# Memorandum

**To:** ISO Board of Governors

**From:** Benjamin F. Hobbs, Chair, ISO Market Surveillance Committee

**Date:** August 24, 2016

**Re:** **Briefing on MSC activities from June 15 to August 16, 2016**

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***This memorandum does not require Board action.***

During the time interval covered by this memorandum, members of the Market Surveillance Committee held a general session meeting of the MSC on June 16, 2016. Also during this time, the MSC has been preparing for the next general session meeting to be held in Folsom in September 19, 2016 by reviewing materials and holding discussions with ISO staff on several upcoming initiatives that will be discussed at that meeting.

The discussions undertaken in the June 16, 2016 meeting are summarized in the next section of this memorandum.

**June 16, 2016 MSC general session Meeting**

Five substantive topics were addressed in the meeting, each being the subject of ISO staff presentations and subsequent MSC and stakeholder discussion.

1. Bid cost recovery enhancements initiative
2. Stepped constraint parameters initiative
3. System and market performance under Aliso Canyon unavailability
4. Regional resource adequacy initiative
5. Transmission access charge wholesale billing determinant initiative

**1. Bid cost recovery enhancements initiative.** The first item concerned alternatives that the ISO is considering in response to the Federal Energy Regulatory Commission's 2006 directive to the ISO to (1) develop a two-tiered procedure for allocating the costs associated with real-time bid cost recovery (BCR), and (2) account in BCR payments for start-up costs for resources that operate across more than one trading day. The discussion began with a presentation by Kallie Wells, Market and Infrastructure Policy group team member at the ISO, in which she summarized the proposed changes.

Presently, real-time BCR costs are recovered entirely from measured demand, unlike day-ahead and residual unit commitment costs which use a tiered system in which costs are first allocated to categories of market parties (such as supply, demand, interties, and virtual transactions), and then allocated within each category to schedule coordinators.  Ms. Wells described a two-tier real-time BCR alternative under consideration by the ISO:

- The first tier would allocate real-time BCR costs among the categories of demand, supply, and interties according to criteria based on changes in forecasts or positions between the markets previous to real-time (day-ahead [integrated forward market] or hour-ahead) and real-time.
- Then in the second tier, each category's share of the costs would be distributed among schedule coordinators according to certain criteria.

Ms. Wells also noted that the ISO is considering other alternatives, including maintaining the status quo (single tier allocation to demand).  MSC members and attendees discussed several issues associated with the allocation proposals, including whether the flexible ramping product is likely to significantly shrink the amount of real-time BCR, which would lessen the need for refining the current cost allocation method.  There was also a discussion of the various real-time BCR cost allocation systems in place at other ISOs, with some ISOs using single-tier allocation and others using two-tier allocation.

Ms. Wells then continued her presentation, turning to the issue of allocation of the start-up portion of BCR over multiple trading days in the case of units that remain on for more than one day.  She noted that these costs only accounted for 4% of day-ahead and real-time BCR during the two-year period between May 2014 and April 2016, which implies that implementing a more complex system to allocate such costs over multiple days may not be worth the effort.

In the final part of her presentation, Ms. Wells discussed an additional change that the ISO has been considering in the allocation of BCR costs, in this case day-ahead market BCR.  Presently, self-scheduled production by resources is netted out of their total production when allocating BCR costs in the day-ahead two-tier procedure.  Ms. Wells pointed out that even flat (constant over the day) self-schedules can increase the system's need for commitments of generation, and thus BCR costs.   MSC members agreed.  MSC member Dr. Scott Harvey further pointed out that there is an inequity in exempting self-schedules because two suppliers with identical patterns of supply over the day could be assigned different allocations depending on whether they were self-scheduled or not.

**2. Stepped constraint parameters initiative.**  The second agenda item concerned an ISO initiative that involves five issues concerning parameters used in the ISO market software.  These issues and possible alternatives to address them were discussed in a presentation by Don Tretheway, Senior Advisor for Market Design and Regulatory

Policy at the ISO. Although the issues are technical in nature, they have the potential to have significant impacts on the ISO's market prices.

The five issues included the following:

1. *Relaxation parameters for transmission flow constraints.* These parameters are used as cost terms in the objective function of the market software; these terms impose a penalty if flow on a transmission component exceeds the stated limit. Presently there is one level of penalty for each constraint. Mr. Tretheway explained that the ISO proposes to introduce a second, lower level that would apply to minor violations, defined as being less than 2% of the limit. The present (higher) parameter would apply to greater deviations. The penalties would also be lower for components below 230kV.

   In the subsequent discussion, MSC members agreed with the general principle that the marginal penalty should be higher for larger deviations. However, the right overall level is uncertain. MSC chairman Dr. Ben Hobbs noted that an effect of the values proposed could be to lessen price spikes, but that effect by itself is an insufficient reason to lower penalties, in the absence of an understanding of the consequences of constraint violations. If violation of a constraint significantly increases the risk of reliability or other problems, the correct penalties (and resulting price effects) might instead be higher than present penalty levels.

2. *Determination of an effectiveness threshold for transmission shift factors.* Shift factors quantify the marginal effect on MW flow through a given transmission component for every 1 MW of change in load or supply at a bus. Presently, the market software resets to zero any factors whose absolute value is less than 2%. However, the computational reasons for doing so have become less of an issue as computers improve. Further, MSC member Dr. Harvey noted in a separate presentation that what matters in market operations is not the size of the factor relative to zero, but the difference between factors at different buses. For instance, in choosing between two resources for relieving a transmission constraint, if two resources have shift factors of (say) +0.4 and +0.43, respectively, this has the same economic significance for redispatching resources as if their shift factors were instead -0.01 and +0.02. However, the truncation procedure would collapse the difference between the factors to zero in the latter case, but not in the former, which is inconsistent. Dr. Harvey concluded that truncation of shift factors can significantly distort prices. In the discussion following the two presentations, MSC members agreed with the ISO's proposal to lower the threshold by at least an order of magnitude.

