California ISO
Your Link to Power

Draft Final Proposal

Modeling of Multi-Stage Generating Units

May 8, 2009

Modeling of Multi-Stage Generating Units

Prepared for Decision by the CAISO Board of Governors Meeting – May 18-19, 2009

1 Summary

The operational capabilities of multi-stage generating resources are similar to an aggregation of individual units. In fact, many are aggregations of sub-resource generating units. As a result, they can provide valuable flexible generation to the system, but they also are more complex to accurately model and dispatch. Specifically, these multi-stage generating units often have output ranges in which they cannot operate. That is, between their minimum and maximum operating levels, there are output levels at which the units cannot be dispatched. Transitioning between operating these operating ranges, or configurations, is costly, takes time, and should be done a limited number of times each operating day. In order to model multi-stage generating resources with these considerations accurately reflected, and to thereby achieve feasible, optimal dispatch for them, the California Independent System Operator (the ISO) proposes to implement the design described in this *Draft Final Proposal*.

The new ISO market design has Forbidden Operating Regions (FOR) captured in the Master File data set by which the ISO records critical operating and business information for each generating unit. FOR are ranges through which a unit must be ramped up or down, but within which it cannot be dispatched. The Forbidden Operating Ranges were intended to be used to prevent infeasible dispatch of multi-stage units at the start of the new ISO markets. However, while the enforcement of the Forbidden Operating Region constraints keeps units from being dispatched at infeasible output levels, it does not economically optimize the dispatch of multi-stage generating units. That is to say, simply forbidding the software from certain dispatch ranges for specific units does not optimize that dispatch with respect to costs, the various operating configurations of multi-stage generating units, and other resources in the market. It is for this reason that the Federal Energy Regulatory Commission mandated[1] that the ISO modify the software used to reach an economic dispatch solution to explicitly account for the operating constraints of multi-stage generating units within three years of the start of the new ISO markets.

The market simulations done in preparation for the start-up of the new markets revealed stability and performance issues relative to enforcement of the Forbidden Operating Region constraints. These issues were reviewed during the October 28th meeting of the ISO Board of Governors, and the Board approved a recommendation to defer the functionality for enforcing Forbidden Operating Regions from the Real Time Market optimization. The Commission has since approved the proposed tariff amendment deferring the implementation of the functionality enforcing Forbidden Operating Regions in the Real-Time. [2]

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1 Paragraph 573 of FERC's September 21, 2006 Order on MRTU "direct(s) the ISO to continue working with software vendors to develop an application that will accurately detail the constraints of combined cycle units, and to file tariff language" for implementation of such improvements no later than three years after MRTU start up.

2 The explanatory memorandum and presentation to the ISO Board of Governors and the approved Board motion to defer this functionality is located at:

Thus, the new ISO market software will not automatically dispatch multi-stage generating units through their Forbidden Operating Regions. This will require market participants and the ISO to manually manage the dispatch of multi-stage units by using outage reporting tools and Exceptional Dispatch. As a result, the ISO now proposes to expedite the design and implementation for the explicit modeling of multi-stage generating units into the market software. Specifically, the ISO is targeting resolution of policy issues associated with this modeling enhancement to go before the ISO Board of Governors for approval in May of 2009, and it is targeting the fourth quarter of 2009 for implementation of these modeling features.

It is planned that reinstatement of the Forbidden Operating Region functionality in the real-time market will tested along with the modeling of multi-stage units. As long as the FOR functionality is not being used to substitute for accurate modeling of multi-stage units, its reinstatement is not anticipated to contribute to unstable results like those seen in market simulation. The rationale for re-instating the Forbidden Operating Region functionality in the real time is that there are some generating resources for which FOR better capture the operating constraints. Specifically, units with operating ranges through which they can ramp up or down, but in which they cannot be dispatched might do better to choose to rely on the FOR functionality than to submit configuration-level bids. Units for which transitions between configurations are more costly and time-intensive would do better to use the multi-stage generating unit modeling to account for this. It may be that some multi-stage generators have, within a configuration, a true FOR. Re-instatement of the FOR functionality will also enable those resources to specify such operating constraints.

At this time, the proposal for changes to modeling multi-stage units will be applied only to those units that have specified Forbidden Operating Regions in the Master File.[3] This will resolve the issue of infeasible dispatch of those units, and will satisfy the FERC mandate. It may well be that additional generating resources other than those with FOR in the Master File would be more accurately modeled and feasibly dispatched were they able to bid in multiple configurations. It is in the best interest of market participants as well as the ISO to extend MSG unit modeling to such resources. Therefore, in conjunction with the testing of the MSG modeling functionality and of the re-instatement of FOR in the real time market, the ISO will evaluate the impact of extending MSG modeling to other generating resources.

With this *Draft Final Proposal*, the ISO offers a conceptual approach for the modeling of multi-stage generation units in the new market software that is based on the pseudo-plant model. Scheduling Coordinators will submit operating parameters and costs associated with up to *ten* configurations of their multi-stage unit. Scheduling Coordinators will be able to submit monotonically non-decreasing configuration-level bid curves into the Integrated Forward Market. The ISO model will use these configuration-based or "sub-resource" bids to determine the optimal dispatch for a given hour. Scheduling Coordinators can submit up to *three* configurations (currently planned default value) of

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http://www.caiso.com/2067/2067aeac40f40.html. *See California Indep. Sys. Operator Corp.,* 125 FERC ¶ 61,081 (2009) http://www.caiso.com/2347/2347502a5c5d0.pdf.

3 Metered Sub-System (MSS) load-following resources will not eligible to bid multiple configurations under this initial implementation due to the significant added complexity posed by the fact that those resources follow load on their own as well as bid into the ISO markets.

their multi-stage unit into the real time market, subject to some restrictions which are described in section 4.2 of this *Draft Final Proposal*.

