Market Parameter Settings for MRTU Market Launch

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Market and Infrastructure Development Division

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Introduction

During 2008 the California ISO (ISO) discussed with stakeholders the conceptual foundations as well as the specific settings of a set of MRTU market parameters that are used for adjusting non-priced quantities in the market optimizations. The parameter values that resulted from these discussions were summarized in an ISO white paper published on October 29, 2008.[1] Around the same time the ISO received the approval of its Board of Governors and filed at FERC its proposed policy on adjustment of non-priced quantities and certain key market parameter values.[2] In the FERC filing the ISO committed to finalize and post for market participants the start-up parameter values that it would implement in the MRTU market software by 45 days prior to market launch. In anticipation of market launch on March 31, the present document contains those start-up parameter values.

Although the parameter values presented in this paper represent the values the ISO expects to utilize in the market software at the time of market launch, the ISO does not intend to preclude the possibility that one or more of the values may be changed prior to launch if evidence that arises in continued testing indicates the need to do so. The ISO commits to inform stakeholders of any such changes as quickly as possible.

The parameters presented in this paper are organized into three sections by market process: the Integrated Forward Market (IFM), the Residual Unit Commitment (RUC), and the Real Time Market (RTM). As described in the documents referred to above, the parameters in these tables are known in the jargon of mathematical optimization as “penalty factors,” which are associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. In particular, the magnitude of the penalty factor values in the tables for each market reflect the hierarchical priority order in which they may be relaxed in that market by the market software.

In addition there is a fourth section that covers two supplementary topics that are not reflected in the market parameter tables, and which were described in a previous white paper released on February 10, 2009.[3] At the time of this paper the ISO is continuing to assess the performance of the market functionality associated with these two topics, and will provide a supplementary update to stakeholders in the near future.

- Inter-interval ramping constraints, which govern how a generating unit’s operational ramping capability can be shared between inter-interval energy schedule or dispatch changes and awards of ancillary services;
- Minimum effectiveness threshold for managing congestion, which prevents the use of extremely ineffective resource re-dispatch to relieve binding transmission constraints.

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1 See “REVISED Update to CAISO Draft Final Proposal on Uneconomic Adjustment Policy and Parameter Values,” dated October 29. 2008, at: http://www.caiso.com/206f/206fe2af4ddf0.pdf.

2 The ISO’s November 4, 2008 FERC filing contains detailed explanations of the market parameters and how they work, available at: http://www.caiso.com/2076/2076858fca90.pdf.

3 See “Supplementary Discussion of MRTU Market Parameters,” dated February 10, 2009, available at: http://www.caiso.com/2351/2351f3c016020.pdf.

Integrated Forward Market (IFM) Parameter Values

Penalty Price Description	Scheduling Run Value[4]	Pricing Run Value	Comment
Market energy balance	6500	500	Market energy balance is the requirement that total supply equal the sum of total demand plus losses for the entire system. In the IFM energy balance reflects the clearing of bid-in supply and demand; in the MPM-RRD component of the DAM it reflects the scheduling of bid-in supply against the ISO demand forecast.
Transmission constraints: Intertie scheduling	7000	500	Intertie scheduling constraints limit the total amount of energy and ancillary service capacity that can be scheduled at each scheduling point.
Reliability Must-Run (RMR) pre-dispatch curtailment (supply)	-6000	-30	The ISO considers transmission constraints when determining RMR scheduling requirements. After the ISO has determined the RMR scheduling requirements, the market optimization ensures that the designated capacity is scheduled in the market.
Pseudo-tie layoff energy	-6000	-30	Pseudo-tie layoff energy is scheduled under contractual arrangements with the Balancing Authority in whose area a pseudo-tie generator is located.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	5000	500	In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the “shadow price” of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Transmission Ownership Right (TOR) self schedule	5900, -5900	500, -30	A TOR Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints.
Existing Transmission Contract (ETC) self schedule	5100 to 5900, -5100 to -5900	500, -30	An ETC Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints. The typical value is set at $5500, but different values from $5100 to $5900 are possible if the instructions to the ISO establish differential priorities among ETC rights.
Converted Right (CVR) self schedule	5500, -5500	500, -30	A CVR Self-Schedule is assigned the same priority as the typical value for ETC

