Opinion on Scheduling Priority for Balanced Schedules

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Introduction

In this opinion, we consider three specific questions about whether MD02 should implement scheduling priority for balanced schedules in the day-ahead market:

> *When there is no transmission congestion, but the total bid and self-scheduled generation cannot satisfy the self-scheduled (vertical) demand of all schedule coordinators (SCs), what priority should be given to preserving balanced schedules when curtailing loads?*
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> *When there is transmission congestion, but it cannot be resolved with adjustment bids, what priority should be given to preserving balanced schedules when curtailing load or generation?*
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> *Should congestion revenue rights (CRRs) attached to self-schedules (either balanced or unbalanced) provide such schedules a higher priority over self-schedules with no CRRs?*

As a general principle, we believe that *system* operation and *market* operation should be distinct. Market operation, consisting of financial contractual relationships among market participants, determines the distribution of financial costs, benefits, and risks. System operation, particularly in the very short run, is concerned first and foremost with keeping the lights on. Market arrangements should impose as few hard constraints as possible on system operators. Instead, market arrangements should provide incentives for participants to provide as much flexibility to the operator as is technically feasible in the form of a deep market for real-time adjustment bids. As an analogy, system operation can be viewed as a checkers game. If too many market participants put their thumbs on pieces to prevent them from being moved, the operator may have no pieces left to play in real-time (or only a few very costly pieces), to the detriment of system reliability and economy.

Scheduling priorities are an example of how market operations can impose hard and costly constraints on system operations. For this reason, we believe that scheduling priorities should be avoided. Rules that give absolute priority to balanced schedules reduce operator flexibility, reduce incentives for submission of adjustment bids, and therefore make the ISO's job more difficult. Furthermore, bestowing absolute priority to preserving balanced schedules gives special treatment to some market participants, and is counter to the goal of avoiding undue discrimination. We believe that financial means exist and should be used to hedge financial risks.[1] Constraints on the physical system should not be used to accomplish financial risk management objectives of individual parties; financial contracts are a more efficient way to accomplish those objectives, and do not compromise the ISO's ability to reliably manage operations. Although scheduling priority may reduce the cost of selling electricity for the market participants with scheduling priority, this is accomplished by increasing the cost of selling electricity for all other market participants. The transmission network has a finite capacity, so that granting priority to one market participant necessarily means that other market participants cannot be granted this same level of priority. Therefore, as a general rule, system operation should occur without regard to the forward market positions of individual market participants. Under these circumstances, market participants can more confidently take forward market positions because they know that idiosyncratic financial commitments do not impact system operation.

The physics that governs electricity supply and consumption also argue against granting scheduling priority. Electricity cannot be delivered point-to-point. A generator injects electricity at one location in the network and load-serving entities withdraw electricity from another location in the network. The purchase of a financial right to receive a fixed quantity of electricity at a given location in the transmission network at a previously agreed upon price completely insulates a load-serving entity that withdraws that quantity of electricity at that location in network from any revenue uncertainty. There is no need for the load-serving entity to match its consumption with the output of the generation units owned by the firm that sold the forward contract.

An important benefit of a day-ahead market without scheduling priority is that it reduces the barriers to entry for third parties to provide standardized forward contracts to hedge spot price volatility and differences in prices across locations in the transmission network. This increases the likelihood that relatively liquid markets for standardized financial instruments to hedge this spot price risk will form. The experience from other markets around the world is instructive in this regard. For example, in the British, Australian and Nordic power markets there is a clear distinction between market operation and system operation. All units are dispatched and adjusted based only on their energy bids. As a consequence, suppliers and load-serving entities have little incentive to sign physical forward contracts that are tied to delivery of electricity from specific generation units. In the NordPool, for instance, this has led to the development of an extremely liquid market for standardized financial contracts. In 2001 the total amount of energy sold in the Nordic Power Exchange control area was approximately one-seventh of the total volume of forward contracts traded during 2001.[2] Over the past five years, there has been an explosive growth in the trading of standardized financial contracts. In particular, between 1998 and 2001, the amount was traded in financial contracts in NordPool increased ten-fold. Although the British and Australian financial markets are primarily over-the-counter, so that accurate

[1]We are aware that there are significant pre-existing physical contracts that may not permit the degree of financial hedging that a purely financial contract would allow. However, it is not in the interest of ratepayers to accommodate the physical parameters of those contracts if doing so increases total wholesale energy and ancillary services costs. If these legacy contracts create cost risks to utilities that cannot be hedged, the ratemaking process should acknowledge those costs and not punish the utilities for factors beyond their control.

