Memorandum

To: ISO Board of Governors

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

Date: December 6, 2017

Re: **Briefing on MSC activities from October 14 to Dec. 1, 2017**

This memorandum does not require Board action.

During the period covered by this memorandum, the Market Surveillance Committee (MSC) consulted with ISO staff on several initiatives. In addition, MSC members drafted an Opinion on the contingency modeling enhancements initiative, which the MSC adopted at its general session meeting on December 1, 2017. During that meeting, there were also presentations and discussions on three topics: the commitment cost and default energy bid enhancements initiative; issues concerning load shift and load consumption under the third phase of the energy storage and distributed energy resources initiative; and the on-going transmission access charge structure review.

The contingency modeling enhancements initiative Opinion is summarized below, followed by a description of the presentations and discussions at the meeting.

Opinion on Contingency Modeling Enhancements

Two recent initiatives by the California ISO address the efficient inclusion in market schedules of preventive and corrective approaches to managing contingencies.[1] The first, the generator contingency and remedial action scheme modeling (GCARM) initiative, was the subject of an MSC Opinion adopted in September,[2] and was subsequently approved by the Board of Governors. That initiative is designed to include preventive constraints in market models to account for the need to maintain feasible flows immediately after two types of contingencies: (1) generator outage events and (2) transmission outage events that are directly followed by deliberate disconnection of generation, other transmission, or load as a result of triggering of so-called remedial action schemes. Meanwhile, the second initiative,

[1]The two initiatives are contrasted on p. 29 of California ISO, *Generator Contingency & RAS Modeling*, Draft Final Proposal, July 25, 2017, www.caiso.com/informed/Pages/StakeholderProcesses/GeneratorContingency_RemedialActionSchemeModeling.aspx

[2]J. Bushnell, S.M. Harvey, and B.F. Hobbs, *Opinion on Modeling of Generator Contingencies and Remedial Action Schemes in the California ISO Markets*, Market Surveillance Committee of the California Independent System Operator, August 28, 2017, www.caiso.com/Documents/MSCOpinionGeneratorContingencies_RemedialActionSchemes-Aug28_2017.pdf

the contingency modeling enhancements (CME),[3] differs in that it explicitly optimizes both preventive and corrective actions in response to certain transmission contingencies. The corrective actions involve the search for a feasible system redispatch that satisfies generator ramp and network constraints in order to return the system to a secure operating point within 30 minutes or other time period. The Opinion adopted on December 1, 2017[4] addressed the CME initiative.

The major conclusion of the Opinion was that implementation of the preventive-corrective modeling approach to represent system actions to satisfy system operating limits within the time required has the potential both to lower the cost and to improve system security. Such an explicit representation of system response to contingencies is, in theory, the most efficient approach to managing those constraints, and results in the identification of "contingent capacity" that is able to respond post-contingency. However, we also concluded that the CME simulations conducted by the ISO, although helpful, do not provide unambiguous evidence of large cost savings, since the costs of meeting operating limits with minimum on-line constraints versus the CME approach were calculated only for a single day and we do not have an estimate of the number of days per year such differences would exist. Nevertheless, there will be a desirable increase in price transparency for the unloaded capacity that resolves these constraints in the market, which is now missing in the current mechanisms employed by the ISO.

We also concluded that there may also be additional long-run benefits through an improved price signal what would incent investments in resources able to meet contingent capacity needs at a lower cost. However, these benefits may be small or even provide a disincentive to invest in flexible capacity if the procurement of contingent capacity at low or zero prices in the day-ahead market reduces the returns to flexible capacity.

In the future, there is a potential for increased savings from extending the preventive-corrective modeling approach to consider a greater range of contingencies and system disturbances. This could improve the definition of, for instance, reserve and flexible ramping requirements by allowing them to more accurately reflect system conditions. We also note that that the ISO has agreed to implement these constraints under the settlement agreement related to the Sept. 8, 2011 Pacific southwest outage.

