Memorandum

To: ISO Board of Governors

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

Date: March 21, 2019

Re: Briefing on MSC activities from January 25, 2019 to March 19, 2019

This memorandum does not require Board action.

During the period covered by this memorandum, the MSC wrote and adopted a formal Opinion on the ISO's local market power mitigation enhancement initiative. [1] This Opinion is summarized in the next section below. The MSC also prepared a draft of an Opinion on the reliability must-run and capacity procurement mechanism initiative. The latter was posted on March 18, 2019, and is scheduled for adoption on March 20, 2019. The recommendations from that draft opinion are summarized in the last section of this memo.

The MSC is scheduled to hold a general session meeting in Folsom on April 5, 2019.

Opinion on Local Market Power Mitigation Enhancements

On March 5, 2019, the MSC adopted an Opinion on the ISO initiative to revise its local market power mitigation (LMPM) procedures. The present proposal addresses several issues that have arisen since LMPM was expanded to encompass the energy imbalance market (EIM). The primary issue is greater uncertainty in estimates of variable costs of generation, which makes the setting of default energy bids more difficult, increasing the risk of both over- and under-mitigation. Over-mitigation can result in overuse of limited energy resources and disincentives for participation in the voluntary EIM markets. Under-mitigation poses a risk of market power exercise. This greater uncertainty is the result of lower quality of information on natural gas supply costs in many EIM balancing authorities (BAs), and the inherent nature of long-term hydropower storage, which makes opportunity costs dependent on uncertain future inflows and market conditions. Market power mitigation cannot function without estimates of variable costs, and so the ISO must estimate them; in choosing their values, the degree of uncertainty, as well as the consequences of possible over- vs. under-mitigation need to be weighed. In addition, there are issues in defining competitive supply that can potentially flow into a BA, which can affect whether supply in BA is declared noncompetitive and subject to mitigation.

[1] This proposal fell under the EIM Governing Body's primary approval authority and was approved by the EIM Governing Body at their March 12, 2019 meeting.

The ISO's LMPM enhancements proposal has a number of features designed to address the need for default energy bids (DEBs) in the EIM and the uncertainty involved in their estimation. These features can be classified as either DEB- or quantity-oriented. The features that address DEBs focus on improving estimates of natural gas costs and long-term energy market prices that determine opportunity costs for the large amount of hydropower facilities that exist in many EIM balancing authorities. Meanwhile, the quantity-oriented features in essence attempt to limit the risk of overuse from too low DEBs by attempting to indirectly restrict the upward dispatch of mitigated resources in a balancing authority if that supply expansion would either (a) change that BA from an importing to an exporting region, or (b) increase net exports from that region, if it is an exporting region.

The MSC's recommendations can be summarized as follows.

Limits on Transfers among BAs When Offers are Mitigated. Our recommendation on imposing limits on changes in inter-BA transmission flows as a measure to avoid the risk of overuse of mitigated resources whose DEBs have been underestimated is as follows. As long as these export restrictions are not applied as a matter of course but are available as a last resort to a BA in which application of mitigation is resulting in power being exported for less than its cost, we accept the availability of these restrictions as being an acceptable price to pay for encouraging EIM entities to participate in the EIM with a broader set of resources. They are a blunt but potentially necessary instrument to lower the risk of adverse efficiency and reliability consequences of understated DEBs.

We note that limiting exports in the market run based on levels calculated by the mitigation run could have unintended consequences. These could include:

- limiting the effectiveness of market power mitigation in some circumstances;
- overly restricting the use of flexible ramp resources to meet unexpected changes in net load in other BAs between the advisory and binding real-time dispatch intervals that could reduce EIM benefits in general and the EIM flexible capacity diversity benefit in particular, and potentially lead to wealth transfers between the owners of resources located within the BA implementing the export limit and the BA operator; and
- the use of advisory interval flows in the mitigation run to define limits in the binding interval of the next market run of the real-time (5 minute) dispatch market. The result could be overly tight constraints on inter-BA transfers in the market run because of changes in load or supply availability from the previous advisory dispatch for the same interval. This could perversely result in the application of mitigation causing prices in the market dispatch to be raised above the level that would have prevailed had there been no mitigation.

