Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Market Monitoring

Date: May 9, 2012

Re: **Market Monitoring Report**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides comments by the Department of Market Monitoring (DMM) on Management's proposals for refinements to rules for commitment costs. The memo also includes a summary of DMM's annual report on 2011 market performance.

- **Commitment cost refinements.** DMM is supportive of Management's proposed changes to rules for start-up, minimum load and default energy bids. Proposed changes to ensure recovery of greenhouse gas emissions costs and penalties for gas operational flow orders attributable to ISO real-time unit commitments and dispatches are based closely on research and proposals provided by DMM. We are also supportive of the concept of including an additional cost for major maintenance in variable costs included in start-up and minimum load bids. However, the details of the specific methodology and allowable magnitude of these costs have not yet been developed. Thus, we recommend continued discussion and review of this process by the ISO and stakeholders as this provision is implemented. Finally, given the additional costs being included in start-up and minimum load bids through these changes, DMM is also supportive of the proposal to lower the cap for start-up and minimum load bids under the registered cost option to 150 percent of estimated costs.
- **Annual report on market performance.** [1] Each year the Department of Market Monitoring publishes an annual report on the performance of markets administered by the ISO. As indicated in this report, DMM finds that the nodal market design implemented in 2009 continues to facilitate efficient and competitive overall market performance. Overall wholesale prices continue to be about equal to prices we estimated would result under extremely competitive conditions.

[1] A copy of the report is also available on the ISO website at: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

COMMITMENT COST REFINEMENTS

Management is requesting Board approval to make several modifications in rules for calculating and limiting start-up and minimum load bids. Some of these changes would also be applied to default energy bids used to limit bids for energy above minimum load levels when units are needed to relieve congestion on uncompetitive constraints.

Greenhouse gas emissions

The first major modification is to include emissions costs associated with California's greenhouse gas cap-and-trade program in each unit's start-up, minimum load and default energy bids. The ISO's proposed treatment of these costs is based directly on research and a proposed methodology provided by DMM in a February 2012 whitepaper.[2] As discussed in the whitepaper, it is reasonable to assume these emissions costs are applicable to all energy produced by generating units in California. These costs also can be calculated very accurately by combining each unit's emissions rates (per MWh produced) with publically available data on the cost of emissions credits. At current futures prices, these emissions costs could add a cost of about $8/MWh to the variable cost for a typical generating unit.[3]

Consistent with DMM's recommendation, the ISO proposes to base the price for greenhouse gas allowances on publically available indices of futures prices for these allowances. Some stakeholders have expressed concern that these prices could be volatile or that liquidity in the secondary market for these allowances could be limited, and thereby subject to potential manipulation. As part of the state's cap-and-trade program, the California Air Resources Board is implementing an active market monitoring program to protect against manipulation of allowance and the associated indices. This effort will include monitoring by the independent entity that performs market monitoring for the PJM markets (Monitoring Analytics). DMM believes that this effort should be sufficient to protect against any such manipulation and will collaborate as necessary in this effort.

Major maintenance costs

DMM also supports the concept of including an additional cost for major maintenance in variable costs included in start-up, minimum load bids, and, in some cases, default energy bids. However, determining appropriate levels for major maintenance adders on a unit-by-unit basis may require substantial judgment and review of unit cost and operational data. For instance, this may be somewhat analogous to determining the variable cost of driving a car (beyond gas, tires and oil) in terms of the cost each time a specific car is started and per

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[2] *California Greenhouse Gas Cap and Generation Variable Costs*, whitepaper by ISO Department of Market Monitoring, February 10, 2012, http://www.caiso.com/Documents/WhitePaper_CaliforniaGreenhouseGasCap_GenerationVariableCosts.pdf.

[3] Based on a unit with a heat rate of 10,000 MBtu/MWh.

mile it is then driven. The details of this methodology and allowable magnitude of these costs have not yet been developed. The ISO plans to subcontract this task to an outside entity (Potomac Economics).[4] DMM would have preferred that additional details of this process be developed as part of this stakeholder process to ensure thorough transparency and review. Thus, we recommend continued discussion and review of this process by the ISO and stakeholders as this provision is implemented.

Lower cap for registered cost bids

Given the additional costs being included in start-up and minimum load bids through these changes, DMM also supports the proposal to lower the cap for start-up and minimum load bids under the registered cost option to 150 percent of estimated actual costs. DMM believes this package of changes provides a reasonable balance between the need to ensure that commitment cost bids accurately reflect actual commitment costs, allowing generators opportunities to earn market revenues, and protecting against the inefficiencies and excessive costs that can result when start-up and minimum load bids significantly exceed actual costs.

