

The economic commitment of a generating resource in the ISO markets is based on its market energy and ancillary service bids as well as the cost of starting up the resource and its costs at its minimum operating level (pmin). That is, commitment costs – start-up (SU) and minimum load (ML) costs – are integral to the optimization's choice to utilize the resource. Furthermore, commitment costs are part of the ISO's bid cost recovery (BCR) calculation that determines whether or not a resource has a revenue shortfall over the course of a day. If, based on the BCR calculation, the resource does have a shortfall – meaning that its commitment and market bid costs are not covered by its market revenues – then the resource receives a BCR uplift payment. Thus, the accurate specification of a resource's commitment costs is critical to efficient commitment and fair compensation of generating resources in our market.

Since the implementation of the ISO's LMP market design on April 1, 2009, the ISO has made several market rule changes to increase the options and flexibility for market participants to specify start-up and minimum load costs. The first effort involved reducing the minimum time period for electing either the proxy cost option or the registered cost option from six months to 30 days. Through a second initiative, which was approved by the ISO Board of Governors in July 2010, the ISO committed (a) to evaluate the default variable operations and maintenance cost adder to minimum load cost values every three years,[1] (b) to allow scheduling coordinators to make independent elections of either the proxy or registered cost option for start-up and minimum load costs, and (c) to permit (non-negative) daily bidding of start-up and minimum load costs on behalf of resources subject to the proxy cost option.

In this current initiative – Commitment Costs Refinements 2012 – the ISO and stakeholders have evaluated additional improvements to the specification of start-up and minimum load costs. In this draft final proposal, the ISO proposes the following changes to the calculation of minimum load and start-up costs:

- The proxy minimum load and start-up costs calculated by the ISO will be modified to incorporate the following :
    - Costs associated with greenhouse gas emissions incurred under California's upcoming greenhouse gas cap-and-trade program.
    - The cost of the ISO's grid management charge.
    - A fixed adder to cover major maintenance expenses.
- In conjunction incorporating these additional costs components into the ISO's proxy cost calculations, the registered cost cap for minimum load and start-up costs will be reduced from 200 percent to 125 percent of the respective projected proxy cost, as calculated by the ISO for the resource every 30 days.

[1] The review and update of O&M values was recently completed and was approved by the ISO Board of Governors in December 2011. The updated O&M values will be effective in April 2012 subject to FERC approval.

This initiative has also evaluated changes to the ISO's cost-based calculations used for default energy bids (DEB)[2] and generated bids.[3] Consistent, with the changes to the calculation of costs for start-up and minimum load, the ISO proposes that the DEB and generated bid calculation be modified to include (1) greenhouse gas costs, and (2) ISO grid management charge costs.

Finally, the ISO proposes a mechanism for recovery of costs associated with operational flow orders incurred in the natural gas market.

The changes described above will apply to Generating Units, Pseudo Tie Generating Units, and Resource-Specific System Resources. Consistent with existing market design, only variable costs of generation, and not fixed costs, have been considered for inclusion into the ISO's cost calculations.

2 Process and Timetable

The timeline for this stakeholder initiative culminates in taking a policy recommendation to the ISO Board of Governors in May 2012. The table below summarizes the key steps in the stakeholder process starting with the release of the issue paper and ending with submission of the ISO management proposal to the Board.

February 3, 2012	Issue paper posted
February 8	Conference call
February 17	Comments due *
February 29	Straw proposal posted
March 7	On-site stakeholder meeting
March 14	Comments due *
April 11	Draft final proposal posted
April 18	Stakeholder conference call
April 23	Comments due *
May 16-17	Board of Governors meeting

* Please e-mail comments to comcosts2@caiso.com

[2] Default energy bids (DEB) are energy bid curves that replace a resource's submitted bid curve in the event that the resource is mitigated according to the local market power mitigation (LMPM) algorithm. Please see ISO tariff section 39 for additional information.

[3] A generated bid is a cost-based bid which can be inserted on behalf of a market participant, for example, pursuant to generally applicable SIBR validation rules, and for Resource Adequacy bidding obligations.

3 Identified opportunities for improvements to bid costs

3.1 Changes to the registered cost option for start-up and minimum load costs

The current structure for generators to specify start-up and minimum load costs allows for two options: (1) the proxy cost option which is variable and tied to the natural gas price index and the heat-rate characteristics of the generating resource, and (2) the registered cost option which is a static value that is fixed for a minimum of 30 days after is it specified by the generator. The cap on the value that may be specified for the registered cost option for either start-up or minimum load is currently equal to 200 percent of the resource-specific projected proxy cost value as calculated by the ISO every 30 days.

The original motivation for providing the registered cost option was the recognition that there were potentially costs associated with starting up a resource and/or operating at minimum load that were not captured within the projected proxy cost calculation. However, the ability to register minimum load costs up to 200 percent of actual costs served as a key mechanism in adverse market behavior that inflated bid cost recovery (BCR) uplift payments in the first half of 2011. This resulted in two emergency filings to revise the tariff's bid cost recovery provisions. Although these filings addressed the observed behavior, there may still be opportunities to exploit this 200 percent cap. This could involve: (1) resources bidding in such a way as to receive BCR in the DA market and then not delivering the DA schedule in real-time, or (2) deviating in real-time to avoid shutdown instructions. Both of these strategies could be profitable if a resource can earn minimum load costs that are in excess of its actual minimum load costs. Consequently, and also because it was proposing to explicitly incorporate additional costs into its calculated proxy costs for resources, the ISO proposed as part of this initiative to examine lowering this 200 percent cap.