2 Key Criteria for Evaluating Potential Solutions

This section provides some key evaluation criteria the ISO believes are important. Stakeholders are invited to identify and suggest other criteria that should be considered in assessing potential solutions.

- Any policy that is developed should achieve the objective of more accurately incorporating the operating parameters of multi-stage generating units so that the units will be economically and feasibly dispatched, and so that the market can benefit from their full participation.

- Any policy that is developed should address the need for Bid Cost Recovery for the embedded generators, i.e. operating configurations, of multi-stage generating units.

- Policy and design options should be evaluated for implementation feasibility and costs for both the ISO Stakeholder and for the ISO. This evaluation should be done keeping in mind (1) the magnitude of the potential issue, and (2) work that has already been done on multi-stage modeling for other markets.

3 Candidate Design Options

There are two primary categories of models for multi-stage generating units. These are pseudo-plant (or configuration-based) models, and pseudo-unit models. Discussion of these approaches is included below:

Pseudo-plant models treat various configurations of a multi-stage unit as units themselves, allowing the resource owner to bid these configurations or pseudo-plants into the market independently. The market optimization chooses which configuration, if any, is part of the optimal solution. In this type of model, the configurations are mutually exclusive, which means that only one configuration can be chosen by the optimization. This pseudo-plant model is employed by the market being developed by ERCOT.

The pseudo-plant approach is problematic from an implementation standpoint. A 3 x 1 combined cycle unit that could have more than ten possible configurations would thus require ten pseudo-plants. A 4 x 2 combined cycle unit could have over forty possible configurations or pseudo-plants. Modeling each of the potential configurations of a resource would give more granularity to the dispatch results. However, investigation into recent attempts to model multi-stage units based on the pseudo-plant approach has shown this to be infeasible due to the large number of variables and permutations with which the optimization engine must cope. In particular, these trials take more time to run than is acceptable for real time dispatch due to their complexity.

Pseudo-unit models divide resources into mutually exclusive aggregations that may include portions of an embedded unit. For example, a 3 x 1 combined cycle generating unit would be modeled as three separate pseudo-units. Each of the three pseudo-units would be one gas turbine plus one third of a steam turbine. This is similar to the way the NYISO and PJM approximate the modeling of different configurations of multi-stage generators. This is less than ideal because such a model requires market participants to assign costs and operating parameters to pseudo-units, which is not necessarily intuitive or accurate. In addition to assigning costs to such a pseudo-unit, resource owners would need to provide operating constraints for them.

Although the pseudo-unit model is much simpler from an implementation standpoint, it does not appreciably improve the ability of market participants to offer the inherent flexibility of multi-stage units into the market.

4 Proposed Resolution

The ISO's *Draft Final Proposal*, summarized below, seeks to respect the implementation constraints we will face while providing the framework necessary to accurately bid and model and dispatch multi-stage units. Multi-stage units, for the purpose of the current implementation effort are those with Forbidden Operating Regions specified in the Master File. The set of resources includes combined cycle, steam-injected gas turbines, steam turbines, and a handful of other units. Forbidden Operating Regions have been specified for many of these units in order to avoid being dispatched back and forth between operating configurations. A true FOR is simply a range through which a unit can be ramped but within which it cannot be dispatched. Therefore, there is no functionality associated with that range that prevents the market optimization from repeatedly moving from one side of a FOR to the other. Any generating unit with a specified Forbidden Operating Region that actually represents a "dead zone" between operating configurations, and not simply a range through which to be ramped, will be able to benefit from multi-stage modeling.

4.1 IFM Bidding

We recommended that the model optimize over up to *ten* configurations of each multi-stage units as mutually exclusive resources in the IFM. Under this proposal, market participants will be able to submit bid curves for the individual configurations of their multi-stage units into the IFM. Those bids must follow all the bid-submission rules for standard resources including being non-decreasing. The IFM will yield a schedule for at most one configuration per multi-stage unit.

4.2 Real Time Bidding

We recommend that Market Participants be able to bid in up to *three* configurations of a multi-stage unit into the Real Time Market. This limitation is recommended in order to limit the number of configurations over which the Real Time Market must optimize, but at the same time enable the multi-stage units to fully participate in the market. If one of a multi-stage unit's configurations is taken in the IFM, then that configuration or one that can support the day-ahead energy schedule and RUC schedules or awards must be bid into the real time market for that same hour. Two other configurations may also be bid into the real time market provided that transitions within those three configurations are feasible and that the transition from the previous hour is feasible. All configurations bid into the real time market must reflect a reservation of capacity in the amount and for the product of any day-ahead award of ancillary services. The SIBR software will validate real-time configuration-level bids to ensure that these stipulations are met, and that transitions between bid-in configurations are feasible according to the information in the ISO Master File data.

To reiterate, the main limitations, in addition to the number of configurations that participants may bid into real time for an MSG unit, are the requirements as follow:

1. At least one configuration's bid must be sufficient to cover any day-ahead energy schedule **and** any Resource Adequacy must-offer obligation;
2. At least one configuration's bid must be sufficient to cover any Residual Unit Commitment schedule or award **and** transition to this configuration must be feasible given the configurations bid into the previous hour;
3. All configurations bid into real time must reserve capacity to fulfill day-ahead ancillary services awards;
4. Configurations bid into the real time market for a particular hour can be feasibly transitioned between one another by the 15-minute unit commitment that occurs in real time; and
5. At least one configuration bid into the real-time market must be feasible given the configurations bid into the previous hour.

The intention of the first three requirements listed above is not to place any additional or different burdens on MSG units. The motivation is to ensure that the units are not physically withheld from the real time ISO market. If, between the day-ahead and real-time market timeframes, the costs associated with operating at a particular level or in a given configuration change, market participants should submit bids commensurate with those updated costs and trade-offs.

The fourth and fifth requirements are intended to avoid situations in which a resource cannot be utilized by the market because it cannot be feasibly transitioned from the configuration in which it is operating to the ones it has bid into the market for the subsequent interval. In section 4.8 below, there is a discussion of the transition matrix which will contain the cost and operating constraints associated with transitioning between configurations. Transitions for which those parameters are specified are feasible by definition.

