California Independent
System Operator Corporation

October 29, 2012

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER13- ___-000

Tariff Amendment to Allow Recovery of Greenhouse Gas Compliance Costs

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") submits this amendment to its tariff to include greenhouse gas compliance costs in the calculations set forth in the ISO tariff for determining resource commitment costs (start-up and minimum load costs), default energy bids (bids used in the automated local market power mitigation process), and generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).[1] The ISO requests that the Commission accept these tariff revisions effective as of January 1, 2013, so that they go into effect on the same date that the California Air Resources Board ("CARB") plans to implement its new cap-and-trade program for greenhouse gas emissions.

This tariff amendment is just and reasonable as it provides for cost recovery of an additional cost that resources with a CARB compliance obligation will incur as of January 1, 2013. The ISO requests that the Commission issue its order by December 28, 2012 (*i.e.*, 60 days from the date of this filing) to provide the ISO with several days after issuance of the order to allow for orderly deployment of the software and business systems necessary to implement these changes.

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1 The ISO submits this filing pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d. Capitalized terms not otherwise defined herein have the meanings set forth in the ISO tariff. References to numbered sections are references to sections of the ISO tariff unless otherwise indicated.

I. Background

Pursuant to its tariff, the ISO performs optimized economic commitment of resources in the markets it operates based on the resources' market bids as well as their commitment costs, which consist of the costs of starting up the resources (start-up costs) and the costs of running the resources at their minimum operating levels (minimum load costs). On a 30-day basis, scheduling coordinators for resources may choose either the proxy cost option or the registered cost option for specifying their start-up costs and their minimum load costs to be used for the resources in the ISO markets processes.[2] The ISO tariff includes provisions for calculating these commitment costs under the proxy cost option[3] and for calculating maximum commitment cost values registered in the Master File for resources that choose the registered cost option.[4]

Further, the ISO tariff includes incremental energy costs in the calculation of default energy bids and generated bids. Default energy bids are used to mitigate generator bids that are identified as having potential market power and are calculated for each resource under one of three options: the variable cost option, the negotiated rate option, or the locational marginal price option.[5] Generated bids are generated by the ISO when a bid is not submitted by a scheduling coordinator and is required for a resource adequacy requirement or other purpose set forth in the ISO tariff.[6]

On February 8, 2012, the ISO initiated a stakeholder process called Commitment Costs Refinements 2012 to discuss possible modifications to these and other ISO tariff provisions in several respects.[7] The first set of tariff changes produced by that stakeholder process is the subject of the instant filing: revisions to include greenhouse gas costs in the calculation of commitment costs and incremental energy costs.[8]

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2 ISO tariff section 30.4.

3 ISO tariff section 30.4.1.1.

4 ISO tariff section 39.6.1.6.

5 ISO tariff section 39.7.1.

6 ISO tariff sections 30.7.3.4, 40.6.8; ISO tariff Appendix A (definition of generated bid).

7 Materials relating to this stakeholder process are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx.

8 In subsequent filings, the ISO will propose tariff changes as needed to implement other proposals coming out of the stakeholder process for Commitment Costs Refinements 2012.

The ISO proposes these tariff revisions to reflect the fact that the CARB plans to implement a cap-and-trade program for greenhouse gas emissions on January 1, 2013. The cap-and-trade program will establish an overall limit on greenhouse gas emissions from capped sectors, including electricity generating facilities, and facilities subject to the cap will be obligated to acquire allowances to emit greenhouse gases.[9] By slowly lowering the number of available allowances over a period of years, the cap-and-trade program is intended to reduce greenhouse gas emissions to 1990 levels by the year 2020 and ultimately to achieve an 80 percent reduction from 1990 levels by 2050. The CARB will distribute greenhouse gas allowances by allocating them at no cost to various entities and by selling them at periodic auctions, while also permitting bilateral trading of allowances.[10]

The California cap-and-trade program will apply to the emissions of in-state generators and the emissions of the generation behind energy imported from outside the state. The resources subject to California's greenhouse gas regulations include those fueled by natural gas (which constitute the vast majority of such resources), coal, and oil, as well as cogeneration facilities. The greenhouse gas regulations will not apply to resources that emit less than the equivalent of 25,000 metric tons of carbon dioxide (mtCO2) annually.[11]

California's cap-and-trade program is somewhat similar to the Regional Greenhouse Gas Initiative ("RGGI") that applies in a number of states in the balancing authority areas of the eastern independent system operators – PJM, the New York Independent System Operator, and ISO New England. Similar to California's program, the RGGI includes an overall cap on and allowances for greenhouse gas costs that are sold at auction and can be traded bilaterally.[12]

As a result of the California cap-and-trade program, each resource subject to California's greenhouse gas regulations will bear a per-megawatt-hour cost associated with the greenhouse gas allowance needed for its energy output.[13] Nearly unanimously, participants in the stakeholder process for Commitment Costs Refinements 2012 expressed support for making those costs a component

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[9] A facility can also meet a limited portion of its greenhouse gas allowance obligation by developing or purchasing the rights to a greenhouse gas offset project.

[10] Information regarding the cap-and-trade program is available on the CARB's website at http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

[11] *See* http://www.arb.ca.gov/regact/2010/capandtrade10/finalfro.pdf, at §§ 95812, 95852.2.

[12] Background information regarding the RGGI is available at http://www.rggi.org/.

[13] Greenhouse gas emissions are proportional to the amount of fuel burned by the resource.

of the calculations under the existing ISO tariff for start-up and minimum load costs, as well as a component of the calculations under the existing tariff for default energy bids and generated bids.[14]

Working out the inclusion of greenhouse gas costs in the calculations under the ISO tariff was the subject of stakeholder discussion starting in February 2012. The stakeholder process included issuance by the ISO of an issue paper, a straw proposal, and a draft final proposal. In addition, the ISO's Department of Market Monitoring ("DMM") issued a white paper in the stakeholder process that included proposed equations for incorporating greenhouse gas costs.[15] As discussed below, the ISO adopted the DMM's proposal for calculating greenhouse gas costs.

The ISO held a total of three conference calls with stakeholders to discuss each of these documents and provided opportunities for written stakeholder comments. The ISO Governing Board authorized the ISO to prepare and submit this tariff amendment at its May 17, 2012 meeting.[16] Subsequently, the ISO drafted proposed tariff revisions to implement the proposal, provided another opportunity for written stakeholder comments, held a conference call on the draft tariff revisions, and updated the draft based on stakeholder comments.[17]

II. Proposed Tariff Revisions

A. Calculation of Start-Up and Minimum Load Costs

Section 30.4.1.1 of the existing ISO tariff sets forth provisions for calculating start-up costs and minimum load costs under the proxy cost option for both natural gas-fired resources and non-natural gas-fired resources. The ISO proposes to break out existing section 30.4.1.1 into new sections 30.4.1.1.1, 30.4.1.1.2, and 30.4.1.1.3, in order to make the different sets of tariff provisions more readily understandable, and to modify the provisions to add the costs of

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[14] Throughout this filing, the ISO uses the phrase "greenhouse gas costs" to mean the costs of greenhouse gas allowances pursuant to California's cap-and-trade program.

[15] *California Greenhouse Gas Cap and Generation Variable Costs*, issued by the DMM on February 10, 2012 ("DMM White Paper"). The DMM White Paper is provided in Attachment C to this filing and is available on the ISO's website at http://www.caiso.com/Documents/WhitePaper_CaliforniaGreenhouseGasCap_GenerationVariableCosts.pdf.

[16] Materials related to the ISO Governing Board's approval are posted on the ISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx.

[17] A list of key dates in the stakeholder process is provided in Attachment E to this filing.

greenhouse gas allowances as a new component of the existing calculations of start-up and minimum load costs.

As set forth in section 30.4.1.1.1, start-up costs for natural gas-fired resources include a greenhouse gas cost adder for each resource registered with the CARB as having a greenhouse gas compliance obligation, which is calculated for each start-up as the product of the resource's fuel requirement per start-up, the greenhouse gas emissions rate authorized by the CARB, and the applicable greenhouse gas allowance price.[18] Section 30.4.1.1.1 also states that minimum load costs for such resources include a greenhouse gas cost adder for each resource registered with the CARB as having a greenhouse gas compliance obligation, which is calculated as the product of the resource's fuel requirement at minimum load, the greenhouse gas emissions rate authorized by the CARB, and the applicable greenhouse gas allowance price.

These calculations track the equations for including greenhouse gas costs in the calculations of start-up and minimum load costs set forth in the DMM White Paper.[19] It is just and reasonable to include the greenhouse gas costs as an additional component of the ISO's existing calculations of start-up and minimum load costs, especially given the inclusion of provisions in the ISO tariff to allow generators to recover emission mitigation costs.[20] Further, including the greenhouse gas costs as variable costs of generation under the ISO tariff is also comparable to the approaches the eastern independent system operators (in particular, ISO New England) have taken in order to incorporate the costs of greenhouse gas allowances incurred pursuant to the RGGI as components of the calculations of variable generation costs under their tariffs and operating manuals.[21]

Section 30.4.1.1.2 states that start-up costs and minimum load costs for non-natural gas-fired resources include greenhouse gas allowance costs for

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[18] The greenhouse gas allowance price is calculated pursuant to new section 39.7.1.1.1.4 of the tariff, which is discussed below.

[19] DMM White Paper at 11-13; Draft Final Proposal, Commitment Costs Refinements 2012, at 7-8 (Apr. 10, 2012) ("Draft Final Proposal"). The Draft Final Proposal is provided in Attachment D to this filing and is available on the ISO's website at http://www.caiso.com/Documents/DraftFinalProposal-CommitmentCostRefinements.pdf. The ISO also notes that, consistent with the recommendation of the DMM, the ISO's calculations do not include any administrative fees associated with compliance with California's cap-and-trade program. Draft Final Proposal at 8

[20] *See San Diego Gas & Electric Co.*, 95 FERC ¶ 61,418, at 62,561-62 (2001) (accepting tariff amendment to allow for recovery of emissions costs).

[21] DMM White Paper at 10-12 (describing methods used by eastern independent system operators to account for greenhouse gas costs).

each resource registered with the CARB as having a greenhouse gas compliance obligation, as provided to the ISO by the resource's scheduling coordinator. In addition, section 30.4.1.1.2 specifies that, for each such resource, the information provided by the scheduling coordinator must be consistent with information submitted to the CARB. These tariff revisions reflect the fact that the set of non-natural gas-fired resources is significantly smaller than the set of natural gas-fired resources and is not homogenous, as it includes resources with different fuel types such as diesel, distillate, and jet fuel. Accordingly, a once-size-fits-all approach to start-up and minimum load costs cannot be utilized and with so few resources in this category, it is not practical to develop unique cost indices based on fuel type. In addition, the information supplied for a non-natural gas-fired resource, including information on greenhouse gas allowance costs, must be accurate and sufficient.[22]

The ISO's sole proposed addition to section 30.4.1.1.3 is a new section title indicating that the section applies to multi-stage generating resources. The ISO also proposes to modify section 30.4.2 of the tariff, which addresses transition costs for such resources, to include the greenhouse gas allowance price and to make other minor clarifications.