4 Penalty values are negatively valued for supply reduction and positively valued for demand reduction.

			Self-Schedules.
Ancillary Service Region Regulation-up and Regulation-down Minimum Requirements	2500	250	In the event of bid insufficiency, AS minimum requirements will be met in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
Ancillary Service Region Spin Minimum Requirements	2250	250	Spinning reserve minimum requirement is enforced with priority lower than regulation up minimum requirement in scheduling run.
Ancillary Service Region Non-Spin Minimum Requirements	2000	250	Non-spin reserve minimum requirement is enforced with priority lower than spin minimum requirement in scheduling run.
Ancillary Service Region Maximum Limit on Upward Services	1500	250	In the event of multiple AS regional requirements having bid insufficiency, it is undesirable to have multiple constraints produce AS prices equaling multiples of the AS bid cap. An alternative way to enforce sub-regional AS requirements is to enforce a maximum AS requirement on other AS regions, thereby reducing the AS prices in the other regions without causing excessive AS prices in the sub-region with bid insufficiency.
Self-scheduled CAISO demand and self-scheduled exports using identified non-RA supply resource	1000	500	Pursuant to section 31.4, the uneconomic bid price for self-scheduled demand in the scheduling run exceeds the uneconomic bid price for self-scheduled supply and self-scheduled exports not using identified non-RA supply resources.
Self-scheduled exports not using identified non-RA supply resource	800	500	The scheduling parameter for self-scheduled exports not using identified non-RA capacity is set below the parameter for generic self-schedules for demand.
Regulatory Must-Run and Must Take supply curtailment	-750	-30	Regulatory must-run and must-take supply receive priority over generic self-schedules for supply resources.
Price-taker supply bids	-550	-30	Generic self-schedules for supply receive higher priority than Economic Bids at the bid cap.
Conditionally qualified Regulation Up or Down self-provision	-285	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 received higher priority to maintaining the availability of regulation, over spinning and non-spinning reserve.
Conditionally qualified Spin self-provision	-280	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 receives higher priority to maintaining the availability of spinning reserve, over non-

			spinning reserve.
Conditionally qualified Non-Spin self-provision	-275	NA	This penalty price for conversion of self-provided non-spinning reserves balances the maintenance of AS self-schedules with ensuring that the conversion to energy occurs before transmission constraints are relaxed.
Conditionally unqualified Reg Up or Down self-provision	-75	NA	In instances where AS self-provision is not qualified pursuant to the MRTU tariff, the capacity can still be considered as an AS bid, along with regular AS bids. The price used for considering unqualified AS self-provision is lower than the AS bid cap, to allow it to be considered as an Economic Bid.
Conditionally unqualified Spin self-provision	-50	NA	Same as above.
Conditionally unqualified Non-Spin self-provision	-35	NA	Same as above.

Residual Unit Commitment (RUC) Parameter Values

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Transmission constraints: Intertie scheduling	2000	250	The Intertie scheduling constraint retains higher relative priority than other RUC constraints.
Market energy balance	1600	0	The RUC procurement may be less than the Demand forecast if the CAISO has committed all available generation and accepted intertie bids up to the intertie capacity.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
Maximum energy limit in RUC schedule	250	0	Limits the extent to which RUC can procure energy rather than unloaded capacity to meet the RUC target. For MRTU launch the limit will be set so that the total energy scheduled in the IFM and RUC will be no greater than 99% of the RUC target unless this limit is relaxed in the RUC scheduling run.
Limit on quick-start capacity scheduled in RUC	250	0	Limits the amount of quick-start capacity (resources that can be started up and on-

			line within 5 hours) that can be scheduled in RUC. For MRTU launch the limit will be set to 75%.
Day-Ahead energy schedules resulting from the IFM run	250	0	These values preserve schedules established in IFM in both the RUC scheduling run and pricing run.