4.3 Bid Cost Recovery

We recommend that Bid Cost Recovery be available at the resource level, and that the ISO only pay commitment costs (including transition costs) associated with the real time market. If, however, a resource self-schedules energy and/or self-provides ancillary services in the real time, then IFM commitment costs (including transition costs) would be eligible for BCR. If a unit is not taken in the real-time market, then day-ahead commitment costs would be used for the BCR calculation for that hour. Because configurations are essentially modeled as individual generators in the market optimization, and re-aggregated for the purpose of settlements, it is essential to alter the BCR calculation methodology for multi-stage units. If the standard BCR calculation methodology were used, it would result in significant double-payment of eligible commitment costs.

The net revenue calculation for any given hour will be performed at the resource level although the cost component of that calculation will be informed by the configuration-level costs. In actuality, the sequential netting that is performed to arrive at the BCR values is complex. For the purpose of gaining intuition for how the calculation would be done in the case of MGS units, but without going through the rigorous accounting, please consider the simple example included as Appendix B to this Proposal.

4.4 Resource Adequacy Offer Obligations

In order to meet resource adequacy offer obligations, multi-stage units with such contractual arrangements should offer in at least one configuration into each the day-ahead and real-time markets.[4] If a multi-stage resource with an offer obligation does not offer in a configuration that can fulfill the offer obligation, the SIBR system will insert a default energy bid and $0 ancillary services bid for the configuration designated by the Scheduling Coordinator as the default configuration for meeting the unit's resource adequacy obligation.[5] The SIBR system will *not* extend the bid curve for a configuration that was not bid in to the full megawatt value of the RA obligation.

In the real-time market, in which the number of configurations that can be bid in for a multi-stage unit is limited to three, the automatic insertion of the default price-taking resource adequacy would be a fourth configuration. Rather than overwrite a submitted configuration-level bid, the system will insert a fourth configuration bid for the resource.

The validation of the fulfillment of the Resource Adequacy must-offer obligation will be based on the generation capacity bid in for a configuration. It will not be based on the increment of generating capacity that can be provided by a configuration. For example, consider a multi-stage unit with two configurations, (C1 and C2) with MW ranges (100, 250) and (300, 525), and a resource adequacy contract for 300 MW. The RA offer obligation is met by bidding in the second configuration (C2) with a minimum operating level of 300 MW and a maximum of 525 MW despite the fact that the incremental capacity that is provided by C2 is only 225 MW which is less than the RA contract.

4.5 Residual Unit Commitment

A multi-stage unit with a resource adequacy contract can be committed in the Residual Unit Commitment run at any configuration with capacity equal to or greater than the configuration

4 Note that the real-time RA offer obligation does not extend to long-start units. If long-start RA units are not picked up in the day-ahead market, they are not required to offer their RA capacity in real time. There is true for all RA units, multi-stage units and otherwise.

5 Note that the RA offer obligation does not currently extend to Ancillary Services. This change has been filed with FERC within the filing of the Standard Capacity Product tariff language. It is anticipated that a FERC Order will be released in response to this filing during 2009. The ISO filing is available at the following link: http://www.caiso.com/239e/239ee59b11f50.pdf

committed in the day-ahead market. If a configuration is given a RUC schedule or award, the scheduling coordinator is obligated to offer the configuration for the megawatt value scheduled/awarded into the real-time market. Additionally, the configuration chosen to support the RUC commitment must be one to which the unit can feasibly transition. If the configuration scheduled or awarded by RUC can additionally accommodate the day-ahead energy schedule and ancillary service award and any Resource Adequacy offer obligation, then bidding in this configuration to that megawatt value will satisfy the all the real-time bidding requirements. In that case, the Scheduling Coordinator has two remaining configuration-level bids that are restricted only in that they can be feasibly transitioned within and between hours, and that capacity is reserved and the configuration is certified to provide any day-ahead AS award.

4.6 Reliability Must Run Units

Reliability Must Run (RMR) units will be dispatched and settled per their contracts. RMR contracts negotiated in the future can include different costs for different configurations. Currently there is only one MSG unit with an RMR contract. Ramifications for the dispatch and settlement of this unit will be analyzed, and any required tailored treatment of this unit will be consistent with the RMR contract.

4.7 Ancillary Services

We propose that multi-stage generating units that are certified to provide Ancillary Services obtain certification to provide AS at the configuration level, and can then bid in AS for those configurations for which they are certified.

Any ancillary services award from the day-ahead market will carry through to the real-time market. Thus, bids for any configuration in the real-time must respect the reservation of awarded AS capacity. SIBR will reject real-time bids for which energy bid plus the day-ahead awarded AS capacity exceed the upper operating limit of the configuration. SIBR will also reject bids for configurations that are not certified to provide ancillary services if the resource received an AS award in the day-ahead market.

4.8 Information Submittal

Market participants with multi-stage generating units will need to submit detailed information on those units[6]. In particular, information will be required for each configuration and will include the same specificity as is required for generators in general. Parameters such as operating minimum and maximum values, minimum run times, minimum down times, ramp rates, AS certifications, heat rates, and *etcetera* will be stored at the configuration level. **The ISO recommends that each configuration be able to submit a single operational ramp rate, and up to two AS ramp rates – one for Spinning and Non-Spinning Reserves, and one for Regulating Reserves.**

6 A sample of the form used by ERCOT for the capture of this information was included as Appendix B to the Straw Proposal posted on February 17, 2009. This document and the glossary that accompanies it are available at the following link: http://www.caiso.com/2078/2078908392d0.html

Additionally, the ISO will require data related to the transitions between the configurations of each multi-stage unit. This information will be stored in a "transition matrix," a simple example of which is provided below. For each transition between configurations that is feasible, the ISO will require transition time and cost information as well as the number of times in an operating day that this transition can be made. This is akin to the start-up and shut-down related data provided for single-stage generators since each transition between the configurations of multi-stage units is like a shut down of one configuration and a start up of another. Note that, in the example below, the all transitions between configurations are feasible.