Because of costs of securing gas day-ahead for upward corrective capacity, there is a rationale for allowing non-zero offers in the day-ahead market for corrective capacity. Similarly, for demand response, there are likely to be real costs in addition to opportunity costs that consumers incur if response capability is designed as corrective capacity day-ahead. Such offers would need to be subject to local market power mitigation tests and the

[3]California ISO, *Contingency Modeling Enhancements*, Draft Final Proposal, August 11, 2017, www.caiso.com/Documents/DraftFinalProposal-ContingencyModelingEnhancements.pdf

[4] J. Bushnell, S.M. Harvey, and B.F. Hobbs, *Opinion on Contingency Modeling Enhancements,* Market Surveillance Committee of the California Independent System Operator, Dec. 1, 2017, www.caiso.com/informed/Pages/BoardCommittees/MarketSurveillanceCommittee/Default.aspx

ISO would ideally develop a holistic capacity bidding approach across all operating reserve products. The policy implications and implementation of a mitigation system might be so complex as to delay implementation of the enhancements. We believe that, even absent the ability of resources to make capacity offers, the current proposal represents a useful incremental improvement over current practices. It is therefore acceptable to proceed with the current proposal and defer further consideration of non-zero offers to a later initiative. This could take place in the context of planned California ISO initiatives addressing comprehensive real-time and day-ahead market enhancements.

However, if problematic signs emerge that the proposed practice of not allowing contingent capacity offers is distorting ancillary service procurement or creating other compensation issues, measures to adjust the compensation of corrective capacity would need to be expedited. The MSC recommends that the ISO should immediately prepare a backstop modified settlement procedure, such as the possibility of paying spinning or non-spinning reserve prices to day-ahead corrective capacity, that can be implemented rapidly if problems arise with corrective capacity day-ahead prices being much lower than real-time prices for such capacity or being too low to compensate demand-response resources.

We understand that the penalty prices that would be applied to corrective capacity in the real-time markets have not yet been determined. Moreover, some of the ISO's current policies concerning the scheduling and settlement of corrective capacity in the current market are also not clear. As a result, we have not been able to assess the extent to which the implementation of CME (and the differing rules regarding capacity bids for reserves and corrective capacity in the day-ahead market, combined with limited reoptimization of reserves in the fifteen minute market) will reduce the supply of flexible capacity available to balance load and generation in real-time dispatch if these corrective constraints bind in that dispatch. However, it appears to us that there is a potential for unintended consequences from these effects if the corrective constraints bind more than very occasionally in real-time dispatch. The ISO needs to assess the potential for such unintended consequences and be prepared to adjust elements of the CME implementation on an expedited basis if these problems arise in actual operations.

In the Opinion, we agreed with the ISO's proposal to not alter the allocation and auction of congestion revenue rights to reflect the implementation of contingency modeling enhancements, based upon the simulation results that indicate that the CME constraints are unlikely to bind often. However, the ISO should monitor the constraints after implementation to confirm that this is indeed the case, and if not, then consider implementation of a system to allocate congestion revenue rights for corrective congestion.

General Session Meeting of September 8, 2017[5]

Besides the adoption of the CME Opinion, the MSC general session meeting had the following three agenda items: (1) the ISO staff proposal for dynamic mitigation of commitment cost offers, under the commitment costs and default energy bid enhancements initiative; (2) treatment of load shift and load consumption under the third phase of the energy storage and distributed energy resources initiative; and (3) the transmission access charge structure review. The discussions are summarized below.

During the public comment period prior to those agenda items, Dr. Eric Hildebrandt, Director of Market Monitoring at the ISO asked the MSC membership to review recent analyses that addressed the current system of auctioning congestion revenue rights. He also requested that the MSC take an active role in the discussions of possible changes to the system over the coming months.