Since an EIM BA can choose to impose or not impose these limits, we hope that EIM entities will not have a need to do so often. If they are imposed frequently, this will have the consequences noted above, and make EIM prices more difficult to predict by increasing the complexity of the network constraints and thus congestion cost calculations. Frequent use should be viewed as a signal that there may be a continuing issue with DEB accuracy that the ISO needs to address. Alternatively, if it is concluded that the DEBs involved are accurate or even somewhat high, it might be an indication that a BA is either attempting either to exercise market within a constrained

EIM subregion, or to benefit a subset of market parties in its area by decreasing energy prices but also earning congestion rents on the limits. This implies that the use and impacts of these limits needs to be carefully monitored and action taken if this option is utilized on more than a sporadic basis and by more than one EIM entity at a time.

Default Energy Bids for Hydropower Offers. Regarding the calculation of hydropower DEBs, we support the general procedure, but recognize its imperfections and limitations. One limitation is the potential use of future energy prices to set opportunity costs at times of the year beyond the time when reservoirs are expected to refill and spill in the case of larger storage reservoirs. This may not be not the situation in all years, but during wet years, a reservoir that is likely to spill in the spring should not be able to use late summer power prices to determine DEBs early in the previous winter. Conversely, in dry years, some reservoirs may have higher opportunity costs in the summer then estimated by the proposed methodologies. However, due to the complexity and lack of transparency of hydro operations and constraints, the large uncertainties surrounding inflows and future energy prices, and the changes in generation use that will come with the expansion of the EIM, we are not confident that a more accurate and practical design can be developed at this point in time. Therefore, we support implementation of the proposed procedure, while recommending that the ISO should monitor its performance over time, and make improvements based on what is learned. If offers are often at the DEBs, this might be either an indication that DEBs are too low, or alternatively indicate that there is a potential for the exercise of market power if close examination of the DEBs indicates that they are well above a particular resource's opportunity cost.

One element of the ISO's proposed opportunity cost calculation for hydro resources with storage is the use of forward power prices. It is necessary for the ISO to use forward prices at trading hubs to determine forward prices for use in the DEB procedure. This is because forward prices with acceptable liquidity are available only at a limited number of regional hubs. In many cases, the hydro resources are not located at a trading hub so the ISO's proposed designs includes rules for determining which trading hub should be relied on to provide forward prices for calculating opportunity costs for each resource. The actual relationship between resource locations and their trading opportunities is complex; there is no simple rule that can be used to accurately measure these relationships, and some resources may have opportunity costs that reflect forward prices at multiple trading hubs.

The ISO proposes to address these complexities involving trading opportunities in estimating opportunity costs by defining a default trading hub for each balancing area. In addition, the ISO will allow a market participant to select additional trading hubs for use in this calculation if the market participant can "show the CAISO firm transmission from the resource to one of these hubs or an electrically similar location." However, we do not support the use of distant hub prices in the calculation of the DEB merely if firm transmission rights are held.

In an efficient and liquid wholesale market, the opportunity costs presented by future export opportunities, or sales at "distant hubs", would be fully captured in local futures prices. The difference between the local and distant futures price would reflect the costs of transmitting the power to the distant hub. Therefore, in a fully integrated transmission market, such as the ISO's internal market, the futures price at the local hub would be the appropriate price upon which to base opportunity costs. If, however, the transmission market is *not* efficient or liquid, the above logic can break down. First, there may be no hub near to the resource. Second, a distant hub price could represent a legitimate opportunity cost *if* transmission rights from the resource to the hub have a use-it-or-lose-it character, are likely to be in surplus, and are not easily marketed to other participants. Some stakeholders have pointed to exactly these kinds of inefficiencies in arguing for the use of a distant hub.

Therefore, the ISO's proposed use of a distant hub is appropriate if a participant can be plausibly shown to possess export opportunities, through the ownership of transmission rights, that are not readily transferable to others and would otherwise have no value to the owner, or if there is no hub located near to the resource. We do not feel that the mere ownership of transmission rights should be sufficient evidence to allow a firm to base all its default energy bids upon a distant hub. The conceptually correct test would be whether the supplier typically makes incremental sales supported by its hydro generation at the distant hub at times when prices are high at the distant hub.

We would prefer that use of prices at a distant hub to set a DEB should be allowed without an adjustment for the price of transmission rights only if a showing that such rights cannot be sold at a reasonable price, used to support spot sales, or otherwise earn revenues that would represent an opportunity cost for selling at the distant market. This could be implemented as follows: as a condition for using a distant hub's energy prices in a DEB calculation, the resource owner should provide information on the opportunity cost of transmission rights it holds. We prefer that the ISO not assume, as a default, that this value is zero just because the owner possesses firm rights.