<u>Table 2</u>: Simple Example of a Transitions Matrix

		"To" Configuration			
		0 – offline	**1**	**2**	**3**
"From" Configuration	**0 – offline**		**$ # minutes max/day**	**$ # minutes max/day**	**$ # minutes max/day**
	1	**$ # minutes max/day**		**$ # minutes max/day**	**$ # minutes max/day**
	2	**$ # minutes max/day**	**$ # minutes max/day**		**$ # minutes max/day**
	3	**$ # minutes max/day**	**$ # minutes max/day**	**$ # minutes max/day**	

There will be the need to have a default configuration flag for the purpose of meeting resource adequacy offer obligations as noted above. The need for additional data items may become apparent in the implementation stage of this effort.

Data for the ten (or fewer) configurations associated with a given multi-stage resource will be stored in the Master File. Any changes to the configurations can be made through the ten-day process by which changes are made to Master File data.

4.9 Local Market Power Mitigation

We recommend that Local Market Power Mitigation (LMPM) be performed on a configuration-by-configuration basis. Since LMPM is performed on all clean bids submitted for use in the IFM, individual configurations' bids may be flagged for mitigation. Configurations (or pseudo-plants) that are incremented up in the All Constraints Run would have their bid mitigated based on the relevant operating parameters which would be included in the configuration-level information. In addition, if a unit has a configuration committed in the Competitive Constraints Run, and another committed in the All Constraints Run, both configurations' bids would be flagged for mitigation.

Default Energy Bids, whether cost-based or negotiated, will be developed by configuration.

Two examples of how the market power mitigation will be implemented are included in Appendix B to this proposal. The second example is new to this *Draft Final Proposal* and is provided to address questions in the stakeholder comments on the first market power mitigation example provided previously.

4.10 Self-Schedules

Self-Schedules must be such that transitions between configurations are feasible. In addition, market bids must be feasible given self-schedules. For each hour, only one configuration is permissible in a self-schedule. It is possible to change the self scheduled configuration between DA and real-time for the same trade hour.

Note that if a multi-stage unit submits a self-schedule for part of its capacity, any additional capacity for which the participant wants to submit economic bids must be for the same configuration. The reason for this is that submitting a self-schedule in a particular configuration indicates to the market software that the unit is being self-committed into the configuration. To submit an economic bid for a different configuration would run counter to the iterative nature and logical structure of the market software. SIBR will not accept bids for a configuration other than the one self-scheduled.

Based on stakeholder feedback, the ISO understands that this causes concern for participants bidding in units with both RA contracts and firm energy obligations, for example bi-lateral contracts. The full RA capacity must be bid in (or self-scheduled) in order to meet the offer obligation. The bi-lateral contract, however, might be more efficiently delivered by a different, perhaps lower, configuration and so the participant would like to self-schedule in this configuration. Again, the market optimization software does not permit a sequential evaluation of two alternative dispatch configurations of a multi-stage unit. The optimization can only pick one configuration for dispatch. In order to satisfy the RA must-offer obligation as well as protect the bid for the bi-lateral contract, market participants will need to submit economic bids for both configurations. Participants can structure those economic bids so as to protect the schedule for the bi-lateral contract.

4.11 Outage & De-Rate Reporting

For multi-stage units that are comprised of one physical generating unit, SLIC tickets for each configuration impacted by an outage or de-rate of that unit will need to be submitted. Multi-stage units comprised of more than one generating unit are likely to have more configurations, and thus putting in SLIC tickets for each effected configuration could be onerous. For this reason, the ISO's ideal proposal is that the SLIC tool for outage and de-rate reporting be adapted such that, within a resource's SLIC screen, a Scheduling Coordinator can select specific units within the multi-stage resource that are out or de-rated. The SLIC tool would then be able to extrapolate these outages or de-rates to the configurations of which the unit is a component.

The extent to which this is ideal proposal is feasible is not certain at this time. It may be that SLIC cannot readily be augmented to extrapolate sub-resource generating unit outages and de-rates to the effected configurations. If that is the case, participants will have to submit SLIC tickets for each configuration of their multi-stage units that is impacted by an outage or de-rate. Stakeholder feedback has indicated that, while the ideal SLIC functionality would be desirable, the burden of submitting SLIC tickets for individual configurations is not troublesome, and may be preferred to uncertainties associated with more dramatic modifications to the SLIC tool.

Based on stakeholder input, the current proposal is to enable SLIC to manage the outrages, de-rates and re-rates at the plant level, and to manage ramp-rate changes at the configuration level.

4.12 Uninstructed Deviations

Under the new ISO market design, penalties for uninstructed deviations from dispatches are tabulated but not assessed. In part, this is because multi-stage units are not currently being modeled and thus dispatched accurately, and so penalizing participants for deviated from sub-optimal dispatches would be unfair. The extent of uninstructed deviations will continue to be carefully monitored after the implementation of MSG unit modeling to determine if there is a need to seek authority to impose uninstructed deviation penalties. To clarify, the ISO is not proposing to seek authority to implement uninstructed deviation penalties as part of this stakeholder effort. The change in modeling to more accurately dispatch units is intended and expected to alleviate many instances of uninstructed deviations. Simply, the monitoring effort associated with uninstructed deviations will continue, and will be informed by the change in the accuracy of unit dispatch.

Telemetry data will indicate to the ISO the operating range of the configuration in which the resource was dispatched. The ISO will incorporate into the market systems the individual telemetry data from each unit that is part of a multi-stage resource. If the resource is operating within the range of the dispatched configuration and deviates from instructions, the usual non-response to dispatch rules will apply. If the resource is outside the configuration's range based on telemetry data, then it will be dispatched to the boundary of the actual configuration based on the requirements of the dispatcher.

