Attachment D

CALCULATION OF DEFAULT ENERGY BIDS

D. Calculation of Default Energy Bids

The overall intent of the Default Energy Bid mitigation system is to mirror competitive outcomes in those situations where participants might have market power. CAISO believes that under competitive outcomes generators would be paid at least their variable costs. Consequently the Default Energy Bid (DEB) is designed to approximate that cost. Additionally, pursuant to CAISO Tariff 39.7.1.6 the method for calculating RMR Unit Default Energy Bids is also discussed. The RMR DEBs are calculated similarly to non-RMR Units but utilize costs specified to their RMR Contracts.

A~~n~~ SC may modify the ranking of the three options for calculating the DEB up to two times during any 365-day period. If a~~n~~ SC would like to modify the ranking of options for calculating the DEB more than two times during any 365-day period, additional changes must be approved by the CAISO ~~or Independent Entity responsible for determining DEBs~~ under the Negotiated Rate Option.

This appendix is concerned solely with the calculation of the Default Energy Bid (DEB), which forms part of the broader Market Power Mitigation (MPM). The DEB is only used for Market Power Mitigation in the incremental direction. There is no decremental mitigation as infeasible schedules will not be accepted in the Day-Ahead Market. In all four variations of the Default Energy Bid (DEB) will be calculated, namely Day-Ahead and Real-Time DEBs for both peak and off-peak separately. There is no hourly variation except in the transition hours between Off-Peak and Peak and vice versa.

D.1 Day-Ahead

The Market Power Mitigation (MPM) process determines when to use Default Energy Bids (DEB) and RMR Proxy Bids to in place of market bids in the CAISO markets. The MPM process analyzes the potential to exercise local market power and determines bid mitigation based on a single processing run that decomposes each resource's locational market price (LMP) into components relating to energy, losses, and competitive and non-competitive congestion components. Under this method, which is known as the LMP decomposition method, mitigation will be based on the non-competitive congestion component of each resource's LMP. If the non-competitive constraint congestion component is greater than zero its bid will be mitigated to the higher of the DEB, or RMR Proxy Bid, as applicable, and its competitive LMP if it is lower than the unmitigated bid. The purpose of the DEB is to mimic the variable cost of the generating units, so that in the IFM generators are dispatched based on their variable costs rather than their submitted Bids. Hence, the purpose of the DEB is to allow incremental dispatch based on variable cost. Once the MPM is complete, DAM LMPs are set for the dispatched capacity when the DAM runs.

D.2 Real-Time

In real-time generators enter the simplified Real Time Market Process (RTM) with their DAM schedules subject to a bidding rule that they may not submit an Energy Bid component at a lower Bid price than their highest accepted DA Energy Bid. Again mitigation only occurs in the incremental direction. Decremental dispatches are based on submitted bids that conform to the bidding rule. CAISO carries out the same process as in the DAM. Mitigation of bids remains at the hourly level although LMPs are dispatched at the 5 minute level, settlement at the 10 minute level, and unit commitment and Ancillary Service procurement at the 15 minute level.

D.3 Characteristics of the Default Energy Bid (DEB)

A Default Energy Bid is a monotonically increasing staircase function consisting of a maximum of 10 economic bid segments, or 10 ($/MW, MW) pairs and an End MW value. Each Default Energy Bid is identified by the DEB ID; it is also identifiable by the Resource ID, the Market in which it is applicable, the period of the day in terms of On Peak and Off Peak when it is applicable, and the time it is updated.

In addition to the DEB_ID there is also a Segment Number that indicates the sequence of segments. A segment of a Default Energy Bid is represented by the Start MW and the Price in terms of $/MWh. Each segment of the Default Energy Bid is associated with a field that indicates which methodology has been used to determine the segment. A DEB may be calculated using more than one methodology as explained below.

Separate DEBs are calculated for the DAM and the RTM, as well as for peak and off-peak hours. The Default Energy Bid is eligible to set the LMP at its location. LMPs set by mitigated bids will not be revisited and reset due to the presence of an updated gas index.

There are three methodology options for calculating DEBs:

- LMP Option: A weighted average LMP based on the lowest quartile of validated and/or corrected LMPs set at the Generating Unit location during Trading Hours in the last 90 days when the Unit was dispatched. Generating Units must pass a competitiveness screen to qualify for this option in which 50% of their MWh dispatches over the prior 90-days must have been dispatched competitively.
- Negotiated Rate Option: An amount negotiated with the CAISO~~ or its designated agent~~. Even i~~I~~f a Resource has ranked the Negotiated Rate Option as the first choice, the CAISO will not ~~only~~ calculate a new or updated -negotiated default energy bid until the SC has commenced the negotiated default energy bid process and has provided sufficient information. ~~complete curve of the~~ the ~~latest Negotiated Rate Option.will be selected.~~

- Variable Cost Option: This option is based on the variable cost of the unit and includes a 10% adder for non-RMR capacity and a Variable Energy Opportunity Cost, if applicable. Furthermore this option is supplemented by the Frequently Mitigated Unit (FMR) adder whereby certain units that are often mitigated qualify for a contribution towards their going-forward fixed costs. If a Resource has ranked the Variable Cost Option as the first choice, the complete curve (i.e., including all segments) of the Variable Cost Option will be calculated and selected.

Each Resource (through their SC) will rank the three alternatives for Default Energy Bid calculation according to their order of preference for each resource. There will be a single ranking for all hours of all days. Resources that are subject to CAISO Tariff Appendix II must choose the Variable Cost Option, otherwise a $0/MWh bid will be used as the Default Energy Bid.

The details of the three alternatives are described below.