1. Commitment Costs and Default Bid Enhancements

Ms. Cathleen Colbert, Senior Market Design Policy Developer at the ISO, briefed the Market Surveillance Committee on the recent evolution of the commitment costs and default bid enhancements initiative, in particular the proposed dynamic market power mitigation test for commitment cost bids. Her presentation emphasized the role in the present proposal of the residual supply index on determining the competitiveness of binding and nonbinding transmission constraints, accounting for the ability of suppliers to ramp or shut down. The proposed use of analogous tests to determine the competitiveness of minimum on-line constraints was also discussed. How those tests would then be used under the proposal to mitigate unit commitment costs was then reviewed by Ms. Colbert. Ms. Colbert also discussed how these procedures would be applied to supply that was exceptionally dispatched. Her part of the presentation concluded with a summary of how the proposal would address inter-temporal concerns, to prevent already committed units from being able to exercise market power by later altering their offers.

The last part of the presentation was made by Dr. George Angelidis, Principal at the ISO, he discussed how mitigation tests are applied in the energy imbalance market to identify potential uncompetitive conditions on contract paths between balancing areas.

These presentations stimulated discussion by MSC members and stakeholders on the details of the proposal, as well as the basic operation of the tests in the energy imbalance market. Dr. Scott Harvey, member of the MSC, concluded this agenda item by making several points about the proposal. One point concerned exceptional dispatch. He asked why all exceptionally dispatched generation would

[5] All presentations are available at www.caiso.com/informed/Pages/BoardCommittees/MarketSurveillanceCommittee/Default.aspx

not be mitigated, given that operators need to move quickly and may not have many options. The ISO explained that a software tool had been introduced which allowed ISO operators to economically evaluate alternative resources for exceptional dispatch. In another point, Dr. Harvey asked about the calculation of adjustments of flow on a nonbinding constraint when a candidate unit for mitigation is decommitted in the competitiveness test. The concern is that a decommitment would require a matching increment in generation from other resources, and this might either exacerbate or mitigate congestion problems on the constraint in question.

2. Load Shift and Load Consumption

This agenda item concerns issues surrounding the design of incentives for "load consumption" (defined as increases in load in response to low or negative prices) and "load shift" (changes in the timing of load as a result of thermal or electric storage, or deferral of energy-consuming activities) under Phase 3 of the energy storage and distributed energy resources initiative. Mr. John Goodin, Manager, Infrastructure & Regulatory Policy at the ISO, started the discussion by making a short presentation in which he outlined some advantages of restricting incentives to load shifts from stationary devices, and discussed some of the conceptual issues involved in defining baselines for "load consumption" and distinguishing between what was termed "productive" and "unproductive" consumption. He concluded by asking the MSC for recommendations on what issues and impacts to consider in policy development. These included: market efficacy, whether wholesale payments for load shifting would significantly alter consumer behavior, interactions with retail rate setting, the basis for assessing the value of load consumption, and the risk of double payments.

Dr. Jim Bushnell then followed with a presentation on "Addressing Retail Problems with Wholesale Products". In that presentation he described the ideal set of prices, which would dynamically reflect the full marginal cost of supply, a large portion of which is the wholesale locational marginal price. In the ISO's markets, however, wholesale locational prices only apply to nondistributed supply and a limited amount of participating demand response; many resource investment decisions, including distributed resources in front of and behind the meter, face a different set of prices. The latter prices included fixed (volumetric) components to recover investment costs for the distribution and transmission networks and do not vary over time, except for some pre-determined time-of-day rates. Some customers in California also pay demand charges. Dr. Bushnell showed a map based on his work with Prof. Sev Borenstein of UC Berkeley that indicates that California has among the lowest fixed customer charges for electricity in the US, and as a partial result, its retail per kWh rates exceed marginal social cost by a greater margin than any other region in the US. These distortions, together with the lack of time variations that reflect system conditions, dampen incentives for efficient implementation of storage and energy using technologies.

Dr. Bushnell concluded by discussing how and whether wholesale market products can be used to fix problems in retail pricing. They could counteract retail pricing imperfections, but there can be issues concerning identifying baselines if payments are made relative to some assumed "without program" consumption. There can also be “double payment” issues, for instance by paying consumers to reduce energy use at the same time they then avoid paying the retail price. Wholesale market products could promote use of storage, but if poorly designed, biases could result in favor of behind-the-meter installations versus larger, and perhaps more efficient front-of-meter installations. Dr. Bushnell also cautioned against making a priori judgments about good and bad consumptive uses of energy.