5 Stakeholder Feedback

Stakeholder feedback on the *Revised Straw Proposal* was generally supportive. The stakeholder comments matrix included as Appendix C to this *Draft Final Proposal* summarizes this feedback. In addition, brief responses are provided. The *Draft Final Proposal* also seeks to provide additional clarification and examples that was requested in the written stakeholder comments.

6 Conclusion

The ISO is targeting the fourth quarter of 2009 for the incorporation of modeling multi-stage generating units within the ISO market systems. Particularly in light of the significant enhancements that this *Draft Final Proposal* offers, significant software performance issues may need to be overcome. Given the importance and value of competing enhancements to the new market design in this first year of its operation, it may be necessary to prioritize and compromise to accomplish important market enhancements. The ISO will seek to keep stakeholders apprised should changes become necessary in the planned implementation of multi-stage generating unit modeling.

Having completed a thorough process of soliciting and incorporating stakeholder feedback, the ISO will be presenting this *Draft Final Proposal* to its Board of Governors at the May 18-19, 2009 meeting. If questions, comments or concerns arise on multi-stage generating unit modeling in general, or this *Draft Final Proposal* specifically, please address them to gbiedler@caiso.com or call Gillian Biedler at 916-608-7203.

7 Appendix A: MSG Unit Bid Cost Recovery Example

The following simple example describes the Bid Cost Recovery calculation for a day in which an MSG resource was dispatched in only three hours, and in which real-time dispatch is hourly:

Table 1: Simple Example of Bid Cost Recovery for MSG Units

	Hour Ending		Configuration	Bid Costs	MW * LMP	Net Revenue
Day-Ahead	13	Economic Bid	C1	$10,000 (SU and ML)	120 MW*$25	($7,000)
Day-Ahead	14	Economic Bid	C2	$2,000 (transition)	200 MW*$30	$4,000
Day-Ahead	15	Economic Bid	C2	-	190 MW*$15	$2,850
Real-Time	13	Economic Bid	C1	$10,000 (SU and ML)	30 MW*$25	($9,250)
Real-Time	13	Self-Schedule	C1	-	120 MW*$25	$3,000
Real-Time	14	Economic Bid	C1	-	Not Taken	$0
Real-Time	14	Self-Schedule	C1	-	150 MW*$35	$5,250
Real-Time	15	Economic Bid	C2	$2,000 (transition)	25 MW*$18	($1,550)
Real-Time	15	Self-Schedule	C2	-	190 MW*$18	$3,420

	Hour Ending		Bid Costs	BCR Calculation	Rationale
Bid Cost Recovery	13	Day Ahead	($7,000)		Defer to RT dispatch
Bid Cost Recovery	13	Real Time	($9,250)	($9,250)	In RT, C1 was dispatched
Bid Cost Recovery	13	RT- Self-Schedule	$3,000		SS not eligible for BCR
Bid Cost Recovery	14	Day Ahead	$4,000	$4,000	No RT dispatch, defer to DA costs
Bid Cost Recovery	14	Real Time	$0		No RT dispatch
Bid Cost Recovery	14	RT- Self-Schedule	$5,250		SS not eligible for BCR
Bid Cost Recovery	15	Day Ahead	$2,850		Defer to RT dispatch
Bid Cost Recovery	15	Real Time	($1,550)	($1,550)	In RT, C2 was dispatched
Bid Cost Recovery	15	RT- Self-Schedule	$3,420		SS not eligible for BCR
	Overall Value Eligible for Bid Cost Recovery			**($6,800)**	

In this simplified case, the resource came up short for this day, and is eligible for Bid Cost Recovery in the amount of $6,800.

8 Appendix B: MSG Unit Local Market Power Mitigation Examples

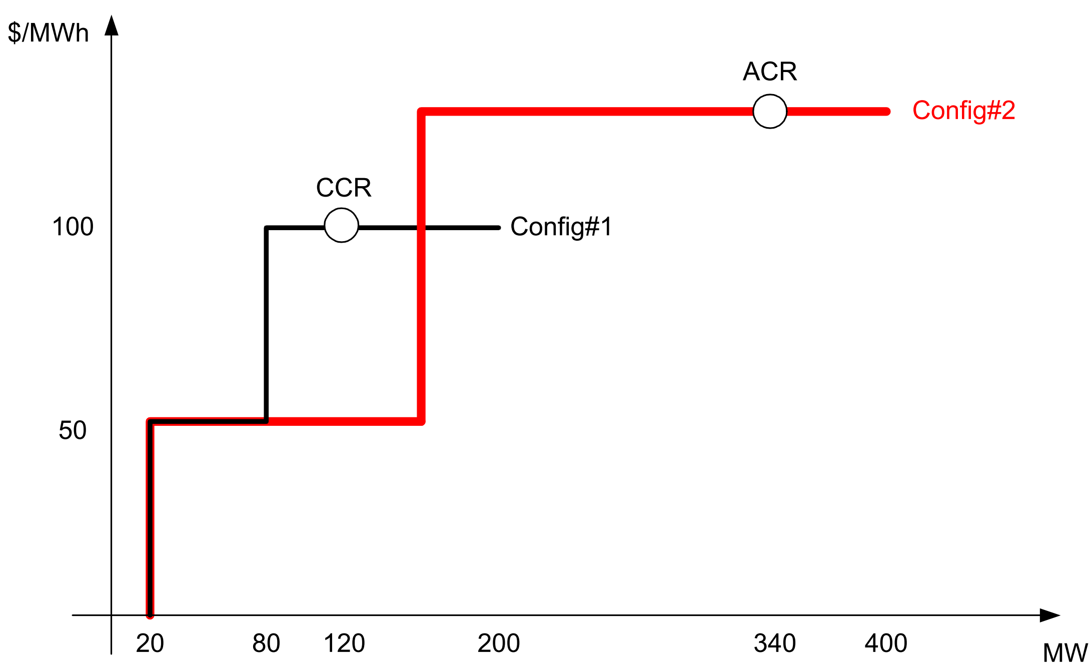
8.1 Example 1

Assumptions

1. The MSG resource has 2 identical Gas Turbines (GT1 and GT2) and 1 Steam Turbine (ST). The feasible configurations are:
   a. Configuration 1: (GT1 and ST) or (GT2 and ST)
   b. Configuration 2: GT1 and GT2 and ST