D.4 LMP Option

If a Generating Unit chooses the LMP-Option as the first choice, they must have ~~either a negotiated curve or~~a cost-based curve as second choice, as the generator may not be eligible for the LMP option, or if eligible, the option may not be feasible due to not enough data available. If a Resource has ranked the LMP Option as the first choice, the LMP Option calculation method will be used to construct the DEB to cover as much capacity as possible to the extent that the LMP Option method is feasible. The DEB for the remaining capacity will be constructed using ~~either the Negotiated Rate Option~~ the Variable Cost Option ~~according to the Resource's preference~~. Moreover, the segments that are not based on LMP are linked to the segments of ~~Negotiated Rate Option or~~ the Variable Cost Option ~~depending on which one is used~~.

The LMP-Based DEB is only calculated if it is the first choice of the Scheduling Coordinator. Since the methodology for calculating the LMP-Based DEB needs predefined segments and ~~one of~~ the Variable Cost Option~~other two~~ method~~s~~ as the fall back, the calculation will start with the second choice of the Resource, ~~which could be either~~ the Variable Cost Option ~~or the Negotiated Rate Option~~. By doing so, the resource's predefined segments are stipulated, namely;

- The first MW point is the Minimum Load
- The last MW point is the Maximum Capacity
- Each forbidden region is represented by a separate bid segment.

- The LMP-Based calculation will be used to modify the bid price for each segment that passes the Feasibility Test, which tests the availability of data for calculating the weighted average of the LMPs for the bid in each segment.
- Not eligible to include a Variable Energy Opportunity Cost adder in its calculation.

In the event that a resource fails the Feasibility Test, the second choice will be substituted for that particular segment, if the second choice is missing~~-~~ the CAISO will fall back to the most recently calculated Variable Cost Option default energy bid curve~~or not on file (in the case of Negotiated rate option), use the third choice~~. Finally, adjustments are made to ensure that the staircase bid curve is monotonically increasing.

~~Variable~~ An energy opportunity cost will not be added to any segment of the LMP-based option for the default energy bid when the LMP-based calculation sets the default energy bid for ~~the~~one or more segments. If the Scheduling Coordinator successfully registers an energy use limitation in the ULPDT for the resource that has selected LMP option and the LMP option is in effect, if the Variable Cost Option is used for a bid segment then the Variable Default Energy Bid calculation could have an opportunity cost component. Details on the procedure establishing the ~~Variable~~ Energy Opportunity Cost are discussed in Attachment N of the Market Instruments Business Practice Manual.

D.4.1 Feasibility Test

The LMP-Based DEB will not apply during the first 100 days after the new market power mitigation under the New California ISO Nodal Market is in operation. After the first 100 days, the following feasibility test applies to each bid segment. A bid segment will pass the Feasibility Test only if there are a threshold number of data points to allow for the calculation of an LMP-Based DEB This threshold number will set at a level that is designed to avoid excessive volatility of the LMP DEB that could result when the LMP is calculated based on a relatively small number of prices. The initial threshold condition in the DA is set to twenty-nine (29 – approximately 2%) on Peak, and fifteen (15 – approximately 2%) on Off-Peak, out of a total of 1440 possible peak values and 720 possible Off-Peak values. For Real-Time the thresholds are slightly lower around 1%. For Peak Real-Time the threshold is set at one hundred and seventy-three (173) and for Off-Peak the initial threshold is set at Eighty-seven data points (87), out of a total of 17,280 possible peak values and 8,640 possible Off-Peak values.

Thus for example, for a segment to be eligible to be calculated via the LMP methodology for the DA Peak DEB then a dispatch within that segment must have occurred a minimum of 29 times in the last ninety days. The feasibility test is done separately for each market (Day-Ahead and Real-Time) and for each type of period (Peak and Off-Peak).

D.4.2 LMP-based DEB Price Calculation

If a resource has passed the Eligibility Test and a DEB segment has passed the Feasibility Test, the LMP based DEB price for a segment is calculated to be the weighted average of the GPI-normalized LMPs that are in the lowest quartile of the set of GPI-normalized validated or corrected LMPs whose corresponding schedules/dispatches fall in the segment. The LMP Option default energy bid is not eligible to include the Variable Energy Opportunity Cost adder in the calculation.

D.4.3 Monotonicity Adjustment

Right-To-Left Adjustment

The LMP-Based DEB must be monotonically increasing. The Right-To-Left Adjustment only applies to the LMP-Based DEB segments, i.e., not including the Cost-Based or Negotiated DEB segments that have been substituted into the LMP-Based DEB curve. The Right-To-Left Adjustment will replace any LMP-Based DEB segment with a value greater than the next LMP-Based segment to the right with the value of that segment, beginning with the right most LMP-Based DEB segment and moving in sequence to the left most LMP-Based DEB segment. If there are two adjacent segments with the same price, they will be collapsed to make one segment spanning both MW ranges.

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Left-To-Right Adjustment

The Left-To-Right Adjustment applies to all the DEB segments, i.e., including the LMP-Based DEB, and the Cost-Based DEB segments or Negotiated DEB segments. The Left-To-Right Adjustment will start from the left-most DEB segment to ensure that price of a segment on the right is greater than the price of the segment on the left. The segment on the right that is not greater than the price of the segment on the left shall be merged to the price of the segment immediately on the left. If there are two adjacent segments with the same price, they will be collapsed to make one segment spanning both MW ranges.