In the ensuring discussion, Dr. Ben Hobbs, Chair of the MSC, suggested that consumers have many options to be flexible, including electric vehicle charging, pre-cooling of living spaces, pool pre-heating, and storage, and that these opportunities and the resulting bill savings will be factored into consumer decisions about what types and efficiency of batteries to buy, and whether to make investments in energy efficiency investments and PV installations. It is desirable that reforms of retail rates or introduction of wholesale products into retail markets not worsen existing biases for or against certain types of flexibility or investments. He also voiced concern over locking in products designed for particular technologies, since those market products may become quickly outmoded because of technology change but difficult to alter once in place.

Discussion then followed among ISO staff, MSC members, and stakeholders. Among other issues raised were treatment of combined heat and power facilities, and efficiency implications of incentives for front-of vs behind-the-meter installation of storage.

3. Transmission Access Charge Structure Review
Mr. Chris Devon, Senior Infrastructure & Regulatory Policy Developer at the ISO, began this agenda item by outlining two fundamental types of decisions involved in redesigning the transmission access charge (TAC) within the ISO. The first decision type is the TAC structure, in terms of whether it is applied on a volumetric (per kWh) basis (the present system), demand charge basis (e.g., based on coincident peak), fixed customer charge basis, or some combination. The second decision type is the measurement point: should the TAC be applied to net consumer consumption (“consumer downflow”, which is the present system) or to net flow from the high voltage grid to the distribution system (“transmission downflow”, as proposed by some stakeholders)?

Decisions on TAC structure and measurement point affect economic efficiency by altering incentives for dispatch of existing resources as well as investment in new resources. For instance, basing TAC structure on coincident peaks might diminish incentives for behind-the-meter generation, while using “transmission downflow” could increase the financial value of front-of-meter distributed generation to load serving entities. Mr. Devon highlighted several issues involved in assessing the market impacts of changes. Examples include the magnitude of consumer response to changes; how the TAC are ultimately translated by load serving entities into energy, demand, and customer charges; and the reduction in transmission investment and operations costs that could result if transmission downflow changes.

Dr. Hobbs then followed with a presentation that described a simple modeling analysis of the economic implications of changing the measurement point from consumer downflow to transmission downflow. These implications include changes in (i) the amount of power provided by three sources of energy (bulk power resources; front-of-meter distributed generation (DG); and behind-the-meter DG); (ii) consumer prices; and (iii) overall supply and network costs. Simple assumptions are made so that the fundamental economic issues can be highlighted. The model consisted of equations representing the balance of supply and demand; the price incentives to suppliers in each of the three parts of the system; and how ISO market prices, TAC allocation, and distribution network cost allocation affect those price incentives.

Dr. Hobbs concluded that the economic efficiency impacts of those shifts depend on the size of the TAC and the divergence of retail rates from marginal cost of serving load. In addition, whether there are avoidable EHV and/or distribution network costs arising from changes in bulk and DG generation also affects the overall net benefits of changing the TAC point of measurement. On one hand, if network costs are largely independent of transmission downflow, $/kWh retail rates and the total cost of energy supply will likely increase if TAC is allocated to transmission downflow. That is, allocation of TAC costs to load net of front-of-meter DG would in that case likely decrease market efficiency. On the other hand, if marginal avoided network costs are similar to average network costs, then increases in DG could result in lower total generation and network costs of supply. Thus, the key tradeoff is between potential increases in supply costs (if increased DG is at the expense of cheaper bulk supply) and saved network costs.

Discussion with stakeholders ensued concerning the assumptions and implications of that analysis. There was agreement that understanding the drivers of future grid costs and the relationships between the average and marginal long run cost of the grid would be crucial to understanding the benefits, if any, of reforming TAC.