Section 39.6.1.6 of the existing ISO tariff states that the maximum start-up cost and minimum load cost values registered in the Master File by scheduling coordinators for resources that elect the registered cost option are limited to 200 percent of the projected proxy cost. The ISO has modified section 39.6.1.6 to add that the calculation of the projected proxy cost will include, for resources with a compliance obligation, a projected greenhouse gas allowance price component.

Consequently, new section 39.6.1.6.2 states that, for resources that are registered with the CARB as having a greenhouse gas compliance obligation, the ISO will calculate a projected greenhouse gas allowance price component to be used in establishing maximum start-up and minimum load costs after the twenty-first day of each month and will post it on the ISO website by the end of that month. The section also states that the projected greenhouse gas allowance price component will be applicable for scheduling coordinators electing the registered cost option until a new projected greenhouse gas allowance price component is calculated and posted on the ISO website. The projected greenhouse gas allowance price component will be calculated by averaging the

[22] *See, e.g.*, ISO tariff section 4.6.4 ("[a]ll information provided to the CAISO regarding the operational and technical constraints in the Master File shall be accurate and actually based on the physical characteristics of the resources"); ISO tariff section 30.4.1.1 ("In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's Proxy Costs, the CAISO will assume that the unit's Start-Up Costs and Minimum Load Costs are zero.").

applicable daily greenhouse gas allowance prices calculated over the first twenty days of the month using the methodology set forth in section 39.7.1.1.1.4 of the tariff (discussed below). The ISO had proposed to use a futures price to calculate the projected greenhouse gas cost similar to how the ISO calculates projected natural gas costs for the registered cost option under the existing tariff. The ISO and stakeholders expressed concern that the futures market may not be sufficiently developed to rely on futures prices. Accordingly, the ISO will rely on an average of the daily price index values. In addition, stakeholders expressed a need for the ISO to have flexibility to develop a default methodology in the Business Practice Manual to be available in the event the tariff methodology cannot be utilized.

B. Calculation of Default Energy Bids

Section 39.7.1.1 of the existing ISO tariff sets forth the methodologies the ISO uses to calculate default energy bids under the variable cost option for natural gas-fired resources and non-natural gas-fired resources, and section 39.7.1.1.1 addresses the calculation of the incremental cost component of such default energy bids. Similar to the revisions to section 30.4.1.1 discussed above, the ISO proposes to break out section 39.7.1.1.1 into new sections 39.7.1.1.1.1, 39.7.1.1.1.2, 39.7.1.1.1.3, and 39.7.1.1.1.4, in order to make the different sets of tariff provisions easier to follow, and to modify the provisions to include the costs of greenhouse gas allowances as a new component of the existing calculations of default energy bids.

Section 39.7.1.1.1.1(b) states that, for each natural gas-fired resource registered with the CARB as having a greenhouse gas compliance obligation, the ISO will calculate a greenhouse gas cost adder as the product of the resource's incremental heat rate, the greenhouse gas emissions rate authorized by the CARB, and the applicable greenhouse gas allowance price. This calculation tracks the equation for including greenhouse gas costs in the calculation of incremental energy costs used for default energy bids as set forth in the DMM White Paper. Also, as noted above, including the greenhouse gas costs as variable costs of generation in the existing calculations under the ISO tariff is just and reasonable and is comparable to the approaches the eastern independent system operators have taken in order to incorporate the costs of greenhouse gas allowances incurred pursuant to the RGGI as components of the calculations of variable generation costs under their tariffs and operating manuals.[23]

Section 39.7.1.1.1.2(b) also states that the cost curves calculated for non-natural gas-fired resources under the existing tariff provisions will include greenhouse gas allowance costs for each such resource registered with the

[23] DMM White Paper at 10-12. *See also* Draft Final Proposal at 7-8.

CARB as having a greenhouse gas compliance obligation, as provided to the ISO by the scheduling coordinator for the resource. This information will be stored, updated, and validated in the Master File. As discussed above, the information supplied for a non-natural gas-fired resource, including information on greenhouse gas allowance costs, must be accurate and sufficient.

Section 39.7.1.1.1.3 mostly retains the existing provisions in section 39.7.1.1 regarding calculation of the natural gas price for use in calculating the default energy bids under the variable cost option for natural gas-fired resources. The ISO has modified the existing tariff provisions to state that the ISO will calculate the natural gas price using gas price indices derived from prices contained in publications identified in the Business Practice Manual, instead of naming the specific publications used to calculate the natural gas price in the tariff. The ISO has made this modification to recognize that the publications or names of publications used to calculate the natural gas price may change over time. Identifying the publications in the Business Practice Manual rather than in the tariff will enable information regarding the publications used to calculate the natural gas price to be promptly updated to reflect these types of changes, without such changes having to be made pursuant to the longer tariff amendment process.

Section 39.7.1.1.1.4 sets forth the methodology for calculating the greenhouse gas allowance price referenced in several of the tariff sections discussed above.[24] This methodology largely parallels the methodology for calculating the natural gas price contained in section 39.7.1.1.1.3. Similar to that preceding tariff section, section 39.7.1.1.1.4 begins by stating that, to calculate the greenhouse gas allowance price, the ISO will use different greenhouse gas price indices for the day-ahead market and the real-time market for each trading day and each greenhouse gas price index will be calculated on a daily basis using at least two prices from two or more publications identified in the Business Practice Manual that set forth indices of prices for greenhouse gas allowances. In other words, as discussed further below, the real-time market for any given trading day will use the most recently published greenhouse gas price index and the day-ahead market for that same trading day will use the greenhouse gas price index published one day earlier.

Section 39.7.1.1.1.4 goes on to state that if a greenhouse gas price index is unavailable for any reason, the ISO will use the most recent available greenhouse gas price index, and if one or more published prices are determined by the ISO not to reflect market fundamentals or if published prices are not available for an extended period, the ISO will establish the greenhouse gas allowance price specified in the Business Practice Manual. In addition, as

[24] The ISO also proposes to revise Appendix A to the ISO tariff to define the greenhouse gas allowance price as a price calculated by the ISO pursuant to section 39.7.1.1.1.4.

discussed above, the average of the daily values calculated pursuant to section 39.7.1.1.1.4 will be used under section 39.6.1.6.2 to calculate the projected greenhouse gas allowance price component to be used in establishing maximum start-up and minimum load costs. Therefore, the ISO has included a provision in section 39.6.1.6.2 stating that the ISO will calculate a projected greenhouse gas allowance price utilizing an alternative methodology specified in the Business Practice Manual if the values calculated pursuant to section 39.7.1.1.1.4 do not reflected market fundamentals.

The ISO proposes to include these latter tariff revisions to address concerns expressed in the stakeholder process that the ISO should have sufficient flexibility to address the potential risks that published prices might not always reflect sufficient market liquidity or stability to be meaningful or might not be available for an extended period. If such an event were to occur, the tariff revisions would permit the ISO to establish a default greenhouse gas allowance price pursuant to the Business Practice Manual using the best information available, which is not known at this time.

Similar to the corresponding provisions in section 39.7.1.1.1.3, section 39.7.1.1.1.4 then states that for the day-ahead market, the ISO will update the greenhouse gas price index using prices for greenhouse gas allowances published on the day that is two days prior to the applicable trading day, unless prices for greenhouse gas allowances are not published on that day, in which case the ISO will use the most recently published prices for greenhouse gas allowances that are available. Similarly, the real-time market will utilize the greenhouse gas price index published one day prior to the applicable trading day, which will also be used in the day-ahead market for the next trading day.

C. Calculation of Generated Bids

The ISO proposes to modify the provisions regarding generated bids in section 30.7.3.4 of the tariff, which addresses validation after market close. The ISO has clarified section 30.7.3.4 to state that the ISO will create a generated bid to the extent that a scheduling coordinator fails to enter a bid for a resource that is required to submit a bid in the full range of available capacity consistent with the bidding provisions of section 30 of the tariff. Also, the ISO has modified section 30.7.3.4 to state that the generated bid will be based on published pricing data for greenhouse gas allowances, if applicable, and that the generated bid components will be calculated as set forth in sections 30 and 40.6.8 of the tariff. The ISO will generate bids on behalf of resource adequacy resources that fail to submit bids. The ISO also generates bids pursuant to generally applicable bidding rules set forth in section 30.

In addition, the ISO has modified section 40.6.8, which addresses the use of generated bids, to state that, as provided in the Business Practice Manuals, a generated bid for energy will include a greenhouse gas cost adder for a resource registered with the CARB as having a greenhouse gas compliance obligation.

III. Effective Date

The ISO requests that the tariff revisions contained in this filing be made effective as of January 1, 2013. As discussed above, that is the date on which the CARB plans to implement its cap-and-trade program for greenhouse gas emissions. The ISO respectfully requests that the Commission issue its order by December 28, 2012 (*i.e.*, 60 days from the date of this filing) to provide the ISO with several days after issuance of the order to allow for orderly deployment of the software and business systems necessary to implement these changes.

IV. Communications

Correspondence and other communications regarding this filing should be directed to:

Nancy Saracino
General Counsel
Sidney M. Davies
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 351-4400
Fax: (916) 608-7296
nsaracino@caiso.com
sdavies@caiso.com

Michael Kunselman
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004
Tel: (202) 239-3300
Fax: (202) 654-4875
michael.kunselman@alston.com
bradley.miliauskas@alston.com

V. Service

The ISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with Scheduling Coordinator Agreements under the ISO tariff. In addition, the ISO has posted a copy of the filing on the ISO website.

VI. Contents of this Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean ISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	DMM White Paper
Attachment D	Draft Final Proposal
Attachment E	List of key dates in the stakeholder process

VII. Conclusion

For the reasons set forth in this filing, the ISO respectfully requests that the Commission accept the tariff revisions proposed in the filing effective as of January 1, 2013.

Respectfully submitted,

/s/ Bradley R. Miliauskas

Nancy Saracino
General Counsel
Sidney M. Davies
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630

Michael Kunselman
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Counsel for the
California Independent System
Operator Corporation

Attachment A – Clean Tariff

Tariff Amendment to Allow Recovery of Greenhouse Gas Compliance Costs

California Independent System Operator

Fifth Replacement FERC Electric Tariff

October 29, 2012

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6.5.2.3.4 Natural Gas and Greenhouse Gas Price Indices

The CAISO will publish relevant natural gas price indices and greenhouse gas price indices when available.

* * *

30.4.1.1 Proxy Cost Option

30.4.1.1.1 Natural Gas-Fired Resources

For each natural gas-fired resource, the Proxy Cost option uses formulas for Start-Up Costs and Minimum Load Costs based on the resource's actual unit-specific performance parameters. The Start-Up Cost and Minimum Load Cost values utilized for each such resource in the CAISO Markets Processes will be either (a) or (b) below:

(a) Formulaic values adjusted for fuel-cost variation on a daily basis as calculated pursuant to a Business Practice Manual.

Start-Up Costs also include: (i) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price; and (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; and (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement at Minimum Load, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

(b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's Proxy Costs, the CAISO will assume that the unit's Start-Up Costs and Minimum Load Costs are zero.

30.4.1.1.2 Non-Natural Gas-Fired Resources

For each non-natural gas-fired resource, Start-Up Cost and Minimum Load Cost values under the Proxy Cost option shall be based on either (a) or (b) below:

(a) The relevant cost information of the particular resource, which will be provided to the CAISO by the Scheduling Coordinator and maintained in the Master File.