D.5 Variable Cost Option

The Cost-Based DEB will be calculated based on the Incremental Heat Rate curve (for gas fueled units) multiplied by the applicable gas costs~~Gas Price Index plus applicable transportation rates~~[1] or Incremental Cost Rate curve (for non-gas fueled units), plus a Grid Management Charge (GMC) adder made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee

[1] See Attachment C of Market Instruments Business Practice Manual for existing fuel regions definition including the natural gas commodity price and applicable transportation rates.

component divided by the bid segment MW size, plus an Operation and Maintenance (O&M) adder consistent with Exhibit 4-2 unless a custom O&M adder is negotiated with the CAISO~~ or the independent entity~~. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will add a greenhouse gas allowance cost. The cost will be calculated per Attachment K, using the projected Greenhouse Gas Allowance Price described in section G.1.3. This ~~figure~~ amount will then be multiplied by a configurable scalar (e.g., 110%), ~~plus~~ the DEB Adder, plus a Frequently Mitigated Unit adder if applicable and a Variable Energy Opportunity Cost if applicable, to produce the Cost-Based DEB[2].

~~RMR Units default to the Variable Cost Option and do not receive either the scalar or the DEB Adder. They do receive the RMR Contract specified values of ISO Annual Charge Adjustment (ACA) Charge and the ISO Scheduling Coordinator Administration Charge as specified in their RMR Contract Schedule C. Average Heat Rates are determined from the FERC Filed Schedule C for either gas and distillate fueled units and entered into the Masterfile RMR Heat Rate field. Fuel price, both gas and distillate are provided by the independent entity. The Cost-Based DEB is then calculated using the Incremental Heat Rate curve multiplied by the fuel price.~~

~~The values used for the Gas Price Index (GPI) is described in Attachment C.~~

~~Note, if the resource is subject to a greenhouse gas compliance obligation as indicated in the Master File, the CAISO will add to any energy curve calculated with the Variable Cost Option an incremental energy curve representing the cost of meeting that obligation. See Appendix Attachment K for details.~~

D.5.1 Average Heat Rate and Average Cost Curves

Gas-fired resources~~Generator units~~ are required to submit to CAISO in the Master File the Average Heat Rates (Btu/kWh) measured for ~~at least~~a~~n~~ minimum of 2 and a maximum of ~~up to~~ 11 ~~generating~~ operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels, respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear between operating points.

Non-gas fired resources are required to submit to CAISO in the Master File the ~~An~~ Average Cost Curve ($) measured for a minimum 2 and a maximum 11 operating points (MW),), where the first and last operating points refer to the minimum and maximum operating levels, respectively~~is used in place of the Heat Rate Curve for a non-gas fueled unit~~. The Average Cost Curve is the dollar amount of fuel-equivalent costs incurred by resource for providing energy at the operating

[2] CAISO continues to use the current emissions chargeback process. CAISO only reimburses generators for legitimately incurred emissions costs due to CAISO dispatches.

point for that bid-segment. The average cost curve formed by the ($, MW) pairs is a piece-wise linear between operating points.

Heat Rate Curves or Average Cost Curves are stored, updated and validated in the Master file. For RMR Units, the Average Heat Rate Curve is determined from FERC filed RMR Schedule C data.

D.5.2 Incremental Heat Rate and Incremental Cost Curves

For gas-fired resources, DEBs under the Variable Cost Option are calculated to reflect the incremental heat rates that reflect the marginal requirement of heat input (Btu/h) for providing an extra 1 MW output at a given operating point. The incremental heat rates (Btu/kWh) are calculated from the average heat rates. For non-gas fired resources, DEBs under the Variable Cost Option are calculated to reflect the incremental cost curves that reflect the marginal cost of providing an extra 1 MW of energy at a given operating point. The incremental cost curves ($/MW) are calculated from the average cost curves.

The resulting incremental ~~heat rate~~ segments, incremental heat rate and incremental cost curves, are a step function due to use of piece-wise linear average ~~heat rate~~ curve. For gas and non-gas resources, t~~T~~wo average heat rate or average cost pairs yield one incremental heat rate or incremental cost segment that spans across two operating points. The first step is to convert the average heat rate to requirement of heat input (Btu/h) or average cost for each operating point by multiplying the average heat rate or average cost with the MW of the operating level. The actual incremental heat rate or incremental cost is then derived ~~as~~ by dividing the change of requirement of heat input or change in cost from one operating point to the next by the change of MW between two consecutive operating points. The specific formula for calculating incremental heat rates or incremental costs calculated from average rates or average costs is provided below.

$$IHR_{Sn}^{ini} = \frac{AvgHR_{n+1} * MW_{n+1} - AvgHR_n * MW_n}{MW_{n+1} - MW_n}$$

Where:

IHR_{Sn}^{ini} is the initial incremental heat rate for segment S_n between two consecutive generator MW output operating points (n+1) ~~$(n-1)$~~ and (n).

$AvgHR_n$, $AvgHR_{n+1}$ ~~$AvgHR_{n-1}$~~ are the average heat rates measured at the operating points (n) and ~~$(n-1)$~~ (n+1), respectively.

MW_n, MW_{n+1} ~~MW_{n-1}~~ are the generator MW output levels at the operating points n ~~(higher level)~~ and ~~$n-1$~~ (n+1) ~~(lower)~~, respectively.

Formula: Incremental Heat Rate Calculation

$$ICC_{Sn}^{ini} = \frac{AvgCC_{n+1} * MW_{n+1} - AvgCC_n * MW_n}{MW_{n+1} - MW_n}$$

Where:

ICC_{Sn}^{ini} is the initial incremental ~~heat rate~~cost for segment S_n between two consecutive generator MW output operating points (n+1) and (n).

$AvgCC_n$, $AvgCC_{n+1}$ are the average costs measured at the operating points (n) and (n+1) ~~$(n-1)$~~, respectively.

MW_n, MW_{n-1} are the generator MW output levels at the operating points n and (n+1), respectively.

