Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: May 9, 2012

Re: **Decision on Commitment Costs Refinements**

This memorandum requires Board action

EXECUTIVE SUMMARY

The ISO market design provides market participants with the ability to indicate and recover the costs of committing a generation resource in the ISO market. These costs include the costs incurred to start a resource and the costs of running a resource at its minimum operating level. There are two options available to market participants to indicate these costs:

- The proxy cost option uses a formulaic approach to calculate commitment costs. This option uses a natural gas price index and heat-rate characteristics of a generating resource to determine its commitment costs.
- The registered cost option uses a static value for commitment costs that is submitted by the scheduling coordinator for the resource and is fixed for 30 days. Under the current market design, this cost is capped at 200 percent of the resource's calculated projected proxy costs. This option is intended to account for costs that may not be reflected in the ISO's proxy cost calculation.

The accurate specification of a resource's calculated costs is critical to efficient commitment and fair compensation of generating resources in the ISO market. Through the commitment costs refinements policy development, Management and stakeholders have developed improvements to the specification of cost-based start-up and minimum load costs. Some of these modifications are also applicable to generated energy bids and default energy bids.[1]

Management recommends the following enhancements to these modifications to the provisions for commitment costs:

[1] A generated bid is a cost-based bid which can be inserted on behalf of a market participant under certain market bid validation rules and applicable bidding obligations.

- Modify proxy minimum load costs, proxy start-up costs, generated energy bids, and proxy energy bids to incorporate the following:
    - Costs associated with greenhouse gas emissions allowances incurred under California's upcoming greenhouse gas cap-and-trade program;
    - The volumetric elements of the ISO's grid management charge;
- Modify proxy minimum load and start-up costs to incorporate a fixed adder to cover major maintenance expenses;
- Establish provisions for reimbursing generating resources for the costs of penalties incurred for violating gas operational flow orders or for emissions of NOx and SOx due to being exceptionally dispatched, mitigated, or dispatched by the ISO in the real-time. The costs of these penalties will be provided to the ISO and included in the calculation of real-time bid cost recovery; and
- Reduce the registered cost cap for minimum-load and start-up costs from 200 percent to 150 percent of the monthly projected proxy cost.

Moved, that the ISO Board of Governors approves the proposed tariff change regarding modifications to the provisions for commitment costs as described in the memorandum dated May 9, 2012; and

Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.

DISCUSSION AND ANALYSIS

Based on stakeholder feedback and ISO staff analysis, Management developed a set of proposed recommendations to refine the ISO's calculations of start-up and minimum load costs. Because some of these refinements also apply to energy bids above minimum load, some of these recommendations also extend to generated energy bids and default energy bids.

<u>Greenhouse gas emissions allowance costs</u>

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

As a result of the greenhouse gas cap-and-trade program, California's thermal generating resources will bear a per-MWh cost associated with the GHG allowances needed for their energy output. Therefore, Management recommends including those costs in the cost-based calculations for minimum load and start-up costs, as well as in the calculation of default energy bids and generated bids. In order to mitigate for potential illiquidity and volatility in the nascent cap-and-trade market, Management recommends the average of three price indices be used to determine the costs of greenhouse gas allowances. A greenhouse gas allowance index is a price assessment which reflects daily transactions in the market for those allowances. Indices for greenhouse gas allowances, and other commodities, are available from several commercial sources such as Platts, the Intercontinental Exchange, and Argus Media. Administrative fees associated with greenhouse cap-and-trade compliance will not be included in cost-based calculations because those administrative costs are not attributable to the marginal cost of generating electricity.

Grid management charges

The ISO's grid management charge is a fee assessed to market participants to recover the ISO's operational costs. Some of the elements of the grid management charge are charged on a volumetric basis, meaning that they are based on the megawatt hour quantities either scheduled or injected or withdrawn from the grid. The ISO proposes to include the volumetric elements of the grid management charge into the proxy start-up, proxy minimum load, default energy bid, and generated bid calculations. In particular, the ISO will include the following elements of the grid management charge calculation: market services, system operations and $0.005 per megawatt hour bid segment charge.

Management recommends that administrative fees not associated with per-megawatt hour operation not be included in any of the cost-based calculations mentioned above. This is because they are related to general costs of participating in the ISO market and, therefore, are not part of the marginal cost of operating. Examples of these administrative grid management charges are the scheduling coordinator fee, inter-scheduling coordinator trade fee, and the interest on invoice true-up.