Start-Up Costs will include greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; and (ii) greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator.

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with information submitted to the California Air Resources Board.

(b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's Proxy Costs, the CAISO will assume that the unit's Start-Up Costs and Minimum Load Costs are zero.

30.4.1.1.3 Multi-Stage Generating Resources

If a Multi-Stage Generating Resource elects the Proxy Cost option, that election will apply to all the MSG Configurations for that resource. The Proxy Cost values for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration.

* * *

30.4.2 Transition Costs

Scheduling Coordinators may register and the CAISO will validate Transition Costs for Multi-Stage Generating Resources as described below. Once accepted by the CAISO, such Transition Costs will apply until modified and will apply for a minimum of thirty (30) days. Scheduling Coordinators may change their Transition Costs pursuant to the time line that applies to changes to the Master File. During the registration process, the Scheduling Coordinator shall submit a dollar value for each upward Transition Cost, including a Transition Costs multiplier which consists of the Transition Costs dollar value divided by the applicable monthly Thousand Thousand British Thermal Units (MMBtu) Gas Price Index on the day that the Scheduling Coordinator is registering the Transition Costs value with the CAISO. At the time of registration, the CAISO will validate that the upward Transition Costs dollar value and the Transition Costs multiplier are consistent. The CAISO will further validate the upward Transition Costs dollar values using the two rules described below, and will include the validated values in the Master File. The Scheduling Coordinator shall also submit a fuel input value, which consists of a quantity of natural gas in MMBtu, for each downward MSG Transition such that the fuel input value accurately reflects the operating characteristics of the Multi-Stage Generating Resource, which the CAISO may reject if perceived to be inconsistent with such characteristics. Through the Bid validation process in the CAISO Markets, the CAISO will adjust both the downward and upward

Transition Costs by the daily Gas Price Index when Scheduling Coordinators submit Bids into the CAISO Markets for Multi-Stage Generating Resources to calculate the Transition Costs per the submitted Bid.

Rule 1: The CAISO will constrain the Transition Costs along each of the feasible, unidirectional MSG Transition paths from Off to each MSG Configuration such that their sum is between one-hundred (100) percent and one-hundred twenty five (125) percent of the MSG Configuration's proxy Start-Up Cost value plus ten (10) percent; where the MSG Configuration's proxy Start-Up Cost value is determined using the same methodology provided in Section 30.4.1.1 except that the CAISO will use the monthly Gas Price Index and the monthly Greenhouse Gas Allowance Price as opposed to the daily values. If the Scheduling Coordinator flags an MSG Configuration as able to Start-Up as part of its registration requirements in Section 27.8, the CAISO will use a value of $0 as the lower bound for the MSG Transition paths up to the MSG Configuration flagged as able to Start-Up.

Rule 2: The CAISO will validate that the sum of Transition Costs for incremental MSG Transitions along a feasible, unidirectional path between two MSG Configurations is between one-hundred (100) percent and one-hundred twenty five (125) percent of the Transition Cost associated with the direct transition to the target MSG Configuration.

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30.7.3.4 Validation after Market Close

To the extent that a Scheduling Coordinator fails to enter a Bid for a resource that is required to submit a Bid in the full range of available capacity consistent with the bidding provisions of Section 30 or the Resource Adequacy provisions of Section 40, the CAISO will create a Bid for the Scheduling Coordinator, which is referred to as the Generated Bid. This does not apply to Load-following MSSs. The Generated Bid will be created only after the Market Close for the DAM and will be based on data registered in the Master File, and, if applicable, published natural gas pricing data and published pricing data for greenhouse gas allowances. The Generated Bid components will be calculated as set forth in Sections 30 and 40.6.8. The Scheduling Coordinator may view Generated Bids, but may not modify such Bids. The CAISO will provide notice to the Scheduling Coordinator of the use of a Generated Bid prior to Market Clearing of the IFM. In addition, validation of export priority pursuant to Sections 31.4 and 34.10.1 and Wheeling Through transactions pursuant to Section 30.5.4 occur after the Market Close for the DAM.

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39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for resources that elect the Registered Cost option in accordance with Section 30.4 will be limited to 200% of the Projected Proxy Cost. The Projected Proxy Cost will include a gas price component and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 36.6.1.6.

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas-fired resources, the CAISO will calculate a gas price to be used in establishing maximum Start-Up Costs and Minimum Load Costs after the twenty-first day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators electing the Registered Cost option until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery point, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the caps for Start-Up and Minimum Load costs for resources electing the Registered Cost option. The most geographically appropriate will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set forth in the Business Practice Manual will be added to the baseline gas price for each resource that elects the Registered Cost option to create a final gas price for calculating the caps for Start-Up and Minimum Load Costs for each such resource.

For non-natural gas-fired resources, the Projected Proxy Costs for Start-Up Costs and Minimum Load Costs will be calculated using the information contained in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

39.6.1.6.2 Projected Greenhouse Gas Allowance Price

For resources that are registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a projected Greenhouse Gas Allowance Price component to be used in establishing maximum Start-Up Costs and Minimum Load Costs after the twenty-first day of each month and will post it on the CAISO Website by the end of that month. The projected Greenhouse Gas Allowance Price component will be applicable for Scheduling Coordinators electing the Registered Cost option until a new projected Greenhouse Gas Allowance Price component is calculated and posted on the CAISO Website. The projected Greenhouse Gas Allowance Price component will be calculated by averaging the applicable daily Greenhouse Gas Allowance Prices calculated over the first twenty (20) days of the month using the methodology set forth in Section 39.7.1.1.1.4. If Greenhouse Gas Allowance Prices calculated pursuant to Section 39.7.1.1.1.4 do not reflect market fundamentals, the CAISO will calculate a projected Greenhouse Gas Allowance Price using the methodology specified in the Business Practice Manual.

* * *

39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, adding ten percent (10%) to the sum, and adding a Bid Adder if applicable. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel cost plus ten percent (10%) of fuel cost plus a Bid Adder if applicable.

39.7.1.1.1 Incremental Cost Calculations Under the Variable Cost Option

39.7.1.1.1.1 Natural Gas-Fired Resources

(a) Calculation of incremental fuel cost – For natural gas-fueled units, incremental fuel cost is calculated based on an incremental heat rate curve multiplied by the natural gas price calculated as described below.

Resource owners shall submit to the CAISO average heat rates (Btu/kWh) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average heat rate pairs yield one (1) incremental heat rate segment that spans two (2) consecutive operating points. The incremental heat rates (Btu/kWh) in the incremental heat rate curve are calculated by converting the average heat rates submitted by resource owners to the CAISO to requirements of heat input (Btu/h) for each of the operating points and dividing the changes in requirements of heat input from one (1) operating point to the next by the changes in MW between two (2) consecutive operating points as specified in the Business Practice Manual. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental heat rate is limited to the maximum of the average heat rates for the two (2) operating points used to calculate the incremental heat rate segment. The unit's final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Heat rate and cost curves shall be stored, updated, and validated in the Master File.

(b) Calculation of greenhouse gas cost adder – For each natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a greenhouse gas cost adder as the product of the resource's incremental heat rate, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

39.7.1.1.1.2 Non-Natural Gas-Fired Resources

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Cost curves will include greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource. Cost curves shall be stored, updated, and validated in the Master File.

39.7.1.1.1.3 Calculation of Natural Gas Price

To calculate the natural gas price, the CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market and each gas price index will be calculated using at least two prices from two or more publications identified in the Business Practice Manual. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index. For the Day-Ahead Market, the CAISO will update the gas price index between 19:00 and

22:00 Pacific Time using natural gas prices published on the day that is two (2) days prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available. For the Real-Time Market, the CAISO will update gas price indices between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one (1) day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

39.7.1.1.1.4 Calculation of Greenhouse Gas Allowance Price

To calculate the Greenhouse Gas Allowance Price, the CAISO will use different greenhouse gas price indices for the Day-Ahead Market and the Real-Time Market and each greenhouse gas price index will be calculated on a daily basis using at least two prices from two or more publications identified in the Business Practice Manual that set forth indices of prices for greenhouse gas allowances. If a greenhouse gas price index is unavailable for any reason, the CAISO will use the most recent available greenhouse gas price index. If one or more published prices are determined by the CAISO not to reflect market fundamentals or if published prices are not available for an extended period, the CAISO will establish the Greenhouse Gas Allowance Price using the methodology specified in the Business Practice Manual. For the Day-Ahead Market, the CAISO will update the greenhouse gas price index between 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published on the day that is two (2) days prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. For the Real-Time Market, the CAISO will update greenhouse gas price indices between the hours of 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published one (1) day prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. The CAISO will calculate each Greenhouse Gas Allowance Price during a year using prices for greenhouse gas allowances from that same year.

* * *

40.6.8 Use Of Generated Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Sections 40.5.1 or 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market. Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market. If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage. As provided in the Business Practice Manuals, a Generated Bid for Energy will be calculated and will include a greenhouse gas cost adder for a resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation. A Generated Bid for Ancillary Services will equal zero dollars ($0/MW-hour). Notwithstanding any of the provisions of Section 40.6.8 set forth above, the CAISO will not insert any Bid in the Real-Time Market required under this Section 40 for a Resource Adequacy Resource that is a Use-Limited Resource unless the resource submits an Energy Bid and fails to submit an Ancillary Service Bid.

* * *

Appendix A

Master Definitions Supplement

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- Greenhouse Gas Allowance Price

A price calculated by the CAISO pursuant to Section 39.7.1.1.1.4.

* * *

- Projected Proxy Cost

A calculation of a resource's Start-Up Costs and Minimum Load Costs for a prospective period used to determine the maximum Registered Cost for the resource {as set forth in Section 39.6.1.6 for a 30-day period as set forth in Section 30.4.}

* * *

Attachment B – Marked Tariff

Tariff Amendment to Allow Recovery of Greenhouse Gas Compliance Costs

California Independent System Operator

Fifth Replacement FERC Electric Tariff

October 29, 2012

* * *

6.5.2.3.4 Natural Gas and Greenhouse Gas Price Indices

The CAISO will publish relevant natural gas price indices and greenhouse gas price indices when available.

* * *

30.4.1.1 Proxy Cost Option

30.4.1.1.1 Natural Gas-Fired Resources

For each natural gas-fired resource~~s~~, the Proxy Cost option uses ~~fuel-cost adjusted~~ formulas for Start-Up Costs and Minimum Load Costs based on the resource's actual unit-specific performance parameters. The Start-Up Cost~~s~~ and Minimum Load Cost~~s~~ values utilized for each such resource in the CAISO Markets Processes will be either (a) or (b) below:

(a) ~~either be these f~~Formulaic values adjusted for fuel-cost variation on a daily basis as calculated pursuant to a Business Practice Manual.~~, or values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.~~

Start-Up Costs also include: (i) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price; and (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

Minimum Load Costs also include~~s~~: (i) operation~~s~~ and maintenance costs as provided in Section 39.7.1.1.2; and (ii) a greenhouse gas cost adder for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource's fuel requirement at Minimum Load, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

(b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's Proxy Costs, the CAISO will assume that the unit's Start-Up Costs and Minimum Load Costs are zero.