Formula: Incremental Cost Curve Calculation

D.5.3 Adjustment of Incremental Heat Rate

Initial incremental heat rates and incremental cost curves calculated using the equations in Section D.4.1.2 will be adjusted as described in this section in order to reduce cases where – due to Left-To-Right adjustments made to ensure that DEBs are monotonically non-decreasing — DEBs under the Variable Cost Option would significantly exceed a unit's actual incremental costs for a significant portion of the unit's capacity. This adjustment is applied only to incremental heat rate or incremental cost segments that correspond to operating ranges below 80% of the units' maximum operating capacity (PMax).

Specifically, initial incremental heat rates or incremental cost curves calculated using the equations in Section D.4.1.2 will be adjusted if necessary so that the resulting incremental heat rates (Btu/kWh) or incremental costs ($/MW) do not exceed the maximum of the average heat rates corresponding to the upper and lower operating points of each incremental heat rate segment. The formula used to make this adjustment is provided below respectively for adjustments to incremental heat rates and incremental costs.

$$Cap_{Sn} = \max(AvgHR_n, AvgHR_{n+1})$$

$$IHR_{Sn}^{adjusted} = \min(IHR_{Sn}^{ini}, Cap_{Sn})$$

Where:

Cap_{Sn} is the maximum limit for segment S_n ;

$IHR_{Sn}^{adjusted}$ is the adjusted incremental heat for segment S_n .

Formula: Adjusted Incremental Heat Rate Calculation

Similarly, for non-gas resources, the formulas used for adjustments to incremental cost curves costs are as follows:

$$Cap_{Sn} = \max(AvgCC_n, AvgCC_{n+1})$$

$$ICC_{Sn}^{adjusted} = \min(ICC_{Sn}^{ini}, Cap_{Sn})$$

Where:

Cap_{Sn} is the maximum limit for segment S_n ;

$ICC_{Sn}^{adjusted}$ is the adjusted incremental cost for segment S_n .

Formula: Adjusted Incremental Cost Curve Calculation

Examples of this adjustment are provided in Attachment J.

D.5.4 Variable Operation and Maintenance Adder

The Variable Operation and Maintenance (O&M) cost adder is an amount in terms of $/MWh. The exact amount is dependent on technology and/or fuel type of a resource. The default value for the O&M adder is listed in exhibit 4.2. In addition, CAISO will review the default O&M adder values used for DEBs and proxy Minimum Load Cost every three years. RMR Units use the FERC Filed RMR Variable O&M cost. Scheduling Coordinators can also negotiate a custom

O&M adder pursuant to Tariff section 39.7.1.1.2 (section D.5 of the BPM) in which case the custom O&M adder will be used to calculate Minimum Load cost as well as Default Energy Bids under the Variable Cost option.

Scalar

The configurable scalar is set to be 110% by default. RMR units do not receive the scalar.

D.5.6 FMU Bid Adder

Frequently Mitigated Unit ~~DEB~~ Adders only apply to the Cost-Based DEB and do not apply to LMP-Based DEB or Negotiated DEB. In general, the Frequently Mitigated Unit ~~DEB~~ Adder (~~DEBA~~FMU Adder) is resource specific; i.e., each resource can have a unique ~~DEBA~~FMU adder. The CAISO will establish a baseline $/MWh value of ~~DEBA~~ FMU adder for all eligible resources except those that have negotiated special ~~DEBA~~ FMU adder values with the CAISO.

~~**Eligibility for DEB Adder**~~

A resource is eligible to have a ~~DEB~~ Frequently Mitigated Unit Adder included in its Cost-Based DEB prices for every segment if and only if the resource is a Frequently Mitigated Resource (FMR). The determination of FMR is established on a monthly basis. The determination of FMR for each month is based on data for the 12-month period ending on the 15th day of the prior month. For example, the determination of FMR for June of 2008 will be evaluated based on data for the period between May 16, 2007 and May 15, 2008.

A resource is designated as an FMR if the resource is mitigated in over 80% of its run hours over the rolling 12-month period. An hour is considered a mitigated hour if the unit had been scheduled in a mitigated segment in the hour in DA, or the unit had been dispatched in a mitigated segment in RT in at least one of the 5-min intervals of the hour.

The FMR determination will be done outside this system, initially by the Department of Market Monitoring, and the results will be uploaded into the system.

D.5.7 Left-To-Right Adjustment

The Left-To-Right Adjustment applies to all DEB segments. The Left-To-Right Adjustment will start from the left-most DEB segment to ensure that price of a segment on the right is greater than the price of the segment on the left. The segment on the right that is not greater than the price of the segment on the left shall be merged to the price of the segment immediately on the left.

D.5.~~8~~5 Summary Examples

Example: Variable Default Energy Bid for Gas-Fired Resource

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's heat rate curve for resource without a greenhouse gas compliance obligation.

For a gas-fired Combined Cycle Gas Turbine (CCGT) with a segment with an 8,000 Btu/kWh Incremental Heat Rate, the DEB for that segment would be calculated as follows, given a gas price of $4.50/~~mmBTu~~ MMBtu and the proxy gas transport cost were $. 50, making a GPI of $5/ MMBtu~~mmBTU~~. The 8,000 Btu/KWh heat rate is converted into MMBtu/MWh by multiplying 0.001 to the incremental heat rate. In addition the O&M cost is $2.80/MWh and the GMC adder is $0.50. Presume that this unit is not eligible for the ~~DEBA~~FMU adder or a Variable Energy Opportunity Cost adder on top of the fuel cost estimate.