3. *Relaxation parameters for the power balance constraint*. MSC members agreed that having the equivalent of a sloped demand curve (in the form of increasing stepped penalties) for power balance violations, in which smaller violations have

lower marginal penalties, is very reasonable, since small deviations have relatively little system consequences. However, as a stakeholder pointed out, the details of the implementation are important and need to be documented and reviewed.

4. *Relaxation parameters for transfer limits among balancing areas in the energy imbalance market (EIM).* Presently these limits are enforced as “hard” constraints in which no violations are allowed in the market software. Diverse opinions were expressed during the meeting discussion about whether or not violations should be allowed and, if so, what penalties would be appropriate in order to discourage balancing authorities from leaning on other balancing authorities.

5. *The level of the bid floor in the energy market.* Mr. Tretheway’s presentation lead to a discussion of the desirability of decreasing the floor to as low as minus $1000/MWh.

**3. Aliso Canyon.** The third substantive item on the agenda concerned the Aliso Canyon-related operating restrictions and their effect on the ISO system and markets. A presentation by Cathleen Colbert, Senior Market Design and Policy Developer, Market & Infrastructure Policy at the ISO, summarized the challenges posed by those restrictions, and the ISO’s proposals for managing those restrictions by imposing additional market constraints and taking other measures.

The proposed constraints include:

- A constraint in the day-ahead market on the amount of gas that can be burned by generating units in the affected area.
- Reservation in the day-ahead market of electricity transfer capacity on Path 26 into the affected area for possible use in real-time, in case local available generation is insufficient.
- Placing bounds on deviations of total gas burn in the affected area in real-time from the amount of gas burn that is scheduled day-ahead.

Ms. Colbert presented the general mathematical formulation of these constraints, which was followed by MSC and stakeholder discussion of how those constraints would specifically be applied. Examples of implementation issues include penalty parameters for constraint violations and the precise definition of hourly limits in the real-time market. MSC members also discussed alternative formulations for achieving the goals of the constraints. For instance, Dr. Harvey suggested that to accommodate the gas burn constraints in real-time, generators could be allowed to switch from providing energy to providing reserves, or vice versa.

In addition, the ISO intends: to increase information about gas needs by releasing 2 day-ahead advisory generation schedule results from the day-ahead market; to improve the timeliness of gas price information for use in market power mitigation; and to increase the flexibility of commitment cost re-bidding and after-the-fact cost recovery. Ms. Colbert also reviewed three options under consideration for using real-time gas information to improve real-time dispatch, including: (1) having generators bid gas price and transport cost; (2) use real-time estimates of gas prices in dispatch based on volume-weighted prices of trades; and (3) change the margin of error used in commitment costs and default energy bids.

**4. Regional resource adequacy initiative.** Chris Devon, Senior Infrastructure Policy Developer at the ISO, presented the ISO's position that there is a need for consistency in reliability assessments across any expanded ISO footprint. In particular, consistency is needed concerning counting rules for the contribution of resources to system adequacy and in the definition of planning reserve margin requirements. He also discussed in detail the issues involved in allocating maximum import capability among subregions, while respecting pre-existing commitments and contractual obligations. Mr. Devon then reviewed questions concerning qualification of imports for meeting resource adequacy requirements, such as firmness of commitments and how far in advance those commitments should be made.

The definition of uniform counting methodologies resulted in significant discussion. Mr. Devon explained the exceedance methodology that the ISO proposes for initial use for solar and wind resources, and resource-specific methods proposed for application to other resources. He then mentioned the advantages of a more sophisticated "expected load carrying capability" model, which could in theory provide a more accurate and consistent representation of the contribution of resources to system reliability. Dr. Hobbs then made a presentation that summarized the need to have location-specific credits for renewable resources, due to the diversity of resource quality and thus their contributions to system reliability. His presentation summarized his simulation study of the impacts of inaccurate credit estimates upon system costs, generation mixes and reliability. He concluded that costs to consumers of meeting a given reliability constraint could be significantly increased by granting resources too much or too little credit relative to their actual marginal contribution.

Mr. Devon concluded his presentation by discussing how a probabilistic reserve margin criterion could be established by setting a loss-of-load-expectation requirement. Discussion then followed among MSC members and stakeholders of what the target loss-of-load-expectation should be set at, and the role of benefit-cost analysis in determining the optimal level of reliability.

**5. Initiative on transmission access charge wholesale billing determinant.** The final agenda item was introduced by Lorenzo Kristov, Principal, Market and Infrastructure Policy at the ISO. His presentation briefly summarized six general questions posed in the recent ISO issue paper on defining the wholesale bill determinant to be used to calculate transmission access charges in an expanded ISO footprint.

Most of this agenda item was devoted to a presentation by Craig Lewis of the Clean Coalition regarding the potential for distributed generation (DG) that is connected directly to the distribution system to lower net loads upon the transmission grid and the consequent need for transmission expansions. Mr. Lewis presented their model-based projections of possible growth in DG in California, how much transmission investment could be deferred as a result, and possible consequences in terms of revenue requirements to be recovered via the transmission access charge. Mr. Lewis concluded that DG should be netted from metered retail load in determining the transmission revenue requirement for a participating transmission organization. MSC members and stakeholders then engaged in a discussion of the assumptions of the study. A particular issue is the relationship of transmission investment to total energy requirements versus peak requirements, and how in particular DG would affect the resulting needs for transmission investment. The MSC requested details on the analysis assumptions and procedures for its review.