30.4.1.1.2 Non-Natural Gas-Fired Resources

For each non-natural gas-fired~~all other~~ resource~~s~~, ~~this option~~ Start-Up Cost and Minimum Load Cost values under the Proxy Cost option shall be based on either (a) or (b) below:

(a) ~~t~~The relevant cost information of the particular resource, which will be provided to the CAISO by the Scheduling Coordinator and maintained in the Master File.~~, or values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.~~

Start-Up Costs will include greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator.

Minimum Load Costs also include: (i) operation and maintenance costs as provided in Section 39.7.1.1.2; and (ii) greenhouse gas allowance costs for each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator.

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with information submitted to the California Air Resources Board.

(b) Values specified by Scheduling Coordinators pursuant to Sections 30.7.9 and 30.7.10.

In the event that the Scheduling Coordinator for a unit does not provide sufficient data for the CAISO to determine the unit's Proxy Costs, the CAISO will assume that the unit's Start-Up Costs and Minimum Load Costs are zero.

30.4.1.1.3 Multi-Stage Generating Resources

If a Multi-Stage Generating Resource elects the Proxy Cost option, that election will apply to all the MSG Configurations for that resource. The Proxy Cost values for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration.

* * *

30.4.2 Transition Costs

Scheduling Coordinators may register and the CAISO will validate Transition Costs for Multi-Stage Generating Resources as described below. Once accepted by the CAISO, such Transition Costs will apply until modified and will apply for a minimum of thirty (30) days. Scheduling Coordinators may change their Transition Costs pursuant to the time line that applies to changes to the Master File. During the registration process, the Scheduling Coordinator shall submit a dollar value for each upward Transition Cost, including a Transition Costs multiplier which consists of the Transition Costs dollar value divided by the applicable monthly Thousand Thousand British Thermal Units (MMBtu) Gas Price Index on the day that the Scheduling Coordinator is registering the Transition ~~c~~Costs value with the CAISO. At the time of registration, the CAISO will validate that the upward Transition Costs dollar value and the Transition Costs multiplier are consistent. The CAISO will further validate the upward Transition Costs dollar values using the two rules described below, and will include the validated values in the Master File. The Scheduling Coordinator shall also submit a fuel input value, which consists of a quantity of natural gas in MMBtu, for each downward MSG Transition such that the fuel input value accurately reflects the operating characteristics of the Multi-Stage Generating Resource, which the CAISO may reject if perceived to be inconsistent with such characteristics. Through the Bid validation process in the CAISO Markets, the CAISO will adjust both the downward and upward Transition Costs by the daily Gas Price Index when Scheduling Coordinators submit Bids into the CAISO Markets for Multi-Stage Generating Resources to calculate the Transition Costs per the submitted Bid.~~ For the first thirty (30) days following the effective date of this provisions, if the CAISO is not able to validate the Transition Costs amounts submitted by the Scheduling Coordinator for a Multi-Stage Generating Resource prior to the effective date of this provision, the applicable Transition Costs for this first month shall be $0.~~

Rule 1: The CAISO will constrain the Transition Costs along each of the feasible, unidirectional MSG Transition paths from Off to each MSG Configuration such that their sum is between one-hundred (100) percent and one-hundred twenty five (125) percent of the MSG Configuration's proxy Start-Up Cost value plus ten (10) percent; where the MSG Configuration's proxy Start-Up Cost value is determined using the same methodology provided in Section 30.4.1.1 except that the CAISO will use the monthly Gas Price Index and the monthly Greenhouse Gas Allowance Price as opposed to the daily values. If the Scheduling Coordinator flags an MSG Configuration as able to Start-Up as part of its registration requirements in Section 27.8, the CAISO will use a value of $0 as the lower bound for the MSG Transition paths up to the MSG Configuration flagged as able to Start-Up.

Rule 2: The CAISO will validate that the sum of Transition Costs for incremental MSG Transitions along a feasible, unidirectional path between two MSG Configurations is between one-hundred (100) percent and one-hundred twenty five (125) percent of the Transition Cost associated with the direct transition to the target MSG Configuration.

* * *

30.7.3.4 Validation after Market Close

To the extent that a Scheduling Coordinator~~s~~ fails to enter a Bid for a resource that is required to submit a Bid~~s~~ in the full range of available capacity consistent with the bidding provisions of Section 30 or the Resource Adequacy provisions of Section 40, the CAISO will create a Bid for the Scheduling Coordinator, which is referred to as the Generated Bid. This does not apply to

Load-following MSSs. The Generated Bid will be created only after the Market Close for the DAM and will be based on data registered in the Master File, and, if applicable, published natural gas pricing data and published pricing data for greenhouse gas allowances. The Generated Bid components will be calculated as set forth in Sections 30 and 40.6.8. The Scheduling Coordinator may view Generated Bids, but may not modify such Bids. The CAISO will provide notice to the Scheduling Coordinator of the use of a Generated Bid prior to Market Clearing of the IFM. In addition, validation of export priority pursuant to Sections 31.4 and 34.10.1 and Wheeling Through transactions pursuant to Section 30.5.4 occur after the Market Close for the DAM.

* * *

39.6.1.6 Maximum Start-Up Cost and Minimum Load Cost Registered Cost Values

The maximum Start-Up Cost and Minimum Load Cost values registered in the Master File by Scheduling Coordinators for resources that elect the Registered Cost option in accordance with Section 30.4 will be limited to 200% of the Projected Proxy Cost. The Projected Proxy Cost will include a gas price component and, if eligible, a projected Greenhouse Gas Allowance Price component calculated as set forth in this Section 36.6.1.6.

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas-fired resources, the CAISO will calculate a gas price to be used in establishing maximum Start-Up Costs and Minimum Load Costs after the twenty-first day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators electing the Registered Cost option until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery point, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the caps for Start-Up and Minimum Load costs for resources electing the Registered Cost option. The most geographically appropriate will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set forth in the Business Practice Manual will be added to the baseline gas price for each resource that elects the Registered Cost option to create a final gas price for calculating the caps for Start-Up and Minimum Load Costs for each such resource.

For non-natural gas-fired resources, the Projected Proxy Costs for Start-Up Costs and Minimum Load Costs will be calculated using the information contained in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

39.6.1.6.2 Projected Greenhouse Gas Allowance Price

For resources that are registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a projected Greenhouse Gas Allowance Price component to be used in establishing maximum Start-Up Costs and Minimum Load Costs after the twenty-first day of each month and will post it on the CAISO Website by the end of that month. The projected Greenhouse Gas Allowance Price component will be applicable for Scheduling Coordinators electing the Registered Cost option until a new projected Greenhouse Gas Allowance Price component is calculated and posted on the CAISO Website. The projected Greenhouse Gas Allowance Price component will be calculated by averaging the applicable daily Greenhouse Gas Allowance Prices calculated over the first twenty (20) days of the month using the methodology set forth in Section 39.7.1.1.1.4. If Greenhouse Gas Allowance Prices calculated pursuant to Section 39.7.1.1.1.4 do not reflect market fundamentals, the CAISO will calculate a projected Greenhouse Gas Allowance Price using the methodology specified in the Business Practice Manual.

* * *

39.7.1.1 Variable Cost Option

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental ~~fuel~~ cost (comprised of incremental fuel cost plus a greenhouse gas cost adder if applicable) with variable operation and maintenance cost, adding ten percent (10%) to the sum, and adding a Bid Adder if applicable. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel cost plus ten percent (10%) of fuel cost plus a Bid Adder if applicable.

39.7.1.1.1 Incremental ~~Fuel~~ Cost Calculations Under the Variable Cost Option

39.7.1.1.1.1 Natural Gas-Fired Resources

(a) Calculation of incremental fuel cost – For natural gas-fueled units, incremental fuel cost is calculated based on an incremental heat rate curve multiplied by the natural gas price calculated as described below.

Resource owners shall submit to the CAISO average heat rates (Btu/kWh) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average heat rate pairs yield one (1) incremental heat rate segment that spans two (2) consecutive operating points. The incremental heat rates (Btu/kWh) in the incremental heat rate curve are calculated by converting the average heat rates submitted by resource owners to the CAISO to requirements of heat input (Btu/h) for each of the operating points and dividing the changes in requirements of heat input from one (1) operating point to the next by the changes in MW between two (2) consecutive operating points as specified in the Business Practice Manual. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental heat rate is limited to the maximum of the average heat rates for the two (2) operating points used to calculate the incremental heat rate segment.

The unit's final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Heat rate and cost curves shall be stored, updated, and validated in the Master File.

(b) Calculation of greenhouse gas cost adder – For each natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a greenhouse gas cost adder as the product of the resource's incremental heat rate, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

39.7.1.1.1.2 Non-Natural Gas-Fired Resources

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Cost curves will include greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling

Coordinator for the resource. Cost curves shall be stored, updated, and validated in the Master File.

39.7.1.1.1.3 Calculation of Natural Gas Price

~~Heat rate curves and average cost curves shall be stored, updated, and validated in the Master File.~~ To calculate the natural gas price, the CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market and each gas price index will be calculated using at least two prices from two or more ~~of the following~~ publications identified in the Business Practice Manual.~~: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily and the Intercontinental Exchange.~~ If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index. For the Day-Ahead Market, the CAISO will update the gas price index between 19:00 and 22:00 Pacific Time using natural gas prices published on the day that is two (2) days prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available. For the Real-Time Market, the CAISO will update gas price indices between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one (1) day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

39.7.1.1.1.4 Calculation of Greenhouse Gas Allowance Price

To calculate the Greenhouse Gas Allowance Price, the CAISO will use different greenhouse gas price indices for the Day-Ahead Market and the Real-Time Market and each greenhouse gas price index will be calculated on a daily basis using at least two prices from two or more publications identified in the Business Practice Manual that set forth indices of prices for greenhouse gas allowances. If a greenhouse gas price index is unavailable for any reason, the CAISO will use the most recent available greenhouse gas price index. If one or more published prices are determined by the CAISO not to reflect market fundamentals or if published prices are not available for an extended period, the CAISO will establish the Greenhouse Gas Allowance Price using the methodology specified in the Business Practice Manual. For the Day-Ahead Market, the CAISO will update the greenhouse gas price index between 19:00 and 22:00 Pacific

Time using prices for greenhouse gas allowances published on the day that is two (2) days prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. For the Real-Time Market, the CAISO will update greenhouse gas price indices between the hours of 19:00 and 22:00 Pacific Time using prices for greenhouse gas allowances published one (1) day prior to the applicable Trading Day, unless prices for greenhouse gas allowances are not published on that day, in which case the CAISO will use the most recently published prices for greenhouse gas allowances that are available. The CAISO will calculate each Greenhouse Gas Allowance Price during a year using prices for greenhouse gas allowances from that same year.

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40.6.8 Use Of Generated Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Sections 40.5.1 or 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market. Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market. If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage. ~~A Generated Bid for Energy will be calculated a~~As provided in the Business Practice Manuals, a Generated Bid for Energy will be calculated and will include a greenhouse gas cost adder for a resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation. A Generated Bid for Ancillary Services will equal zero dollars ($0/MW-hour). Notwithstanding any of the provisions of Section 40.6.8 set forth above, the CAISO will not insert any Bid in the Real-Time Market required under this Section 40 for a Resource Adequacy Resource that is a Use-Limited Resource unless the resource submits an Energy Bid and fails to submit an Ancillary Service Bid.