Stakeholder feedback

Market participants in favor of changes to the cap on the registered cost option generally focused on the need to prevent generating resources from having incentives to submit high registered cost values to recoup more than their actual costs through bid cost recovery. CDWR-SWP, the CPUC, NCPA, PG&E, SCE, and SDG&E expressed support for lowering the cap for the registered cost option for start-up and minimum load costs. In general, market participants in support of revising the registered cost cap did not recommend eliminating this option altogether, but instead recommended revisions to it. Such feedback included moving the cap closer to 100 percent of the calculated projected proxy cost values for start-up and minimum load, and adding the calculation of additional cost elements to the proxy cost calculation to reduce the need for market participants to rely on the registered cost option to recover these other cost components.

For example, Calpine stated support for maintaining the registered cost option, and recommended changing the registered cost cap to 175 percent of calculated costs to help accommodate for potential volatility in the nascent California GHG allowance market. Several stakeholders propose that the registered cost for start-up and minimum load costs be eliminated altogether. Several market participants expressed significant concerns over lowering the cap on the registered cost option. CalPeak, GenOn Energy, La Paloma, NRG Energy, Wellhead and WPTF are opposed to any change to the 200 percent cap on the registered cost option. Generally, comments by these participants maintain that neither the proxy cost option nor a lowered registered cost option are adequate to recover start-up and minimum load costs in the ISO market. NRG states that cost recovery has provided protection for significant costs related to natural gas procurement, as well as the volatility of natural gas prices. In addition, several of these market participants commented that the 200 percent registered cost cap is the only means for their units to earn a contribution toward fixed costs when committed by the ISO at minimum load.

Proposal

The original intent of the registered cost option for start-up and minimum load costs was to (1) enable market participants to bid in higher start-up and minimum load costs for resources with non-fuel related costs not captured in the variable operations and maintenance (O&M) adder, and (2) account for expected fuel price volatility. The current 200 percent cap on the static registered cost value was set so as to enable market participants to account for these cost elements.

In this draft final proposal, the ISO proposes to keep the registered cost option, but to lower the registered cost cap to 125 percent of the projected proxy cost. The ISO proposes to keep the registered cost option to accommodate resources that have costs that are not incorporated into the proxy cost calculation. However, these additional costs should in the future be fairly limited. The additional cost components the ISO is also proposing to incorporate into its proxy cost calculations reduce the additional costs that are not explicitly accounted for and would need to be accounted for under the projected proxy cost multiplier. These additional costs – greenhouse gas costs, GMC costs, and major maintenance costs – are described in more detail below.

The ISO's proposal for a 125 percent registered cost cap is also based on the analysis of historical fuel price levels and fuel price volatility, the results of which are described in Appendix A to this paper. This analysis found that average spot natural gas prices exceeded the natural gas projected proxy price by at most 10 percent, and this was at most 10 percent of the time.[4] Thus the 125 percent cap, over a month, more than covers what would generally be the fuel price risk associated with purchasing natural gas on the spot market. The 125 percent cap should also account for any risk in the intra-day markets for natural gas and any non-fuel costs that will still not be accounted for in the proxy cost calculations.

3.2 Greenhouse gas emissions costs

The California Air Resources Board (CARB) is implementing a cap-and-trade program for greenhouse gas (GHG) emissions starting in January 2013.[5] Under cap-and-trade, an overall limit on GHG emissions from capped sectors, including electricity generating facilities, will be established and facilities subject to the cap will have to acquire allowances to emit GHGs. By slowly lowering the number of available allowances, the cap-and-trade program is intended to reduce GHG emissions to 1990 levels by the year 2020, and ultimately achieving an 80 percent reduction from 1990 levels by 2050.

Consequently, California's thermal generating resources will bear a per-MWh cost associated with the GHG allowances needed for their energy output. Therefore, there is reason to consider including those costs in the cost-based calculations for minimum load and start-up costs, as well as default energy bids and generated bids. Key considerations in defining how those costs might be determined are (1) determining GHG emission quantities and (2) identifying an appropriate price index to use for the GHG allowance cost.

4 The values differed for the different locational gas indices used by the ISO.

5 More information on the cap-and-trade program is available at following link: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm

Stakeholder feedback

Nearly unanimously, stakeholders expressed support for the inclusion of costs associated with the CARB's GHG cap-and-trade program.

Southern California Edison (SCE) is concerned about the liquidity and volatility in the GHG allowance market and recommends additional monitoring and safeguards.

Calpine, La Paloma and Western Power Trading Forum (WPTF) support the inclusion of administrative fees associated with the cap-and-trade program. SCE opposes the inclusion of such administrative fees.

Calpine is concerned by the plan to use CARB rather than EPA emissions rates.

California Department of Water Resources – State Water Project (CDWR-SWP) conveyed their concern that consideration of GHG cap-and-trade compliance costs for cost-based calculations stating that this will lessen the incentive of generating resources to reduce GHG emissions.

San Diego Gas & Electric (SDG&E) recommends that a rolling average of the GHG allowance price be used only if the market lacks liquidity.

SDG&E also requests clarification of the ISO's proposal with respect to resources that emit less than 25,000 mtCO2 each year, and thus do not have a compliance obligation under the cap-and-trade program. Western Power Trading Forum (WPTF) suggests that the ISO defer to the California ARB's published list of entities covered by the cap-and-trade regulation rather than put in an exemption.

Pacific Gas and Electric (PG&E) recommends a separate stakeholder process to address additional cost allocation issues associated with California's GHG cap, such as potential ISO compliance requirements when it imports emergency power. The ISO clarifies that we will not be registered as a Purchasing-Selling Entity for the purpose of completing e-tags, thus will not have a compliance obligation as an importer under the GHG regulations.