In general, we are reluctant to endorse a perspective that says that because market imperfections exist that prevent efficient trading of renewable energy credits, transmission, and energy, the ISO should help embed these inefficiencies in the West by providing an incentive to maintain those inefficiencies in order to support higher DEBs. We would rather see incentives provided to increase the liquidity of these markets. It is for this reason that we prefer that an estimate of the opportunity cost of transmission rights be deducted from prices at distant hubs if those prices are to be included in the DEB formula.

However, we recognize that estimation of the value of bilateral transmission rights is likely to be difficult, and that it may be impractical to do so at present. One significant complication in applying the opportunity cost of transmission rights to a distant hub from the local hub, even if that cost could be estimated, is that some resources may not be located at or electrically close to their assigned "local" hub. Consequently, their opportunity cost of point-to-point firm rights that would enable them to convey their power to the distant hub will be difficult to determine, since the likelihood of a liquid market for such rights from their location is even lower than between recognized hubs in the West. Another complication is that transmission rights might be traded for particular hours that might not correspond to when the resource would sell the energy that corresponds to the opportunity cost being calculated. All these complications mean that the value of transmission rights would be difficult to estimate and verify.

If it is impractical to estimate the opportunity costs of transmission rights, or to require market parties to do so as a condition of using distant hub prices in the DEB calculations, we recommend that the ISO continue to examine questions concerning the value of firm transmission rights and their relevance to hydropower opportunity costs.

In summary, despite the above concerns with some of the details of DEB calculation for hydropower plants, we support the general approach that is proposed based upon gas costs and forward prices for energy. The risk that the hydropower DEBs calculated in this manner will understate actual opportunity costs is partially mitigated by the ability to impose flow restrictions discussed above, as well as the option that resources have to utilize customized negotiated DEBs. We prefer that the forward prices used in the DEB calculations be adjusted, if practical, by opportunity costs for transmission provided by resource owners and checked by the ISO, as described above. If this is not practical, we would support implementation of the proposal, at least for the near term, but the ISO should continue to work to refine this aspect of the proposal.

Other Recommendations. Concerning some other aspects of the proposal, the MSC supports the proposed changes in how the competitive LMP will be used in the calculation of mitigated bids. An example is the use of that LMP plus a small value at the mitigated bid, if greater than the DEB in order to lower the risk of a large increase in the resource's schedule in the market run. The Committee also supports the procedures proposed for updating gas prices, given the quality of price data that is likely to be available in non-ISO BAs.

Draft Opinion on the Reliability Must-Run and Capacity Procurement Mechanism

The Market Surveillance Committee was asked to comment on the ISO's proposed reliability must-run and capacity procurement enhancements initiative (RMR/CPM). The initiative leading to this proposal has been addressed during MSC meetings on Aug. 3, 2018, Sept. 28, 2018, and Jan. 25, 2019. The MSC's draft Opinion was posted on March 18, 2019, and scheduled for adoption on March 20, 2019.

Both RMR and CPM are forms of backstop procurement of resource adequacy (RA). When the ISO determines that the bilateral RA market in California has not (or will not) result in sufficient resources to meet anticipated reliability standards, it has the authority to directly contract with resources to provide RA and other reliability services. The timing and a pricing of backstop contracts have long been contentious features, in part because the terms of backstop contracts can influence the strategies of buyers and sellers in the bilateral RA market.

The ISO's proposal covers a wide variety of aspects of backstop procurement, and the Opinion does not comment on all of them. The following issues are addressed in the Opinion. First, the ISO is taking steps to clarify and formalize the relative roles of RMR procurement and the CPM. Going forward, RMR will be reserved for units that both fill a critical reliability need and are at risk of retirement (ROR) while all other backstop actions will flow through the CPM process. The second issue addressed is the process through which the risk of retirement, and reliability need, is determined. The ISO proposal recognizes these concerns and relies upon three features to mitigate the possibility that resources who do not plan to retire would use the threat of retirement to receive a payment greater than that available through the market or through CPM. The features include a legally binding affidavit concerning the intent to retire or mothball the resource; reimbursement of going-forward capital investments over several years, rather than receiving the full amount of the new investment up front; and the lack of a guarantee that a resource requesting RMR status will receive it. The third issue addressed is the compensation that RMR and CPM resources would receive, and the fourth issue concerns performance incentives.