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Appendix A

Master Definitions Supplement

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- Greenhouse Gas Allowance Price

A price calculated by the CAISO pursuant to Section 39.7.1.1.1.4.

* * *

- Projected Proxy Cost

A calculation of a resource's Start-Up Costs and Minimum Load Costs for a prospective period used to determine the maximum Registered Cost for the resource {as set forth in Section 39.6.1.6~~.1~~ for a 30-day period as set forth in Section 30.4.}

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Attachment C – DMM White Paper

Tariff Amendment to Allow Recovery of Greenhouse Gas Compliance Costs

California Independent System Operator

Fifth Replacement FERC Electric Tariff

October 29, 2012

California Greenhouse Gas Cap and Generation Variable Costs

White Paper

Department of Market Monitoring

February 10, 2012

Contents

Introduction

California will implement a greenhouse gas cap and trade program beginning in 2013 that will apply to electrical power generation, among various other sources of greenhouse gasses. The California ISO Department of Market Monitoring (DMM) has prepared this paper to summarize California's upcoming greenhouse gas cap regulations and outline an approach for incorporating the costs of greenhouse gas allowance costs into the ISO's calculation of generating units' variable costs.

The ISO currently calculates generating units' variable energy costs for energy, start-up, minimum load, and transitions between multi-stage generator configurations. The ISO uses these costs to:

- Create default energy bids used for market power mitigation.[1]
- Calculate bid caps for minimum load and start-up costs.
- Create energy, minimum load and start-up bids in the event a market participant does not submit a required bid.

Market participants will incur costs under the greenhouse gas cap regulations to cover the greenhouse gas emissions of the generation under their control. As these emissions are proportional to a generating unit's energy output, it seems appropriate to include the cost of greenhouse gas allowances in the ISO's calculation of generating units' variable costs.

This paper:

- Provides a brief overview of how California will implement its greenhouse gas cap regulations, as they relate to electrical power generation.
- Summarizes the ISO's calculations of generating units' variable costs for energy, start-up, minimum load, and transitions between multi-stage generator configurations.
- Describes the methods used by other ISOs to account for greenhouse gas emission costs under the Regional Greenhouse Gas Initiative (RGGI) in effect in the eastern United States.
- Outlines a method for the ISO to account for greenhouse gas emission in its calculation of generating unit variable costs. This method calculates CO_2 emissions for each natural gas-fired units based on a standard emission rate and each unit's heat rate and start-up fuel characteristics. It determines the CO_2 compliance instrument price based on a daily published index. Market participants would provide emission rates for other types of resources to the ISO.

California's greenhouse gas cap

California is scheduled to begin to enforce its greenhouse gas cap in 2013 under regulations administered by the California Air Resources Board (CARB). These regulations will apply to various

[1] Default energy bids are calculated for the ISO by Potomac Economics, an independent entity under contract to the ISO.

sources of greenhouse gasses, including electrical power generation. California's greenhouse gas cap is referred to as a "cap and trade program" because it establishes a statewide aggregate cap on greenhouse gas emissions, but not specific limits for individual greenhouse gas sources.

The cap will establish a limited quantity of compliance instruments that entities operating sources of greenhouse gasses, such as electric generators, will have to acquire to cover their greenhouse gas emissions. Because the compliance instruments will be able to be bought and sold, entities will make economic decisions whether to use them to emit greenhouse gasses, or to reduce their emissions and sell the compliance instruments they control to others that cannot reduce emissions as economically.

In the electrical power generation industry, the cap will apply to the emissions of in-state generators and to the emissions of the generation behind energy imported from out of the state. The overall greenhouse gas cap for 2013 will be set at 2 percent below 2012's forecast emissions. The cap will decline 2-3 percent every year until 2020, when it will be about 15 percent below 2012 levels.[2]

A similar cap and trade program, the Regional Greenhouse Gas Initiative (RGGI), has been in effect in the eastern United States since 2009. It covers ten states in the northeast and mid-Atlantic region and is a mandatory CO_2 cap that applies only to the electrical power sector. A number of the states within RGGI are within the eastern ISOs, (i.e. PJM, New York ISO, and ISO New England).

Greenhouse gas compliance instruments

The primary compliance instrument for the California cap will be "allowances" issued by the Air Resources Board. Entities controlling greenhouse gas sources will also be able to meet up to 8 percent of their obligation with "offsets." These offsets will be issued for things such as reforestation projects that reduce greenhouse gasses, and for qualified greenhouse gas reduction actions entities undertook prior to the initial compliance period. Entities will demonstrate compliance by periodically surrendering compliance instruments to the Air Resources Board.

Allowance distribution

The Air Resources Board will distribute allowances by allocating them at no cost to various entities and selling them at periodic auctions. An allowance will convey the right to emit a metric ton of CO_2 ($mtCO_2$).[3]

The Air Resources Board will allocate most of the allowances that will be needed for the electrical power generation sector at no cost to the various utilities that directly serve load. These load-serving utilities will be required to place a portion of their allocated allowances into a consignment account. The Air Resources Board will auction off allowances from this account along with the allowances that have not been allocated to other entities covered by the regulations including generation owners and power importers. The load-serving utilities will be required to use the auction proceeds to offset increased costs due to the greenhouse gas cap or for energy efficiency programs.

[2] http://globalclimate.epri.com/doc/EPRI_Offsets_W10_Background%20Paper_CA%20Offsets_040711_Final2.pdf

[3] In reality, because the greenhouse gas regulations cover other gasses besides CO_2, an allowance conveys a right to emit a metric ton of CO_2 equivalent. However, the vast majority of the ISO generation fleet emits negligible amounts of these other gasses.

The auctions will start in August 2012 and continue quarterly after that. Each auction will include allowances for the current year and a portion of allowances for three years in the future. Each year's allowances will be auctioned through sealed bids. A single allowance price applicable will be set based on the highest priced bid accepted. The auction settlement prices and the names of the bidders will be public information, but the allowance quantities purchased at each auction will only be released as aggregated information.

The auctions will have a reserve, or floor, price that will initially be $10 per allowance. To limit the price of allowances, 4 percent of allowances will be set aside to be sold at set prices that will initially range from $40-$50 per allowance. Both the reserve price and the price of allowances set aside to be sold at fixed prices will increase annually after 2013 by 5 percent plus the rate of inflation.

Bilateral trading of allowances will be allowed. Entities will be required to report these trades and the transaction price to the Air Resources Board through its "Market Tracking System "once the exchange takes place. The Air Resources Board will publically release the prices of completed transfers.

Forward contracts for California carbon allowance are currently trading on the InterContinental Exchange (ICE). The price published on December 9, 2011 for forward contracts for 2013 vintage California allowances for delivery in December 2013 is $15.70 per allowance.4 This equates to a cost of $8.35/MWh for a natural gas fired unit with a 10 MMBtu/MWh heat rate. 5

The cost of carbon allowances to electricity generation facilities varies with the output of the facility, and as such is expected to be included in the variable cost and energy bids from affected units. This will have an impact on the wholesale price for electricity in California and potentially other states in the western region. Because of this linkage, it is important that the market for carbon allowance is both efficient and free of market manipulation. To this end, the Air Resources Board has required that there exist an independent market monitor for the carbon allowance market.

Compliance

Entities that control greenhouse gas sources will demonstrate compliance by periodically surrendering compliance instruments to the Air Resources Board as follows:

- Every year they will have to surrender compliance instruments for at least 30 percent of their emissions in that year.
- Every 3 years they will have to submit compliance instruments for the remainder of their emissions during the 3-year period.

Each allowance will have a *vintage,* or the year for which it is issued by the Air Resources Board. Allowances that have a vintage for the year in which they are being submitted or an earlier year can be used for compliance. Allowances with vintages in future years cannot be used for compliance.

[4] https://www.theice.com/marketdata/reports/ReportCenter.shtml?reportId=10

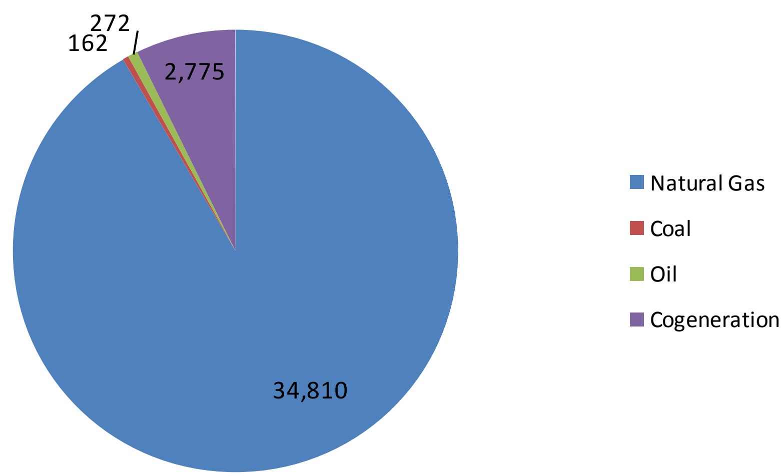
[5] $8.35/MWh = (10 MMBtu/MWh) (0.053165 mtCO_2/MMBtu) ($15.70/allowance) (1 allowance/ mtCO_2), this calculation is explained further down in this paper.

Applicability

The California greenhouse gas cap regulations will apply to in-state generators that emit at least 25,000 mtCO2 equivalents annually. These are generators that use combustible fuels, including natural gas, coal, and oil. Geothermal generators and most biomass/biogas generators are subject to the reporting requirements but are exempt from the requirement to surrender compliance instruments for their emissions. [6]

There are about 38,000 MW of generation in the ISO that use combustible fuels and for which the ISO calculates variable costs for energy, start-up, minimum load, or transitions between multi-stage generator configurations. Of this amount, the actual amount subject to the greenhouse gas cap regulations is probably somewhat less because some units are likely either too small or do not operate frequently enough to emit enough annual CO2 to have to comply with the regulations. The figure below breaks out this generation by fuel-type, showing the vast majority is natural gas-fired.

Generation Subject to Greenhouse Gas Regulations for which ISO Calculates Variable Costs



The greenhouse gasses related to electrical power generation include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6). The regulations provide global warming potential adjustment factors to adjust these gasses to CO_2 equivalents. CO_2, CH_4, and N_20 are all produced by natural gas combustion, the fuel used by the vast majority of the ISO generation fleet that uses combustible fuels, but only CO_2 is produced in significant amounts. Generators may also emit CO_2 from acid gas scrubbers, SF_6 from circuit breakers and other equipment, HFC from cooling units, and CH_4 from coal storage.[7]

The greenhouse cap regulations will classify imports as coming from specified or unspecified sources. Imports will be subject to the regulations to the extent they come from a specified source that emits at least 25,000 mtCO_2 annually. Emissions from specified sources will be calculated at the emission rate of

[6] http://www.arb.ca.gov/regact/2010/capandtrade10/finalfro.pdf § 95812. (c)(1) page 46, § 95852.2. (b)(1) pages 84-86

[7] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/08_ElectricitySec.pdf

the specific source. All imports from unspecified sources are subject to the regulations and their associated emissions are calculated at a default rate. The entity that is listed as the purchasing-selling entity on the e-tag at the point the energy enters California will have the compliance obligation under the greenhouse gas cap regulations.