Real Time Market Parameters

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Energy balance/Load curtailment and Self-Scheduled exports utilizing non-RA capacity	6500	500	Scheduling run penalty price is set high to achieve high priority in serving forecast load and exports that utilize non-RA capacity. Energy bid cap as pricing run parameter reflects energy supply shortage.
Transmission constraints: Intertie scheduling	7000	500	The highest among all constraints in scheduling run, penalty price reflects its priority over load serving. Energy bid cap as pricing run parameter reflects energy supply shortage.
Reliability Must-Run (RMR) pre-dispatch curtailment (supply), and Exceptional Dispatch Supply	-6000	-30	RMR scheduling requirement is protected with higher priority over enforcement of internal transmission constraint in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Pseudo-tie layoff energy	-6000	-30	Same priority of protection as RMR schedule in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	5000	500	Scheduling run penalty price will enforce internal transmission constraints up to a re-dispatch cost of $5000 per MWh of congestion relief. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage.
Real Time TOR Supply Self Schedule	-4500	-30	In RTM, TOR self-schedule scheduling run penalty price is much higher in magnitude than generic self-schedule but lower than transmission constraint. Energy bid floor is used as the pricing run parameter as any type of energy self-

			schedule.
Real Time ETC Supply Self Schedule	-3200 to -4500	-30	In RTM the range of penalty prices for different ETCs supply self-schedules are much higher in magnitude than generic supply self-schedules but lower than TOR. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Ancillary Service Region Reg-Up and Reg-Down Minimum Requirements	2500	250	Scheduling run penalty price is below the one for transmission constraint. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Spin Minimum Requirements	2250	250	Scheduling run penalty price is lower than the one for regulation-up minimum requirement. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Non-Spin Minimum Requirements	2000	250	Scheduling run penalty price is lower than the one for spin minimum requirement. Pricing parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Maximum Limit on Upward Services	1500	250	Scheduling run penalty price is lower than those for minimum requirements to avoid otherwise system-wide shortage by allowing sub-regional relaxation of the maximum requirement. AS market bid cap as pricing run to reflect the otherwise system-wide shortage.
Self-scheduled exports not using identified non-RA supply resource	800	500	Scheduling run penalty price reflects relatively low priority in protection as compared to other demand categories. Energy bid cap as pricing run parameter to reflect energy supply shortage.
Final IFM Supply Schedule	-2000	-30	Scheduling run penalty price is much higher in magnitude than supply generic self-schedule but lower than ETCs. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Regulatory Must-Run and Must Take supply curtailment	-750	-30	Scheduling run penalty price reflects the higher priority of regulatory must-run and must-take supply received over generic self-schedules for supply resources. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Price-taker supply bids	-550	-30	Scheduling run penalty price for generic supply self-schedules is 10% higher in priority than Economic Bids at the bid cap.

			Energy bid floor is the pricing parameter for all energy supply self-schedules.
Qualified Load Following self-provision Up or Down	-8500	0	Scheduling run penalty price reflects the highest priority among all categories of AS self-provision. AS bid floor is used as the pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Reg Up or Down Award	-7750	0	Scheduling run penalty price is higher than the penalty price for energy balance constraint to reflect higher in priority over energy. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Spin Award	-7700	0	Scheduling run penalty price is lower than the one for Reg-up. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Non-spin Award	-7650	0	Scheduling run penalty price is lower than the one for Spin. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Reg Up or Down Real Time self-provision (RTPD only)	-285	0	Scheduling run penalty price allows the conversion of AS self-schedules to Energy to prevent LMP of local area from rising so high as to trigger transmission constraint relaxation. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Spin self-provision (RTPD only)	-280	0	Scheduling run penalty price is below the one for regulating-up. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Non-Spin self-provision (RTPD only)	-275	0	Scheduling run penalty price is below the one for spin. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally unqualified Reg Up or Down Real Time self-provision (RTPD only)	-75	0	In scheduling run, AS self-provision not qualified in pre-processing can still be considered as an AS bid with higher priority in the Energy/AS co-optimization along with regular AS bids. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally unqualified Spin Real Time self-provision (RTPD only)	-50	0	Same as above.

Conditionally unqualified Non-Spin Real Time self-provision (RTPD only)	-35	0	Same as above.

Additional Market Parameters

The topics discussed in this section were included in the ISO's February 10, 2009 white paper, "Supplementary Discussion of MRTU Market Parameters," and were subjects of a conference call with stakeholders on February 12. At the time of issuing the present paper the ISO is continuing to test and evaluate the functionality associated with these two market features and will provide an update to stakeholders in the near future. Readers should therefore view the material presented below as accurate from a conceptual perspective, but should recognize that the configurable parameter values discussed here are subject to possible revision in the near future.