Gas operational flow orders

Another modification included in Management's proposal is to allow generators to recover penalties that may be applicable for gas usage in excess of scheduled amounts (plus allowable thresholds) during periods when daily operational flow orders are issued.

The potential importance of having some mechanism to ensure generators could recover these costs was emphasized in 2011 when PG&E was required to test the integrity of its natural gas pipeline system following the San Bruno pipeline rupture and fire. To discourage excessive gas system imbalances during this period, PG&E instituted regular operational flow orders, which included potential penalties for users that deviated from their scheduled gas usage beyond specific thresholds over each 24 hour period. In 2011, these thresholds were quite high (± 25 percent) and penalties for any usage in excess of these thresholds were quite low (e.g. equal to about $2.50/MWh for a typical generating plant). However, under more extreme conditions these thresholds could be much lower and such penalties could add hundreds to dollars to the cost of some incremental generation.

DMM recommended that the ISO address this issue as part of the unit commitment cost initiative, and provided a detailed proposal at the start of the stakeholder process.[5] DMM's

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[4] A general description of the approach is provided in *Major Maintenance Adders Plan*, Potomac Economics, Ltd., April 13, 2012, http://www.caiso.com/Documents/PotomacEconomicsMethodology-Development-MajorMaintenanceCostAdders.pdf.

[5] *Potential Methodology to Account for OFO Penalties Incurred due to Real-time Energy Dispatches*, whitepaper by ISO Department of Market Monitoring, February 2012, http://www.caiso.com/Documents/DMMMethodology-Account_OperationalFlowOrderPenaltiesIncurred_EnergyDispatches.pdf.

proposal is designed to ensure that generators can recover any penalties for gas operational flow orders that are directly attributable to real-time unit commitments and dispatches by the ISO that participants may not be able to completely manage through the market bids and schedules they submit. Under DMM's proposal, generators would recover any operational flow order penalties associated with three categories of ISO dispatches:

- **Real-time commitments.** Fast start peaking units can get committed in the real-time market, and thereby cause a generator's gas burn to exceed scheduled levels.
- **Hours with real-time energy bid mitigation.** As part of the real-time local market power mitigation process, generators may have their market bids may be lowered to their default energy bids — which will not include any adder for potential operational flow order penalties.
- **Exceptional dispatch.** Resources may not be able to avoid commitment or dispatch for additional out-of-market energy through an exceptional dispatch issued by the ISO.

Under the ISO's proposal, any penalties associated with incremental gas deviations related to these types of real-time dispatches could be recovered from the ISO through bid cost recovery payments.

The Market Surveillance Committee and some suppliers have suggested that the ISO develop a process for automatically including potential operational flow order charges in minimum load and default energy bids when operational flow orders are declared. DMM does not recommend pursing this approach for several reasons.

- Unlike greenhouse gas emission costs, costs associated with operational flow order penalties are not hourly marginal costs (i.e., a per-MWh cost). Operational flow order penalties are incurred based on an entity's overall daily gas imbalances over a 24 hour period. Generators have the opportunity to manage their gas imbalances by the way they bid and schedule units over this 24-hour period. They may also procure additional gas during this period to offset any additional unexpected usage.
- Unlike greenhouse gas emission costs, operational flow order charges are only assessed for the portion of gas that a generator uses in excess of its scheduled amount plus the allowable threshold.
- It is not possible to accurately assess − before the fact − whether generation from a unit will be subject to operational flow order penalties.
- Finally, DMM believes that automatically including potential operational flow order charges in commitment and default energy bids of some or all units could create a significant incentive for suppliers to exercise market power, and would undermine the effectiveness of the ISO's local market power mitigation provisions.

Opportunity costs

The Market Surveillance Committee and some suppliers have also suggested that the ISO develop a way to include potential opportunity costs in commitment costs for some use-limited units, such as those with limitations on the number of starts or run hours due to air emissions permits. In prior annual reports and Market Surveillance Committee meetings, DMM has supported conducting further discussion on how some types of opportunity costs could be included in commitment costs. However, as noted in the Market Surveillance Committee's opinion on this topic, accurately accounting for these opportunity costs on a unit-by-unit basis and updating these costs would be extremely complex.

If the ISO were to pursue this approach, DMM believes the framework for this should be developed and vetted as part of the stakeholder process and that some kind of standard approaches and limits be developed. Given the complexity of this issue and wide range of other important initiatives currently facing the ISO and stakeholders, DMM does not recommend that such modifications be pursued at this time. We also note that under the current market design, there are several mechanisms by which use-limited units can manage their starts and run hours.