[2]Nord Pool ASA, "Derivatives Trade at Nord Pool's Financial Market," April 15, 2002 (available at www.nordpool.com).

volume figures are difficult to obtain, the diversity of products offered and the liquidity of these market have increased over time.

Allowing scheduling priority for balanced schedules or holders of CRRs would run counter to the CAISO's goal of fostering the development of an active forward market for energy as well as for locational price differences in the short and long term. For this reason, we strongly support a regime that does not give scheduling priority to balanced schedules or to holders of CRRs. However, we can imagine certain circumstances when we would not object to the ISO giving scheduling priority to balanced schedules or holders of CRRs. However, all of these circumstances are instances when generators or loads in a balanced schedule and those in an unbalanced schedule are equally effective at relieving a binding constraint. In all other instances we do not support granting generation units scheduling priority.

We now discuss specific instances when we would not object to the ISO allowing scheduling priority. We should note that we do not believe these circumstances would occur very frequently, if at all.

Balanced Portfolio as a Tie-Breaker Under Conditions of Insufficient Aggregate Supply

We first consider the treatment of balanced schedules when there is no congestion, but aggregate self-scheduled and bid supply is inadequate to meet aggregate self-scheduled demand.

To promote resource adequacy and limit market power, we believe that an effective market design should provide incentives to forward contract supply to match load. This is, for example, a rationale for the available capacity (ACAP) mechanism now under discussion. Therefore, we believe that it is reasonable to provide priority for balanced schedules when system-wide resources are inadequate. However, this priority should be in the nature of a tiebreaker: when all demand bids have been exhausted and resources are still insufficient, self-scheduled load lacking a matching self-scheduled supply should be curtailed first, assuming that it is equally effective at relieving the demand insufficiency (Of course, "curtailment" in the day-ahead market of course does not literally mean load interruption, but rather that the load would instead be rolled over to the hour-ahead or real-time market.) Pro-rata rules should be used to allocate curtailments among unbalanced price-taking loads. Under this policy, absence of congestion would mean that loads balanced by supply would be fully protected.[3]

However, we strongly believe a preferable solution would be for all market participants to submit economic adjustment bids for all transactions.[4] We believe that a deep market in

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[3]As an illustration, consider the following example. The first SC (call it SC1) submits a balanced schedule of 4000 MW of supply and load. SC2 provides an unbalanced schedule with 3000 MW of load and 1000 MW of supply. SC3 submits a load schedule of 500 MW of supply and 1000 MW of load. Finally, SC4 offers to supply 1000 MW. Our proposal would curtail 1200 MW of SC2's load and 300 MW of SC3's load. This balances supply and demand, and involves curtailment of 60% of the unbalanced portion of each SC's load. Balanced portions of load schedules are fully protected. Such a procedure might be implemented by assigning a default bid equal to the price cap to unbalanced self-scheduled load, and a different, slightly higher default bid to the balanced self-scheduled load.