Proposal

The ISO proposes to follow the methodology recommended by the Department of Market Monitoring (DMM) for calculating the cost of greenhouse gas allowances.[6] In summary, the ISO proposes to calculate each unit's greenhouse gas emissions based on the unit's heat rate characteristics, as registered with the ISO, and the emission rate used by the California ARB in assessing GHG compliance obligations. The standard GHG emission rate for natural gas used by the ARB is that which can be calculated under U.S. Environmental Protection Agency regulations and is 0.053165 mtCO2/mmBTU.[7] The ISO also proposes to use a different unit-specific emission rate for a unit if the market participant submits documentation that the unit has a different emission rate for ARB compliance purposes.

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6 DMM's proposal is available at the following link: http://www.caiso.com/Documents/WhitePaper_CaliforniaGreenhouseGasCap_GenerationVariableCosts.pdf

7 U.S. EPA Greenhouse Gas regulation, Subpart C, Table C-1 and C-2, http://ecfr.gpoaccess.gov/cgi/t/text/textidx?c=ecfr&sid=f095b41950528f0d4d3090382efcd1ce&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

The ISO proposes that the cost of greenhouse gas allowances be incorporated into the various elements of generators' variable costs as follows:

- Incremental energy costs used for default energy bids and generated bids : Include greenhouse gas allowance costs as a per MWh incremental cost, which can be calculated as:

  Allowance cost per MWh =

  incremental CO_2 emissions per MWh ($mtCO_2$/MWh) * 1 allowance per $mtCO_2$ * greenhouse gas allowance price

  Where,

  Incremental CO_2 emissions per MWh ($mtCO_2$/MWh) = unit's incremental heat rate (mmBTU/MWh) * (0. 053165 $mtCO_2$/mmBTU)

- Minimum load energy costs: Include greenhouse gas allowance costs as a per MWh cost for a unit's minimum load output, which can be calculated as:

  Allowance cost per MWh =

  average CO_2 emissions per MWh at minimum load ($mtCO_2$/MWh) * 1 allowance per $mtCO_2$ * greenhouse gas allowance price

  Where,

  Average CO_2 emissions per MWh ($mtCO_2$/MWh) = unit's average heat rate at minimum load (mmBTU/MWh) * (0. 053165 $mtCO_2$/mmBTU)

- Start-up costs: include greenhouse gas allowance costs as a cost per start-up, which can be calculated as:
  Allowance cost per start-up =

  CO_2 emissions per start-up ($mtCO_2$/start-up) * 1 allowance per $mtCO_2$ * greenhouse gas allowance price

  Where,

  CO_2 emissions per start-up ($mtCO_2$/start-up) = unit's start-up fuel requirement (mmBTU/start-up) * (0. 053165 $mtCO_2$/mmBTU)

Consistent with the DMM recommendation, the ISO proposes that the only greenhouse gas emissions that should be included in cost-based calculations are those that vary with output. Accordingly, the ISO proposes not to include the administrative fees associated with cap-and-trade program compliance in the calculations of costs associated with resource starts or incremental energy output.

Generating resources that do not emit more than 25,000 $mtCO_2$ in the previous year do not have a GHG cap-and-trade compliance obligation. The ISO proposes not to include greenhouse gas allowance costs in its calculation of variable costs for these resources. The ISO proposes to rely on the California ARB's assessment of entities that have a GHG cap-and-trade compliance obligation.[8]

Consistent with the DMM recommendation, the ISO proposed to base the GHG allowance price on publically available indices of GHG allowance futures prices. Similar to the current method the ISO uses for determining natural gas prices, the ISO proposes to use the average of prices from three separate commercially published indices. In the event three prices are not available, the ISO will use the average of the prices from two separate indices. The price used will be the published daily settlement price of the California GHG futures product with the next delivery date.

Several market participants expressed concern that these prices could be volatile and/or that liquidity in the secondary market for GHG allowances could be limited. The experience in the secondary market for GHG allowances under the Eastern states Regional Greenhouse Gas Initiative (RGGI) showed that a relatively stable and liquid secondary market developed within the first year.[9] Since traders would have the experience of that market, it seems that the secondary market for California GHG allowances would develop even more quickly.

The ISO previously proposed to help mitigate any volatility and lack of liquidity in the GHG allowances market by using a 30-day rolling-average of the published index prices. However, stakeholders pointed out that it would be appropriate for the cost-based calculations to reflect any daily volatility in the GHG allowance market. Consequently, the ISO now proposes to: (1) use a daily GHG allowance price for the costs that the ISO calculates daily, (2) use the average of the daily GHG allowance price over the first twenty days of each month to determine allowance costs to be used in the calculation of registered costs to be fixed for the next month.

Some stakeholders commented that the ISO needs to implement additional monitoring and safeguards to protect against manipulation of allowance prices. The ISO believes that this will be an important protection and notes that, as part of the implementation of the GHG cap-and-trade program, the California ARB will be implementing an active market monitoring program to guard against manipulation of allowance prices and the associated indices.

The GHG cap-and-trade program will go into effect on January 1, 2013. The ISO's plan is to implement the inclusion of GHG allowance costs into cost-based calculations at that time. The other elements of this proposal (including the change to the registered cost cap) are planned for implementation along with the separation of the netting of day-ahead and real-time BCR calculations planned for fall 2013 implementation..

3.3 Operational Flow Orders

Natural gas is generally shipped to generating resources via pipelines. Under some conditions pipeline operators may issue Operational Flow Orders (OFO), under which generators will incur financial penalties if their natural gas usage is more or less than a specified tolerance band. These OFOs are typically issued in circumstances that require controlled flow in an effort to protect pipelines or to maintain reliability of natural gas delivery. If a circumstance arises such that the generator is not able to adjust its use of natural gas, it can be assessed an OFO penalty due to its noncompliance with that OFO.