- Use-limited units under resource adequacy contracts are granted an exemption from the all-hours must-offer requirement. This allows these units to bid into the market only during peak hours of each month if necessary to limit their run hours.
- Fast start use-limited peaking units can be scheduled to provide contingency only non-spinning reserves. This ensures that they will be dispatched only in the event of a contingency during these hours.
- Use-limited units can incorporate any opportunity costs in the energy bid they submit. These energy bid prices are only subject to mitigation if they can relieve congestion on an uncompetitive constraint that becomes congested during the local market power mitigation process.
- Finally, under the ISO's proposal, use-limited resources will be able to submit start-up and minimum load bids up to 150 percent of actual projected start-up and minimum load costs.

Transition costs

As noted in our October 2011 and February 2012 reports to the Board, DMM continues to recommend that the ISO develop an improved approach for limiting bids submitted by multi-stage generating unit owners representing the cost for these units to transition from one configuration to another.[6] This issue was not addressed as part of the ISO's initiative on commitment costs. However, the ISO's final proposal indicates it will re-visit this issue at a later date when additional resources are modeled as multi-stage generating units.

ANNUAL REPORT

Each year the Department of Market Monitoring publishes an annual report on the performance of markets administered by the ISO. As indicated in this report, DMM finds that the nodal market design implemented in 2009 continues to facilitate efficient and competitive overall market performance:

- Total wholesale electric costs fell by 9 percent. This represents a 6 percent decrease after adjusting for lower natural gas prices. This decrease was driven by a significant increase in hydro-electric generation, an increase in low priced imports and moderate loads.
- Almost 100 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive. Day-ahead prices continued to be about equal to prices we estimated would result under competitive conditions.
- Price spikes in the 5-minute real-time market decreased over the course of the year. This improved price convergence between the hour-ahead and real-time markets. The ISO made changes to procedures and software that reduced the incidence of real-time price spikes.

Costs associated with several smaller components of overall wholesale costs increased in 2011. However, these cost increases were attributable to temporary market conditions or were addressed by actions taken by the ISO:

- Revenue imbalance offset costs associated with divergence of hour-ahead and real-time prices totaled about $166 million, up 15 percent from 2010. These costs increased significantly in the first few months of the year and were exacerbated by the introduction of convergence bidding in February 2011, which increased the volume of transactions clearing at these different market prices. These costs decreased by the end of the year as price convergence in these markets improved and convergence bidding on inter-ties was suspended.
- Bid cost recovery payments totaled about 1.5 percent of total energy costs in 2011, compared to less than 1 percent in 2010. This increase was primarily attributable to costs resulting from manipulative bidding behavior that was identified and corrected by June 2011.

[6] See Department of Market Monitoring Report, October 20, 2011, p. 1 and p 4, http://www.caiso.com/Documents/111027Department_MarketMonitoringReport-Memo.pdf.

- Ancillary services accounted for about 2 percent of total energy costs, up from about 1 percent of total wholesale costs in 2010. This increase was largely attributable to very high hydro conditions in the first half of the year, which decreased the availability of ancillary services from hydro resources as they provided energy instead of reserves.

- Exceptional dispatches, or out-of-market unit commitments and energy dispatches to meet constraints not reflected in the market software, remained relatively low. Energy from exceptional dispatches totaled approximately 0.3 percent of total system energy in 2011. However, the above-market costs associated with these commitments and dispatches increased from $25 million in 2010 to $43 million in 2011. This increase is attributable to a combination of increased volumes of exceptional dispatches, along with higher minimum load and energy bid prices for units receiving exceptional dispatches.

Finally, our annual report also includes several findings and recommendations concerning the longer-term performance of the ISO markets:

- About 300 MW of new gas-fired capacity came online in 2011, while over 350 MW of gas generation was retired. In 2012, another 450 MW of gas capacity is expected to be retired, while about 650 MW of new gas generation is projected to come online. Beyond 2012, significant reductions in total gas-fired capacity are possible due to the state's restrictions on use of once-through cooling technology.

- Meanwhile, the amount of new renewable generation coming online has begun to increase dramatically. About 650 MW of nameplate capacity from renewable sources came online in 2011, including about 540 MW of wind projects. Because of the relatively low peak summer capacity value of wind resources, this 650 MW of new renewable capacity represents about 195 MW of potential summer peak capacity. In 2012, about 3,000 MW of new renewable nameplate capacity is expected to come online, including over 2,000 MW of solar capacity. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.

- The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, in 2011 it became increasingly apparent that the state's current process for longer-term procurement may not ensure the investment and revenues needed to support sufficient new or existing gas-fired capacity required to integrate the increased amount of intermittent renewable energy coming online. The ISO and the California Public Utilities Commission are addressing this issue through several initiatives in 2012. This represents a major market design challenge facing the ISO and state policy makers.