ISO's generator variable costs calculations

The ISO calculates various components of generation variable costs. This section provides an overview of these various components of variable costs and the various ways that the ISO markets use these costs. This provides a frame of reference for considering how to incorporate the cost of greenhouse gas compliance instruments into the ISO's calculations.

Energy bids for generators in the ISO market consist of three-parts: energy, start-up, and minimum load. Additionally, multi-stage generators have transition costs to move from one configuration to another. Although market participants submit these energy bid components, the ISO calculates each generating unit's actual variable costs for these components using set formulas. The ISO uses its calculation of these costs to:

- Create default energy bids used for local market power mitigation.
- Calculate bid caps for minimum load and start-up costs.
- Create energy, start-up, and minimum load bids in the event a market participant does not submit a required bid.
- Calculate daily transition costs based on current gas prices to dispatch multi-stage generators.

Bids for imported energy include only an energy bid component and do not include start-up, minimum load or transition cost components. The ISO does not calculate default energy bids for imported energy because import bids are not subject to local market power mitigation. Although the ISO creates bids for imported energy if a required bid is not submitted by a market participant, these bids are not based on actual costs unless actual costs are negotiated on a case-by-case basis with Potomac Economics, the independent entity contracted by the ISO to calculate default energy bids and negotiate variable costs of generation if they differ from the standard values used by the ISO. Since the ISO does not calculate costs for imported energy, the following sections do not discuss these costs further.

Energy costs

The ISO calculates generating units' variable costs to provide incremental energy above minimum load for two purposes:

- Calculating *default energy bids* that are used in the local market power mitigation process if the generation owner has elected the cost-based option for default energy bids.[8]
- Creating energy bids if a required bid is not submitted for a unit.

[8] See footnote 1.

The ISO's local market power mitigation process reduces energy bids to the default energy bid for a unit in the event a unit is flagged as having market power. Market participants can elect to have the ISO calculate a unit's default energy bid calculated using one of three options:

- Variable Cost Option: The ISO calculates default energy bids for each unit for several output levels submitted by the market participant. For each of these output levels, the ISO determines the unit's incremental fuel costs and adds a standard variable operations and maintenance cost. It then adds 10 percent to this amount.[9] For natural gas-fired units, the ISO bases fuel costs on the unit's incremental heat rate multiplied by a standard current daily natural gas cost. For non-gas-fired units, the ISO uses fuel cost based on per MWh fuel costs submitted by the unit's owner and verified by the ISO.

- LMP Option: The ISO calculates default energy bids based on the past locational marginal prices at a unit's location.

- Negotiated Option: The market participant negotiates a unit's actual costs that the ISO will use for the unit's default energy bids with Potomac Economics. These costs typically involve components that are not considered in the standard formula and inputs (e.g. variable operations and maintenance costs) used under the variable cost default energy bid option.

The ISO creates bids if a required bid is not submitted for a unit using the same methodology as the cost-based default energy bid option but without the 10 percent adder.

Start-up and minimum load costs

The ISO calculates units' start-up costs based on a unit's start-up fuel and natural gas prices. Minimum load costs are calculated based on a unit's heat rate characteristics and natural gas prices.[10] The ISO also includes standard per MWh operations and maintenance cost in its calculation of minimum load costs.[11] The ISO adds 10 percent to its calculation of minimum load costs to arrive at the minimum load costs used by the ISO market. If a unit is not natural-gas fired, then the market participant submits the unit's actual start-up and minimum load costs, which are subject to review by the ISO.

The ISO uses these costs differently depending on whether a market participant has elected the proxy cost or the registered cost option for the start-up or minimum load costs of a unit. Market participants can elect either of these two options for both a unit's start-up and minimum load costs or just the start-up or the minimum load costs. The ISO implements these options as follows:

- Proxy Cost Option: Market participants can submit daily start-up and/or minimum load bids that can be no more than the unit's actual costs. The ISO uses the unit's actual start-up and/or minimum load costs to create a bid if a market participant does not submit a required bid.

[9] The ISO adds an additional amount to default energy bids under the cost-based default energy bid option if a unit's bids are frequently mitigated under the ISO's market power mitigation procedures. The standard operations and maintenance costs depends on the generation technology.

[10] Each natural gas fired unit's start-up fuel requirement is based on the actual heat input required plus the auxiliary electrical power required converted into heat input.

[11] Market participants can negotiate non-standard operations and maintenance costs with Potomac Economics.

- Registered Cost Option: Market participants can submit a start-up and/or minimum load bid that stands for 30 days. This bid can be up to twice the unit's actual costs as calculated by the ISO.

Multi-stage generator transition costs

In addition to start-up and minimum load costs, the ISO accounts for transition costs for multi-stage generators. Currently, the ISO provides a mechanism for market participants to specify their transition costs, subject to rules governing the shape and magnitude of the bids. This is not a cost-based approach and, as such, would not need to be altered to accommodate accounting for emission costs. The current approach, however, does not lend easily to verification and may potentially be leveraged for strategic purposes that are not consistent with competitive behavior. The Department of Market Monitoring has recommended that a cost-based approach be applied to specifying transition costs to avoid these potential issues. A cost-based approach could be applied with separate verifiable fuel and non-fuel components provided for each configuration transition. This approach would also lend to a more explicit inclusion of applicable emissions cost.

Natural gas costs

The ISO uses daily natural gas price indices published by commercial suppliers for the generator costs that it calculates daily.[12] The ISO uses the appropriate price indices for each of the three major load-serving utility regions within the ISO to calculate each generator's natural gas price. The ISO adds a natural gas transportation cost based on the published rates for each of these regions. The ISO uses the average of at least two different natural gas prices from different commercial suppliers to calculate natural gas prices.

The ISO uses published natural gas price futures price information for the generator start-up and minimum load costs that it calculates monthly under the registered cost option. The Henry Hub natural gas futures price for the price of are used because, although it is far from California, it is a widely traded location for futures so it would tend to be a relatively more reliable indication of future prices. The ISO adjusts the Henry Hub futures price to California prices by using the futures prices for basis swaps between Henry Hub and southern and northern California gas prices, respectively. Finally, the ISO adds the appropriate gas transportation rate for within each of the major gas transportation utility regions.

The ISO calculates the Henry Hub price it will use for the following month after the twenty-first day of each month. It uses the average of the futures prices over the first twenty days of the month for physical delivery in the following month. The ISO averages the prices over twenty days to reduce the effect of any temporary price increases or decreases that may be occurring in futures prices on the day the ISO calculates the gas price from the futures price. Similar to the Henry Hub futures price, ISO also averages the basis swaps between Henry Hub and southern and northern California gas prices over the first twenty-one days of each month.

[12] Gas prices used to calculate default energy bids are actually determined by Potomac Economics.

Operations and maintenance costs

The ISO uses two standard variable O&M rates with combustion turbine and reciprocating engine units having the higher rate. The ISO is proposing to expand this to ten different rates that vary by fuel source and technology.

Methods used by other ISOs to account for carbon emissions costs

As previously described, the California greenhouse gas cap and trade program is somewhat similar to the Regional Greenhouse Gas Initiative (RGGI) that applies to a number of these states are belong to the various eastern ISOs (i.e. PJM, New York ISO, ISO New England). Similar to California's program, RGGI consists of an overall cap and allowances that are sold at auction and traded bilaterally.

RGGI's implementation in these ISOs provides a useful benchmark for determining appropriate measures the CAISO should take to accommodate the implementation of California's program. The following table summarizes the methods the eastern ISOs use to account for CO_2 allowance costs under RGGI.

Methods Used by Other ISOs to Account for Greenhouse Gas Costs

ISO	Method
PJM	The cost of RGGI CO_2 allowances are included in the fuel costs submitted by the market participant. Market participants determine their fuel costs according to a standard methodology developed by PJM.[13] This standard methodology allows market participant's flexibility in determining fuel costs. For example, they can use the procurement cost or the daily spot market price, but they have to stick to the same methodology for 30 days. Market participants submit their actual costs for other generating unit variable costs, such as operations and maintenance costs. Market participants can either use procurement cost or the spot market price, for determining a CO_2 allowance price, but generally use daily spot market prices. Market participants submit their own calculation of CO_2 emission rates for each unit.
ISO - NE	ISO-NE calculates CO_2 allowance costs for each generator using standard CO_2 emissions rates based on the type of fuel used by each generator. It multiples these CO_2 emission amounts by each unit's heat rate and the CO_2 allowance price. It bases the CO_2 allowance price on a daily index of the spot market price for RGGI CO_2 allowances provided by a commercial service.[14] Market participants submit their actual costs for other generating unit variable costs, such as operations and maintenance costs.

[13] http://pjm.com/~/media/documents/manuals/m15.ashx.

[14] http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-a.pdf, p.25.

ISO	Method
NYISO	The NYISO calculates CO_2 allowance costs for each generator based on emissions rates for each generator submitted by market participants. The NYISO calculates each generator's CO_2 allowance cost by multiplying its emission rate by its heat rate and the CO_2 allowance price. It bases the CO_2 allowance price on a daily index of the spot market price for RGGI CO_2 allowances provided by a commercial service.[15] Market participants submit their actual costs for other generating unit variable costs, such as operations and maintenance costs.

Greenhouse gas allowance costs

Similar to the eastern ISOs currently covered by RGGI, it is appropriate that the ISO include the costs of greenhouse gas allowances as a variable cost of generation. This section outlines an approach for the ISO to include these costs in its calculation of generating units' variable costs for incremental energy, minimum load energy, start-ups, and multi-stage generator transitions.

DMM recommends the ISO calculate the cost of greenhouse gas allowances for natural gas-fired generation based on its calculation of each unit's CO_2 emissions and the price of allowances. Because each generator's CO_2 emissions are proportional to the amount of fuel that it burns, the ISO would calculate each unit's greenhouse gas emissions based on the unit's heat rate characteristics and a standard emission rate. For generating units that use other types of fuels, market participants could provide the ISO with the unit's greenhouse gas emission rate (rate per MMBtu). This emission rate would be subject to verification by the ISO. This approach would be consistent with the ISO's current approach of only calculating fuel costs for gas-fired generators. Fuel costs for other types of units are submitted by market participants and verified by the ISO.

Under the California greenhouse gas cap regulations, market participants will determine the emissions of the generation under their control using methods specified in Air Resources Board regulations.[16] These methods range from taking continuous direct physical measurements of greenhouse gas emissions to calculating the emissions based on standard emission rates determined by the fuel type and the amount of fuel burned. As described above, DMM proposes that the ISO use the later method to calculate the variable costs of natural gas fired generation. In the event this method resulted in emissions rates that were significantly different than a generator's actual emissions, a potential accommodation might be to allow market participant to have the option to submit the actual emission rate of a natural gas unit if they could document the actual emission rate was greater than the standard rate used by the ISO.

The only greenhouse gas emissions that should be included in the ISO's calculation of generating unit variable costs are those that vary with output. Consequently, emissions such as fugitive SF_6 from circuit breakers and other equipment should not be included.

[15] http://www.nyiso.com/public/webdocs/documents/tariffs/market_services/att_h.pdf, First Revised Sheet No. 470C.

[16] Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations), http://www.arb.ca.gov/regact/2010/ghg2010/mrrfro.pdf.