{([IHR * GPI] + O&M + GMC) * 1.1} + ~~DEBA~~ FMU adder (if eligible) + Variable Energy Opportunity Cost adder (if eligible)

{([8 * $5] + $2.80 + $0.50) * 1.1} + $0 + $0

= $47.63/MWh

Example: Variable Default Energy Bid for Gas-Fired Resource with a GHG Component

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's heat rate curve for resource with a greenhouse gas compliance obligation.

For a gas-fired Combined Cycle Gas Turbine (CCGT) with a segment with an 8,000 Btu/Kwh Incremental Heat Rate, the DEB for that segment would be calculated as follows, given a gas price of $4.50/MMBtu and the proxy gas transport cost were $. 50, making a GPI of $5/ MMBTU. The 8,000 Btu/KWh heat rate is converted into MMBtu/MW by multiplying 0.001 to the incremental heat rate. In addition the O&M cost is $2.80/MWh and the GMC adder is $0.50. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e. Presume that this unit is not eligible for the FMU adder or a Variable Energy Opportunity Cost adder on top of the fuel cost estimate.

{([IHR * GPI] + O&M + GMC+ [Unit Conversion Factor*IHR*Emission Rate[3]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost adder (if eligible)

{([8 * $5] + $2.80 + $0.50+ [8*0.053165*15.34])* 1.1} + $0 + $0

= $54.81/MWh

Example: Variable Default Energy Bid for Gas-Fired Resource with a GHG Component and a Binding Energy Use Limitation

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's heat rate curve for resource with a greenhouse gas compliance obligation and also an eligible energy use limitation record in the ULPDT. See Attachment N for details on establishing the Variable Energy Opportunity Costs of the registered use limitation.

For a gas-fired Combined Cycle Gas Turbine (CCGT) with a segment with an 8,000 MMBtu/kWh Incremental Heat Rate, the DEB for that segment would be calculated as follows, given a gas price of $4.50/MMBtu and the proxy gas transport cost were $. 50, making a GPI of $5/MMBtu. The 8,000 Btu/KWh heat rate is converted into MMBtu/MW by multiplying 0.001 to the incremental heat rate. In addition the O&M cost is $2.80/MWh and the GMC adder is $0.50/MWh. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e. Presume that this unit is not eligible for the FMU adder on top of the fuel cost estimate. Based on applying the approach in Attachment N of the Market Instruments Business Practice Manual, the CAISO establishes a Variable Energy Opportunity Cost adder for the month of $25/MWh[4].

{([IHR * GPI] + O&M + GMC+ [Unit Conversion Factor*IHR*Emission Rate[5]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost adder (if eligible)

{([8 * $5] + $2.80 + $0.50+ [8*0.053165*15.34])* 1.1} + $0 + $25

{($40+$2.80+$0.5+$6.52)*1.1} + $0 + $25

= $79.81/MWh

[3] Emission rate used is set by the GHG_EMISSION_RATE field in RDT.

[4] Adder varies based on CAISO processes described in Attachment N of Market Instruments Business Practice Manual.

[5] Emission rate used is set by the GHG_EMISSION_RATE field in RDT.

Example: Variable Default Energy Bid for Non Gas-Fired Resource

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's cost curve for resource without a greenhouse gas compliance obligation.

For a non-gas fired resource with a segment with a $20/MWh Incremental ~~-~~Cost, the DEB for that segment would be calculated as follows. Note – there is no conversion factor applied to the incremental cost since it is in $/MWj. In addition, the CAISO will add the O&M cost (say~~is~~ $2/MWh[6]) and the GMC adder (say ~~is~~ $0.50/MWh). Presume that this unit is not eligible for the FMU adder or Variable Energy Opportunity Cost adder on top of the fuel cost estimate.

{(ICC + O&M + GMC + [Unit Conversion Factor*IHR*Emission Rate[7]*GHG Cost] [Unit Conversion Factor*IHR*Emission Rate[8]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost adder (if eligible)

{($20 + $2.80 + $0.50) * 1.1} + $0 + $0

= $25.63/MWh

Example: Variable Default Energy Bid for Non Gas-Fired Resource with GHG Component

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's cost curve for a non-gas fired resource with a greenhouse gas compliance obligation.

For a non-gas fired resource with a segment of a $20/MW Incremental Cost, the DEB for that segment would be calculated as follows. Note – there is no conversion factor applied to the incremental cost since it is in $/MWh. In addition, the CAISO will add the O&M cost is $2/MWh[9] and the GMC adder is $0.50. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate provided the resource has registered it~~'~~s heat rate in the Masterfile.~~.~~ Assume resource has an incremental heat rate of 8000 mmBtu/kWh. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e. Presume that this unit is not

[6] Variable Operation & Maintenance

[7] Emission rate used is set by the GHG_EMISSION_RATE field in RDT.

[8] Emission rate used is set by the GHG_EMISSION_RATE field in RDT.

[9] Variable Operation & Maintenance

eligible for the FMU adder or Variable Energy Opportunity Cost adder on top of the fuel cost estimate.

{(ICC + O&M + GMC + [Unit Conversion Factor*IHR*Emission Rate[10]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost adder (if eligible)

{($20 + $2.80 + $0.50 + [8*0.053165*15.34]) * 1.1} + $0 + $0

= $32.80/MWh

Example: Variable Default Energy Bid for Non Gas-Fired Resource with GHG Component and a Binding Energy Use Limitation

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's cost curve for a non-gas fired resource with a greenhouse gas compliance obligation and also an eligible energy use limitation record in the ULPDT. See Attachment N for details on establishing the Variable Energy Opportunity Costs of the registered use limitation.