Major maintenance costs

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 hours a unit is operated, the number of times it is started, or its energy output. Major maintenance costs related to energy production above minimum load can already be reflected in default energy bids negotiated with the ISO. This modification will account for major maintenance expenses that are related to the hours a unit is operated or the number of times it is started and will include these costs in resources' proxy minimum load or start-up costs, as applicable.

Operational flow orders

Natural gas is generally shipped to generating resources via pipelines (as opposed to on-site storage). Under some conditions, pipeline operators may issue an operational flow order, under which generators will incur financial penalties if their natural gas usage is more or less than a specified tolerance band. These operational flow orders 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 operational flow order penalty due to its noncompliance with that order.

Management recommends that operational flow order penalty costs can be recovered by market participants after they are incurred 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 operational flow order penalty associated with either an “over burn” or an “under burn” of natural gas. The operational flow order penalty costs will be included in a re-evaluation of the real-time bid cost recovery calculation for that day with the operational flow order penalty costs added into the calculation of the generator’s net shortfall or surplus over the day.

Management further recommends the following:

- Bundled gas customers that receive an operational flow order penalty will be responsible for assigning the operational flow order cost to the various supply resources whose collective dispatch created the charge;
- Natural gas balancing penalties other than operational flow orders will not be included in cost-based calculations; and
- NOx and SOx emissions, which are currently recouped through a balancing account, will instead be treated in the same manner as the proposal here to consider operational flow order penalties. 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 to the ISO. The ISO will subsequently re-evaluate the generator’s real-time bid cost recovery net surplus or shortfall and make adjustments accordingly.

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 the start up of a resource or its operation 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 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, a lower cap would mitigate future incentives to engage in such behavior.

Management proposes to keep the registered cost option, but to lower the registered cost cap to 150 percent of the projected proxy cost. Management recommends retaining 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 because of the proposed enhancements to cost-based calculations. Enhancing the cost-based calculations to include greenhouse gas costs, grid management charge costs, and major maintenance costs will reduce the additional costs that would otherwise need to be included in the registered cost option.

As noted above, the value of costs specified under the registered cost option is capped and can be changed only once every 30 days. Thus, market participants who elect the registered cost option are exposed to some amount of fuel price risk. Management's recommendation of a 150 percent registered cost cap is based on an analysis of historical fuel price levels and fuel price volatility. The intent of this analysis was to determine a level for the registered cost cap that enables market participants to reasonably protect against potential fuel-price volatility. The analysis showed that the 150 percent cap more than covers what would generally be the monthly fuel price risk associated with purchasing natural gas on the spot market. In addition, based on feedback from stakeholders and the Market Surveillance Committee, the recommended cap should also account for risk in the intra-day markets for natural gas, potential natural gas balancing charges, opportunity costs for start-limited or run-hour limited resources, and other non-fuel costs that will still not be accounted for in the proxy cost calculations. Under current tariff authority, a market participant can switch from the registered cost option to the proxy cost option when the proxy cost option is higher. This provides a "safety valve" in the event of significant natural gas price spikes. Management recommends that this provision remain in place.

POSITIONS OF THE PARTIES

Stakeholders have been supportive of the ISO's efforts to more accurately account for the various commitment costs addressed in this initiative. Likewise, stakeholders are supportive of the changes to the cost-based calculations to generated bids and default energy bids so that they too accurately reflect the cost components outlined in this recommendation.

Although there is support from load-serving entities for a lower cap on registered start-up and minimum load cost, generators were opposed to the ISO's original proposal that the cap be lowered to 125 percent of the projected proxy value. In consideration of their feedback, and input from the Market Surveillance Committee, Management's recommendation is to lower the cap on registered start-up and minimum load costs to 150 percent of the projected proxy value. A stakeholder matrix and the final opinion of the Market Surveillance Committee are attached for your reference.

CONCLUSION

Management requests Board approval of this proposal for modifications to the provisions for commitment costs as described in this memorandum. Management plans to implement the inclusion of greenhouse gas cap-and-trade program allowances in cost-based calculations simultaneously with the launch of the California Air Resources Board's greenhouse gas cap-and-trade program and implement the remaining changes described here at the same time as the separation of the netting of day-ahead and real-time bid cost recovery calculations, currently scheduled for the fall of 2013.