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8 http://www.arb.ca.gov/cc/capandtrade/covered_entities_list.pdf

9 http://www.rggi.org/docs/MM_2010_Annual_Report.pdf, page 5.

The ISO sought stakeholder input into three general issues listed below, and requested identification of additional issues to be addressed:

- The circumstances under which OFO penalties are assessed vary. In concert with stakeholders, the ISO proposed to develop a proposal as to the circumstances under which OFO penalties would be appropriately recovered through the ISO.
- Since an OFO penalty is a daily cost and not an hourly marginal cost (i.e., a per-MWh cost), the structure of proxy commitment costs, default energy bids, or generated bids is not congruous with that of the OFO penalties. The ISO sought input on what mechanism would best be used for compensating generators for OFO penalties that would be appropriately recovered through the ISO.
- There are situations in which multiple generators bundle their purchases of natural gas such that they appear to the supplier as one customer. As a result, the deviation of some subset of generators in that bundled group can cause an OFO penalty to be assessed to the whole group. The ISO sought input into the manner and extent to which these bundling arrangements should be considered in cost recovery through the ISO.

Stakeholder feedback

CDWR-SWP and SDG&E contend that generators can mitigate for the risk of an OFO penalty within their economic bids.

The California Public Utilities Commission (CPUC) advocates that a generator's OFO penalties should be recoverable only when the ISO dispatches a generator in real time, and the generator has elected the proxy cost option.

GenOn, NRG Energy, Sempra United States Gas and Power (USGP), Wellhead, and the Western Power Trading Forum (WPTF) support the inclusion of OFO penalties accounted for in cost-based calculations.

Six Cities recommends that "winter balancing" penalties also be eligible for *ex post* cost recovery.

SCE suggests that penalties for "over burn" as well as "under burn" be considered.

Proposal

The ISO proposal follows the DMM recommendation closely.[10] In summary, DMM recommends that OFO penalty costs can be recovered by market participants *ex post* under circumstances that are attributable to three pre-specified types of ISO dispatch: exceptional dispatch, real-time commitments, and instances of bid mitigation. Following such events, the ISO proposes that stakeholders apply to the ISO for cost recovery with evidence of their OFO penalty associated with either an "over burn" or an "under burn" of natural gas. The OFO penalty costs will be included in a re-evaluation of the real-time BCR calculation for that day with the OFO costs added into the calculation of the generator's net shortfall or surplus over the day.

In contrast with the DMM recommendation, the ISO does not propose to differentiate between resources under the registered cost and the proxy cost option for minimum load as originally proposed by DMM. This recommendation is based on the proposal made in this initiative to change the cap on the registered cost option.

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[10] http://www.caiso.com/Documents/DMMMethodology-Account_OperationalFlowOrderPenaltiesIncurred_EnergyDispatches.pdf

Bundled gas customers that receive an OFO penalty need to determine among themselves which party will submit these costs to the ISO for recovery. A mechanism will be required to make sure that no more than 100 percent of any OFO is being recovered by a bundled group of generators.

The ISO does not propose at this time to include cost recovery for natural gas balancing penalties other than Operational Flow Orders.

The ISO further proposes to modify its treatment of NOx and SOx emissions so that recovery of costs penalties associated with these emissions are treated in the same way as the OFO penalty cost recovery described here. In particular, if a generator is assessed a penalty for NOx or SOx emissions due to an exceptional dispatch or a real-time ISO commitment, the generation owner should submit documentation of that penalty. The ISO will subsequently re-evaluate the generator's real-time bid cost recovery net surplus or shortfall and make adjustments accordingly.

3.4 Grid management charge line item in cost-based calculations

The ISO's grid management charge (GMC) is a charge assessed market participants, and is the cost-recovery mechanism for the ISO. The GMC calculations and allocation were recently changed and are now assessed based on the methodology described in the GMC draft final proposal an excerpt of which is provided below:[11]

> The ISO proposes that the three GMC charge categories be allocated based on gross MWh (capacity and CRR holdings) and MWh (energy). The Market Services category includes awards of ancillary services, and schedules and dispatch instructions of generation, imports, load, and exports. The System Operations category includes all flow quantities for generation, load, imports, and exports. The CRR Services category includes the total MWh quantity awarded through both the allocation process and auction.
>
> The ISO's draft final proposal to allocate the charges as follows to each user of the ISO's services: The Market Services charge will be applied to the scheduling coordinator's gross absolute value of awarded MWh of energy and MW of AS in the forward and real time markets. The System Operations charge will be applied to the scheduling coordinators gross absolute value of actual MWh of real time energy flows. The CRR Services charge will be applied to each scheduling coordinators total MW holdings of CRR that are applicable to each hour. The three administrative charges will be applied to each scheduling coordinator based on their use of the associated transactions.

The GMC charges that fall into the Market Services and System Operations categories are volumetric, meaning that they are based on the MWh quantities either scheduled or injected/withdrawn from the grid. As such the ISO recognizes that inclusion of these costs in the calculations of cost-based bids – default energy bids, proxy minimum load costs, and generated bids – may be appropriate, and sought stakeholder feedback on this issue.

[11] http://www.caiso.com/Documents/DraftFinalProposal-2012GridManagementChargeFeb15_2011.pdf

Stakeholder feedback

Stakeholders who commented on this element of the issue paper expressed nearly unanimous support of including volumetric GMC charges into cost-based calculations. Some stakeholders recommended that administrative charges GMC also be included in cost-based calculations.

