Memorandum

To: ISO Board of Governors

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

Date: December 7, 2016

Re: **Briefing on MSC activities from October 9, 2016 to Dec. 2, 2016**

This memorandum does not require Board action.

During the time period covered by this memorandum, members of the Market Surveillance Committee held a general session meeting of the MSC on November 18, 2016. The members also reviewed materials on initiatives discussed at that meeting, and also conferred with ISO staff on several initiatives.

The discussions that took place during the November 18, 2016 general session meeting are briefly summarized in the remainder of this memorandum.

Four sets of issues were addressed in the meeting by an ISO staff presentation and subsequent MSC and stakeholder discussions. These issues included the following:

1. The generator contingencies and remedial action scheme modeling initiative.
2. The expansion of the flexible resource adequacy criteria and must-offer obligation 2 initiative.
3. The regional resource adequacy initiative, emphasizing the issue of whether and how imports of power can be counted for resource adequacy purposes.
4. The commitment costs and default bid enhancement initiative.

The major points of discussion in each of these agenda items are summarized below.

1.* Generator contingencies and remedial action scheme modeling*. The first agenda item was introduced by Mr. Perry Servedio, Sr. Market Design & Regulatory Policy Developer at the ISO. His presentation, along with the subsequent discussion by MSC members and attendees, addressed two broad modeling issues that have the potential to both lower costs and increase the reliability of the energy schedules resulting from the ISO's market.

The first modeling issue is how to accurately include generator contingencies as security constraints in the market software, while the second is how to represent the pre-planned automatic tripping of generators when a transmission line outage occurs (so-called remedial action schemes). The first issue is a priority because such contingencies, if not considered when constructing market schedules, could leave the system insecure.

The second, higher priority, issue is important because remedial action schemes can actually permit fuller use of the transmission grid by removing generation that is anticipated to be most likely to be responsible for overloads of transmission if a transmission contingency occurs. Recognizing the greater transmission use that then becomes possible in the presence of such a scheme allows for less expensive market solutions. Also, if remedial action schemes are handled outside of the market, as they are today, there can be reliability concerns.

Mr. Servedio's presentation reviewed how these two issues would be modeled in the day-ahead and real-time market software, and the potential improvements in security and efficiency that could result from their inclusion. A technical issue that received some attention in the subsequent discussion concerned the assumptions that are made about where make-up power would be obtained when a generator goes off line; these assumptions can affect the assumed post-contingency flows and congestion that the market software would need to manage.

Discussion followed among MSC members and the audience of a pricing phenomenon that would arise in the remedial action scheme modeling, which is that a generator at a bus that participates in a scheme may receive a different energy price than another generator at the same location that does not participate. This is because a component of the local marginal price includes the shadow prices associated with post-contingency constraints on flows if a generator contributes to those flows. Since the generator participating in the scheme might not contribute to those flows, it would not see that component reflected in its price. The MSC and audience discussed whether this would provide desirable incentives for generators to participate in remedial action schemes.

Although the following point was not made at the MSC meeting, I would point out that the above price differentiation that arises from the modeling of the remedial action scheme at a location can be viewed as being similar to the situation under the flexible ramping constraint, as it existed prior to the recent implementation of the flexible ramping products. If there are two generators producing at a location, one of which also helps meet the flexible ramping constraint while the other doesn't, the total payment per MWh of output differs between the plants. This is because one plant is also paid the shadow price of the flexible ramping constraint times its contribution to that constraint. In the flexible ramping constraint case, the shadow price is not folded into the energy price, so both plants receive the same energy price, but different total revenue per MWh because of flexiramp payments. In the remedial action scheme examples given by Mr. Servedio, the relevant shadow prices for flow constraints under the contingency are paid to one generator but not to the other. But because those shadow prices are folded into their respective energy prices rather than separated out, this leads to the apparent price difference. In both the flexible ramping constraint and remedial action scheme cases, the revenue difference occurs because one generator affects an additional constraint in the market that the other generator does not.

***2.* Flexible resource adequacy criteria and must-offer obligation 2 initiative.** The second agenda item concerned the supplemental issue paper released on November 8, 2016. Dr. Karl Meeusen, ISO Senior Advisor for Infrastructure Policy summarized the content of that paper and the issues it raises concerning the flexibility of capacity that has qualified for flexible resource adequacy designation since that category was created. He then posed the question of whether the attributes that are required of such capacity should be adjusted to meet flexibility goals in addition to the 3 hour evening ramp. Examples include whether generating units exceeding a threshold Pmin/Pmax ratios (ratios of minimum output to total capacity) should be capable of two starts a day, and the need for flexible capacity on weekends as well as weekdays. These questions will be examined as part of an expanded flexible resource adequacy and must offer obligation phase 2 initiative.