Inter-interval Ramping Constraints

The maximum amount of supply available to the ISO markets is generally thought of as the sum of the bid-in capacity of all generators and demand response resources. Because the market optimization honors resource performance constraints, however, the available supply in any given market interval is further constrained by available ramping capability. Modeling ramp rate constraints correctly is an important element of the MRTU market design that enables the ISO markets to produce feasible inter-interval schedule changes and dispatch instructions.

The MRTU design treats ramping constraints in a manner that balances the requirements of reliability, market supply and schedule feasibility.[5] The MRTU approach is implemented in the software as a pair of ramp rate constraints that apply to inter-interval energy schedules and ancillary services awards. These constraints apply to each generating unit during the ramping process between two consecutive market clearing intervals, in both the day-ahead and the real-time markets. One constraint, in the upward direction, uses the resource's ramping capability to limit a weighted sum of its inter-interval energy schedule change or dispatch instruction and its regulation up, spinning, and non-spinning reserve awards. The second constraint, in the downward direction, limits a weighted sum of the resource's inter-interval energy schedule or dispatch change and its regulation down award.

The constraints are expressed as the following equations:

$$(p_{i,t}^{En} - p_{i,t-1}^{En}) + \alpha(p_{i,t-1}^{Ru} + p_{i,t}^{Ru}) + \beta(p_{i,t-1}^{Sr} + p_{i,t}^{Sr}) + \eta(p_{i,t-1}^{Nr} + p_{i,t}^{Nr}) \le RampRate(p_{i,t-1}^{En}) \cdot T$$

and

$$(p_{i,t}^{En} - p_{i,t-1}^{En}) - \alpha(p_{i,t-1}^{Rd} + p_{i,t}^{Rd}) \ge -RampRate(p_{i,t-1}^{En}) \cdot T$$

[5] See ISO MRTU Tariff sections 31.3 and 34.5 and the ISO Business Practice Manual for Market Operations sections 6.6 and 7.1.

where,

> $p_{i,t}^{En}$, $p_{i,t-1}^{En}$ = energy schedules of unit *i* in intervals *t* and *t-1*
>
> $p_{i,t}^{Ru}$, $p_{i,t-1}^{Ru}$, $p_{i,t}^{Rd}$, $p_{i,t-1}^{Rd}$, $p_{i,t}^{Sr}$, $p_{i,t-1}^{Sr}$, $p_{i,t}^{Nr}$, $p_{i,t-1}^{Nr}$ = Regulation Up, Regulation Down, Spinning, and Non-Spinning Reserve awards to unit *i* in interval *t* and *t-1*
>
> $RampRate(p_{i,t-1}^{En})$ = operational ramp rate of unit *i* at dispatch level $p_{i,t-1}^{En}$ (MW/minute)[6]
>
> T = length of an interval (minute)
>
> α , β , η = ramp-sharing coefficients.

These ramp rate constraints apply to all the MRTU markets, both day-ahead and real-time, but with different ramp-sharing coefficients depending on the length of the optimization interval in each market. The ISO's recommended coefficient values are listed in the following table.

Market	Interval Length (minute)	α	β	η
IFM	60	1.00	0	0
RTUC	15	0.75	0	0
RTED	5	0.25	0	0

The coefficient α has a positive value. This means that Regulation Up or Down has to compete with energy for the unit's ramping capability. This choice of coefficient value is based on operational reliability considerations. Specifically, it is important that the ISO retain the regulating capability of its supply of Regulation Reserve during the period of the inter-interval ramp, as this is often the time when Regulation Reserve is particularly needed. Setting this coefficient to zero and thereby sharing Regulation Reserve ramping with energy change ramping could significantly reduce the effectiveness of regulation to meet control performance.

In the MRTU markets a generating unit can be awarded Regulation Reserve in a MW amount that can be up to 10 minutes of its ramping capability in each interval. Thus in order to preserve 100 percent of the unit's ramping capability to meet its awarded Regulation Reserve at all times in the IFM, it would be necessary to set α = 3.00. Ignoring for the moment any potential awards of spinning or non-spinning reserves, a setting of α = 3.00 means that the unit's ramping capability during the 60-minute period between the midpoint of hour t-1 and the midpoint of hour t will be sufficient to cover both its inter-hour energy schedule change and 100 percent of its Regulation Reserve awards in each hour, at all times during that period. With α = 1.00 in IFM, the inter-interval ramp rate constraints preserve ramping capability for up to 20 minutes within the 60-minute inter-hour period for the awarded Regulation Reserve in intervals t and t-1. This means that there is at least one-third of the average Regulation Reserve award across consecutive hours available at all times during the inter-interval ramp. Of course, if there is no inter-hour energy schedule change then all of the awarded Regulation Reserve is available at all times.