[4]In theory, these adjustment bids could include single bid curves for balanced curtailment of matching supply and demand schedules, as is done in the eastern ISOs. Our understanding is that CAISO market participants did not want the ISO to pay for such a feature, so it is not provided for in the MD02 design. Nonetheless, such bids can occasionally be rational when unusual contract provisions or high transaction costs imply very high penalties if only

adjustment bids is not merely desirable, but essential for the success of the market. There are four reasons for this. First, extensive bids give more flexibility to the system operator to manage congestion. Second, such bids provide an economic adjustment procedure that is more likely to maximize market benefits than arbitrary pro rata rules. Third, in the absence of market power, individual participants maximize their net benefits by submitting bids that reflect their actual costs and benefits and allow them to profit by adjusting to changing market conditions. Fourth, a deep market makes exercise of market power more difficult. In general, we view attempts by market participants to insulate themselves from market conditions by submission of balanced schedules without adjustment bids to be neither in their own interest nor in the interest of the market. Autarky is an undesirable fiction in a tightly interconnected system whose physics mean that one participant's actions can greatly affect others.

Balanced Portfolio as a Tie-Breaker Under Congestion

We note that the above tie-breaking principle can be extended to situations in which there is congestion and there are insufficient economic bids to relieve it. The general principle would be: if curtailment of 1 MW of an unbalanced transaction would be equally effective in relieving congestion as curtailment of 1 MW of a balanced transaction, curtailment of the former transaction is preferred.

However, we believe that where swing factors of the transactions differ, then their relative effectiveness in alleviating congestion should govern. If, for instance, curtailing 1 MW of price-taking load in a balanced schedule relieves congestion as effectively as curtailing 2 MW of price-taking load in an unbalanced schedule, then the former load should be curtailed.[5] To do otherwise is unlikely to be efficient and furthermore represents undue discrimination against market participants with unbalanced transactions.

In theory, implementing our tie-breaking procedure can be accomplished by a security-constrained forward market operation procedure that inserts slightly higher default bids for price-taking loads in balanced schedules than for such loads in unbalanced schedules. Such a procedure could also include adjustment bids for symmetric reduction of load and supply in balanced schedules. This general approach has been discussed in the power engineering literature, recommended by FERC, and implemented by the eastern ISOs.

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one side of a balanced schedule is curtailment. However, in a well-functioning market, these circumstances should be very rare, and it can be shown that a strategy of submitting separate supply and demand bids is a dominant strategy. That is, submission of separate bids is not less profitable than submitting a single balanced curtailment bid, and can be more profitable. These benefits to market participants directly flow from the fact that submitting separate bids provides the ISO with more options to manage congestion.

[5] As an example, consider a three node, three line triangular network with equal reactance between the nodes, all load at node C, and supply at both nodes A and B. SC1 has submitted a balanced schedule of 1000 MW supply at B and 1000 MW load at C. The other two SCs have submitted unbalanced schedules, with SC2 injecting 2000 MW at A and SC3 withdrawing an equal amount at C. No market participants have provided adjustment bids. If there is congestion on the line between B and C, then backing off supply at B (and a matching load at C) will be twice as effective in relieving that congestion compared to reducing supply at A (and an equal amount of load at C). This means that the balanced schedule will be curtailed first. To instead curtail the unbalanced supply at A first will require that twice as much load be curtailed at C.

Under normal circumstances, this procedure will curtail price-taking load or balanced schedules only as a last resort, after all economic bids that effectively relieve the constraint are taken. Furthermore, price-taking balanced schedules will be curtailed only if unbalanced schedules that are equally or more effective in relieving the congestion are unavailable.

Other procedures can be devised to implement the same general idea of using portfolio balance as a tiebreaker. A key feature of any such system, however, must be recognition of relative swing factors. We do not believe that an absolute priority should be conferred upon balanced schedules. As an extreme case, it would not be reasonable to curtail 10 MW of unbalanced price-taking load in order to preserve 1 MW of a balanced schedule when the latter is ten times as effective in relieving a congested line. We believe that this recognition of swing factors is necessary in order to avoid undue discrimination among loads, and to minimize the amount and cost of curtailment to market participants.

CRRs Should Not Confer Priority for Scheduling

We do not recommend assigning priority of CRR protected schedules over non-CRR protected schedules because assigning a higher priority to schedules with financial transmission rights changes the nature of those rights, making them in part physical rights. We strongly support keeping CRRs as purely financial hedge for transmission costs, as in the eastern ISOs.