Proposal

The ISO proposes to include the volumetric elements of the GMC into the proxy start-up, proxy minimum load, default energy bid, and generated bid calculations. In particular, the ISO will include in those calculations the following elements of the GMC calculation: Market Services, System Operations, and $0.005/ bid segment charge.

The ISO does not propose to include administrative fees in any of the cost-based calculations mentioned above. Examples of administrative GMC charges are the Scheduling Coordinator fee, inter-SC trade fee, and the interest on invoice true-up. Administrative charges are not associated with per-MWh operation; rather, they are related to general costs of participating in the ISO markets.

3.5 Major maintenance adder to the proxy cost calculations

As noted above, there are two options for specification of start-up and minimum load costs, one of which is the proxy cost option. Generators often find that using the proxy cost option to capture start-up and minimum load costs is preferable to the registered cost option because the proxy start-up costs change daily along with the natural gas price index. Election of the proxy cost option enables generators to avoid potential risk associated with fuel price fluctuations over the 30-day period for which the registered cost option is fixed. However, stakeholders have provided feedback on many occasions that a significant drawback of using the proxy cost option is that the current calculation does not consider major maintenance associated with operating a generating unit.

Stakeholder feedback

Stakeholders unanimously support the inclusion of a major maintenance adder as part of cost based calculations for start-up and/or minimum load costs. The point was brought up by several participants that major maintenance expenses are more closely linked to start-up events for generators with certain attributes, and to run-hours for other generators. Several stakeholders indicated in their feedback that a major maintenance adder component to proxy calculations should be robust to such generator characteristics.

Proposal

The ISO proposes that a major maintenance adder should be included in cost-based calculations. Major maintenance expenses are marginal costs to the extent that the schedule for performing such maintenance is based on: the run-hours for the unit, the number of starts, or the energy output.

In support of this effort, the ISO has engaged Potomac Economics to develop default values for major maintenance costs. Potomac Economics will rely on publically available data, experience with development and monitoring of major maintenance cost adders in other markets, and information provided by the ISO and ISO market participants.

Potomac Economics' paper describing their methodology for determining major maintenance costs will be posted to the Commitment Cost Refinements 2012 webpage separately from this draft final proposal.[12]

3.6 Transition costs

Resources modeled using the multi-stage generating (MSG) modeling functionality define their multiple operating ranges and the costs and constraints associated with transitions between the ranges in their master file registration. Currently, there are rules associated with the specification of transition costs.[13] Based on the impression that the rules were not adequate to enable MSG resources' transition costs to be fully and accurately specified, the ISO proposed to switch from this rule-based approach to proxy transition costs. The proposal was that proxy transition cost values would be based on specific and defined operating characteristics. Today, cost-based calculations consider resource-specific heat-rate data, an index of the natural gas price and, in the case of minimum load costs, operations and maintenance (O&M) costs. When the ISO presented this straw proposal within the recent stakeholder initiative on MSG Enhancements,[14] stakeholders were unanimously opposed to this change. The feedback we received was that the calculation of proxy costs does not consider all of the costs associated with an MSG resource making a transition from one operating configuration to another.

The ISO sought stakeholder feedback on the specific, quantifiable costs associated with MSG transitions that can be captured and used to reflect transition costs through a defined proxy cost calculation.

Stakeholder feedback

CPUC and CDWR-SWP expressed similar sentiments; namely that the costs not captured under the current rules should be explicitly identified and thereafter refining the manner in which transition costs are specified only as needed.

Both NRG and Calpine support a registered cost option for transition costs.

PG&E, Sempra USGP, and SDG&E advocate that transition costs be handled in a manner consistent with the proxy start-up and proxy minimum load calculations. SDG&E further recommends that the proxy transition costs include a fixed adder.

Wellhead recommends that changes to transition costs be considered in a separate stakeholder initiative.

Proposal

The ISO's Board of Governors recently approved the ISO's recommendations to make multi-stage generating unit modeling registration required for certain types of generating resources. This will

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12 http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx

13 Documents related to the commitment costs initiative in which the transition cost validation rules were developed are available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingMitigationCommitmentCosts.aspx

14 Documents related to the policy initiative through which MSG enhancements are available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/Multi-StageGenerationEnhancements.aspx

effectively triple the number of generators using the MSG functionality many of which have not been through market simulation. Accordingly, the ISO agrees with the feedback provided by the CPUC and CDWR-SWP that more understanding of precisely what costs are not being captured under the existing rules that govern transition costs is needed. Determining what costs – if any – are not covered, and what the benefits of changing dramatically the specification of transition costs might be is premature at this point. In line with feedback from SDG&E, the ISO proposes to further examine the need for changes to the specification of commitment costs at a later date when the fleet of resources modeled through the MSG functionality is more complete.

4 Conclusion

The ISO will conduct an on-site stakeholder meeting to review this straw proposal on April 18, 2012. The ISO appreciates stakeholder comments and discussion on this straw proposal. Please send your comments by close of business on April 23, 2012 to comcosts2@caiso.com.

5 Appendix

Below are several charts depicting analyses of daily natural gas spot prices and futures prices. Spot prices are for the SoCal City Gate, SoCal Border, and PGE City Gate delivery points. The futures price is the maximum NYMEX contract price for the first 21 calendar days of the prior calendar month. (Thus, for example, the February 2002 future price is the max of NYMEX prices for January 1 – 21 of 2002.) Data for SoCal City Gate prices are not included until 3rd quarter 2008.

In the first chart below, the maximum spot price is the highest daily price for the calendar month. They are shown along with the futures prices which are calculated using the methodology described above. Figure 1 shows summer price spikes in 2005 and 2008, but that the volatility of fuel prices has significantly diminished recently.