Of the eastern ISO's that currently account for greenhouse gas allowance costs, the approach DMM outlines in this section is most similar to the ISO New England approach (i.e. use both standard emission rates and daily spot market allowance prices based on a published index). This approach seems most consistent with the ISO's general methodology to calculating other components of generator's variable costs in which it uses standard costs, such as fuel costs and operations and maintenance costs. In contrast, PJM allows market participants to submit their own calculations of generator greenhouse gas emission rates and allowance prices, but it also allows them to submit their own calculations of the other generator variable cost components, such as fuel costs and operations and maintenance costs.

Greenhouse gas allowance cost calculation

Under the California greenhouse gas cap program, market participants will have to surrender one greenhouse gas allowance for every 1,000 metric tons of CO_2 ($mtCO_2$) emitted by the generation under their control. The standard CO_2 emission rate for natural gas under U.S. Environmental Protection Agency and state regulations is 0.053165 $mtCO_2$/MMBtu.[17]

Using these values, the cost of greenhouse gas allowances could be incorporated into the various elements of generators' variable costs as follows:

- Incremental energy costs: 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 =

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

CO2 emissions per start-up ($mtCO_2$/start-up) * 1 allowance per mtCO2 * greenhouse gas allowance price

Where,

CO2 emissions per start-up (mtCO2/start-up) = unit's start-up fuel requirement (MMBtu/start-up) * (0. 053165 mtCO2/MMBtu)

- Multi-stage generator transitions: include greenhouse gas allowance costs as a cost per transition, which can be calculated as:

Allowance cost per transition =

CO2 emissions per transition ($mtCO_2$/transition) * 1 allowance per mtCO2 * greenhouse gas allowance price

Where,

CO_2 emissions per transition ($mtCO_2$/transition) = unit's transition fuel requirement (MMBtu/transition) * (0. 053165 $mtCO_2$/MMBtu)

For all of the calculations described below, the ISO could use a documented greenhouse gas emission rate submitted by market participants for non-natural gas units and potentially for natural gas units if their actual emission rate varied for some reason from the standard rate.

In addition to the calculations above, there ISO could screen, using similar calculations, to determine if a generating unit emitted the 25,000 $mtCO_2$ annually needed to make it subject to the greenhouse gas cap regulations. These units would include small units or peakers that run infrequently. The ISO would not include greenhouse gas allowance costs in its calculation of variable costs for units that did not emit more than 25,000 $mtCO_2$ in the previous year. Market participants could provide justification to the ISO if they believed that a unit's emissions would exceed the minimum threshold in an upcoming year when in the previous year they did not.

Greenhouse gas allowance price

The ISO could determine the price of greenhouse gas allowances by using a published price index of the daily spot price of CO_2 allowances in the bilateral over-the counter market, similar to its existing methods for determining natural gas prices. This is the method the NYISO and ISO-NE use to determine the price of RGGI CO_2 allowances. PJM allows market participants to use either the spot price or their acquisition cost of allowances, but most reportedly use the spot price. The rationale for using the spot price of allowances is that it reflects the current cost of procuring an allowance, the replacement cost of using an allowance already held to generate, as well as the opportunity cost of not generating and selling the allowance.

Similar to the way that the ISO currently uses published natural gas prices for the various generator variable cost components it calculates, the ISO could determine greenhouse gas allowance prices as follows:

- Costs calculated daily: Use a published daily spot-market price.

- Costs calculated monthly (i.e. start-up and minimum load costs under registered cost option): Use the average of a published daily spot-market price over the first twenty days of each month to determine allowance costs to be used in the calculation of the registered costs to be fixed for the next month.

When calculating the CO_2 allowance costs to use for a one-month period under the registered cost option, using the average price over twenty days smoothes out any temporary price increases or decreases that may have occurred at the time of the monthly calculation. This avoids locking any temporary price changes into the calculation for an entire month. This is the similar to the method that the ISO currently uses to calculate natural gas prices used for start-up and minimum load costs under the registered cost option, which are also locked-in for a month. The difference is that the ISO currently uses natural gas futures prices for delivery in the next month, while the approach DMM is proposing here for greenhouse gas allowances averages each day's current spot price for greenhouse gas allowances. This difference is justified as natural gas spot and futures prices may diverge because natural gas storage is limited. Conversely, greenhouse gas spot market prices should correlate fairly well with futures prices.[18] For example, the spot prices should rise in the case of an anticipated future shortage, just as the futures prices would, because allowances purchased in the spot market can easily be retained in anticipation of a shortage. This has been the case for futures trading for RGGI carbon allowances, where futures prices for delivery in the current month are very close to futures prices for delivery at the end of the year.[19]

An alternative to using the spot market price of allowances would be to either use the market clearing prices from the quarterly auctions of greenhouse gas allowances that will be conducted by the Air Resources Board or the prices of bilateral trades reported in the Air Resources Board's market tracking system. However, neither of these methods would represent the current value of allowances. Auction prices would not capture price changes that occur between auctions. Prices of trades reported in the market tracking system may not accurately capture current prices because the trades are not reported until the buyer takes physical delivery, which may occur a significant period of time after the sale takes place.

Several providers produce price index services that are available by subscription that include California carbon allowance prices. It appears that these prices are based on surveys of brokers that trade carbon allowance forwards in the over-the-counter market.[20] In addition, forward contracts for California greenhouse gas allowances are traded on the Intercontinental Exchange (ICE), which publishes a daily summary of prices. The published prices for California greenhouse gas allowances all appear to be for delivery in December of each year. Conversely, if an index listing current spot prices is not developed, then the ISO could use the price of futures or forwards with the next upcoming delivery date.

[18] The futures price should differ from the spot market price by the risk-free interest rate to account for the purchaser of a future being able to defer payment until taking delivery.

[19] http://www.rggi.org/docs/MM_2010_Annual_Report.pdf, page 19.

[20] The term "over-the counter" refers to trades of financial products in which the counter-party is not one of the public exchanges. "Forward" contracts are sales contracts with delivery at a future date that are traded in the over-the-counter market. "Futures" contracts are sales contracts with delivery at a future date that are traded on one of the public exchanges and the parties to the contract are required to post financial assurance.

Attachment D – Draft Final Proposal

Tariff Amendment to Allow Recovery of Greenhouse Gas Compliance Costs

California Independent System Operator

Fifth Replacement FERC Electric Tariff

October 29, 2012

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

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

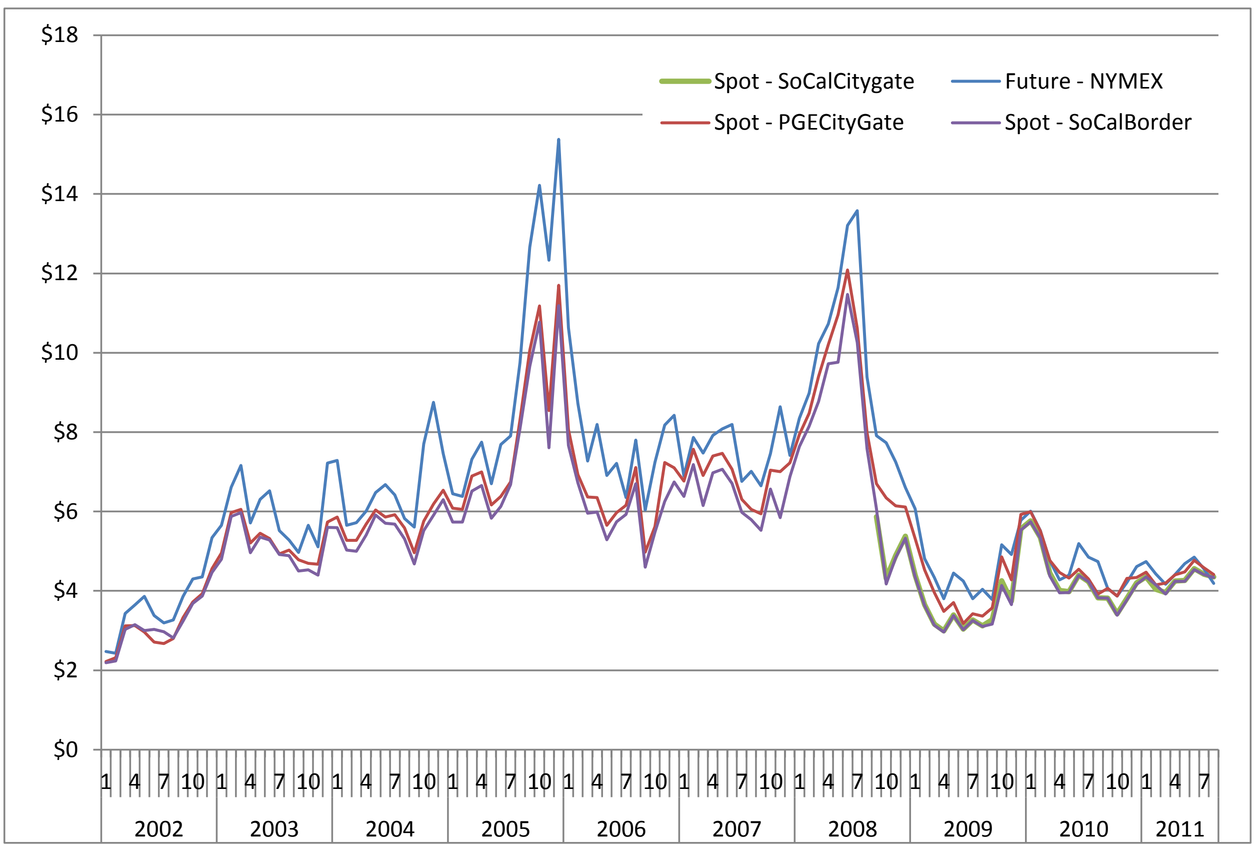
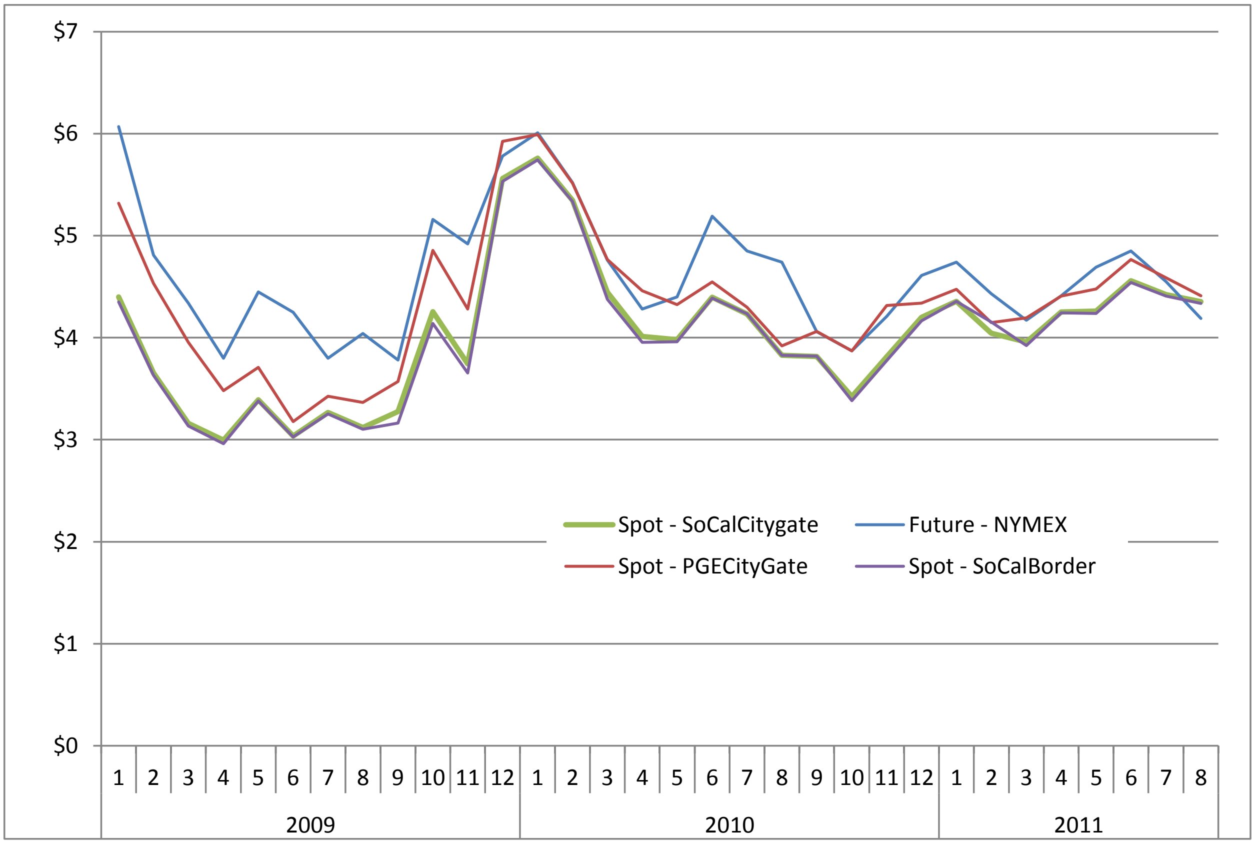