For a non-gas fired resource with a segment with a $20/MW Incremental Cost, the DEB for that segment would be calculated as follows. Note – there is no conversion factor applied to the incremental cost since it is in $/MW. In addition, the CAISO will add the O&M cost is $2/MWh[11] and the GMC adder is $0.50. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e~~.~~ provided the resource has registered it's heat rate in the Masterfile. Assume resource has an incremental heat rate of 8000 MMBtu/kWh. Presume that this unit is not eligible for the FMU adder on top of the fuel cost estimate. Based on applying the approach in Attachment N of the Market Instruments Business Practice Manual, the CAISO establishes a Variable Energy Opportunity Cost adder for the month of $25/MWh[12].

{(ICC + O&M + GMC + [Unit Conversion Factor*IHR*Emission Rate[13]*GHG Cost] (if eligible)) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost adder (if eligible)

{($20 + $2.80 + $0.50 + [8*0.053165*15.34]) * 1.1} + $0 + $25

[10] Emission rate used is set by the GHG_EMISSION_RATE field in RDT.

[11] Variable Operation & Maintenance

[12] Adder varies based on CAISO processes described in Attachment N of Market Instruments Business Practice Manual.

[13] Emission rate used is set by the GHG_EMISSION_RATE field in RDT.

= $57.80/MWh

~~Left-To-Right Adjustment~~

~~The Left-To-Right Adjustment applies to all Cost-Based DEB segments. The Left-To-Right Adjustment will start from the left-most DEB segment to ensure that price of a segment on the right is greater than the price of the segment on the left. The segment on the right that is not greater than the price of the segment on the left shall be merged to the price of the segment immediately on the left.~~

D.6 Negotiated Rate Option

The third method by which a DEB might be calculated is ~~simply entitled~~ the "Negotiated Rate Option". Under this option, the ~~independent entity~~CAISO would use documentation supplied by the ~~market participant~~Scheduling Coordinator and its discretion to determine the negotiated DEB. Non-RMR Units that are also non-gas fueled i.e. distillate fuel may also use this option instead of providing a cost curve. The ~~independent entity~~CAISO would supply the distillate price index and the generator would provide the Average Heat Rate.

New or modified use-limitations-based opportunity costs must be established pursuant to CAISO Tariff section 30.4 and the businesses processes set forth in the Business Practice Manual. Scheduling Coordinators may, however, submit documentation of non-use limitation based opportunity costs for potential inclusion in the negotiated default energy bid.

D. 6.1 Information Needed

In order to establish a Default Energy Bid for a Generating Unit based on the Negotiated Rate Option, the Scheduling Coordinator for the Generating Unit must provide the CAISO~~'s Market Monitoring Unit or an alternative independent entity selected by the CAISO~~ with the following information:

1. The proposed Default Energy Bid for the Generating Unit to be used under the Negotiated Rate Option.

2. The market and time periods for which the proposed bid would be applicable (DAM and RTM; peak and off-peak hours; start and end dates).

3. A descriptive explanation and justification of the basis or need for the proposed bid, including numerical calculations and supporting documentation including the Generating Unit's operating costs (e.g. fuel costs, operation and maintenance costs) and opportunity costs (if eligible).

~~4. The rank order of the three options for determining the Generating Unit's Default Energy Bid to be used if the proposed bid is accepted under the Negotiated Rate Option.~~

5. If applicable, any formulas, methodology or criteria proposed for modifying the bid to be used under the Negotiated Rate Option in response to potential changes in costs, operational or market conditions, or other relevant factors.

6. If applicable, the Scheduling Coordinator may propose two alternative bids: (a) a preferred bid reflecting the Scheduling Coordinator's preferred bid under the Negotiated Rate Option, and (b) a temporary bid that could be utilized on an expedited basis pending more detailed review, discussion and negotiation concerning the preferred bid for the Generating Unit.

D.6.2 Review of Information Submitted to the CAISO of Independent Entity

After receipt of a request to establish a bid under the Negotiated Rate Option, the CAISO~~'~~s ~~Market Monitoring Unit or an alternative independent entity selected by the CAISO~~ will review the information and provide a written response within ten (10) business days. The CAISO will assess bid levels or formulas proposed by Scheduling Coordinators on the basis of one or more of the following:

- Operating cost data~~, opportunity cost~~ and other appropriate input from the Market Participant;
- The CAISO's estimated costs of the Electric Facility, taking into account the best data available to the CAISO;
- An Appropriate average of competitive bids of one or more similar Electric Facilities

Additional information may be requested from the Scheduling Coordinator as necessary to assess the reasonableness of the proposed bid and other potential bid levels. To expedite this process, the Scheduling Coordinator shall make representatives available to explain and discuss the rationale and supporting documentation for the proposed bid with the CAISO~~ and any alternative independent entity selected by the CAISO~~. All information provided by a Scheduling Coordinator shall be subject to confidentiality provisions of the CAISO Tariff.

D.6.3 Effective Date of a Default Energy Bid Established by the Negotiated Rate Option

Any DEB submitted by a Scheduling Coordinator in accordance with these provisions shall become effective within three (3) business days after acceptance by the CAISO.

Any DEB proposed in writing by the CAISO to a Scheduling Coordinator shall become effective within three (3) business days after acceptance by the Scheduling Coordinator is received by the CAISO.