<u>Figure 1</u>: Natural gas future and monthly <u>maximum</u> spot prices

January 2002 – August 2011

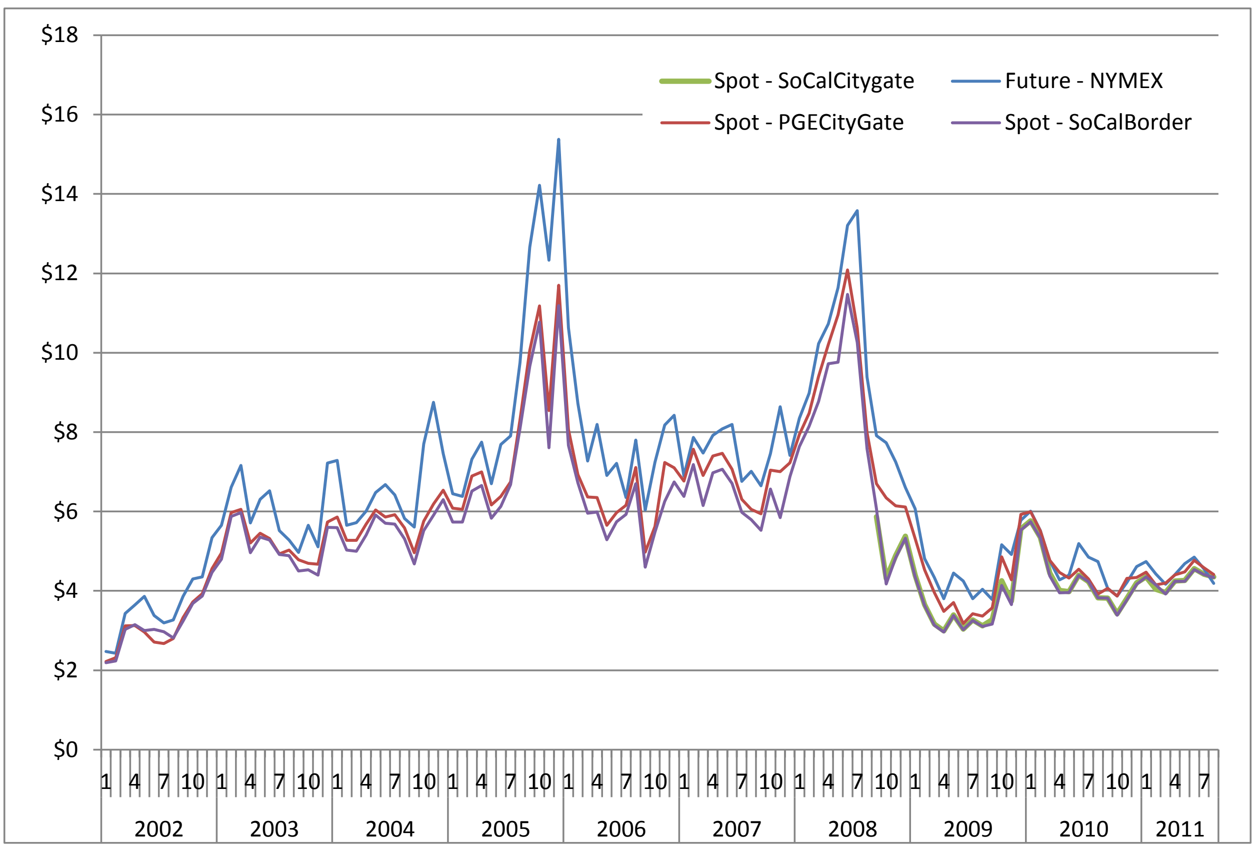
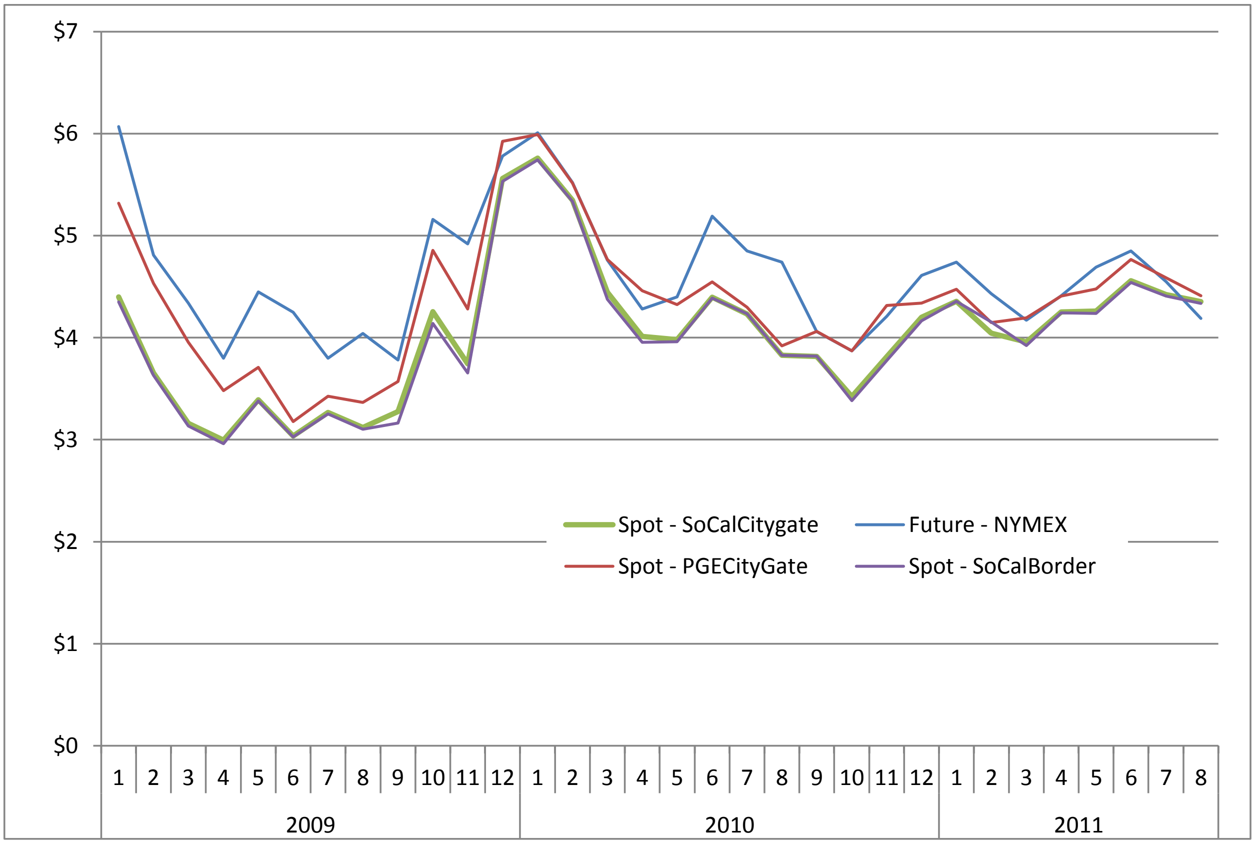