Figure 2, the second of the four charts shows the same data as above, but for a more recent period of time, January 2009 through August of 2011. This chart shows significantly lower price volatility in the last several years.

<u>Figure 2</u>: Natural gas future and monthly <u>maximum</u> 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 <u>maximum</u> 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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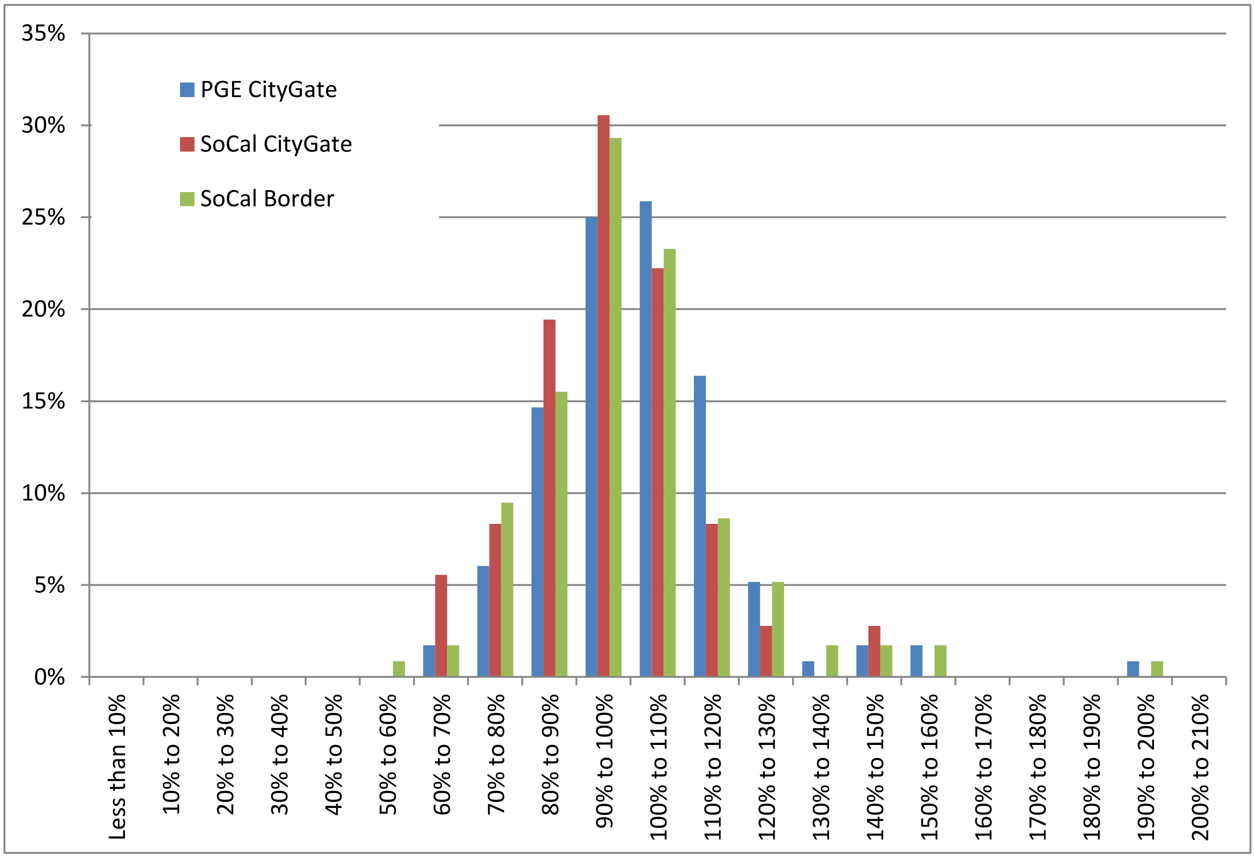
[15] These analyses follow closely the techniques used by the Department of Market Monitoring when the original registered cost option cap was being developed: *MRTU Market Power Mitigation: Bid Caps for Start-Up and Minimum Load Costs Draft Revised Proposal* (August 8, 2007)

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:

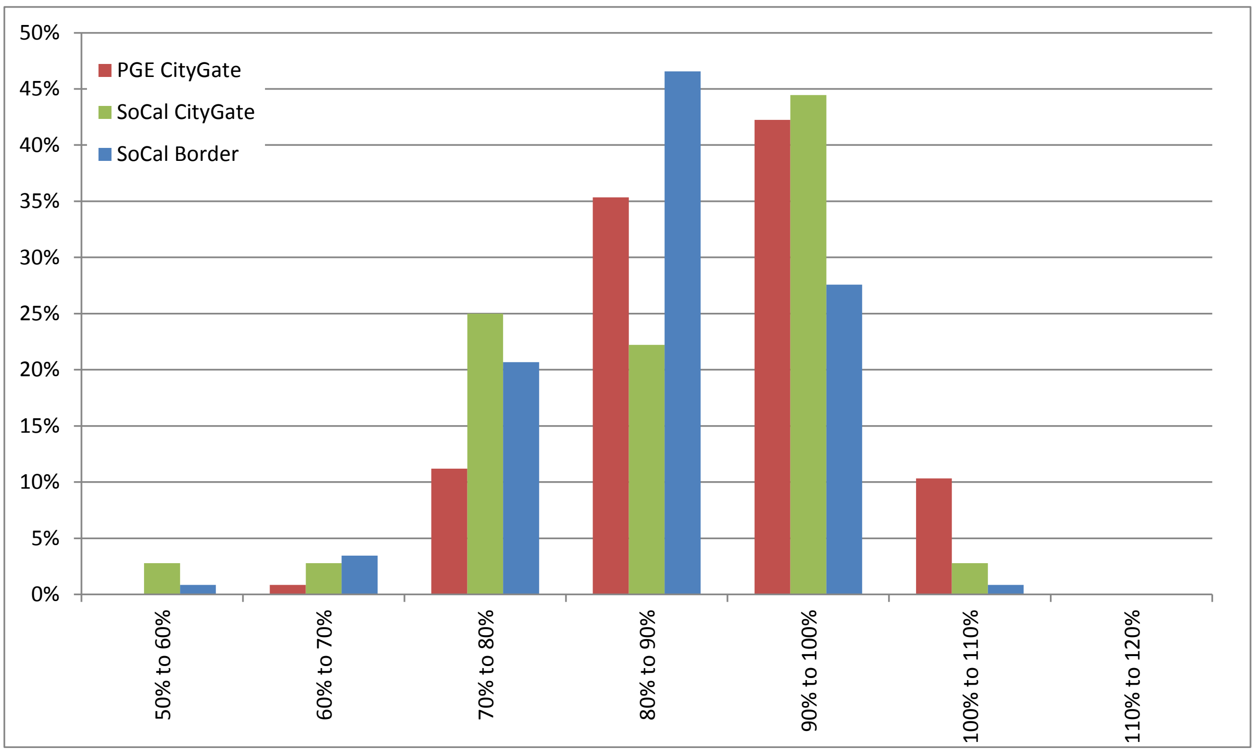
Bin	PGE CityGate	SoCal CityGate	SoCal Border
Less than 10%	0%	0%	0%
10% to 20%	0%	0%	0%
20% to 30%	0%	0%	0%
30% to 40%	0%	0%	0%
40% to 50%	0%	0%	0%
50% to 60%	0%	0%	1%
60% to 70%	2%	6%	2%
70% to 80%	6%	8%	9%
80% to 90%	15%	19%	16%
90% to 100%	25%	31%	29%
100% to 110%	26%	22%	23%
110% to 120%	16%	8%	9%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

Attachment E – List of Key Dates in Stakeholder Process

Tariff Amendment to Allow Recovery of Greenhouse Gas Compliance Costs

California Independent System Operator Corporation

October 29, 2012

Date	Event/Due Date
February 3, 2012	ISO issues paper entitled “Issue Paper – Commitment Costs Refinements 2012”
February 8, 2012	ISO hosts stakeholder conference call that includes presentation entitled “Refinements to Commitment Costs, 2012” and discussion of paper issued on February 3
February 10, 2012	ISO Department of Market Monitoring issues paper entitled “California Greenhouse Gas Cap and Generation Variable Costs White Paper”
February 17, 2012	Due date for written stakeholder comments on paper issued on February 3
February 29, 2012	ISO issues paper entitled “Straw Proposal – Commitment Costs Refinements 2012”
March 7, 2012	ISO hosts stakeholder conference call that includes presentation entitled “Refinements to Commitment Costs, 2012” and discussion of paper issued on February 29
March 14, 2012	Due date for written stakeholder comments on paper issued on February 29
April 11, 2012	ISO issues paper entitled “Draft Final Proposal – Commitment Costs Refinements 2012”
April 18, 2012	ISO hosts stakeholder conference call that includes presentation entitled “Refinements to Commitment Costs, 2012” and discussion of paper issued on April 11
April 24, 2012	Due date for written stakeholder comments on paper issued on April 11
August 6, 2012	ISO issues draft tariff language to include greenhouse gas costs in the calculation of resource commitment and incremental energy costs
August 17, 2012	Due date for written stakeholder comments on draft tariff language issued on August 6
August 22, 2012	ISO hosts stakeholder conference call that includes discussion of draft tariff language issued on August 6
October 17, 2012	ISO issues revised draft tariff language to include greenhouse gas costs in the calculation of resource commitment and incremental energy costs