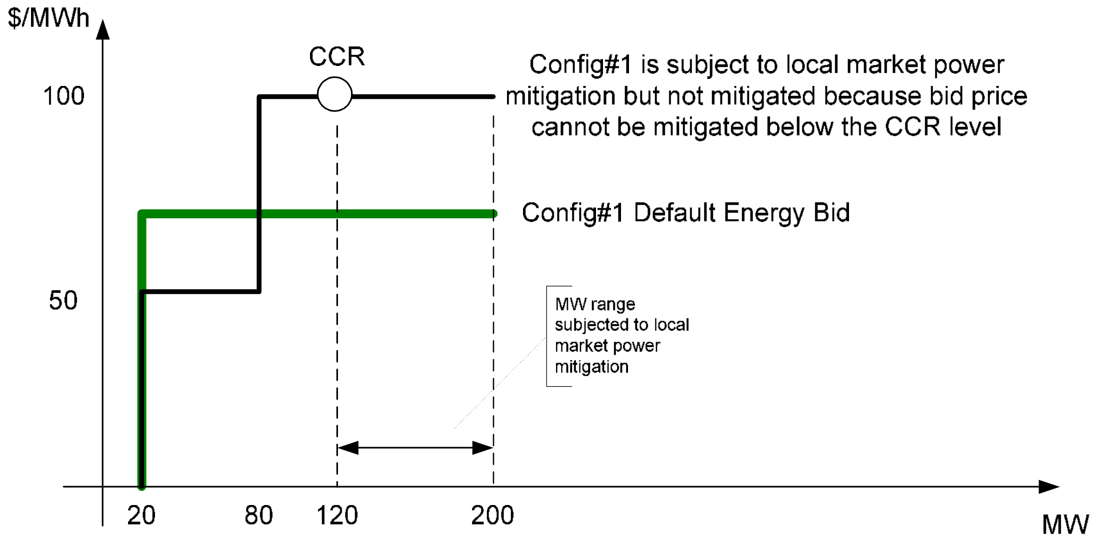
2. The bid curves are as follow:
   a. Configuration 1 (MW, $/MW): (20, 50), (80, 100), (200, 100)
   b. Configuration 2 (MW, $/MW): (20, 50), (160, 130), (400, 130)

3. Configuration 1 (Config#1) is committed in the Competitive Constraints Run (CCR) at 120 MW; configuration 2 (Config#2) is committed in the All Constraints Run (ACR) at 340 MW, as is shown below:



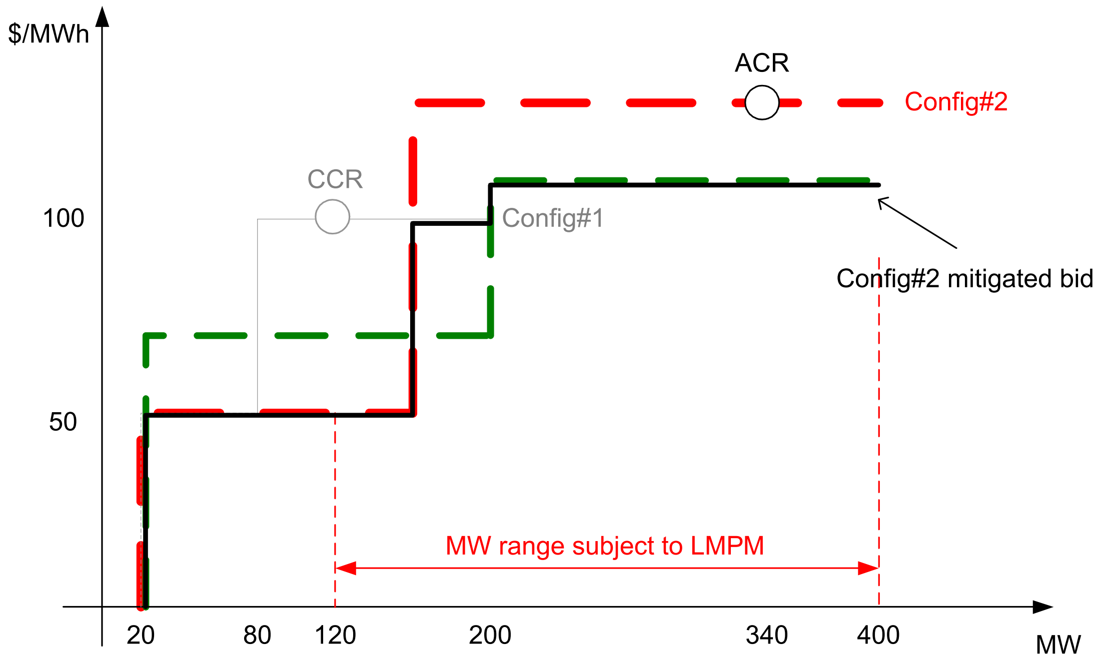
Configuration 1 Mitigation

Config#1 is subject to local market power mitigation but not mitigated because bid price cannot be mitigated below the CCR level.



Configuration 2 Mitigation

Config#2 is mitigated to the lower of the submitted bid price and the default energy bid price but not lower than the CCR bid price of the CCR corresponding configuration.