Figure 2, the second of the four charts shows the same data as above, but for a more recent period of time, January 2009 through August of 2011. This chart shows significantly lower price volatility in the last several years.

Figure 2: Natural gas future and monthly maximum spot prices

January 2009 – August 2011



The third and fourth charts below take a different approach to the display of the natural gas prices.[15] To construct Figure 3, first the ratio of the monthly maximum spot price (for each of the three delivery points) as a ratio of the futures price was calculated. Given the sample period, there were 116 observations. The rationale for this calculation is to ascertain the extent to which the futures price is a good instrument by which to hedge against spot price volatility. The percentage differences from each of the monthly maximum spot-to-futures ratio were divided up into bins in 10% increments. For example, if a month's maximum daily spot price were 105% of that same month's futures price, then that would contribute an observation to the "100% to 110%" bin. Also note that the vertical axis is in percentage terms. This describes the percentage of all observations

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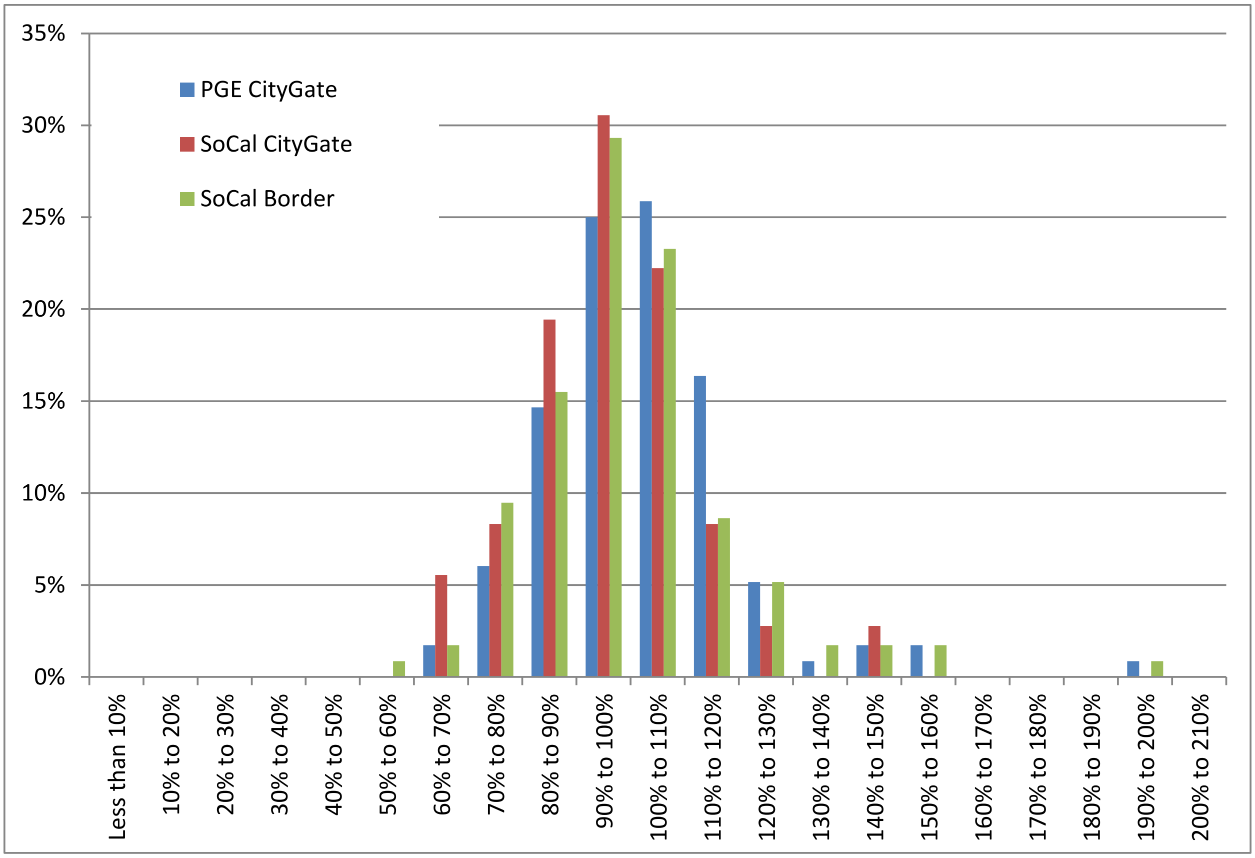
[15] These analyses follow closely the techniques used by the Department of Market Monitoring when the original registered cost option cap was being developed: *MRTU Market Power Mitigation: Bid Caps for Start-Up and Minimum Load Costs Draft Revised Proposal* (August 8, 2007)

that fall into each bin. Again for example, over the entire sample, 25% of the PGE City Gate ratios of maximum spot price to futures price were in "90% to 100%" bin.