Discussion ensued concerning whether there is a need for multiple flexible capacity categories meeting several needs (such as both within-hour and 3 hour ramps), or if a single flexible resource category can meet them all. In discussions and in previous formal opinions, the MSC has repeatedly indicated a preference for relying on the ISO's day-ahead and real-time markets as the primary source of financial incentives for flexibility rather than resource adequacy designations. There is a need to understand the extent to which the ISO's spot energy and flexible ramping prices reward flexibility, as well as possible explanations for why the ISO's market designs might lead to insufficient incentive for flexibility in those markets, if that is actually the case.

A study of returns to flexibility in the spot markets would be a useful complement to the supplemental issue paper's proposal for an assessment of the ability of the flexible resource adequacy showings to meet the ISO system's flexibility needs. It was suggested by MSC Chair Ben Hobbs during the discussion that this could be done as an expansion of the Department of Market Monitoring's routine analyses of the gross margins that new capacity of various types would earn in the ISO's spot markets.

3. Counting of imports as resource adequacy. The third substantive item on the agenda concerned one of several important questions in the regional resource adequacy initiative, which is the type and amounts of energy imports that should be allowed to be counted towards resource adequacy obligations. Mr. Chris Devon, Senior Infrastructure Policy Developer at the ISO, began the discussion with a presentation outlining the issues involved in this question.

Among the issues presented and then discussed at the meeting are whether energy contracts with shorter lead times than the present month-ahead firm showing requirements should be eligible to be counted towards resource adequacy requirements; if so, what limitations might be put on such contracts; and the creation of incentives to ensure that those contracts indeed perform as intended during times of system stress. MSC member Dr. Jim Bushnell and the other MSC members emphasized that assigning appropriate responsibility for a significant penalty for such resources not showing up when needed could, in theory, substitute for a requirement for a month ahead-of-time firm requirement. One point that was made was that if load curtailments are necessary because short lead-time energy contracts did not perform, there would need to be an ability to focus any needed load curtailments on load-serving entities and regions whose resource adequacy showings included those contracts.

4.* Commitment cost and default bid enhancement initiative*. The final item on the agenda concerned the ISO's initiative to build more flexibility into the bidding of commitment costs. Ms. Cathleen Colbert, Senior Market Design and Policy Developer, Market & Infrastructure Policy gave a presentation that provided an overview of the tradeoffs involved. A major tradeoff is between the potential that more flexible bidding rules could allow bids to be more reflective of the full set of costs involved in committing generating units, and thus encourage offers when those units are needed, versus the risk that such flexibility would increase opportunities to exercise market power. Another issue that has arisen as a result of the Aliso Canyon situation is whether commitment cost bids can appropriately reflect "externalities" in the gas network. The term externalities, in this context, refers to the reflection of gas network limitations in, for example, high imbalance charges or operational flow orders that impose real costs on the system that might not be adequately reflected in present commitment cost bids.

Mr. Keith Collins, Manager of Monitoring and Reporting in the ISO Department of Market Monitoring followed by making a presentation in which he outlined his department's recommendations for reform of commitment costs. He stressed the benefits of more timely updating of gas price indices. These were demonstrated by data he showed indicating that if the Intercontinental Exchange price information is used to update the day-ahead indices then errors in gas prices and resulting commitment costs would be greatly reduced. Mr. Collins then suggested some proposals for consideration in the longer term (post-2017). These included pre-validation of gas costs submitted by market participants together with a post-market review process, and consideration of how dynamic criteria for mitigating commitment cost bids might be designed and implemented.

Following these presentations, there was extensive discussion of alternative ways in which that exercise could be detected and mitigated, including a conduct-and-impact test similar to what the eastern ISOs have. Such a test would be a significant departure from the pivotal supplier/uncompetitive constraint philosophy presently embodied in the California ISO's local market power mitigation mechanisms. On one hand, a conduct-and-impact test has the advantage of directly addressing whether market power is actually having an impact on prices and bid cost recovery payments. On the other hand, however, in practice there are computational challenges to applying the test on a individual supplier basis, and it could allow markups just below the conduct or impact thresholds.

MSC member Dr. Scott Harvey briefly discussed his previous suggestion of a possible modification to the present ISO uncompetitive constraint approach in which the market software would detect whether imposition of a transmission constraint has caused a generator to be committed which otherwise would not have. There would also need to be dynamic market power tests tto identify generators whose bids are so high that they were not committed despite the constraints, thereby potentially increasing local prices.