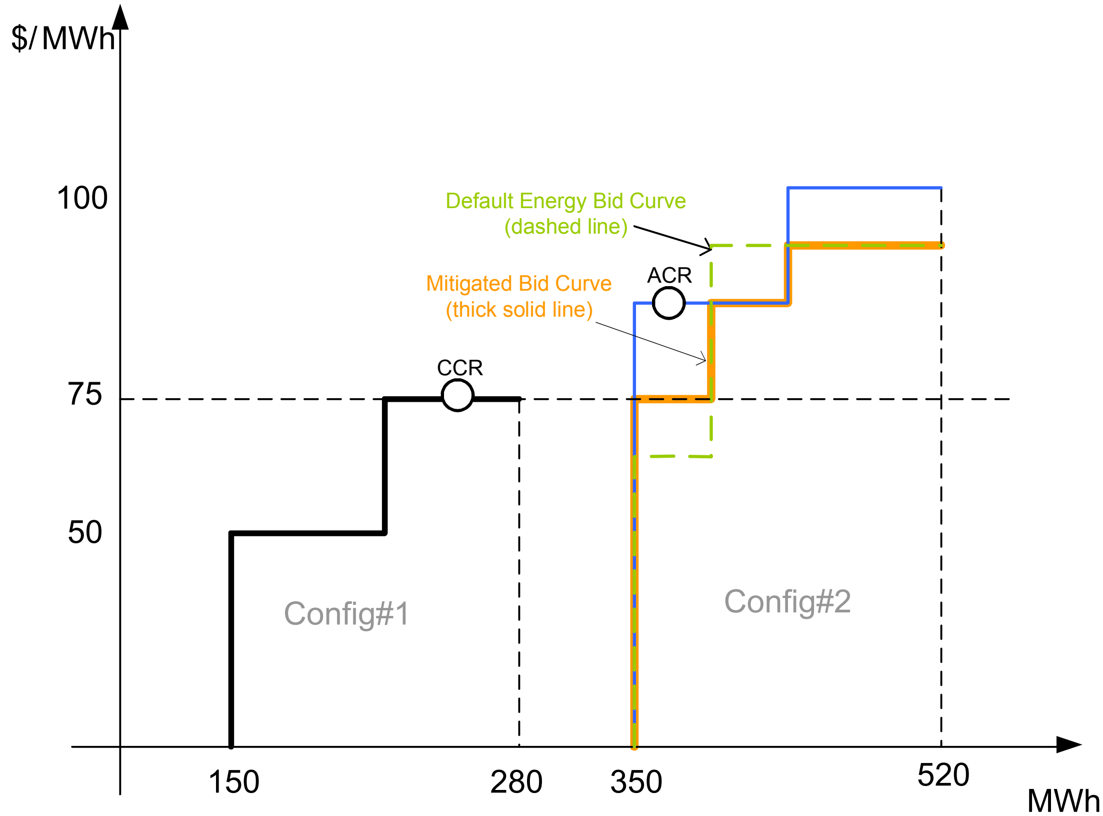
8.2 Example 2

<u>Assumptions</u>

1. The MSG resource has 2 configurations such that:
    a. Configuration 1: Pmin = 150, Pmax = 280
    b. Configuration 2: Pmin = 350, Pmax = 520

2. The bid curves are as follow:
    a. Configuration 1 (MW, $/MW): (150, 50), (230, 75), (280, 75)
    b. Configuration 2 (MW, $/MW): (350,75), (430, 85), (520, 100)

3. Configuration 1 (Config#1) is committed in the Competitive Constraints Run (CCR) at 260 MW; configuration 2 (Config#2) is committed in the All Constraints Run (ACR) at 360 MW, as is shown below:



Configuration 1 is not mitigated. Configuration 2 has a mitigated bid curve (think orange line) that is the higher of the Default Energy Bid Curve (dashed green line) and the last bid segment from the Competitive Constraints Run, but not above the submitted bid curve (thin blue line) for Configuration 2.

9 Appendix C: Stakeholder Feedback on the MSG unit modeling *Revised Straw Proposal*

The following matrix summarizes the stakeholder feedback on the *Revised Straw Proposal* on multi-stage modeling. The *Revised Straw Proposal*, upon which this *Draft Final Proposal* is largely based, was posted on April 13, 2009, and a stakeholder conference call was held to discuss it on April 17, 2009. The written comments upon which the following matrix is based were due April 24, 2009. All documents related to the stakeholder process for multi-stage generating unit modeling are posted and available at the following link: http://www.caiso.com/2078/2078908392d0.html.

Management Proposal	Calpine Corp.	J.P. Morgan Ventures Energy Corp.	Pacific Gas & Electric	Reliant Energy	San Diego Gas & Electric	Southern California Edison	Management Response
MSG units limited initially to those units that have Forbidden Operating Regions in the Master File	No Comment	No Comment	Conditional Plans to evaluate the dispatch of pump storage hydro units under new market. May seek MSG modeling for those units.	No Comment	No Comment	Conditional Encourages the ISO to set a timeline for extending MSG modeling to units without Forbidden Operating Regions.	The initial implementation of MSG modeling is intended to mitigate the suspension of the Forbidden Operating Region (FOR) functionality. Those units with FOR will be addressed first. The ISO will work to establish a timeline for opening the functionality to other units. It is management's position that the MSG modeling should ultimately be extended to all units it would enable to be accurately modeled. This goal needs to be balanced against software performance limitations which are not fully known at this time.
Up to *ten* configurations of an MSG unit can be bid into the **DA market**. One must meet RA obligation.	Support Supports configuration-based modeling of MSG units. Comfortable with limiting DA configurations to ten.	Support	Support	Notes that the transition matrix needs to include the maximum number of times per day that a unit can be transitioned between two configurations.	Support Notes that the transition matrix is the key to accurate modeling	Support	Management agrees that ten configurations will adequately capture the operating configurations of MSG units. Capturing the cost and operational considerations associated with all feasible transitions is indeed essential to successful MSG modeling. The maximum number of times a transition can occur within a day will be included in the transition matrix.
Up to *three*	Support	Conditional	Support	No Comment		Support	MSG resources that receive a DA