In its draft Opinion, the MSC supported the general framework that is proposed for CPM. However, the MSC also recognized that that actions by the California Public Utilities Commission and perhaps the California state legislature, as well as future ISO initiatives, may result in significant changes in RA policy. If such changes occur, elements of the CPM framework will need to be revisited. The MSC also noted that the current level of the CPM soft offer-cap needs to be re-evaluated. The level of the cap will affect the relative attractiveness of seeking or accepting a CPM designation versus announcing an intent to mothball or retirement, with the possibility of receiving an RMR designation. As another example, the soft-offer cap initiative and other future processes might explore more comprehensive approaches to local market power mitigation in RA procurement.

The MSC also agreed with the general framework for RMR as targeting risk-of-retirement by resources needed to provide essential reliability services that are not sufficiently compensated for in ISO markets to be accompanied by cost-of-service payments for those units. The MSC expressed its support for a regulatory approach that does not pro-forma link these cost-of-service payments to a depreciation schedule chosen previously by the unit owner, but instead determines an appropriate depreciation schedule on its regulatory merits.

The MSC acknowledged concerns about resources with local market power potentially having an incentive to strategically claim an intent to retire. The MSC noted, however, that RMR generating units are not free to return to market unless their must-run status is removed through a transmission upgrade or other changes in market conditions. The RMR contract provides the ISO with an option to renew under cost-based terms as long as the reliability need, and therefore the unit's local market power, remains. Therefore, a unit that chooses to enter into an RMR contract will not possess the same degree of market power upon returning to the market, if it chose to do so.

If toggling back and forth between market-based operations and RMR remains a significant concern, the option framework could be extended to give the ISO or some other party an option to renew the generator's RMR contract, even after the reliability need is resolved. However, the MSC stated that it would foresee difficulties with giving the ISO discretion over exercise of this option, so this would be a significant alteration to the RMR process.

The MSC agreed that performance requirements for RMR and CPM designated capacity are highly desirable, especially for RMR where there is no other economic incentive to be efficient and available when needed. The MSC's understanding is that the resource adequacy availability incentive mechanism (RAAIM) would be applicable for 17 hours per day, 7 days per week, so generators that comply with that requirement are very likely providing the reliability services that are needed under almost all foreseeable scenarios. For extremely idiosyncratic scenarios in which a unit is needed at other times, the ISO could maintain the ability to negotiate targeted performance metrics for units that are meeting niche reliability needs.

The MSC agreed with the proposal to apply a must-offer obligation on RMR and CPM plants. However, it is crucial to ensure that default energy bids (DEBs) reflect all critical costs. A particular issue is increased maintenance costs that might be necessary if an older, less reliable unit is dispatched or made available for a large number of hours.

Another concern with applying the RAAIM mechanism is that CPM or RMR status might be granted to generators with high outage rates near the end of their useful life. It might be uneconomic to make investments to reduce these outage rates to levels that would avoid RAAIM penalties because of the unit's short remaining life or other for reasons. As a result, a RMR resource that is near the end of its useful life and experiencing or expecting high outage rates might reasonably expect to incur RAAIM penalties that would be unrecoverable under present RMR rules.

The ISO proposal recognizes these issues and addresses them through the inclusion of opportunity costs into the default energy bids (DEBs) of RMR and CPM units. However, opportunity costs remain a complicated and contentious aspect of DEB calculations. Moreover, an aging resource may not be able to completely avoid a relatively high forced outage rate by limiting its hours of operation. If the opportunity cost framework used to calculate DEBs proves insufficient to address these concerns, the ISO should consider a unit-specific outage benchmark for such units, applying the same RAAIM framework but with a different reliability threshold target. Alternatively, a targeted performance metric could be negotiated that would focus on periods when a generator is most likely to be needed.

Finally, the MSC recommended that transmission planning that could affect the need for RMR designation recognize that the avoided cost of generation will include just the RMR unit's going-forward cost (including possible opportunity costs for land and salvaging components), and not the entire full-cost-based RMR compensation, which includes sunk costs, depreciation, and return on book value. Because that going-forward cost may be very different from the full cost, situations are possible in which a transmission investment that removes the need for RMR status would be less expensive than the cost of service based RMR compensation, but more costly than the RMR generator's going-forward costs. Consistent with the ISO TEAM (Transmission Economic Assessment Methodology) philosophy that transmission planning should work towards minimizing social cost, the incremental rather than full RMR cost should be the basis of determining if a network upgrade is economic. Under such a scenario, the RMR unit owner could be offered compensation comparable to the projected transmission replacement cost, which could be well below that unit's cost-of-service.