Any DEB agreed upon by the CAISO and a Scheduling Coordinator under the Negotiated Rate Option shall be filed at FERC within the first seven (7) days of the next calendar month. The DEB shall remain in effect unless:

1. The DEB is modified by FERC;

2. The DEB is modified by mutual agreement of the CAISO and a Scheduling Coordinator; or

3. The CAISO or Scheduling Coordinator provides written notification that the DEB is no longer acceptable for use under the Negotiated Rate Option. For example, if the DEB expires, is terminated, or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

D.6.4 Applicable DEB Pending Agreement Over Negotiated Rate Option

Pending any agreement between the Scheduling Coordinator and the CAISO with respect to a DEB to be used under the Negotiated Rate Option, the Generating Unit's Default Energy Bid shall be based on either:

1. The other DEB options provided in 39.7.1 (i.e., Cost-Based Option or LMP-Option); or

2. A temporary DEB established by the CAISO.

The second of these options – a temporary DEB established by the CAISO – would be applicable only in the event that the CAISO determines that market or operational conditions warrant establishing a temporary DEB (or modifying a DEB) pending any agreement or resolution of a DEB proposed by the SC under the Negotiated Rate Option. For example, this option may be necessary in the event of a sudden increase in operating costs or other conditions that may warrant immediate use of a special DEB level to avoid potential disruptions of supply critical for system local reliability. The CAISO may also need to establish a DEB under this option in the event that sufficient data are not available to calculate a DEB under any of the other options for establishing a DEB under the CAISO tariff.

Any modified DEB established by the CAISO would be based on the same criteria the CAISO would use to assess bid levels or formulas proposed by Scheduling Coordinators:

1. Operating cost data~~, opportunity cost~~ and other appropriate input from the Market Participant

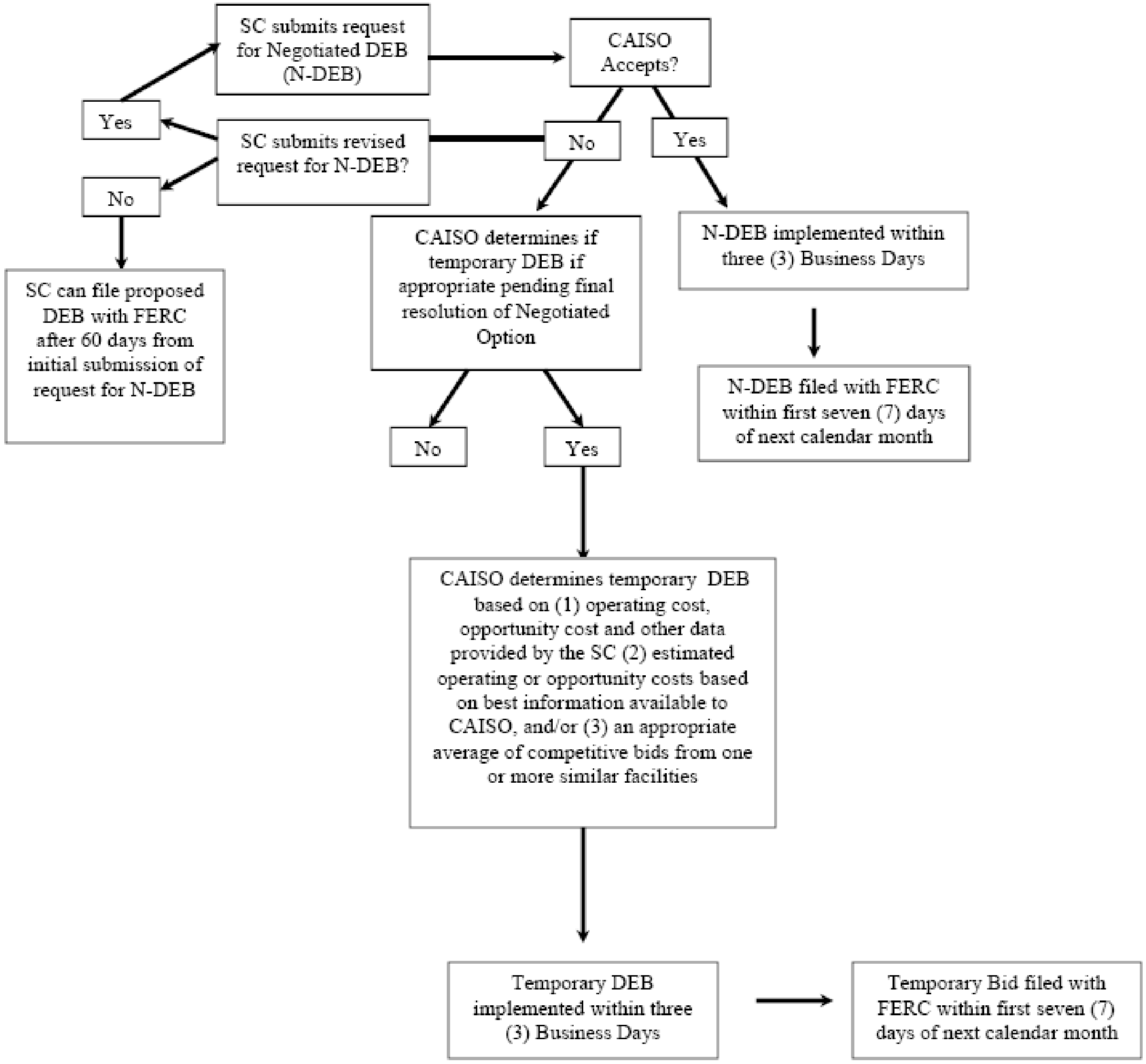
2. The CAISO's estimated costs of the Electric Facility, taking into account the best data available to the CAISO

3. An appropriate average of competitive bids of one or more similar Electric Facilities

D.6.5 Dispute Resolution

If a Scheduling Coordinator and the CAISO cannot reach mutual agreement on a bid to be used under the Negotiated Rate Option, the Scheduling Coordinator may file at FERC pursuant to Section 205 of the Federal Power Act for approval of a rate to be used under the Negotiated Rate Option after 60 days from the commencement of initial negotiations on the proposed DEB. Figure 1 provides a decision tree depicting this process, starting from the point at which a Participant submits a request for approval of DEB under the Negotiated Rate Option through the point at which a DEB is either agreed upon or filed at FERC due to an inability to reach agreement.