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configurations can be bid into the **RT market**. One must meet RA and RUC obligation, one must meet DA schedule, and all must honor DA A/S awards.	Limitation to three configurations balances desired flexibility with processing time constraints.	Seeks clarification that MSG resources will not face offer obligations or restrictions not imposed on other generating units.	Notes that one configuration's bid should meet the DA and RUC schedules and be feasibly transitioned to from the previous interval's configuration.		Seeks clarification on the requirement that configurations bid into the RT market be feasibly transitioned between one another.		schedule must bid a configuration into RT that can fulfill that schedule. The RT bid for the energy and/or A/S capacity can be different from the bid submitted in DA. Specifically, the RT bid can be structured to reflect changes in operating conditions and/or opportunity costs. If different configurations bid in to successive intervals, the transition matrix should indicate that the transition between these two configurations is feasible.
Forbidden Operating Region Functionality will be evaluated for re-instatement in the RT market.	No Comment	No Comment	No Comment	Conditional Seeks confirmation that MSG modeling would be appropriately used for units such as a steam turbine which is currently modeled as having a Forbidden Operating Region..	No Comment	No Comment	MSG modeling can effectively be used to model combined-cycle units, steam units, and steam-injected gas turbine units. There may be other generation technologies that could also be accurately modeled and dispatched using MSG functionality. For some units, however, the Forbidden Operating Region functionality will better capture their operating constraints than MSG modeling would. Additionally, it is possible that some MSG units will have true FORs within a configuration. Therefore, the proposal is to re-

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							instate FOR functionality in the RT market once MSG functionality is in place..
Self-Schedules must be for a configuration that satisfies RA obligation. Any additional market bids must be for the same configuration as the Self-Schedule	Support Given the structure of the market optimization, this limitation is understandable and acceptable, though not ideal.	No Comment	No Comment	No Comment	No Comment	Does not Support	If an MSG unit self-schedules a configuration, it is thus indicating that it must be dispatched in that configuration. To then submit a market bid for a different configuration is at odds with the iterative logic and structure of the optimization software. Participants can structure their market bids so that RA capacity is offered, and the desired schedule is protected.
Bid Cost Recovery is calculated based on the configuration dispatched in RT	Support	No Comment	No Comment	Conditional Seeks clarification as to the limitations to changes in scheduled configurations while retaining eligibility for BCR. Also, requests summary of difference in BCR between MSG and non-MSG units.	No Comment	Conditional Would not support a BCR scheme in which a unit committed in the DA and not in the RT would not be eligible for BCR.	The final proposal clarified that a unit committed in DA and not in RT would be eligible for BCR based on the DA commitment costs.
RA must-offer obligations must	Support	No Comment	Conditional	Conditional	No Comment	No Comment	Management confirms that RA units are not currently required to

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be met in the DA and RT by submitting a configuration that can supply the obligated MWs	Clarifies that the obligation of RA units to offer A/S bids is not in effect at this time. This obligation will not be specific to MSG units.		Notes that the requirement that RA units bid in A/S capacity is not yet approved by FERC.	Seeks clarification that there is not a requirement that long-start RA units bid into the RT market. Seeks clarification that satisfaction of the RA obligation is not calculated based on the *incremental* capacity made available by a configuration.			offer A/S capacity. This requirement is pending approval by FERC. It will not be limited to MSG RA units. Long-start MSG units with RA obligations must offer their RA capacity into the DA market. If the unit is not taken in the DA market, it is not required to offer into the RT market. Its obligation would be met by the DA bid or self-schedule. The RA obligation would be met by offering in a bid or self-schedule for a configuration such that the MW value meets or exceeds the RA obligation. Thus, the satisfaction of the obligation is based on the total capacity of the configuration and not the incremental increase from a lower configuration.
RMR units will be dispatched and paid according to their contractual arrangements	Conditional Recommends more study, particularly in the case of units with partial RMR contracts	No Comment	No Comment	No Comment	No Comment	No Comment	Management appreciates this thoughtful observation. This issue will be studied further. As with the whole of the MSG modeling proposal, it is designed to limit the extent to which treatment of MSG units differs from non-MSG units.

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Local Market Power Mitigation	Conditional Poses clarifying questions which the final draft proposal will seek to address.	No Comment	No Comment	No Comment	No Comment	No Comment	An additional example was added to the appendix of the Draft Final Proposal to help clarify this issue. In short, bids are only mitigated down (not up). Thus, the mitigated price is the higher of the accepted price or the DEB, but *not* higher than the submitted bid.
Outage and de-rate reporting	No Comment	No Comment	Conditional Is supportive of the goal to save participants the task of entering outages and de-rates by configuration, but has implementation feasibility concerns.	Conditional Seeks confirmation that outages and de-rates can be submitted on an hourly basis, and that participants can ensure that RT dispatches are consistent with outages.	No Comment	Does Not Support Does not support the goal of automated extrapolation from unit level outage information to configuration availability. Supports configuration-level outage reporting which places more of a burden on stakeholders and less on the SLIC system.	Management is mindful that unit-level outage reporting, and automated extrapolation of that information to configurations may not be feasible. This was proposed to alleviate the burden that configuration-level reporting could place on participants. If the proposal is not feasible, then configuration-level outage reporting will be implemented. Management appreciates Stakeholder willingness to take on configuration-level outage reporting.
Uninstructed deviations (UD) will be monitored to assess the need to seek authority	No Comment	No Comment	No Comment	No Comment	No Comment	Objects to the notion that successful implementation of MSG modeling is a step toward	Under MSG modeling, dispatches will be more accurate, and thus UD should decrease. Management recognizes that MSG units operating in the wrong configuration have the potential to

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to charge penalties						implementing UD penalties.	cause reliability problems. Management simply recommends monitoring of UDs, and points out that, if UDs are problematic, penalties could be sought.