The RTUC has an interval length of 15 minutes, which is 75 percent of the 20 minutes maximum possible ramp capability that could be needed for the Regulation Reserve awards in intervals t

6 Note that the operational ramp rate is expressed as function of the unit's operating level, which is how it is implemented in the market software.

and t-1. The setting of $\alpha = 0.75$ will preserve sufficient ramp capability for awarded Regulation Reserve between two consecutive 15-minute RTUC intervals, without any ramp sharing between the Regulation Reserve award and the inter-interval energy schedule change.

The RTED has an interval length of 5 minutes, which is 25 percent of the 20 minutes ramping needed for potential Regulation Reserve awards. Setting $\alpha = 0.25$ will preserve sufficient ramp capability for Regulation Reserve awards between two consecutive RTED intervals, also without the need for ramp sharing with the inter-interval energy dispatch change.

Setting β and η equal to zero means that operating reserves (Spinning and Non-Spinning) are able to share the unit's ramping capability with energy. That is, the unit can be awarded operating reserves up to its maximum ramping capability in an interval regardless of the size of its inter-interval energy schedule change. Stated another way, the award of operating reserves to the unit does not prevent its full ramping capability from being used to move between operating levels in two consecutive intervals. However, the total A/S award in the upward direction (the sum of Regulation Up, Spinning, and Non-spinning) or downward direction (Regulation Down) to each generating unit cannot exceed its 10-minute ramp capability.

The coefficient values in the table above have been set based on the outcomes of MRTU testing process. In the course of testing it was found that if the values are set too high – for example if all three coefficients are set to equal 3.0 in the IFM constraint equations – there will be no ramp sharing between the energy schedule change and the provision of ancillary services. As a result the market will use the available resources most conservatively and will create unnecessary transitory shortage conditions. In the worst cases observed, the market was extremely short of supply in certain hours and had to curtail demand dramatically in order to reach a solution.[7]

Minimum Effectiveness Threshold

In response to the ISO's November 4, 2008 FERC filing on the market parameters, some parties argued that the process of adjusting non-priced quantities should contain a minimum effectiveness threshold, i.e., a minimum percentage of effectiveness for a resource that would be used to relieve congestion on a particular constraint. Without a minimum effectiveness threshold, it was argued, the software could accept extremely ineffective resource adjustments to relieve a constraint, which could result in large quantities of energy bids at low prices being adjusted in the IFM.

In its December 12, 2008 reply the ISO acknowledged that without a lower limit on effectiveness the market software could accept significant quantities of low-priced energy bids to achieve a small amount of congestion relief on a particular constraint. The ISO noted further that the MRTU software does have a lower effectiveness limit setting which can be specified by the ISO at a level that will produce congestion management scheduling results consistent with good operational practice. At the time of that filing the lower effectiveness limit was set in the market simulation software at 0.5 percent effectiveness (i.e., 0.005), which prevented the optimization from adjusting the schedule of a resource that was less effective on any particular constraint in order to relieve congestion on that constraint.

[7] The recent FERC order on the Midwest ISO Ancillary Services Market accepted the similar concept of ramp sharing for the Midwest ISO Ancillary Services market design. ORDER AUTHORIZING MIDWEST ISO ANCILLARY SERVICES MARKET START-UP, Docket No. ER09-24-000 (Dec. 18, 2008)

As the ISO noted in the December filing, for most of the prior market simulation process the lower limit had been left at the factory default setting of 0.01 percent effectiveness (i.e., 0.0001), and had only recently been raised to 0.5 percent to allow the ISO to assess how it would affect market scheduling solutions. Thus the ISO could not, at that time, provide its recommendation for the MRTU start-up value of this parameter. The ISO believes it is prudent to continue to consider the appropriate level of this threshold and will provide a recommendation in the near future. What this setting does in effect is to reduce slightly the set of allowable re-dispatch solutions for relieving congestion on a given constraint, to eliminate those solutions that would be operationally unsound because they include the use of highly ineffective resource adjustments which an operator following good utility practice would not use.