Figure 1. Decision Tree on Negotiated DEB Option (N-DEB)



D.6.6 Possible scenarios leading to renegotiation of a DEB under Negotiated rate option

All default energy bids (DEB) approved under the Negotiated Bid option are only applicable to the specific resource or configuration (if the resource is a multi-stage generator) that is active in the Master File and an associated scheduling coordinator (SC) who negotiated the bid with the CAISO. CAISO may require the renegotiation if the negotiated values have become outdated, possibly erroneous, or for which the Scheduling Coordinator has changed under Section 39.7.1.3.2.1. A negotiated default energy bid will be reviewed and potentially renegotiated or terminated under the following circumstances:

1. *Change in S~~s~~cheduling C~~c~~oordinator*
    a. resource switches from the scheduling coordinator which negotiated the default energy bid to another scheduling coordinator
    b. resource is acquired by a different scheduling coordinator through a merger or acquisition but they keep the same scheduling coordinator identifier in the Master File

2. *Change in resource attributes/status*
    a. resource changes ID/name in the Master File
    b. resource switches to a multi-stage generator from a non-multi-stage generator or resource switches from a multi-stage generator to a non-multi-stage generator
    c. resource switches fuel
    d. resource air permit restriction changes
    e. resource or a configuration within a multi-stage generator retires

3. *Change in negotiated elements*
    a. conditions underlying resources' negotiated default energy bids are no longer applicable or accurate
    b. vendor data is no longer available to use for a negotiated element in the negotiated default energy bid calculation
    c. change/expiry of the tariff rates/fees/taxes/adders included in the negotiated default energy bid calculation

4. *Change in any other material item which might affect the default energy bids approved under the negotiated rate option.*

It is the responsibility of the scheduling coordinator to ensure that the conditions and data underlying any default energy bid created under the Negotiated Rate Option for a resource accurately reflect current conditions and to notify the CAISO of any changes that may affect their negotiated default energy bid. To the extent that any default energy bid created under the Negotiated Option for the resource or multi-stage generator configurations require modification or reinstatement after termination, they will be reestablished under the process for creating negotiated default energy bids. To the extent that a negotiated default energy bid is terminated, the default energy bid for the resource and any configurations will be based on the next ranked option identified in the Master File until a new negotiated default energy bid is established.

D.6.6 NDEBS that include ~~Eligibility to include use-limited~~ opportunity costs as of April 1, 2019

Scheduling Coordinators with NDEBs that include a previously negotiated opportunity cost in effect prior to April 1, 2019, may continue with existing NDEBs subject to the SCs or the CAISO's right to renegotiated the NDEBs per Tariff section 39.7.1.3. If a Scheduling Coordinator pursues an opportunity cost under section 30.4 of the CAISO tariff, the CAISO will initiate renegotiation of the NDEBs. A~~n~~ Scheduling Coordinator cannot have opportunity costs calculated pursuant to section 30.4 and a previously negotiated opportunity cost reflected in the NDEB in effect at the same time.

Resources under negotiated rate option for the default energy bid filed prior to April 1, 2019 are not eligible for Start-Up Opportunity Costs, Minimum Load Opportunity Costs, or Variable Energy Opportunity Costs pursuant to Section 30. If a Scheduling Coordinator wants to modify a Negotiated Default Energy Bid on file prior to April 1, 2019, the Scheduling Coordinator can elect to modify or terminate the Negotiated Default Energy Bid and to leverage the Opportunity Cost procedures for calculating or negotiating Variable Energy Opportunity Costs pursuant to Section 30.4.1.1.6.1.2.

Negotiated Default Energy Bids filed after April 1, 2019 must request to register use limitations under the use limitation registration process. If Scheduling Coordinator successfully registers use limitations, the ISO will establish calculated or negotiated Opportunity Cost adder(s) pursuant to Section 30.4.1.1.6.1.2 in the resource's Proxy Costs and/or Negotiated Default Energy Bid filed at FERC. If the CAISO rejects the request to register use limitations but the Scheduling Coordinator believes it has costs related to managing an operational limitation, the Scheduling Coordinator can request a Negotiated Default Energy Bid after receiving the notification from the CAISO that the use limitation registration was rejected. Details on the use limitation registration are discussed in Section 2.1.15 of the Market Operations Business Practice Manual.

D.7 RMR Units

An RMR unit will have its Bids mitigated to the RMR Proxy Bids which are determined by the ~~independent entity~~ the CAISO for each RMR resource using specific RMR contract values that have been filed with FERC. RMR contractual capacity is the capacity between a units Minimum Generating Capacity (PMin) and their Maximum Net Dependable Capacity (MNDC). The value of MNDC may be less than the Maximum Generation Capacity (PMax) of the unit.

The Bids utilized in the MPM process for RMR Units will be the RMR Proxy Bids for the RMR contractual capacity. RMR units are not eligible to receive the 10% adder for their RMR contract capacity. For available capacity in excess of the MNDC the Scheduling Coordinator representing the RMR unit must rank order their calculation preference between the same three methodologies, namely LMP Option, Variable Cost Option and Negotiated Rate Option. This preference will then apply to the non-RMR capacity between the MNDC and the PMax of the unit. The independent entity will concatenate these two calculation methodologies (RMR Proxy Bids for the RMR capacity and preference based for the non-RMR capacity), adjust them for monotonicity and submit them to CAISO as a single Bid curve to be used in the MPM process.

Minimum Load and Startup Cost bid curves for RMR Units also utilize RMR Contract data and are also determined by the independent entity.