Figure 3: Frequency of maximum spot as a percentage of futures price

January 2002 – August 2011



The data behind Figure 3 are included below:

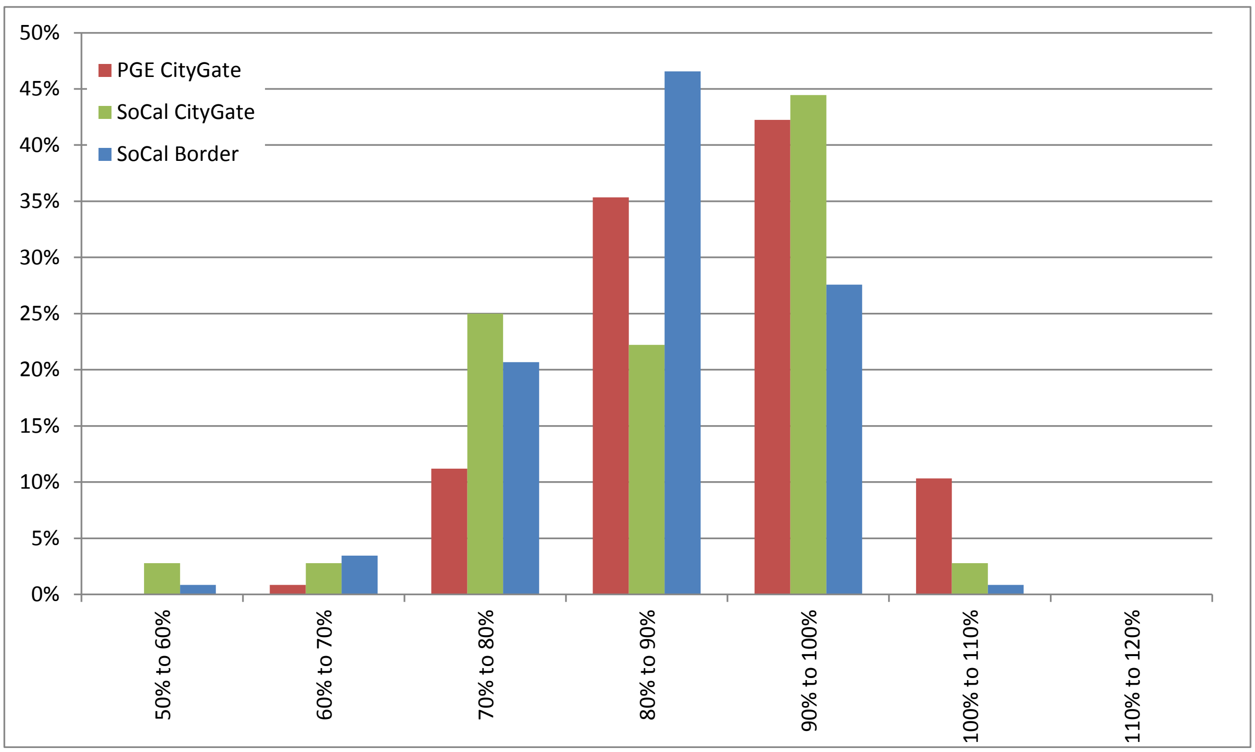
Bin	PGE CityGate	SoCal CityGate	SoCal Border
Less than 10%	0%	0%	0%
10% to 20%	0%	0%	0%
20% to 30%	0%	0%	0%
30% to 40%	0%	0%	0%
40% to 50%	0%	0%	0%
50% to 60%	0%	0%	1%
60% to 70%	2%	6%	2%
70% to 80%	6%	8%	9%
80% to 90%	15%	19%	16%
90% to 100%	25%	31%	29%
100% to 110%	26%	22%	23%
110% to 120%	16%	8%	9%
120% to 130%	5%	3%	5%

130% to 140%	1%	0%	2%
140% to 150%	2%	3%	2%
150% to 160%	2%	0%	2%
160% to 170%	0%	0%	0%
170% to 180%	0%	0%	0%
180% to 190%	0%	0%	0%
190% to 200%	1%	0%	1%
200% to 210%	0%	0%	0%

Figure 4 shows utilizes the same basic principle as that used for Figure 3, however, the %age differences from each of the monthly average spot-to-futures ratio were divided up into bins in 10% increments. This chart shows what one would expect: that the ratio of average spot-to futures price is skewed reflecting the risk premium associated with buying natural gas in advance. By buying a futures contract, one pays a premium to lock in that monthly price. Still, for over 90% of all three delivery points fall into the bins spanned by 70% to 100%.

Figure 4: Frequency of average spot as a percentage of future

January 2002 – August 2011



The data behind Figure 4 are included below:

Bin	PGE CityGate	SoCal CityGate	SoCal Border
50% to 60%	0%	3%	1%
60% to 70%	1%	3%	3%

70% to 80%	11%	25%	21%
80% to 90%	35%	22%	47%
90% to 100%	42%	44%	28%
100% to 110%	10%	3%	1%
110% to 120%	0%	0%	0%